OCS Study
BOEM 2019-023

Gulf of Mexico Decommissioning Trends and Operating Cost Estimation

US Department of the Interior
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Table of Contents

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

The U.S. Gulf of Mexico (GoM) plays an important role in oil and gas production in the United States. In 2017, the GoM produced 604 million barrels of oil and 1.17 trillion cubic feet of natural gas, about 10% of domestic oil and gas production, and generating around $34 billion in revenues for oil and gas companies.

The industry deploys capital in drilling, development and production which support vast local, regional and international equipment and supply networks, construction yards, and service providers. Worldwide, about one-third of global oil production and a quarter of gas production was produced offshore circa 2017. Although expensive to drill, develop and operate offshore, the potential for large conventional deposits and high flow rates makes offshore plays an important part of many companies investment strategies.

Industry has an impressive track record of advancing its capabilities. In 1949, for example, the original Bay Marchand well was located in water depth less than 50 ft (15 m) and produced 290 barrels of oil per day. Today, backed by numerous innovations, a well at Chevron's Jack/St Malo in approximately 7000 ft (2134 m) water depth produces about 17,000 barrels of oil per day. The deepest structure in the GoM circa 2017 is Shell's Stones FPSO in 9560 ft (2915 m) water depth.

In this report, shallow water refers to water depth less than 400 ft (122 m) and deepwater to water depth greater than 400 ft (122 m), but there is nothing special about this selection and 300 ft (91 m), 600 ft (183 m) or 1000 ft (305 m) cut-offs could also be used without significantly changing the trends or inventory data of the study. Both the shallow water and deepwater regions have played an important role in the development of the industry but their future prospects are quite different. As shallow water prospectivity declines and deepwater continues to produce at record levels, differences between the regions will become ever more pronounced.

The shallow water GoM has witnessed significant changes over the past decade and will continue to be subject to significant changes in the future. The late 1970s and early 1980s was a time of numerous discoveries and intense development activity, but starting in the mid-1990s commercial discoveries on the shelf became less prolific and in recent decades exploration has been dramatically curtailed. Shelf production is not being replenished by drilling and many industry observers believe the region is 'fished out', that is, no longer prospective for future discoveries.

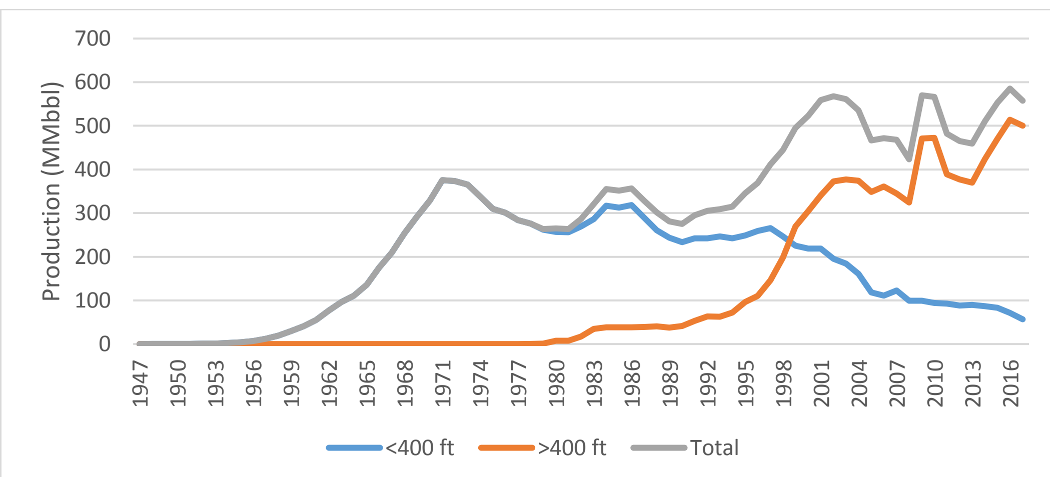


Figure 1. Oil production in the shallow water and deepwater Gulf of Mexico

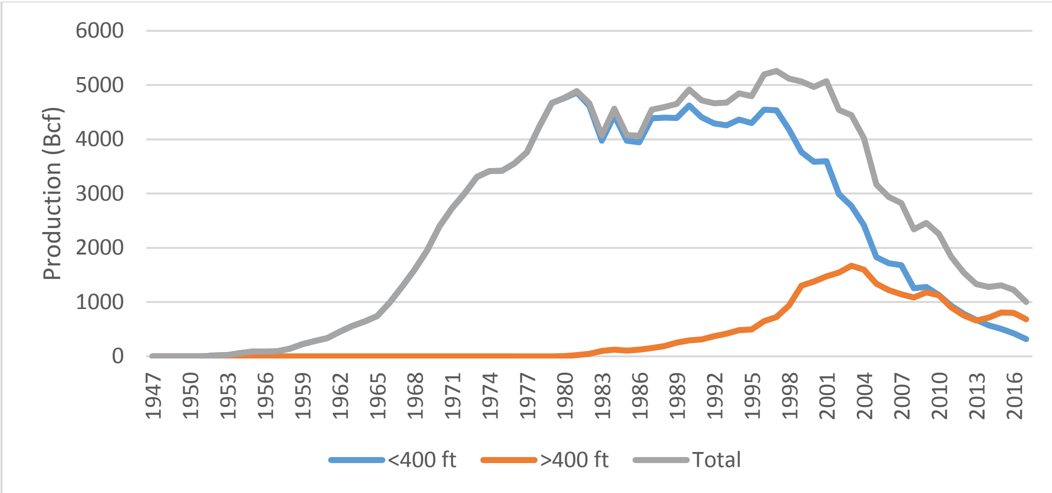


Figure 2. Gas production in the shallow water and deepwater Gulf of Mexico

Both oil (Figure 1) and gas (Figure 2) production on the shelf has been in decline for over two decades. Dwindling commercial prospects, sustained low oil and gas prices, smaller operators with smaller budgets, and the success of onshore shale development means that drilling and installation activity in shallow water has been dramatically reduced in recent years.

Fortunately, the deepwater GoM is also a highly prolific hydrocarbon basin, and as shelf production has declined industry activity has moved southward into deeper water, and is now near the U.S.-Mexico border. With participation of all the majors and several independents oil production continues to increase Gulf-wide. Deepwater wells are expensive to drill and complete and deepwater reservoirs are increasingly complex to develop, but the continued discovery of large deposits have kept operator interest high.

As with many large scale development activities on public lands, offshore exploration and development requires environmental impact statements to be performed. The environmental impacts of leasing, development and production are evaluated as part of the Bureau of Ocean Energy Management (BOEM's) compliance with the National Environmental Policy Act which requires federal agencies to study the environmental impacts of their decision-making. One source of environmental impacts is the construction, production and decommissioning of offshore infrastructure, and to perform these studies it is necessary to forecast how structure inventories are expected to change with changes in leasing programs and business conditions.

BOEM geologist and engineers evaluate GoM resources and economist and social scientist forecast drilling, construction, and decommissioning activity arising from future GoM lease sales, including the number of exploratory and development wells expected to be drilled, the number of fixed and floating structures expected to be installed and decommissioned, and pipeline activity each year associated with future lease sales. As part of these studies, detailed forecasts are sometimes desired for fast changing or highly uncertain activities where information gaps exist. The primary purpose of this report is to synthesize and develop information on GoM infrastructure inventories and trends and to construct forecast models for structure decommissioning and active inventories in both the shallow and deepwater regions.

The second objective of this study is to quantify operating costs in the region and to provide a framework for a critical examination by bringing together its many disparate branches. It is well known that offshore operations are expensive, but how expensive and how and why costs change over time are more elusive. Manned platforms need to be self-sufficient in terms of their utility requirements and crew has to be transported via helicopter or crew boat and all materials have to be supplied via marine vessels. There are space and weight limitations associated with working in a confined area and added risks associated with weather and operations in the open ocean. When wells need to be serviced and equipment replaced, there are significant costs involved with the vessels and crew required to perform the operation. In remote and harsh environments costs increase further.

When oil and gas prices are high, operators focus on drilling and development to bring on production and not much attention is paid to operating expense, but when oil and gas prices fall and remain low for a period of time, company focus shifts to operations and efforts to reduce operating expenditures to stay profitable. Unlike the capital expenditures required to drill a well, build a platform, equip facilities, construct and install pipeline, operating cost is much less transparent with no readily available and reliable data sources. The data that is available comes in different forms and quality and varies widely across field applications. Inferences are required and site-specific attributes need to be accounted for, most of which are not observable and can only be extrapolated with a high degree of uncertainty.

Companies maintain detailed production cost for their properties, of course, but this information is not shared or reported unless required by regulation. Thus, the amount and quality of operating cost information available for analysis is tightly constrained and misconceptions frequently arise, both in the data and in the limitations of models built from the data. As a corollary, it is fair to say that many companies do not understand the value of their operating cost data nor the manner in which it can be utilized to improve operations because of its opaque connection with accounting and the difficulty to organize and interpret the information in a useful manner.

This report is organized in five parts. In Part 1, GoM production and activity statistics are reviewed circa 2017, structure classifications and economic limit factors are discussed, and reserves and resource estimates are summarized. In Part 2, well trends and structure inventories in the shallow and deepwater GoM are examined and economic limit statistics are computed in each region. In Part 3, the methodology for structure decommissioning forecasts are presented and model results described in the shallow and deepwater. In Part 4, two chapters review critical infrastructure issues, platform hubs and pipeline networks, along with the benefits, costs, and risk of maintaining idle infrastructure. In Part 5, the report concludes with a detailed review of GoM operating cost data, factor models, and activity based costing.

Outline

Part 1. Overview

Chapter 1. Production & Active Inventories

Chapter 2. Structure Classification

Chapter 3. Installation & Decommissioning Activity

Chapter 4. Economic Limit Factors

Chapter 5. Reserves & Resources

Part 2. Well Trends & Structure Inventory

Chapter 6. Well Trends

Chapter 7. Shallow Water Structure Inventory

Chapter 8. Shallow Water Economic Limit Statistics

Chapter 9. Deepwater Structure Inventory

Chapter 10. Deepwater Economic Limit Statistics

Part 3. Decommissioning Forecast

Chapter 11. Methodology & Parameterization

Chapter 12. Two Examples

Chapter 13. Shallow Water Decommissioning Forecast

Chapter 14. Deepwater Decommissioning Forecast

Part 4. Critical Infrastructure Issues

Chapter 15. Tiers, Hubs & Pipeline Networks

Chapter 16. Costs, Benefits & Risk

Part 5. Operating Cost Review

Chapter 17. Offshore Production Facilities

Chapter 18. Operating Cost Characteristics

Chapter 19. Financial Statements & Other Methods

Chapter 20. Field Examples

Chapter 21. Factor Models & Production Handling Agreements

Chapter 22. Activity-Based Costing

In Part 1, background information on GoM production and activity statistics, economic limit factors, and reserves and resource estimates are presented. In Chapter 1, oil and gas production and active inventory trends circa 2017 broken out by water depth region and production classes are introduced.

Chapter 2 describes structure classifications and describes what water depth thresholds are used by different disciplines. Structure type categories are based on the form of the jacket and hull and the manner the structure is fixed to the seabed. Production status describes whether the structure is producing, idle (formerly producing) or auxiliary (never or no longer producing). Manning status, number of wells, complex association and the distinction between major and minor structures are also discussed.

In Chapter 3, installation and decommissioning activity is summarized for the shallow and deepwater Gulf of Mexico through 2017. There has been a dramatic decline in the number of shallow water structures installed in recent years and record levels of decommissioning due in large part to the maturity of the region, aging infrastructure, lack of prospects and low oil and gas prices (Figure 3). It is no longer possible for operators to continue 'kicking the decommissioning can' down the road. The number of shallow water structures peaked in 2001 at nearly 4000, while and circa 2017 the number of standing structures on the shelf is less than one half at 1908 and in steady decline (Figure 4).

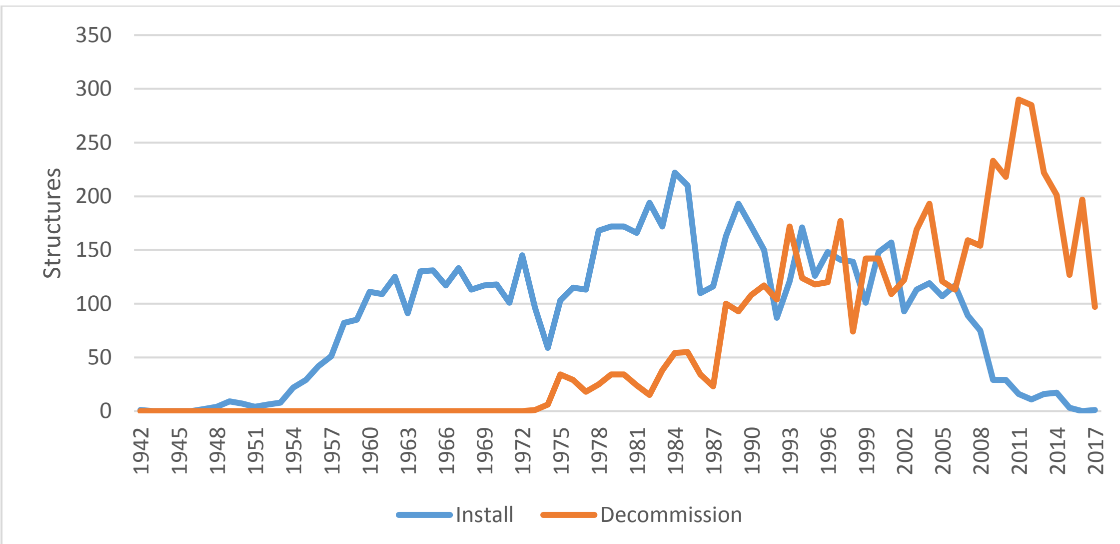


Figure 3. Structures installed and decommissioned in the shallow water Gulf of Mexico

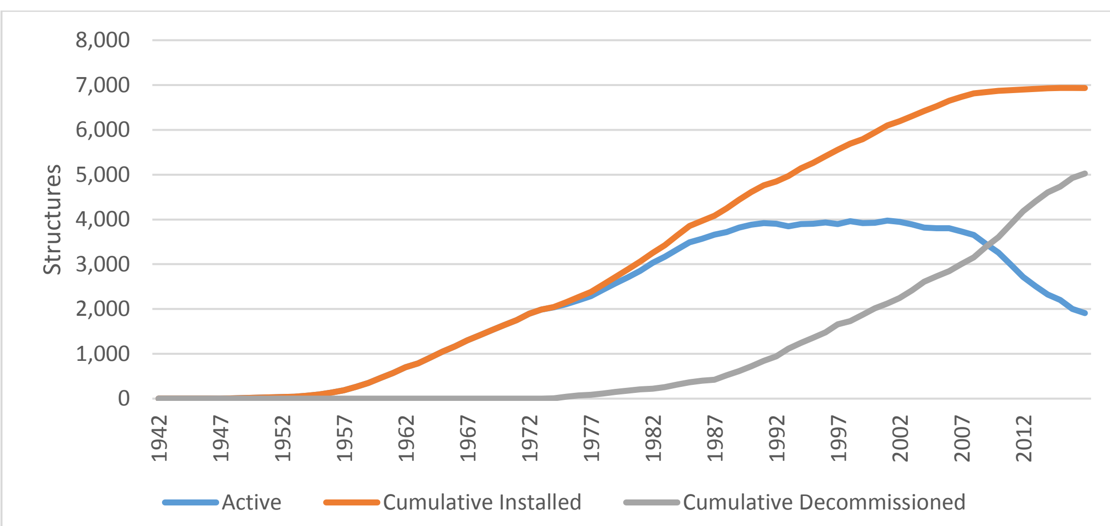


Figure 4. Active shallow water structure inventory in the Gulf of Mexico

In deepwater, the number of active structures has held steady at about 100 for the past decade, with fixed platforms declining at about the same rate as new floaters are being installed (Figure 5).

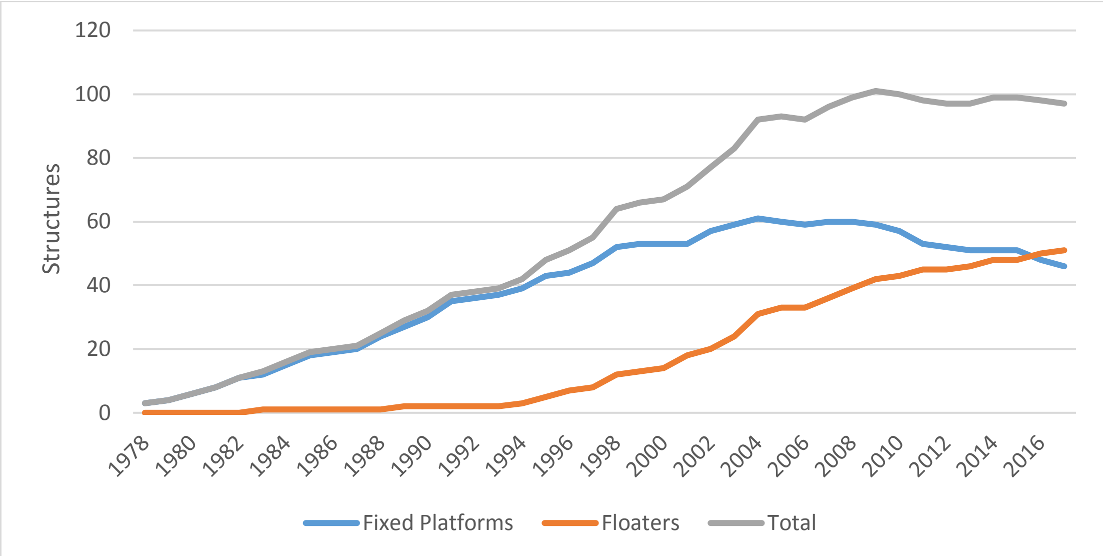


Figure 5. Active deepwater structure inventory in the Gulf of Mexico

In Chapter 4, the operating cost characteristics of offshore production and some of the factors that impact economic limits are described. When the net revenue from production falls below operating cost for a sustained period of time there is no economic benefit derived and operators will eventually shut-in wells and idle structures. Economic limits are not publicly reported or directly observable but can be proxied using structure revenue the last year of production.

Reserves and resource assessments underlie all investment decisions made by oil and gas companies and a clear understanding of aggregation units and some familiarity with geologic processes are useful in evaluation. A mini-case study of the Eugene Island 330 field, the second largest oil and gas field in the GoM, is described along with a high-level overview of GoM geology and deepwater exploration plays. Much of the remaining undiscovered resources in the deepwater GoM are believed to be Paleogene, and these developments will have low recovery rates and technical challenges which may constrain future activity if economic and technical solutions cannot be found.

In Part 2, GoM well trends and structure inventories are examined. Although the focus of this report is mostly at the structure level, wells are the most basic evaluation unit and provide additional insight into activity trends in each region. In Chapter 6, trends in exploration and development drilling, well abandonments, producing and idle wells, and subsea drilling are highlighted.

In Chapter 7, the primary features of producing, idle and auxiliary structure classes in shallow water circa 2017 are examined. For producing structures, production, cumulative production and revenue are the most important features. For idle structures, idle age, idle age at decommissioning and well status are the main characteristics. For auxiliary structures, manning status and complex association are the most useful descriptors.

In Chapter 8, the economic limits of shallow water structures are quantified to gain insight into production cost near the end of production and the business practices of operators. Decommissioned structures are treated as a statistical ensemble and subclasses of structures are empirically evaluated. Summary statistics for 3054 decommissioned shallow water structures are tabulated by primary production, structure type, manned status and water depth. The P50 adjusted gross revenue the last year of production is $1.2 million for gas structures and $630,000 for oil structures. A cost allocation example is used to help explain why/how operating cost for some structures can be so small and remain profitable. Factor models are used to distinguish the impact of structure and operator attributes on economic limits.

In Chapter 9, deepwater structures are organized into three groups: fixed platforms in water depth 400-500 ft, fixed platforms and compliant towers in water depth >500 ft, and floater inventories. Floater equipment capacity and capacity-to-reserves ratios are computed, followed by summary statistics for production, reserves, PV-10 and gross revenue for each class. Gross revenue statistics are broken out by individual structure in the second half of the chapter.

In Chapter 10, the economic limits of deepwater decommissioned structures and subsea wells are summarized. Twenty-three deepwater structures have been decommissioned through 2017, and since 2000 about 150 subsea wells have been permanently abandoned. Abandoned subsea wells provide a means to test hypothesis on differences between oil and gas wells and the impact of tieback distances and altitude variations on economic limits.

In Part 3, the methodology and model results for the two regional decommissioning forecasts are described. In Chapter 11, forecast models and schedule methodologies are presented for the producing, idle and auxiliary structure classes. Different models are required for the different types of structures and implementations are specific to each water depth region. For producing structures, decommissioning forecasts apply economic models based on decline curves and cash flow analysis, but for structures that are not currently producing or have never produced, alternative methods are needed. A user-defined methodology is adopted to schedule idle structure decommissioning and statistical methods are applied for auxiliary structures.

In Chapter 12, two examples illustrate the decommissioning forecast methodology for producing structures. Chevron's Tick platform in 720 ft water depth was evaluated circa 2012 and Anadarko's Horn Mountain spar in 5400 ft water depth is evaluated circa 2016. Decommissioning timing and reserves estimates under oil and gas price variation illustrate model sensitivity.

In Chapter 13, exponential and hyperbolic decline curves are used to bound the decommissioning time for each individual producing structure, schedule approaches are adopted for idle structures, and historic activity trends are employed for auxiliary structures. Transition probabilities are used to capture the structure transitions between classes. The three submodule results are combined in a composite forecast and sensitivity analysis is performed. From 2017-2022, between 474-828 structures are expected to be decommissioned in the shallow water GoM, and by 2027, between 704-1199 structures are expected to be decommissioned.

Historically, deepwater installation and decommissioning activity in the GoM has always been small with activity levels that can be counted on one hand most years and two hands in high activity periods. High capital expenditures, reserves thresholds and long time periods required in planning and execution constrain investment and the number of structure installations, and in the case of decommissioning, operators seek to maintain facilities for as long as possible because of their value in regional development. These trends are not expected to change for the foreseeable future.

In Chapter 14, between 27 to 51 deepwater structures are expected to be decommissioned through 2031, and between 12 to 25 structure removals are expected from 2017-2022.

In Part 4, a review of critical infrastructure issues brings together many of the main points of our previous discussion and introduce a few new concepts. In Chapter 15, critical infrastructure is defined and three classes of hub platform are identified. In Chapter 16, the potential benefits, costs and risks associated with maintaining infrastructure beyond their useful life are described. The role of government regulations in incentivizing operators and managing activity are also briefly discussed.

The objective of Part 5 is to understand the various components that enter operating cost and how they change with the changing needs of the reservoir, and why operating cost is different between properties and during different stages of their life cycle. Numerous examples are provided with worked-out details to develop analytic skills and intuition regarding cost estimation. Six chapters cover offshore production facilities (Chapter 17), operating cost characteristics (Chapter 18), public disclosure requirements and other methods (Chapter 19), field examples (Chapter 20), factor models and Production Handling Agreements (Chapter 21), and activity-based cost models (Chapter 22).

In Chapter 17, a brief description of the equipment and processes that comprise an offshore production facility are introduced since these are the facilities that require labor to operate and consume the chemicals and services that constitute production cost. Production processes are for the most part easy-to-understand, consisting mostly of phase separation using temperature and pressure changes that only require tanks and vessels to perform. Simplified block diagrams are used in the description.

Chapter 18 begins with a review of cost categories, rules-of-thumb and a comparison between oil and gas and mining operations to illustrate operating cost ranges and differences that arise between extraction industries. This material, although elementary, is included to ensure basic definitions and concepts are not neglected. The chapter concludes with a general description of operating cost factors that expands upon the discussion started in Chapter 4.

Chapter 19 summarizes the disclosure requirements of public companies and describes survey, software and computer methods used in operating cost estimation. Operating cost for ten public oil and gas companies with the majority of their production and reserves in the GoM are examined over a ten year period. A review of production and lifting cost metrics and the strengths and weaknesses of lease operating statements, survey, and computer methods are outlined. The UK North Sea operating cost survey is the best publicly available data on offshore oil and gas production cost in the world and main results are highlighted.

According to U.S. SEC regulations, if a field comprises more than 15% of an operator's total reserves in a given year, then field data must be broken out separately and reported in financial statements. In Chapter 20, GoM fields reporting operating cost between 2010-2016 are presented. The sample is small but informative of operating cost ranges in the region.

In Chapter 21, factor models and Production Handling Agreements are described. Factor models are popular in cost modeling because they are easy to implement in spreadsheets and allow for versatile and efficient implementation. Unfortunately, their reliability is often poor and rarely is any attempt made to validate and/or calibrate models with empirical data. Factor models for lease operating cost, workovers and gathering and transportation services are illustrated and their limitations described. Production Handling Agreements are common in the deepwater GoM and govern the relationship between the owner of a production handling system and third-party producers who wish to use the facility for operations. Three examples illustrate how contract terms are negotiated between parties and the manner in which risk enters agreements.

In Chapter 22, activity-based cost models for each of the main operating cost categories concludes the review and report. Activity-based cost models provide a more accurate and auditable assessment of cost and a detailed view of operations provided they are performed by experienced personnel with an understanding of their limitations. Activity-based cost models require a different set of assumptions and expertise than the previous models discussed and relies heavily on understanding the nature of commercial contracts, operational requirements and regional markets.

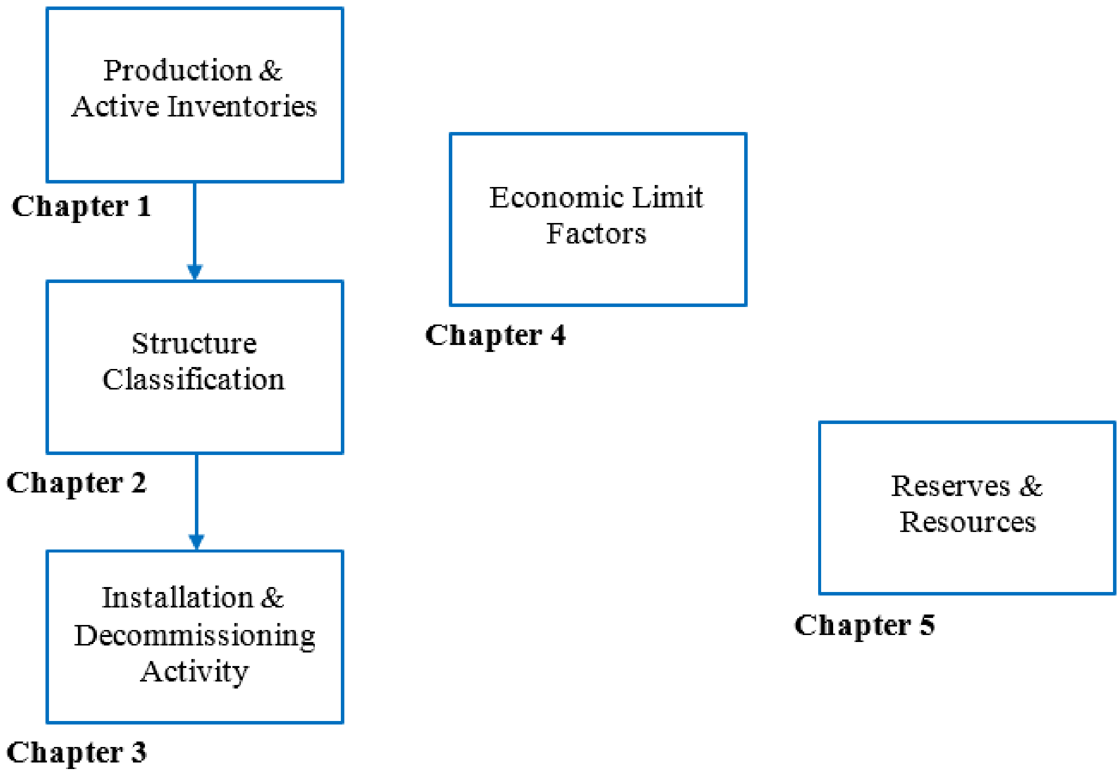
DATA SOURCE

This report deals primarily with data and statistics which are generally (but not always) straightforward to understand with minimal levels of reporting uncertainty. That is, the data represents factual information that is relatively easy to interpret assuming the data is processed properly and definitions and relationships are clearly understood. If confusion arises it can usually be traced to incomplete information or misunderstanding operational issues, or both, or the exclusion of factors that may be relevant that the reader or authors are unaware. In some cases, there may be problems with the data itself and issues may arise in interpretation or unusual situations, but these are usually exceptional (one-off) issues and are remediated with additional work.

Operators report production, installation and removal activity, drilling and wellbore abandonments in the Outer Continental Shelf of the United States electronically to the BOEM within a certain period of time after custody transfer of production and completion of operations. After review and quality control, which may take anywhere between three to six months, the BOEM uploads the data to the Technical Information Management System database.

Wellbore data was assembled from the BOEM Borehole database. Structures were identified using the BOEM Platform Masters and Platform Structures databases. Data for the installation and decommissioning trends (Part 1) and field data (Parts 1, 4) were evaluated from February-April 2018. Data for the structure inventory and decommissioning forecast models (Parts 2, 3) was evaluated from March-July 2017 and updated selectively. Data from company financial statements (Part 5) was examined in 2016. The forecast models in Part 3 use data through 2016 in evaluation, and although it would be preferable to use data through 2017-2018, it will not make a material difference to the model outputs.

PART 1. OVERVIEW



CHAPTER 1. PRODUCTION & ACTIVE INVENTORIES

Oil and gas production and active inventory trends in the shallow water and deepwater GoM are described and structure terminology is introduced. The shallow water GoM has witnessed significant changes over the past decade and will continue to be subject to significant changes in the future. Shelf production is not being replenished by drilling and most industry observers believe the shelf is fished out. Fortunately, the deepwater GoM is a highly prolific hydrocarbon basin and oil production continues to increase Gulf-wide. Differences between the shallow and deepwater regions and future prospects are highlighted.

1.1. THE SETTING

The federal waters of the GoM are administered by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) and are described in terms of three administrative areas, referred to as the Western, Central and Eastern planning areas.

1.1.1. Gulf of Mexico

The Gulf of Mexico is an ocean basin bounded on the northeast, north and northwest by the Gulf Coast of the United States, on the southwest and south by Mexico, and on the southeast by Cuba (Figure A.1). The Gulf of Mexico basin formed approximately 200 to 160 million years ago and is approximately 930 miles (1500 km) wide with a surface area of 615,000 square miles (1.6 million km^2).

The deepest portion of the GoM is the Sigsbee[1] Abyssal Plain, which lies in the western portion and is extremely flat and almost level at a depth of 3700 m (12,000 ft). Seismic refraction and reflection measurements has revealed that the sedimentary layers continue to about 7 km (4.3 mi) beneath the sea floor (Ewing et al. 1960).

There are two large carbonate platforms at the entrance of the Gulf, the Yucatan Peninsula/Campeche Bank on the west and the Florida Platform on the east, both supporting wide and shallow submerged shelves. The indentation in the Northeast section south of Mobile, Alabama is called the De Soto Canyon, and another feature is the Mississippi Canyon that formed at the base south of the river's exit into the Gulf. The area of the continental shelves within the GoM is approximately 200,000 square miles (517,998 km^2).

1.1.2. Shelf vs. Slope

The continental shelf is a broad, relatively shallow submarine terrace of continental crust forming the edge of a continental landmass. Almost everywhere the shelves represent a continuation of the continental landmass beneath the ocean margin. The continental shelf extends outward to the continental slope and rise where the deep ocean begins and leading to the abyssal plain (Figure A.2). The width of the continental shelf around the U.S. varies considerably, from approximately 12 to 250 miles (19 to 400 km), depending on location (BOEM 2017).

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[1] Charles Dwight Sigsbee was the commanding officer of the steamer *George S. Blake* which discovered the feature in 1873-1875 during mapping of the basin (Wikipedia).

The continental shelf in the GoM has a gentle seaward slope of less than 1° over most of its extent with an average gradient of about 1 in 500 and outer limits ranging from 600 to 1000 ft water depth. The area of the continental shelves within the GoM is approximately 200,000 square miles (517,998 km^2). The continental slope has a gradient that increases to about 1 in 20 and extends up to 9000 ft (2743 m) water depth (Garrison and Ellis 2017).

The surface of the shelf is generally smooth with low relief irregularities resulting from the presence of relict Pleistocene stream and shoreline deposits, fault scarps formed by active growth faults, and mounds produced by active salt and shale diapirism. Seafloor topography on the slope and rise are complex and include areas of possible landsliding and faulting, mud seeps, undulations and rocky outcrops. Irregular rocky seafloor with sharp relief of tens of feet, fault scarps of 100-300 ft high, and areas of possible landslide contribute to the difficult conditions on the slope. Rugged topography suggests failures in the geologically recent past on the flank of the domes.

1.1.3 Shallow Water vs. Deepwater

Shallow water and deepwater are relative terms, of course, and the most common thresholds used to distinguish deepwater include 400 ft (122 m), 600 ft (183 m), 200 m (660 ft), 300 m (1000 ft), 400 m (1310 ft), 1500 ft (457 m) and 600 m (1968 ft). Today, the shelf is synonymous with shallow water and the slope and beyond with deepwater (Figure A.3), but this was not always the case. Griff Lee's (1980) definition of deepwater is "that depth just beyond the deepest existing platform … gradually increasing with age and the progress of the offshore industry." Different water depth thresholds are used for different reasons and reflect oceanographic and biological processes, geologic conditions, jurisdictional issues, structure design considerations, etc.

For the purpose of this report, shallow water is assumed to correspond to water depths less than or equal to 400 ft (122 m) and deepwater to water depths greater than 400 ft (122 m). Other selections are possible, of course, but this choice is based on an historical event, the nature of structure data, and the purpose of the report.

In 1978, Shell installed its Bourbon platform in 423 ft water depth and Cognac in 1023 ft water depth, but Cognac got all the attention for breaking the 1000 ft threshold and the Bourbon platform which first broke 400 feet was forgotten. The region between 400-1000 ft water depth is not especially productive and only 50 or so platforms have been installed, but rather than group these structures with the much larger number of shelf platforms numbering in the thousands we prefer to break them out separately and consider them as part of the deepwater grouping to better understand their characteristics. In recent years, a new category ultra-deepwater has been used to refer variously to water depth >5000 ft (1520 m), >2000 m (6550 ft), or >10,000 ft.

1.1.4. Sigsbee Escarpment

The Sigsbee Escarpment is a major geomorphological feature of the GoM seafloor, basically an underwater mountain about 2000 ft (610 m) in height at its tallest, and extending for several hundred miles across the Central and Eastern GoM (Figure A.4). The escarpment and associated canyons were caused by deformation of underlying salt deposits and erosion during periods of low sea level in the geologic past. As the salt deforms, it creates faulting, scarps, and other potential geohazards which need to be understood and quantified to determine if development in the area is of acceptable risk. Below the slope break, the escarpment dips at steep angles (5-25°), and near the base of the escarpment, major slump activity is observed out to several miles, clear evidence of numerous past failures that would have devastating consequences for any infrastructure in the debris flow.

1.1.4 Protraction Areas

Planning areas are subdivided in named protraction areas, and each protraction area is divided into 3 mi × 3 mi (5760 acres or 23 sq. km) lease blocks, unless clipped by an existing marine boundary or edge of a planning area. The large mostly rectangular interior deepwater protraction areas such as Green Canyon and Walker Ridge are defined as 2° East-West by 1° North-South, or about 120 mi by 60 mi in areal extent.

1.2. Production

Since 1947, the Outer Continental Shelf of the GoM has produced about 20.7 billion barrels (Bbbl) of oil and 187 trillion cubic feet (Tcf) of natural gas. The hydrocarbon liquids from a gas well are referred to as condensate and are added to oil production when reporting total liquid hydrocarbons, while the natural gas from an oil well is referred to as associated gas and combined with the gas well gas from gas wells.

More than half of total oil production (12.2 Bbbl) and about 80% of the Gulf's natural gas production (160 Tcf) have been produced in water depths less than 400 ft which has been in decline since the mid-1990s (Figures A.5, A.6). In water depths greater than 400 ft, oil production continues to increase, marked by significant fluctuations due to hurricane activity and the Macondo oil spill. To date, the deepwater GoM is largely an 'oily' province, and gas production has not been enough to outpace the shallow water decline.

In 2017, the GoM produced about 604 million barrels (MMbbl) of oil and 1 Tcf of natural gas, about 10% of domestic oil and gas production, generating around $34 billion in gross revenues. About 57 MMbbl oil and 318 Bcf natural gas was produced in water depth less than 400 ft, representing about 13% of the total offshore oil production and one-third of the total offshore gas production in the Gulf.

Most majors and large independents no longer operate in the shallow water GoM and left the region long ago, although in many cases they discovered and operated the fields for many years. Other smaller operators have entered the shelf by acquiring assets and/or entire companies but because of the smaller capital reserves of these companies, there has been concern that operators will be unable to pay for their decommissioning obligations prompting changes in financial requirements and bonding levels in recent years (Federal Register 2014).

The deepwater GoM produced 87% of the oil and condensate production in the Gulf and about two-thirds of the natural gas production in 2017. GoM oil production is near its all-time peak and is expected to stay flat or increase incrementally in the future, while GoM gas production has fallen steeply and is expected to continue to decline.

1.3. Active Inventory

A total of 7053 structures have been installed in the GoM and 5048 structures have been decommissioned through 2017, leaving an active (or 'standing') inventory of 7053 − 5048 = 2005 structures circa 2017.

The vast majority of GoM structures reside in water depth less than 400 ft, and circa 2017 there were 1909 shallow water structures and 97 deepwater structures (Table A.1). Almost all installation and removal activity is in shallow water.

About 70% of shallow water structures reside in water depth <150 ft (46 m) and over two-thirds of all structures reside in <100 ft (31 m) water depth (Table A.2). Caissons and well protectors number about half of fixed platforms and fixed platforms represent about two-thirds of the active inventory circa 2017.

In water depth >400 ft, there has been 65 fixed platforms and 55 floaters installed through 2017, and 18 fixed platforms and five floaters have been decommissioned.

1.4. STOCK CHANGES

Active inventory represents the number of standing structures at a specific point in time and is determined as the difference between the cumulative number of structures installed up to that point and the cumulative number of structures decommissioned.

A bath tub analogy differentiates flow and stock variables (Figure A.7). Installations add to the inventory of active structures while decommissioning removes structures from stock, and the relative difference between these two flows over a period of time (normally taken as one year) determines the change in inventory over the period.

Using the calendar year as the time period of evaluation, when the number of installations during the year exceeds the number of decommissioned structures active inventory will grow, and vice versa, when decommissioning activity exceeds installation activity the number of standing structures will decline.

At the beginning of offshore development, installations will normally far exceed decommissioning activity, but as a region matures and fields deplete, at some point decommissioning will begin to dominate and active inventory will decline. New discoveries may still be made in the region but the contribution of new structures relative to decommissioning activity will be small. To characterize the decline in standing structures, the change in the active inventory relative to its size is used to describe its 'decline rate'. Since 2009, the decline rate of the active inventory has ranged between 5% to 9% per year (Table A.3).

1.5. TRENDS

1.5.1 Shallow Water

The best single summary graph describing infrastructure trends in shallow water is shown in Figure A.8, where the cumulative number of installed and decommissioned structures is plotted along with their difference, the active inventory. In Figure A.9, the shallow water active inventory is broken out by water depth category.

In 1973, the first structure in the GoM was decommissioned, and by the mid-1980s removal rates regularly exceeded 100 structures per year and began to attract the attention of both state and federal regulators. Rigs-to-reef programs were developed during this time to help maintain the ecosystems established by the structures after decommissioning. For nearly 20 years beginning in the late 1980s shallow water inventories held relatively steady between 3800 to 4000 structures as installation and removal rates were approximately equal which held the active inventory in a quasi-equilibrium.

Before the mid-1980s, decommissioning was a relatively minor affair with activity levels averaging less than 30 structures per year. From the mid-1980s through 2006, cumulative removals approximately track cumulative installations and the number of active structures were in temporary equilibrium. Since 2008, installation activity has slowed down considerably while decommissioning has accelerated, causing the active inventory to drop in a fashion that mimics its rise in the 1970s.

From 1987-2006, there were on average 134 shallow water structures installed per year and 122 structures removed. From 2007-2017, there were on average 26 structures installed per year and 198 structures decommissioned. Over the past decade decommissioning activity has been particularly intense with over 40% of all activity in shallow water taking place and at rates about ten times greater than installations.

1.5.2 Deepwater

In 1978, the first structure in water depth >400 ft was installed in the GoM, and circa 2017 a total of 120 structures have been installed – 65 deepwater fixed platforms, three compliant towers, and 52 floating structures. To date, a total of 18 deepwater fixed platforms and five floating structures have been decommissioned.

In 2002, deepwater fixed platform inventories peaked as decommissioning activity exceeded new installations for the first time (Figure A.10). Deepwater floater inventories continue to rise at a slow but steady pace (Figure A.11).

1.6. Oil vs. Gas Structures

Structures are classified as 'primarily oil' (or 'oil') or 'primarily gas' (or 'gas') based on their cumulative gas oil ratio (CGOR), defined as the total cumulative gas production measured in cubic feet (cf) to cumulative oil production measured in barrels (bbl). Typically, a CGOR threshold greater than 10,000 cf/bbl is used to classify a well as primarily gas while CGOR < 10,000 cf/bbl identifies wells as primarily oil, and this same classification can be used for structures. There is no universally agreed-upon value of the threshold, however, and cutoffs smaller than 5000 cf/bbl or values greater than 10,000 cf/bbl may be employed. Note that lowering the threshold will reduce the oil structure count and increase the number of structures classified as gas producers.

1.7. Production Status

1.7.1 Classification

Structures are classified according to their production status at a specific point in time (Figure A.12), whether they are currently producing, i.e., structure produced during year of evaluation (producing); currently not producing, i.e., structure did not produce any hydrocarbons during year of evaluation but previously produced (idle); or structures that have no (current) production links to wells but serve in a support role (auxiliary). Installation and decommissioning represent the beginning and end of a structure's life, but between these two end states there are multiple pathways a structure may take.

Producing, idle and auxiliary classification are not BOEM-assigned attributes but are inferred from publicly available data and operator identification. Idle structures that plug and abandon all their wellbores and are repurposed for another function are re-classified as auxiliary even though they previously produced, but these are not reported in public data. Auxiliary structures that no longer serve a useful purpose but have not been decommissioned are considered a separate category, idle-formerly auxiliary. No attempt was made to identify members of this class and its existence is simply noted.

1.7.2 Shallow Water

At the end of 2017, there were 1909 standing structures in water depth less than 400 ft in the Gulf of Mexico - 887 producing structures, 660 idle structures and 361 auxiliary structures (Figure A.13). Of the 887 producing structures, 564 were primarily oil producers and 323 were primarily gas producers.

Idle structures are broken out into two idle age categories, 1-3 yr idle and >3 yr idle, with caissons and well protectors consolidated into one category for simplicity (Table A.4). Well protectors number about one third of the number of caissons, and caissons and well protectors number about one-third of the total number of structures.

Fixed platforms are the majority structure type across all categories. A little less than half of all structures are producing and about a quarter of all structures have been idle >3 years circa 2017. Auxiliary structures comprise about 20% of the total inventory.

1.7.3 Deepwater

The inventory of structures in water depth >400 ft circa 2017 consisted of 46 fixed platforms, three compliant towers, and 48 floaters (Tables A.6, A.7). Of the 97 active structures, 86 were producing in 2017, six were idle, and five served as auxiliary structures.

Most deepwater fixed platforms reside along the edge of the continental slope near the base of the shallow water planning areas in water depths up to 1350 ft (Figure A.14). About half of fixed platforms reside within 400-500 ft water depth and the remaining half populate the 500-1000 ft water depth region. Six fixed platforms have been installed in water depth >1000 ft and all of these installations were producing circa 2017.

Most floaters are concentrated in the Mississippi Canyon and Green Canyon areas and range in water depths from 1500 up to 9560 ft (Figure A.15). Most deepwater planning areas are sparsely populated in structures.

CHAPTER 2. STRUCTURE CLASSIFICATION

There are many ways to classify offshore structures and the most common categories involve structure type, production status, and structure function. Fixed platforms and floaters are the general structure classifications and several subclasses are employed that distinguish the jacket type and hull and the manner the structure is fixed to the seabed. Production status classifies structures as producing, idle (formerly producing), and serving in a support role. Manning status, complex association, number of wells, and major and minor structures are also useful in assessment. The chapter concludes with a summary description of the water depth thresholds that arise in different disciplines.

2.1. STRUCTURE TYPE

2.1.1 Shallow Water

Shallow water structures in the GoM are distinguished according to their jacket type and number of pieces of equipment topsides. A caisson is a large-diameter cylindrical shell or tapered steel pipe that supports a small deck and a few pieces of equipment (Figure B.1). Structures with less than six pieces of equipment are classified as minor and almost all caissons are minor (Figure B.2). Caissons are commonly used for small reservoirs that require one or two producing wells and their production is delivered to another facility through a flowline for processing, or if high-pressure gas, may be exported direct to a sales line or shore. In the GoM, caissons have been used in water depth up to 150 ft (46 m).

Jackets consist of three or more legs and the bracing system that connects the legs and are by far the most popular structure type in the Gulf. Jackets are secured to the seafloor with piles and are referred to variously as well protectors and fixed platforms (Gerwick 2007). Well protectors usually have three or four legs and most are minor structures, while fixed platforms have four or more legs and may be a major or minor structure. Major fixed platforms resemble the jacket structure of well protectors but are larger and more robust with facilities for drilling, production, and workover operations. Fixed platforms come in a wide variety of configurations and are secured to the seafloor with piles and skirt piles designed for the loads, seafloor terrain and environmental conditions at location (Chakrabarti 2005). Most well protectors are unmanned and fixed platforms may be manned or unmanned.

Fixed platforms perform a variety of functions and for structures with processing capacity both oil and gas export lines will typically exit the structure, but this was not always the case and at the beginning of the pipeline build-out in the GoM two-phase pipelines were common meaning only one export pipeline was employed (e.g., Massad and Pela 1956, Lipari 1962, Swift 1966). By the early-1970s most hydrocarbon streams from major processing platforms were separated and transported individually (e.g., Frankenberg and Allred 1969, Hicks et al. 1971). Minor fixed platforms that do not perform processing or partial processing will usually have bulk and service lines similar to caissons and well protectors, and in cases where a structure was installed to support equipment capacity or quarters, no pipeline may be required. For fixed platform pipeline junctions, oil and/or gas export lines will cross (enter and exit) the structure.

2.1.2 Deepwater

Deepwater development is of a completely different character than in shallow water. Deep water is cold and has high hydrostatic pressure, both of which are drivers for solids deposition, especially the formation of hydrates. Reservoirs may be in unproduced geology in new or existing basins/plays and deeper reservoirs are characterized by higher pressure/temperature or challenging reservoir-fluid properties and impurities (Thurmond et al. 2004, Chaudhury and Whooley 2014, Reid and Dekker 2014). Development factors can be driven by location (e.g., seabed terrain), water depth, remoteness from existing infrastructure, and extreme environmental conditions. Frequently, combinations of these factors are represented in a single project, contributing to high project complexity, high cost, and long periods between investment sanction and first production (Dekker and Reid 2014).

Deepwater facilities come in a variety of types and configurations that reflect the multiple tradeoffs in cost and risk involved in development strategies (Ronalds and Lim 2001, Ronalds 2002, Cullick et al. 2007, D'Souza and Aggarwal 2013, D'Souza et al. 2016). Deepwater facilities host dry tree wells, direct vertical access wells and subsea wells, and may process and/or transport production from third-party facilities. Deepwater structures may be owned and operated by the well owners or a third party. Whenever subsea wells are involved in development, integrated flow assurance is a key factor in design.

Fixed Platforms

Almost all of the deepwater fixed platforms were installed to drill and complete wells from platform rigs with full oil and gas processing capacity. Deepwater fixed platforms host export lines and may serve as a pipeline junction for other export lines running across the structure and as a source of gas lift or chemical injection to assist nearby production. If subsea well production is processed at the facility, the structure will host umbilical and electrohydraulic control systems, storage tanks, and related equipment. Deepwater fixed platforms can readily accommodate subsea tiebacks because of their structural stability and strength, and when production ceases they remain prime candidates to transition into a support role for regional development.

Several deepwater fields are produced from fixed platforms and many (not all) are named[2] including: Bourbon (year of installation, 1978), Cognac (1978), Cerveza (1981), Ligera (1982), Tequila (1984), Snapper (1985), Boxer (1988), Bullwinkle (1988), Marquette (1989), Tick (1991), Amberjack (1991), Alabaster (1991), Corral (1992), Pimento (1993), Lobster (1994), Pompano (1994), Phar Lap Shallo (1995), Spectacular Bid (1995), Enchilada (1997), Spirit (1998), Salsa (1998), Virgo (1999), Cyrus (2002), Tarantula (2004), Simba (2005). In 2015, Walter Oil and Gas installed the latest fixed platform in 1186 ft at the Coelacanth field in EW 834 (Figure B.3).

Cognac was the first structure in >1000 ft (305 m) water depth (Figure B.4), and Bullwinkle is the deepest fixed platform in the GoM at 1350 ft (411 m) water depth (Figure B.5).

Compliant Towers

There are only three compliant towers (CT) in the GoM, and as their name suggests, the structures are compliant in the sense that they do not attempt to resist all environmental lateral forces through

[2] Prospects are named for easy reference and many offshore fields adopt the same name in development. Local birds, fish, flowers, gods, movie and cartoon characters, scientists, etc. are commonly employed. The geologist or team who finds the field is usually granted naming rights.

their piling alone. Instead, the structures are designed to permit limited movement with the waves. Thus, the structure requires less steel (strength) in construction and their foundation bases do not expand with increasing water depth like fixed platforms.

CTs have a constant cross section throughout the water column much like radio transmission towers on land. Lena (22840) is a guyed tower fixed with guy wires to the seabed while Baldpate (33039) utilizes axial tubes as flex elements (articulated tower) and Petronius (77012) utilizes flex legs.

Lena was installed in 1983 and is near the end of its 35 year life, generating about $18 million in gross revenue in 2016. Baldpate and Petronius are of more recent vintage being installed in 1998 and 2000 and are still prolific producers, generating $153 and $188 million, respectively, in 2016.

Floaters

Floating structures are categorized into four main classes (Figure B.6): floating production storage and offloading vessel (FPSO), semisubmersible (semi), surface piercing articulating riser (spar), and tension leg platform (TLP).

Within each floater class, configurations have evolved into subclasses and occasionally new hybrid classes arise. For example, spars currently come in three varieties – classic spar, truss spar, and cell spar (Sablok and Barras 2009). A smaller version of the TLP is referred to as a mini TLP (MTLP) and classified by design as SeaStar MTLP and Moses MTLP (D'Souza and Aggarwal 2013), while a larger extended TLP (ETLP) is under construction at Chevron's Big Foot field. Mobile offshore production units (MOPU) such as the MinDoc employed at the Telemark/Mirage/Titan fields represent a hybrid structure class (Bennett 2013).

Spars are the most common floater type in the GoM followed by TLP/MTLPs and semisubmersibles (Table B.1). Floaters span a wide range of water depths from 1500 ft (Prince, MTLP) up the current maximum of 9560 ft (Stones, FPSO).

2.2. MANNED STRUCTURES

A manned platform is defined as having personnel normally present 24 hours a day, while on an unmanned platform or an 8-hr manned facility personnel are not normally present 24 hours a day and must be transported off the structure to shore or a manned platform at night or be housed at a tender vessel.

All manned platforms have a helideck where the helicopter lands which are usually located at the top of the structure and at maximum distance from the drilling rig, if present, and production equipment.. Small structures can accommodate small helicopters and larger platforms can accommodate both large and small helicopters.

Production crew on a manned facility can range from 6 to 60 or more. In shallow water, manned platforms typically serve as a hub from which staff manage and supervise regional operations, and shuttling to unmanned facilities via helicopter is common. In deepwater, although the structure itself may serve as a regional hub for production, operating crew do not normally shuttle between facilities. All deepwater structures are manned 24-hour while only about a third of the shallow water inventory is manned.

In shallow water, a total of 811 manned structures have been installed and 208 of these structures have been removed through 2017, leaving an active inventory of 603 manned platforms in water depth <400 ft (Figure B.7). In shallow water, most manned structures are fixed platforms, and the few caissons and well protectors identified as manned are attached to manned complexes. According to BOEM structure naming convention, if a complex is manned then all the structures in the complex are classified as manned.

About a third of manned platforms are auxiliary structures without wells directly boarding the structure. Auxiliary manned structures are used in field operations and pipeline transmission services and have been the most stable structure class over the past 30 years holding steady at around 200 total structures (Figure B.7).

The number of manned platforms in shallow water peaked at about the same time as the total number of active structures but at one-third the level, and whereas decommissioning has depleted shallow water inventories by about half from its peak (from 3974 structures in 2001 to 1908 structures circa 2017), the number of manned platforms − being some of the most important structures, either anchored to the largest reservoirs with the most processing equipment or interconnected across multiple pipeline networks - have not been significantly impacted declining by only a few dozen structures from its peak.

Shallow water manned structures supporting deepwater facilities and pipelines have been immune from the high pace of decommissioning that pervades the shallow water because they are not tied to declining shallow water fields.

2.3. Multi-Structure Complexes

A group of structures is referred to as a complex if they are physically connected by a walkway or bridge structure. A k-complex is defined to be the collection of k connected platforms, so for example, a 2-complex is comprised of two connected structures, a 3-complex is comprised of three connected structures, and so on. The bridge that connects two offshore structures is called a catwalk and supports pipelines, pedestrian movement and materials handling. The connecting structures are usually fixed platforms but in some cases caissons or well protectors may be used. A complex is really not much different than any group of structures used in development, except that they are connected.

Multi-structure complexes are entirely a shallow water phenomena since before the technology and installation capability were available to allow structures to be constructed vertically, they were built out horizontally to isolate and separate drilling operations from production and quarters and other functions. In many early developments from the 1950s and 1960s, after drilling platforms were installed a central processing facility was used to process and export production from the producing platforms.

In 2017, there were 1348 single-structure complexes in the GoM, excluding three compliant towers and 48 floaters, all single structure complexes (Table B.2). Note that when these 51 structures are added to the 1954 structure count yields 2005, the total number of active structures Gulf-wide circa 2017.

A total of 262 structures were identified as part of two-structure complexes, 153 structures associated with a 3-complex, 84 structures associated with a 4-complex, and so on. When counting the total number of structures in a complex, only C-C, FP-FP and WP-WP types are represented in the caisson, fixed platform and well protector columns in Table B.2. Mixed platforms include any combination of C-WP, C-FP, or WP-FP.

There are 17 complexes with five or more structures per complex. The largest active complex in the GoM circa 2017 has 15 structures. About two-thirds of structures in multi-structure complexes are fixed platforms.

2.4. Production Status

Structures transition between various states during their lifetime. Producing platforms will become idle when their reservoirs are depleted or transition directly into decommissioned status. A few idle structures may be repurposed to serve an auxiliary role if they are well-positioned and can be used in field operations.

2.4.1 Producing Structures

Structures where wells first board and that have produced during the last year are classified as producing. Producing structures include minor structures such as caissons and well protectors as well as major fixed platforms. Almost all caissons and well protectors are producing or formerly producing.

Platforms with a drilling or workover rig or the capacity to accommodate a rig are either producing or formerly producing, and if conductors can be located the structure is also either producing or formerly producing. Rigs are often removed after drilling operations are complete, however, so the lack of a rig does not imply the structure does not hold wells. Also, conductors may be run through platform legs in some cases and removed in others, and may not always be (visually) observable in photographs.

2.4.2 Auxiliary Structures

Auxiliary structures are used in support of operations but do not have any wells - or no longer have any wells - that directly board the structure. On auxiliary structures no trees or conductors or active well slots will be found. Auxiliary structures are installed new or may be converted from formerly producing structures.

Auxiliary platforms have been used for many years for processing or export operations, to expand capacity at existing structures and for pumping or compressor stations, storage, quarters, pipeline junctions and meters. Sometimes small platforms are built adjacent to larger platforms to increase available space or to permit carrying heavier equipment loads on the principal platform. In other cases, large platforms may be built next to small structures.

During the early years of offshore development in the GoM it was common to separate drilling operations from production and quarters and so many auxiliary structures are associated with a complex. In later decades, as improved technology and construction capability allowed multiple functions to be combined, there was less need for auxiliary structures and smaller numbers were installed.

One way to transform a formerly producing structure into an auxiliary structure is to plug and abandon all the wellbores and to run production from another field/platform across the facility.

Another way is to recertify the structure as a transport and fuel depot hub. Many of the most recent installations of auxiliary structures have been in support of transportation companies to link deepwater production to shelf infrastructure.

2.4.3 Idle Structures

A third class of structure that is important to distinguish are formerly producing structures that have not produced for one year or more, referred to colloquially as ‘idle iron’ or ‘idle - formerly producing’. By definition, all idle structures previously produced hydrocarbons but at the time of evaluation the structure did not produce during the previous year. The reason for the cessation of production is not publicly reported and the utility of the structure is not (directly) observable which restricts the conclusions that may be inferred about idle structures.

First, it is important to note that idle structures are a natural feature of all offshore oil and gas developments and collect as part of the active inventory until decommissioned. Second, an idle structure may return to production if any of its inactive or unplugged wells are brought back online, say through recompletion or a sidetrack operation, but the longer a structure is idle the less likely it will return to production. Finally, if all the wells on an idle structure are permanently abandoned it may be repurposed in a support function.

There are many reasons why a structure may stop producing, including: reserves depletion, uneconomic production, well failure, scheduled workovers, weather damage, third-party problems (i.e., pipelines), recompletion delay, investment review, etc. Production cessation may be short or long-term and since BOEM databases do not identify utility, classifications that group all idle structures within the same class will overestimate structure counts.

Some idle structures may return to production and others may be repurposed for another function, but the number of structures that make these transitions are believed to be relatively few because several conditions have to be satisfied simultaneously for the transition to occur. In some cases, operatorship and a review of active pipelines crossing the structure provide clues to make a meaningful inference (e.g., if the operator is a gas transmission company and all the wells on the structure have been permanently abandoned the structure has likely been repurposed), but the interpretation is subject to uncertainty and only applies for a subclass of structure. In deepwater, identification of structures that have made the transition from producing/idle to auxiliary is easier because the number of structures to examine is much smaller and pipeline interconnections are less complicated.

2.5. Number of Wells

The number of wells required to develop a field and the number of wells that can be drilled from a structure are primary descriptors. Small reservoirs might contain two or three wells, while major fields will usually have many productive fault blocks and numerous pay sands and require dozens of wells to develop.

Engineers determine how wide wells should be spaced without suffering any significant loss of reserves, and the depth and areal extent of the reservoirs will determine the number of structures required in development. One well may be used to access several vertically separated reservoirs and directional drilling from platforms is common.

Multiple structures may be used to develop one field or multiple fields may be developed from one structure. In shallow water, platform construction and installation is cheap relative to well cost, and so for fields with large areal extent spread over several lease blocks, multiple drilling platforms are common. In deepwater, structures are expensive and time consuming to construct and install, and usually a field only requires one structure in development. For some large deepwater deposits two structures may be used (e.g., Mars, Mad Dog), but this is not common. After deepwater structures are installed marginal reservoirs become economic to produce when tied back to existing infrastructure since a significant part of the capital expenditures in development are eliminated.

Example. East Breaks 160 (Cerveza) field

The East Breaks blocks 160-161 structure map and stratigraphic cross section are depicted in Figures B.8 and B.9 for five exploration wells (Schanck et al. 1988). The two wells at the boundary were drilled straight down, while wells 160#1, 160#2, 161#3 were all drilled directionally. Well 160#2 penetrated five reservoir sands according to the cartoon. In Figure B.10, the spider diagram shows the bottomhole locations of directional wells drilled from a central location, in this case a drilling rig located on a platform in 935 ft water depth in the northeast corner of block EB 160.

Through September 2017, the East Breaks 160 (Cerveza) structure produced 14.8 MMbbl oil and 96.6 Bcf gas, while the adjacent East Breaks 159 (Ligera) structure in 924 ft water depth produced 14.5 MMbbl oil and 181.1 Bcf gas. ■

Example. East Cameron 270 field

Block 270 of the East Cameron 270 field is a 2500 acre tract located about 65 miles from the shoreline in 170 feet water depth. The discovery well was drilled in 1970 and defined gas pays at 6470 ft, 7680 ft, 7970 ft, and from 8310 to 8710 ft (Holland et al. 1980). Two 8-pile, 18-slot platforms were assigned to the block *(*Figure B.11) and several platforms on adjacent leases by other operators produce from the same field.

The A platform was set in August 1971 and 13 wells were drilled from the platform resulting in nine single and three dual completions. The B platform was installed in August 1971 and 12 wells were drilled resulting in five single and seven dual completions. Production commenced in 1973 and terminated in 2013 after producing 2 MMbbl of oil and 693 Bcf of gas.

Adjacent lease blocks 254, 255, and 273 terminated in 2007, 1986 and 1989, respectively after producing 0.9 MMbbl oil and 95 Bcf gas (EC 254), 0.1 MMbbl oil and 26 Bcf gas (EC 255), and 0.2 MMbbl oil and 109 Bcf gas (EC 273). Block 272 is still active and circa 2017 has produced 50.2 MMbbl oil and 199 Bcf gas. ■

2.6. Deepwater Thresholds

Different water depth thresholds are used for different reasons and reflect oceanographic and biological processes, geologic conditions, jurisdictional issues, structure design considerations, and other factors.

2.6.1 Depth Zone

Oceanographers recognize three major depth zones in the ocean – the surface zone; a layer below the surface zone in which temperature, salinity and density experience significant changes with increasing depth; and the deep zone that reaches to the seabed.

The surface zone typically extends to depth of 100 to 500 m and is also called the mixed layer because winds, waves and temperature changes cause extensive mixing within it and ocean parameters change seasonally.

Below the surface zone lies a layer in which ocean-wave properties experience significant change with increasing depth, referred to as the thermocline (for temperature changes), halocline (for salinity) and pycnocline (for density) as shown schematically in Figure B.12. The water depth zones for the three parameters in Figure B.12 are shown at the same depth but will normally occur at different depths.

Each zone will have different acoustic and light transmission properties and the boundaries may give reflection from sonic transmission. Understanding the form of these changes is important for oceanographic modeling (Garrison and Ellis 2017) and for vessels that operate covertly (submarines) and rely upon accurate measurement of sound waves (Payne 2010).

2.6.2 Photic Zone

The photic zone or euphotic zone is the depth of the water in a lake or ocean where most photosynthesis occurs (Skinner and Murch 2011). Formally, it is defined where the amount of sunlight is such that the rate of carbon dioxide uptake (or the rate of oxygen production) is equal to the rate of carbon dioxide production (or the rate of oxygen consumption).

The photic zone extends from the surface down to a depth where light intensity falls to one percent of that at the surface and its thickness depends on the extent of light attenuation in the water column (Figure B.13). Typical euphotic depths vary from only a few centimeters in highly turbid lakes to around 200 meters in the open ocean. It also varies with seasonal changes in turbidity. Plant life is restricted to the upper 200 m of the ocean because in this zone sufficient light energy is available for photosynthesis. Below the photic zone lie the aphotic (twilight) and abyssal (midnight) water depth zones.

2.6.3 Exclusive Economic Zone

Under the United Nations Convention on the Law of the Seas (UNCLOS) coastal states have jurisdiction over the 200 nautical miles of continental shelf adjacent to their coastlines and UNCLOS Article 76 gives countries extended claims to up to 350 nautical miles based on a complex formula depicted graphically in Figure B.14 (Cavnar 2009). The term ‘continental shelf’ as applied by UNCLOS is a legal phrase that refers to what scientist broadly call the continental margin and mixes technical and legal terminology.

2.6.4 Wave Base

Wave forces are usually the dominant design criterion affecting offshore structures. A wave is a traveling disturbance of the sea state. The disturbance travels, but the water particles within the wave move in a nearly elliptical orbit with little net forward motion. A deepwater wave is one for which the seafloor has no effect. Normally, waves do not exceed 400 m wavelength - the distance between two consecutive peaks/crest of a wave - even under storm conditions, although in the Pacific Ocean wavelengths as long as 600 m have been measured.

Since waves only generate orbital motion to a depth of about half a wavelength, referred to as the wave base, this has led to the adoption of 200 or 300 m water depth as being considered ‘deepwater’ by design engineers and many regulatory agencies (Gerwick 2007). In this context, deepwater refers to the water depth where surface waves do not impact the seafloor. At 300 m water depth surface waves from the strongest recorded storm are not expected to move seafloor sediment on the edges of the world's continental shelf.

2.6.5 Depositional Models

Deepwater in a geologic context refers to an environment in which the reservoir sand is deposited by gravity-flow processes. Reservoirs deposited by gravity-flow processes, such as turbidities, typically consist of sheet-like to lenticular sands with rapid lateral facies changes and numerous interbedded shale breaks. The volume and producibility of turbidity reservoirs is markedly different from tabular shelf sands or growth-fault sands which have better lateral continuity and fewer shale breaks (Figure B.15).

Example. East Breaks 160 (Cerveza) depositional model

The East Breaks intraslope basin is located 100 miles offshore and south of Galveston (Braithwaite et al. 1988). The basin lies downslope of the modern shelf/slope break at water depths of 300 to 1300 feet and extends 35 miles northeast-southwest (Figure B.16). Proximity to the shelf was the key factor that controlled the depositional style and structural history of the field. ■

CHAPTER 3. INSTALLATION & DECOMMISSIONING ACTIVITY

Installation and decommissioning trends in the shallow water and deepwater GoM reflect geologic prospectivity and production trends in each region. The number of structures in water depth less than 400 ft peaked in 2001 at 3972 and numbered 1908 circa 2017, while deepwater inventories numbered 97 circa 2017 and have not yet peaked. Record levels of shallow water decommissioning in recent years is the result of the maturity of field production, sustained low oil and gas prices, and tougher regulatory conditions and oversight. Higher levels of deepwater decommissioning are expected in the years ahead unless alternative uses for structures are found. In this chapter, GoM installation and decommissioning activity is described for the shallow and deepwater regions.

3.1. CUMULATIVE ACTIVITY

A total of 7053 structures have been installed in the GoM and 5048 structures have been decommissioned through 2017, leaving an active inventory of 7053 − 5048 = 2005 structures circa 2017 (Tables C.1, C.2). Ninety-seven structures comprise the deepwater inventory, 48 floaters, three compliant towers, and 46 fixed platforms.

3.1.1 Shallow Water

Since all oil and gas fields have finite lives and the useful life of structures are usually tied to field production, the more structures installed in a region the more structures will need to be removed, and the number of structures that have been decommissioned at any point in time will be roughly proportional to the number installed. Regions with older structures are expected to have a higher decommissioning percentage compared to regions with structures of more recent vintage.

Three floating mobile offshore production units (MOPUs) have been installed in shallow water on lease blocks West Cameron 44, South Timbalier 41, and South Timbalier 145 in 34, 68, and 92 ft water depth (10, 21, and 28 m), respectively. Complex 1252 was installed in June 2003 and removed in July 2008, and complex 1490 was installed in November 2004 and removed in May 2007, complex 24205 was installed in November 1994 and removed in May 2003. Complex 1252 was manned and only complex 24205 was associated with production, producing 11,867 bbl oil and 16.3 Bcf gas in the ST 41 field.

3.1.2 Deepwater

Only a small number of deepwater projects are sanctioned each year and only a few structure installations occur annually. In total, 65 fixed platforms and three compliant towers have been installed in water depth greater than 400 ft, and circa 2017, there were 46 fixed platforms and three compliant towers in the region. In total, 53 floating structures have been installed in the GoM and five floaters have been decommissioned circa 2017, leaving an activity inventory of 48 at years end 2017.

Sixteen of the 18 decommissioned fixed platforms were primarily gas producers, and the average time to decommission after the last year of production was five years with a range between two to 10 years (Table C.3). Five floaters have been decommissioned through 2017: GC29/Llano (semi, 1989), Cooper (semi, 1999), Typhoon (MTLP, 2006), Red Hawk (spar, 2014), and Gomez (semi, 2014).

The first two deepwater structures decommissioned in the GoM were both semisubmersible developments. Placid Oil's GC52/Llano development in 1989 was decommissioned less than a year after installation because of well problems, and Newfield's Cooper development was decommissioned in 1999. Both semisubmersibles were towed away for decommissioning.

Chevron's Typhoon MTLP suffered catastrophic damage from Hurricane Rita in September 2005 and was decommissioned at a deepwater reef site at Eugene Island 367 in June 2006. After ATP Oil & Gas declared bankruptcy in 2013 and no buyers for its Gomez semisubmersible could be found, it was decommissioned in March 2014 and towed back to port at Ingleside, Texas. Anadarko decommissioned its Red Hawk spar in September 2014 at a deepwater reef site in Eugene Island 384.

The three semisubmersibles were each removed within one year of last production, Typhoon was decommissioned two years after last production, and Red Hawk was decommissioned six years after last production. All the decommissioned semisubmersibles were towed back to shore while the majority of the other deepwater decommissioned structures – fixed platforms and floaters - were either reefed in-place or towed to a deepwater reef site.

3.2. Shallow Water Trends

3.2.1 Annual Activity

Decommissioning activity fluctuates year-to-year and from 2007 through 2017 between 100 and 290 structures were decommissioned annually (Figure C.1). Activity levels exceeded 200 removals per year from 2009 through 2014, peaking in 2011 at 290 structures decommissioned.

In 2016, there were 197 structures decommissioned (70 caissons and well protectors, 127 fixed platforms) and 697 well abandonments (585 permanent abandonments, 112 temporary abandonments) in water depth less than 400 ft. No structures were installed in 2016.

In 2017, 97 shallow water structures were decommissioned (38 caissons and well protectors, 59 fixed platforms) and 518 wells were abandoned (336 permanent abandonments, 182 temporary abandonments). One shallow water structure was installed in 2017.

High level of decommissioning activity in recent years are due in large part to the aging infrastructure and maturity of producing properties in the region coupled with low oil and gas prices. Clean-up activity from the 2005 and 2008 hurricane seasons has only contributed incrementally to decommissioning activity and is now nearly complete (Kaiser and Narra 2017).

NTL 2010-G05 idle iron guidelines have also played a role in increased levels of decommissioning activity since operators are required to decommission structures that no longer serve a useful purpose within five years of no longer serving a useful purpose, unless special circumstances apply or a temporary exemption is granted.

3.2.2 Installation by Decade

There has been a dramatic decline in the number of shallow water structures installed in recent years and over the past decade only 29 structures on average have been installed per year (Table C.4). Caissons, well protectors and fixed platforms all show similar installation trends across time, peaking in the 1977-1986 period when about one-quarter of all installations occurred at an average rate of 170 structures/year, declining to 145 structures/year from 1987-1996, and 123 structures/year from 1997-2006. Four percent of shelf structures have been installed over the past decade, similar to the first decade of activity in the region.

Installation activity has fallen so dramatically so fast due in large part to the maturity of shelf production and the lack of new discoveries. Over 97% of proved reserves in shallow water have now been produced. New discoveries in mature areas are possible but large discoveries are not likely unless new plays provide opportunities not previously considered, such as deep gas. The shelf is gas prone and small offshore gas fields will have a difficult time competing with cheaper onshore shale plays when gas prices are in the $4/Mcf range.

Oil wells on the shelf continue to produce but new fields have been difficult to find. Large legacy fields such as those located at Eugene Island 330, West Delta 30, Grand Isle 43, Main Pass 41, Ship Shoal 208, West Delta 73 and Grand Isle 16 are probably the best opportunity for operators to seek additional (incremental) production. Small fields often have less upside potential compared to large fields but a case-by-case evaluation is necessary. Sidetrack drilling in depleted reservoirs are attractive mostly to niche players and those with large portfolios that can balance and manage the risk involved.

The bottom line is that structure installation in shallow water are not expected to add materially to shelf inventories in the near-term unless there is a dramatic change in current conditions or new plays arise in the future.

3.2.3 Decommissioning by Decade

The first structure decommissioned in the GoM was in 1973 but it was not until the mid-1980s that activity levels began to pick up (Table C.5). From 1987-1996, 108 structures per year were decommissioned on average, increasing to 136 structures/yr from 1997-2006, and nearly doubling to 208 structures/yr from 2007-2016 where over 40% of all decommissioning activity to date has occurred.

Historically, caissons and well protectors were removed in greater numbers than fixed platforms, but as their inventory declines more fixed platforms are now being removed than simple structures, a trend that is likely to continue. More manned fixed platforms are also in queue for removal. Over the past decade, the number of structures decommissioned is almost an order-of-magnitude larger than installation activity.

3.3. DEEPWATER TRENDS

3.3.1 Annual Activity

No more than a handful of deepwater structures are installed or decommissioned each year (Figure C.2). Since 1978, the number of new deepwater structures can be counted on one hand every year except 1998 and 2004 when nine structures were installed, and in 2002 and 2003 when six structures were installed. This is due to several factors but the most obvious are the significant capital expenditures and planning required in development and execution. There are only a limited number of market participants with the requisite experience and capital to successfully operate in the deepwater space, and as these operators pursue investment opportunities worldwide they allocate their capital to seek the best returns on a risk-adjusted basis.

Drilling deepwater wells represent significant capital spending, and to ‘prove-up’ a development, several wells need to be drilled before a final investment decision is made. Only the largest discoveries require a structure, and once installed can be used to develop smaller fields in the region via subsea wells if opportunities exist (Heijermans and Cozby 2003, Reid and Dekker 2014, Yoshioka et al 2016), or the facility may be re-purposed as a compressor or pump station or a fuel storage depot.

3.3.2 Installation by Decade

In recent years, the number of deepwater platform installations have diminished significantly (Table C.6), indicating that (large) reservoirs requiring stand-alone structures are not being discovered in the 400-1500 ft water depth region, and where finds are made, subsea tiebacks to existing infrastructure is the preferred development option. Installation activity for fixed platforms peaked in the decade 1987-1996 while floater installations peaked from 1997-2006. Over the past decade two floaters were installed on average per year, compared to three floaters per year over the preceding decade 1997-2006. Activity levels are small and will likely remain small for the reasons described above.

3.3.3 Decommissioning by Decade

The first deepwater structure was decommissioned in 1989 and over the next twenty years only seven deepwater structures were decommissioned (Table C.7). Through 2017, a total of 23 deepwater structures have been decommissioned, five floaters and 18 fixed platforms (Figure C.3). Deepwater structures have been decommissioned every year since 2009, usually only one or two per year, with slightly higher levels of activity in 2011 and 2016.

CHAPTER 4. ECONOMIC LIMIT FACTORS

The economic limit of production refers to the production rate where it is no longer economic or profitable to produce. When the direct operating cost is greater than the net revenue of production, no economic value is being generated and a rational operator will cease production if the condition persists for too long, attempt to remedy the situation by spending capital to increase production or attempt to reduce cost, search for a buyer for the property or consider other alternatives. Economic limits are not publicly reported or directly observable but gross revenue the last year of production for decommissioned structures serves as a useful proxy. The purpose of this chapter is to summarize the operating cost characteristics of offshore production and the primary factors that impact economic limits.

4.1. Operating Cost Characteristics

The risk and cost in oil and gas operations is finding the resource and selecting the best method that maximizes the value to extract it. The cost of operations after concept selection is determined by the development type and complexity, production fluid, location, age, and design choices that are made. The majority of field development cost occurs upfront in capital expenditures for the wells, and offshore, for the platform and export pipeline. If subsea wells are used in development, additional equipment, flowlines and umbilicals need to be installed and operating cost is higher than for systems that employ only dry tree wells, for all else equal.

Wells are used to make contact with reservoir sands and serve as the conduit for the hydrocarbon fluids that flow to a facility for processing and export. Changes in temperature and pressure between the well and surface facilities are used for processing and provide a significant portion of the energy requirements of the facility. Near the end of primary production, where the reservoir energy has been used up and equipment is older, operating cost start to increase. The volume of water produced will usually increase over time and the volume of oil and gas will decline. As pressure declines and eventually dissipates, oil will no longer flow to the surface naturally and must be pumped using artificial lift and secondary production methods if economically viable.

Well interventions are performed throughout the life of a well to protect value (e.g., by repairing or preventing corrosion or scale, maintaining gas lift systems) or to create value (e.g., shutting off water or adding gas-lift to accelerate production) and are a primary means of protecting or increasing reserves and production. The primary objective of stimulation (aka, workovers) is to restore impaired well/reservoir connectivity. The nature of impairment, treatment options, and post treatment production issues often change over the life of the well and the results of operations are uncertain and site-specific.

Production cost vary depending on the characteristics of the producing formation, location, method of recovery, cost and frequency of workover activities and many other factors (Figure D.1). Operating cost depends on the type of production (heavy oil, condensate[3] oil, wet gas, dry gas), quality of production (sweet, sour, corrosive), age of production (early, mid-life, mature), operational requirements (chemical treatment and monitoring, corrosion and scale), level of production, drive mechanism (solution gas, depletion drive, water aquifer), location (protected

[3] Condensate refers to hydrocarbons that are gaseous in the reservoir but liquid at the surface.

waters, shelf, deepwater), the number and type of wells (dry tree, wet tree), structure type (caisson, well protector, fixed platform, floater) and size, production characteristics (gas lift, water injection, gas injection), water production, distance to market, well servicing requirements (workovers, sand production and control), distance to port (boat and helicopter transportation), degree of automation (manned, unmanned), production crew size, structure function (producing, auxiliary), complex size (single, multiple), and insurance requirements.

Labor, transportation, well servicing, and contract services are usually the main expenses (Table D.1). Fuel, chemicals, insurance, gathering and transmission are usually secondary. The relative proportion of each cost category is site- and time-specific. As properties age, they generally require more workovers and chemical cost may increase but labor cost is mostly fixed unless significant reorganization occurs, while transportation cost and insurance will fluctuate with market conditions. Workovers are largely discretionary and operators typically plan for a workover when they wish to accelerate or enhance production, which usually occurs on high producing wells in high commodity prices environments. Insurance is discretionary for large operators and mid- to small-size operators are the primary players in the market. Gathering and transmission fees are volume-based and are usually a small fraction of the total operating cost.

4.2. Cash Flow Model

The economic limit is the production rate at which the net revenue from the sale of production equals the cost of production:

$$\text{Net revenue} = \text{Production cost}$$

Net revenue *NR* is gross revenue *GR* less the royalty payment *ROY* and lease operating expense (synonymous with production cost or direct operating cost) is denoted *LOE*:

$$NR = GR - ROY = LOE$$

Gross revenue is estimated as the sum of the product of the (sales) price for oil and gas denoted by P^o and P^g and the quantity of oil and gas sold, Q^o and Q^g, respectively. Royalty in the U.S. GoM is based on a fixed percentage of gross revenue, $ROY = r \cdot GR$, with r either 12.5%, 16.67% or 18.75%. For example, from 1983-2007 the royalty rate in <200 m water depth was 16.67%, and from 2008 to the present the royalty rate was 18.75%.

Direct operating cost are defined to include all direct cost to maintain operations, property-specific fixed overhead charges, production and property taxes, but exclude depreciation, abandonment costs, and income tax (Gallun et al. 2001, Mian 2002, Seba 2003). Public companies in the U.S. are required to disclose lease operating expense according to Security and Exchange Commission (SEC) requirements using three categories: direct lease operating expenses, other lease operating expenses, and indirect lease operating expenses. In financial reports, companies combine all their properties on an aggregate or regional total (or by business segment) which does not allow for asset-specific information to be extracted except in special cases (see Chapter 19 for additional details).

If the lease operation expense, commodity price and royalty rate are known/assumed for a given property, the cash flow model can be solved for the economic production rate in terms of the primary (oil or gas) stream:

$$Q_{el} = \frac{LOE}{P(1-r)} .$$

Example. Economic limit calculation

If lease operating cost is \$500,000 per year and future oil price is expected to be \$50/bbl, the property needs to produce at least 12,000 bbl per year (33 barrels oil per day) to cover operating expense assuming a 16.67% royalty rate. For a smaller royalty rate, the economic limit will be smaller. For example, at 12.5% royalty rate the economic limit is 11,400 bbl per year (31 bopd). Conversely, if crude prices turn out to be higher than expected production limits can be lower and still cover cost. At \$80/bbl, the economic limit is 7500 bbl per year (21 bopd). ■

Q_{el} represents when production is no longer 'profitable.' Continued production at or below the economic limit creates no economic gain and would serve no economic purpose. Of course, operators may continue to produce when production falls below Q_{el} if they believe prices will increase in the future allowing the property to return to profitable status or if adjustments can be made to reduce operating cost. For example, operators may be able to reduce their maintenance cost by delaying or reducing maintenance for a period of time, while labor and logistics cost may be reduced in some cases by downsizing crew or sharing logistics (helicopter and marine vessel) services.

4.3. General Considerations

4.3.1 Reserves Application

Economic limits are used in conjunction with decline curves to terminate production forecasts in reserves assessment (Figure D.2). Producing wells are the basic unit of analysis in all production forecasts and are frequently consolidated at a lease, structure, or unit level. Economic limits correspond to the aggregation level applied. At the time of evaluation T, well production is described by $Q(t)$, $t \leq T$, and assuming an economic limit EL, future commodity price P and royalty rate r, well abandonment time T_a is determined using the economic limit EL as terminal criteria (Figure D.3):

Step 1. Forecast $\hat{Q}(t), t > T$

Step 2. Compute $NR(t) = \hat{Q}(t)P(1-r)$

Step 3. Determine $T_a = \min\{t \mid NR(t) = EL\}$.

4.3.2 Production Beyond Economic Limit is Not Reserves

According to basic economic theory, a structure will produce hydrocarbons as long as its net revenue exceeds its direct operating expenses. When the direct operating cost is greater than the net revenue of production, no economic value is being generated and a rational operator will cease production if the condition persists for too long, attempt to remedy the situation by spending capital to increase production or reducing cost, search for a buyer for the property or consider other alternatives. There are many reasons why an operator may continue to produce marginal properties even if it is not economic to do so (e.g., to hold the lease), but the production beyond the economic limit is not, by definition, reserves.

4.3.3 Strategic Factors Complicate Interpretation

Strategic factors impact economic limits and complicate interpretation. The operator may perform a workover in an attempt to restore production or intends to spend capital to sidetrack or drill new wells to increase production. The operator may produce at marginal rates to delay decommissioning, either to delay expenditures or to synchronize operations with other decommissioning activities to minimize costs and maximize efficiency (Price et al. 2016). The operator may continue to produce below the economic limit in anticipation of a future sales agreement. Historically, marginal properties have been sold as a package with other properties and unexplored acreage to avoid decommissioning altogether, but there are limits to 'kicking the decommissioning can' down the road.

Since the economic limit of a particular property or asset is not reported or known precisely to outside observers, the length of time that an operator may produce below its economic limit (e.g., six months, one year, etc.) is unobservable and uncertain. Lease conditions explicitly forbid maintaining a lease if it is not producing in commercial quantities, but the interpretation of what is commercial varies by state and in practice landowners will have difficulty demonstrating such violation because of the lack of information on cost and the proprietary nature of operations. For the legal aspects of producing below the economic limit see general treatments by Lowe (2003) and Maxwell et al. (2007).

When the value of an asset's reserves is less than its expected decommissioning cost operators are unlikely to be able to divest the structure on a stand-alone basis and may have to pay the buyer or make other arrangements to assume responsibility for the property. A company may make a business decision to continue production below its economic limit to postpone incurring these expenses and to seek potential alternative uses of the facility. Many structures retain residual value beyond their productive life because of their (potential) ability to reduce future development cost, and operators may delay decommissioning unless holding cost (insurance and maintenance costs) and hurricane risk outweigh the potential benefits. In most cases the tradeoffs faced by a particular company cannot be quantified reliably. Regulations play a determining factor in timing decisions.

4.3.4 Proxy for Commercial Operations

Economic limits serve as a proxy for rational decision-making and as with all proxy measures the correspondence is not perfect. An operator may shut-in wells before the economic limit is reached if they decide for strategic reasons to exit the region or a hurricane severely damaged or destroyed facilities.

Since production and revenue change over time and operating cost are dynamic and vary with a number of factors, a well may reach its economic limit several times during its life cycle before returning to commercial production. Operating cost would have to exceed production revenue for a sustained period of time, perhaps nine to twelve months or more, before an operator would consider shutting in a well. If an operator cannot achieve its economic threshold, operations will cease temporarily or permanently and the structure idled, decommissioned or divested.

As long as a well is not permanently abandoned, however, shut-in wells may be restarted and worked over at a later date or serve as a site for a sidetrack well (Brandt and Sarif 2013). It is only when a well is permanently abandoned and a structure decommissioned that the revenue at the end of its life serves as a proxy for its economic limit. Frequently, only one or two producing wells hold offshore structures at the end of their life.

Ultimately, the criteria operators employ when terminating production is unobservable, but that does not negate the application of the economic limit as a proxy for commercial operations.

4.4. Economic Limit Factors

Many factors impact the economic limit of offshore production (Figure D.4). Some of the factors are observable such as structure type and primary production, while other factors are unobservable or difficult to assess such as the impact of scale economies, asset concentration, and strategic decisions.

4.4.1 Structure Type

Simple structures like caissons and well protectors host a small number of wells and are expected to have a lower operating cost than fixed platforms, for all other things equal, and the average shallow water fixed platform is expected to have a lower economic limit than the average deepwater structure. Structures that are part of a multi-structure complex are expected to achieve cost savings relative to isolated structures that are not part of a complex since multi-structure platforms can be manned directly saving on logistical cost (personnel are within walking distance and not a boat ride or helicopter trip away) and economies similar to regional operations arise.

4.4.2 Water Depth

Water depth in the GoM is related to distance to shore and the type of structure required. As water depth increases the distance to shore increases approximately linearly (except for some locations around the mouth of the Mississippi River where the continental shelf is short), and as shore distance increases so will the cost of transportation from onshore bases. The need for a robust platform and higher insurance and communication cost also increase with water depth and contribute to higher operating cost. Differences in water depth should translate into differences in economic limits for all things equal.

4.4.3 Oil vs. Gas

Gas fields are generally cheaper to lift than crude oil (i.e., gas is less viscous, highly compressible, and wants to come out of the ground), recover more resources (greater drainage area per well) and at higher rates, and handling and treating are cheaper (gas streams typically only need to be dehydrated before export), and of course, wells producing gas provide a free source of energy to drive the equipment if adequate volumes are available. As properties mature these cost advantages become less pronounced, and because oil is both more desirable and valuable as a commodity and is priced at a premium to natural gas (historically about one-and-a-half times the price of gas on a heat-equivalent basis), one might expect oil structures to exhibit a lower economic limit relative to gas structures.

4.4.4 Manned Status

Structures that are producing from one or two wells near the end of their life will generate similar levels of revenue but the operating cost between structure types will differ, especially if a platform is manned or is part of a multi-structure complex or floating structure. For manned platforms direct operating cost will be greater than for unmanned platforms and economic limits are expected to be greater.

4.4.5 Operator

Independents typically produce from numerous marginal fields relative to large independents and majors and one would expect independents to be able to produce at lower rates, on average, than majors because of the nature and type of their asset portfolios and specialization, scale and regional economies, and organizational structure. Most majors do not operate properties once they reach a certain minimum level and divest or decommission assets low on their decline curves (referred to as portfolio rebalancing).

Small operators seek scale and synergies to reduce operating cost and enhance downhole opportunities. One of the advantages of consolidating operations, as viewed by the large legacy property owners is the ability to reduce logistical cost as they seek to squeeze out marginal oil and gas from mature properties. The sustainability of this business model over the years has been a mixed bag as viewed from the number of companies that stay in business, but value has been generated and activities have added incremental barrels making shallow water GoM production decline less steep.

4.4.6 Well Type

Well type is relevant if a platform handles wet tree (subsea) wells. Operating costs for subsea wells are much larger than for dry tree wells since platform rig access is not available, power and chemicals have to be supplied remotely, flowlines have to be maintained and regularly pigged, etc. In the shallow water GoM the population of wet tree wells are very small (see Chapter 6), so the need to distinguish well type in shallow water does not arise, but in deepwater subsea wells are quite common (~40% producing wells circa 2017) and need to be distinguished in economic limit evaluations.

Subsea wells flow their production back to a host platform for processing and should have a higher economic limit than dry tree wells, for all things equal, since the wellbore is not accessible from a platform and will cost more to operate and maintain. Low flow rates present problems for all subsea wells and depending on the diameter of the pipe will present additional challenges. In gas wells, for example, low flows may not sweep produced water from the flowlines, requiring additional pigging frequency to prevent corrosion and creating a higher risk for hydrate formation or greater hydrate chemical inhibitor cost. One might expect that the greater the distance between well and host the greater the economic limit, again with the provision that all other things are equal, and that differences in altitude of the well relative to the host may also be important.

4.4.7 Other Factors

Age may play a role in structure maintenance requirements but because maintenance costs are periodic, relatively small, and are often budget on a long-term basis it is unlikely that a strong correlation will be found between age and economic limit. For all things equal, older structures require greater maintenance cost than younger structures, and one might suspect that structures closer to cessation of production would also have higher operating cost than structures more distant.

The manner in which oil is produced – via gas lift, waterflood, or natural flow – will impact operating expenditures. Gas lift is currently used on about one third of producing oil wells in the shallow water GoM and access to gas lift allows operators to produce at lower production rates relative to oil wells without access to gas lift. Waterflooding has been employed on a number of oil fields while tertiary methods (e.g., CO2 flooding, chemical) are not economic.

Water production increases at the end of the life cycle of oil and gas production, especially for black oil water drive reservoirs and if waterfloods are employed, and because the treatment and disposal of produced water costs money, as water production increases so does operating expense. The cost to handle, process, and treat this waste stream may be a limiting factor in production. Wells that water-out are expected to reach their economic limit at a higher production level relative to wells that are not similarly burdened.

Companies with a geographic concentration of assets are more likely to achieve lower economic limits than a distributed collection of isolated assets because supply vessels and personnel can be utilized in a more effective and cost efficient manner. Helicopter and boat charters in regional operations, for example, can be optimized to more efficiently service operations and labor may be more effectively utilized.

CHAPTER 5. RESERVES & RESOURCES

Reserves and production are the primary factors that determine the value of oil and gas companies. In this chapter, reserves and resource assessments for the GoM are summarized along with a high level description of the geology of the shallow water and deepwater regions. A mini-case study of the Eugene Island 330 field, the second largest oil and gas field in the GoM, is described along with examples of depositional environments to conceptualize model construction. Deepwater exploration plays are highlighted. Field naming conventions and a description of the five reservoir fluids bracket the chapter and can be skipped in a first reading. The chapter begins with associations between assessment units.

5.1. AGGREGATION UNITS

Many different units and levels of organization are used in oil and gas production, reserves and resource evaluations (Figure E.1). A frequent point of confusion, a clear understanding of definitions and aggregation units are needed to interpret data properly and select the right unit for assessment.

5.1.1 Reservoir, Well, Lease

A reservoir is the subsurface deposit of oil and/or gas located in the pores of a reservoir rock and held by structural, stratigraphic, or combination traps. A reservoir refers to an individual sealed hydrocarbon bearing sand, also sometimes called a block or pool that denotes the compartmentalization. Isolated accumulations of hydrocarbons (compartments) are characterized by a single pressure system and segregated from other accumulations by sealing mechanisms. By definition, fluids do not flow from one reservoir to another.

Within a single reservoir, the crude oil or natural gas has physical characteristics that do not vary much because equilibrium conditions have been reached between the fluids and the rock over millions of years, but the properties of petroleum fluids in different reservoirs in the same field can be very different. Reservoir fluids vary among reservoirs due to different source rocks, diagenesis, tectonic environments, and other factors. Reservoirs vary widely in terms of their depth, vertical thickness and lateral extent. The GoM has a multiplicity of small traps with a great petrological and textual diversity and a variety of geologic ages. Reservoir size is limited by faulting and facies changes and there may be more than one producing zone (sand) in a reservoir. Reservoirs may be unitized for conservation purposes.

A well is an orifice in the ground made by drilling from which petroleum or natural gas is obtained. Wells may be drilled straight down, at an angle, or sidetracked from another wellbore, and are classified as exploration or development if the purpose is to find commercial accumulations of hydrocarbons or develop them. Exploratory wells are almost always drilled from MODUs, development wells can be drilled and completed from a MODU, can be drilled from a MODU and completed at a platform rig, can be partially drilled from a MODU with TD reached at the platform rig and then completed at the platform, or can be drilled and completed entirely from the platform.

One of the central problems in development regards the number of development wells required to efficiently drain the deposit. Small reservoirs might contain two or three wells, while major fields will usually have many productive fault blocks and numerous pay sands and require dozens of wells to develop, including injection wells for waterflooding. Dry tree wells have their Christmas trees on the platform while subsea wells have their tree on the seabed. Direct vertical access wells are a special type of subsea well with wellhead located on the seafloor underneath the platform and accessible from a platform rig.

A lease is the instrument by which a leasehold or working interest is created in minerals. In the GoM, leases are obtained via auction and the payment of a bonus bid, and are subject to rent during the primary term and royalty during production. Section 8 of OCSLA stipulated that GoM tracts be auctioned by competitive, sealed bidding based on a cash bonus bid with a fixed royalty on oil and gas production paid to the government of not less than 12 ½ percent, or a royalty bid of not less than 12 ½ percent with a fixed cash bonus. The lease areas offered could not exceed 5760 acres and would last for a period of not less than five years or as long as oil and gas was being commercially produced or drilling operations were underway.

In 1954 the first leases offshore Louisiana offered a 16 2/3 percent royalty rate, a $3/acre annual rental fee, and a five year primary term. The royalty rate was apparently the sum of the mandated 12 ½ percent royalty plus an amount equal to the severance tax that had been levied by the State of Louisiana (Austin et al. 2004). Early Louisiana leases charged a rental fee of one-half of the cash bonus, and since many of Louisiana bids at the time went for $7500 per 5000 acre block, the annual rental would be $3750 or less than $1/acre. Texas at the time charged a $2/acre rental fee. A $3/acre rental fee was adopted along with a minimal bid of $15/acre to reject low-bids that would prevent fair value from being achieved.

Example. Garden Banks 426 (Auger) reservoirs

The Auger field was discovered in 1987 in 2847 ft water depth and is made up of four main pay horizons referred to as the Yellow “N”, Blue “O”, Green “Q”, and Pink “S” sands ranging from 15,000 ft to 19,000 ft subsea and covering four blocks in Garden Banks 426, 427, 470 and 471 (Figure E.2). ■

Example. Mississippi Canyon 582 (Medusa) exploration and development wells

The Medusa field is located in Mississippi Canyon in 2200 ft water depth over blocks MC 538 and 582 (Figure E.3). The T4b reservoir is one of the three major productive intervals and occurs east of a salt weld that bisects the field (Lach et al. 2005). Five faults are depicted in the schematic of various length and width. Faults often restrict flow and compartmentalize the sands, and thus, reservoirs that are faulted and with poor communication will require more wellbores than better connected reservoir sands. Six dry tree wells A1 through A6 were completed in the initial development phase of Medusa targeting the three main reservoirs T1b, T4b, and T4c (Figure E.4). ■

Example. Mississippi Canyon 582 (Medusa) discovery well drilling curve

The Medusa discovery well MC 582-1 reached total measured depth of 16,950 ft (15,621 ft TVDSS) in September 1999 and drilled four sidetracks (Figure E.5). Measured depth is measured along the wellbore, while true vertical depth is measured straight down, either from the water line or mudline. MD is always greater than TVD except in a perfectly straight vertical wells. The datum is usually the water line or the rig floor, so MD usually includes water depth. Sidetrack wells in exploration drilling are used to test different parts of the reservoir. ■

5.1.2 Field, Structure, Unit

Fields, structures and units are collections of reservoirs, wells and leases, respectively, and represent a higher level of aggregation. Aggregation simplifies analysis in some cases and presents more complex interpretation in others. For example, in economic evaluation, fields are generally inappropriate for assessment because the field production profile will not reflect differences in development, ownership and capital expenditures, while in resource assessments they are the preferred entity being a natural geologic unit. In reserves evaluation and production forecasting, wells are the appropriate assessment unit and are rolled-up to structures and leases in economic assessment.

A field is an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to the same general geologic feature and/or stratigraphic trapping condition. The field is a construct agreed upon by a set of conventions/rules determined by regulatory agencies and identified by location and name. There may be two or more reservoirs in a field separated vertically by impervious strata, laterally by local geologic barriers, or by both. The area may include one lease, a portion of a lease, or a group of leases with one or more wells that have been approved as producible.

By definition, a field refers to a commercial accumulation and is not a prospect. A prospect is the exact location where the geological and economic conditions are favorable for drilling an exploratory well, and derives from two Latin words 'pro', meaning forward or ahead, and 'spicere,' meaning to see or look (Martin and Kramer 1997). Offshore fields in the GoM typically consist of a series of stacked sands that may be vertically aligned in a structural trap or fault block. Reservoirs are often developed with as few wells as possible necessitating completion in multiple sands. The sand with the largest acreage often determines the areal extent of the field. As a field is developed, its limits may expand into adjacent blocks as determined by the regulatory agency. Field production is a blend from all the reservoirs that comprise the field, and because reservoirs may be produced at different times and have different fluid properties, crude production will exhibit variation over time. Field names are given by area code and block number of discovery wells.

A structure refers to a steel jacket that is pinned to the seabed by long steel piles or a floating platform anchored in place by tension legs or mooring. Conductor pipes and risers deliver fluid from one or more reservoirs to topsides equipment for processing and export. A deck is used to hold equipment for metering, processing, quarters, export and related functions. Multiple structures may be used to develop one field or multiple fields may be developed from one structure (Figure E.6). A structure has one operator but a field may have several operators depending on the nature of lease ownership. Structures are identified by complex number and lease block.

When more than one company is operating a field, the field can be unitized to coordinate development efforts or to increase production via pressure maintenance, waterflood, or enhanced oil recovery. The costs and production are then shared proportionally to each member's acreage or reserves position in the field. Unitization can either be voluntary or forced by government decree. A unit represents the total area incorporated in a unitization agreement that consolidates leases from different owners for the development and operation of oil and gas recovery. In brief, a unit acts as a single entity, same as a lease.

Example. Field-structure-lease association

The Mars-Ursa field is the largest field in the GoM and identified as the Mississippi Canyon 807 field (Figure E.7). Circa 2017, the Mississippi Canyon 807 field includes lease blocks MC 762-766, MC 805-810, and MC 850, 851, 853, 854. Three tension leg platforms are used to develop the field: Mars A (24199). Mars B (2385) also known as Olympus, and Ursa (70004). The Yellow reservoir is the main reservoir at both the Ursa and Mars reservoirs which is the reason BOEM consolidates the fields into one geologic unit.

The deepwater Hoover platform (183) is used to develop the Hoover (AC 25), Madison (AC 24), Diana (EB 945), and Marshall (EB 949) fields. The Hoover field consists of lease blocks AC 25 and 26. ■

Example. Green Canyon 65 (Bullwinkle) and tieback fields

The, Bullwinkle field was discovered in Green Canyon block 65 in 1983 and first production was in 1989. After peaking in 1992 subsea tiebacks at Rocky (1995), Troika (1996), Angus (1998), and Aspen (2002) were brought online and production capacity at Bullwinkle was doubled to handle 200 Mbopd and 320 MMcfpd (Figures E.8, E.9). New export lines were also installed due to operator preferences on export destination. Through September 2017, cumulative production at the Bullwinkle field was 122 MMbbl oil and 208 Bcf gas, and facilities have handled about 284 MMbbl oil and 485 Bcf gas from tieback fields (Table E.1). ■

Example. Stacked sands at South Timbalier 21

The South Timbalier 21 field was discovered in 1957 in 46 ft water depth and currently consists of four South Timbalier blocks, ST 21, 22, 27, and 28. South Timbalier block 21 is the largest producing block responsible for about two-thirds of field production. Original oil-in-place was estimated at 300 MMbbl, and through September 2017 the field produced 259 MMbbl and 426 Bcf gas. Remaining reserves are estimated at 1.5 MMbbl oil and 3.1 Bcf gas. There are six vertically stacked sands in the field and the sand with the largest acreage is also the deepest (Figure E.10). ■

5.1.3 Play, Trend, Fairway

Rolling up fields into composite units lead to plays, trends and fairways. A play is a trap, reservoir rock and seal combination that has been shown by previously discovered fields to contain commercial petroleum in an area. A trend or fairway is the area along which the play has been proven and more fields may be found.

Plays and trends are referred to by the age of the rock where the fields are found, not the age of the oil which will have been deposited after the rock was laid down. The principle production trends of the GoM shelf are the Miocene, Pliocene and Pleistocene trends which become progressively younger to the south. The Lower Tertiary trend is the latest deepwater play and include discoveries and developments such as: Great White, Tobago, Kaskida, Buckskin, Hadrian, Shenandoah, Jack, Julia, Hal, Chuck, St Malo, Das Boot, Stones, Cascade and Chinook.

Example. Lower Tertiary trend

The Lower Tertiary trend, also referred to as the Wilcox or Paleogene, refers to the trend of reservoirs that were formed between 65 and 38 million years ago (Figure E.11). In contrast to the conventional deepwater Miocene reservoirs which are 5 to 24 million years old, the Lower Tertiary trend is buried deeper (25,000 to 35,000 feet), has higher pressures (17,000 to 24,000 psi), and stronger rock formations. High temperature (220 to 270 °F), low gas-oil ratio (170 to 250 cf/bbl), and low permeability contribute to the difficult reservoir characteristics. The result of these conditions is that additional wells are required in development along with subsea pumps and boosting systems and regular intervention to maximize recovery rate (Torbergsen et al. 2016). ■

5.2. Geologic Time

The universe is estimated to be about 13.8 billion years old and the Milky Way galaxy in which the Earth and its solar system inhabits, is only a bit younger at about 12 billion years. The Earth was formed about 4.5 billion years ago, and for the first four billion years of the Precambrian there is no fossil evidence for life. The first life, probably bacteria followed by algae, appeared approximately three to four billion years ago and evolved in the oceans. There is relatively little organic matter preserved in Precambrian sedimentary rocks and most are buried deep and are not good reservoir or source rocks for hydrocarbons. No significant deposits of oil and gas are known in Precambrian rocks.

Geologic time scales are used to classify the age of the rock which hydrocarbons inhabit and it is important to realize that the age of the rock usually has no direct correspondence with the time hydrocarbons accumulated except providing for a rough lower bound (i.e., hydrocarbons are usually at least as old as the rock in which it is trapped). Large divisions of geologic time are called eras, and eras are subdivided into periods, periods into epochs, and epochs into ages (Table E.2). Within each period and epoch, reference is often made to late, middle and early times to refer to specific intervals.

The exact timing of the subdivisions and intervals are less important than realizing their relative position. For examples, the late Pliocene runs from 3.6 to 1.8 million years before present, and the Early Pliocene runs from 5.3 to 3.6 million years before present. The Late Tertiary generally refers to the Eocene and Paleocene epochs. It is also common to group epochs when describing reservoir and depositional environments. By far the most common groupings are the Neogene, which groups the Miocene, Pliocene and Pleistocene, and the Paleogene which refers to the Eocene and Paleocene (or Late Tertiary).

At the start of the Paleozoic era 570 million years ago, known as the Cambrian explosion, a great abundance of diverse plants and animals are found in the fossil record. During the Ordovician period in the Paleozoic era, fish came into existence. Plants and animals adapted to life on land in the Silurian period. During the Mississippian and Pennsylvanian periods, also known as the Carboniferous period, extensive land areas were covered by swamps and inland oceans which formed many of the world’s coal deposits. Oil and gas was also being formed at this time, but generally occurs in rock laid down at later time.

Example. Deepwater Gulf of Mexico reservoir characteristics

The Neogene reservoirs in the GoM from the Miocene, Pliocene and Pleistocene epochs can be broadly characterized as over-pressured, high permeability, unconsolidated and highly compacting containing black undersaturated oils of medium gravity and moderate GOR, and often with some aquifer support (Lach and Longmuir 2010). The vast majority of production in the deepwater GoM circa 2017 are from Neogene reservoirs. The P50 recovery factor for Neogene fields has been estimated at about 32% OOIP (original oil-in-place), with P90 and P10 recovery factors of 16% and 49%, respectively.

The Paleogene fields, except for those in the Alaminos Canyon, are deep, highly over-pressured, and low to moderate permeability, cemented sandstones, containing black, highly undersaturated oils with moderate viscosity and low gravity and low GOR (Lach and Longmuir 2010). The natural drive energy that has permitted good primary recoveries in the Neogene reservoirs is not expected in Paleogene reservoirs. For Paleogene fields with artificial lift, the P50 recovery factor is estimated at around 10%. ■

5.3. BOEM Field Naming Convention

BOEM's Field Naming Committee determines those leases in the GoM capable of producing and associated with a specific geologic structure in a single field (BOEM 1996). Field names are assigned for a lease or group of leases so that oil and gas reserves and production can be allocated on the basis of the geologic framework that contains the hydrocarbon accumulation.

Fields are usually named after the area and block on which the discovery well is located. When assigning leases to fields the following conventions apply:

- Structural lows are used to separate fields with structural trapping mechanisms.
- Faults are rarely used to separate fields.
- The structure or stratigraphic condition with pay having the largest areal extent on a lease determines the field expanse.
- Reservoirs that overlap areally are always combined into a single field regardless of the fact they may be on two separate structures or stratigraphic conditions.
- Fields are never separated vertically.

Wells from the same platform can be in two separate fields, but one well is rarely in two fields, i.e., a well with two completions, each in a separate field. Four examples of BOEM field designations are shown schematically in Figures E.12 through E.15. Additional examples can be found on the BOEM website.

Example. Salt dome with fault trap downdip on the domal structure

In Figure E.12, a piercement salt dome with traps against the salt and a fault trap down on the flank is depicted. Traps against the salt in blocks 2, 3, and 4 have hydrocarbon discoveries (only block 3 is depicted) and the fault trap in block 13 has a discovery. Blocks 2, 3, 4, and 13 would all be considered on the same structure and therefore in the same field. ■

Example. Two structural highs with a separating structural low

The structural low between the two anticlinal features in Figure E.13 is sufficient to designate two separate fields. ■

Example. Series of traps against a large fault without separating structural lows

A long fault with a series of traps against the fault is shown in Figure E.14. In this case, there are no separating lows between the traps and so they are combined into a single field. ■

Example. Multiple accumulations with different structural styles in a salt-bounded mini-basin

In Figure E.15, four different hydrocarbon accumulations are shown each with a different structural style: a piercement salt dome with a flank trap, a fault trap, stratigraphic trap, and a trap against a salt ridge. Because of their structural size and relative positions the hydrocarbon deposits are placed into three fields. Field A is the salt dome with flank trap in block 3. Field B is described by the two traps along the fault in block 7. Field C is the salt ridge trap. ■

5.4. RESERVES

5.4.1 Reserves Categories

The American Petroleum Institute introduced proved reserves categories in 1937 following an oil resource evaluation for the United States. Today, the Petroleum Resources Management System (PRMS) is the standard companies use to provide a consistent approach to estimating petroleum resources from development projects and presenting results within a common classification system. The PRMS framework maps petroleum quantities according to their range of uncertainty against the possibility of the quantities being commercially produced. PRMS has been used by the U.S. Security and Exchange Commission (SEC) as a guide for their security reporting requirements and updated rules, "Modernization of Oil and Gas Reporting" (SEC 2008). In January 2010, the Federal Accounting Standards Board (FASB) issued ASU No. 2010-03, "Oil and Gas Reserves Estimates and Disclosures," which aligned the reserves estimation and disclosure requirements of the FASB with the changes required by the SEC rule.

Proved reserves are considered reasonably certain to be producible using current technology at current prices and is referred to as P1 or P90, denoting a 90% certainty that at least the specified amount will be produced. This conservatism in reporting proved reserves is inherent in what is generally regarded as prudent business management, but is also the basis for what regulatory authorities require to protect investors.

Probable reserves are considered as likely as not to be recoverable and is referred to as P2 or P50, that is, having a 50% certainty of being produced. As fields are developed and produced, initial reserves estimates almost always increase (referred to as reserves growth), and the ultimate recovery of a field at decommissioning will often reflect 2P reserves[4] more closely than P1 reserves. Probable reserves are often used as the basis for development decisions.

Possible reserves are speculative and have a chance of being developed under (very) favorable circumstances. Possible reserves are referred to as P3 or P10, and have a 10% chance of being produced.

5.4.2 Reserves and Cumulative Production

According to BOEM estimates, oil and gas (proved) reserves from producing fields in the GoM as of December 31, 2015 were 23.1 Bbbl of oil and 193.8 Tcf of natural gas, or 55.4 Bboe (Burgess et al. 2016). Reserves are relatively easy and reliable to estimate at a given point in time since they are based on producing wells and standard decline curves. Cumulative production through 2015

[4] In industry parlance, cumulative reserves are represented by 2P and 3P: P1 = 1P, 2P = P1 + P2, and 3P = P1 + P2 + P3.

from all fields accounts for 19.6 Bbbl of oil and 186.5 Tcf of natural gas, or about 52.8 Bboe, leaving approximately 3.5 Bbbl oil and 7.3 Tcf gas recoverable, or about 4.8 Bboe (Table E.3).

In water depth less than 500 ft (152 m), BOEM estimates remaining shallow water reserves at 899 MMboe, about 20% of the GoM total reserves of 4779 MMboe. In water depth greater than 500 ft (305 m), BOEM estimates reserves at 3880 MMboe, about 80% of total reserves. To date, shallow water production in water depth less than 500 ft (152 m) has contributed about 80% of total GoM production, compared to about 20% for fields in water depth greater than 500 ft (152 m).

5.4.3 Field Distribution

In 2015, there were 1312 fields in the GoM, 260 oil fields and 1052 gas fields (Burgess et al. 2016). BOEM applies a gas oil ratio threshold of 9700 cf/bbl to delineate oil and gas fields and the count includes producing and non-producing fields at the time of evaluation (i.e., fields with zero reserves as well as developments in progress).

Field counts grow relatively slowly year to year since capital spending is required before a field makes the list, and in some cases, existing fields may simply be enlarged and not contribute as a new field. The lease blocks that overlie fields expire, terminate, are relinquished or consolidated, but fields do not apply such designations. For fields, classifiers include PDP (proved developed producing), PDN (proved developed nonproducing), PUD (proved undeveloped), and RJD (reserves justified for development).

Central GoM oil and gas fields are larger than Western GoM oil and gas fields and the average gas field is smaller than the average oil field (Figures E.16, E.17). The median oil field in the GoM was about 50 MMboe, about seven times the size of the 7 MMboe median gas field on a heat-equivalent basis. The mean oil field is 107 MMboe compared to 28 MMboe for the mean gas field. The large difference between the mean and median statistics is due to the occurrence of a few giant deposits.

5.4.4 Largest Fields

In Tables E.4 and E.5, the top 20 largest fields by original reserves circa December 31, 2015 are depicted for the shallow water and deepwater, and in Figures E.18 and E.19 the top 50 fields are graphed with remaining reserves.

Twenty of the top 25 fields and 36 of the top 50 fields reside in shallow water, and almost all of these fields have only a small percentage of their reserves remaining, collectively about 200 MMboe, or about 20% of total shallow water reserves. All of these fields except Eugene Island 330 were discovered in the 1950s and 1960s and have produced for over 50 years. Most of the remaining reserves in shallow water fields represent less than 5% of original reserves and for the top 50 fields average 2.7% (2.2% standard deviation). Eugene Island 188 field has the most remaining reserves at 12%, followed by Eugene Island 361 and Ship Shoal 230 fields at 8%, and Grand Isle 43 and Main Pass 73 fields at 6%.

The deepwater Mars-Ursa field is the largest oil and gas deposit in the U.S. GoM at 1.49 Bbbl of oil and 2.1 Tcf of natural gas, or 1.85 Bboe. The Eugene Island 330 field in 248 ft water depth is the second largest field in the GoM at 799 MMboe, followed by shallow water fields at West Delta 30 (797 MMboe), Grand Isle 43 (711 MMboe), and Tiger Shoal (711 MMboe). These fields are all classified as ‘giants’ since they have produced more than 500 MMboe, the cutoff traditionally used for the very largest fields. Remaining reserves at Mars-Ursa is estimated at 347 MMboe circa

2016, while at the EI 330, WD 30, GI 43 and Tiger Shoal fields there are approximately 16, 11, 41, and 29 MMboe remaining reserves, respectively. The deepwater Stampede field was not producing at the time of the assessment.

5.4.5 Field Discoveries

The number of discoveries in shallow water has been in decline since the early 1980s, and since mid-2000 new deposits account for less than 200 MMboe reserves per year (Figure E.20). Since 2009, the contribution of new shallow water discoveries to reserves has been negligible.

5.4.6 Reservoir Distribution

In terms of reservoirs, the units that are rolled-up and aggregated into fields, there were 2367 combination (saturated oil rims with associated gas caps) reservoirs, 8905 undersaturated oil reservoirs, and 18,734 gas reservoirs in the GoM circa 2015 (Burgess et al. 2016).

For combination reservoirs, the median reserves size is 0.9 MMboe and the mean is 3.0 MMboe. For undersaturated oil reservoirs, the median reserves is 0.3 MMbbl and the mean is 1.9 MMbbl. For gas reservoirs, the median reserves is 2.0 Bcf and the mean is 8.4 Bcf. Large differences between the mean and median statistic reflects the lognormal distribution of reservoir volumes.

5.5. Eugene Island 330 Field Case Study

The Eugene Island 330 field was discovered in 1970 by Pennzoil and Shell on blocks 330 and 331 using the new technology of ‘bright spot’ identificaiton (Holland et al. 1990). By the end of 1971 two platforms had been set and development was under way in water depth ranging from 210 to 266 ft. Four platforms were set during 1972 and first production began. Eventually nine drilling and production platforms and four satellite production platforms were installed across seven lease blocks and 192 development wells and 26 exploratory wells were drilled circa 1990 (Figure E.21).

Hydrocarbon accumulations occur in more than 25 Pliocene-Pleistocene sandstones and trapping mechanisms are combinations of structural and stratigraphic varieties, including four-way dip closure, fault closure, and facies change (Holland et al. 1990). The field is a rollover anticline formed on the downthrown side of a large, northwest-trending, salt diaper related growth fault. The reservoir energy results from a combination water-drive and gas-expansion system. There are 10 major reservoir sand series that range from 55 to 400 ft in gross thickness with net pays from 27 to 49 ft (Holland et al. 1990). Oil gravity range from 23 to 36 °API. Eight of 10 reservoir sandstone units are predominately oil producing, with productive areas ranging from 6500 acres (2633 ha) to less than 200 acres (81 ha). Most of the sandstones are cut by faults which break them into several distinct reservoirs and require separate wells.

Eighteen and 24-slot 8-pile platforms were selected for the drilling platforms due to the large number of directional wells required. On block 330, there were three drilling platforms and a central four-pile platform installed for production equipment. On blocks 331 and 314, two drilling platforms were connected to production platforms, and on blocks 313 and 338 one drilling platform was set on each block.

In December 1978, average daily production peaked at 61,000 bbl of oil, 9000 bbl of condensate, and 400 MMcf of gas (Lewis and Dupur 1983), and by 1983 cumulative production reached 224 MMbbl oil and 1.03 Tcf gas and water injection began on blocks 331 and 314 to slow decline rates.

Through September 2017, cumulative production was 455 MMbbl of liquid hydrocarbons and 1.9 Tcf of gas (Figure E.22). Production declines in 2006 and 2008 are due to hurricane impacts, and in 2015, field production was 5 MMbbl of oil and 9 Bcf of gas. Remaining reserves are estimated to be 11.7 MMbbl oil and 22.6 Bcf gas.

Production increases only occur with capital spending and at every major production uptick observed investment was required. This is shown better in the monthly vs. cumulative production plot made by Laherrere in Figure E.23 where reserves estimates circa 2000 were predicted at about 450 MMbbl oil.

The goal of every operator is to recover the maximum amount of oil and gas at the highest present value. At various times in the life cycle of production operational decisions will arise on drilling new wells, upgrading equipment, performing secondary operations, etc. to enhance recovery or maximize value. The pressure histories of three reservoir sands provide insight into some of the early operational issues that arose which are relatively common across the industry (Figure E.24):

- The GA sandstone is normally pressured with water-drive. The reservoir pressure decreased less than 8% after the production of 71% of the recoverable reserves. Ultimate recovery is expected to exceed 37% of the original oil in place.
- The LF sandstone reservoirs have weak water drive systems, and during early production the pressure dropped 34% after only 8 MMbbl of oil had been produced. The operator revised its production plan to allow water influx to approximately match production withdrawal, which resulted in the production of the next 7 MMbbl with only an additional 7% pressure drop.
- The OI sandstone reservoir in fault block A exhibited a classic gravity-segregation drive mechanism. A gas cap developed after a 16% decrease in pressure occurred prompting an immediate response for a gas injection program that began in 1979.

In 2005, Hurricane Rita passed through the area causing significant damage to EI 330B and EI 330C platforms and claimed connecting platform EI 330S. In order to prevent repeated damage from future storms, Devon and partners in May 2006 sanctioned raising the decks on EI 330B and EI 330C platforms 4.25 m (14 ft). Operations were successfully completed using the Versabar (Van Kirk and Day 2007).

In 2008, Hurricane Ike passed through the field and caused significant damage to Shell's EI 331A platform, but both of the raised structures escaped damage. Shell's EI 331A platform was previously a 24-slot production platform, but well plug and abandonment work was completed in 2005 and the facility was operated as a pipeline hub for Auger oil production at the time of Ike's arrival (Abadie 2010). There was no visible damage to the topsides structure but when the jacket was inspected by divers three legs were found to be severely damaged and numerous diagonal braces were buckled, broken or missing. Shell engineers determined it was not feasible to repair the jacket and the platform was removed to avoid risk of collapse in future storms (Abadie et al. 2011). Eleven pipelines crossing the structure had to be re-routed or abandoned.

The topsides and deck of the EI 331A platform was removed before the 2009 hurricane season and in 2010 the platform was towed using the Versabar (Figure E.25) to an existing SARS (Special Approved Reef Site) in EI 313 (Figure E.26). The jacket was toppled and reefed in one piece to provide the best habitat for marine life and joined several other jacket structures at the site (Figure

E.27). Underwater ROV cameras documented fish and other marine life following the jacket during its tow operation and reefing.

In September 2009, lease block EI 352 N2/3 was terminated, and in June 2016, lease block EI 313 SE 1/4 was terminated. All other blocks are active and producing circa 2017 (Figure E.28).

5.6. Undiscovered Resources

The BOEM assesses the amounts of undiscovered technically and economically recoverable resources (UTRR) located outside of known oil and gas fields in the U.S. Gulf of Mexico (DOI 2017). Each reservoir in a BOEM-designated field is assigned to a distinctive play and reservoirs are aggregated to the sand level and each sand is aggregated to the pool level. Plays are aggregated into 'assessment units' according to geography and rock age and a probabilistic approach applied with economic thresholds to evaluate undiscovered resources. The exercise is speculative but has a scientific basis and is well recognized in industry.

The UTRR in the Western GoM in <200 m water depth is estimated at 95% probability to be at least 0.51 Bbbl of oil and 15.8 Tcf of natural gas, or 3.33 Bboe (Table E.6). The mean estimate of UTRR oil and gas in the Western GoM is 5.2 Bboe, and the 5% probability upper estimate UTRR is 7.78 Bboe. In the Central GoM in <200 m water depth, the low, mean and high estimates for UTRR resources are 5.2, 7.8, and 11.0 Bboe, respectively.

Gulf-wide, across all water depths and planning areas, including the Eastern GoM and Straits of Florida, the low, mean and high estimate for undiscovered technically and economically recoverable resources are 61.5, 73.7, and 86.9 Bboe, respectively. The mean estimate is comprised of 48.5 Bbbl oil and 141.8 Tcf natural gas.

5.7. Gulf of Mexico Geology

5.7.1 Shallow Water (Modern Shelf)

The principal productive trends of South Louisiana and adjacent offshore are those south of the Lower Cretaceous shelf edge shown in Figure E.29. The geology, trends, and general interpretation in this 30-year old map hasn't changed much over the past three decades. Stable, unfaulted, south-dipping beds lie north of the shelf edge with little conventional production. South of the shelf edge salt structures and growth faults populate the region and provide multiple traps (Branson 1986, Percy and Ray 1986, Salvador 1987).

The productive trends strike roughly parallel to the coastline and become successively younger to the south and extend into Texas on the west. To the east, production terminates near the Lower Cretaceous shelf edge with none of the trends extending beyond that feature into southeastern or offshore Mississippi. The boundaries between trends are never as simple or clear-cut as depicted in cartoons and tend to overlap due to the continuous deposition across epoch boundaries. Bay Marchand and several West Delta fields with Pleistocene, Pliocene, and upper Miocene production are examples of trend overlap.

Offshore Texas is characterized by a series of large, down-to-the-basin expansion fault systems that trend parallel to the Texas coastline (DOI 2017). The shallow sections of these fault systems have been thoroughly explored and rollover anticlines on the downthrown sides of the faults have been prolific gas producers from Miocene reservoirs. The Louisiana shelf is characterized by a series of normal fault-related trends that generally become younger across the shelf, from the Miocene sediments in the inner shelf to the Pliocene and Pleistocene sediments on the middle and outer shelf. The complexity and abundance of salt structures increase to the south and near the shelf edge significant tabular salt bodies form the Sigsbee Escarpment.

The Miocene fields in Louisiana lie mostly offshore and produce from Upper Miocene sediments on the large salt domes located along the coastline. Example include West Delta 30, West Bay, Grand Isle 16, Caillou Island, Timbalier Bay, and Bay Marchand. Pliocene development in the GoM dates from the 1950's and the trend is situated on the continental shelf with the Pliocene-Pleistocene trend boundary running eastward and close to the 100 ft water depth contour from West Cameron to South Timbalier. From South Timbalier the boundary trends more northeasterly as the shelf narrows and runs close to the 300 ft contour through Grand Isle, West Delta and South Pass.

Example. Eugene Island 126 field

The Eugene Island 126 field is a piercement-type salt dome structure discovered in 1950 and typical of those found in the region with normal complex faulting characteristics (Figure E.30). The field is located approximately 25 miles offshore in 38 to 50 ft water depth in Eugene Island blocks 119, 120, 125 and 126. Through September 2017 the field produced 141 MMbbl oil and 234 Bcf gas. In 2015, field production was 380,000 bbl oil and 565,000 boe, or about 1041 bopd and 1548 boepd (Figure E.32). Remaining reserves are estimated at 4.9 MMbbl oil and 13.5 Bcf gas.

The salt reaches the surface of the seafloor and the structure is mapped on top of the salt and on a reservoir sand below the Pliocene-Miocene contact (Atwater 1959). The salt stock is nearly circular and measures approximately two miles in diameter at a depth of 4000 ft (Figure E.31). The salt upwelling brought sands up to surface within 6000 feet before truncation, while on the south flank beds terminate at about 10,000 ft. Directional holes drilled from multiple platforms located around the periphery of the salt were used in development, and in 1956 there were 28 wells with average daily production of 6300 bopd and 5.4 MMcfpd gas (Figure E.33). ■

5.7.2 Deepwater (Modern Slope)

The slope occurs between the modern shelf edge and the Abyssal Plain and includes the Sigsbee Escarpment, large compressional structures in front of Sigsbee Escarpment, and the depositional limit of Louann salt. In Figure E.34, a generalized cross section is cut in the northwesterly direction from the deepwater Jack/Cascade field through the shelf at Davy Jones and the False River field[5] onshore Louisiana. The presence of salt is a dominant feature.

The slope contains a wide variety of salt-tectonic features and is characterized by displaced salt sheets (allochthons), with a gradual transition from small, isolated salt bodies lower slope. Allochthonous means out-of-place and the salt is currently not in the position within the

[5] The Tuscaloosa trend play in Louisiana was opened up by the discovery of the False River field a few miles northwest of Baton Rouge in 1974. The Tuscaloosa sandstone is a Cretaceous age sandstone that ranges from 35-200 ft thick and between 16,000 to 22,000 ft deep and overlain by shale caprock. Efforts to commercially extract hydrocarbons from the Tuscaloosa trend have not been successful to date.

stratigraphic column where it was deposited. As a result of load-induced evacuation, flowing Jurassic Louann Salt has climbed the Mesozoic and Cenozoic stratigraphy as allochthonous tiers which creates complex traps for hydrocarbon accumulations.

The deepwater GoM comprises a thick Cenozoic sedimentary fill (>50,000 ft [15,000 m]) and a structural setting that includes multilevel allochthonous salt systems, extensional and contractional faults, and large, salt cored fold belts. The source rocks in the northern deepwater GoM are found at great subsurface depths, commonly overlain by more than 30,000 ft (13,000 m) of strata. For a description of the geologic evolution of the northern deepwater GoM, including seismic profiles and a series of chronostratigraphic and tectonic charts, see (Weimer et al. 2017) and the references listed therein.

The first deepwater plays were the Flexure Trend located on the upper continental slope in water depth ranging from 600 to 3000 ft. The term flexure is used in a bathymetric rather than a structural sense and refers to the slope position and not to a particular structural style. The flex trend is mainly an oil-producing trend in the east and becomes gas productive to the west in Garden Banks and East Breaks. The first discovery was made by Shell in 1975 in Mississippi Canyon 194 which became the site of the Cognac platform.

Example. Mississippi Canyon 194 (*Cognac) field*

Cognac accumulations are trapped on a faulted, northwest plunging nose between 5000 and 11,000 ft covering lease blocks in Mississippi Canyon 194, 195, 150 and 151. A fixed platform was installed in 1978 in MC 194 in 1025 ft (321 m) water depth with two rigs and one of the rigs was later removed and replaced with production equipment (Figure B.4).

The initial development plan included 72 drainage points and seven injection wells. From 1978-1981, a total of 61 wells were drilled and cased and 38 wells were completed from two rigs. About half of the wells were high angle (> 50°) extended reach wells. First production occurred in 1979 and peak production was achieved in 1983 (Figure E.35). Cumulative production through September 2017 was 182 MMbbl of oil and 762 Bcf of natural gas. Circa 2015, production was 500,000 bbl oil and 600 MMcf gas and remaining reserves are estimated at 3.1 MMbbl of oil and 5.4 Bcf gas. ■

5.8. Deepwater Exploration Plays

Deepwater exploration to date has focused on four major geologic provinces (Zarra 2007): Basins, Subsalt, Fold Belt, and Abyssal Plain. Basins represent large areas with a thick accumulation of sedimentary rocks and subsalt refers to sedimentary rock structures located below a layer of salt. Fold belts describe a bend in sedimentary rock layers and include the Perdido fold belt in the western GoM, the Mississippi Fan fold belt in the eastern GoM and the Keathley-Walker fold belt near the Sigsbee Escarpment (Figure E.36). The Abyssal Plain is a flat seafloor area at an abyssal depth (3,000 to 6,000 m [10,000 to 20,000 feet]), adjacent to a continental rise and thought to be the upper surfaces of land-derived sediment that accumulates in abyssal depressions. These four geologic provinces formed from complex interactions between Mesozoic-Cenozoic sedimentation and tectonics.

The first deepwater exploration plays were the flex trend (1975-1988) and minibasins (1985-1995) that occurred in the Basins province (Figure E.37). The flex trend occurs at the edge of continental shelf and discoveries were followed by larger discoveries on the middle slope such as Mars, Ursa, and Mensa. The fold belt play (1997-2005) yielded fields such as Neptune and Perdido. The subsalt Paleogene play started on the shelf in areas where the salt partially overhung the prospects followed by discoveries in deeper water where the shallow allochthonous salt extended across the entire prospect such as Thunder Horse and Atlantis (Todd and Replogle 2010). The Mesozoic play has seen several non-commercial discoveries and dry holes, as well as several successes such as Vicksburg and Appomattox, currently in development.

Most GoM deepwater fields are located in Basins and Subsalt plays with significantly fewer Fold Belt and Abyssal Plain discoveries (Table E.7). Most of the deepwater field discoveries since 2004 have been led by six operators – Anadarko, BP, Chevron, ExxonMobil, Hess and Shell. BP and Chevron's current development activity is focused on Lower Tertiary play fields. Anadarko's significant basin presence grew following the acquisition of Kerr McGee in 2006 and Freeport McMoRan Oil & Gas in 2017. Shell's current exploration focus is the frontier Jurassic play.

Example. Garden Banks 426 (Auger) deposition model

The Auger field is made up of four main stacked pay horizons that range in age from lower Pleistocene to lower Pliocene age (Bilinski et al. 1992). The two shallower pay sands contain condensate rich gas with the deeper zones being volatile oils. Original ultimate recovery was estimated at 220 MMboe with a 2:1 oil/gas ratio, and circa September 2017 the Auger field had produced 267 MMbbl oil and 935 Bcf gas with a resurgence in recent years (Figure E.38).

Regional studies have shown Auger sands to be stacked sequences of turbidite flows (Figure E.39). The "N" and "O" sands are interpreted to be channel features in the upper fan area, and the "Q" sand is interpreted to be a stacked lobe and channel sequence topped by channel-like sand. The "S" sand is interpreted to be a sheet sequence characterized by finely laminated sand/shale deposited in a distal to lower fan region. There is little faulting and few discontinuities in the reservoirs and over half the original reserves occur in the "S" sand. ■

Example. Ewing Bank 873 (Lobster) deposition model

The Ewing Bank 873 field was discovered in 1991 on the flank of a salt withdrawal mini-basin in 775 ft water depth (Edman and Burk 1998), and circa September 2017, the EW 873 field had produced 172 MMbbl oil and 158 Bcf gas (Figure E.40). The reservoir is a combination structural-stratigraphic trap consisting of six stacked and overlapping Pliocene turbidite sand lobes (Figure E.41). These lobes comprise three compartments which exhibit their own characteristic pressure regime and fluid properties (Burk et al. 1999). The drive mechanism for the field is a moderate aquifer drive with waterflood support.

The A7 well forms its own compartment with the most biodegraded and lowest quality oil (17.9° API, 3.62 wt% sulfur) and steep pressure decline because of its small size and limited aquifer support (Figure E.42). Lobes 10, 20, 30 comprise the west compartment with a hydrocarbon column approximately 2900 ft thick, and lobes 70 and 80 the east compartment with pay zone about 4350 ft thick. Pressure maintenance was begun early using three downdip water injectors (A11, A12, A14) to maintain reservoir pressure. ■

5.9. THE FIVE RESERVOIR FLUIDS

There are five types of reservoir fluids often referred to as black oil, volatile oil, retrograde gas, wet gas and dry gas (Figure E.43). The reservoir fluids are characterized by their producing GOR, API gravity, color and C6+ fraction (McCain 1990). The C6+ fraction are those (liquid) hydrocarbon compounds with six or more carbon atoms, such as hexane, heptane, octane, etc. also sometimes referred to as the heavy hydrocarbon liquid constituents. The type of reservoir fluid reflects the characteristics of the reservoir and the liquid and gas production trends specific to each class.

Black oils are characterized as having initial producing GORs less than 2000 cf/bbl and stock tank gravity below 45°API. Producing GORs increase during production after reservoir pressure falls below the bubble point pressure of the oil. There is a large quantity of heavy hydrocarbons in black oils and for low gravity crude sulfur content is high.

Volatile oils, also called high shrinkage crude oils, release a large amount of gas in the reservoir when reservoir pressure falls below the bubble point of the fluid. The dividing line between black oils and volatile oils is somewhat arbitrary but usually identified with producing GOR between 2000 and 3300 cf/bbl. Oil gravity is usually 40°API or higher and increases during production after the bubble point is reached. Heptane plus content of crude ranges from 12.5 to 20 mole percent.

Retrograde gases are so-named because they exhibit a dew point, and when reservoir pressure falls below this point, liquid from the gas condenses in the reservoir. The liquid does not flow and normally cannot be produced and the result is that the composition of the reservoir fluid will change during production. The lower limit of the initial producing GOR for retrograde gas is approximately 3300 to 5000 cf/bbl but the upper limit varies with the reservoir conditions and above 50,000 cf/bbl can be considered a wet gas. The surface gas for retrograde gases are rich in intermediates and processed to remove propane, butanes, pentanes and heavier hydrocarbons. At high GOR, the quantity of retrograde liquid in the reservoir is very small. Stock tank liquid gravities vary between 40° and 60° API and increases as reservoir pressure falls below the dew-point pressure.

A wet gas exists solely as a gas in the reservoir throughout the reduction in reservoir pressure and no liquid is formed in the reservoir. However, at the surface separator some liquid, often referred to as condensate, will form. The 'wet' gas designation does not mean the gas is wet with water, since all reservoir gas is normally saturated with water, but refers to the hydrocarbon liquids that condense out at the surface. Wet gases have high producing GORs which remain constant during production, and the gravity of the stock tank liquid does not change noticeably during the life of the reservoir. Normally, a gas with a GOR greater than 50,000 cf/bbl can be treated as a wet gas.

In a dry gas reservoir no hydrocarbon liquid is formed in the reservoir or at the surface, although some liquid water usually condenses. The word dry indicates that the gas does not contain hydrocarbon liquids.

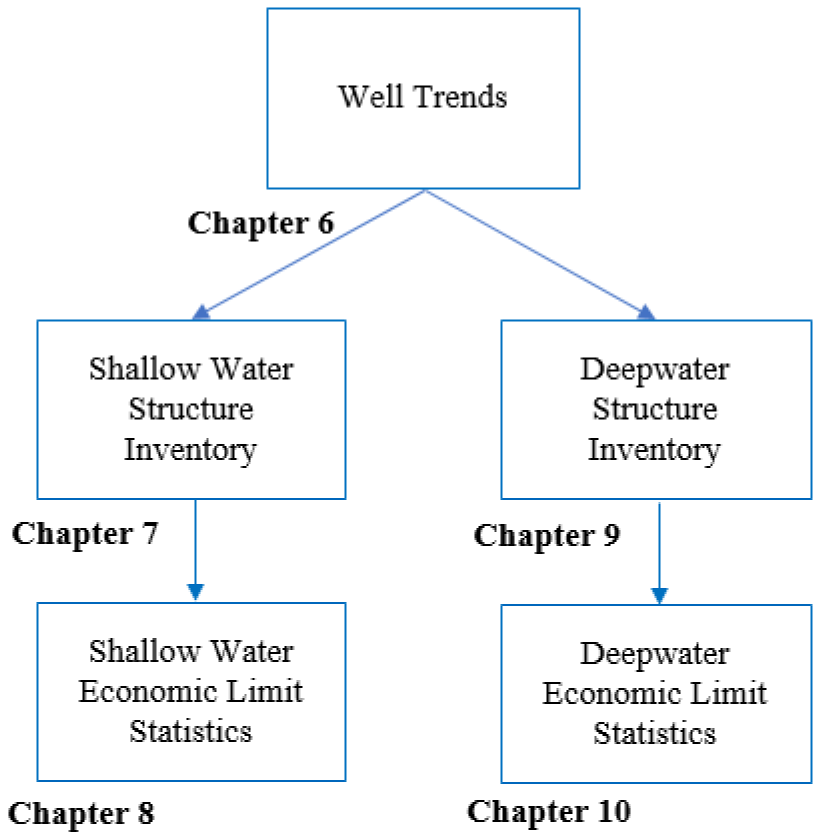
Example. Mississippi Canyon 696 (Blind Faith) reservoir fluids

The Blind Faith development is composed of four subsea wells from two oil reservoirs in Mississippi Canyon blocks 695 and 699 in approximately 7000 ft water depth (Subramanian et al. 2009). The wells are tied back about five miles via dual flowlines to block MC 650 in 6500 ft water depth. Two of the wells produce commingled fluid from multiple zones within the Pink reservoirs via stacked frac-pack completions. Two other wells produce from the deeper Peach reservoir via single frac-pack completions.

The Blind Faith reservoirs contain high pressure, undersaturated oils (28° to 33°API). The Pink and Peach fluids are quite different in terms of bubble point and GOR (Table E.7). The fluids have a low paraffin content and a dead oil paraffin wax appearance temperature from 80-100 °F. Flowline insulation was designed to achieve 100°F arrival temperatures topsides at turn down rates of 10,000 blpd, 0% water cut.

Asphaltenes in the Pink fluids range from 1.4 to 2.9 wt% and in the Peach fluids from 2.4 to 5.8 wt%. Asphaltenes are a solubility class of the crude oil defined as soluble in aromatic solvents and insoluble in paraffinic solvents. Asphaltenes may precipitate from the crude oil during depressurization and may deposit on the pipe walls and valves or accumulate in equipment. Mitigation techniques employed are asphaltene inhibitor (dispersant) injection. ■

PART 2. WELL TRENDS & STRUCTURE INVENTORY



CHAPTER 6. WELL TRENDS

Wells are a central feature in oil and gas development and activity levels provide important information on capital spending and trends. In this chapter, GoM well inventories and trends are described for wells drilled, exploration and development wells, abandoned wells, producing and idle wells, and subsea completions.

6.1. WELLS SPUD

A total of 52,976 wells have been drilled in the GoM through 2017: 46,243 wells (87%) in water depth <400 ft and 6733 wells (13%) in water depth >400 ft. Well counts include all wellbores drilled, exploration and development, including sidetracks. A dozen geologic and stratigraphic wells drilled for general scientific purposes are included in the tally. A sidetrack is a new section of wellbore drilled from an existing well drilled to access or test a different area of the reservoir, and is different than a bypass which is a remedial drilling effort in which a portion of a hole is redrilled because of drilling problems. Sidetrack counts are included in the well counts but bypass wells are not.

The number of wells spud in shallow water peaked during the decade from 1976-1985, when more than 1000+ wells were drilled annually, reaching a maximum of 1321 wells in 1984, the most wells ever drilled in the GoM in a single year (Figure F.1). In the late-1990s, 1000+ well years were achieved occasionally, and again in the year 2000, but in subsequent years the number of shallow water wells spud has dropped significantly, hovering around 200 wells/yr from 2009-2014 before declining to new lows. In 2014, 194 wells were spud, 70 in 2015, 26 in 2016 and 39 in 2017. The majority of shallow water wells have been drilled in less than 150 ft water depth.

Deepwater drilling started in the early 1970s and by the mid-1980s reached levels of 200 wells spud per year. Deepwater drilling activity is much smaller than in shallow water and less volatile from year-to-year, historically ranging between 100 to 300 wells/yr (Figure F.1). In 2014, 135 deepwater wells were spud, 139 in 2015, 101 in 2016 and 60 in 2017. In the last three years, more deepwater wells have been spud each year than in shallow water.

6.2. EXPLORATION WELLS

The purpose of exploration is to find commercial quantities of oil and gas. By definition, an exploration well is drilled outside known reservoirs, and therefore, operations almost always take place from a mobile offshore drilling unit (MODU). Jackups are used exclusively for drilling exploration wells in the GoM in water depth less than 500 ft; in deeper water, semisubmersibles and drillships are required.

Exploration is part of discretionary capital spending and activity fluctuates annually with changes in oil and gas prices, discoveries, company budgets, new technology, and many other factors. Without exploration drilling prospects cannot be tested and new reserves will not be found, and if companies do not replace their reserves, production will eventually decline.

The early history of oil and gas exploration in the GoM is nicely described in several publications, a few of which include McGee (1949), Beu (1988), and Austin et al. (2004). In 1937, the Creole field was discovered about a mile from shore south of Creole, Cameron Parish, Louisiana, and in 1946, Magnolia discovered a field about 10 miles southeast of Eugene Island, Terrebonne Parish.

From 1947-2017, there were 14,978 exploration wells drilled in shallow water and 3792 exploration wells drilled in deepwater (Table F.1). Excluding sidetracks, shallow and deepwater exploration well counts totaled 12,895 and 2549 wells, respectively, meaning that historically about 16% of shallow water exploratory wells and nearly half of all deepwater exploratory wells were sidetracked. The differences in the two regions are due in large part to differences in the cost and complexity of drilling. In deepwater, complex geology and expensive wells requires operators to extract the maximum amount of information from the drilling campaign.

From the early-1960s through 2006, between 200 to 500 shallow water exploration wells were drilled each year, peaking in the mid-1980s between 400 to 500 wells (Figure F.2). High levels of volatility characterize activity during this time. Since 2006 exploration well counts have been in steep decline and have recently bottomed out. In 2008, 153 exploration wells were drilled followed by 60 wells in 2009 and less than 50 wells/yr thereafter. From 2006-2017, 2280 shallow water exploration wells were drilled. A total of nine exploration wells were drilled from 2015-2017.

Deepwater exploratory drilling has never exceeded 200 wells/yr and over the past two decades have ranged between 50 to 150 wells per year. The number of deepwater exploration wells have fluctuated within a more narrow range than shallow water, hitting a low in 2010, the year of the Macondo oil spill and the deepwater drilling moratorium before bouncing back. A weak correspondence between shallow and deepwater activity from 1980-2010 is no longer observed. From 2000-2017, 1858 deepwater wells were drilled, or about 185 wells/yr. From 2015-2017, 260 deepwater exploration wells were drilled.

Exploration activity in shallow water has dropped due to a combination of factors, including lack of new discoveries, sustained low oil and gas prices, and the growth and success of onshore shale plays, especially unconventional shale gas. The lack of new discoveries is due in large part to the maturity of the region. Reservoir sands trapped by stratigraphy, faults and salt bodies in the Western and Central GoM have been extensively explored and the probability of major new (large) discoveries in the region are low. Oil prospects continue to attract attention in and around existing oil fields and deeper in the Miocene section, but success rates and commercial finds have not been significant to date.

There has been no significant new plays or prospects announced by operators in shallow water in several years, and previous excitement for deep gas plays >15,000 ft TVD (e.g., Davy Jones) has not materialized because of high cost complicated wells and disappointing production. On the other hand, deepwater exploration continues to attract attention and capital spending because of continued discoveries and a perception of high regional prospectivity, although much of the remaining deepwater resources are estimated to be Paleogene, which will have low recovery rates and technical challenges which may constrain future activity if economic solutions cannot be found.

Government estimates of the undiscovered conventionally recoverable resource for deep gas on the GoM shelf is approximately 5 to 20 Tcf, with the mean estimated at 10.5 Tcf (MMS 2003), and may remain that way until drilling technologies mature or a company develops an appetite for a high cost high risk gas play.

Example. Treasure Island play

In 2006, James Moffett, co-chairman of the board for McMoRan Exploration Co gave a talk titled "Davy Jones – A Major Wilcox Discovery and Its Implications for the Ultra-Deep Shelf Play in the GoM's Shallow Water" in New Orleans in which he outlined the buried treasure awaiting the drillbit at the Treasure Island play, a reference to the pirate nomenclature of the Davy Jones, Blackbeard, Lafitte, and Boudin prospects.

Exxon abandoned Blackbeard in 2006 after spending $200 million and reaching 30,067 ft. McMoRan picked up the Blackbeard prospect from Exxon along with Davy Jones and other acreage for an undisclosed amount. McMoRan subsequently deepened Blackbeard to 32,997 ft and found Miocene hydrocarbon bearing sands, and drilled six deep wells on lease blocks in South Marsh Island, Eugene Island blocks 26 and 223, South Timbalier 144, and Brazos to delineate the play.

Several problems were encountered when completing the wells, including stuck pipe, gummed-up drilling fluids, inability to flow test wells, etc. Bottom hole pressures of the wells approached 28,000 psi and mechanical difficulties eventually prompted the company to plug the holes in 2015 and suspend work. A total of $1.2 billion was reportedly spent before abandoning the endeavor. ■

6.3. DEVELOPMENT WELLS

Wells drilled to produce known reserves are classified as development wells. Development wells are drilled and completed in a variety of ways, using MODUs or a platform rig, or a combination of the two (e.g., batch pre-drilling from a MODU and completion via a platform rig). In some cases, successful exploration wells may be completed as producers. Completion operations involve installing production tubing and the wellhead, perforating the producing interval(s), stimulating, and in deepwater, frequently performing a gravel pack fracture. All development wells are not the same, of course, and there are various levels of complexity in drilling and completion requirements. One of the distinguishing characteristics of sidetrack wells is that they do not incur the full cost of drilling and in some cases may be drilled with a smaller rig. In a sense sidetrack wells can be considered a third or even one-quarter of a well in terms of drilled footage and cost.

In mature fields, sidetrack drilling can slow production decline if successful in adding new reserves, but this is generally a niche play and risky for old wells in depleted reservoirs, appealing mostly to the small-to-mid size operators because of its specialized nature and limited capital requirements. Upside potential is often low outside giant fields. Sidetrack drilling is also not cheap and requires rig mobilization and a few weeks drilling time, and the important point is the limited potential for revenue generation and reserves additions – the well may not pay off the cost to sidetrack – and thus these decisions are made carefully and methodically in mature fields. Geophysical technology is usually key to successful redevelopment.

The number of wells required in field development depends upon the size and complexity and depth of the reservoir sands, number of fault blocks, desired production rates, well type, development strategies, and other factors. The majority of development wells are usually drilled during the early stages of field development in the traditional spend-produce business model, but development drilling will also occur throughout a field's life as producing zones are plugged back and sidetracks drilled or additional phases of development occur. Phased developments are often the preferred strategy for complex reservoirs or where the operator wants to limit initial development costs.

Circa 2017, a total of 31,148 shallow water and 3046 deepwater development wells with sidetracks were spud, and 23,208 shallow water and 1654 deepwater development wells were spud without sidetracks. About one-third of shallow water development wells are sidetracked compared to over 80% of deepwater development wells. In development, sidetrack operations are the preferred means to access additional pockets and fault block reserves to maximize the value of existing infrastructure.

In shallow water, development drilling followed exploration activity and peaked in the mid-1970s before exploration plateaued, and then peaked again at lower levels in the late-1990s (Figure F.3). If exploration drilling is successful development wells will be needed, but development drilling also arises from the inventory of fields discovered and developed to date, which acts to reduce volatility in comparison. There is also a weak correspondence with exploratory drilling that can be inferred by inspection. From the mid-1960s through 2004, shallow water development well counts ranged between 400 to 1000 wells per year with smaller levels of activity from 1986 through 1992 due in part to depressed oil prices. In 1978, deepwater production began from the Bourbon and Cognac fields, a decade after the first exploration wells were drilled in the region because of the technical hurdles in development and the longer time in evaluation and planning. In deepwater, development drilling has never exceeded more than 200 wells per year.

In 2000, there were 772 shallow water and 168 deepwater development wells drilled. In 2017, 43 shallow water and 26 deepwater development wells were drilled. Trends in shallow water development drilling reflects the production decline in the region and since 2008 less than 200 development wells per year have been drilled. The number of deepwater development wells has also declined during this period, but deepwater oil production, after production upsets due to the 2008 hurricane season, has increased. From 2000-2017, 4995 shallow water and 1414 deepwater development wells were drilled.

6.4. ABANDONED WELLS

Through 2017, 52,964 wells have been drilled in the GoM and 27,405 wells have been permanently abandoned , leaving remaining well inventories circa 2017 at 25,559. Permanently abandoned (PA) wells represent the final state of a wellbore, while temporarily abandoned (TA) wells represent a transitory state for wells on their way to production or permanent abandonment.

There are many different pathways wells follow during their lifetime depending on why they were drilled, where they were drilled, how they were drilled, and whether the well was a keeper (successful) or not (Figure F.4). After wells are drilled they are temporarily abandoned before structures are installed to protect the wellbore or subsea equipment is ready to handle production. Producing wells that cease production for a long period for time may also be temporarily abandoned if they are expected to be utilized (e.g., sidetracked) in the future or if they are waiting to be permanently abandoned. Permanent abandonment is the final state of all wells. Wells may switch status between producing and shut-in or producing and TA one or more times, and if a sidetrack is drilled from the wellbore it will create a new well and forward path.

Wells that haven’t produced for many years are required to be placed in TA status, essentially requiring a long cement barrier or mechanical bridge plug, or both, but conductors are left in place. TA wells may remain inactive for many years. All TA wells will eventually be reclassified as permanently abandoned after final operations are performed unless exemptions for exceptional circumstances (e.g., hurricane destruction) are granted.

Permanent abandonment activity and PA wells are unambiguous in the sense that their status denotes the final end state of the well and once entered will not lead to another state (unless found to be leaking in which case the well will be reclassified as TA during remediation), while TA activity and TA status wells are more elusive because of their different objectives and transitory nature. Temporarily abandoned wells are neither producing nor permanently abandoned but are on their way to one of these states. Whereas PA inventory can only increase with time, TA inventories can increase or decrease as status codes change and new stock added.

In water depth <400 ft, there were 25,254 PA wells out of 46,243 wells drilled in the region, leaving 20,989 wells remaining to be permanently abandoned circa 2017 (Table F.2). In water depth >400 ft, there were 2151 PA wells out of 6733 wells spud, leaving a well inventory of 4582 deepwater wells remaining to be plugged circa 2017.

In shallow water, plug and abandonment activity began soon after the first wells were drilled in the region, either because they were not successful or because of production cessation. By the mid-1960s abandonment activity reached 300 permanent abandonments per year and has stayed above this level ever since (Figure F.5). In later years larger numbers of well abandonments coincided with higher structure decommissioning activity, reaching 500 permanent abandonments in 1983 and 900 permanently abandoned wells in 2009 and 2010. Before structures are decommissioned, all wells associated with the structure must be permanently abandoned, and thus one would expect a correlation between PA activity and structure decommissioning.

In deepwater, PA activity is on a much smaller scale because well inventories are smaller and younger and potentially more valuable until assets are abandoned, while TA activity is higher on a relative basis because of development requirements and associated option values (Figure F.6). About 25% of total deepwater abandonment activity circa 2017 were TA wells (566/2151), compared to about 12% (3063/25,254) in shallow water.

6.5. PRODUCING & IDLE WELLS

Wells start to decline immediately after they first produce and as wells stop producing they collect in inventory, sometimes returning to production via recompletion or well work, sometimes through a sidetrack at a later date (although strictly speaking this is a 'new' wellbore that is producing), and sometimes not returning to production.

Wells fail for any number of reasons and are shut-in for remedial work one or more times during their lifetime. Most wells require regular maintenance and will produce more and for longer periods of time with intervention. Some wells require more intervention than others and the level of intervention is one factor contributing to production volatility. When wells remain inactive for a long period of time (i.e., several years) they have likely depleted their reservoirs or have mechanical problems that are not economically justified to remediate and are unlikely to return to production.

In 2017, there were 3463 wells in the GoM that produced hydrocarbons during the last 12 months, 2644 wells in water depth <400 ft and 819 wells in water depth >400 ft (Table F.2). The number of producing wells varies with the size and age of the well inventory, the time of assessment, the number of wells completed during the year, and the development status of projects. The number of producing wells is small relative to the total active well inventory, a mere 13% (2644/20,989) in shallow water and 18% (819/4582) in deepwater, but this is not uncommon in the long lifetimes of field development.

The number of producing wells in shallow water has declined markedly over the last three decades (Figure F.7). In 1985, there were 7681 shallow water producing wells, and circa 2017 there were 2644 producing wells. Spikes in the years 2004-2005 and 2008 are attributed to hurricane activity and response. Every four years or so 1000 wells have dropped out of production. In 1997, over 7000 wells were producing; in 2003, there were ~6000 producing wells; in 2007, ~5000 producing wells; in 2011, ~4000 producing wells; in 2015, ~3000 producing wells. If these dropout trends continue, which seems likely considering the age of producing wells and the lack of replacements, by 2019 one would expect ~2000 producing wells, and by 2023 or so ~1000 producing wells.

Deepwater wells are on a completely different trend than shallow water and have not yet peaked, although activity levels have certainly leveled-off over the past decade (Figure F.7). Since 2002, there have been 800 or more producing deepwater wells most years, hitting a high in 2007 at 867 and numbering 819 in 2017.

In Figures F.8 and F.9, running totals of wells drilled, abandoned and producing are depicted for the shallow water and deepwater, respectively. In Figure F.10, the difference between cumulative drilled and abandoned wells yields the active well inventory in the shallow water and deepwater regions. Active shallow water inventories peaked over 25,000 in 2004 while deepwater inventories started to level off at this time. Producing wells are a subset of the active inventory.

6.6. Subsea Completions

In subsea completions the tree resides on the seafloor requiring mobilization of an intervention vessel or MODU whenever well work is required. In direct vertical access (DVA) wells, a subclass of wet well, the tree resides on the seafloor but is accessible from a rig on the platform. The Auger and Ursa TLPs and the Perdido spar employ direct vertical access wells.

Subsea wells are identified separate from dry tree wells because they differ in several fundamental ways in terms of their capital expenditures, operational requirements and limitations, and decommissioning liability. Subsea wells are more expensive to equip, workover, operate and decommission[6] than dry tree and DVA wells, perhaps an order-of-magnitude or more, and are expected to be abandoned at a higher production rates, for all things equal, because of the back pressure that arises delivering the fluid to the host and less frequent interventions to maintain the well's productivity (see Chapter 10 for additional details). Subsea wells have greater difficulty flowing with high water cuts because of hydrate formation and if gas lift or subsea compression is used to flow to a lower abandonment pressure, flow assurance issues such as asphaltene deposition may result.

The first subsea well was drilled in 1958 and operators experimented with pilot subsea production systems in shallow water through the mid-1970s to 'prove-up' the technology in anticipation of

[6] Note that drilling and completion cost are not included, since for all things equal, the cost to drill and complete a subsea well may be comparable to a dry tree well depending on how the wells are drilled and completed (e.g., with or without a platform rig, number of stages, number of casing strings, well complexity, etc.).

moving into deeper water (Burkhardt 1973, Childers and Loth 1976). The first deepwater subsea well was drilled in 1988. Subsea wells are generally not needed in shallow water because well protectors or fixed platforms can be employed for isolated small reservoirs and there is no advantage using wet wells. In deepwater, subsea wells are an important and integral component in an operator's development toolbox and large numbers began to be drilled in the mid-1990s (Figure F.11).

To date, 1443 subsea wells have been drilled, 112 in shallow water and 1331 in deepwater (Table F.3). Most shallow water wet wells are old and about two-thirds (73/112) of shallow water wells have been permanently abandoned compared to about 15% (178/1331) for deepwater wells. Since 2008, only three shallow water subsea wells have been drilled (Figure F.12) compared to almost 400 in deepwater (Figure F.13). Circa 2017, there were 383 producing subsea wells, eight in shallow water and 375 in deepwater.

CHAPTER 7. SHALLOW WATER STRUCTURE INVENTORY

The purpose of this chapter is to review the primary characteristics of shallow water structures in the GoM circa 2017. Structures are classified according to their production status, whether they were producing in 2017 or did not produce during the year but previously produced (idle), and structures with no production links to wells but serving in a support role (auxiliary). For producing structures, production, cumulative production and revenue are the primary features that describe the inventory. For idle structures, idle age, idle age at decommissioning and well status are the main features. For auxiliary structures, structure type, installation and removal rate quantify relevant characteristics.

7.1. PRODUCING STRUCTURES

7.1.1 2017 Revenue

In 2017, oil and gas production in the GoM in water depth less than 400 ft generated approximately $3.9 billion in gross revenue, $2.8 billion from oil sales and $1.1 billion from gas sales (Table G.1). Oil producers generated about $2.8 billion in total revenue, or on average about $5 million per structure. Gas producers generated $1.1 billion in total revenue, or about $3.4 million per structure.

Half of the producing inventory generated $2 million or less during 2017, about one-third of the inventory generated less than $1 million, and about 20% of structures generated less than $500,000 (Figure G.1). Structures generating half a million dollars a year are still economic since most are unmanned and part of regional operations where labor and logistics costs are shared and allocated across a portfolio of properties, but once revenues fall below a minimum threshold and cash flows are no longer adequate to cover direct cost, operators will find it increasingly difficult to maintain production from marginal producers.

Most of the revenue generated from oil and gas production on the shelf is from the top quartile of producers, and platforms hosting multiple wells dominate production (Figure G.2). Oil production generates about three-quarters of the revenue for shelf assets and for the average oil structure, associated gas contributes about 10% of sales revenue on an aggregate basis. For the average gas structure, liquids play a more sizeable role in sales revenue, ranging from about a third if condensate prices are equal to crude oil prices, down to about a fifth if condensate is priced at a 60% discount to crude oil.

In the U.S. Gulf Coast, condensate is normally priced between 40 to 60% crude oil prices, while casinghead gas may be priced at a 25 to 50%+ premium relative to gas well gas depending on market conditions. Condensate, sometimes called the ‘Champaign’ of crude oil because of its transparent appearance, fetches a lower price than crude oil along the Gulf coast because its narrow boiling point range means that it is less valuable to refiners and markets are more limited. On the other hand, associated gas is worth more than gas well gas because in the reservoir it will have ‘picked up’ heavier hydrocarbons which are subsequently stripped out and sold as valuable NGL streams.

7.1.2 Total Primary Production

Total primary production circa 2017 (i.e., crude oil for oil structures, natural gas for gas structures) is summarized in Table G.2 and depicted in Figures G.3 and G.4 for all shallow water oil and gas producing, idle and decommissioned structures. Only the primary product is depicted so that natural volume units (barrels and cubic feet) are used instead of heat-equivalent units, but the shape of the curves and conclusion are essentially unchanged with heat-equivalent units. Structure counts run along the x-axis. Cumulative production by structure on a log scale is depicted on the ordinate.

Producing oil structures extracted in total 6.2 Bbbl oil through 2017, which for an inventory of 563 structures, represents an average cumulative production of about 11 MMbbl per structure. Idle oil structures produced about 1.1 Bbbl oil through 2017, or an average 4.5 MMbbl/structure, and decommissioned oil structures produced in total 2.8 Bbbl oil or about 2.9 MMbbl/structure. Producing gas structures extracted 23.1 Tcf through 2017, or about 72 Bcf per structure, while idle gas structures produced 22 Tcf gas, or 52 Bcf/structure.

Decommissioned gas structures have produced the largest volume of gas among the three structure classes at 89.3 Tcf, but on an average structure basis is the smallest among the three classes. The average production across both oil and gas structures is lowest for decommissioned structures and highest for producing structures.

Gas recovery rates are significantly higher than oil recovery rates, and so one might suspect higher average production rates for gas structures relative to oil structures. Using the heat conversion 6 Mcf/boe yields recoveries of 11.7 MMboe/structure for producing gas structures, 8.2 MMboe for idle gas structures and 4.5 MMboe for decommissioned gas structures.

7.1.3 Total Cumulative Primary Production

If the production from each structure shown in Figures G.3 and G.4 are plotted in a cumulative fashion, the graphs in Figures G.5 and G.6 result. The ordinate scales are now much larger, as one would expect, increasing by two orders-of-magnitude compared to Figures G.3 and G.4, to accommodate the cumulative volumes.

For oil structures, total cumulative primary production is approximately 6.2 Bbbl for producers, 2.8 Bbbl for decommissioned structures, and 1.1 Bbbl for idle structures, or about 10 Bbbl total. For gas structures, total cumulative primary production is 89.3 Tcf for decommissioned structures, 23.1 Tcf for producing structures, and 22 Tcf for idle structures, or about 134 Tcf total. Secondary products are excluded from the tally and account for the incremental difference with total GoM shallow water production (for oil, 2.1 Bbbl condensate: 12.2 – 10.1 Bbbl; for gas, 53 Tcf associated gas: 186 – 134 Tcf).

7.1.4 Future Dynamics

What will Figures G.3 and G.4 look like in five or ten or twenty years?

When a structure stops producing it will ‘jump’ to either the idle inventory curve or directly to the decommissioned curve depending on the decision of the operator, increasing the structure counts on those curves by one and bringing along its cumulative production which will expand the receiving curve to the right and upward and change its shape while shifting the producing inventory curve to the left and downward due to shrinking production volume.

In recent years, the number of new installations in shallow water have been much smaller than the number of structures that cease production, and assuming this trend continues in the future, the producing structure curve will continue to shrink and shift left over time. Note that the producing oil curve in Figure G.3 falls to the right of its idle curve, while the producing gas structure curve in Figure G.4 falls on the left of its idle inventory curve having already made this transition.

Idle inventory will expand or shrink depending on the annual net change of transitions, expanding right if additions are greater than decommissioning, or moving leftward if additions are less than decommissioning. Idle structures are fed by those structures that stop producing and are reduced by decommissioning activity, but eventually all idle structures will be absorbed in the decommissioned inventory.

Decommissioned structure inventories can only grow in size since decommissioning is an absorbing final state that picks up structures from both producing and idle inventories and does not return any structures. The decommissioned structure curve will shift right and up over time.

7.2. IDLE STRUCTURES

7.2.1 Idle Inventory

Idle structures are formerly producing structures that have not produced for at least one year. Idle structures may transition back into producing status if inactive wells are reactivated or sidetracking is successful, or if all inactive wells are permanently abandoned an idle structure may be re-purposed to serve another function in field development.

By definition, all idle structures previously produced hydrocarbons, but for some reason – the cause is not publicly reported – the structure was not producing for the previous 12 months. There are many possibilities why production may stop, such as: well failure, scheduled workovers, third-party problems (i.e., pipeline repair), recompletion, investment review, hurricane damage, fire, etc.

In 1990, idle structure counts in the shallow water GoM totaled 505 structures, and up through 2010 every five years about 100 idle structures on average were added to the GoM idle inventory (Table G.3). In 2009, the number of idle structures peaked at 1077, but henceforth have declined every year. In 2017, there were 662 idle structures in the shallow water GoM.

7.2.2 Idle Age

Idle age describes the number of years since the structure last produced (Figure G.7, bottom arrow). If the last year of production of a structure is denoted by L, then circa 2017 the idle age of a structure is simply 2017 – L.

The idle age of GoM shallow water structures vary widely as one might expect and in 2017 there were 82 structures less than two years idle and 252 structures greater than 10 years idle (Table G.4). About 60% of the idle inventory circa 2017 have not produced in more than five years and about 40% of the inventory hasn't produced in more than 10 years. Idle structures are roughly evenly distributed between caissons/well protectors and fixed platforms.

The longer a structure sits idle the less likely it will be brought back to production but a useful function for the structure may be found. Because structure function is not publicly reported, a portion of idle structures will be serving a useful purpose in field operations and partially explain their old age.

Before 2010, structures idle ≤ 3 years were generally the most populated category, but as idle structures age they move into older vintage categories if not decommissioned. In recent years, structures idle >10 years is the most common category.

7.2.3 Idle Age at Decommissioning

The idle age of a structure at the time of decommissioning provides information on how long structures are idle before being decommissioned (Figure G.7, top arrow). If the last year of production of a structure is L and the structure was decommissioned in year D, then the age of the structure at decommissioning is simply $D - L - 1$. Trends in this data provide information on how operators are managing their idle structures. Structures idle for less than two years at the time of decommissioning are described as the producing or the 0-1 yr class, and other categories include structures idle for 2-5 yr, 6-10 yr, and 10+ yr at the time of decommissioning.

After a structure's application for decommissioning is approved by federal regulators the operator has one year to perform the activity, and because an operator is given a 6-month time to file its application after the cessation of production, the 0-1 year category is considered a transition direct from production status to decommissioning. The total number of structures and the percentage of structures that fall within each category by decade is shown in Table G.5.

A total of 4326 producing and formerly producing structures have been decommissioned since 1973. Structures producing and idle for less than two years at the time of decommissioning contributed the majority of the transitions, 1500 total structures, followed by the 2-5 yr idle class at 1453 structures, and the 6+ yr idle class at 1373 structures. Hence, on a historical basis decommissioned structures have an approximately equal probability of arriving from the producing, 2-5 yr, and 6+ yr categories (Figure G.8).

The idle age of structures at the time of abandonment have changed over the past two decades. From 1997-2006, there were 483 structures idle <2 years at the time of decommissioning and 328 structures idle ≥ 6 years decommissioned, out of a total of 1197 structures. From 2007-2016, there were 536 structures idle <2 years decommissioned and 682 structures idle ≥ 6 years decommissioned, out of a total of 1875 structures. Young idle structure decommissioning as a percent of the total decreased from 41% to 29% over the past two decades, while the proportion of older idle structures increased from 27% to 36%

Structures decommissioned by idle age group by year is graphed in Figure G.9 and in a stacked representation in Figure G.10. The 0-1 yr group was the most populated group in early years followed closely by the 2-5 yr group which has dominated in recent years. Producing inventories are shrinking in absolute numbers as the idle classes contribute a larger portion of decommissioning activity and these trends are expected to continue in the future.

7.3. Auxiliary Structures

The number of auxiliary installations have never exceeded more than 50 structures per year and decommissioning rates are typically less than half the install rate at between 10 to 25 structures per year (Figure G.11). In Figure G.11, annual installation and decommissioning activity as well as the active auxiliary inventory is depicted on the left vertical axis, while the cumulative number of installations and removals are denoted on the right vertical axis. The horizontal axis is time in years.

One way for an operator to transform a producing or idle structure into an auxiliary structure is to plug and abandon all the wellbores and to run production from another field/platform across the facility. Another transformation pathway is to recertify a producing or idle structure as a transport and fuel depot hub after abandoning its wells.

Most of the transportation platforms on the shelf were originally anchored by field production and as production was exhausted transformed into auxiliary structures. Two other classes of auxiliary structures on the shelf include those that handle deepwater production and those that support transportation companies. Most of these structures are built for purpose.

Since auxiliary structures are not associated directly with well production, caissons and well protectors are not a common structure type, and the vast majority of auxiliary structures are fixed platforms. Circa 2017, 192 of the 357 auxiliary structures were classified as 24-hr manned. Over the past decade, auxiliary structure decommissioning has ranged from 7 to 15% of the annual number of structures decommissioned in the Gulf (Figure G.12). The historic average decommissioning rate of auxiliary structures is 14% of total decommissioning activity.

CHAPTER 8. SHALLOW WATER ECONOMIC LIMIT STATISTICS

Net revenue during the last year of a structure's productive life serves as a proxy for the economic limit of production and encapsulates all the relevant cost information available. By reviewing a large group of decommissioned structures, economic limits are quantified and compared using structure attributes to gain insight into operating cost thresholds and business practices. Summary statistics are tabulated by primary production, structure type, manned status and water depth for 3054 decommissioned structures from 1990 to 2017. The P50 adjusted gross revenue the last year of production was $1.2 million for gas structures and $627,000 for oil structures. For gas structures, P20 and P80 economic limits are $282,000 and $3.97 million; for oil structures, $135,000 and $2.01 million, respectively. Factor models distinguish the impact of individual variables and show that majors have economic limits $820,000 per structure greater than independents holding all other factors constant.

8.1. METHODOLOGY

8.1.1 Revenue Model

For decommissioned structures, the net revenue near the end of its productive life is a proxy of its economic limit and is straightforward to compute since the production profile $Q(t)$, royalty rate r, and oil and gas prices $P^o(t)$ and $P^g(t)$ are all known and available historically. If the last year of production is denoted as T_a, then the net revenue the last year of production NR_{LY} determined from monthly oil and gas production volumes and average monthly oil and gas prices from T_a-1 to T_a is determined as:

$$NR_{LY} = \sum Q(t)P(t)(1-r).$$

In shallow water, the vast majority of decommissioned structures are under royalty rates of 16.67%, with significantly fewer at 12.5% and 18.75%. Since royalty is for all practical purposes constant across the sample and relative differences negligible, gross revenues are considered a suitable proxy and used

$$GR_{LY} = \sum Q(t)P(t).$$

8.1.2 Categorization

Structures are categorized according to structure type and oil structures are distinguished from gas structures. Manned structures and structures associated with a multi-structure complex are identified. Caissons and well protectors are functionally equivalent and are consolidated into one structure type category. Three water depth subcategories are applied: <100 ft, 100-200 ft, and 200-400 ft. Major integrated operators (majors) are distinguished from independents.

8.1.3 Sample

The sample consists of 3054 structures that ceased production and were decommissioned between 1990 and 2017. Of the 3054 structures, 512 were decommissioned oil structures (319 C/WP, 193 FP) and 2543 were decommissioned gas structures (1249 C/WP, 1293 FP). The sample was split roughly evenly between major and minor structures with 1568 C/WPs and 1486 FPs and unmanned facilities were dominant (2947 unmanned, 108 manned). The vast majority of structures resided in water depth <200 ft and only 281 structures (mostly fixed platforms) were in water depth >200 ft. The sample contained 108 manned structures (27 oil, 81 gas), 114 multi-structure platforms, and 289 structures operated by majors. Chevron had the largest presence among majors (234 decommissioned structures) followed by BP (23), Shell (18), Texaco (14) and Total (7).

8.1.4 Exclusions

Structures that stopped producing before 1990 and were decommissioned on/after 1990 were excluded from the sample because of the increased uncertainty and potential bias associated with long-term price adjustments. Structures that stopped producing after 1990 and not decommissioned by 2017 (idle structures) were not part of the sample because their ultimate status is not yet determined. All hurricane-destroyed structures identified through MMS/BOEM official records were excluded since these represent (at least in part) pre-mature removals which would bias (upward) the economic limit statistics.

8.1.5 Adjusted Gross Revenue

The gross revenue the last year of production is computed using monthly production data and average monthly Henry Hub prices for natural gas and West Texas Intermediate prices for crude oil for the 12 months prior to production cessation. In Figure H.1, model data from a typical decommissioned gas structure is illustrated. The product streams and commodity prices are shown across 12-mo time windows from the end of production. Crude and condensate prices, and gas well gas and casinghead (associated) gas prices, are assumed equal, and because they are generally not equal will enter as model error/noise. Computed gross revenue are adjusted to 2016 dollars using the CPI.

8.2. DISTRIBUTIONS

8.2.1 Oil vs. Gas Structures

The adjusted gross revenue distribution the last year of production for all shallow water oil and gas structures for all water depths and structure type is summarized in Table H.1 and depicted in Figure H.2. The economic limit for gas structures exceed the economic limit for oil structures. The median P50 values are $1.23 million for gas structures and $627,000 for oil structures. For gas structures, P20 and P80 economic limits range from $282,000 to $3.97 million, respectively. For oil structures, P20 and P80 economic limits range from $135,000 to $2.01 million.

The gap between oil and gas structure economic limits is expected to grow if actual sales prices were available. Oil and condensate prices, and gas well and casinghead prices, are assumed equal, but in reality condensate is usually priced at a discount to crude oil and casinghead gas is worth more than gas well gas. In other words, the liquid revenue stream from gas wells is priced higher than what is expected to occur in practice, while for oil wells the gas stream is priced lower than what operators will receive, and these differences will expand the gap observed. Oil structure revenues will increase slightly from the higher sales price of casinghead gas while gas structure revenues will decrease from lower condensate sales prices.

8.2.2 Structure Type, Manned Status

Structure type and manned status exhibit expected aggregate behavior for each class (Figures H.3-H.6). Caissons and well protectors are exclusively unmanned structures with lower fixed operating cost than fixed platforms and are expected to exhibit a lower economic limit. Manned structures have a higher operating cost than unmanned structures, for all other things equal, and are more valuable to manage regional operations which accounts for far fewer removals. For gas structures, the difference in economic limits by structure type is less pronounced than for oil structures, indicating similar well counts and cost characteristics at the end of their life. The spread in the distributions between manned and unmanned gas platforms are similar to oil structures.

8.2.3 How Can Some Economic Limits Be So Low?

The economic limits for some structures can be very low, on-the-order of a hundred thousand dollars (the approximate labor cost of one individual) and remain profitable. As long as operators can recover their direct cost of operations a structure can continue to produce. A hypothetical example is used to illustrates how labor and transportation cost are allocated to structures in a regional operation. In regional operations operators can achieve cost savings by using bundled labor and sharing transport services.

Example. Labor and transportation cost allocation

Field operations involve five platforms, a manned complex with two connected structures P1/P2 and three unmanned structures P3, P4 and P5 (Table H.2). For a permanent six-man production crew working a one week tour (one week on/off), total man hours is 52,560 hrs per year and total annual flight hours for operations is 286 hrs. Total labor cost at $100,000/person leads to an annual cost of $1.2 million, or $22.83/man-hr ($1.2 million/52,560 man-hr).

Satellite platform P3 requires a three-man crew visit three times per week and 8 hr per visit, 15 min flight time from the manned complex. This leads to

$$3 \text{ man} \cdot 8 \text{ hr/visit} \cdot 3 \text{ visits/wk} \cdot 52 \text{ wk/yr} = 3744 \text{ man hours/yr}$$

$$0.5 \text{ hr/trip} \cdot 3 \text{ visits/wk} \cdot 52 \text{ wk/yr} \cdot 78 \text{ flight hours/yr.}$$

Satellite platforms P4 and P5 require a two-man crew visit once per week, 8 hr per visit, 30 min flight time. Complex C is charged $1.1 million for labor while platform P3 is allocated $86,000 and platforms P4 and P5 are allocated $19,000 each. Helicopter cost is based on $2000/hr flying time. Total transportation cost of $572,000 (286 hr * $2000/hr) is allocated according to flight hours similar to the labor cost allocation.

The total labor and transportation cost range from $2.5/bbl at platform P3 to $41/bbl at platform P5. Average operational cost is $5.1/bbl. Allocated labor and transportation cost at platforms P4 and P5 are about $125,000 which would not be able to maintain production outside regional operations. The unit cost for P5 is high but still profitable for the 3000 barrels received. If the price of crude oil is less than $41/bbl, platform P5 may be temporarily shut-in if cost cannot be reduced. If P5 is decommissioned the operator saves on transportation cost to the facility and unit cost will be reduced to $4.8/boe. As high cost structures are shut-in some costs are saved but remaining expenses will be allocated across fewer properties. ■

8.3. TIME TRENDS

8.3.1 Structures

The average adjusted annual gross revenue from 1990-2017 for shallow water decommissioned structures is $2.45 million with a standard deviation of $969,000 (Figure H.7). From 1990-1999, the average gross revenue and standard deviation was $2.55 million ($620,000); from 2000-2009, the average gross revenue and standard deviation was $3.0 million ($1.1 million); and from 2010-2017, the average gross revenue and standard deviation was $1.59 million ($580,000).

For six years of the 28-year time period, the average adjusted gross revenues exceeded $3 million, and in four of those years hurricane activity occurred the same or previous year which likely contributed to a knock-out affect for damaged-but-not destroyed structures (Kaiser 2014). Hurricane activity in 1992 (Andrew), 2005 (Katrina and Rita) and 2008 (Ike and Gustav) appear to have prompted damaged structures to be removed earlier than normal and with higher gross revenues than average.

8.3.2 Oil vs. Gas Structures

For gas structures, the mean adjusted gross revenue and standard deviation from 1990-2017 was $2.6 million ($1.1 million), and for oil structures the mean adjusted gross revenue and standard deviation was $1.91 million ($2.4 million). Before 2007, the average gross revenues of gas structures always exceeded the average gross revenues of oil structures, but after 2007 average oil structure gross revenues usually dominate (Figure H.8). In 2013, a small number of structures that stopped producing contributed to much higher than average gross revenues resulting in a spike. Average gas structure gross revenue was about twice the average oil structure revenue from 1990-2009 but in the most recent decade the trend has reversed (Table H.3).

8.3.3 Water Depth

The economic limits for oil and gas structures in water depth <100 ft most often fall at the bottom of the revenue range, while structures in the 200-400 ft water depth category often bound the upper interval (Figures H.9, H.10). Greater water depth usually corresponds to longer distance to shore and higher logistical cost which contribute at least partially to the trends shown. Each graph shows a few years of higher-than-average volatility due in part to small sample sizes.

8.3.4 Moving Time Windows

The adjusted gross revenue distribution the year before the last year of production and the third and fourth year before cessation is shown in Figures H.11 and H.12. In the figures, 0-1 y represents the last year of production, 1-2 y represents the second to last year of production, and so on. The revenue distribution differentiates at the low-end and is greater at the mid- and high-end for both oil and gas structures. This is easy to understand since production is usually (although not always) higher before the last year of production, while prices may be higher or lower which contributes to the year-to-year variation.

For gas structures, P50 the last year of production was $1.22 million, while for the third and fourth year before production cessation P50 was $2.34 and $1.97 million, respectively. For oil structures, the P50 values the last year of production was $627,000, while the third and fourth year before production cessation was $1.15 and $1.32 million, respectively. P50 values do not always increase in the years before cessation due to production and price variability but in all cases are greater than the last year of production.

8.4. Factor Model

8.4.1 Model Specification

A factor model is used to investigate the impact of individual variables on economic limits controlling for multiple simultaneous effects. A linear model is specified with a fixed term coefficient:

$$EL = \alpha_0 + \sum \alpha_i X_i ,$$

where the variables are selected by the user and the factor coefficients are determined via regression. The values of the model coefficients will depend on the period of the evaluation and the selection of the model variables.

Factor variables examined include structure type, production type, water depth, manning status, operator type and complex type and are defined as indicator variables: Type = structure type (0 if C/WP, 1 if FP), Oil/Gas = primary production (0 if oil, 1 if gas), WaterDepth = water depth category (0 if <200 ft, 1 if >200 ft), manned status (0 if unmanned, 1 if manned), Major = operator type (0 if independent, 1 if major) and Complex = complex identification (0 if single-structure complex, 1 if multi-structure complex).

8.4.2 Results and Discussion

The first model constructed is a four-factor model:

$$EL_A = \alpha_0 + \alpha_1\text{Type} + \alpha_2\,\text{Oil/Gas} + \alpha_3\text{WaterDepth} + \alpha_4\,\text{Manned}$$

All the coefficients are positive and significant (Table H.4). For an unmanned oil C/WP in less than 200 ft water depth, for example, the average economic limit is $1.22 million with an 95% confidence limit between $821,000 and $1.62 million. For an unmanned gas fixed platform in <200 ft water depth, EL = $2.65 million. For an unmanned oil fixed platform in <200 ft water depth, EL = $1.33 million.

Among the four descriptor variables structure type plays the smallest contribution to the economic limit, about an order-of-magnitude smaller than the other variables which are all approximately of the same size. The distinction between oil and gas production type is the most significant factor, only slightly greater than the fixed term coefficient which can be interpreted as an average fixed cost of operation.

In the second model, a term is added to distinguish if an operator is a major integrated company:

$$EL_B = \alpha_0 + \alpha_1\text{Type} + \alpha_2\,\text{Oil/Gas} + \alpha_3\text{WaterDepth} + \alpha_4\,\text{Manned} + \alpha_5\text{Major}$$

For all things equal, one would expect majors to have a greater economic limit than independents because of greater administrative and overhead cost, greater planning requirements, and absence of marginal properties in portfolios that contribute to higher average production cost. From Table H.3, decommissioned structures operated by majors increased the economic limit by $820,000 and was statistically significant.

Finally, in the third model a term is added to identify those structures that were part of a multi-structure complex at the time of decommissioning:

$$EL_C = \alpha_0 + \alpha_1\text{Type} + \alpha_2\,\text{Oil/Gas} + \alpha_3\text{WaterDepth} + \alpha_4\,\text{Manned} + \alpha_5\text{Major} + \alpha_6\text{Complex}.$$

One would expect structures that are part of a complex would have a lower economic limit of production compared to isolated structures, and indeed, multi-complex structures on average had a lower economic limit by $310,000, about one third as large as the primary terms but a larger contributor than structure type.

8.5. Limitations

8.5.1 Generalization

There are few generalized statements that can be made about offshore operations because of the dynamic nature of the industry and broad spectrum of company strategies and sizes within the sector. Conceptual and economic relations for economic limits allow one to frame issues in a transparent and clear manner and to quantify relations in a first-order approximation, but because there are usually multiple interacting and overlapping factors and other relevant factors that cannot be observed, it is generally impossible to measure or recognize them all and special cases often abound. Conceptual relations and simple econometric techniques are usually adequate to perform useful analysis but remain constrained in their ability to characterize operations without a deeper understanding of the engineering and technical considerations involved in development and production. Using end-of-year revenue as a proxy for the economic limit is a gross approximation.

8.5.2 Gross Revenue Approximation

Gross revenue is an approximation to actual revenues received since sales prices and product quality are unobservable, and royalty rates were not included in the assessment. Market prices are believed to be a reasonable proxy of sales prices but adjustments for quality (gravity, sulfur content, heating value), transportation expenses, hedging programs, contract conditions, etc. cannot be performed. Price adjustments for quality and transportation are usually considered second-order effects (i.e., dollars on the barrel) and are frequently neglected but for particular properties may have a significant impact. Royalty rates are essentially constant across the sample and do not enter in an meaningful way. The gross revenue computation is an approximation but is believed to be a relatively robust and reliable measure.

8.5.3 Structure Classification

A four legged jacket structure with two or three wells and minor topsides equipment would normally be classified as a well protector, but in some instances a fixed platform identification may have been adopted so the distinction between these two structure classes is not always well-defined. Caissons and well protectors were consolidated into the same category for convenience. Platforms could have been decomposed into minor and major structures but this was not pursued because of the duplicity of the categorization with structure type. Structure size could be proxied by number of well slots, maximum production or deck size, but was not considered since structure type and water depth provide at least partial overlap. There are also constraints on data availability and other issues that constrains application. Manned multi-structure complexes identify all structures as manned and introduces ambiguity on manning status for a subset of the sample but is otherwise considered of negligible impact.

8.5.4 Interpretation

Economic limit data and statistics are straightforward to understand and interpret with minimal levels of uncertainty. A rationale operator will terminate operations at/near its economic limit unless other conditions prevail. Production data is highly reliable in aggregate although in some cases well links to platforms may be erroneous. Oil and gas prices are market based and reliable. Large samples and application of median statistics help ensure potential errors/bias average out and outlier impacts are small.

8.5.5 For All Other Things Equal

The disclaimer ‘for all other things equal’ was frequently used when discussing or reporting results, one of the favorite monikers of economist. Rarely, however, if ever, never in fact, are all other things equal, especially for offshore fields since developments are man-made and built at different times and at different locations using different technologies by different operators applying different economic criteria and tradeoffs. Of course, there are also significant commonalities involved in development and decision making and the interplay between the two will impact evaluation and results. Regression models are only able to control for factors in an approximate manner. Although engineering requirements are similar throughout the world and the physics of drilling and fluid flow obey the same laws and properties everywhere, best practices and design choices are unique and change over time by region and operator and may or may not dominate the unique project-specific nature of development.

8.5.6 Independence

Structures are treated as a statistical ensemble with elements considered independent of one another for the purpose of evaluation, while in practice significant interrelationships and dependencies are present based on regional operations, pipeline activities and service (e.g., gas-lift) requirements. These dependencies, while interesting and a key feature of GoM operations, are for most practical purposes difficult to establish and incorporate in models and were not considered. The impact of these conditions may or may not be significant.

8.5.7 Aggregation

Structures served as the assessment unit in evaluation but different units may be applied at higher or lower levels of organization such as a well, lease, unit, or field. Caution should be exercised when establishing correlations between high-level aggregate data and complexities arise if the aggregate units do not represent the business/financial groupings of operators. Aggregation consolidates information, stripping away some useful characteristics while smoothing out variation, and if the data sets are not large enough moderate levels of correspondence may be discovered between unrelated or irrelevant variables. Usually, the experience of the analyst and careful assessment will be adequate to handle ambiguity and eliminate the irrelevant factors, but this is not a given nor does it always hold. Consolidation is necessary in many contexts but does not always apply nor should be used without a clear and definitive basis and understanding of operational and logistical requirements. Aggregation may mask or distort relevant information or present trends of a dominant class (i.e., gas structures) at the expense of smaller subcategories.

8.5.8 Categorization and Volatility

As a larger number of attributes are applied to delineate structure data, categories become more granular and the data that populate individual categories smaller in size. This creates a tradeoff in evaluation since the benefits that accrue when creating more homogenous and refined categories become curtailed with smaller sample sizes which increases volatility and the potential impact of outlier data. Sample averages of sparsely populated shallow water categories may not be representative.

CHAPTER 9. DEEPWATER STRUCTURE INVENTORY

The deepwater inventory in the GoM consisted of 48 fixed platforms, three compliant towers, and 47 floaters circa 2016. These structures are grouped according to fixed platforms in water depth 400-500 ft, fixed platforms and compliant towers in water depth >500 ft, and floaters. All of the floaters were producing circa 2016 while 12 of the 48 fixed platforms no longer produce and at least five of these structures have been converted to pipeline junctions. In the first part of the chapter, floater equipment capacity and capacity-to-reserves ratios are examined, and then well type, production, reserves, PV-10 and revenue statistics are reviewed for each of the three categories circa 2016. In the second half of the chapter, gross revenue statistics are broken out by structure, and material concludes with a description of the four projects sanctioned and under construction circa 2017.

9.1. FLOATER EQUIPMENT CAPACITY

Topsides includes all the equipment to separate, treat, dehydrate, and prepare production for export; to treat the produced water; compress the gas for treating and export; and to provide metering for custody transfer of oil and gas, utilities, storage and related system elements. In some cases, water injection and gas injection systems are needed. Equipment capacity is normally designed to match development requirements (right-sized), but in some cases may be built with extra capacity in anticipation of future tiebacks (over-sized).

Nameplate equipment capacity describes the maximum oil and gas processing capability of the structure and is described by the gas-to-oil equipment capacity (G/O) ratio measured in cubic feet per day (cfpd) per barrel per day (bpd). Since the daily rates cancel, the G/O ratio is described more simply in cubic feet of natural gas per barrel crude (cf/bbl) similar to the gas-oil ratio (GOR) describing production. Similar to the GOR threshold, a value of G/O <5000 cf/bbl generally indicates an oil structure although thresholds as high as 10,000 cf/bbl may be applied. Values of G/O <1000 cf/bbl imply heavy reservoir oil.

For GoM floaters, equipment capacity data is publicly available while fixed platforms data is much more limited, and so the focus in this and the next section is on floaters.

Example. Jolliet TLP nameplate capacity

The Jolliet tension leg platform (complex 23583) was the first TLP installed in the GoM in 1990 and was designed for a maximum production rate of 35,000 bpd oil and 50 MMcfd gas. The nameplate G/O capacity ratio is computed as 1429 cf/bbl:

$$\text{G/O} = \frac{50\ \text{MMcfpd}}{35{,}000\ \text{bopd}} = 1429\ \text{cf/bbl}.$$

Cumulative oil production from Jolliet through 2016 was 36 MMbbl oil and 136 Bcf natural gas, or a cumulative gas oil ratio of CGOR = 3797 cf/bbl. Production of natural gas usually increases as oil reservoir sands deplete. ■

In Figure I.1, the nameplate equipment capacity for all floaters (except Independence Hub) is depicted and lines of constant slope G/O = 10, 5, 2.5, 1, 0.5 Mcf/bbl are overlaid. Structures in construction circa 2017 are shown italicized and in red. Groupings of equipment capacity that fall along vertical and horizontal lines are due to standardized well and equipment designs.

Most floater G/O capacity falls in the G/O slice between 1 and 2.5 Mcf/bbl, indicating the mostly liquid and oily nature of deepwater reservoirs developed to date. Many recent developments in the Lower Tertiary trend (e.g., Stones, Jack, St Malo, Cascade, Chinook) are heavy oil developments with equipment capacity G/O < 0.5 Mcf/bbl. Independence Hub is the only (dry) gas development in deepwater with a stand-alone structure with G/O > 10 Mcf/bbl. Independence Hub's gas processing capacity of 1 Bcfpd and 5000 bpd condensate capacity would plot in the top left slice off the chart.

About half of deepwater floaters have oil processing capacity that ranges between 30 to 100 Mbpd and gas processing capacity between 50 to 200 MMcfpd (shaded box, Figure I.1). Average nameplate processing capacity for the floater inventory is 77 Mbpd oil and 150 MMcfpd natural gas or 102 Mboepd and a standard deviation of 56 Mboepd. This translates to an annual average nameplate capacity of 40 MMboe with standard deviation of 22 MMboe. The most common oil capacity category is 25-50 Mbopd, and when combined with gas processing shifts one category to the right to 50-75 Mboepd (Figure I.2).

Five structures have oil processing capacity >150 Mbpd (Ursa, Jack/St Malo, Atlantis, Mars, Thunder Horse) and five structures have gas processing >350 MMcfpd (Devils Tower, Ursa, Auger, Na Kika, Lucius). Semis have the largest average processing capacity and also the largest variation across structure type reflecting their application in both small and large field developments (Lim and Ronalds 2000).

9.2. Floater Capacity-Reserves Statistics

9.2.1 Capacity-to-Reserves Ratio

At the time of project sanction, the capacity of production equipment and export pipelines are usually known and sized for the well plan and expected maximum flow rates expected. Capacity-to-Reserves (CR) ratio is defined as the oil and gas production handling capacity installed expressed in heat-equivalent barrels on an annual basis to total expected production (i.e., reserves) expressed in barrels oil equivalent:

$$\text{Capacity-to-Reserves} = \frac{\text{Equipment Capacity (boe)}}{\text{Total Production (boe)}}.$$

Equipment capacity does not include water handling, water injection or gas injection. The capacity term is available via industry publications at the design basis and the denominator needs to be computed (estimated).

Over time, fields that were not considered in the original development plan may be tied back and processing capacity at the structure may be increased, or wells may not produce as expected. In either case, the CR ratio will change, increasing if equipment capacity was increased or expected reserves were not realized, or decreasing if additional production is brought back to the facility. Once equipment is installed it is rarely downsized but increasing capacity to handle additional flows is not uncommon.

Equipment capacity is not directly observable unless reported by the operator and subsequent changes to design may or may not be reported. Total production also changes over time with reserves growth or unanticipated problems or with new field tiebacks. Only at the end of production when the structure is decommissioned are reserves known with certainty.

Equipment specifications may change as tieback fields are added and these are often reported by operators if significant work was required at the facility:

- Mars TLP was originally designed to handle 100 Mbpd oil and 100 MMcfpd gas, but with subsea tiebacks from the King, Europa and Deimos fields production capacity was later expanded to 220 Mbopd and 220 MMcfpd.
- Auger TLP processing capacity has been expanded three times since installation, from its original 55/130 Mbpd/MMcfpd capacity to its current 105/420 nameplate.
- Production at the Na Kika hub initially included six fields in 2003, but third third-party tieback fields in the Galapagos development – Isabella (2011), Santiago (2014) and Santa Cruz (2015) - required processing capacity to be expanded to 150/550 nameplate.
- The Thunder Hawk semi was initially designed with 45/70 capacity but with third-party tiebacks Big Bend and Danzler in 2015 the facility expanded oil processing capacity to 60 Mbopd and added gas lift capabilities.

CR ratios have a greater tendency to decline over time due to reserves growth and tieback fields that add production to the structure beyond the design basis. Operators will not add capacity unless reserves are proved-up. If tiebacks occur when the structure is at or near peak production, capacity will need to be added, while if the tieback occurs late on the decline curve, capacity additions will be more limited or not needed.

9.2.2 Capacity-to-Reserves Statistics

The average CR ratio for all floaters circa 2016 (except Heidelberg) is 0.32 with a standard deviation of 0.31 (Figure I.3). About 75% of the floaters have CR ratios less than 0.4 with the majority ranging between 0.10 and 0.30.

The four outliers at the high-end include:

- Cascade and Chinook which have produced 29 MMbbl oil and 4.8 Bcf gas through 2016. In 2016, 4.4 MMbbl oil and 0.7 Bcf was produced at the FPSO.
- Prince produced 0.7 MMbbl oil and 1.2 Bcf gas in 2016 from four wells and cumulatively have produced 10.1 MMbbl oil and 11.2 Bcf gas.
- Gulfstar (Tubular Bells) had six producing wells in 2016 and has produced 17.1 MMbbl and 35.6 Bcf gas to date.
- Telemark/Mirage/Titan fields produced 13.4 MMbbl and 14.3 Bcf from four producing wells through 2016.

Heidelberg was excluded because its four wells have only recently started producing and reserves estimates could not be reliably computed.

9.3. WELL TYPE

There are two types of offshore wells that are important to distinguish – wet tree wells and dry tree wells. Wet wells have remote subsea wellheads which are connected to their host by steel or flexible catenary riser systems, lazy wave systems or hybrid risers, and in some cases (e.g., Auger, Olympus, Perdido) the wellhead/tree is located on the seabed directly below the structure to reduce topsides weight and are referred to as direct vertical access (DVA) wells. DVA wells are subsea wells since the wellhead/tree is on the seabed but because they allow (direct) rig access from the platform and do not come with all the expensive subsea equipment (e.g., manifolds, flowlines, umbilicals, jumpers, etc.) and flow assurance issues common to wet wells, they are (somewhat) similar to dry tree wells.

Dry trees reside above the waterline and are connected to the wellbore with a top-tensioned riser. Dry tree and DVA wells allow direct access from the platform while a wet well requires mobilizing an intervention vessel or MODU to access the well. Wet wells are more expensive to operate, more expensive to intervene, have a higher economic limit, and have smaller recovery rates relative to dry tree and DVA wells, for all things equal. FPSOs and most semisubmersibles are wet well developments, while spars and TLPs permit both dry and wet well tiebacks.

In 2016, there were 52 wet wells tied back to fixed platforms in 400-500 ft water depth compared to 485 dry tree wells, and for fixed platforms and compliant towers in >500 ft water depth there was 210 wet well and 906 dry tree wells (Table I.1). For floaters, wet wells outnumbered dry tree wells 746 to 648. Subsea wells represent a larger percentage of wells in floater developments and a larger percentage of producing wells circa 2016.

9.4. Production

In 2016, there were 36 fixed platforms, three compliant towers, and 47 floating structures that were producing. Two recently installed structures, Walter Oil & Gas Coelacanth (2606) and Shell's Stones (2503), first produced in 2016. All the floaters except one (Independence Hub) and the three compliant towers are classified as oil producers (i.e., CGOR >5000 cf/bbl), while most of the fixed platforms are also oil producers (30 vs nine gas producers).

Sixteen platforms in 400-500 ft water depth produced 2.5 MMbbl oil and 10.5 Bcf gas in 2016, while the 20 fixed platforms and three compliant towers in >500 ft water depth produced 37 MMbbl oil and 119 Bcf gas (Table I.1). The 47 structures in the floater class produced 469 MMbbl oil and 651 Bcf gas.

Through 2016, deepwater fixed platforms and compliant towers have produced about 2.2 Bbbl oil and 9.4 Tcf gas over their lifetime, while floating structures have produced 5.7 Bbbl oil and 11.8 Tcf gas (Table I.1). In Table I.2. the distribution of production on a heat-equivalent basis is depicted for oil and gas structures with idle structures denoted in parenthesis. Floaters populate most of the high volume oil categories.

9.5. Gross Revenue

Gross revenue is a first-order estimate of revenues received and is computed using the average Light Louisiana Sweet crude ($40.6/bbl) and Henry Hub natural gas price ($2.52/Mcf) in 2016. Condensate is valued at crude oil prices even though it is normally discounted and will generate less revenue per barrel. Associated gas is valued at gas-well gas prices even though it will realize additional revenue from NGL sales. Also, since product impurities are not available on a well basis no adjustments for quality are made. Net revenue received by the operator is gross revenue reduced by the royalty payment to the federal government, which for most structures is 16.67% (18.75% royalty applies for leases issued after 2008).

Structures which generate less than a few million dollars annually may be considered marginal or approaching marginal status because the direct operating cost for deepwater structures – production and maintenance crew, helicopter flights, service boats, chemicals, maintenance expenses, etc. – are approximately of this magnitude. However, if structures are part of regional operations or serve third-party production or transportation services, they may be able to operate profitably at lower revenue levels.

Collectively, the 16 producing structures in 400-500 ft water depth generated about $129 million, or $8.1 million per structure in 2016, compared to $1.8 billion total, or $78 million per structure for structures in >500 ft water depth (Table I.1). Floaters generated about $21 billion total, or about $440 million per structure on average in 2016.

Twelve fixed platforms were not producing and 11 fixed platforms and one floater had gross revenue less than $5 million (Table I.3). Of the 12 nonproducing structures, seven were idle and five were serving in an auxiliary role.

There were 18 structures which generated between $5-30 million and many of the structures of this class, especially structures at the low-end of the revenue category, would be considered as approaching marginal status. There were 20 structures which generated between $30-100 million and 20 structures which generated between $100-500 million. Eight structures, all floaters, generated between $500-1000 million, and another eight floaters each generated more than $1 billion.

The Independence Hub semi (1766) fell in the <$5 million category and ceased production in 2016 and has subsequently abandoned all its wells. The Mirage/Titan semi (2089) generated $47 million in 2016 and last produced in October 2016 with cumulative production 13.5 MMbbl oil and 14.4 Bcf natural gas. Circa 2017, wells on Mirage/Titan were not abandoned.

9.6. RESERVES

Reserves are estimated using producing well inventories circa 2016 and standard industry models and assumptions on decline curves (e.g., Poston and Poe 2008). See Chapter 11 for additional discussion and Chapter 12 for examples. If reserves are computed according to SEC/SPE definition (PRMS 2007), there is a 90% chance the estimates will increase from current estimates in the years ahead, and so the values computed are considered a lower bound conservative estimate.

Fixed platforms in 400-500 ft water depth are estimated to have proved reserves of 4.3 MMbbl of oil and 16.5 Bcf of gas, compared to 135 MMbbl of oil and 447 Bcf of gas for fixed platforms and compliant towers in >500 ft water depth, and 1.8 Bbbl of oil and 2.3 Tcf of gas for floaters (Table I.1).

9.7. PV-10

Whereas gross revenue is a snapshot of the value of production, PV-10 provides an indication of the (discounted) value of future production arising from proved reserves. PV-10 denotes the present value of the expected cash flows generated from reserves discounted at 10% on a before-tax basis computed using a standard set of assumptions and procedures on decline rates, oil and gas price, operating cost, and inflation rate. PV-10 requires a cash flow model to compute and is a simple extension of the reserves estimation, and although it is not a GAAP (generally accepted accounting procedure) measure[7], it is still commonly used and reported.

PV-10 values were computed for each producing structure using a constant oil price of $60/bbl and gas price of $3/Mcf, 16.67% royalty rate, and $7/boe operating cost (Table I.4).

Eighteen fixed platforms had reserves values less than $10 million and seven structures had values between $10 and $50 million. Eighteen structures, mostly floaters, had PV-10 values greater than $500 million.

In total, the fixed platforms and compliant towers in water depth >500 ft had a PV-10 of about $4.1 billion, compared to the PV-10 of floaters estimated at $51.3 billion. The PV-10 value of fixed platforms in 400-500 ft water depth was about $160 million.

9.8. Fixed Platforms, 400-500 ft

There are 22 fixed platforms that reside in 400-500 ft water depth circa 2016 (Tables I.5 and I.6). Sixteen of the 22 fixed platforms were producing circa 2016.

9.8.1 Idle

Six of the 22 fixed platforms were idle circa 2016 with last year of production ranging between 1992 to 2012.

Two of the idle structures are toppled (Taylor Energy's complex 23051 and McMoRan's 23925) and two of the structures serve as pipeline junctions (Manta Ray Gathering 23212 at Ship Shoal 332, Poseidon Oil Pipeline 23353 at South Marsh Island 205).

Taylor Energy's complex 23051 in 475 ft water depth in Mississippi Canyon 20 was destroyed by Hurricane Ivan in 2004 and will likely never be fully decommissioned because of safety and technical issues. The hurricane caused a mudslide in the region and the platform slid 400 ft down slope, resting on its side partially buried by more than 100 ft of mud and sediment in 440 ft water depth. Nine of the 25 wells have been plugged and abandoned, the platform deck has been removed, and the oil pipeline has been decommissioned circa 2016. In September 2014, oil sheens estimated at about two barrels per day were leaking from one or more of the wells (USCG 2013). Taylor Energy has reported spending more than $480 million through 2015 on its efforts to stop the leak and decommission the platform.

Freeport McMoRan Oil & Gas complex 23925 in Ewing Bank 947 was toppled by Hurricane Ike in 2008 and the operator applied for a permit to reef the jacket in-place having previously removed the deck, but BSEE has not granted the permit due to uncertainties related to site contamination and instability issues.

[7] The GAAP measure is called the 'standardized measure' and is similar to PV-10 except that it is computed on an after-tax basis and includes income tax and decommissioning cost in the computation (PRMS 2007). Standardized measures are reported by public companies at the corporate level for all assets and are normally consolidated by region in financial statements.

Manta Ray Gathering, originally a joint venture between Shell Gas Transmission, Marathon and Enterprise, acquired complex 23212 in 1992 when production ceased and currently supports the Leviathan Offshore Gathering System and Poseidon Oil and Allegheny Systems.

Energy XXI GOM complex 22685 at South Pass 49 last produced in 2004 and W&T Offshore complex 10192 at High Island 389 stopped producing in 2012.

9.8.2 Gross Revenue <$5 million

Nine fixed platforms generated less than $5 million in 2016 and producing well counts ranged between one to five wells per structure. Annual production for all nine structures totaled less than 1 MMbbl crude and 100 MMcf gas and most structures in this class can be considered marginal or approaching marginal status.

Three structures (Energy XXI GOM 23893, Renaissance Offshore 1076, and Fieldwood Energy 80015) produced less than 10,000 bbl oil and less than 100 MMcf gas in 2016 and are probably no longer commercially viable. Gross revenues for these structures are estimated at less than $2 million per structure.

Bennu Oil & Gas complex 2027, Energy XXI GOM complex 23151 and Alabaster (23893), and Fieldwood Energy's complex 80015 all have one producing well circa 2016. Structures with one or two producing wells are in a difficult position since if a well fails or stops producing for any reason it probably will not be economic to perform a workover.

9.8.3 Gross Revenue $5-30 million

Seven fixed platforms generated between $5 and $30 million in 2016. Fieldwood Energy complexes 1500 and 23800 generated the largest revenues in the subclass, followed by Manta Ray Gathering complex 70.

9.9. Fixed Platforms and Compliant Towers, >500 ft

There are 26 fixed platforms and three compliant towers in water depth greater than 500 ft circa 2016 (Tables I.7 and I.8). These structures contain about twice the number of wells, four times the number of subsea wells, and generate more than ten times the revenue of fixed platforms in 400-500 ft.

9.9.1 Idle

There are six idle fixed platforms in water depth greater than 500 ft circa 2016. These structures may be serving an auxiliary role as a pipeline junction such as Triton Gathering's Pimento (23788) and Shell Oil's Boxer (23277) or intend to serve such a role in the future. Idle structures are owned by ATP Oil & Gas (1320, last produced in 2012), Chevron (23760, Tick last produced in 2015), Fieldwood Energy (70016, Spirit last produced in 2013), and Fieldwood SD Development (10242, Tequila last produced in 2009). Production from Chevron's Jack-St Malo field is routed through the Boxer platform.

9.9.2 Gross Revenue <$5 million

Two structures generated less than $5 million in 2016, Cerveza (10178) and Enchilada (27056). Shell installed Enchilada in 1997 in Garden Banks block 128 to support hub activity in the region as well as handling inflows from Auger pipeline junctions (Smith and Pilney 2003). Cerveza and Ligera were installed in 1981 and 1982 for the East Breaks 160 field development.

9.9.3 Gross Revenue $5-30 million

Eight structures generated between $5-30 million in 2016, including ExxonMobil's compliant tower Lena (22840), Fieldwood's Ligera (10212) and Tequila (10297), MC Offshore Petroleum's Marquette two complex (23567-1, 23567-2), W&T Energy VI's Virgo (113), and Whistler Energy II's Boxer (23503).

Exxon began talks with the Louisiana Artificial Reef Council in 2015 to reef Lena in-place and is undergoing environmental studies and federal review (Truchon et al 2015). The Marquette two-platform complex was installed in 1989 to develop the Jolliet field and reservoirs in a 15-block unit at Green Canyon block 52. The platforms process production from the Jolliet TLP, about nine miles south, and the GC 52 unit production (Tillinghast 1990). MC Offshore Petroleum is operator of Marquette and Jolliet.

9.9.4 Gross Revenue $30-100 million

Seven structures generated between $30-100 million in 2016, including Ankor Energy's Simba (1482), EnVen Energy Ventures Cognac (22178) and Lobster (24129), Flextrend Development's Phar Lap Shallo (24201), Stone Energy's Amberjack (23883), W&T Offshore complex 147, and Walter Oil & Gas newly installed Coelacanth (2606).

9.9.5 Gross Revenue $100-500 million

Shell's Salsa platform (90014) and Stone Energy's Pompano (24130) were the largest producers, generating about $400 million and $260 million, respectively, followed by Chevron's compliant tower Petronius (70012) and Hess's compliant tower Baldpate (33039), Fieldwood's Bullwinkle (23552), and Eni's Corrla (23875).

9.10. Floaters

There are 47 floating structures in the GoM circa 2016 and all but one are primarily oil producers (Tables I.9 and I.10). These structures produced almost 90% of the crude oil in the GoM in 2016 and two-thirds of its natural gas production and these percentages are expected to increase in the future since the vast majority of remaining reserves are located at fields developed by floaters and subsea tiebacks. Eight floaters each generated more than $1 billion during 2016.

9.10.1 Idle

There were no idle floating structures circa 2016 but in 2017 the Independence Hub semi (1766) and the Mirage/Titan semi (2089) were no longer producing.

9.10.2 Gross Revenue <$5 million

Anadarko's Independence Hub semisubmersible (1766) was installed in 2007 to develop 10 subsea gas fields and after ten years had exhausted its reserves. In 2016, Independence Hub generated about $100,000 and the last of its wells ceased production and were permanently abandoned. Gas export from LLOG's Who Dat development is currently being routed through the Independence Trail export line.

9.10.3 Gross Revenue $5-30 million

Three structures generated between $5-30 million in 2016: Anadarko's Gunnison (1288), Eni's Morpeth MTLP (70020), and MC Offshore's Jolliet (23583). If tiebacks or alternative uses are not found for these structures they will comprise the next batch of floater removals.

9.10.4 Gross Revenue $30-100 million

Thirteen structures generated between $30-100 million in 2016, including: Anadarko's Nansen (821) and Boomvang (822) spars, Bennu's Mirage/Titan semi (2089), Chevron's Genesis spar (67) and Blind Faith semi (1930), ConocoPhillips Magnolia TLP (1218), Eni Allegheny MTLP (251), EnVen Energy Ventures Prince MTLP (811), Murphy's Front Runner spar (1290), Noble Energy's Neptune spar (24235), Shell's Ram Powell TLP (24229), and W&T Energy VI Matterhorn MTLP (1088).

9.10.5 Gross Revenue $100-500 million

Fourteen structures generated between $100-500 million in 2016, including: Anadarko's Marco Polo (1323) and Heidelberg spar (2597), BHP's Neptune (1799), Energy Resource Technology's Helix (2133), Eni's Devil Tower (1175), ExxonMobil's Hoover/Diana (183), Freeport McMoRan's Marlin (235), Horn Mountain (876) and Holstein (1035) structures which were sold to Anadarko in 2017, Hess' Gulfstar (2498, aka Tubular Bells), LLOG's Who Dat (2424), Murphy's Medusa (1090), Petrobras' Cascade & Chinook (2229), and Shell's Brutus (420).

9.10.6 Gross Revenue $500-1000 million

Eight structures generated between $500-1000 million in 2016: Anadarko's Constitution (1665), BP's Na Kika (1001) and Mad Dog (1215), Chevron's Tahiti (1819), Murphy's Thunder Hawk (2045), and Shell's Olympus (2385, aka Mars B), Auger (24080) and Mars (24199).

9.10.7 Gross Revenue >$1000 million

Eight structures generated more than $1 billion each in 2016, about $10 billion in total. These structures included a mix of new installations and redevelopments: Anadarko's Lucius (2576, installed 2014), BHP's Shenzi (1899, installed 2008), BP's Thunder Horse (1101, installed 2005) and Atlantis (1223, installed 2007), Chevron's Jack/St Malo (2440, installed 2014), LLOG's Delta House (2513, installed 2014), and Shell's Perdido (2008, installed 2009) and Ursa (70004, installed 1998).

Lucius and Delta House are relatively new installations with virgin wells high on their production curves, while Ursa and Thunder Horse are older fields that have been revitalized with tieback and redevelopment activity. Ursa is part of the giant Mars-Ursa basin and is the largest field in the

GoM at 1.85 Bboe reserves. Atlantis is the 13th largest field at 411 MMboe reserves and North Thunder Horse comes in as the 33rd largest field with 320 MMboe reserves (BOEM 2017).

9.11. Projects sanctioned or under construction circa 2017

Deepwater floaters sanctioned or under construction circa 2017 include: Big Foot (ETLP), Stampede (TLP), Appomattox (semi), and Mad Dog Phase 2 (semi), also known affectionately as Big Dog. Deepwater projects that involve subsea tiebacks to existing infrastructure are not considered but number at least one or two dozen.

The Big Foot oil field is located in Walker Ridge block 29 in 1585 m (5200 ft) water depth and is estimated to hold over 100 MMboe reserves. An extended TLP was selected as the development concept but during installation nine of its 16 tendons lost buoyancy and the TLP was severely damaged by a loop current while preparing for hookup in 2015. Production is expected to commence in mid-2018.

Hess installed the Stampede TLP in 2017 in approximately 3500 ft (1067 m) water depth and first production is expected in early 2018. Stampede is located in Green Canyon blocks 468 and 512 and is estimated to have resources in the range of 300-350 MMboe. Topsides processing capacity is approximately 80,000 bpd oil and 40,000 MMcfpd natural gas.

The Appomattox development is located in Mississippi Canyon blocks 348 and 392 in approximately 7400 ft (2195 m) water depth and will be developed with a semisubmersible initially producing from the Appomattox and Vicksburg fields with recovery estimated at 650 MMboe. First production is scheduled for 2020. The project calls for a subsea system featuring six drill centers, 15 producing wells and five water injection wells. Average peak production capacity is estimated at 200,000 boepd. If the Gettysburg and Rydberg prospects are sanctioned for development the total estimated resources would be 800 MMboe.

BP sanctioned the Mad Dog Phase 2 project in December 2016 as a semisubmersible development moored in Green Canyon in 4500 ft (1372 m) water depth about six mi (10 km) southwest of the existing Mad Dog spar. Production capacity is expected at 140 Mbpd crude and 60 MMcfpd natural gas with first production in late 2021.

CHAPTER 10. DEEPWATER ECONOMIC LIMITS

The economic limits for deepwater wells and structures are greater than shallow water wells and structures because more complex wells and larger structures require higher operating and maintenance cost which translate to higher economic limits near the end of production. Gross revenue statistics are described for the last year of production for 23 decommissioned deepwater structures from 1990 to 2017 and 153 permanently abandoned subsea wells from 2000-2016. The average inflation-adjusted revenue the last year of production of all decommissioned structures, fixed platforms and floaters, was $13.4 million with a median value of $3.1 million. The average and median inflation-adjusted gross revenues for fixed platforms were $9.5 million and $2.2 million, respectively. Subsea oil wells had an average economic limit of $5 million compared to $11 million for gas wells. Background information on flowing pressure, intervention type and frequency, and flow assurance issues provide the set-up for subsea well economic limits.

10.1. Decommissioned Structures

Twenty-three deepwater structures have been decommissioned in the GoM through 2016, five floaters and 18 fixed platforms (Table J.1). The average inflation-adjusted revenue the last year and second-to-last year of production was $13.4 million and $40 million, respectively, with median values $3.1 million and $9.2 million. The gross revenue distribution the last year and second-to-last year of production shows the majority of structures reaching their economic limit at less than $5 million (Figure J.1).

Sixteen of the 18 decommissioned fixed platforms were primarily gas producers. The five floaters that have been decommissioned through 2017 include three semisubmersibles, one spar and one MTLP. Four of the floaters decommissioned were oil structures and one was a gas structure. Chevron's Typhoon MTLP suffered catastrophic damage from Hurricane Rita in September 2005 and was decommissioned in June 2006. After ATP Oil & Gas declared bankruptcy in 2013 and no buyers for its Gomez semisubmersible could be found, it was decommissioned in March 2014.

The average and median inflation-adjusted economic limits for fixed platforms were $9.5 million and $2.2 million, respectively. The large difference between the statistical measures is due to two structures with last year revenues of $63 and $68 million. In total, there were ten structures with economic limit less than $4 million and 16 structures with economic limit less than $10 million.

The five floaters had an average inflation-adjusted revenue the last year of production of $28 million and a median value of $11.2 million. If the Typhoon MTLP is removed from the sample because of its exceptional nature, the average economic limit of the group increases to $33 million.

For fixed platform oil structures, the average last year gross revenue was $34 million, and for fixed platform gas structures, $6.5 million. For floater oil structures, the average last year gross revenue was $12.4 million, and for floater gas structures, $88 million.

10.2. Bottom Hole Flowing Pressure

Wells reach their economic limit at a particular production rate or bottom hole flowing pressure (BHP). For subsea developments, where tubing head pressure may have to be several thousand psi to drive produced fluids for miles from the subsea wellhead to the receiving facility, economic limit BHPs will be higher than for dry tree wells where only the water column has to be overcome, for all other things equal. Operators may install gas lift in the production tubing or at the wellhead to reduce BHP and thereby increase ultimate recovery, or may install subsea separation, compression or pumping equipment, although the later technology is not yet widely adopted. Flowing a well at low abandonment pressure increases the potential for asphaltene deposition and below the bubble point well productivity will be reduced.

Wells located downslope from the host in deeper water require more energy to reach the platform because of the hydrostatic head to arrive at station relative to wells located uphill which flow downward (Figure J.2). Operators usually prefer downslope wells for operational reasons and will locate the host accordingly. Upslope wells involve more design challenges and present greater operational risk.

Example. Well abandonment pressure at Gemini

The Gemini field is located in Mississippi Canyon 292 in 3400 ft water depth and was developed as a subsea development tied back 27.5 miles to the Viosca Knoll 900 platform. There is a minimum rate at which a gas well needs to produce in order to prevent the liquids from falling back into the well and killing the well. Engineers determined that a minimum gas flow rate of 10-15 MMcfd is required to lift the fluids and flow into the pipeline (Kashou et al. 2001). Below 10 MMcfd the well is expected to die and will be unable to produce. A well abandonment pressure was calculated to be about 1500-1600 psia which translates into a flowing bottomhole pressure of 1350-1450 psia. ■

10.3. SUBSEA WELL INTERVENTION

A well intervention is defined as any physical connection made to a completed well to alter production. Subsea well interventions are classified according to the methods used to connect to the well, the activities performed while re-entering the well, and the type of vessel used in the operation (Nelson and McLeroy 2014).

10.3.1 Subsea Operations

Subsea well operations include:

- Pumping. Pumping chemicals downhole to improve the production rate is the simplest operation.
- Wellhead/Tree Maintenance. Operations vary depending on the condition of the equipment and manufacturers' recommended maintenance procedures.
- Slickline. A single strand wire used to run tools in the wellbore for placement or removal.
- Wireline. A braided line used to lower or retrieve heavier equipment and for logging and perforation.
- Coiled Tubing. Coiled tubing is metal pipe used to pump chemicals directly to the bottom of the well through the tubing for circulation, logging, drilling and production operations.

- Snubbing (Hydraulic Workover). Snubbing operations involve running a bottom hole assembly on a drill string against well pressure to perform the desired tasks, such as fishing or milling.
- Tubing Retrieval. Pulling and replacing the tubing hanger and production tubing due to performance deterioration or a new completion.

10.3.2 Classification and Vessel Requirements

Light well interventions (also called Type I or Class A) are serviceable using a variety of equipment that can be deployed from numerous types of vessels. Examples include: borehole survey logging, fluid displacement, gas lift valve repair, perforating, sand washing, pulling tubing plugs, stimulation, zonal isolation.

Medium well interventions (Type II or Class B) are more specialized than light interventions and are related to production and safety issues. Examples include: casing leak repairs, fishing, well abandonment, remedial cementing, sand control gravel packing, SCSSV failure, water shut offs, paraffins, asphaltenes, hydrates.

Heavy well interventions (Type III or Class C) is typically associated with the deployment of drilling rigs. Examples include: tubing packer failure, ESP replacement, horizontal well sand control, completion change out, re-entry sidetracks, and subsea tree change out.

Light well interventions generally apply riserless wireline technologies or derivatives of this technology to enter the wellbore. The market is mature and the vessels deployed are usually small where a temporarily installed package is deployed over the side using a subsea lubricator or other means to access the well. The technology may be used in combination with more advanced technology such as coiled tubing (CT) operations on larger dedicated intervention vessels.

Medium well interventions typically employ CT operations where fluids are pumped through a coil into the wellbore or used to drive certain components (Zijderveld et al. 2012). CT units require more space than wireline packages, and often wireline and CT techniques are used together. If well returns come back to the surface and need to be cleaned or treated on the vessel, a riser based system will be required to create a flow path.

For heavy well interventions, large vessels are used to pull out production tubing or to pull the tubing hanger. Due to the diameter of the tubing, deepwater drilling rigs with a full size BOP stack is required.

10.3.3 Intervention Frequency

Subsea wells represent high risk high cost assets compared to dry tree and direct vertical access (DVA) wells due to the complexities and difficulties of subsea and the costs associated with intervention.

All wells require intervention to achieve their maximum recovery. Dry tree and DVA wells receive regular and planned interventions because most structures allow the use of workover rigs on the facility, while subsea wells require a MODU or marine vessel and do not receive the same interventions and workovers (Figure J.3). Operators often forego production-improvement workovers on subsea wells because the combination of high cost and uncertain improvement fail to justify capital investment.

Recovery factors for subsea wells are expected to be lower than dry tree and DVA wells, perhaps 10 to 25% less, and economic limits are expected to be higher. The low frequency of interventions and back pressure that arises due to the distance to the host facility are the primary reasons for the reduced performance. Reservoirs with delayed pressure maintenance or non pro-active intervention programs will have recoveries less than equivalent wells with regular maintenance.

10.4. Flow Assurance

10.4.1 Objective

In subsea production systems, fluid from the reservoir travels through a number of system components, starting at the perforations at the completion and through the wellbore tubing and casing, past the SSCV and into the tree, manifold, jumpers, flowline, riser and platform piping and equipment. The objective of flow assurance is to keep the flow path open for the life of the well.

10.4.2 Issues

The primary flow assurance issues for subsea systems are hydrate, wax, asphaltene, scale, and corrosion. Each of these components may occur at different places and different times during the life cycle of production, and therefore, anticipating their occurrence and designing system to mitigate, reduce, or remediate is the key element of flow assurance strategies. Subsea systems are designed for different operating stages, from normal production, shutdown, startup and remediation. Startup may be cold or warm. Systems must be robust and flexible to handle dynamic and changing conditions.

The occurrence of hydrate, wax, asphaltene, scale, and corrosion may arise downhole in the production tubing of the well, at the wellhead or manifold on the seabed, in the connecting jumpers or flowlines, at the riser at the base of the host, and in the equipment and piping topsides. They may occur early or late in life and during different operating states. Start-up/warm-up and shut-down/cool-down are transient conditions where flowing temperatures change and may enter regions of hydrate risk, wax appearance, etc.

Early in production, flow rates and temperatures are high, but later in life, flow rates and temperatures will decline. If systems are not designed for these changing conditions, operational problems (upsets) will occur. Early in production, fluid quality (viscosity, GOR, water cut) is similar to the fluid samples obtained during well testing, but later in life, as reservoir pressures decline, fluid quality changes which may cause operational problems if unable to manage.

10.4.3 Common Design Strategies

Hydrocarbons have different physical and chemical characteristics that give rise to different flow characteristics. Understanding the properties of the fluids is necessary to design a successful flow assurance strategy. After defining the main components management techniques are outlined.

Hydrates

Hydrates are ice-like solids classed as clathrates, sometimes referred to as ‘dirty snow,’ which form when water and light hydrocarbons or other small compounds are present together at low temperatures and high pressures (Cochran 2003). In deepwater development, ambient temperatures near the seabed are approximately 39°F (4°C) which is well within the hydrate formation region at typical operating pressures.

In hydrates a guest gas molecule is trapped within a hydrogen-bonded cage of water molecules (Figure J.4). Many different gases are capable of forming hydrates provided the molecules are small enough to fit within the cavity of the cage. High molecular weight gases are typically too large to form hydrates, but methane, ethane, propane and butane, as well as N_2, CO_2 and H_2S are small enough to fit inside. The crystalline structure of gas hydrate crystals depends on gas composition, pressure and temperature. Three crystalline structures are common at moderate pressure and ten structures are present at pressures above 100 MPa (Makogan and Makogan 2016).

Historically, hydrates have been managed by keeping the fluids warm, removing water, or by injecting thermodynamic inhibitors such as methanol (MeOH) and glycols such as monoethylene glycol (MEG). Thermodynamic inhibitors suppress the point at which hydrates form much like an antifreeze for water-ice. The more severe the hydrate problem, the more inhibitor is required, and production facilities can reach a limit rate of methanol treatment due to storage and injection constraints (Kopps et al. 2007). In recent years, the most prominent advance in hydrate inhibitors is the development of Low Dosage Hydrate Inhibitors (LDHI).

For gas systems, the typical approach for hydrate control has been to rely on continuous dosing with glycol or methanol. For oil systems, insulated systems that maintain temperatures above the hydrate formation temperature during steady state allow hydrates to be controlled with a minimum usage of glycol or methanol. During shut-downs and start-ups, the system drops below the hydrate temperature and additional operational steps are required such as pressure relief (blow-down) or removal of wet fluids by pigging during shut-down, and circulation of hot oil and methanol dosing during start-up.

Waxes

Waxes are high molecular weight saturated organic mixtures of n-alkanes, i-alkanes, and cycloalkanes with carbon chain lengths ranging from C18 to C75+ (Speight 1999). Waxes precipitate from petroleum fluid as the temperature falls below the wax appearance temperature (WAT) and deposit to the contact surface of the well tubing, pipeline or vessel. If not under control, wax deposits may block the flow path completely.

The formation of wax crystals depends mostly on temperature change. The temperature at which crude oil develops a cloudy appearance due to its wax (paraffin) content precipitating out is called the WAT or cloud point. The pour point is defined as the lowest temperature crude oil flows. Both WAT and pour point are important design characteristics in subsea systems. Pressure and composition also affect wax formation but to a lesser extent than temperature change. Wax management is often considered with hydrate management strategies.

Most operators rely upon pigging for control of wax deposition supplemented with inhibitors for reduction of the deposition rate. As system offsets increase, the time required for roundtrip pigging increases, and the cost of a dual flowline system is substantial. Subsea pig launchers can be employed with a single line but incur the cost of intervention vessels. Wax deposition can be prevented, delayed or minimized using paraffin inhibitors such as crystal modifiers or dispersants. The former are chemicals that interact with the growing wax crystallization while dispersants prevent the wax nuclei from agglomerating on the pipe surface by disrupting its crystal growth.

Asphaltenes

Asphaltenes are dark-colored, friable and infusible[8] hydrocarbon solids sometimes called the 'cholesterol' of petroleum. Defined as the fraction which precipitates upon the addition of an excess of n-alkane, the diversity of asphaltene production issues arise from the variety of oil types and production conditions. Asphaltenes are represented by the polynuclear aromatic layers with folded alkane chains, creating a solid structure known as a micelle. Some rings may be non-aromatic but many are fused and share at least one side. The tendency of asphaltenes to precipitate from a given crude is broadly related to the molecular weight, aromaticity and polarity of the asphaltenes (Figure J.5).

Asphaltenes are common in heavy viscous crude and are usually controlled using inhibitors before destabilization and flocculation occurs (Jamaluddin et al. 2002, Tavakkoli et al. 2016). Pressure and composition appear to be the most significant factors, and although they are superficially similar, they result in different precipitated fractions with different behavior (Mullins et al. 2007). Asphaltene deposition tends to occur above the bubble point, concentrating the hazard to the wellbore and wellbore formation, and occasionally to the wellhead or flowline. Below the bubble point, asphaltene solids tend to re-dissolve, but the process can be slow and incomplete.

Example. Serrano flowline blockage

The Serrano flowline is located in 3500 ft of water and is tied back six miles to the Auger tension leg platform (Figure J.6). Three subsea wells produce through an electrically heated 6 inch by 10 inch pipe-in-pipe insulated flowline. The heated system was selected to reduce/eliminate potential hydrate formation due to subsea temperatures (Louvet et al. 2016). In November 2006, generator power to the heating system was lost and wells were shut-in for one week, but once the well valves was opened back for restart it would not flow. It was suspected that a hydrate formed in the flowline but sand and paraffin buildup was also considered a possibility. In December 2007, after six months of intensive planning a coiled-tubing operation was deployed to retrieve a sample of the blockage for diagnostic purposes (Hudson et al. 2009). Analysis of the sample dictated the cleanout strategy which involved pumping diesel and solvents to clean the flowline. Operations were successful and production resumed at pre shut-in rates. ■

10.5. Abandoned Subsea Wells

Production and gross revenue statistics the last year of production for 153 permanently abandoned subsea wells between 2000-2015 are presented in Table J.2 according to primary product (oil, gas), distance from host in miles (<5 miles, 5-10 miles, >10 miles) and altitude between wells and host ($>500^+$ ft, $>500^-$ ft, <500 ft). Altitude is defined as subsea well water depth minus host structure water depth and three categories are applied: greater than 500 ft downslope ($>500^+$ ft), greater than 500 ft upslope ($>500^-$ ft), and less than 500 ft upslope or downslope (<500 ft).

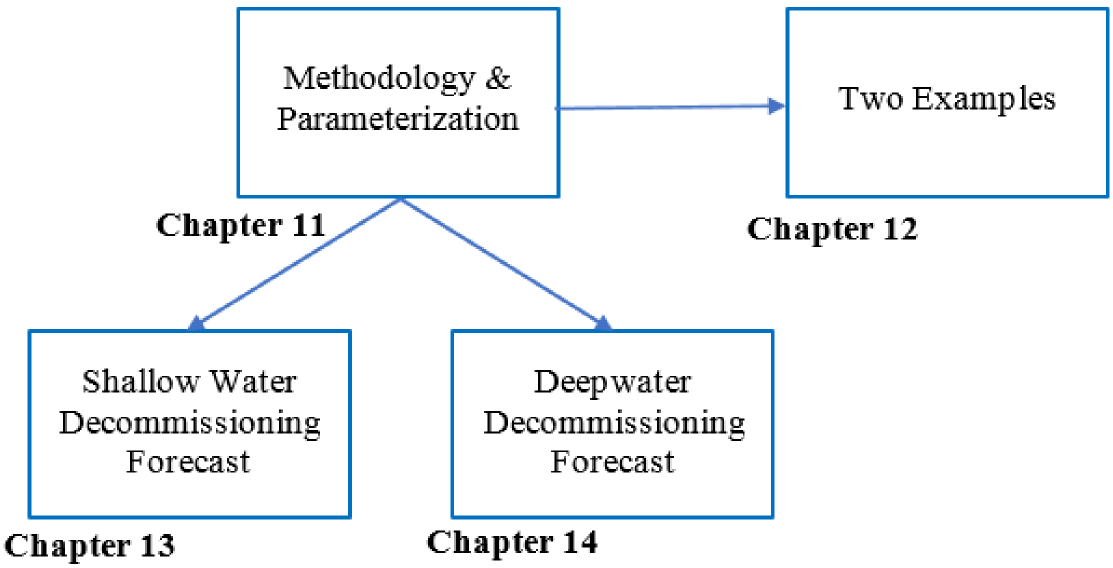
The sample is relatively small, especially for oil wells where there are less than 20 total wells, but because the sample represents the majority of permanently abandoned deepwater wet wells in the GoM is considered representative. Categories without at least five to ten wells may not be representative or subject to significant outlier influence. Most oil subcategories are not adequately populated and meaningful conclusions cannot be drawn but the gas well subcategories are larger and provide a more useful sample.

[8] Meaning they have no well defined melting point but decompose with heating leaving a carbonaceous residue.

The revenue the last year of production for gas wells ranged from \$4.5 million for wet wells less than five miles to the host, \$7.6 million for wells 5-10 miles away, and \$24 million for wells ≥10 miles away. For oil wells, the economic limits vary from \$4.7 million (≤5 miles) to \$7 million (5-10 miles). The oil well ≥10 mile category was a three well sample and is not statistically significant. In total, subsea oil wells had an average economic limit of \$5 million compared to \$11 million for subsea gas wells, and exhibits the same proportional difference as shallow water dry tree wells shown in Chapter 8 but about ten times larger. Also, with standard deviations on the order-of-the mean variation is large for every subcategory statistic.

For gas wells, the impact of altitude differences on economic limits appears significant. For downslope gas wells, the average gross revenue was \$24 million at the end of production across all categories, compared to about \$6 million for wells near the host and upslope. For oil wells, the samples are too small to be meaningful.

PART 3. DECOMMISSIONING FORECAST



CHAPTER 11. METHODOLOGY & PARAMETERIZATION

Decommissioning forecasts requires the use of different models to describe the behavior of different structure classes. For producing structures, decommissioning forecasts are developed using economic models based on decline curves and cash flow analysis, but for structures that are not currently producing or have never produced, production data obviously cannot be employed. A user-defined methodology is adopted to schedule idle structure removal rates and statistical methods are used to reflect auxiliary structure decommissioning characteristics. There is some variation on how shallow and deepwater decommissioning forecasts are modeled and these differences are explained. The chapter concludes with the model parameterization of structure installation rates.

11.1. OVERVIEW

11.1.1 Shallow Water vs. Deepwater

At the end of 2016, there were 2009 standing structures in water depth <400 ft in the Gulf of Mexico - 960 producing structures, 675 idle structures and 374 auxiliary structures (Table K.1). Each class is an important contribution to the total with about half of the shallow water inventory producing, one-third idle and 20% auxiliary. Both oil and gas structures are common in shallow water and the vast majority of wells are dry tree wells.

In water depth >400 ft, deepwater structures circa 2016 numbered 48 fixed platforms, three compliant towers, and 47 floaters. Of the 98 active structures 86 were producing, about 90% of the total number of structures, seven were idle and five served in auxiliary roles. In deepwater, producing structures dominate and are the most important structure class. Most deepwater structures and all floaters except one are primarily oil producers, and both wet and dry tree wells are common. One further defining characteristic of deepwater is the greater probability structures will be repurposed. In deepwater, structures are expensive to construct, install and decommission and maintain a higher residual value late in life. The probability a deepwater structure will be repurposed and re-used in support of field operations after field reserves are exhausted is higher than in shallow water.

11.1.2 Model Framework

Three models are used in shallow water to quantify decommissioning activity and represent the links between the producing, idle, and auxiliary structure subgroups and the final state (Figures K.1 and K.2). In deepwater, the approach is simplified by scheduling idle, auxiliary and marginal structures (structures that produce below their economic limit) together (Figure K.3). In both the shallow and deepwater procedures, the submodules are combined using a scenario-based procedure that incorporates exogenous factors such as oil and gas prices, royalty rates and model-specific parameters. For all active structure forecast, the user must assume future installation rates for structures in each water depth category.

11.1.3 Producing Structures

For producing structures, decline curve models and cash flow analysis are used in a manner analogous to reserves estimation (US SEC 2008, PRMS 2007). Economic limits are used to determine the time when a structure is no longer economic, that is, generating net revenue greater than its direct operating cost. These methods are well established and easily understood. There are some choices in how the procedure is implemented and differences will arise from the choices that are made, but these differences are not expected to result in wide variation because the procedures are constrained by best practice. The major constraints limiting the reliability of decline curve methods is the impact of the assumption of 'constant reservoir and investment conditions' which underlie all methods. The procedure is repeatable as long as all model assumptions are transparent and clearly specified.

11.1.4 Idle Structures

For idle structures, decline curves and cash flows cannot be applied because the structure is not producing and has not produced for at least one year, even though the structure has the potential to produce if an inactive well is brought back online or a new well is drilled and successful. One approach is to use observations on the characteristics of idle structures that have been decommissioned to infer the conditions prevalent at the time of decommissioning on an aggregate basis and then to use this information in a probabilistic manner to infer future behavior of existing inventories. An alternative approach is to develop a user-defined model to capture and reflect expected decommissioning characteristics.

To a large extent the available information and how much processing one wants to perform dictates which approach to apply, and for practice purposes, the level of uncertainty of the various approaches are believed to be comparable. Hence, the choice of what approach to adopt is subjective and driven by user-preference and the use of the model results.

Using physical insight and knowledge of structure inventories, we can perform simple decommissioning schedules without sweating the details as long as we understand the manner in which the schedule is constructed and the assumptions and uncertainties involved. We introduce 'toy' allocation models that are deliberately simple but rich enough to capture activity characteristics. Allocation methods are entirely empirical and user-defined, however, and have no economic basis, and since we cannot be certain a specific model captures all of the important system characteristics (in fact, it cannot), development of alternative parameterizations and comparison is usually desirable to gain confidence in the results.

A mechanism to schedule removals that is easy to understand and apply and captures one or more features of class behavior is constructed. We assume removals occur uniformly over a specified future time period determined by the user; e.g., 10 years, 20 years, etc. and postulate that the number of removals within a given idle structure subgroup G, $NR(G)$, is uniformly distributed over the future time horizon T, $NR(G) \sim U(T)$. There is no complicated math here, only careful physical reasoning based on accurate inventory data. Assigning a time period to 'clear' the inventory is a heuristic procedure because private information (i.e., company plans) are unavailable and the structures themselves have no production profile to model.

11.1.5 Auxiliary Structures

Auxiliary structures are primarily a shallow water phenomena and are distinct from the idle structure class since the vast majority have never produced and were installed to support operations, frequently as part of a multi-structure complex. In deepwater, structure costs are significantly more expensive and operators do not install non-producing structures, but after production ceases the structure may be re-purposed for an alternative function such as a pipeline junction.

To schedule auxiliary structure decommissioning time, an approach similar to idle scheduling can be used where a user defines an allocation to match decommissioning activity. Schedules can also be developed using historic activity statistics. Both methods have comparable levels of uncertainty. To illustrate an approach different from idle structures, empirical statistics based on historic activity levels are applied in shallow water. In deepwater, since the number of auxiliary structures are small they are grouped within a functional category with other similar structures and a simplified decommissioning schedule is applied to the category.

11.2. Producing Structures

For all producing structures, the main model parameters include the decline curves estimated for each producing well associated with the structure, oil and gas prices, economic limits, and regulatory requirements (Table K.2). Each model parameter has a number of additional assumptions which are highlighted and implementation differences in the shallow water and deepwater are described.

11.2.1 Producing Wells

Production forecasts employ producing wells as the basic unit of analysis. Because wells are drilled and come on-line at different points in time and have different reservoir pressures, fluid and decline characteristics, individual well forecasts need to be performed. Since structures serve as the aggregation point for wells, structure production forecasts are performed by summing the forecasts for each individual producing well, not by forecasting[9] the aggregate (i.e., structure) production. Wells that have not produced for the last 12 months at the time of evaluation are not evaluated for their future production potential and wells that have not yet been drilled are also not part of the evaluation according to industry conventions.

11.2.2 Oil Wells vs. Gas Wells

There are basically two kinds of producing wells recognized by regulatory agencies – oil wells and gas wells – which are distinguished according to the relative quantities of hydrocarbon liquid and vapor produced using gas oil ratio (GOR) or the cumulative gas-oil ratio (CGOR). Oil wells, after initial separation, produce crude oil and associated (also called casinghead) gas. Gas wells, after initial separation, produce gas well (nonassociated) gas and condensate. The gas from both types of wells is normally processed onshore to produce residue gas (which is mostly methane) and natural gas liquid (NGLs)[10] which consist of ethane, propane, butanes, and natural gasoline.

[9] It may be tempting to perform production forecasts based on the consolidated well production profile, but this would be a (big) mistake since the model will not capture the decline characteristics of individual wells and can lead to significant error**.**

[10] Most gas plants employ a cryogenic process that lowers the temperature of the gas stream through expansion and condenses the NGLs. Many plants produce a raw mix; i.e., unfractionated, NGL product that is transported by pipeline to a fractionation facility where the individual specification products are produced, stored and transported to market.

11.2.3 Commodity Prices

Crude oil and condensate are liquids at normal conditions. Crude oils generally have a gravity in the range of 20-45°API. Condensate is a very light crude oil (> 50°API) with a narrow distillation spectrum and in the U.S. Gulf Coast has been priced at a 40 to 60% discount to West Texas Intermediate (WTI) and Louisiana Light Sweet (LLS) crude oil on a historic basis. Heavier crudes (low API gravity) have higher sulfur content and viscosity and greater levels of impurities such as metals and will be priced at a discount to lighter sweeter crudes, generally a few dollars per °API and percent sulfur, depending on market conditions, refinery configurations, local supply and demand, and other factors.

Gas well gas and casinghead gas is used offshore for a structure's energy requirements and is used throughout shallow and deepwater for gas-lift. Gas production usually only needs to be dehydrated for export. Gas export lines can handle a wide variety of gas composition as long as high levels of carbon dioxide or hydrogen sulfide are not present. There are many different types of contracts involved in gas plant processing and fractionation and producers are often involved in the ownership and operation of gathering systems and gas processing plants, which means they receive a portion of the revenue associated with gas plant processing.

Associated gas is worth more than gas well gas because in the reservoir it will normally 'pick up' heavier hydrocarbons from the crude oil which are subsequently stripped out and sold as NGL streams. Associated gas has a higher heat content (expressed as Btu/Mcf) than dry gas which translates to greater market value and the NGL content of is usually expressed in barrels per million cubic feet (bbl/MMcf). Gas with <2–3 bbl/MMcf are considered lean and gas with >10–15 bbl/MMcf are considered rich. In the U.S. Gulf Coast, there are active markets for ethane, propane, butanes, and natural gasoline. On a volumetric basis, there may be a 25 to 50%+ premium for casinghead gas relative to gas well gas depending on NGL market conditions.

11.2.4 Well Forecasting

The best well production forecasts will consider the oil and gas streams separately but will not perform independent forecasts of each because the behavior of the two streams (coming from the same well are related to the same reservoir and to each other) are correlated to varying degree. For black oil reservoirs, for example, after the pressure in the reservoir falls below the bubble point pressure of the fluid, more natural gas will come out of solution and the relative volumes of oil and gas will change, which should be reflected in the production forecast. The GOR for black oil reservoirs will begin to increase after the bubble point is reached and will be reflected via the CGOR time trend for the well.

Various decline curve models such as exponential, hyperbolic, harmonic, etc. are fit to historic data and the model with the highest fit parameter is normally selected as the 'best' predictor for future production (Poston and Poe 2008). For wells in different stages of their life cycle producing from different reservoirs and formation conditions and for different levels of intervention the ability of this approach to reflect future production trends may be challenging because the model assumptions require status quo conditions that fail to take into consideration standard business practices that attempt to maintain production and extend the life of wells for as long as possible (via capital spending and well intervention).

For 'oil' producers, crude oil is the primary product and the main forecast variable and the derived secondary product is associated gas. For 'gas' producers, gas well gas is the primary product and forecast variable and the secondary product is condensate. Best practice is to forecast the dominant (primary) well stream using decline curve analysis and to use the forecast production curve of the primary stream along with an extrapolated CGOR or CCGR trend to forecast the secondary stream as shown in Figure K.4 (Yu 2014). In this manner, the secondary stream is derived from the primary stream rather than being forecast independently which leads to better and more accurate forecasts. An alternative approach would forecast the combined heat-equivalent boe stream and then decompose this stream into its oil and gas components as shown in Figure H.5 but this is a less common method since it convolutes well streams in a manner that convolutes reservoir physics.

In shallow water, both exponential and hyperbolic decline curves are applied to all producing wells beginning from their peak production or their last local peak if the model fit from first peak is not adequate. Exponential decline models describe a fast pace (constant percentage) reduction in production whereas hyperbolic decline curves provide for a much slower decline rate. For the 960 producing shallow water structures reality is expected to be bound between these two model extremes. Since we cannot predict for an individual well which approach will result in a more accurate forecast *a priori* and there are such a large numbers of wells we don't try and apply both models to delineate ranges. Secondary streams are a derived product. In deepwater, the best-fit decline curve model is applied to the primary stream with the secondary forecast as a derived product.

11.2.5 Constant Reservoir and Investment Conditions

All production forecast require boundary conditions and model assumptions. "Constant" (aka status quo) conditions at the time of evaluation is the standard industry and regulatory approach. Constant conditions refers to a broad set of assumptions that implies no production problems in the future, no new sidetracks will be drilled, no change in operating conditions due to mechanical problems, no processing constraints, no significant spending outside normal operating and maintenance requirements, no operational changes due to commodity price variation, etc.

Obviously, "constant reservoir and investment conditions" do not reflect reality and normal operating conditions since the business strategy of companies is to maintain profitable production for as long as possible via well intervention and judicious use of capital spending. Normal business conditions do not obey the primary model assumption required in forecasting. Operators are *always* intervening in one way or another to maintain optimal conditions and maximum cash flows. The model assumption arises because an operator's future capital investment and operational plans and outcomes are unknown and unobservable outside the company, and rather than allow speculation to dominate the forecast, best practice is to simply not permit it. Thus, the status-quo assumption is needed to forbid/restrict speculation on unknown futures. Under this assumption new wells are not allowed and investment to recover 'additional' production (beyond that estimated by decline curve) is not permitted. The implication for decommissioning forecasting is that reserves will be underestimated and abandonment time with arrive earlier than anticipated.

In shallow water, the status-quo assumption is balanced out by using both slow (hyperbolic) and fast (exponential) decline curve models to bound the expected decommissioning times. In deepwater, the status-quo assumption is balanced in a different way by adding a fixed time to the economic limit year determined from the decline curve (Figure K.6). For deepwater structures the time delay is estimated using historic statistics between the last year of production and the actual time of decommissioning, which has ranged between two to ten years. Both approaches act to balance the earlier-than-normal decommissioning forecast predicated on the status-quo assumption.

11.2.6 Gross Revenue

For oil wells, future gross revenue is computed using assumed oil and associated gas sales prices and volumes $q_i^{oil}(w)$ and $q_i^{ass}(w)$ predicted from the well forecast. For monthly production volumes, gross revenue in year *t* is computed as the sum of the product of production and price for each component stream:

$$GR_t^o(w) = \sum_{i=1}^{12} q_i^{oil}(w)P^{oil} + \sum_{i=1}^{12} q_i^{ass}(w)P^{ass},$$

where assumed oil prices are denoted as P^{oil} and associated (casinghead) gas prices are denoted as P^{ass}. For gas wells, gas well gas and condensate sales prices and volumes $q_i^{gas}(w)$ and $q_i^{cond}(w)$ are applied:

$$GR_t^g(w) = \sum_{i=1}^{12} q_i^{gas}(w)P^{gas} + \sum_{i=1}^{12} q_i^{cond}(w)P^{cond},$$

where condensate prices are denoted as P^{cond} and gas well prices are denoted as P^{gas}.

In most models, oil and condensate liquids are combined and prices are assumed equal ($P^{oil} = P^{cond} = P^o$), and similarly, gas well and casinghead gas volumes are added together and their prices are assumed equal ($P^{gas} = P^{ass} = P^g$). This is acceptable because there are other model parameters with even greater uncertainty, but it is still useful to recognize the price differentials when performing sensitivity analysis (Table K.3).

The end result is the well revenue forecast flowchart and the simplified gross revenue expression for a well:

$$GR_t(w) = q_t^o(w)P^o + q_t^g(w)P^g.$$

Gross revenue is an approximation to actual revenues received since sales prices are unobservable. Market-based prices are believed to be a reasonable proxy of sales prices but adjustments for quality (gravity, sulfur content, heating value), transportation expenses, the use of hedging programs, contract conditions, etc. cannot be performed using public data.

11.2.7 Structure Production and Revenue

Structures collect and process production for individual wells before being sent to shore, so the oil and gas production and gross revenue associated with a structure is simply the sum of all its producing wells:

$$q_t^o(s) = \sum_w q_t^o(w),\ \ q_t^g(s) = \sum_w q_t^g(w),\ GR_t(s) = \sum_w GR_t(w).$$

Platform (dry tree) wells are usually owned in the same proportion as the structure's working interest owners but subsea wells drilled off the platform lease frequently involve different ownership. When well and structure ownership positions are different, companies arrange a production-handling agreement (PHA) to process at the host platform and pay for these services separately. PHAs are not modeled nor are the ownership positions in wells and structures considered which will allocate well revenue differently to different players and may impact decommissioning timing decisions. In shallow water since subsea wells are not common these additional complexities do not frequently arise; in deepwater subsea wells contribute a significant share of well production and these issues play a larger role.

11.2.8 Net Revenue

Net revenue is the revenue realized after subtracting the royalty payment to the landowner. In the GoM, royalty payments are defined through the royalty clause as a percentage or share of production proceeds that the lessee pays to the lessor computed from the gross revenue of production after deduction for transportation and processing fees, if applicable:

$$ROY(s,t) = GR(s,t)roy(s,t),$$

where $ROY(s,t)$ denotes the royalty payment, $GR(s,t)$ is the gross revenue, and $roy(s,t)$ is the royalty rate of structure s in year t. In the U.S., royalty rates are fixed throughout production and for offshore leases in federal waters is either 12.5%, 16.67% or 18.75% depending on the time of sale and water depth of the lease.

From 1954-1982, areas for leasing in the GoM were nominated by oil and gas companies and lease terms were for five years and the royalty rate was 1/6 (16.67%). In 1983, area-wide leasing was introduced which made available all unleased and available blocks in a program area and modified some of the lease conditions. The first lease sales held from 1983-1986 had a 16.67% royalty rate in water depth less than 200 m. From 2008-present, the royalty rates increased to 18.75% in water depth less than 200 m with deep gas relief provided for wells drilled greater than 15,000 ft subsea.

11.2.9 Economic Limit

The economic limit is the production rate beyond which the net operating cash flows (net revenue minus direct operating cost) are negative. Direct operating cost normally include all direct cost to maintain operations, property-specific fixed overhead charges, production and property taxes, but exclude depreciation, abandonment costs, and income tax. Since direct operating cost are not publicly available for offshore structures empirical statistics were previously computed to infer economic limits based on gross revenues at the end of production.

In shallow water, the median adjusted net revenue the last year of production for structures decommissioned from 1990-2017 was shown in Chapter 8 to be \$1.23 million for gas structures and \$627,000 for oil structures. For oil structures, the adjusted net revenue the last year of production was smaller for minor structures (\$352,000 for caissons and well protectors) and larger for larger structures (\$873,000 for fixed platforms), while for gas structures there was essentially no difference between structure types).

In deepwater, the average and median inflation-adjusted economic limits for fixed platforms were shown in Chapter 10 to be \$9.5 million and \$3.1 million, respectively, which continues the trend observed for fixed platforms in shallow water. Five decommissioned floaters had an average inflation-adjusted revenue the last year of production of \$28 million and a median value of \$11.2 million.

11.2.10 Abandonment and Decommissioning Time

A structure is assumed to cease production when net revenue falls below its direct operating expense or economic limit $EL(s)$ as shown in Figure K.7. Net revenue is estimated as a function of time for assumed oil and gas prices and when $NR(s) < EL(s)$ production is no longer commercial:

$$T_{EL} = \min \{t \mid NR(s) < EL(s)\}.$$

T_{EL} is called the economic limit year or EL-yr for short. In shallow water, structures are assumed to be decommissioned one year after they reach their economic limit. In shallow water the decommissioning time T_a is therefore determined as

$$T_a = T_{EL} + 1.$$

The one year period reflects general regulatory requirements but variation is expected based on special circumstances and other factors which can delay the timing of decommissioning. For example, if a structure is repurposed to serve a useful function after reaching its economic limit then it would not be governed by this relation. Historically, non-producing structures on an active producing lease could remain for as long as the lease was producing, but once the lease ceased producing then all the structures had to be removed. In 2010, new regulations in the form of NTL 2010-G05 were enacted that require operators to decommission structures within five years after they no longer serve a useful purpose regardless of the producing status of the lease.

In deepwater, a more general decommissioning timing equation is applied:

$$T_a = T_{EL} + \tau,$$

where the EL-yr is added to a user-defined time period τ parameterized by historic data on the time between the cessation of production and decommissioning time. For fixed platforms, the time period τ is selected as three, five, or 10 years which bounds historic activity statistics. For floaters, the time period τ is selected as two years.

11.3. Idle Structures

11.3.1 Parameter Models

The simplest decommissioning schedule to apply to idle structures is to assume the entire idle inventory is removed at a uniform rate over T years. For example, since the size of the shallow water GoM idle inventory I circa 2016 numbered 675 structures, if the user assumes a 10-year future horizon for decommissioning, then I/T = 675/10 = 67.5 idle structures per year will be scheduled for removal. If the user postulates a larger value of T (e.g., 20-years), annual activity will be smaller and occur over a longer period. This model has appeal due to its simplicity and may be appropriate in particular circumstances, but it fails to capture differences between idle age and the larger number of older idle structures that are expected to be removed in the future.

A three-parameter model generalizes the one-parameter approach and uses information on idle age and user-preference to perform the decommissioning schedule. Age groups are described by the number of years since the structures last produced and are mutually exclusive. After selecting the idle age group parameter p, the structure set I is decomposed into idle structures that are less than or equal to p years idle at the time of evaluation and those idle structures that are greater than p years idle:

$$I = \{I\text{ (Idle age} \le p\text{ years)}\} \cup \{I\text{ (Idle age} > p\text{ years)}\}.$$

The number of structures that fall within each subgroup are identified by the symbols $I(\le p)$ and $I(>p)$ and will change with time. The value of I is known at the time of evaluation while the value of p is user-defined and is a positive integer denoting years. For example, for $p = 7$, Table K.4 yields $I(\le 7) = 363$ and $I(>7) = 312$. The sum of the two subgroups is the value of I at the time of evaluation (in this case, 675). In recent years a greater number of older idle structures have been removed and are associated with a higher probability of decommissioning relative to younger idle structures. The idle inventory is subdivided into two subgroups to allow/reflect different removal rates per group.

After the user posits the time period in which the subgroup elements are decommissioned, a uniform mechanism is applied for removal. For example, for $T_1 = 4$ years, the structures of $I(<p)$ would be removed at an annual rate of $I(<p)/T_1$ over each of the next four years.

11.3.2 Scenarios

Subgroup $I(\le p)$ inventory are allocated for decommissioning uniformly over a time period T_1 and subgroup $I(>p)$ inventory are allocated over time period T_2. The values of T_1 and T_2 are user-defined and with the selection of p determine a three-parameter schedule denoted (p, T_1, T_2). Normally, T_1 and T_2 would be selected so that $T_1 \ge T_2$ to reflect the expected faster removal rate of older structures, but this is not a requirement of the formulation. Selection of the model parameter T in the one-parameter model and (p, T_1, T_2) in the three-parameter model are referred to as a 'scenario' and after selection completely determines the decommissioning schedule for the idle structure inventory.

11.3.3 Model Equations

In the three-parameter model, the user selects the value of p which subdivides the idle inventory into two age groups, $I(\le p)$ and $I(>p)$, and also selects values for T_1 and T_2 for each group which schedules decommissioning for the members of the age groups uniformly over a T_1-year and T_2-year future horizon.

For the idle inventory subgroup $I(\le p)$ the time horizon T_1 sets the annual number of decommissioned structures and the time to clear the inventory. Assuming uniform activity per year, activity in year i is determined as c_i and is constant for each year through T_1, i =1, 2, …, T_1:

$$c_i = \frac{I(\le p)}{T_1},\ i = 1, 2, \ldots, T_1.$$

Using a vector notation the removal schedule can be written $R_S(I > p)$:

$$R_S(\ I \le p\ ) = (c_1, c_2, \ldots, c_{T_1}\ )$$

Similarly, for the structures in the idle inventory subgroup $I(>p)$, T_2 determines the annual removal activity in year i as d_i which is constant for each year through T_2, i =1, 2, …, T_2:

$$d_i = \frac{I(>p)}{T_2},\ i = 1, 2, \ldots, T_2.$$

In vector notation:

$$R_S(\, I > p\,) = (d_1, d_2, \ldots, d_{T_1}\,).$$

The decommissioning schedule for the entire idle inventory is determined by summing the vectors $R_S(I \le p)$ and $R_S(I > p)$:

$$R_S(I) = R_S(I \le p) + R_S(I > p)$$

If $T_1 > T_2$, the composite vector for the removal scenario $R_S(I)$ will appear as:

$$R_S(\, I) = (c_1 + d_1, c_2 + d_2, \ldots, c_{T_2} + d_{T_2}, c_{T_2+1}, \ldots, c_{T_1}).$$

All the vector elements sum to the size of the inventory and the last element of the vector is determined by the structures in the $I(\le p)$ subgroup since $T_1 > T_2$. If $T_1 = T_2$, c_i and d_i will terminate simultaneously.

The value of the model parameters (p, T_1, T_2) can be bound between upper and lower values to incorporate uncertainty in the assessment. As additional parameters are added, however, the number of possible scenarios quickly grows and complicates the aggregation process. To compute the average of two or more scenarios, a normalization procedure is required as illustrated below.

Example. $S = \{p = 10, T_1 = 10, T_2 = 5\}$.

Using Table K.4 with $p = 10$ yields subgroup counts of I ($\le$ 10) = 431 and I (>10) = 244. The decommissioning schedule vectors for this scenario are written as:

$R_S\,(I \le 10) = (43.1, 43.1, 43.1, 43.1, 43.1, 43.1, 43.1, 43.1, 43.1, 43.1)$

$R_S\,(I > 10) = (48.8, 48.8, 48.8, 48.8, 48.8)$

$R_S\,(I) = (91.9, 91.9, 91.9, 91.9, 91.9, 43.1, 43.1, 43.1, 43.1, 43.1)$

Note that the $R_S(I \le 10)$ vector occurs over ten years while $R_S(I > 10)$ occurs over five years and the sum of all the elements in $R_S(I)$ is 675. The period of the schedule is 10 years. ■

Example. $S = \{p = 10, T_1 = 20, T_2 = 10\}$.

Using the same value $p = 10$ as the previous example, the subgroup counts of I ($\le$ 10) = 431 and I (>10) = 244 are the same, but now each of the time periods are doubled so that $T_1 = 2(10) = 20$ years and $T_2 = 2(5) = 10$ years. In this case $c_i = 431/20 = 21.6$ for $i = 1, 2, \ldots, 20$ and $d_i = 244/10 = 24.4$ for $i = 1, 2, \ldots, 10$. In terms of the individual vectors:

$R_S\,(I \le 10) = (21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6, 21.6)$

$R_S\,(I > 10) = (24.4, 24.4, 24.4, 24.4, 24.4, 24.4, 24.4, 24.4, 24.4, 24.4)$

$R_S\,(I) = (46, 46, 46, 46, 46, 46, 46, 46, 46, 46, 22, 22, 22, 22, 22, 22, 22, 22, 22, 22)$ ■

The multiplication works using non-integer values as long as the same multiplier is applied to both T_1 and T_2 and values are rounded to the nearest integer.

Example. $S = \{p = 10, T_1 = 10, T_2 = 5\}$, $q = 1.4$

Using the multiplier $q = 1.4$, $T_1 = 1.4(10) = 14$ years and $T_2 = 1.4(5) = 7.5 \sim 8$ years. The effect will be to expand each time horizon by 40%. In this case, $c_i = 431/14 = 30.8$ for $i = 1, 2, \ldots, 14$ and $d_i = 244/18 = 30.5$ for $i = 1, 2, \ldots, 8$. In terms of the individual vectors:

R_S $(I \leq 10)$ = (30.8, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8)

R_S $(I > 10)$ = (30.5, 30.5, 30.5, 30.5, 30.5, 30.5, 30.5, 30.5)

R_S (I) = (61.3, 61.3, 61.3, 61.3, 61.3, 61.3, 61.3, 61.3, 30.8, 30.8, 30.8, 30.8, 30.8, 30.8)

Note that 61.3(8) + 30.8(6) = 675. The period of the schedule is 14 years. ■

Example. $S = \{p = 7, T_1 = 5, T_2 = 3\}$

Using Table K.4 with $p = 7$, $I(\leq 7) = 363$ and $I(>7) = 312$, the values of $T_1 = 5$ and $T_2 = 3$ determine the individual removal schedules over five years and three years, respectively. Since both values of T_1 and T_2 are smaller than the previous scenarios, it is intuitively clear that the decommissioning schedule will require a higher and faster rate of removal to clear the inventory determined as follows:

R_S $(I \leq 7)$ = (72.6, 72.6, 72.6, 72.6, 72.6)

R_S $(I > 7)$ = (104, 104, 104).

The total decommissioning scenario is determined by adding these two vectors:

R_S (I) = (176.6, 176.6, 176.6, 72.6, 72.6) ■

11.3.4 Normalization

Normalization ensures that decommissioning schedules are consolidated in a manner consistent with the model output. In normalization, all the decommissioning schedules are combined and averaged to yield a composite schedule. For example, if the scenario $(p, T_1, T_2) = (10, 10, 5)$ yields the decommissioning schedule vector $R_{(10,\ 10,\ 5)}$ over 10 years and scenario (7, 5, 3) yields a decommissioning schedule vector $R_{(7,\ 5,\ 3)}$ over five years, the 'average' of these two scenarios is computed by dividing the total annual activity by total activity over the maximum horizon and using the percentage vector as a multiplying factor.

Example. Vector normalization

If the decommissioning schedule vectors $R_{(10,\ 10,\ 5)}$ and $R_{(7,\ 5,\ 3)}$ are normalized on a percentage basis by dividing each entry by the row sum total (i.e., 675), then

$r_{(10,10,5)}$ = (0.136, 0.136, 0.136, 0.136, 0.136, 0.064, 0.064, 0.064, 0.064, 0.064)

$r_{(7,5,3)}$ = (0.262, 0.262, 0.262, 0.108, 0.108).

The average aggregate schedule is the average of these two vectors computed term-wise:

$$\bar{r} = \frac{1}{2}(r_{(10,10,5)} + r_{(7,5,3)}) = (0.20, 0.20, 0.20, 0.12, 0.12, 0.03, 0.03, 0.03, 0.03, 0.03).$$

The allocation percentage for the decommissioning schedule is denoted by $\bar{r}$, and when multiplied by the idle inventory yields the average idle structure schedule $\bar{R}$:

$$\bar{R} = 675 \cdot \bar{r} = (135, 135, 135, 81, 81, 20, 20, 20, 20, 20). \ \blacksquare$$

Example. Tableau normalization

Tableau normalization is equivalent to vector normalization except that a table is used to organize the calculations as shown in Table K.5. The procedure is mostly self-explanatory. The decommissioning schedules to be normalized are entered as rows in a common tableau with columns representing years. In each scenario, column sums show the total number of removals each year for the two scenarios and each row sums to 675. The total number of structures in the two scenarios (1350 =2*675) is the normalizing factor, which when divided into the total column sum, yields the normalized decommissioning activity percentage per year. The elements of the percentage vector sum to one and when multiplied by the idle structure count yields the average decommissioning schedule. ■

11.4. Auxiliary Structures

Decommissioning forecasts for auxiliary structures entail the same difficulty in forecasting as idle structures because of the lack of production stream associated with the structure. In some cases, the auxiliary structure may be associated with a producing structure or as a pipeline junction or other role. In principle, for those cases where a link with one or more producing structures can be made it would be a simple matter to apply the correspondence for the auxiliary structure, but this would not by itself ensure a more reliable forecast considering the uncertainties inherent in the model. In deepwater, idle structures are more likely to be repurposed because of the greater capital costs associated with deepwater structures, their potential use in support activities, and operators reluctance to decommission valuable assets.

In shallow water, a simple aggregate model is adopted that captures the global characteristics of the structure class without recourse to structure linkages by using historic average activity. Another way to estimate future decommissioning is to base activity on the historic percentage/range relative to total producing and idle structures. Historically, an average of 20 auxiliary structures in shallow water have been decommissioned per year over the past two decades, representing between 7 to 15% of total structure decommissioning activity over this time.

In deepwater, only a few auxiliary structures were in inventory circa 2016, and these structures can either be ignored due to their small number or decommissioned according to an assumed schedule. Most of the deepwater auxiliary structures are pipeline junctions which are expected to remain useful for a significant period of time.

11.5. Installed Structures

The size of the active inventory at any point in time is based on the difference between the cumulative number of installed and decommissioned structures at the time of evaluation:

$$\text{Active}_t = \text{CumInstalled}_t - \text{CumDecom}_t$$

Since new structures are continually being installed in both the shallow and deepwater GoM and are expected to continue to be installed in the future, to forecast active inventories it is necessary to assume an installation rate for each water depth region and add this to the decommissioning forecast results. Assuming a future installation rate is a speculative exercise, of course, since no one knows - or should pretend to know for that matter – what the future will bring, but under status quo conditions a reasonable case can be made based on historic activity.

There has been a dramatic decline in the number of shallow water structures installed in recent years. Caissons, well protectors and fixed platforms all show similar installation trends across time, peaking in the 1977-1986 period at an average rate of 170 structures/year, declining to 145 structures/year from 1987-1996, and 123 structures/year from 1997-2006 (see Table C.4). Over the past decade, 28 shallow water structures on average have been installed per year, while over the past five years about 11 shallow water structures per year have been installed.

For fixed platforms in water depth >400 ft, declining installations have been dramatic, while floater installations have held reasonably steady. From 1987-1996, 2.6 fixed platforms were installed per year on average, which declined to 1.8 structures per year from 1997-2006, to 0.2 structures per year from 2007-2016 (see Table C.6). Over the past decade there were on average about two floaters installed per year compared to three floaters per year over the preceding decade. Over the 30-yr period from 1987-2016, 54 floaters were installed, or about 1.8 structures per year on average.

CHAPTER 12. TWO EXAMPLES

Two examples are used to illustrate the computational steps involved in decommissioning forecasting. Chevron's deepwater Tick platform is evaluated circa 2012 and Anadarko's Horn Mountain spar is evaluated circa 2016. The examples are presented using the same organization but the different time periods allows reflection on the differences that occur over time and their impact on the model results. One or both examples can be perused. Decommissioning timing and reserves sensitivity to oil and gas prices are performed for each example.

12.1 TICK AND LADYBUG

The Tick and Ladybug projects were evaluated in 2012 and a postscript added circa 2018.

12.1.1 Development (Figure L.1)

In 1991, Texaco, Inc. installed the Tick platform in Garden Banks block 189 in 720 ft water depth as a one piece jacket over three pre-drilled wells (Curtis and Gilmore 1992). Three subsea wells owned and operated by ATP Oil and Gas Corp. were drilled at the Ladybug field and tied back to Tick in 1997 and 2006.

12.1.2 Structure Production (Figures L.2, L.3)

In 2012, Tick produced 97 Mbbl oil and 1.67 Bcf natural gas from five producing wells and generated gross revenue of approximately $15 million during the year. Through 2012, cumulative production was 28.6 MMbbl oil and 259 Bcf natural gas, with about 11.2 MMbbl of the oil and 11.9 Bcf of the gas produced at Ladybug, about half of Tick's total production circa 2012. A cumulative gas oil ratio CGOR of 9056 cf/bbl classifies the structure as primarily oil.

12.1.3 Well Inventory (Table L.1, Figure L.4)

A total of 27 wells were drilled at Tick through 2012. Two wells were temporarily abandoned, 19 wells were idle, and five wells were producing circa 2012. Eight sidetrack wells have been drilled at Tick and two of the five producing wells are sidetracks. Three subsea wells from the Ladybug field tie back to Tick and two of the five producing wells are Ladybug subsea completions. In 2012, there were three oil producers and two gas wells.

12.1.4 Sidetrack Production (Figure L.5)

Wells that have depleted their primary horizons and dry holes may be sidetracked in search of additional production. Sidetrack production occurs after the original wellbore no longer produces and one characteristic of drilling is that sidetrack wells cost less but also usually deliver less than the original wellbore (since, for example, they often target smaller pockets or less promising sands) and high uncertainty levels mean that the sidetrack may not provide a return on capital deployed.

12.1.5 Subsea Production (Figure L.6)

Subsea wells may be drilled as part of the initial field development plan or as discoveries are made in the vicinity of the facility by the operator or a third-party. For third-party fields, Production Handling Agreements are negotiated contracts that allow production to be processed at another operator's facility. In 1997, ATP drilled two subsea wells in the Ladybug field which were tied back to the Tick platform. Flowline issues in the oil line delayed oil receipt until 2000.

12.1.6 Decline Curve Specification (Table L.2)

Each producing well at the time of evaluation is curve-fit based on the historic primary product stream using a hyperbolic decline curve model. For primarily oil wells, future oil production is forecast based on the best-fit parameters and the secondary product (associated gas) is forecast by extrapolating the cumulative gas-oil ratio versus cumulative oil trend. For primarily gas wells, future gas production is forecast using the best-fit model parameters and the secondary product (condensate) is forecast using the cumulative condensate gas ratio versus cumulative gas trend.

12.1.7 Primary Production Forecast (Table L.3)

There are two gas and one oil dry tree wells at Tick circa 2012 and the Ladybug subsea wells are both classified as primarily oil. Production and price determine gross revenue, and after reduction by the royalty rate yields the net revenue. The economic limit is assumed to be $750,000 per well and $5 million at the structure level, whichever comes first. Production ceases when net revenue falls below the economic limit. As prices change, the net revenue per wellbore will change which will impact the time production ceases and the ultimate recovery of each well. At $100/bbl oil and $4/Mcf gas, wells 11500 and 16300 were expected to reach their economic limit in 2014, and the remaining wells in 2016. Remaining reserves for the primary product streams are estimated at 258 Mbbl oil and 1.8 Bcf natural gas.

12.1.8 CGOR and CCGR Trends (Figure L.7)

The relative contribution of oil and gas production at each well changes over time with changes in reservoir and operating conditions. For black oil wells CGOR is often flat while for retrograde and condensate wells often increases with time. For dry gas wells, CCGR is often flat and decreasing with time for wet gas wells. Trends in CGOR and CCGR are used to forecast the secondary product stream for each producing well. Logarithmic transformations are applied to smooth out the cumulative profiles. If the secondary product streams follow historical trendlines, the secondary product forecast will be robust; otherwise, errors will arise in the projections. Because secondary products are usually significantly smaller in volume and revenue contribution than primary products, the impact of model errors is usually not significant.

12.1.9 Secondary Product Forecast (Table L.4)

The secondary product stream is forecast for each producing well based on the CGOR and CCGR trend relations and the primary product forecast. The primary product is forecast using the best-fit decline curve parameters, and then using either the CGOR or CCGR extrapolated trends the secondary product forecast is derived through multiplication. Remaining reserves for the secondary products at Tick and Ladybug wells are estimated to be 10 Mbbl oil and 386 MMcf natural gas, about 10% of the primary product volumes. Liquids from the secondary streams represent about 3% of the total crude oil (453/14,433) remaining to be produced, while gas production from the secondary streams are about half of the total gas production (26.9/55.1).

12.1.10 Structure Production Forecast (Figure L.8)

Structure production is forecast based on the sum of the production forecast of each producing well assuming constant (status quo) conditions at the time of evaluation. When production revenue is not adequate to cover direct operating expense, the structure is no longer commercial and will cease operations. Primary oil and gas production dominate the secondary streams (oil, 258 Mbbl vs. 10 Mbbl; gas, 1803 MMcf vs. 386 MMcf), and the total remaining oil and gas production is estimated to be 268 Mbbl oil and 2.2 Bcf gas at $100/bbl oil and $4/Mcf gas price. Remaining reserves represent a small percentage of the total oil and gas extracted through 2012 (<1% oil, <1% gas) and is a primary indicator that the structure is near its economic limit.

12.1.11 Net Revenue Forecast (Table L.5)

Future net revenue is determined by multiplying the primary and secondary production forecasts with assumed future oil and gas prices and reducing the sum by the royalty rate. Wells cease production at their economic limit or when structure revenue falls below $5 million. At $100/bbl oil and $4/Mcf gas, the economic limit is forecast to occur in 2016. Wells 09021, 10800 and 63501 are still expected to be producing in 2016, but because their combined revenue falls below $5 million the structure is no longer considered commercially viable. Undiscounted future revenue is estimated at $36 million, $23 million of which is expected to arise from the Ladybug wells.

12.1.12 Economic Limit Sensitivity (Table L.6)

It is useful to evaluate the sensitivity of the economic limit to changing oil and gas prices since the well inventory and decline trends are fixed per the status quo conditions. Since Tick wells are far along their decline curves and remaining reserves are small, changing oil and gas prices are not expected to have a significant impact on production volumes or the timing of the economic limit. For example, at $60/bbl oil and $2/Mcf gas, the economic limit is estimated to occur in 2015, while at $120/bbl oil and $8/Mcf gas, the economic limit is estimated to occur in 2017.

12.1.13 Proved Reserves Sensitivity (Table L.7)

Reserves are a function of oil and gas prices and the economic limit threshold. As commodity prices increase, revenues increase and economic limits are delayed which lead to additional incremental production. At $60/bbl and $2/Mcf gas, Tick is estimated to produce 528 Mboe reserves from the 2012 inventory of wells. At $120/bbl oil and $8/Mcf gas, proved reserves from the 2012 inventory of wells are estimated at 715 Mboe. As oil prices double and gas prices quadruple, reserves increase by about a third.

12.1.14 Reserves Valuation Sensitivity (Table L.8)

Tick's reserves circa 2012 are estimated to be worth between $7 to $34 million for oil prices between 60 to 120 $/bbl and gas prices between 2 to 8 $/Mcf, assuming a 10 % discount rate, 16.67 % royalty rate, and $15/boe operating cost. For a low gas price ($2/Mcf), reserves triple in value as oil prices double, while at a high gas price ($8/Mcf), the value of reserves double as oil prices double.

12.1.15 Postscript circa 2018

In 2012, Tick had already exhausted most of its reserves and reached the point when it was unlikely to redeveloped or sold as a structure-of-opportunity unless Chevron paid another company to account for its decommissioning liability. In 2013, ATP declared bankruptcy and no bidders were found for Ladybug, which likely was the determining factor in sealing Tick's fate. In 2015, Tick ceased production and alternative uses for Tick are under review. Deepwater production can be directed across Tick after all its wells are plugged if a suitable development is available and its makes economic sense.

12.2. HORN MOUNTAIN

The Horn Mountain development was evaluated in June 2017 and is organized similar to the Tick/Ladybug example.

12.2.1 Development (Figure L.9)

The Horn Mountain field was discovered in 1999 in Mississippi Canyon in about 5400 ft of water and has been in production since 2002. Two Middle Miocene reservoirs were developed with eight producing and two water injection dry tree wells. All ten wells were pre-drilled using a semisubmersible and batch completed from the spar. In 2015, two subsea wells were tied back to the platform. Leases for the MC 126 and 127 blocks were originally held 67% by BP and 33% by Oxy, with BP as operator. BP sold its interest to Plains Exploration in 2012 which was acquired by Freeport McMoRan, who later sold their interest to Anadarko in 2016.

12.2.2 Structure Production (Figures L.10, L.11)

Horn Mountain production peaked one year after initial production in 2003 at 59 Mbopd oil and 51 MMcfpd natural gas. In 2016, Horn Mountain produced 3.6 MMbbl oil and 5.1 Bcf natural gas from eight producing wells, generating gross revenue of about $159 million during the year. Cumulative production through 2016 was 114 MMbbl oil and 101 Bcf natural gas valued at $7.3 billion undiscounted.

12.2.3 Well Inventory (Table L.9, Figure L.12)

Eleven wells have been drilled at Horn Mountain and three wells have been drilled off-lease. In 2016 there were eight oil producing wells, six dry tree wells and two wet wells. Four dry holes have been drilled in total, one of which was sidetracked and is producing, and circa 2016 two wells are idle. No new wells or sidetracks have been drilled at Horn Mountain since 2003 and the subsea wells first produced in 2016.

12.2.4 Decline Curve Specification (Table L.10)

Each producing well circa 2016 is curve-fit based on its primary product stream using a hyperbolic decline curve model. For the two subsea wells that started producing in 2016 the average decline curve parameters from the six producing dry tree wells and average cumulative gas-oil ratio trends are used to forecast production since better information was not available.

12.2.5 Primary Production Forecast (Table L.11)

The primary production stream forecasts are depicted for the eight producing wells circa 2016. Economic limits are assumed to be $750,000 per well and $5 million per structure, whichever is reached first. At $60/bbl oil and $3/Mcf gas, well 93200 reaches its economic limit in 2022, well

92700 in 2028, well 30600 in 2029, well 31100 in 2035, well 93101 in 2044, and wells 93300, 93600 and 93700 in 2047. Subsea well forecasting is more uncertain than for dry tree wells because of the lack of production data. Remaining reserves are estimated at 19.6 MMbbl and represents about 15% of the total oil expected to be produced under status quo conditions.

12.2.6 GOR and CGOR Trends (Figures L.12, L.13)

Secondary products change during the life of each well with changes in the reservoir conditions and drive mechanisms. For black oil wells, CGOR trends are usually flat which simplifies secondary stream forecasts. CGOR trends for each well are used to forecast the secondary product stream based on the primary product forecast. Logarithmic transformations were applied but linear relations also work well for these wells. Subsea wells 30600 and 31100 are not depicted in the figures.

12.2.7 Secondary Production Forecast (Table L.12)

The secondary product stream is forecast for each producing well based on individual CGOR trend relations and the primary product forecast. CGOR extrapolated trends are multiplied by the primary product forecast to yield the secondary product forecast. Remaining reserves for all the secondary streams are estimated to be 21.3 Bcf natural gas.

12.2.8 Structure Production Forecast (Figure L.14)

Structure production is forecast based on the sum of the production forecasts of each producing wellbore (last columns in Tables L.11 and L.12) assuming status quo conditions at the time of evaluation and $60/bbl oil price and $3/Mcf gas price. Total cumulative production (proved reserves) circa 2016 under the price assumption is estimated to be 117 MMbbl oil and 108 Bcf natural gas.

12.2.9 Revenue Forecast (Table L.13)

Gross revenue is determined as the product of future oil and gas prices and the primary and secondary product streams. Wells cease production at their economic limit or when the structure revenue falls below a specified commercial threshold. In 2047, gross revenue reduced by the 16.67% royalty rate falls below $5 million and is no longer economic. At $60/bbl oil and $3/Mcf gas undiscounted revenue from the future production streams is calculated at $1.2 billion.

12.2.10 Economic Limit Sensitivity (Table L.14)

At $40/bbl oil and $2/Mcf gas, the economic limit occurs in 2042. For higher oil and gas prices, production revenue is greater which delays the economic limit for all things equal. At $100/bbl oil and $5/Mcf gas, for example, the economic limit is forecast to occur 14 years later in 2056. Since Horn Mountain is an oil structure and oil price is the primary determinant in decommissioning timing. For a given oil price, changing gas prices has no noticeable impact. If high oil prices prompt new drilling and additional reserves are recovered, the lifetime of the structure will likely be extended but this is specifically excluded by the status quo assumptions. Similarly, if new deposits are tied-back to the structure the lifetime would also be extended, but again this is also specifically excluded by model assumptions due to its speculative nature.

12.2.11 Reserves Sensitivity (Table L.15)

Reserves are a function of reservoir and well characteristics, oil and gas prices, investment decisions, economic limits and other factors. As commodity prices increase, economic limits are delayed which lead to additional production. At $40/bbl and $2/Mcf gas, Horn Mountain reserves are estimated at 22.2 MMboe for the 2016 well inventory. At $100/bbl oil and $5/Mcf gas, Horn Mountain's reserves are estimated as 24.0 MMboe. The change in reserves is quite small relative to total production and is due entirely to existing well inventories.

12.2.12 Reserves Valuation Sensitivity (Table L.16)

Horn Mountain's remaining reserves circa 2016 are estimated to be worth between $199 to $816 million for oil and gas prices between $40 to $100/bbl and $2 to $5/Mcf, a 10% discount rate, a 16.67% royalty rate, and $15/boe operating cost.

CHAPTER 13. SHALLOW WATER DECOMMISSIONING FORECAST

Decommissioning forecasting requires different models to describe the collection of producing, idle and auxiliary structures and are intended to reflect general characteristics of each structure class. At the end of 2016, there were 2009 structures in water depth less than 400 ft in the Gulf of Mexico - 960 producing structures, 675 idle structures and 374 auxiliary structures. The future cash flows of producing structures are estimated using decline curves to predict expected decommissioning timing. Schedule approaches are adopted for idle and auxiliary structures with uncertainty incorporated in the assessment. Schedule models are intended to reflect general trends and are used as an accounting mechanism to organize the data. Sensitivity analysis is performed and composite model results are presented. From 2017-2022, between 474-828 structures are expected to be decommissioned in the shallow water Gulf of Mexico, and by 2027, between 704-1199 structures are expected to be decommissioned.

13.1. MODEL RECAP

The approach taken is to apply standard economic models where applicable and a scheduled approach where economic models cannot be applied. Structures are classified into one of three categories – producing, idle and auxiliary – and are decommissioned according to models intended to reflect market characteristics and operator behavior of each structure class. At the end of 2016, there were 960 producing structures, 675 idle structures and 374 auxiliary structures in the shallow water GoM. Producing structures are the largest class and standard industry models can be applied in decommissioning forecasting. Idle and auxiliary structures comprise more than half the inventory and require new approaches. The results of this chapter use data through 2016, and while earlier sections of the report presented data through 2017, use of the updated data would not make a material difference to the model outputs excepting shifting the start period of the forecast.

For producing structures, exponential and hyperbolic decline curve models and assumed economic limits and commodity prices determine the time of abandonment assuming no capital spending outside of normal maintenance activities. Two decline models are used to bound activity levels and decommissioning is assumed to occur two years after the economic limit is reached. Economic limits, oil and gas prices, and royalty rate are model parameters (Table M.1). Producing structures are assumed to proceed direct to decommissioning with no transition to idle or auxiliary status.

Structures without production are scheduled for decommissioning using user-defined assumptions and historic data on decommissioning activity. For idle structures, a phase-space ensemble average formalizes the average decom schedules for multiple user scenarios based on decomposing the idle inventory into two idle age categories for decommissioning. The model input acknowledges the uncertainty inherent in the parameter selection and requires the user to specify upper and lower bounds on model parameters. A simple empirical model based on historic decommissioning activity is used to schedule future auxiliary structure decommissioning.

13.2. PRODUCING STRUCTURES

13.2.1 Reference Case

Using hyperbolic decline models and assuming a crude and condensate price of $60/bbl, casinghead and gas well gas of $3/Mcf, an economic limit of $300,000 per structure for all structures, and a one-year delay in which decommissioning is performed after the economic limit is reached, lead to the decommissioning forecast shown in Figure M.1.

In 2017, 46 producing structures are expected to fall below their economic limit and be decommissioned and in subsequent years activity levels decline to five to fifteen structures per year, achieving 148 cumulative decommissioned structures in 2027, 231 cumulative decommissioned structures in 2037, and 301 cumulative decommissioned structures in 2047.

Activity per decade is computed by subtracting the cumulative totals, so that between 2027 and 2036 there are 83 (=231−148) decommissioned structures and 70 (=301−231) decommissioned structures from 2037 to 2046. Annual average activity is computed by dividing cumulative totals by the time period, so that 15 (≈ 148/10) structures on average are decommissioned per year through 2027, decreasing to 12 (≈ 231/20) structures per year through 2037.

13.2.2 Sensitivity Analysis

Sensitivity analysis is performed to ensure the model structure and results behave according to expectation. The impact of $40, $60, $80/bbl oil prices; gas prices of $2, $3, $4/Mcf; and economic limits of $200, $300, $400, $500, and $1000 thousand dollars will lead to 3 × 3 × 5 = 45 combinations for each decline model under the assumption $P^{oil} = P^{cond}$ and $P^{gas} = P^{ass}$. Relaxing the commodity price equivalence and for two different decline models (exponential, hyperbolic) increase the number of combinations another eight fold (2 x 2 x 2) with the total number of scenarios falling into the hundreds. Obviously, a judicious selection of parameters is needed to manage all these combinations.

13.2.3 Hyperbolic vs. Exponential Decline Curve

Hyperbolic decline is the most general form of decline and is often the de facto standard model employed in production forecasting for both conventional and unconventional reservoirs. Intuitively, hyperbolic decline models will predict low/slow levels of decommissioning activity compared to exponential models which posit a constant decline in production from year-to-year.

Assuming $3/Mcf gas price and a $300,000 economic limit for all structures, the cumulative number of structures decommissioned for hyperbolic and exponential models are compared in Figure J.2 for $60/bbl oil and are depicted at 10-year intervals for three oil prices in Table J.2. The form of the decline model has a significant impact on the forecast and provides the greatest range of uncertainty among the model variables.

The first entry in the pair of numbers in Table M.2 is the cumulative number of structures decommissioned according to the hyperbolic model followed in the second entry by the cumulative count for the exponential model circa 2016. For example, using exponential decline curves at $60/bbl oil, the model predicts that there will be 517 structures decommissioned from 2017 through 2027, 700 by 2037 and 812 by 2047.

With 960 producing structures in inventory circa 2016, the exponential model will clear most of the existing inventory by 2047 under the three price assumptions, from 82% (789/960) at high oil prices to about 88% (843/960) at low oil prices. By comparison, the hyperbolic model indicates a much more leisurely removal rate, from 27% (263/960) to 38% (360/960). Using two decline curve models bound the decommissioning forecast results holding all other factors constants.

13.2.4 Price Variation

Oil and gas prices enter gross revenue linearly but because each structure is an aggregate of multiple wells there will be differences in the relative contribution of oil and gas revenue. Doubling one price while holding the other price fixed, for example, will not exhibit proportionate behavior in decommissioning counts. Oil price changes will impact oil structures more than gas price changes, and similarly, for gas structures gas price changes will have a greater impact than oil prices because the primary product stream (usually) plays the dominant role in structure revenue.

When comparing the model results for two different oil prices holding all other factors fixed, the number of decommissioned structures at lower oil price should be higher than for higher prices. For example, in 2027, 29 (=177−148) additional structures are decommissioned for the hyperbolic model at $40/bbl oil compared to $60/bbl, while 38 (= 555− 517) additional structures are decommissioned using exponential decline (Table M.2). Conversely, at higher oil prices holding all other model parameters constant and for all else equal, greater revenue is generated which will delay the economic limit and reduce decommissioning activity compared to lower prices. At $80/bbl crude the hyperbolic model predicts 121 structures decommissioned in 2027 compared to 148 structures at $60/bbl (Table M.2).

Since about two-thirds of shallow water structures are oil producers, oil production and oil prices are expected to have the greatest impact on total decommissioning count and is a primary variable of interest. Fixing oil price and varying gas prices will have a smaller impact on the total number of structures decommissioned because there are fewer gas structures and gas contributes less to total revenue (Table M.3).

The variation of oil and gas price on cumulative structure counts are depicted in Figures M.3 and M.4. Doubling oil prices leads to a larger variation in the cumulative count and a wider gap relative to doubling gas price because of the greater number of oil structures in inventory. Note that the $60/bbl and $3/Mcf curves in Figures M.3 and M.4 are identical.

13.2.5 Economic Limit Variation

In Figure M.5, the impact of changing economic limits are shown for hyperbolic decline models and fixed $60/bbl oil and $3/Mcf gas commodity prices. As economic limits increase, cumulative counts increase at every time period because a greater number of structures reach their thresholds sooner and the spread increases over time. The same characteristic curves hold for exponential models and other price combinations but the relative differences and shape of the plots change.

13.2.6 Oil vs. Gas Structures

Using the exponential model, the impact of oil and gas prices on the number of decommissioned oil structures and on the number of decommissioned gas structures are examined. Oil structures should exhibit a greater sensitivity to oil price changes relative to similar gas price changes, and vice versa with gas structures exhibiting a greater sensitivity to gas prices due to the relative contribution of revenue impacts. Results confirm that the model construction behaves according to expectation at a granular level because the cash flows and other analytic aspects of the construction were developed with full generality. The exponential model is used for illustration and similar trends hold for the hyperbolic model.

In Table M.4, doubling oil price from $40 to $80/bbl at $3/Mcf gas has a negligible impact on gas structure counts (first element in each pair entry, read across the row) – about ten structures at any point in time – and a more significant impact on oil structure counts (the second term of the pair) which vary by 68 in year 2027, 57 at year 2037, and 48 at year 2047.

In Table M.5, doubling gas price from $2 to $4/Mcf at $60/bbl oil has a small input on oil structure counts and a modest impact on gas structure counts (again, read across the row), ranging from 13 to 21 structures for gas structures, 21 at year 2027, 19 at year 2037, and 13 at year 2047.

13.2.7 Commodity Price Adjustment

In all previous models oil prices were assumed equal to condensate prices and associated and non-associated natural gas prices were considered equivalent. Using a more realistic condensate price deck, gas structures will receive less revenue for their liquid hydrocarbon production which will subsequently accelerate the time of their economic limit. For oil structures there should be no changes in model count.

Condensate prices are assumed equal to 60% of the crude price input. After 10 years, the cumulative difference for $60/bbl crude, $3/Mcf gas prices for oil structures and $36/bbl condensate, $3/Mcf gas prices for gas structures leads to an average increase of 31 decommissioned structures relative to the base case (Table M.6). After 20 years, the average difference declines to 19 structures, and at 30 years the average difference is less than a handful.

Over long periods of the time, the significance of the modified pricing assumption appears negligible. There is not a uniform increase in the number of decommissioned structures as economic limits increase because of the nonlinear impact of the commodity price change.

13.2.8 Royalty Relief

Removing the royalty rate on producing assets will reduce the number of structures that reach their economic limit at a given time since net revenues increase incrementally with the elimination of the royalty payment. Overall impacts are expected to be small, however, because of the relatively small role royalty rates play in operator cash flows and decision making at the end of the life of production. Model results support this intuition.

For $60/bbl oil and $3/Mcf gas price scenario, the reduction in the structure counts with royalty relief averaged 25 structures over 10 years, or 2.5 structures per year. At 20 years, the cumulative change declines to 17 structures, and at 30 years, 11 structures. The conclusion is that removing royalty rate on end-of-life producers as reflected in this framework can be ignored in evaluation since the changes are small relative to the impact of other model parameters.

13.3. IDLE STRUCTURES

A phase-space ensemble average is applied in conjunction with a normalization procedure to formalize averaging decom schedules over multiple scenarios. The model input requires the user to specify each of the three model parameters (p, T_1, T_2) in terms of an upper and lower bound. An example illustrates the procedure.

Example. $\{\mathscr{R}_b \mid p = 3, 10; T_1 = 5, 10; T_2 = 3, 7\}$

The bounded average decommissioning schedule is computed by selecting an upper and lower bound for each of the three model parameters. For illustration we select $p = \{3, 10\}$, $T_1 = \{5, 10\}$, $T_2 = \{3, 7\}$.

These model parameters yield the following data for the 2016 GoM shallow water idle structure inventory. For $p = 3$, $I (\leq 3) = 195$ and $I (>3) = 480$. For $p = 10$, $I (\leq 10) = 431$ and $I (> 10) = 244$ (recall Table M.4).

Tableau's are computed describing the decom schedules for each set of triplets. For $p = 3$, the idle inventories yield four decommissioning schedules denoted R_{ij}^p; $i, j = 1, 2$ for each pair of (T_1, T_2) values organized as follows:

$p = 3$	$I (\leq 3)$	$I (>3)$
	$T_1 = 5$	$T_1 = 10$
$T_2 = 3$	R_{11}^p	R_{12}^p
$T_2 = 7$	R_{21}^p	R_{22}^p

Each cell of the tableau requires a separate computation and is comprised of a single decom schedule vector, as follows:

$T_1 = 5$, $T_2 = 3$:	$R_{11}^3 = (199, 199, 199, 39, 39)$
$T_1 = 5$, $T_2 = 7$:	$R_{21}^3 = (108, 108, 108, 108, 108, 68, 68)$
$T_1 = 10$, $T_2 = 3$:	$R_{12}^3 = (180, 180, 180, 20, 20, 20, 20, 20, 20, 20)$
$T_1 = 10$, $T_2 = 7$:	$R_{22}^3 = (88, 88, 88, 88, 88, 88, 88, 20, 20, 20)$

For $p = 10$, the four decommissioning schedules are as follows:

$T_1 = 5$, $T_2 = 3$:	$R_{11}^{10} = (168, 168, 168, 86, 86)$
$T_1 = 5$, $T_2 = 7$:	$R_{21}^{10} = (147, 147, 147, 147, 147, 61, 61)$
$T_1 = 10$, $T_2 = 3$:	$R_{12}^{10} = (124, 124, 124, 43, 43, 43, 43, 43, 43, 43)$
$T_1 = 10$, $T_2 = 7$:	$R_{22}^{10} = (78, 78, 78, 78, 78, 78, 78, 43, 43, 43)$

When all eight vectors are summed and normalized, the average bounded allocation vector $\mathscr{R}_b$ for the idle structure decom schedule is as follows:

Column Sum:	(137, 137, 137, 76, 76, 45, 45, 16, 16, 16)
Percentage:	(0.20, 0.20, 0.20, 0.11, 0.11, 0.07, 0.07, 0.02, 0.02, 0.02)

13.4. AUXILIARY STRUCTURES

Auxiliary structures could be added with idle structures and the combined structure group scheduled according to the phase space approach. A simpler model employs historic average decommissioning rates. If installation and removal trends of auxiliary structures are governed by a stochastic process described through its average, then the average bounded by its standard deviation provides a reliable boundary for future activity. Over the last two decades, auxiliary structure decommissioning activity has been bound between 10 to 30 auxiliary structures decommissioned per year, with 20 structures the average annual decommissioning rate.

13.5. HYBRID MODEL SCENARIOS

13.5.1 Notation

The following shorthand notation is used to designate the model parameters and assumptions in the hybrid model scenarios for the producing (P), idle (I) and auxiliary (A) structure subclasses:

$$\{(P, I, A)\} = \{(\text{Decline}, EL, P^o, P^g), (p, T_1, T_2), (AVG, k)\}.$$

The notation organizes the description and indicates the variables that define the model inputs and is useful to avoid repetitive descriptions.

For producing structures, the decline model indicator Decline is either of hyperbolic or exponential form, the economic limit EL is defined in $1000, and the oil and gas prices are specified in common units ($/bbl, $/Mcf). These four parameters uniquely determine the abandonment time for a producing structure.

For idle structures, the model parameter p subdivides the idle inventory into two classes by idle age, and for each subgroup user-defined parameters T_1 and T_2 are specified which allocate the inventory classes uniformly over the two periods. All the parameters are specified in years and the procedure allocates structures as a class and not on an individual basis.

For auxiliary structures, the average level of decommissioning activity AVG computed over a specified historic time period k in years is used to specify future decommissioning rates. Similar to the idle class, structures are not distinguished individually in forecasting but on a group basis.

13.5.2 Scenario Parameterization

The following scenario parameterization is applied in the model construction:

$$\{(P, I, A) = \{(\text{Hyp}, 300, 60, 3), (7, 20, 10), (20, 20)\}$$

Hyperbolic decline curves, an economic limit of $300,000, oil price of $60/bbl, and gas price of $3/Mcf are the model inputs for producing structures. The idle structure decommissioning schedule is based on the model parameters (7, 20, 10) extended to a 20-yr horizon. The auxiliary structure submodule assumes 20 structures per year are removed over the forecast period based on a 20-year historical average rate.

13.5.3 Composite Results

The results of combining the three submodules for producing, idle and auxiliary structure decommissioning are shown in Figures M.6 to M.9. In Figure M.6 the results of the hyperbolic decline model is depicted for producing structures under reference case conditions and assumed schedules for idle and auxiliary structures. In Figure M.7 the decommissioning model results are broken out by structure class. Idle structures play a dominant role in the results. In Figures M.8 and M.9 the hyperbolic model is replaced with the exponential model and the results are compared. Using exponential decline models yields an upper bound on activity levels. In Figure M.9, the cumulative decommissioning forecast for the hyperbolic and exponential models are compared.

13.5.4 Class Transitions

If structures are allowed to transition between classes prior to decommissioning, transition probabilities can be used in a quasi-equilibrium manner to capture this behavior. Producing platforms will become idle when their reservoirs are depleted or transition directly into decommissioned status. Both transitions are believed to be equally common and much greater than a transition to auxiliary status which occurs less frequently. Idle structures may be repurposed to serve an auxiliary role if they are well-positioned and gain regulatory approval, but the number of these transitions are relatively few, perhaps between 5 to 15% of structures entering the class.

Producing structures are assumed to transition to the idle, decommissioned, and auxiliary classes with probability p_1, p_2, and $1-p_1-p_2$, respectively, that are assumed constant over time (Figure M.10). Idle structures are assumed to transition to the decommissioned and auxiliary class with probability q and 1-q, respectively. Auxiliary structures are assumed to transition direct to decommissioning. Idle structures are not allowed to return to production status because the only way an idle structure could return to production is via capital investment in wells, and this particular type of spending to add/increase production is not permitted in the model framework. Capital investment to change a structure's function is acceptable[11].

Using the transition probabilities $(p_1, p_2, 1-p_1-p_2) = (0.4, 0.4, 0.2)$ for structures exiting the producing class and (q, 1-q) = (0.9, 0.1) for structures exiting the idle class, will reduce the number of structures entering decommissioning in a probabilistic fashion as shown in Figure M.11 for the exponential and hyperbolic decline results.

According to the hybrid model bounds, from 2017-2022, between 556 to 828 structures will be decommissioned, and by 2027, between 830 to 1199 structures are expected to be decommissioned. With the probability transitions incorporated in the evaluation, future activity levels will be reduced and range between 474 to 702 decommissioned structures from 2017-2022, and between 704 to 1014 structures from 2017-2027. In both cases, decommissioning activity is reduced up to about 80% total activity over the forecast period. Decommissioning activity is pushed forward in time to future years and beyond the horizon of the forecast.

[11] This may seem like a quirk of the model, but it is a central assumption in all reserves estimates and production forecasts used in industry (see Section 11.2.5).

13.6. Active Inventory Scenario

In Figure M.12, the active shallow water GoM inventory forecast is depicted for assumed installation rates of 5, 20, and 40 structures per year. Actual activity levels are most likely at the low end of the range between 5 to 20 structures per year. Under the exponential model, reduction in active inventories are more dramatic (Figure M.13).

According to the hyperbolic model, assuming installation rates between 5 to 20 structures per year, in 2027 active inventories will range between 1234 to 1399 structures. By 2036, active inventories are expected to range between 1023 to 1323 structures. These are upper bound limits. Using the exponential model for lower bound limits, by 2027 active structures will range between 865 to 1293 structures, and by 2036 active inventories will range between 562 to 1217 structures.

13.7. Discussion

Shallow water decommissioning activity is expected to continue at a relatively high rate in the short-term with average annual activity between 75 to 150 decommissioned structures per year. The rate of decrease is expected to slow in the years ahead but remain significant and large relative to installation rates which are expected to fall below 20 structures per year.

Active inventories depend on installation rates but will continue to decline following the general downward trend observed over the past decade. It is possible that active inventories will level out if new plays are discovered and developed in the region (e.g., deep gas), but it is much more likely the declining trends will continue at rates similar to historic activity over the next five to ten years.

Structure decommissioning forecast require the use of different models for each structure class and are intended to reflect reality according to model assumptions. The producing structure model is capable of providing good quantitative agreement with operations under the assumptions specified. The scheduling models are intended to permit general correspondence and are used mostly as an accounting mechanism to organize the data. All three models are required in evaluation because each structure class represents a significant percentage of the total inventory.

The model fits are unique based upon the model assumptions, but because several model parameters are unknown or speculative, the results are not unique. There is a general tendency to focus on uncertainty for explicit/model parameters, but this is often misleading because of the large role of implicit parameters that are not modeled in analysis.

13.8. Limitations

Structures in the shallow water GoM represent a system whose elements are considered independent of one another for the purpose of evaluation, while in practice significant local interrelationships and dependencies are present based on regional operations, multi-structure complexes, pipeline activities and service (e.g., gas-lift) functions. These dependencies are difficult to establish and were not considered in the evaluation.

Producing and idle structures comprise about two-thirds of the structure inventory. The accuracy and reliability of the producing structure forecast are presumably better than the idle structure schedule, and so the uncertainty of the composite results is expected to be determined by the uncertainty of the idle schedule. Auxiliary structure inventories are less significant than idle structures and the reliability of their decommissioning schedule is expected to have a smaller impact on the overall results.

Decommissioning forecasting for producing structures are based on rigorous and objective economic models and cash flow analysis, but are subject to severe modeling assumptions that will yield higher- and earlier-than actual decommissioning activity due to the constant investment and reservoir condition assumption.

Unlike the physical laws of nature such as Newton's laws of motion and Maxwell's equations of electrodynamics, the equations used to predict well production are strongly constrained by assumptions. There is no unique expression for well production that can be applied because normal operating and capital spending decisions of operators are a central feature of well performance and cannot be modeled. So although there are elegant mathematical expressions that can be derived using historic data to extrapolate production trends into the future, in practice these expressions are limited in their ability to reliably model well production outside of the assumption space. For offshore structures, complications are compounded because there are multiple wells feeding into host platforms and many structures have no wells at all. Strategic and regional operations and other unobservable conditions complicate evaluation. All of these complexities, interactions and uncertainties means that approximation methods and a clear understanding of assumptions are essential in model construction and interpretation.

Scheduling is a subjective procedure because the user schedules the structures for decommissioning according to *a priori* assumptions, either to reflect statistical characteristics of decommissioning activity or user-preferences. The uncertainty levels of these models are difficult to quantify and the models are less satisfying in the sense that there are no fundamental or deeper knowledge involved in the procedures, but the techniques are required to complete the model evaluation.

There are many complications involved in attempting to develop a more granular and precise scheduling model. For example, if an auxiliary structure is part of a producing complex, it is likely that when the complex is no longer producing the structures of the complex will have limited utility, in which case the link between the producing and auxiliary structures of the complex could be used to activate decommissioning for the auxiliary structures. If the structure is not part of a producing complex it may already serve a useful function for pipeline transmission. Unfortunately, modeling these linkages is both tedious and highly uncertain, and thus of questionable utility. An aggregate model was adopted that captures the global characteristics of the structure class without recourse to structure linkages.

We did not consider the differences that exist between structure types. Caissons and well protectors, for example, have a greater chance of removal after becoming idle and a smaller chance of being used for further operations, for all things equal. No distinction was made between structure type, manning status or production complexes in the models presented. Operator differences were not considered and a single economic limit was applied across all structures. Economic limits are local, characteristic for individual structures, but individual variations may be large and constant economic values will not account for all factors. The aggregate impact of using economic limits linked to structure type is expected to be minimal and is not warranted by the model uncertainty.

Finally, decommissioning models are region specific to account for unique country-specific regulatory, fiscal and ownership issues and models do not transfer between country. For example, in the U.K. North Sea operators are required to provide information regarding decommissioning plans and timing to regulators, and therefore there is limited need for forecasting. In other offshore regions such as southeast Asia, title to structures often transfer to the government after installation which present additional complications. The issues with aging infrastructure and marginal production are broadly similar everywhere, of course, but the models used in their forecasting need to be site-specific.

CHAPTER 14. DEEPWATER DECOMMISSIONING FORECAST

The GoM deepwater inventory circa 2016 consists of 48 fixed platforms, three compliant towers, and 47 floating structures. Deepwater installation and decommissioning activity is slow and sporadic over time and these trends are expected to continue for the foreseeable future because of the significant capital requirements and residual value of structures and long planning horizons needed in development and decommissioning. All of the floaters and about half of the fixed platforms were producing circa 2016 and about a dozen fixed platforms were idle or in auxiliary status. Several fixed platforms and a few floaters are long on their decline curve and are expected to be decommissioned within the next few years unless suitable tieback opportunities materialize or an alternative use for the structures are found. Model results predict between 27 to 51 deepwater structures will be decommissioned through 2031 and 12 to 25 removals are expected to occur from 2017-2022. In 2017, two fixed platforms were decommissioned and one floater was installed.

14.1. MODEL RECAP

The approach taken is to apply economic models where applicable and a scheduled approach where economic criteria cannot be applied. All idle structures and structures with net revenue less than their economic limit $NR < EL$ are scheduled for decommissioning using user-defined model assumptions, while all structures with $NR > EL$ employ a production forecast model. According to the 2016 deepwater GoM inventory, there were 13 idle structures, 15 (marginal) producers with $NR < EL$, 26 platforms with $NR > EL$, and 44 floaters with $NR > EL$. The deepwater decommissioning forecasts are performed using data through 2016, and while earlier sections of the report presented data through 2017, the updated data will not make a material difference to the model results.

Three scenarios are used to tie the model results together: a ‘base’ (expected) case, a ‘slow’ (or low) case, and a ‘fast’ (or high) case. The selection of the slow/low and fast/high model parameters are relative to the base case and refer to the impact on decommissioning activity, not to the model parameters themselves. For example, for producing structures the slow/low scenario applies an oil price of $80/bbl, whereas the fast/high scenario applies an oil price of $40/bbl. High oil prices will generate greater revenue than low prices, and for a given production decline will delay decommissioning, resulting in a slow/low decommissioning trajectory relative to the base case.

For producing structures, an assumed economic limit determines the EL-yr assuming no capital spending outside of normal maintenance activities, and is adjusted by the user-defined parameter τ to determine decommissioning timing (Figure N.1). EL and τ are model parameters based on historical data. The parameter τ helps to balance the model results against the early decommissioning forecast predicted through application of the status-quo assumptions. Base case parameters apply average data on economic limits, removal times, and $60/bbl oil and $3/Mcf gas price (Table N.1).

The slow/low case model parameters are selected to schedule idle structures and structures producing below their economic limit slower than the base case schedule (10 years versus five years), and for all other structures, decline curve estimates are used with EL-yr delays based on the upper range of historic removal times. For platforms, the EL-yr delay is five years in the base case and 10 years in the slow/low case. For floaters, the EL-yr delay is two years across all scenarios.

14.2. DECOMMISSIONING FORECAST

14.2.1 Producing Structures

The expected last year of production for producing fixed platforms in 400-500 ft (Table N.2), fixed platforms and compliant towers in >500 ft (Table N.3), and floaters (Table N.4) are presented by commodity price for the primary production stream. The secondary product price is held fixed at $3/Mcf for oil producers and $60/bbl for gas producers across all price scenarios. For fixed platforms, oil and gas structures are shown separately since there is a mix of producers, while all floaters (except Independence Hub, complex 1766) are oil structures.

14.2.2 Model Scenarios

Using the assumptions described for the base, slow/low, and fast/high scenarios, the expected decommissioning times for each scenario are depicted in Tables N.5-N.7 and graphed for the slow and fast scenarios in Figures N.2 and N.3.

The base case scenario falls between the slow and fast cumulative curves and future decommissioning activity is expected to range between the base and low case scenarios. According to the model results, over the next five years between 12 to 25 deepwater structures are expected to be decommissioned, and over the next decade between 25 to 36 structures are expected to be decommissioned.

In Tables N.8 and N.9, the aggregate base case and slow scenario model results in five-year time periods are depicted.

14.2.3 Sensitivity Analysis

Using the base case model parameters, the royalty rate was reduced by half and eliminated and the model results recomputed. Similarly, economic limits were reduced by half and half again and the model results recalculated. In both cases, there was no noticeable difference in the estimated decommissioning times except in a handful of structures, and for those structures affected there was only a difference of one or two years in the expected timing.

Royalty rates and economic limits are generally considered secondary factors in economic modeling and do not have a major impact on value at the end of production relative to operating cost and commodity prices. Whereas royalty relief may induce capital spending and incentivize operators to invest in new facilities, the ability of royalty relief to maintain production on marginal properties in a high cost environment is less likely to be successful and/or utilized by operators because of its incremental impact relative to other more significant factors.

14.3. ACTIVE STRUCTURE FORECAST

To forecast active structures in a region an installation model is required. Historically, there have only been a handful of deepwater structures installed in any given year, and there is no reason to believe that in the future activity levels will significantly depart from these values. In the near term, projects sanctioned and under construction provide good short-term estimates for activity over the next two or three years, but for time horizons beyond five years speculation is required for every choice of model adopted, and thus our preference is to apply the simplest valid model to infer future activity.

Future fixed platform and floater installation activity over the next two decades is assumed to be bound between historic activity rates. Fixed platform installation activity is assumed to be bound between 0.2 to 2.6 platforms/year and new floater installations are assumed to be bound between 2 to 3 floaters/year.

In Figure N.4, the active inventory of fixed platforms and compliant towers is depicted, and in Figure N.5, the active floater inventory is shown under the slow and base case scenarios for installation rates specific to each structure class. Fixed platform activity is expected to fall at the low end of the range while floaters are more likely to fall within the middle of its range.

Under the slow scenario, fewer structures will be decommissioned which will lead to a larger standing inventory relative to the base case scenario, and thus, the model results for a given installation rate depict the slow scenario above the base case. Similarly, a lower installation rate will depress active structure counts relative to higher install rates since decommissioned structures will not be replenished.

For fixed platforms, the most likely future scenario shows a decline in the standing structures following the slow scenario with an assumed 0.2 structures/year install rate.

For floaters, the most likely scenario yields an increasing inventory that ranges midway between the slow and the base scenarios under an assumed 2 floaters/yr installation rate.

In Figure N.6, the composite active structure forecast is shown with the slow scenario again dominating the base case inventory. Lower installation rates will depress the active inventory since decommissioned structures are not being replaced.

14.4. LIMITATIONS

The purpose of decommissioning modeling is to reflect the dominant operational and behavioral characteristics of companies and to understand the limits and constraints of model assumptions. Numbers are important but absolutes should be avoided and general trends and relative changes emphasized and links between model assumptions and results understood. Modeling always involves a number of assumptions and preferences and the desire to make assumptions transparent arises from the need to understand the results in the context of the model construction. Good modeling practice dictates that procedures be well-defined and assumptions clear and transparent.

Decline models are expected to yield results consistent with the (conservative) capital spending constraints associated with the status quo assumptions. The decommissioning model for producing structures is reliable relative to the assumption set, but given the large number of unobservable factors involved in development and asset reviews as well as the limits imposed by the status quo conditions, it is not surprising that numerical models are limited in their ability to predict the exact outcomes of decommissioning. Using time blocks as employed in this analysis is one way to reduce this uncertainty.

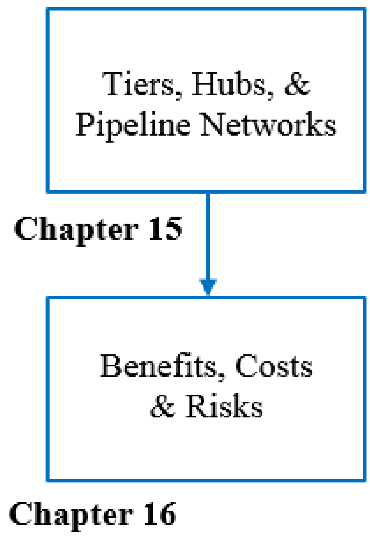
If model parameters are not well known, they can be treated as a free parameter when constructing the forecast, but it is generally preferable to minimize the number of these assumptions and to use historic data if applicable. For example, the economic limit of production is a model input that may be based on historic data of similar structures in the region (first choice), an estimate of the structures direct operating cost (second choice), or simply a number that seems reasonable to the user (third choice free parameter). All are valid but some choices are considered better than others.

Wells long on their decline curve are more likely to yield an accurate production forecast relative to younger wells, and consequently, mature reservoirs are more likely to yield an accurate production forecast relative to younger reservoirs. In terms of decommissioning timing, however, because the potential for tiebacks and alternative uses will vary for each structure, there will still be uncertainty associated with individual structures.

Sidetrack drilling can occur anytime and if successful will extend the life of the structure beyond the forecast model time. Tiebacks may also occur at any time, on or off peak production, depending on many factors. When sidetrack opportunities are no longer available, or are too risky relative to the potential rewards, the facility may be re-purposed as a compressor or pump station for remote pipelines or nearby facilities. The residual value of deepwater assets are high and operators seek every available opportunity to keep the structure in place before decommissioning.

For the active structure forecast, installation rates for fixed platforms and floating structures were based on historic statistics over the past two decades. There are several reasons why such bounds are considered reasonable, and although still speculative, we believe the installation rate assumption is reliable and will reflect future trends for each structure class.

PART 4. CRITICAL INFRASTRUCTURE ISSUES



CHAPTER 15. TIERS, HUBS, AND PIPELINE NETWORKS

High levels of decommissioning in the shallow water GoM over the past decade has drawn attention to the important role infrastructure plays in offshore oil and gas production and raise questions regarding its potential impact on future development in the region. The purpose of this chapter is to identify the role of critical infrastructure, what's important and why, and the nature of the business decisions of operators. Four tiers of infrastructure are used to organize the discussion and opportunities to maximize structure value within and outside field development is discussed using conceptual economic-risk models. Within field opportunities are more easily ranked by cost and risk compared to outside field opportunities which involve a larger number of factors. The most critical offshore infrastructure are large producers, structures containing a high concentration of pipeline linkages or high volume throughput, and large diameter high volume pipelines. The chapter concludes by evaluating the scale-free structure of segments of the GoM export pipeline network.

15.1. INFRASTRUCTURE TIERS

In 2017, over 80% of the oil production in the GoM was produced in water depth greater than 400 ft from around 100 structures, and the remaining 20% of crude oil was produced in shallow water from around 866 producing structures. Deepwater oil production has probably not yet peaked while shallow water oil production continues its long steady decline. As production trends in the regions continue to diverge, the importance of the structures and pipelines in the region for crude production and security of supply will also continue to diverge, with the deepwater becoming more important and critical in the years ahead and the shallow water less so.

The vast majority of oil and gas reserves are currently in deepwater and although the BOEM estimates 13 Bboe undiscovered resources in the shallow water (compared to 74 Bboe in the GoM), these values are speculative with unknown timing and location, meaning that future exploration and development activity will most likely follow current trends and remain concentrated in deepwater. This does not bode well for the shallow water GoM. Although the shallow water region will continue to see new discoveries, these will be small and marginal in nature and of decreasing frequency. In the future, redevelopments at current fields with existing infrastructure will likely provide the majority of incremental recovery in shallow water. Secondary production methods were already being employed in shallow water many years ago, and enhanced oil recovery methods (i.e., CO_2 injection) are unlikely to be implemented because of poor economics and the composition of the shelf players.

Pipelines are used to deliver almost all of GoM oil production to shore and the pipeline network is an important and vital part of the supply chain. As product flows head northward they are aggregated into larger pipelines and often split at platform hubs to deliver to different onshore destinations. The deepwater oil pipeline network is segregated from the shelf network while the gas pipeline networks are somewhat more integrated. Currently, few pipeline constraints or capacity bottlenecks are known to exist. If dominant structures or pipelines are responsible for a large portion (e.g., say greater than 10%) of production or delivery, then such infrastructure would be considered critical in common sense usage, but in the GoM concentration of this form has not (yet) arisen and so either all of the active deepwater structures and export pipelines that deliver crude to shore could be considered critical infrastructure or none at all because of its distributed nature.

According to Merriam Webster, a system is defined as a "group of devices or objects forming a network for distributing something or serving a common purpose," and critical refers to an "indispensable, vital or absolutely necessary component for the operation of a system." Following this definition, four tiers of infrastructure are identified with critical infrastructure defined as the most important and vital for system operations:

I. Critical
II. Active
III. Inactive – Potentially Useful
IV. Inactive – Probably Not Useful.

Active infrastructure are structures that are producing or pipelines that are in-service or currently serving a useful function. Critical infrastructure is a subset of active infrastructure. Inactive (or idle) infrastructure are grouped as potentially useful and probably not useful. The distinction between these two classes are difficult (read impossible) for outside analysts or regulators to determine without additional information from operators, and thus the tenuous and ambiguous distinction of the inactive class is intentional and inherent in the classification.

15.2. INFRASTRUCTURE HIERARCHY

Wells, structures, flowlines and export pipelines are the main components used in oil and gas development in the GoM (Figure O.1). The importance of system components increase at every stage along the value chain from well to onshore destination as flows are combined and increase in volume for processing and export. Large hydrocarbon production sources are important independent of the transport system. Structures are the first point of aggregation followed by hub and transportation platforms. The absence, incapacity, or destruction of aggregation points (hubs) would cause immediate cessation of those upstream operations that do not have alternative routes[12] for transport.

Old wells have the potential for sidetracking and injection operations, but whether such activities are a good investment is site, time and operator specific. Maintaining inactive wells is widely recognized as potentially useful because of the cost savings associated with re-using wells to access reservoirs, but as fields mature these investments become increasingly risky because the success of operations are uncertain and incremental production is typically small. Seeking untapped faulted reservoirs and bypassed targets for production will flatten out the decline curve but strict cost management is necessary to be successful. For wet wells, operators have much less experience in sidetracking because of the high cost involved and the problems associated with delivering high water cut production.

Structures installed to drill wells will usually also process production but in shallow water a broad mix of development options have been pursued. For example, non-drilling central processing

[12] One might think that gas pipelines are less critical than oil pipelines because of declining throughput volumes, but if gas export pipeline is damaged or destroyed, then oil production from all the structures connecting to this line for their gas export (assuming no alternative routes available) would also have to shut down until a replacement line was laid because flaring gas is not permitted in the U.S. GoM except in emergencies and for safety reasons.

facilities in shallow water were common in early developments to process and export production from nearby drilling platforms. Producing structures handle and process hydrocarbon fluids and if off-lease fields are involved or other export pipelines cross the structure are often classified as a 'hub.' The processing capacity at the structure or the actual volumes processed, and the oil and gas export pipeline capacity or volume throughput, are the key parameters quantifying hub operations. Assets can be ranked by production and pipeline capacity or flowrate or degree of connectivity. Large producing platforms and high capacity export systems would generally be considered more critical than marginal producing structures and low capacity export lines. Pipelines with high volume throughput are more critical than pipelines with low volume throughput.

Structures that are producing from their anchor field at the end of its life are usually not critical assets unless they are also serving as a hub, but may nonetheless be useful for future development. The benefits of standing structures are well known to operators and regulators alike in a general sense, but outside specific assets and operator development plans, the benefits will always be difficult to quantify. Marginal producing structures are not considered critical unless serving as a pipeline hub. Structures that are no longer producing may or may not be useful in the future. All potential benefits should be considered speculative unless supported by detailed operator spending and development plans tied to the assets in review.

All deepwater producing platforms and pipelines and all hub platforms represent the most critical infrastructure in the GoM. Shelf junction platforms are an important subcategory of critical infrastructure depending on volumes handled. Several shelf platforms are interconnected with deepwater operations but these are mostly owned and operated by the deepwater operators or their pipeline subsidiaries or affiliates. LOOP represents critical offshore infrastructure and all of the onshore destinations – refineries, gas plants and storage sites – are also critical but not a focus of this discussion.

Shelf producing platforms and pipelines and all other platforms serving a useful function are not critical but remain important for reserves recovery and to reduce production decline for shelf and mature deepwater fields. Inactive structures are all potentially useful but significant constraints often apply to their application and the potential benefits is speculative in most cases. There is also risk for the operator and the federal government if inactive structures are allowed to collect without serving a useful purpose. However, if all wells are permanently plugged and abandoned on inactive structures, then environmental risk (from leaks) can be eliminated and only the contribution from 'economic' risk (and perhaps reputational risk for both parties) managed.

15.3. Economic Lifetime

There is no one organizing principle to understand how the offshore sector is structured and how decisions are made, but an economic-risk framework is often useful for conceptual purposes since all significant capital investment decisions (say, investments greater than a few hundred thousand dollars) are based upon economic and risk considerations. Conceptual models are most useful when only one or a limited number of factors influence the system or play a dominant role. For complex systems, as the number of factors that characterize the system increase, conceptual models become much less useful since holding "all of the other factors" constant will not adequately capture the system behavior.

The economic lifetime of an asset is the point at which the net cash flow from operations turns permanently negative. This is the time when the net income from production no longer exceeds the costs of production and a rational decision maker will no longer wish to operate the venture because it costs more money than its generates. Production may continue beyond this point for strategic or other reasons but only by accepting financial losses.

Offshore assets enter into economic decline when either income is falling or costs are rising, and for many mature developments both are happening. A mature development must nonetheless continue to generate a positive net cash flow and compete against other projects in a company's portfolio for funds, and because the outcomes of decisions are in most cases uncertain, technical and commercial risk analysis is an important component in decision making. Risk is defined as the product of impacts and probabilities. There are two ways to extend the economic lifetime of an asset – reduce operating costs or increase revenue (Figure O.2).

Operating cost represents the major expenditures late in field life and many opportunities may exist to reduce operating expense. The number of staff assigned to a facility may be reduced or maintenance budgets may be cut or delayed. In some cases, operations may be consolidated to achieve better transport and logistic rates or structures de-manned and automated. Other means to reduce operating cost include outsourcing all or some operating and management functions, eliminating or reducing insurance coverage, and renegotiating service contracts. For marginal producers, end-of-life royalty relief may help to reduce cost to maintain profitable operations.

Income may increase by increasing production or by a fortuitous rise in commodity prices. Increasing hydrocarbon production requires investment in workovers, infill drilling, sidetracking, or improved oil recovery techniques. Opportunities may be available to develop nearby fields through the infrastructure. Another way in which companies that own facilities but no longer have the hydrocarbons to fill them can continue to operate profitably is by renting equipment capacity and charging tariffs for the use of export routes[13].

Investment activity may occur at any time during the life cycle of the field and involve low cost maintenance and workover activities such as changing production tubing, re-perforating, acidizing, etc. to moderate cost activities such as sidetracking and equipment changes to high cost activity such as new well drilling and secondary recovery methods. Depending on the timing and type of activity, the uncertainty range of potential impacts will vary from small to large, but generally speaking, the older the field, the greater the cost and risk of opportunities and the smaller volumes that can be expected.

15.4. LIFE CYCLE STAGES

The initial production phase of hydrocarbons from a well or field is the easiest and most profitable phase because of the initial driving forces present. The best areas of the reservoir are drilled in the primary development and other less significant blocks are drilled later if the economics of the incremental barrels are robust. Primary or free flow production refers to the oil produced by the original reservoir energy. As production proceeds, the pressure in the reservoir falls, reducing the

[13] At this stage, however, the business model is more suitable to pipeline companies than oil and gas companies. All of the majors and a few independents have subsidiaries or affiliates of pipeline companies, but this is a different business model and subject to different economic-risk criteria.

natural flow rates of the hydrocarbons, especially oil. The rate of reduction depends on the drive mechanism and development methods.

Primary production uses the reservoir's natural energy which comes from fluid and rock expansion, solution-gas, gravity drainage, aquifer influx or a combination drive. This natural energy (pressure) is created by a pressure differential between the higher pressure in the rock formation and the lower pressure in the wellbore. In aquifer support, for example, reservoir pressure declines slowly – almost linearly – as long as the water replaces the oil in the pores during production. For gas cap mechanisms, the gas cap expands with oil production, but production decline is more rapid than with aquifer support. In most reservoirs, only a small percentage of the original oil in place is recovered during the primary production period, and secondary methods are often used to produce a portion of the of oil that remains.

Primary recovery factors for oil range broadly from 5% to 40% of the oil-in-place depending on a number of factors such as wells drilled, reservoir complexity, fluid properties, development methods, and reservoir drive mechanisms (Figure O.3). This leaves a considerable amount of oil in the reservoir after the pressure has been depleted which may be economic to recover. This is particularly true of oil fields since gas reservoirs for the most part have high recovery factors (>85%). Improved oil recovery refers to engineering techniques that are used to recover more oil from depleted fields. They are referred to variously as secondary and tertiary production, pressure maintenance, waterflooding or enhanced oil recovery (Figure O.4). The distinction between each stage and activities is not precise. For example, primary techniques often include artificial lift and pressure maintenance, whereas secondary techniques also include injection wells to maintain pressure or sweep efficiency.

Secondary recovery consists of replacing the natural reservoir drive or enhancing it with an artificial drive to maintain the pressure in the reservoir. The use of injected water or natural gas are the most common methods, and when water is used it is referred to as waterflooding. Waterfloods or gas injection may be implemented a few years after initial production depending on the behavior of the reservoir pressure decline.

Many of the large oil fields on the shelf have been waterflooded, while in the deepwater Pleistocene through upper Miocene reservoirs exhibit high primary oil recovery and less than two dozen reservoirs are waterflooded (Alkindi et al. 2007, Li et al. 2013). For deepwater Neogene age reservoirs the P50 oil recovery factor is estimated at 32% original oil-in-place, with P90 and P10 oil recovery factors estimated between 16% and 49% (Lach and Longmuir 2010). Paleogene hydrocarbons have permeabilities significantly lower than in the Neogene horizons and with only a dozen or so fields producing to date the recovery factors are estimated at 10%. Older Tertiary reservoirs such as at Atlantis, Tahiti, Neptune, K2, Thunder Horse, Shenzi, Great White, Trident, St Malo, Jack, Cascade and Stones are characterized by high pressure and temperature and low natural reservoir energy, and will benefit from waterflooding if technical hurdles can be overcome.

Example. Deepwater GoM water injection projects

Water injection is not commonly used in deepwater GoM developments because in the majority of Neogene reservoirs there is good primary recovery and drilling cost and facility limitations are significant. In over 80 fields and 450 reservoirs circa 2015, water injection was implemented in only 18 reservoirs in 13 fields, or less than 5% of potential water flooding candidates (Li et al. 2013). Fields that have used water injection for one or more sands/reservoirs include: Amberjack, Bullwinkle, Holstein, Horn Mountain, Lena, Lobster, Mars, Morpeth, Petronius, Pompano, Ram-Powell, Ursa/Princess.

In five of these fields (Holstein, Horn Mountain, Lena, Lobster, Petronius) water injection commenced near the start of production and has been extensive. Four fields (Amberjack, Bullwinkle, Morpeth, Ram-Powell) have had only short periods of water injection. The Mars and Ursa/Princess fields are examples where primary production was followed by water injection after the reservoir pressure was reduced in late, secondary recovery projects.

In Middle to Lower Miocene age reservoirs such as Atlantis, Mad Dog, K2, Shenzi, Neptune, Tahiti, Blind Faith and Thunderhorse, the structural style of the reservoirs and reservoir properties indicate that water injection will be beneficial at later stages of recovery, and the facilities for many of these fields were designed with water injection capacity. Since 2001, when the Paleogene horizon was first encountered, there are about two dozen fields including Great White, Jack, St. Malo, Cascade and Chinook that will benefit from water injection if the technical hurdles can be overcome. ■

Tertiary recovery methods (also called enhanced oil recovery EOR) are usually divided into thermal, chemical, and miscible displacement categories and seek to enhance the sweep efficiency and reduce the capillary forces by making the fluids miscible or improving their mobility. Tertiary methods are the most expensive and economics are usually quite difficult. EOR methods are pursued after primary and secondary methods are performed, and today, EOR contributes about 5% of U.S. oil production and is most frequently used in heavy oil and poor permeability fields. All EOR projects in the U.S. are onshore and most projects require well capitalized companies[14] due to high investment requirements. In the shallow water GoM where most players are juniors such opportunities are unlikely to be pursued.

The cost per barrel of secondary methods is considerably higher than the cost of the primary recovery stage since material and energy inputs are greater and produced volumes are lower. Similarly, the cost of tertiary methods are higher than secondary methods and in most cases are more uncertain and therefore riskier.

15.5. Within Field Opportunities

Within field opportunities, project cost and risk described on a dollar per barrel ($/bbl) basis normally increase from workovers to redevelopment to secondary and tertiary production and return on investment is often smaller at each stage (Table O.1). This economic characteristic causes larger companies to sell or abandon mature assets while smaller companies may see an opportunity and buy the assets to grow their production. Project economics in ‘brownfield’ secondary recovery projects depends upon accurate risk assessment, risk mitigation strategies, and an acceptable return on investment. Progressive deployment of evolving technologies are considered key to successful development.

As a general rule, anytime there is a significant bump (increase) in the production profile of a field or well, one should assume/recognize that an investment was required to initiate the increase. Whether the investment paid for itself and increased the value of the asset to the company is

[14] Onshore, companies with significant tertiary activity include Occidental, Hess, Kinder Morgan, Chevron, Denbury Resources, and EOG Resources.

another matter and one that is usually off-limits to analysis because work activities and project cost is proprietary and closely held.

15.5.1 Workover

Wells need to be maintained for maximum productivity, and in the event that a well stops producing (well failure), a decision has to be made on the merits of attempting to bring the well back on-line. In many instances, a simple back of the envelope economic justification is adequate, such as would occur with a new high producing well with formation damage or other impairment, but for expensive or risky operations a more detailed evaluation may be required. Workover decisions in old wells are risky since the operator may not get their investment back, and so once an older well stops producing a workover may not even be contemplated if production rates are low.

Wells are 'worked over' to increase production and accelerate reserves recovery, reduce operating cost or reinstate their technical integrity. There are many different types of workovers that may be required and workover activity is often budgeted as part of operating and maintenance expense and is not considered capital expenditures. Examples of workover activity include replacing corroded tubing or packer leaks or drilling out and plugging a section of casing to reduce water cut or cross flow in the well or behind casing. If the formation is damaged by pore throat plugging or other impairment, it may be necessary to fracture or acidize the area. If flows are restricted due to sand production or wax or scale deposition, remediation may be required. In a primary cement failure, such as water invading a producing zone behind the casing and between the bad cement, significant production decline may occur. Workovers are the most common activity performed at offshore structures to extract maximum value from field development.

The primary objective of stimulation is to restore impaired well/reservoir connectivity. The nature of impairment, treatment options, and post treatment production issues often change over the life of the well, and the selection of wells and frequency of stimulation is site-specific, usually based on comparison between peer wells in analog reservoirs, well flow modeling, and available budgets. The results of treatment are complex and variable which makes decision making difficult and risky. Stimulation can result in immediate improvement in production rate but the impairment may come back rapidly (Figure O.5). In other cases, the initial improvement may not be dramatic but the longer term performance is improved. In some cases a total loss of production may result and represents the downside risk of well intervention.

The causes of near wellbore impairment are well documented. During completion operations perforations often become plugged with rock fragments and debris and residue from frac fluids. During production, formation impairment are primarily due to movement and rearrangement of reservoir fines, clay-sized particles that cause a reduction in permeability, deposition of solids (e.g., asphaltenes) from produced crudes, and deposition of mineral scales from produced water. Three categories of well impairment are thus defined:

- Scale – Inorganic minerals deposited from water
- Solids – Organic deposits from the oil phase, often a combination of asphaltenes and resins
- Fines – Clay sized particles from pore bodies that capture in pore throats.

Scale formation may occur in the reservoir and inside the production tubing and may be removed chemically or mechanically (Jordan et al. 2001). A well producing at high water cut may be choked back or a change of perforation interval may be considered to shut-off unwanted fluids. Skin problems may be resolved by acidizing or additional perforations. Solids and fines depend on the reservoir pressure and the change in pressure between the reservoir and the wellbore. Fines migration often occurs early in field life, solids and scale later.

The best way to assess the production benefit of stimulation is to evaluate the well production before and after treatment under similar conditions (e.g., choke setting, separator pressure, etc.) (Figure O.5). Unfortunately, almost no literature is available that quantify the results of stimulation, but an important article by Morgenthaler and Fry (2012) provides guidance on how such studies should be performed and evaluated.

Example. Stimulation production improvement

Morgenthaler and Fry (2012) quantified the impact of 128 stimulation treatments performed on deepwater GoM wells in water depth from 1000 to 7000 ft from 2002-2011. The majority of the stimulations were on oil wells (80%) and direct vertical access wells, but interventions on subsea wells were also performed. They defined the ratio of the post-treatment production rate divided by the pre-treatment rate as the Production Improvement Factor (PIF), and evaluated the distribution of PIFs for scale, solvent, and fines migration treatments (Figure O.6).

Although only 25% of scale treatments yield a PIF > 1.5, some scale treatments were performed to prevent tubing or subsurface safety valve plugging, benefits which are hard to quantify. Solvent and acid treatments have similar curves and entail some risk in that 2-5% of treatments lead to total production loss. However, there is also a 50% probability to achieve a PIR > 1.5 and a 10-20% chance that PIF > 2.

Normalized production rates pre and post-treatment are shown in Figures O.7-O.9. Following solvent treatments, wells tended to return to their pre-stimulation performance rapidly and consistently, and because they can be conducted relatively cheaply and cause few problems during flowback, they are considered economically attractive and are performed regularly to maintain production. Scale and acid treatments are more complex and varied. ■

15.5.2 Redevelopment

Redevelopment can take many different forms and occur at different times in the life cycle stage and are distinct from workovers with different objectives. Normally, redevelopment activity involves greater costs and risks than workover activity and entails drilling new wells with the objective to accelerate production or increase reserves. Operators often attempt to re-enter existing wells to reduce cost but this is not always possible. When feasible, re-entry wells may cost one-third to one-half the cost of a new well due in large part to the cost savings from not having to drill and complete the top hole and setting casing. The use of retrofitted platform workover rigs usually provides cost savings[15] compared to jackup rigs.

Directional drilling can be used to reach most targets within a lease block from one location and extended reach drilling can usually achieve a 3 to 5 mile horizontal distance. For wells that can be drilled from the platform, almost all sands with oil and gas deposits that the operator believes will

[15] Platform workover rigs can be retrofitted with drilling equipment and sized to enable lifts by the platform crane, which eliminate the need for a derrick barge. All factors considered, including mobilization cost, rig modifications, and rig rate, workover rigs compete in cost with jackup rigs.

yield a positive return on investment will be drilled. In other words, as long as the expected revenue from production is anticipated to exceed the drilling and completion cost, the target will be drilled.

Hydrocarbons which are inaccessible in isolated fault blocks or layers, or cellar[16] oil left behind below production intervals, will require new wells, sidetracks, or extended reach drilling (Figure O.10). These wells will increase reserve's rather than accelerate recovery and are one of the most common within field redevelopment activities performed.

As geologic models improve and become more detailed, it may be possible to identify reserves which are not being drained effectively or within the economic life of the asset. These are usually referred to as infill wells. Infill drilling means drilling additional wells between the original development wells to accelerate recovery, not necessarily to increase reserves. If the original wells were too far apart, for example, additional wells will reduce the distance the oil and gas has to travel to the wellbore which accelerates production but this has to be balanced against the additional cost of drilling. Incremental recovery does not imply new wells are economic.

The economics of redevelopment is straightforward in theory, compare the income from the incremental recovery Δ expected with the investment cost C for the expected probabilities. If the activity is expected to yield production profile $Q'(t)$ as shown in Figure O.11 and the status quo (do nothing) profile is $Q(t)$, then the production increment $\Delta(t)$ at time t is computed as:

$$\Delta(t) = [Q'(t) - Q'(t)],$$

and the net present value at assumed commodity price P and corporate discount rate D from $t = 0$ through $t = u$ is

$$NPV = \sum_{t=0}^{u} \frac{P\Delta(t)}{(1+D)^t}$$

If NPV(Δ) > C the investment satisfies economic criteria and would be pursued. The investment cost C can be estimated reasonably accurately but the impact Δ is difficult to estimate and uncertain, both in magnitude and profile. Capital can be spent to reduce this uncertainty, say by acquiring additional geophysical data, and this is often done, but there is always a trade-off between collecting more data and its value in decision making. The risk of the investment can be measured by the probability NPV(Δ) < 0 if this metric can be computed reliably.

15.5.3 Secondary Production

A waterflood or water injection involves injecting water through injection wells into the depleted oil reservoir rock. It can be initiated either before or after the reservoir drive has been fully depleted and both methods are common. The injection wells are either drilled or converted from producing wells, and the water is sourced as seawater or from a water producing zone. The water normally has to be treated so that it is compatible with the producing formation, and involves filtering to remove suspended solids, chemical treatment to reduce oxygen levels, and biocide treatment to control bacteria to prevent corrosion and fouling.

In pressure maintenance, water is used to replace the produced fluids to maintain high production rate, and is normally performed when it is discovered that reservoir pressure is decreasing at a high

[16] Attic oil left behind above production intervals are usually accessible with a new perforation, a considerably cheaper and faster operation than well deepening.

rate relative to production volumes. When water is used as the primary source of reservoir energy, it is common to apply a voidage replacement policy, that is, produced volumes are replaced by injected volumes in a 1-1 ratio. In a waterflood, water is used to sweep out some of the remaining oil in the reservoir, and in this form is normally performed at the end of primary production.

In gas injection, there is no need to control for hydrocarbon dew point but it is necessary to dehydrate the gas to avoid water dropout. Injection gas pressures are usually much higher than gas lift or gas export pipeline pressures. In 'cycling' operations, gas is reinjected into the reservoir to prevent condensate liquids from dropping out in the reservoir. Like in black oil reservoirs where production engineers strive to stay above the bubble point of the reservoir, in gas fields it is desirable to keep the reservoir pressure above the dew point to prevent condensate from forming since these liquid hydrocarbons block the flow path of gas in the reservoir rock and are essentially lost (i.e., not producible). After the gas rises to the surface, the condensates are stripped and the dry gas is re-injected through injection wells.

15.5.4 Enhanced Oil Recovery

Enhanced oil recovery involves the injection of substances that are not naturally found in the reservoir, such as CO_2, steam, or chemical floods. EOR can be initiated after primary production or waterflooding. Offshore, tertiary methods are not economic unless special conditions prevail; onshore, CO_2, steam injection, and miscible fluid displacement have been successfully and (presumably) profitably applied in large scale but for a relatively small number of projects. Less than a handful of offshore projects have been implemented worldwide and these are all short-term pilot projects (see Section 16.1.7). Useful reviews on carbon capture and storage cost, risk and liability issues are available in (Kheshgi et al. 2011) and (Anderson 2017) and the references listed therein.

15.6. Outside Field Opportunities

For investment opportunities that (physically) lie outside the field, project cost and risk are more complicated to evaluate and depend on multiple factors, making assessments difficult to perform without detailed data on all available options and development requirements. Without defined problem boundaries, system constraints, and field-specific data, evaluations cannot be performed and benefits are considered speculative and hypothetical in nature.

15.6.1 Satellite Development

In most hydrocarbon basins, the largest fields are discovered and developed first because they are the easiest to find and provide the best economic returns. After field decline, the structures, processing facilities and export systems will continue to have a considerable working life that may prove useful to develop smaller fields that would be uneconomical on a stand-alone basis.

In a satellite development, a portion of the existing offshore infrastructure is used for other developments, which may prolong the economic life of the field and reduce decommissioning rates. The role of the host facility in a satellite development can vary from providing all production and processing support (e.g., as in a subsea tieback) to providing partial support (say for gas-lift or water injection to a nearby field) to providing minimal support but allowing access to one or more export pipeline routes (e.g., host receives pipeline-quality product for compression or pumping services).

Reservoirs/targets outside a 3 to 5 mile from a platform range will be drilled by a MODU and the platform may serve as host if the development is economic (Figure O.12). Large fields will support a greater tieback distance if a stand-alone structure is not selected and gaseous fluids can be transported farther than liquids and require less demanding flow assurance strategies. As distances increase and product quality decrease, flow assurance requirements increase which increase capital spending. Commerciality depends on reservoir size and production rate, fluid type, ownership, and development cost as illustrated generically in Table O.2.

Off the platform, drilling and development cost increase and prospects must be larger to achieve the economic-risk criteria established by the company. For subsea completions, when production problems arise, it may also not be economic to re-enter the well because of the high MODU and vessel intervention cost. Subsea wells (especially oil) are expected to strand more reserves than platform drilled wells and less redevelopment will occur because of the higher cost of access. For subsea gas wells there is less concern of stranding resources but if problems develop premature abandonment may also arise. For third-party tiebacks, successful negotiation is required for bring product back to a host.

Ownership of the reserves and surrounding infrastructure will influence decision making. Operators that maintain a large presence in the region will have more options to monetize their assets relative to smaller players with less infrastructure.

15.6.2 Transportation Hub

At service/junction structures (also called transportation platforms), export pipelines board the structure and compression/pumping stations raise the pressure and then reinject the fluid into export systems to enable flow onward to one or more onshore destinations. Transportation platforms serve as a connecting point for export pipelines to enter the offshore pipeline network and connect to their onshore destinations. In some cases, export pipelines may tap into a pipeline directly and do not need to board a platform. Operators often place a premium on having multiple routes to different destinations to increase the netback value of their production, and several of the larger operators have established a robust network to maximize their options.

Strictly speaking, service/junction platforms do not have processing capacity available unless the structure previously served as an anchor field development, and so the fluids boarding have already been processed to pipeline specification and only need to be pumped or compressed to reach their destination. Ancillary services offered at the facility normally include metering, liquids removal, pig catcher, heating and cooling, etc. Dehydration facilities and slug catchers are often needed for gas transport. Structures may be manned or unmanned. If the service/junction structure handles multiple deliveries and departures for different operators, it will likely have several export lines leaving the platform and its connectivity will be high.

15.6.3 Future Development

When fields are no longer economic to produce, structures installed for drilling will no longer be viable. Within the 3 to 5 mile radius centered at the platform viable targets presumably no longer exist. Processing capacity at the facility may still be useful if present and of sufficient size and in good working order (which will be difficult to maintain without flow/operations), and because export pipelines are connected to the GoM network, if production from another structure or field can be brought back to the structure economically then routes for export do not need to be constructed. Although drilling activities at the facility are no longer viable, the physical space at the platform is potentially valuable since the structure could host compression, pumping, metering, and export equipment.

However, there are also risks associated with such an endeavor and the number of roadblocks in successful execution are numerous: the production volumes from a tieback might be too small or large for the equipment at site, or the product fluids might not be the right type for the equipment or export pipeline (e.g., sour crude, high CO_2 gas). The structure has to have the capacity to accept new risers and the space/weight to store the subsea control systems and storage tanks, and if the structure is no longer active, it is significantly less viable as a potential host. If there is no significant drilling activity in the region, the value of the structure declines considerably, and since the operator of new discoveries will consider all potential options in development may simply prefer a new structure in development (especially if the field is of modest size). Idle/marginal structure will be competing against other structures, both existing and new build, which reduces its potential value and likelihood of re-use. In shallow water, operators are unlikely to rank prospects for drilling based on trying to maintain low-cost infrastructure, whereas in deepwater such considerations will play a larger role because of the greater capital investments and value of infrastructure (hundreds of millions of dollars versus a few million dollars) along with the continuing value such infrastructure holds for future development.

15.7 Hub Platforms

Hub platforms are arguably the most important structure class in the GoM to maintain economic efficiency and commercial development. Unfortunately, there is no standard definition of a 'hub' platform and a variety of hub-types can be defined based on configuration/function and ownership. Generally, hub platforms are recognized as central points for gathering, redistribution and transportation of oil and gas (Huff and Heijermans 2003). Here, three types of hub platforms are distinguished, whether primarily serving in a field development role, primarily in transportation services, or for both on-going development and transportation functions (Figure O.13).

15.7.1 Classification

Three hub classes are identified:

I. Structures that process production from one or more platforms or subsea wells;

II. Structures that serve as a receiving station for processed production;

III. Structures that process production from one or more platforms and/or subsea wells (I) and receive processed production for export (II).

All hub platforms have one or more export and import pipelines and are not explicitly described. Historically, platforms were sometimes referred to as hubs when they acted as a central station to receive and process production from several drilling platforms in a field (Figure O.14), and today this connotation still applies to facilities installed that develop multiple fields as in the Na Kika development (Figure O.15). In modern developments, the owners of the wells may be the same or different from the platform owner and the tie backs may have occurred at the time the platform was installed or at a later date. The fields and structures may be in shallow water or deepwater.

Structures may serve as a central point to gather and fully process production in field development, or as host to tieback fields or structures without full processing capacity. Bullwinkle was already past its peak production when it began to accept tiebacks from the Rocky, Troika (Figure O.16), Aspen and Angus fields (Figure O.17). Falcon Nest is an example of a shallow water platform built to accept deepwater subsea well tiebacks (Figure O.18), not a common strategy but at least a dozen or more fields have been developed in this manner. Other examples of shelf platforms serving one or more deepwater fields include West Delta 43, Main Pass 252, and Bud Lite.

A structure with only dry tree wells that developed an anchor field may transition to hub status if wet wells are later tied back to the platform. Many of the deepwater fixed platforms in >400 ft water depth fall into this category and several of the older floaters are still in operation because of new tiebacks. Bullwinkle and Auger are two early examples of structures installed for large anchor fields that later transitioned to hub platforms. If a structure's field production ceases and the structure is not used for subsea tiebacks, the structure may instead be used as a destination for export pipelines from the operator or third-parties such as the platform at Ship Shoal 332A.

Generally speaking, operators are better able to schedule and re-purpose their own platforms than soliciting or commercializing production from third parties because of timing constraints and other issues. The deciding factor for operator-owned facilities and tiebacks are strategic and economic, while for third-party tiebacks economics is usually the deciding factor. Planning, development and negotiation between parties usually take several years, and as long as the structure is producing the owner(s) of the structure will maintain their bargaining power, but once the structure stops producing the balance of power will likely shift to the third party.

15.7.2 Process and Export Capacity

Hub platforms are described by their oil and gas processing capacity, number of interconnects, and oil and gas export capacity. Processing capacity refers to the equipment used to handle, separate, treat, heat and cool raw hydrocarbons into pipeline quality oil and gas streams. Service and junction platforms do not have processing capacity and are primarily characterized by their pumping and compression capability, slug catching facilities, metering, and dehydration services. For non-hub platforms, oil and gas processing capacity is a reasonably good indicator[17] of oil and gas export capacity and pipeline diameter, but for hub platforms export capacity usually greatly exceed processing capacity.

15.7.3 First Generation Hubs

Shell's Bullwinkle, Enchilada, and Auger developments were the first generation of deepwater hub platforms installed in the mid-1990s. The formula was the same in each case. After anchor field production began to decline, nearby discoveries (mostly, but not always, from the owners of the platform) were tied back and processed at the host platform. Processing capacity expansion at the host with subsea wells and their attendant costs and risks was considered more economic than installing a new structure, would accelerate revenue generation, and simultaneously extend the operating life of the facility which may create future opportunities.

Example. Auger TLP

[17] Oil and gas export lines are sized for the maximum total well flow rates expected from the development, but if an (unanticipated or third-party) tieback field is hosted and available nameplate equipment capacity is exceeded then new processing trains and new export pipelines will be required. It is also common to install new export pipelines to handle streams from different fields/owners.

The Auger field was discovered in 2860 ft water depth in 1987, approved in 1990, and started production in 1994 from the first tension leg platform (TLP) to host a drilling rig and full processing facilities (Brock 2000). The Auger field is located in Garden Banks blocks 426, 427, 470, and 471. By mid-2000, anchor field production was about half of equipment capacity, and remaining development and recompletion opportunities in the field were not adequate to offset production decline. In order to keep the facility full, a decision was made to transform Auger into an infrastructure hub serving as a subsea tieback host for nearby Shell fields and third-party production.

Production capacity was expanded in 1997 and again in 2000 to 100 Mbopd and 400 MMcfpd to serve as host for the Cardamom (GB 471), Macaroni (GB 602), Oregano (GB 559), Serrano (GB 516), and Llano (GB 387) tiebacks (Figure O.19). Macaroni was developed as a subsea tieback in 1999, and in late 2001 the Serrano and Oregano fields were brought online. Llano and Habanero northwest of the anchor field were integrated into the system in 2002 (Figure O.16). Cumulative production to date is summarized in Table O.3.

Auger oil and gas export lines provide access to multiple markets via existing shallow water gathering systems (Figure O.21). The 12-inch (31 cm) oil line, owned and operated by Shell Pipeline Company LP, is routed to GB 128 (Shell's Enchilada platform). At GB 128, Auger's oil ran to the Shell-operated EI 331A platform (before it was destroyed by Hurricane Ike in 2008) where it was delivered into multiple oil pipelines accessing different onshore market locations. One of the gas lines owned by Shell terminates at Enchilada and delivers into the Garden Banks Gas Pipeline System. The second gas line terminates at VR 397 and delivers to the ANR pipeline system (Kopp and Barry 1994). ■

Example. Enchilada

The Enchilada development originally consisted of several fields covering five lease blocks – Garden Banks 83/84 (Elmer), Garden Banks 127/128 (Chimichanga/Enchilada), and Garden Banks 172 (Salsa). In 1990, the Elmer prospect was discovered but was not commercial as a stand-alone development. In 1994, two nearby subsalt discoveries in GB 127 (Chimichanga) and GB 172 (Salsa) by Shell and Amerada Hess formed the basis of a two-platform co-development with Shell as operator (Smith and Pilney 2003). The layout of the Enchilada development circa 2000 is shown in Figure O.22.

The Enchilada GB 127A platform was installed in 633 ft of water in December 1996. It is a 4 leg, 8-pile structure with 24 slots, 15 allocated for wells and 8 for pipelines. The Salsa GB 172B platform was installed in 695 ft water depth in November 1997, also a 4-leg, 8-pile structure with 20 slots (15 for wells, 4 for pipelines, 1 emergency sump). Salsa production is sent to Enchilada and the Salsa B platform was designed only for primary separation and testing of the Salsa wells. Processing facilities at Enchilada were designed to handle 40 Mbopd of high sulfur oil, 20 Mbopd of low sulfur oil, and 40 MMcfpd of gas. Export pipeline capacities were in the range of 250 Mbopd and 1000 MMcfpd gas, a clear indication of its hub status.

In 1997, as part of capacity expansion at Shell's Auger TLP, a gas pipeline, a gas compressor, and an oil pipeline booster pump station were added on Enchilada. Auger production is not processed on Enchilada, but accepts gas where it is measured and reinjected into the 30″ gas export pipeline, and accepts oil where it goes through a booster pump station and re-injected down the 20″ sour oil export line.

Shell's Cinnamon project in GC 89 was a fixed platform development connected to GB 128A by an oil pipeline and a gas pipeline with all separation and processing performed at Enchilada.

In 2000, the Conger 3-well subsea development in GB 215 was flowed back to the Salsa platform. To incorporate Conger fluids into the Enchilada complex, major topsides modifications was required at the Salsa and Enchilada platforms. At Salsa, the facility needed to be manned, and new quartering and power systems were required. Methanol and chemical storage and injection systems, along with separation and testing equipment, pigging and blowdown equipment was also added. Expansion at Enchilada included slug catchers on both boarding pipelines from Salsa, additional treating capacity and compression.

The Sangria 1-well subsea development in GC 177 was tied back to the Salsa platform and required the addition of subsea controls systems, chemical storage and injection systems, and additional process heat and heat exchangers.

In 2002, gas-lift was provided to the Cinnamon development in GC 89 to help further oil recovery. The expansion involved reversing the direction of an existing pipeline between GC 89 and GB 128 and performing topsides revisions. Cinnamon production ceased to be economic shortly thereafter and in 2009 the platform was decommissioned

In 2004, a 16″ gas and 14″ oil sales pipelines from Conoco's Magnolia prospect in GB 783 were routed through the Enchilada platform, and another subsea well at Conger was tied back to Salsa. A helicopter re-fueling station on the Salsa platform was upgraded to service mid-size to large helicopters.

The Enchilada development layout circa 2005 is shown in Figure O.23. Circa September 2017, the Garden Banks 83 field which includes the Elmer, Enchilada and Chimichanga fields in GB 83, 84, 127 and 128 produced 7.8 MMbbl oil and 136 Bcf gas (Figure O.24), with current production levels less than 100,000 bbl oil and 200 MMcf gas. The Garden Banks 171 field (Salsa) in GB 172 and 215 has produced 144 MMbbl oil and 573 Bcf gas through September 2017 (Figure O.25). ■

15.7.4 Second Generation Hubs

Second generation and later hubs were built with wider flexibility and equipment sizes, tied back to a greater number of subsea wells, and were designed with excess transportation capacity in addition to production processing. A greater variety of third-party operators also became interested in hub business models in the mid-2000 time period. Two examples illustrate the class.

Example. GB 72 platform (*Spectacular Bid)*

The GB 72 platform (aka Spectacular Bid) is located in Garden Banks block 72 in the Western GoM in 514 ft water depth (Figure O.26). The platform was designed and installed by a midstream company to use for off-lease processing and as a junction platform for its pipeline systems (Heijermans and Cozby 2003). The platform originally processed production from the GB 72 and VR 408 field and four off-lease fields at GB 117, 158, 161, 205 and also served as the anchor portal for the deepwater Stingray gas pipeline and Poseidon oil pipeline systems. The Cameron Highway Oil Pipeline System (CHOPS) designed for the movement of the Atlantis, Mad Dog and Holstein crude from the southern Green Canyon area also cross this platform to markets in Port Arthur and Texas City, Texas. Circa September 2017, cumulative production from the GB 72 field (covering blocks GB 28, GB 72, GB 73, VR 408) was 13.5 MMbbl oil and 40 Bcf gas (Figure O.27). ■

Example. SS 332A&B platforms

The SS 332A platform was installed in Ship Shoal block 332 in 438 ft water depth to develop a gas field (Figure O.28). El Paso Energy Partners (EPN) acquired[18] the structure from Arco in the early 1990s after production ceased to support the Leviathan Offshore Gathering System, the predecessor of the Manta Ray Gathering System. Circa September 2017, cumulative production from the SS 332 field (covering SS 332 and SS 354) was 6.6 MMbbl oil and 105 Bcf gas (Figure O.29). In 1995, EPN constructed the Poseidon oil pipeline and the Allegheny oil pipeline in 1999 which utilized the SS 332A platform. A new platform (SS 332B) was constructed adjacent to SS 332A to serve as transport hub for CHOPS and the interconnection between the Caesar oil pipeline and Cameron Highway. ■

15.7.5 Hub Transitions

Hubs transition between states as opportunities materialize or fail to materialize, generally transitioning from anchor field dry tree production to subsea development to a non-producing (non-processing) role as transport/junction platform.

15.8. PIPELINE NETWORKS

The GoM offshore oil and gas infrastructure is described as a network defined as a collection of nodes and links in a mathematical graph. Nodes represent supply sources and sinks and include both structures and (onshore) consumers such as refineries, gas plants, and storage facilities. Links represent the pipelines that gather and transport processed oil and gas between nodes. Pipelines that transport raw (bulk) fluids from well to structure and between structures are not considered in this discussion because they are less critical than export systems. A network path is a sequence[19] of links and nodes leading from one node to another node, and the length of a path represents the physical distance along the path.

15.8.1 Evolution

In the 1950s, it was common to barge liquids to shore or employ a two-phase export pipeline from a central processing facility or gathering lines direct to shore to treatment facilities, but eventually pipelines became the preferred mode of transport to reduce operating cost and improve efficiencies. Pipeline systems developed in a stepwise fashion, moving south off the shelf into deeper water and tying into existing infrastructure when capacity was available, and building out new pipeline networks when capacity was not available or where for strategic reasons dedicated pipelines were desired.

Oil and gas export pipeline installation activity per decade is depicted in Figures O.30(a-g), and in Figures O.31(a-d) the active pipeline network at the end of every twenty years is depicted. All pipeline installation up through the end of the 1970s was on the shelf in <400 ft water depth and

[18] EPN was required by the FTC to sell the platform to a new company, Atlantis Offshore LLC, a joint venture between EPN and Manta Ray Offshore Gathering Company LLC, itself a joint venture company owned by Shell Gas Transmission LLC, Marathon Oil Company and Enterprise Oil Products LP.

[19] Tariffs are based on individual links, volumes and product type transported, link ownerships, and characteristics of the link such as age and regulatory oversight.

generally followed long straightline paths to their destination. On the shelf straight paths are the norm because the topology is flat with few obstacles and the gradient of the seafloor is small. In the 1950s and 1960s, gas pipelines direct to shore dominated with few interconnects between systems, and in the 1970s, pipeline segments grew longer with a larger number of interconnects forming at hub platforms and more east-to-west lateral connections established.

In the 1980s, the character of the installations changed as smaller and more numerous pipeline laterals connected into established networks and the first deepwater pipelines began to cross the continental slope. Several of the longer deepwater systems were direct to shore for strategic reasons. In the 1990s, deepwater networks from Green Canyon and Mississippi Canyon were routed direct to shore and as operators continued to develop deeper water fields, pipeline networks followed. In the 2000s, connections to existing infrastructure dominated which has continued over the past decade, while activity levels on the shelf have dropped considerably. In the latest decade pipeline systems have approached the international boundary with Mexico.

Today, production is processed offshore to satisfy oil and gas pipeline specifications and are exported to refineries, gas plants, fractionators, and storage facilities along the Gulf Coast. The GoM pipeline network is structured and organized around critical nodes containing a high concentration of linkages and high volume throughput. As with most networks such as electric power, telecommunications, and transportation, pipeline ‘hubs’ have developed within the region in accord with the business objectives and strategies of companies to enhance economic returns and efficiency.

15.8.2 Oil Pipeline Systems

A sample of the main oil pipeline corridors in the GoM are shown in four cartoons in Figures O.32-O.35. Pipeline schematics do not represent primary data and simplify the pipeline system but are sufficiently descriptive to depict key components of networks. Flowline data is not shown for simplicity. Detailed pipeline networks are available on the web for most transmission companies or can be compiled from GIS data files.

In Figure O.32, the regional pipelines that transport most of the deepwater crude oil in the GoM is depicted along with the main hub platforms. System maps from Poseidon Oil Company (Figure O.33), Shell Midstream Partners (Figure O.34) and El Paso (Figure O.35) show corporate networks and service/junction platforms supporting the regional system. Corporate pipeline networks usually represent segregated systems that interconnect with other systems at hub platforms.

Poseidon Oil Company is currently owned 64% by Genesis Energy LP and 36% by Shell Midstream Partners (SMP). Genesis Energy maintains 19 transportation platforms in its GoM pipeline network circa 2017, four multi-purpose platforms used as hubs and production handling and pipeline maintenance facilities, and 14 service and junction[20] platforms. Genesis Energy hub platforms include EC 373, GB 72, Independence Hub, and Marco Polo.

Shell Midstream Partners maintains eight transportation platforms in the network depicted in Figure O.34: SMI 205A, GC 19 (Boxer), SS 241, Caillou Island, WD 143, SS 30, SP 89E, MP 69. All of these transportation platforms were the sites of formerly producing fields.

[20]Junction and service platforms include HI A5 (CHOPS), HI 264A, HI 264B, HI 264C, HI 330 (HIOS), HI 343 (HIOS), HI 573 (HIOS), HI 582 (HIOS), SS 207, SS 332A, SS 332B (CHOPS), SMI 205 (Poseidon), ST 292, WC 167 (HIOS), and WD 68 (Independence Trail).

Example. Poseidon and Cameron Highway Oil Pipeline System

Poseidon and the Cameron Highway Oil Pipeline System (CHOPS) run parallel to each other along the edge of the shelf but transport crude in different directions and to different markets. Poseidon moves crude from east-to-west and then northward to Louisiana markets, while CHOPS runs in the opposite direction from west-to-east delivering crude to Texas markets (Figure O.33).

Poseidon delivers to three locations at Houma, Louisiana, via Poseidon's 24-inch line from Ship Shoal 332A; at St. James, Louisiana, via SMP's 18-inch line from Houma, Louisiana; and for certain barrels at SS 332A, Poseidon can deliver oil into SMP's Auger pipeline via South Marsh Island 205A, in addition to receiving oil from Auger in a bi-directional line.

CHOPS is owned by Genesis Energy LP and was completed in 2003 after a new platform at SS 332B was installed and a 30-inch pipeline connection to GB 72 was finished. The system originates at the SS 332B hub and passes through GB 72 and extends into two 24-inch pipelines at the High Island A5-C platform. One 24-inch leg terminates in Texas City, Texas, while the second terminates in Port Arthur, Texas. ■

15.8.3 Random vs. Structured Networks

The GoM pipeline network is not random but has structure due to the nature of its evolution. This structure emerged and was determined by a variety of factors, including the location and type of hydrocarbon deposits, the location and capacity of pipeline networks at the time of development, ownership, technology changes, regulatory conditions, and economic criteria. The construction of the system, long north-to-south links supporting one or more large fields direct to shore or to a hub platform create the network backbones, followed by lateral links and more east-west connections. There are a large number of nodes with one or two links and a small number of high-degree nodes, or nodes with more than an average number of links. Intuitively, nodes with the most links are the most critical[21] because their removal/disruption would cause the most damage to the network.

15.8.4 Scale-Free Networks

The degree of a node is the number of links connected to the node. A node with a degree of three means there are three links connecting the node to the rest of the network. Most processing platforms have degree at least two since there is almost always at least one oil export and one gas export line exiting the structure. Simple platforms such as caissons will have degree zero since they transport raw product to a host platform for processing. Complex platforms that process production and serve as a hub may have a dozen or more links. A count of the number of import and export risers at a structure determines its degree. The total flow of oil and gas through export pipeline originating at a platform quantify fluid volumes.

The idea of a 'scale-free' network arises naturally when we consider how offshore pipeline networks are constructed. For a given pipeline network, as new structures are installed new laterals will connect to the existing network or direct to shore and the pipeline network will expand with additional branches and links. As structures are installed, one oil export pipeline will be linked to an existing node and one gas export pipeline will be linked to the same or a different node, increasing node counts and node degrees at every connection point. And thus the network will

[21] Volumes transported through individual links is also an important factor but is more difficult to track because of its dynamic nature.

build out in a way that is broadly reflective of the configuration of the network at the time of the interconnect. Low-link nodes will increase at a faster pace than high-link nodes and the network will be scale-free.

More formally, Barabasi (2003) defines a network as scale-free when the number of links at each node is distributed according to a power law. In other words, if the probability of a node having k links is proportional to $1/k$ raised to a power greater than one, then the network is considered scale-free. The histogram drops off quickly as k increases and is a characteristic of most networks. Normally, the power term varies between one and three and the proportional factor can be generalized as $1/(k+a)^p$ for user-defined values of a to improve model fits if desired. The term 'scale free' does not refer to the size or breadth of the network, but because the power law has no variance and the links are distributed according to a probability density proportional to $1/(k+a)^p$.

Example. Scale-free network parameters

In Figure O.36, a portion of Shell's offshore oil pipeline network in the Central GoM is shown. The network depicted consists of 16 nodes excluding LOOP and Port Fourchon. The most common nodes have one link and there are 11 such nodes, hence the proportion of one-link nodes in the network is 11/16 = 69%. Platform SS 301 has six links (6%) and there is one 5-link node (13%), one 4-link node (6%), and two two-link nodes (13%). The power law $1/(k+a)^p$ was fit to the histogram and the sum of the square error (SSE) was minimized for four values of a shown (Table O.5). All the power law models yielded $p > 1$ and the best power law model (minimum SSE) was for $a = 0.5$ and $p = 1.7$. Hence, the pipeline network in Figure O.36 is scale-free.

Now, consider the expanded network in Figure O.34 with 28 nodes. There are 18 one-link nodes representing 64% (18/28) of the links, three 2-link nodes and three 4-link nodes (each 3/28 = 11%), and four 3-link nodes (4/28 = 14%). The proportions are roughly the same as Shell's smaller network and would therefore be expected to yield network parameters broadly similar. In this case, the best power law model (minimum SSE) was for $a = 0.5$ and $p = 1.6$ (Table O.5). ■

In the previous example, the reader observed that as the network expanded in size and complexity the value of p value remained relatively stable, and this notion can be generalized by considering larger and more connected networks, until ultimately the entire GoM network is evaluated. The argument is that the scale-free parameter for the GoM network should be approximately the same as developed in the example and the exercise is left to the reader. The idea of a scale-free network quantifies the notion of hub links by counting the degree for each node in the network and then normalizing by the number of nodes. If the rate of decline approximates the curve $(1/k)^p$ or $1/(k+a)^p$ for $p > 1$ the network is considered scale-free (Barabasi 2003, Lewis 2005).

15.8.5 Segmented Networks

If no path exists between one part of the network and another part, the network is divided or segmented into components. In the GoM, oil and gas pipelines and pipelines that originate in shallow water and deepwater, are segmented networks. Connections tie the western and eastern pipeline systems. There many standalone components that may be delineated by ownership and starting point.

15.8.6 Directional Flows

A directed graph is a graph containing links with a direction. In terms of pipelines this means that a directed link from node A to node B allows flow from A to B but not in the reserve direction from B to A. Most pipelines in the GoM flow north from the source of supply and then northeast or northwest to Gulf Coast refineries, gas plants, and storage from Texas to Mississippi. The more options operators have to transport their hydrocarbons the better prices they can negotiate. A few pipelines in the deepwater GoM such as Poseidon are bi-directional and allow volume flow in either direction (although not at the same time).

CHAPTER 16. BENEFITS, COSTS AND RISKS

The benefits, costs and risks associated with maintaining active structures and structures beyond their useful life are described and illustrated using several examples. The issues, tradeoffs and uncertainties are described generally rather than trying to resolve, quantify or evaluate specific issues. The role government policy plays in encouraging activity and managing the diverse range of operators are illustrated by various programs, including the end-of-life royalty relief program, the producing in paying quantities guidelines, idle iron guidelines and financial assurance requirements. The chapter concludes with a summary of main concepts.

16.1. POTENTIAL BENEFITS

There are many potential benefits associated with maintaining structures or extending their useful life, but each project and its potential benefits are site and time specific, and unless supported with detailed project-specific data, cannot be evaluated in a general manner. Potential benefits may arise in field redevelopments, life extension projects, integrated asset modeling, rigs to reef programs, pipeline reuse, alternative marine applications, and enhanced oil recovery. Not all of these programs will be viable or economic, and each is associated with specific costs, risks and limitations. The following examples are meant to be illustrative of the type of benefits that can arise. Valuing benefits for hypothetical scenarios without understanding system constraints, economic requirements and technological hurdles is discouraged[22].

16.1.1 Field Redevelopment

The objective of oil and gas companies is to recover oil and gas at a profit, and as part of this mission, they pursue investment opportunities that make economic sense and that fall within their risk-reward boundaries. In field redevelopment, the operator seeks to identify new targets to drill where the revenue is expected to exceed the cost of completion. Many opportunities arise at field(s) currently in production and dozens of examples have been reported in the literature of operators applying new technology to improve the interpretation and understanding of old producing fields.

Cost, risk and degree of difficulty for prospects vary significantly and are often ranked in drilling campaigns from a learning curve perspective. In the early 1990s, horizontal drilling became widely implemented in the GoM among majors and provided new profit opportunities in mature fields. Horizontal re-entries drill new horizontal wells by sidetracking from existing production casings and enjoy lower drilling costs than setting conductor, surface and production casings (Batchelor and Mayer 1997). However, geology and target geometry cause horizontal drilling candidates to differ appreciably in risk and degree of difficulty. For example, drilling up dip prospects in thin dipping beds on a salt flank structure have greater risk than for prospects contained in a low relief faulted anticline.

The technologies to identify prospects and improve recovery have changed over time, of course, but the strategy is always the same: invest in those opportunities consistent with corporate risk-reward criteria and rates of return that add value to shareholders. Do not pursue opportunities where the costs and risks outweigh the benefits. Generate more discounted revenue than the cost

[22] Issues of a speculative/hypothetical nature are always constrained by a large number of disclaimers regardless of whether the disclaimers are enumerated or not.

of the investment. Some redevelopment projects are successful and result in additional recovery at a suitable return, while other projects are not successful. What is considered successful will vary with the operator, but to create value, the investment must yield a return that satisfies company thresholds or at the minimum a positive net present value.

Eventually, new opportunities at a given field dwindle or do not satisfy company requirements and production will no longer be economic. Operators may sell their interest before this time to a company interested in marginal production or redevelopment, or may decide for liability reasons it is better to decommission the facilities themselves.

Example. Eugene Island 188

The Eugene Island block 188 field was discovered in 1956 as a shallow piercement-type salt diaper located in blocks 188, 189, 190, and 192 in 70 ft water depth. The field was developed in the 1960s, redeveloped in 1983-84 and again in 1992 (Mason et al. 1997). From 1956-1975, cumulative oil production was 39.4 MMbbl oil and 53.7 Bcf gas, and through September 2017, the field had produced 60.8 MMbbl oil and 234.6 Bcf gas. Remaining reserves is estimated at 8.2 MMbbl and 30.3 Bcf gas.

In 1991-92, a field study was performed to identify investment opportunities. All pay and potential pay zones were remapped using a new seismic survey. Five well locations were identified and subsequently drilled yielding four successful wells and one dry hole resulting in the production uptick shown in Figure P.1, not as large an increase in oil as the previous development program in 1983-84, but much larger gas production. Recoverable reserves from the drilling program were estimated at 10 MMboe and the operator considered the investment a success. ■

Example. Main Pass 73

The Main Pass 73 field was discovered in 1974 in 135 ft water depth and started production in 1979. The field consists of hydrocarbon bearing sands located in Main Pass blocks 72, 73 and 79 truncated against steeply dipping salt domes. Circa September 2017, cumulative production was 52.8 MMbbl oil and 263 Bcf gas (Figure P.2), with remaining reserves approximately 4 MMbbl and 12.6 Bcf (BOEM 2017).

In 2007, Energy XXI acquired the field, and using ocean bottom node technology and sophisticated image processing algorithms, more accurate and detailed earth models were created to support prospect generation and new drilling (Ammer et al. 2015). Typically, the salt bodies defining the reservoir edges are not well imaged on seismic data, making the accurate mapping of the producing reservoir difficult (Figure P.3). The revised model indicated smaller detached salt bodies and led to a new and optimistic interpretation of the producing sands (Figure P.4). Two new prospects located updip to older well penetrations were drilled in 2011 and completed as producers. The drilling success resulted in the identification of several new prospects located near the boundary of the salt dome. ■

Example. Bay Marchand

The Bay Marchand field is a giant oil field located adjacent to Port Fourchon, Louisiana, in state and federal waters up to about 100 ft water depth (Figure P.5). The field was discovered in 1949 and in 1986 officially became a 'giant' when its 500 millionth barrel of oil was produced. The field is characterized by complex faulting and stratigraphy in the vicinity of a salt dome that have provided numerous pathways for hydrocarbon migration and traps for accumulation (Frey and Grimes 1968). There are over 50 sands and 690 producing reservoirs above salt (Figure P.6).

Daily production peaked in the late 1960s at 75,000 bopd and by the mid-1980s had dropped to 18,000 bopd (Figure P.7). After acquiring a proprietary 3D seismic survey in 1987, better data and new interpretation permitted a renewed drilling program that increased production to 40,000 bopd in 1991 before again declining later in the decade. In 2017, Cantium LLC and Energy XXI GOM LLC operated about 100 structures and 650 wells (active and idle) in the field, and cumulative production in federal waters was 544 MMbbl oil and 573 Bcf gas. Annual production levels over the last decade have hovered around 2 MMboe per year (Figure P.8). Cantium LLC operates Bay Marchand lease blocks BM 2 and 3, South Timbalier 23 and 24, and Grand Isle 26 and 37. Energy XXI GOM LLC operates lease block South Timbalier 26.

In the 1920s, gravity methods were used to locate the field, and after a dozen dry exploration wells drilled over a ten year period, commercial hydrocarbons were established at the crest of the salt dome in 1949 (Figure P.9). The first platforms were made of wood and remained in production for decades (Abriel and Haworth 2009). Bay Marchand facilities (structures, pipelines, and power cables) circa 1990 are depicted in Figure P.10 and are similar today.

In the early 1950s refraction seismic methods were employed to produce a detailed salt contour map, and by the 1970s, 2D seismic data assisted in the location of structural plays and supported injector wells for waterflooding. A number of water injection wells were applied successfully in various units on the eastern flank of the field to support reservoir pressure (Jordan et al. 1969). In the 1980s, 3D surveys allowed the operator to identify a number of new drill locations and improve understanding of connectivity allowing additional production support from water injection wells.

Figure P.11 is a structure map of one of the major producing sands in Bay Marchand, the 8200 ft deep Miocene sand based on 1/4 to 1/2 mi seismic spacing resolution. The solid red and green areas represent proven oil and gas reserves. The hachured red and green areas are possible and probable hydrocarbon zones. The gray areas represent shale outs or permeability barriers interpreted from production histories. Figure P.12 represents the same horizon with improved data and interpretation. The seismic control was reduced to 35 ft which allowed delineation of smaller features and fault blocks which significantly changed the interpretation of the horizon, improving confidence in interpretation and identifying targets for new wells.

In 1998 additional 3D data was collected and 4D production temporal effects were examined. In some cases, water replacement of oil due to production could be mapped and bypassed reserves identified which were subsequently exploited (Figure P.13). In 2000, the operator created a new management strategy for the field to reduce costs and improve profitability, and production staff at the main Romeo platform was cut in half (Offshore 2000). From 1992-1996, field wide operating cost were reported at around $60 million per year, which was subsequently reduced to $46 million and $32 million in 1997 and 1998, resulting in lifting cost improvement from $6/boe to about $4/boe.

In 2011, wide azimuth (WAZ) 3D surveys were obtained to delineate thin beds and better image faults, identify undrained reservoirs, and provide new deep exploration targets (Shank et al. 2014). A large number of wells were repositioned along the flanks and top of salt resulting in improved production and better reservoir management (Figure P.14).

Over the last decade, acquisition and imaging techniques have improved with increases in computational power and processing capability, new algorithms, and more sophisticated imagining techniques, providing new opportunities for development. Using 3D WAZ ocean-bottom cabling technology and a new method of waveform inversion resolved new traps that were not previously visible. Circa 2017, Bay Marchand production has been entirely above the top of salt and along the flanks. The base of salt might hold more hydrocarbons underneath but the prospects need to be identified and de-risked (Figure P.15). ■

16.1.2 Life Extension

Structures that are located in an area of active drilling may extend their life by hosting subsea tiebacks if nearby discoveries arise and the outcome of negotiation between the parties (if host and reserves owners are different) are successful. Tiebacks require flowlines and umbilicals to reach the host and new export pipeline may or may not be required. If processing capacity is available its use would result in savings for the operator but the size of the savings will vary between projects and product quality may limit use. The platform owner is an interested party because a new revenue source will contribute to additional revenue. Pipeline owners are interested parties since they desire to keep their pipelines full to earn a steady income. Resource owners are interested parties if the tieback is the best (or only) option for development.

Example. Thunder Hawk

The Thunder Hawk field was developed in 2009 using a semisubmersible production unit in Mississippi Canyon in 6060 ft (1847 m) water depth with nameplate production capacity of 45 Mbopd and 70 MMcfpd (Yoshioka et al. 2016). Initially, one well was connected and two flowlines were tied back with a single control umbilical. After five years of production, and without any new wells drilled in the field, available production and export capacity created an opportunity for a third-party tieback. In 2015, the Big Bend and Dantzler fields located about 12 and 6 miles (19 and 9.6 km) away in 7200 ft (2195 m) water depth were tied back to Thunder Hawk using dual pipe-in-pipe flowlines and insulated steel catenary risers (Figure P.16). Production capacity was expanded to 60 Mbopd and gas lift capability was added at the host. ■

16.1.3 Gas Lift

The most common types of artificial lift for offshore oil production in the GoM are gas lift and downhole pumping. In gas lift systems, gas is injected directly into the wellbore to lower the hydrostatic head[23]. Gas compression depends on the source pressure, and since gas lift is essentially a closed-loop system except at start-up where another source of gas (e.g., nitrogen) may be required, little gas is consumed in operations. For downhole pumping power generation is required to drive the electric pumps.

Gas lift is common throughout the shallow water GoM and is also used in the deepwater GoM at the base of production and import risers to help lift the fluids through the water column (Everitt 1994, Stair 1999, Borden et al. 2016). If the platform has formation gas available in excess of utility fuel requirements and is in the volumes required, then changing the tubing strings and adding horsepower and a compressor package can usually be accommodated at the platform. Capital investments are modest and gas lift systems are reliable and can be maintained with wireline services which reduce maintenance cost. If adequate gas supply is not available at the platform, then a flowline supplying gas from a nearby platform will need to be laid and the gas

[23] The fundamental mechanism behind gas lift is that the gas injected in the tubing reduces the density of the fluids which act to lower the flowing bottom hole pressure. Lowering bottom hole pressure increases flow from reservoir to well bore.

purchased (at market rates) which will reduce profits from the investment. Automation is common to maintain performance on complex systems (Reeves et al. 2003).

Example. Amberjack gas lift redesign

The Amberjack oil field was developed in 1991 as a single jacket platform in a water depth of 1030 ft in Mississippi Canyon. In 2003, the field had 34 dry tree wells, six of which were dual completions and 27 of which employed gas lift[24] (Hannah et al. 1993, Reeves et al 2003). Wells drilled from 1991 to 1994 were all on gas lift by 1995, and in 2001 these wells were reported to be declining at a 36%/yr average decline rate. In 2002, gas lift valves were redesigned and installed in 10 wells, and in 2003 a gas lift automation system was implemented to improve operational decision making. After implementation there was a 600 boe/d increase in production for several months and the payback of the project was less than a year. ■

Electric submersible pumps are not nearly as popular as gas lift applications in the shallow water GoM because they are less reliable and cannot accommodate high angle wellbores and the subsea safety equipment, but in deepwater applications booster pumps which sit on the ocean floor are increasingly common for high viscous crudes and in many recent Lower Tertiary developments (e.g., Perdido, Cascade/Chinook, Jack/St Malo, Stones) they are an essential part of the development (Kondapi et al. 2017). Typically, ESPs have high failure rates of the electric cable and/or pump operating in a high temperature environment, and have difficulty with the presence of solids in the produced fluid[25]. ESPs do not require a gas supply which is an obvious advantage over gas lift systems but the drawbacks remain significant.

16.1.4 Integrated Asset Modeling

All producing oil and gas fields represent potential redevelopment opportunities since drive mechanisms are known, artificial lift methods are usually in place (if used), flowline networks are installed, and equipment capacity is available. Integrated asset models provide the opportunity to quantify various improvement scenarios and give new life to production. Such options may include gas-lift allocations, surface back pressure optimization, and process facility adjustments to name a few. Reservoir models needs to be coupled with oil production, water injection and gas lift distribution networks in order to evaluate viable investment opportunities.

Example. Ewing Bank 873 (Lobster)

The Lobster platform was installed in 1994 in Ewing Bank block 873 in 775 ft water depth. The platform was originally owned by Chevron Texaco and Marathon and is currently operated by EnVen Energy Ventures which holds lease blocks EW 873, 874 and 917. The platform processes production from the EW 873 Lobster anchor field covering lease blocks EW 873, 874, and 917 (Oyster) and South Timbalier 308 using platform wells and wet trees, as well as three other deepwater fields: Seattle Slew (EW 914), Arnold (EW 963), and Manta Ray (EW 1006). In 2009 a new drilling campaign based on 4D seismic technology designed to target remaining oil and potentially untested targets reachable from the platform (Roende et al. 2009) was successful

[24] In gas lift, gas is delivered from surface compressors by way of the annulus between the casing and production tubing to a series of gas lift mandrels (conduits), which are positioned within the production tubing string. When a predetermined gas pressure is reached, valves within the mandrels open, causing gas to be "injected" into the production tubing, thus reducing the density of produced fluid and enhancing/enabling flowback to the surface.

[25] Like all pumps, ESPs are adversely affected by sand, scale, or free gas.

(Figure P.17). Circa September 2017, the EW 873 field had produced 172 MMbbl oil and 158 Bcf gas, and cumulative oil and gas production from tiebacks are summarized in Table P.1. ■

Another opportunity frequently requiring an integrated production model to proceed are subsea well stimulations. In addition to accelerating recoveries, stimulation can improve recovery volumes and reduce decline rate following treatment and can be an attractive business decision. The cost of subsea well intervention is significantly greater than direct vertical access and dry tree well intervention, however, and will likely require upside production to proceed. In a multi-well recovery, additional production from one well may back out production from other wells, adding to the risk of the operation and requiring an integrated model to account for inter-well interactions and longer term production factors.

16.1.5 Rigs-to-Reef

There are three options for platform decommissioning: complete removal, partial removal, and topple-in-place. In the GoM, active rigs-to-reef programs exist offshore Louisiana and Texas where the state accepts liability for reefed structures in designated areas (of federal waters) and the operator splits the cost savings with the state in lieu of transporting the platform to shore which is set aside in a trust fund to support the administration and management of the reef programs (Kaiser and Pulsipher 2005).

Louisiana's Rigs-to-Reef program celebrated its 30th anniversary in 2017, and since its inception about 350 structures have been donated to the program, on average about 12 structures per year. Texas's Rigs-to-Reef program started in 1990 and through 2017 about 150 structures have been donated, or about six structures per year. Louisiana's reef program is larger and more active than the Texas program due in large part to the higher density of infrastructure offshore Louisiana. In total, about 15% of all platforms decommissioned since 1990 have been located in the Texas and Louisiana reef programs.

Platforms act like artificial reefs (Reggio 1989, Blaine 2001) and are home to some of the most prolific ecosystems in the oceans (Claisse et al 2014, Ajemian et al. 2015, Flower 2015). They are frequently the preferred destination of recreational fishing and commercial diving (Stanley and Wilson 1989), and are capable of harboring threatened species, providing reef habitat, boosting recruitment of overfished species, raising ornamental fish and invertebrates, and acting as foraging sites for top-order predators. They contain coral, algae, bacteria and sponges (Kolian et al. 2017, Sammarco et al. 2004) and tantalizing evidence suggests they can produce anti-viral, anti-bacterial and anti-cancer compounds (Rouse 2009).

16.1.6 Pipeline Reuse

The vast majority of decommissioned pipelines are left-in-place on the seafloor with their ends plugged and buried three feet below the mudline. Therefore, in principal, decommissioned or out-of-service pipelines can be reused in development if economically viable. In practice, however, pipelines are rarely re-used after they have been decommissioned. Only under very special circumstances, if the pipeline is of sufficient length and quality and located near the field development, does the potential for re-use arise. Several conditions must be satisfied simultaneously for pipeline re-use to be viable and such projects are exceptional one-off events.

Example. Lucius and South Hadrian

The oil export pipeline for the Lucius field in Keathley Canyon is an 18-inch (46 cm), 147-mile (237 km) pipeline consisting of three segments: (1) 74 miles (119 km) of 18-inch (46 cm) new build pipe from the Lucius spar to the Phoenix pipeline; (2) test and re-use of a 47-mile (76 km) section of the out-of-service Phoenix gas pipeline converted to oil service; and (3) 26 miles (42 km) of 18-inch (46 cm) new build pipeline to South Marsh Island block 205 transportation platform (Figure P.18). First oil was delivered in 2015 (Schronk et al. 2015). About one-third of the oil pipeline re-used abandoned gas pipeline from Anadarko's Red Hawk spar which was taken out of service in 2008. Pipeline reuse required thorough cleaning of the pipeline, caliper runs, dehydrating, ROV inspection, cathodic protection checks, and span data analysis for fatigue and stress. ■

16.1.7 Alternative Uses

Section 388 of the Energy Policy Actof 2005 (Public Law 109-58) promulgated the "Renewable Energy and Alternative Uses of Existing Facilities on the Outer Continental Shelf" (30 CFR 285, 1000 subpart 3). This federal program allows retired oil and gas platforms to be redeployed for alternative uses such as the production of wind, wave, and current energy, sustainable fisheries, or any other marine related purpose (NOAA 2018).

Mariculture and offshore wind has been discussed and proposed in the GoM for many years but no ventures to date have assembled the capital required to test their business plans and establish viable operations. Commercial offshore operations require a high-value resource to exploit to cover the high cost and high risk operating environment. The re-use of platforms in the GoM for non-petroleum related activities is constrained by poor economics, difficult logistics, and high risk. Fish are not that valuable (yet), offshore wind in the region is not very strong, and low regional population densities mean that markets are relatively distant and conspire to prevent such ventures from gaining much traction (e.g., Kaiser et al. 2010). Hence, although there is always the potential to re-use GoM structures for alternative uses, economic and risk factors have prevented ventures progressing to the financing stage.

16.1.8 EOR via CO_2 Injection

Enhanced Oil Recovery (EOR) is the third stage of recovery after primary and secondary methods have been employed and involve the injection of various materials beyond water and miscible gas into a reservoir to extract additional oil. EOR is most frequently used in fields with heavy oil, poor permeability and irregular fault lines, and CO_2 injection is the most popular method employed in the U.S. followed by thermal methods. In 2010, EOR projects were producing about 300,000 bopd and accounted for about 5% of total U.S. production. About half of all EOR projects were CO_2 and the other half thermal recovery. The Jackson Dome CO_2 supply in Mississippi transports over 1 Bcf of CO_2 daily to 15 fields in the Gulf Coast, and oil production associated with these projects is estimated at 38,000 bopd, or about 14 MMbbl per year (Davis et al. 2011).

Although potential offshore EOR volumes are intriguing to contemplate, they are speculative and highly uncertain. CO_2 project economics are difficult and require several conditions to be viable, including amenable reservoirs, reliable and long-term CO_2 supply, CO_2 pipeline, appropriate well patterns, waterflooded fields, and well capitalized firms (Bondor et al. 2005, Koperna and Ferguson 2011).

Offshore, CO_2 EOR projects are much more difficult and expensive than onshore projects, and circa 2017 the number of commercial projects implemented worldwide is zero. Offshore CO_2 EOR operations are expensive due to the expense of transporting CO_2 to location, the high cost of processing and recompressing produced gas in offshore settings (recycle), the high cost of drilling and reworking offshore wells, the corrosive nature of CO_2, and the high cost of offshore operations and maintenance. Offshore CO_2 EOR projects are uncertain because reservoir behavior is difficult to model and predict (i.e., after filling in the pore volume with CO_2 how much oil will be recovered and how fast and what will the recycle rate be), usually analogs and normalized production curves are applied to estimate operational results and the uncertainties associated with these tools are high. Over the past half century, only a handful of CO_2 pilot projects have been conducted worldwide, most in the GoM.

Example. Carbon storage and EOR projects

The Sleipner and Snohvit natural gas fields offshore Norway and the K12-B gas field offshore Netherlands are characterized by high concentrations of CO_2 (5-13%vol) that must be processed to satisfy the 2.5%vol limit for European natural gas pipeline specifications. The CO_2 is separated from the produced natural gas and reinjected into sandstone formations for storage. Statoil operates the Norway facilities and Gaz de France Production operates the K12-B field. These are carbon storage operations.

There have been nine offshore CO_2 EOR projects and one EGR projects reported by operators, all short-term pilot projects considered successful but not implemented on a large scale (Sweatman et al. 2011). At Weeks Island, Bay St. Elaine, Quarantine Bay, and four oil fields along the Louisiana coast in the 1980s, CO_2 was transported inside refrigerated tanks on barges pushed by tugboats to site, and then injected into wells. At Timbalier Bay, CO_2 was transported via tanker trucks to a pipeline station at Port Fourchon where it was pumped to a compressor and on to an injection well. A Dulang CO_2 EOR project offshore Malaysia used water alternating gas (WAG) injection. ■

In a 2014 study sponsored by the Department of Energy, DiPietro et al. (2014) identified oil reservoirs in the GoM amenable to CO_2 EOR and simulated a CO_2 flood for each reservoir using production and cost estimates to determine which oil fields were economic for CO_2-EOR. An earlier study by Brashear et al. (1982) is also of significance. A total of 391 fields out of 531 oil fields were screened out based on size[26], residual oil saturation and/or well spacing. For the remaining 140 oil fields (696 reservoirs), CO_2 EOR simulations were performed with cash flow models to assess the economics at a reservoir level. A minimum 20% rate of return was required to be considered economic.

To perform the economic calculations, the study assumed that groups of proximate fields will be served by a \$1.5 billion CO_2 pipeline originating at Baton Rouge, Louisiana, supplying 1 Bcf/yr CO_2 at a levelized transportation cost \$1.06/Mcf CO_2 (\$20/mt), oil price of \$90/bbl, CO_2 price of \$1.6/Mcf, 18.75% royalty and a 20% rate of return before taxes. Additional model assumptions can be found in (DiPietro et al. 2014). Economically recoverable resources was estimated at 800 MMbbl with a 5.8 Tcf CO_2 demand, 390 MMbbl in shallow water, 80 MMbbl in deepwater, and 340 MMbbl at undiscovered fields by analogy. Under a scenario with 'next-generation' performance assumptions, economically recoverable resource values increase by an order-of-magnitude.

Because many pre-conditions exist for success only a few CO_2 EOR projects have been pursued to date and they have all been short-term pilot (feasibility) projects that were not implemented

[26] All reservoirs with OOIP <10 MMbbl and all fields with OOIP <50 MMbbl were screened out as too small.

because of economic reasons. Hypothetical studies have not translated into reality because of the difficult economics and complex technical issues associated with modeling outcome and reducing uncertainty. Projects are usually considered ‘successful’ in a technical sense but technical success and profitability are not the same. In brief, there are many complexities and difficulties associated with offshore CO_2 projects that are expected to prevent commercial development.

16.2. Costs and Risks

There are various costs associated with maintaining idle infrastructure, including inspection cost, lighting costs, maintenance and repair cost, and insurance cost. Inspections must be performed periodically above and below water and maintenance cost will vary with the level of corrosion and size of the structure and business plan of the operator.

16.2.1 Inspection Requirements

The OCS Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and periodic unscheduled (unannounced) inspection of all oil and gas operations on the OCS. BSEE regulations require operators perform in-service inspection intervals for fixed platforms according to API Recommended Practice 2A-WSD (NTL 2009-G32). Section 14 of API RP-2A-WSD describes the inspection program survey levels and frequencies to monitor periodically the adequacy of the corrosion protection system and determine the condition of the platform.

The time interval between platform inspections depend upon exposure category (L-1, L-2 or L-3), survey level (Level I, Level II, Level III), and manned status (Table P.2). The three levels of exposure to life safety are manned and non-evacuated, manned and evacuated, and unmanned (Ward et al. 2000a, b). Consequences of failure encompass damage to the environment, economic losses to the operator and the government, and public concerns. Economic losses to the operator can include the costs to replace, repair and/or remove destroyed or damaged facilities, costs to mitigate environmental damages due to released oil, and lost revenue. Economic losses to the government include lost royalty revenues.

A Level I survey is required to be conducted for each platform at least annually and a grade assigned to the coating system. A Level II survey is required for each platform at the minimum survey interval for each exposure category, at least every three years for L-1 platforms and at least every five years for L-2 and L-3 platforms. A Level III survey is required for each platform at the minimum survey interval for each specified exposure category, at least every six years for L-1 platforms and at least every 11 years for L-2 platforms[27].

16.2.2 Maintenance Cost

There is a wide variation in the maintenance programs operators perform to protect their assets. For new capital intensive facilities, operators are likely to invest in continuous, year-round or seasonal maintenance programs, while for idle structures painting will only be performed on an as-needed basis or as dictated by deficiencies found via BSEE audits. The costs to maintain

[27] For unmanned platforms, BSEE may approve an increased interval for Level II and Level III inspections if the operator is in compliance with all structural inspection requirements and the platform is in good structural condition according to previous Level I and Level II surveys.

structures that are not producing or serving an active/useful role in operations primarily include inspections (periodic and mandatory), and if applicable, painting and blasting repair and insurance. Personnel must be transported to site to perform activities and if the structure is audited and found to have safety or other hazards additional cost will be incurred.

Painting and blasting operations on inactive structures are less likely to be prioritized relative to active structures, and so as rust develops and steel degrades, structures may become hazardous to personnel. If there is no maintenance painting, safety and hazardous conditions may arise in operations and decommissioning activity.

Operators allocate their ‘paint budget’ across their fleet of structures. For deepwater platforms and floaters, maintenance painting may range from $500,000 to $1.5 million per year per structure after the service life of the coating is reached (perhaps 7-12 years after application). For shallow water platforms, costs are significantly lower relative to deepwater structures and depend on the extent and distribution of paint degradation and on exposure category.

16.2.3 Lighting Cost

All platforms must have navigation lighting at all times between sunset and sunrise (and sound signaling devices) from the time of installation according to federal regulations. Periodic inspections are made to ensure compliance with lighting requirements. Inactive structures must maintain their lighting systems or will be found in violation of regulations. Structures are designated into one of three classes as A, B, or C depending on the water depth and marine commerce traffic routes. The number of lights required depend on platform size. If one side of a platform is less than 30 feet wide, one light is required. If one side of the platform is greater than 50 ft, four lights must be installed at each corner of the platform. If the platform is between 30 and 50 ft wide, two lights must be installed on diagonal ends. On a class A structure, lighting must be visible for five nautical miles.

16.2.4 Hurricane Exposure

Many of the damaged and destroyed structures in the paths of Hurricanes Katrina, Rita, Ike and Gustav that passed through the GoM from 2005 to 2008 were inactive and no longer served a useful role in production. Clean-up activities have taken nearly a decade and now only the most expensive and difficult destroyed structures remain (Kaiser and Narra 2017). In one exceptional case, Taylor Energy’s Mississippi Canyon 20 toppled platform is unlikely to ever be fully decommissioned. Hurricane clean-up cost can be two to ten times greater than normal decommissioning activity and several operators subsequently went bankrupt or left the region. Today, there are significantly less structures in the shallow water GoM and fewer idle structures, so the impact of future destructive hurricanes will likely be less on a relative basis, but for those idle structures remaining they will continue to pose a liability for the operator and potential environmental risk if all wells are not permanently abandoned.

16.2.5 Environmental & Safety Risk

Structures that no longer serve a useful purpose expose operators to hurricane risk and present collision risk to vessels and tankers, which may lead to environmental issues from leaks, fires and safety concerns. If a hurricane occurs and damages/topples the structure, additional cost will be incurred in clean-up and potential environmental damage if wells are not permanently abandoned.

In the 21st edition of API RP2A a consequence based design criteria was introduced based on two classes of risk, those associated with life safety and those associated with consequences of failure. If the platform is of modest likelihood of failure and low consequence (e.g., old, unmanned, with most wells abandoned), much of the risk of holding the structure in inventory is an economic one rather than a hazard to human life or the public interest. If the platform is of modest likelihood of failure and high consequence (e.g., old, manned, no wells abandoned, no subsurface safety valves), then risk to the public increases.

16.2.6 Bankruptcy Risk

The risk of bankruptcy among small independents is higher than large independents and majors and is reflected in lower credit ratings which quantify the probability a company will default on its debt obligations. If operators go bankrupt or are otherwise unable to pay for their decommissioning obligations, there is a risk that the public will bear the cost of clean-up. Fortunately, the regulatory structure associated with GoM oil and gas operations includes a number of safeguards which reduces the default risk and subsequent exposure of the government.

The risk to the taxpayer is a function of the number of jointly and severally liable lessees in the chain of title and the financial strength of the individual lessees. If a lease includes a major or a large independent there is high financial strength in the chain of title, and the risk of default for these leases is near zero. If there is no major or large independent, the risk is tied to the financial condition of the other independents in the chain of title. All of the companies in the chain would have to default simultaneously for the government to be required to pay the liabilities. The greater the number of companies in the chain of title for the lease, the less likely it is that they would all default and the less risky the lease. The riskiest leases are those with only one lessee in the chain of title. In such case, the risk of default is tied to the individual lessee's financial strength. Sole lease ownership (no title chain) represents the highest risk leases in the GoM.

According to a 2016 Opportune study (Sherman et al. 2016), there were 2243 leases in the GoM with decommissioning liabilities estimated at about $24 billion, and of those leases with liabilities, 408 have no major or large independent in the chain of title with an estimated liability of about $1.4 billion. Decommissioning liabilities at risk represent less than 5% of the total exposure in the GoM.

16.2.7 Aging Infrastructure

Structures that are no longer producing or useful for operations are unlikely to receive the attention and maintenance of active fleets and may fall into a state of neglect and disrepair. Operators with large inventories of idle infrastructure may fall behind on maintenance from corrosion and struggle to keep up with increasing regulations and audits from the BSEE. Safety and environmental risks may ensue from rusting structures and require additional precautions and cost in decommissioning.

16.3. Government Policy

16.3.1 End-of-Life Royalty Relief

Under 43 U.S.C. 1337 (a)(3)(A), the U.S. Department of Interior may reduce or eliminate the royalty or net profit share specified for producing OCS leases to promote increased production (DOI 2010). The basic rule specifies that a lease is becoming uneconomic when royalties exceed

75% of net revenues generated. Under these circumstances, BOEM may modify the royalty rate to extend the productive life of the lease.

The purpose of royalty relief is to allow operators reasonable financial returns to increase ultimate resource recovery and augment receipts to the Federal Treasury. To qualify for royalty relief, operators need to demonstrate the need for royalty relief via supporting information using engineering and economic principles.

Royalty relief for end-of-life leases was enacted in March 1999 but has not been popular with operators, indicating either that royalty relief near the end of production is not an adequate stimulant for operators to continue with marginal production or that the program is cumbersome for applicants. Notwithstanding program changes to improve efficiency and expedite review, we believe that because end-of-life production is generally characterized by marginal cash flows and high costs and risks, the overall benefits of reducing costs via royalty rate reduction/elimination is likely to play a relatively small factor in the economics of operations and decisions of most operators. Conversely, royalty relief at the front end of investment (e.g., deepwater and deep gas royalty relief) provides more incentive to operators to invest and will generate greater interest.

16.3.2 Producing in Paying Quantities

In NTL 2008-N09, Production in Paying Quantities, the MMS has stated that they will periodically perform lease-holding reviews on leases with minimal and/or intermittent production to ensure that leases are "producing in paying quantities":

> *"Under prudent operator standards and historical precedent, the MMS interprets production in paying quantities… to yield a positive stream of income after subtracting normal expenses (i.e., operating costs), which include the sum of minimum royalty or actual royalty payments, whichever is greater, and the direct lease operating costs."*

MMS stated that regional offices will perform an initial review using standard operating expenses and compare against revenue generation. If revenue generation is less than cost, the Regional Supervisor will ask operators to provide cost and production data to demonstrate that their leases are producing in paying quantities:

> *"If the Regional Supervisor determines that your lease did not produce in paying quantities for a period that exceeded 180 days, MMS either may issue an order to show cause as to why your lease did not expire by its own terms at the end of the 180-day period or may issue a determination that your lease has expired."*

16.3.3 NTL 2010-G05

NTL 2010-G05 dissolved the lease boundary in determining decommissioning time lines and redefined the regulatory requirements at the individual wellbore and structure level by specifying the maximum number of years wells and structures are allowed to remain idle before they have to be abandoned. For wells that have not produced for five years or more, operators have three years to either permanently or temporarily abandon the well. For structures that have not produced for five years or more, operators have five years to remove the structure.

16.3.4 Financial Assurance and Bonding

BOEM regulations at 30 CFR part 556, Subpart I, set forth a multi-tiered financial assurance system applicable to oil and gas leases to ensure that OCS obligations are met. There are three stages in the life of a lease when financial assurance is required by regulation: (1) lease issuance, (2) approval of an exploration plan, and (3) approval of a development and production plan or a development operations coordination document (30 CFR §§ 556.900(a), and 556.901(a) & (b)). However, at any time, the Regional Director may determine that additional security is necessary (30 CFR § 556.901(d)).

BOEM has established minimum thresholds for each of nine ratios:

- Cash Flow from Operations/Total Debt
- Current Ratio
- Earnings Before Interest and Taxes (EBIT)/Interest Expense
- Quick Ratio
- Return on Assets
- Return on Equity
- Total Debt/Capital
- Total Debt/Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA)
- Total Debt/Equity

as well as the number of such thresholds that BOEM requires an operator to exceed to determine Financial Capacity exists in excess of lease and other obligations.

On July 14, 2016, BOEM issued NTL No. 2016-N01, Requiring Additional Security, which clarifies the procedures and criteria that BOEM Regional Directors are to use in determining if and when additional security may be required for OCS leases, ROW and RUE. This NTL supersedes and replaces NTL No. 2008-N17.

On February 12, 2017, BOEM withdrew its NTL No. 2016-N01 orders requiring sole liability properties to provide additional security in the form of supplemental bonds, and it appears that BOEM has put implementation on hold pending a review of the requirements.

16.4. Summary and Recommendations

A summary of the main points associated with critical infrastructure is highlighted along with a few recommendations. There is no particular order in the discussion.

Economic criteria govern most operator decisions.

Field redevelopment is part of the normal investment and development processes that occur at companies. If opportunities arise that are deemed commercial or serve a greater purpose, they will be pursued; otherwise, production will be run to the limit. Redevelopment opportunities compete against all opportunities available to an operator within capital constraints. Field developments must make economic sense on a stand-alone basis and developments must be able to generate a return consistent with the risk of the investment. Since all oil and gas fields have finite lives, field production will eventually decline and cease to generate positive cash flows. The operator may decide to try to extend the life of the structure through sidetrack drilling or by routing pipelines across the structure, but economic criteria will be employed unless strategic considerations are important. The structure may be sold to a third-party pipeline transmission company or sit idle as the operator evaluates its opportunities.

Companies seek to leverage their infrastructure.

After structures are installed, costs are sunk and any additional revenue that can be realized will be beneficial to the operator. After peak production, and depending on the field development plan and maturity of production, capacity will likely be available at the platform to serve other fields or in a transport role. If discoveries are made in the vicinity of the platform, the structure may serve as host if facilities can accommodate the production and negotiation is successful (for third-party fields). If discoveries are made farther afield, the structure may still serve a useful purpose in development but the probability of reuse will decline. Larger companies tend to have longer and more stable planning horizons that allow infrastructure to derive greater value than smaller companies short planning horizons.

Companies with a greater number of assets have more opportunities to monetize their infrastructure.

Companies with a larger number of assets seek to use their infrastructure to develop new discoveries and to market their spare production/export capacity to generate revenue. Platforms will attract interest from operators drilling in the region as a potential host for tieback wells or other applications. Overlap of ownership is usually enough to bring arrangements to fruition while third-party access is more complicated and uncertain regarding negotiation outcomes.

Structures can be safely used beyond its reserves life if properly maintained.

After peak production, structures will typically have weight, space, equipment and export capacity available but aging facilities may present additional problems.

Pipelines are rarely reused after decommissioning.

Most pipelines are decommissioned in-situ and in theory can be used to reduce development cost. Pipelines are rarely reused however because of corrosion, location, and economic issues. Potentially useful pipelines in development are either active or out-of-service lines. Pipelines have specific requirements on sulfur content, pressure, and related specifications. A low sulfur oil pipeline or a high pressure gas pipeline, for example, cannot accept product that violate the pipeline specifications.

Almost all production profile 'bumps' observed are the result of investment.

As a general rule, anytime there is a significant bump (increase) in the production profile of a field or well, one should recognize that investment was required that created the incremental increase. Whether the investment paid for itself and increased the value of the asset to the company is another matter and one that is usually off-limits to analysis because work activities and project cost is proprietary and closely held.

The impact of redevelopment decisions vary from quantifiable to highly uncertain

Workovers are the most common investment made in field development but outcomes are often highly uncertain and beyond quantification. In theory, if the NPV of the workover activity is positive using the company's cost of capital or management approved discount rate, then the investment will proceed, or if such calculations are not made (and frequently they are not), simple payback measures may be employed for justification, say 6 months for project approval. For new/young wells, workovers rarely require economic justification and paybacks will occur quickly, but for mature/old wells workover decisions are not nearly as straightforward and the investment may not be economic. Important distinctions arise between dry tree and wet tree wells, since in the former case access is much easier and cheaper, especially if a drilling or workover rig is available topside. For other within field development opportunities project cost and risk increase.

Benefits of maintaining infrastructure beyond its useful life are speculative.

Whether existing infrastructure can serve a useful purpose depends on operator development plans, fortuitous timing, prospectivity in the region, the strategic decisions of companies, and other factors. The benefits of maintaining infrastructure beyond its useful life are always speculative unless detailed data is available for evaluation.

Expand the Rigs-to-Reef program incentives.

The Rigs-to-Reef programs in the GoM are widely viewed as beneficial to operators, local economies, marine habitats and other users of the Gulf. Government policy could expand the Rigs-to-Reef program and provide increased incentives for operators to reef their platforms. For example, policy that allow operators to leave their jacket structure in place for an extended period of time if properly marked and bonds are maintained would serve operators economic efficiency if properly managed (Abadie et al. 2011). This is not to be confused with occasional talk of 'standing reefs' which few operators, regulators, or public officials consider a good idea.

Maintaining idle infrastructure costs money and incurs risk, but if all wells are permanently abandoned environmental risk is significantly reduced and structures become mostly an economic risk to operators

There are various cost associated with maintaining idle infrastructure, including inspection cost, maintenance and repair cost, and insurance cost. Inspections must be performed periodically above and below water and maintenance cost will vary with the level of corrosion and size of the structure and preferences of the operator. Structures that no longer serve a useful purpose expose operators to hurricane risk and present collision risk to vessels and tankers, and may lead to leaks, fires and safety concerns. Permanently abandoning all wells on idle structures would significantly reduce environmental risk and make the structures mostly an economic risk to operators.

Many factors impact investment decision-making and potential asset utilization

Oil and gas wells will never actually deplete their reservoirs, but other factors – low product prices, high operational costs, financial problems, or the lack of resources to characterize the reservoir and identify the potential for additional recovery – will influence decision-making and investment opportunities. Historically, large well-financed independent producers have entered into fields previously operated and owned by the majors, and after additional production assets were sold down the food chain ending with smaller underfinanced and understaffed operators working off the cash flows from producing wells and unable or uninterested to workover idle wells. Offshore, there are more capital constraints and expertise thresholds that have limited the number of operators in the region. Old wells may have potential but since they are presumably marginal targets a special effort is required to pursue opportunities.

Federal regulations allow offshore structures to be permitted for alternative uses, but the economics for commercial endeavors are constrained by difficult economics.

Cost-benefit analysis should be performed for idle infrastructure on a site-by-site basis.

When production expires on a lease, contract terms require decommissioning, and therefore for changes to lease terms the burden is on operators to "make-their-case" with government regulators to maintain infrastructure beyond their useful life. This will involve providing the reasons the structure is expected to serve a useful purpose, drilling plans in the region or if the structure is to be used as a transport platform regional development plans. Hard budgets and timelines and capital expenditure plans are required for regulators to make an informed decision.

NTLs clarify regulations but are not regulations in the strict definitional/legalistic sense, but they are believed flexible enough to allow inactive structures on a case-by-case consideration. It is not the role of the regulator to surmise or speculate what might or might not be useful to an operator because this would be a hypothetical and purely speculative exercise. It is incumbent upon the operator in discussion with regulators to explain and provide supporting documentation and evidence why one or more structures should be allowed to be fallow beyond the life of a particular lease. NTL guidelines allow BOEM flexibility on regulatory interpretations on a case-by-case basis.

Large fields means greater opportunities for redevelopment.

The presence of a structure is a necessary but not sufficient condition to support redevelopment investment. Large fields typically provide the greatest opportunity for reserves growth but any field where infrastructure exists is a viable candidate for field redevelopment. The important point is that the operator makes decisions based on their knowledge of the field and the benefits/costs of investment. This is private information and not shared outside the company but could serve as the basis of negotiation with regulators to keep specific infrastructure in place for a specific period of time until well test results are known and development decisions finalized. This sort of give-and-take between operators and regulators is one of the hallmarks of GoM operations and regulatory oversight and has contributed to the longevity of field production.

Application of geophysical technology is a key factor in the life extension of mature fields.

Geophysical technology is used to identify and screen opportunities to reduce risk and increase confidence in decision making. With better information and reduced uncertainty, better decisions can be made. Technology adoption requires capital spending and there is a tradeoff between the cost of acquiring, processing and interpreting new data versus the value of the information. Tradeoffs are usually difficult to quantify.

Brownfield secondary recovery project investment requirements.

Project economics in 'brownfield' secondary recovery projects depends upon accurate risk assessment, risk mitigation strategies, and an acceptable return on investment. Progressive deployment of evolving technologies are considered key to successful development.

Deepwater structures have greater re-use potential and value than shallow water structures.

This is not a generalized statement of fact, but several factors lend credence to its credibility. Deepwater structures cost one or two orders-of-magnitude greater than shallow water structures, are located where the majority of undiscovered reserves are believed to be found in the future, and are mostly owned by companies with significant deepwater production and asset portfolios, meaning they can be more easily integrated within existing corporate networks. Shallow water fixed platforms are old, can be replaced with a few million dollars, and are generally less useful to handle new discoveries in shallow water which are likely less frequent over time.

Consequence-based criteria in platform design was adopted to save costs and increase the profitability of marginal projects in shallow water.

In the 21st edition of API RP2A a consequence based design criteria was introduced based on two classes of risk, those associated with life safety and those associated with consequences of failure. If the platform is of modest likelihood of failure and low consequence (e.g., old, unmanned, with most wells abandoned), much of the risk of holding the structure in inventory is an economic one rather than a hazard to human life or the public interest. If the platform is of modest likelihood of failure and high consequence (e.g., old, manned, no wells abandoned, no subsurface safety valves), then risk to the public increases. The strategy of inspection and financial security may play a useful role in managing inactive structures rather than requiring early abandonment.

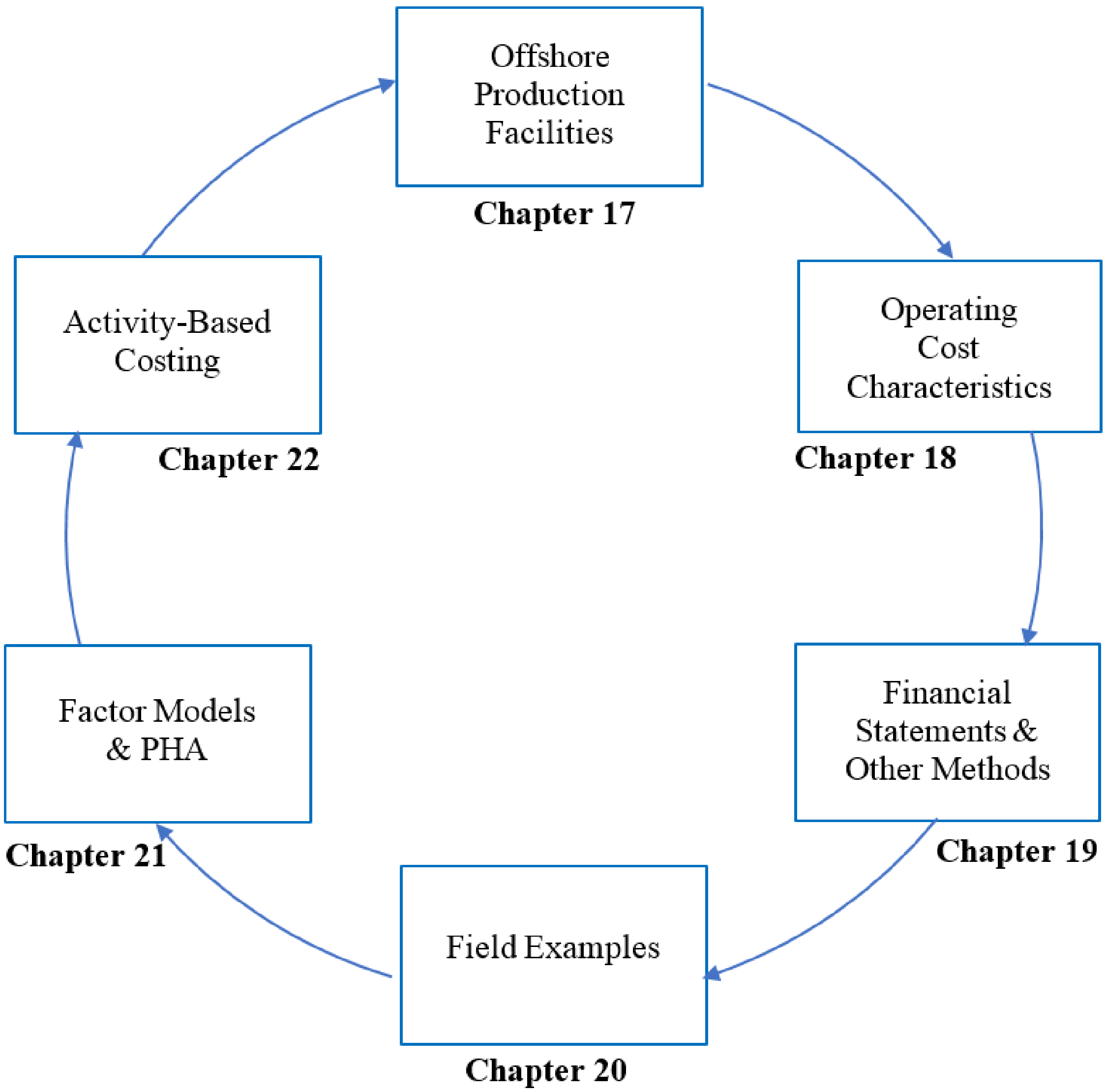
Alternatives to lease-centric regulations might benefit and/or help sustain shallow water operations by focusing on a system-wide perspective.

Field-centric regulations are used in Texas state waters and might serve to encourage system-wide perspective on development and decommissioning economics and efficiency. To a large extent, operators that have a large regional presence already capture economies of scale to reduce transportation and logistics cost and minimize overhead expenditures.

Undiscovered resources are not a good reason to maintain idle infrastructure.

According to BOEM estimates, there are 73.7 Bboe undiscovered resources believed to exist in the GoM, with about 13 Bboe expected in water depth <200 m. The use of existing shallow water infrastructure for future development will continue to occur along with the occasional new installation, but inactive structures should not be held in inventory in anticipation of application of the undiscovered resources. There is no precedent for this anywhere in the world and no evidence to suggest that the structures will be useful in future ventures.

PART 5. OPERATING COST REVIEW



CHAPTER 17. OFFSHORE PRODUCTION FACILITIES

The equipment between the wells and export pipeline or other transportation system is referred to variously as topsides and surface facility. The processes are for the most part easy-to-understand and reliable, consisting mostly of phase separation, temperature changes and pressure changes that require various tanks and vessels to perform. There are no chemical reactions to make new molecules as in refining, and because natural gas is frequently available from processing "fuel is free" which explains why fuel cost for the majority of a field's life is usually small. The purpose of this chapter is to provide a summary description of the equipment that comprise an offshore production facility. The five chapters following this chapter provide the framework to evaluate and understand offshore operating cost models and to bring together its many disparate branches.

17.1. GULF OF MEXICO OPERATIONS MARKET

Over the decade 2007-2017, the U.S. Gulf of Mexico oil and gas operations market has ranged in value between $5 to $10 billion per year (Figure Q.1). Operations includes services, maintenance, logistics, transportation, engineering and decommissioning but excludes production crew salary and workover expense which together may contribute an additional 20 to 30% of the total.

As a percent of capital spending, operations are estimated to contribute between 15 to 25% of total expenditures (Figure Q.2). Total spending includes well, subsea, EPC (Engineering Procurement Construction) and topsides equipment, reservoir and seismic, and operations.

Several consulting firms such as IHS, Wood Mackenzie, Infield, and others provide estimates on market values which vary amongst each other depending on the categories employed and methods. The methods used to derive the spending estimates are not disclosed and are probably accurate no better than +/- 40%.

17.2. OFFSHORE PRODUCTION FACILITIES

Oil and gas wells produce a mixture of hydrocarbon gas, condensate, and oil; water with dissolved minerals such as salt; other gases, including nitrogen, carbon dioxide, and possibly hydrogen sulfide; and solids, including sand from the reservoir, scale, and corrosion products from the tubing. For the oil or gas to be sold, they must be separated from the water and solids, treated, measured, and transported to their sales point.

17.2.1 Typical Oil Facility

The first processing step in an oil well is separating the gas from the liquid and the water from the oil (Figure Q.3). Because reservoir rock is largely of sedimentary origin, water was present at the time of rock genesis and therefore is trapped in the pores of the rock. Rocks deposited in lakes, rivers or estuaries have fresher water than rocks that originated in a sea or ocean. Separation is achieved in a pressure vessel using gravity and may be two-phase, separating gas from liquids, or three-phase, separating gas, oil, and water (Bothamley 2004, Deneby 2011, O'Connor et al. 1997, Thro 2007,).

Since gas takes up a much larger volume than its equivalent mass of liquid, crude oil needs to reduce its gas content before transportation, and oil pipeline owners specify a maximum vapor pressure to prevent the lighter components in the oil from flashing into gas. Reid Vapor Pressure (RVP) is a measure of volatility and is defined as the pressure at which a hydrocarbon liquid will begin to flash to vapor under specific conditions. RVP specification is typically less than 12 pounds per square inch at 100°F but for some pipelines may be as low as 8.6 psi. The process of reducing the vapor pressure in the oil to meet pipeline specifications is called stabilization and stabilized oil is also called ‘dead’ crude.

Offshore, there are two or three stages of separation per train where the gas is flashed from the liquid, reducing the vapor pressure of the oil and releasing gas, which must then be compressed back to a higher pressure and combined with the separator gas (Bothamley 2004). As additional stages are added, the horsepower required to compress the gas is lower and more stabilized oil will be produced. Adding additional stages of separation and compression will increase liquids and reduce compression horsepower, but the capital cost of equipment increases and the incremental benefits to hydrocarbon value is less, so rarely are more than three stages applied (Arnold and Stewart 2008).

No separation is perfect and there is always some water left in the oil and oil left in the water (Bommer 2016). The purpose of oil treating is to get the water out of the oil for pipeline specifications, and the purpose of water treatment is to remove the oil-in-water content for overboard discharge or reinjection. The lower the API gravity, the less efficient the separation and the more energy requirements for treatment. Heat and an electrostatic grid is normally used to promote the coalescing of water droplets. Usually, acceptable water content for pipeline specification is 0.3 to 0.5% by volume, and basic sediment, water, and other impurities (BS&W) is also specified, typically at 1% or less by volume. High water and salt content can increase corrosion problems in production equipment and export pipeline.

Heat is used to aid oil-water separation, glycol regeneration and fuel-gas superheating. Shelf facilities that produce a stabilized crude that meets pipeline specifications or receive cool production from remote wellheads require heating to attain export vapor pressure and BS&W specifications. Glycol regeneration typically requires the highest temperature at the facility at 400 °F. The main choice for process cooling are air, direct seawater, and an indirect cooling medium. Air cooling is typical on GoM platforms and some projects lift seawater for cooling purposes.

The amount of oil left in the water from a separator is normally between 100 and 2000 ppm by mass (Bothamley 2004). This oil must be removed to acceptable levels before the water can be disposed of in the sea. In the GoM, producers are limited to a maximum measurement of 42 ppm for a single sample and no more than 29 ppm average for a given month. Equipment used for produced water treating include water skimmers, plate coalesces, gas flotation devices, and hydrocyclones. A general rule-of-thumb is to use two types of water-treating equipment for a gas facility and three types for an oil facility (Bothamley 2004).

17.2.2 Typical Gas Facility

Gas treating involves separation from the liquids and compression, dehydration, removing H_2S and CO_2, and additional processes to control hydrocarbon dewpoint.

Gas wells are often high pressure at the beginning of production which must be reduced at the point the gas flows through a wellhead choke. When gas pressure is reduced the gas cools and liquids can condense and hydrates can form which plug the choke and flowlines. High pressure gas wells often require a line heater to keep the well from freezing. For subsea wells hydrate formation is often inhibited by injecting solvent such as methanol or monoethylene glycol (MEG).

A separator is used to settle liquid out from the gas. The separator pressure is set higher than the pipeline pressure so that as the gas goes through subsequent processes each with some pressure drop it arrives at the required pipeline pressure. Hot gas leaving the high pressure (HP) separator can cause process and corrosion problems with the downstream treating system, and because hot gas will carry more water vapor, dehydration systems would need to be larger and more expensive than if the gas were cooled first (Thro 2007). Thus, it is sometimes necessary to install a gas cooler downstream of the first stage separation. The cooler may be an aerial cooler or a shell-and-tube exchanger that uses seawater.

When natural gas is produced from a reservoir, it is saturated with water vapor and might contain heavy hydrocarbon compounds as well as impurities. Liquids and solids are easy to remove by screens and filters. Water vapor is reduced to prevent hydrate formation and corrosion in the pipeline. Gas that contains too much carbon dioxide (CO_2), hydrogen sulfide (H_2S), or nitrogen (N_2) must be treated. H_2S gas is highly toxic and CO_2 forms a strong acid in the pressure of water and combined they are corrosive and possibly deadly even at low concentrations. If the quantity of H_2S is significant, it must be converted to a solid or liquid sulfur compound for sale or disposal. Nitrogen is neither corrosive nor hazardous but it takes up space in the pipeline, increases handling cost, and reduces heating value. If the CO_2+N_2 content is less than 3-4% by volume, most pipelines will accept the gas and individual limits may be specified (e.g., CO_2 < 2%, N_2 < 3%). Heavy hydrocarbons are removed if in significant concentration because they lead to operational problems if they drop out in the line as liquid. For small streams of rich gas remote from processing facilities, hydrocarbon dewpoint control is necessary.

All offshore gas facilities require gas dehydration to avoid water condensing in the export pipeline which will accelerate the rate of corrosion and hydrate formation problems. A standard specification for offshore pipelines is 4 to 7 pounds per MMscf (approximately 0° to 32°F dewpoint at 1000 psi). Water is often removed with a glycol dehydration system which uses triethylene glycol (TEG) to absorb the water vapor from the gas. Wet TEG is then heated up to 400 °F to release the water and is recycled through a loop system. An alternative is to flow wet gas into the pipeline and to add a sufficient amount of inhibitor (e.g., methanol) to prevent hydrate formation. Typical temperature requirements for gas export range from 120-140 °F.

Stabilization removes the light hydrocarbons from the liquid stream, either by reducing the pressure and letting the lighter components flash, or by a combination of pressure reduction and heating. The resulting condensate has a low vapor pressure which can be stored in tanks without excessive vapor venting or reinjected back into either the liquids or gas export line.

The vast majority of gas production in the GoM is processed at onshore gas plants and fractionators and recovery of liquid hydrocarbons at offshore facilities in the form of natural gas liquids (NGLs) is not common and only performed if necessary to meet pipeline specifications on heat content or vapor pressure or if a C4/C5 fuel is required at site (Bothamley 2004, Thro 2007). If required, lean-oil absorption, refrigeration or turbo-expander plants are employed.

Gas streams that exit stabilization and other processes are often at lower pressure than the main gas stream and must be compressed so they can be processed with the rest of the gas. Compression may also be required to inject into the export line at the pipeline pressure and export gas from other facilities that cross the platform often need compression to make it to shore.

17.3. EXPORT REQUIREMENTS

17.3.1 Oil Export Pipeline

Oil export pipelines in the GoM generally transport "spec" crude; i.e., RVP < 12 psi, BS&W < 1% vol, T < 140 °F, directly to refineries along the Gulf Coast region (Table Q.1). Because of the low vapor pressure crude spec, only very small amounts of butane or lighter material can exist in the stabilized crude product.

Sulfur content refers to the amount of sulfur and sulfur compounds present expressed as a percentage by weight. Oil pipelines usually specify sulfur not greater than 0.5% by weight. Oil high in sulfur and resin are usually of low viscosity and vice versa. To facilitate the flow of crude oil in pipelines, heating, chemical treatment, and mixing with lighter oil and condensate are common methods to improve viscosity. Light oil with high volatility is more likely to gasify during transportation which can cause damage to the pipeline system (e.g. gas etching).

17.3.2 Gas Export Pipeline

Gas export pipelines may operate in low-pressure multiphase, moderate pressure single-phase, or high-pressure dense phase. Gas export pipeline systems in the GoM generally transport dehydrated but hydrocarbon wet gas to onshore gas plants for additional processing and NGL recovery.

Gas pipelines generally require water content <7 lbs/MMscf (shelf) and 2-4 lbs/MMscf (deepwater) depending upon contract requirements or hydrate avoidance requirements (Table Q.2). CO_2 specification is usually not greater than 3% by volume. Hydrogen sulfide specifications typically range between ¼ to 1 grain per 100 scf (100 scf is sometimes abbreviated Ccf), where ¼ grain corresponds to 4 ppm, so the H_2S specification is equivalent to 4 to 16 ppm per Ccf. Heating value may be bounded by loose (e.g., 980 – 1400 Btu/cf) or tight constraints (e.g., 1000 – 1075 Btu/cf) depending on system configuration.

CHAPTER 18. OPERATING COST CHARACTERISTICS

There are many factors that impact operating cost and they frequently overlap and change over time with different factors important at different times in a field's life. Unlike capital expenditures, operating cost are much less transparent which complicates assessment and interpretation. The general direction in which factors impact cost are usually intuitive but it is the identification of factors and their relative combination which makes evaluation difficult. This combination of multiple interacting, dynamic and unobservable conditions is the main reason simple explanations are rarely successful in prediction. The chapter begins with basic terminology and important cost characteristics are distinguished, including fixed and variable costs, direct and indirect costs, unit and life-cycle cost, and marginal cost. Rules-of-thumb and a comparison between oil and gas and mining operations describe typical cost ranges. The chapter concludes with a general description of operating cost factors.

18.1. COST CHARACTERISTICS

18.1.1. Fixed Costs versus Variable Costs

One way to view costs is to categorize them based on their behavior and how a given cost will respond as a level of activity changes. In the oil and gas industry, the most common measures of activity are production and number of producing wells. As the level of production changes, some costs in total will not change (fixed costs), or not change much, while other costs will change proportionally or nearly so as the level of activity changes (variable costs). Cost that remain fixed with respect to activity levels are called fixed and costs that change are referred to as variable cost.

An offshore worker's salary is an example of a fixed cost. Assuming the production worker salary is $100,000 per year, the company will pay the $100,000 regardless of how much the platform where the worker is assigned is producing. For a four-man production crew, the total cost for the crew will be fixed at $400,000 per year (ignoring inflationary changes and potential raises), and as production at the facility declines the crew cost per barrel oil produced will increase. For example, if the platform produces 200,000 barrels during the year, then the cost per barrel for the production crew is $2/bbl, but when production declines to 50,000 barrels the crew cost is $8/bbl.

The behavior of variable cost differs from that of a fixed cost. Whereas the total cost of a fixed cost will remain constant regardless of production, the total cost of a variable cost will change as the level of activity changes, increasing with increasing activity and vice versa. In other words, the total cost varies depending upon the level of activity. Chemical cost for treating produced water and hydrate control are examples of a variable cost. If a structure does not produce, the total chemical cost will be zero, but as the production rate increases, the total chemical cost will typically increase because treatment is volume based. Black oil reservoirs are typically supported by water drive and water cuts typically increase as production declines, necessitating greater chemical usage with total fluids produced as a field matures. Not all chemical costs are variable, however, and to complicate matters further, chemical costs depend upon market conditions and have their own level of variability and consumption rates depend upon other factors such as operator preferences and design considerations.

18.1.2. Direct versus Indirect Cost

Another way to categorize cost is based upon their connection to an activity, product or department within an organization. Two categories are used to describe costs based on traceability, direct and indirect (Seba 2003). A cost that can be traced directly to an activity, product or department is referred to as a direct cost. A cost that requires some method of assigning it to an activity, product or department is referred to as an indirect cost.

For example, consider a production crew housed at a complex and responsible not only for operations at the complex but also at three other (unmanned) platforms in the region. Various members of the crew visit and work on each of the platforms on a semi-regular and as-needed basis. At the end of the year the operator wants to know the labor and transport cost it took to maintain the unmanned facilities. Some method of allocation is required.

If the worker and flight hours at each platform are recorded, then it is an easy matter to assign labor and transport cost to the individual platforms, but if this data was no recorded or transmitted to the accounting department then the operator has a choice on how it assigns crew salary and logistics. Possible methods could be based on production levels at each platform or a simple uniform method could be applied. For the transport cost, distance is a good proxy for flight hours and the total number of visits per platform could be used in allocation. The main point is that regardless of the method, the crew salary and transport cost at the unmanned platforms is an indirect cost because the cost is assigned to each structure.

18.1.3. Operating Cost versus Capital Expenditures

Capital expenditures (CAPEX) represent the investment required to design, construct and commission the hardware for field development, and include the wells, platforms, facilities, equipment, pipelines, and everything else with a lifetime greater than one year. CAPEX is typically defined as those items whose useful life exceeds one year, and as such, U.S. tax regulations require each item be depreciated on a specific schedule when computing net income (Gallun et al. 2001). Operating expenditures (OPEX), also referred to as lease operating expenses (LOE), lifting cost or production cost, represent items whose useful life is one year or less and cost are expensed for accounts.

Unlike the capital expenditures required to drill a well, build a platform, equip facilities, construct and install pipeline, etc., operating cost is much less transparent with no readily available and reliable public data sources. The data that is available comes in different forms and quality and varies widely across field applications. Inferences are required and site-specific attributes need to be accounted for, most of which are not observable or known to outside analyst and can only be inferred with a high degree of uncertainty. Various organizations provide operating cost estimates but these are of variable quality and usually do not describe the source data or methods in detail. The UK North Sea is a notable exception and provides the best and most transparent offshore operating cost data in the world.

For offshore development, the majority of capital expenditures occur ‘upfront’ in the exploration and development stage, whereas operating costs start at first production and run through the life-cycle of the field. It has often been suggested that over the lifetime of an offshore field, the total undiscounted OPEX will exceed the total undiscounted CAPEX, and although this certainly seems reasonable empirical evidence has never been presented. More importantly, because OPEX occurs over a long period of time compared to CAPEX, its impact to profitability is usually less significant than the schedule and cost overruns that impact CAPEX and the changes in commodity prices that occur over the life of the asset.

Example. UK North Sea cost expenditures, 1970-2015

The most reliable regional expenditure description in the world is the UK North Sea because the regulator and producers cooperate on annual surveys of capital and operating expenditures (Oil and Gas Authority 2017). In Figure R.1, the total expenditures for exploration and appraisal cost, development cost, operating costs and decommissioning cost is presented in 2015 pounds. The data presented does not involve significant estimation procedures or other algorithms to infer cost. ■

18.1.4. Unit Operating Cost vs. Life-cycle Cost

Unit operating cost (UOC) is calculated as the ratio of operating cost divided by total production at a specific point in time. Usually, the time period is on an annual basis, but if the entire life-cycle of the field is considered then the unit cost is referred to as life-cycle cost (LCC) or average cost. Crude oil, natural gas liquids and natural gas are often added arithmetically to provide an oil-equivalent or gas-equivalent volume. The UOC formula is as follows:

$$\text{UOC (\$/boe)} = \frac{\text{Annual OPEX(\$)}}{\text{Annual Production (boe)}}$$

LCC is integrated over time and smooths out the annual variations and time trends present in UOC. Life-cycle cost refers to the average operating cost (undiscounted) over the life of the field, computed as total operating cost divided by total production:

$$\text{LCC (\$/boe)} = \frac{\text{Total OPEX(\$)}}{\text{Total Production (boe)}}$$

Unit operating cost often follow a ‘bathtub shape curve’ reminiscent of the hazard functions[28] in reliability theory, where high initial rates of failure are followed by a stable constant failure rate period and increasing failure rates with wear and tear on the equipment (Figure R.2). Operating cost are not the same as a piece of equipment since it is composed of many different components and processes, not only equipment, but wells, reservoirs, fluids, weather conditions, etc. However, with this being said, the analogy his useful since operating cost are expected to be high initially as production systems are brought on line and problems are fixed, quickly followed by low and relatively stable UOC during and after peak production, and finally increasing towards the end of plateau and the beginning of decline. If additional production is added to a structure from sidetracking or a tie-back, then unit cost may fall from previous levels.

The older an offshore asset, the more expensive it is to run due to increased maintenance if all other factors are held constant. However, if the infrastructure can be shared as part of regional operations or operating cost can be shared with other companies or if new wells add to production, operating cost may stabilize for a period of time. Operators actively look for ways to reduce cost during high cost and low price periods. There is no clear cut relationship between the age of infrastructure and its unit operating cost because of these and other factors.

[28] The origins of hazard curves are unclear but Klutke et al. (2003) traced it back as early as 1693 where it appears in actuarial tables.

Example. GoM shelf asset unit and life-cycle cost

One of the few examples of capital and operating expenses for a GoM development found in the literature was described by Dickens and Lohrenz (1996). In 1960, a shallow water lease block was acquired for $2.5 million, and after spending about $5 million on exploratory drilling and assessment, the operator believed that a commercial deposit existed (Table R.1). The operator spent $44.5 million from 1964 through 1966 to develop the field and in 1965 first year production totaled 900,000 bbl and peaked at 6.7 MMbbl in 1969 (Figure R.3). In 1974, production began to decline and the operator spent $4.1 million in 1980-1981 on capital improvements in an attempt to slow the decline, but abandonment came in 1987 and cost $5.2 million.

The field produced 69 MMbbl oil and generated $417 million (undiscounted) gross revenue. Unit operating cost ranged from less than $2/bbl up to $15/bbl over the lifecycle of production. Total capital cost was $57 million and total (undiscounted) operating cost was $83 million, yielding an average life-cycle development and production cost of $0.83/bbl and $1.21/bbl, respectively. ■

Example. GoM deepwater average production cost

The life-cycle operating cost for three deepwater fields in the GoM was estimated by consulting firm IHS using Questar software (Figure R.4). Average field life operating cost for Lucius (spar), Big Foot (ETLP), and Jack/St Malo (semi) was estimated at $9/boe, $11/boe, and $17/boe, respectively (IHS Global 2015). Costs include labor, inspection and maintenance, logistics, chemicals, wells, insurance, and transportation. ■

18.1.5. Marginal Revenue vs. Marginal Cost

The profitability of an offshore development is comprised of the aggregate production associated with all the individual wells and structures in the field. To understand field operations and to improve performance, aggregate (field) production data and aggregate (field) operating cost will not yield an accurate assessment, since it is necessary to account for cost at the well and structure level and to identify the types of cost involved (Doering 1993). For example, a well with a high variable cost might be a candidate for closure, but closing a well with high fixed cost can decrease the profitability of other wells in the field that must absorb the additional fixed cost. There are complex tradeoffs that require granular analysis.

Maximum production does not guarantee maximum profit. High water-cut wells frequently need to be shut-in to reduce treatment and compression cost to improve financial performance. It is the marginal revenue and marginal cost that are important in decision making, but these are often difficult for operators to compute. For mature properties (e.g., when water cuts approach 90% or more) a sustained focus on cost is necessary to stay profitable, and when producing from an integrated system of infrastructure success depends on precise and clear knowledge of cost.

18.2. RULES-OF-THUMB

18.2.1 Rules-of-Thumb Should Be Avoided

The first rule-of-thumb is that rules-of-thumb should be avoided. Although rules-of-thumb are useful to guide design and decision-making, technology and best practices change and markets evolve over time, and site- and region-specific conditions are usually highly variable and need to be understood to inform discussion. Within companies, rules-of-thumb develop over years of experience and these are often supported with empirical evidence which may or may not apply to a particular facility because of some specific characteristic of the facility. Unlike development and equipment costs which can be decomposed and estimated accurately, operating cost depend upon site-specific conditions that can vary widely across many dimensions. Individual variation across properties is wide and general/generic bounds provided by rules-of-thumb should only be used as a last resort and if no other information is available.

18.2.2 Comparison to Commodity Price

Crude oil and natural gas are fluids which flow from the reservoir through tubing and pipe and are processed using equipment driven in large part by the hydrocarbon streams generated at site. Because oil and natural gas are also highly valued in the market, operating costs per barrel (or cubic foot) is much less than the price of the commodity being sold, usually ranging from <5% to 20% of the commodity price throughout its lifetime. Near the end of field life, operating cost increases to the upper part of this range and may extend beyond and is one of the clearest signs of the marginal nature of operations.

18.2.3 Cost Component Range

For offshore GoM operations, personnel and logistics typically represent 40-50% of operating costs, with repairs and maintenance the second largest category between 10-40% of total cost, and chemicals and workovers 10-20% (Figure R.5). Insurance, if an operator opts for coverage, usually will not exceed 5-10% of direct LOE, and gathering and transportation expenses are also usually no more than 5-10% direct LOE. Third-party processing fees apply to well owners that do not have a working interest in a processing platform and pay fees for access, often between 20-50% of total cost.

As properties age, they generally require more workovers and chemical cost may increase, but labor cost is mostly fixed, while transportation cost and insurance will fluctuate with market and environmental conditions and can increase or decrease on a short-term basis (Table R.2). Workovers are largely discretionary and operators typically plan for a workover when they wish to accelerate or enhance production, which usually occurs when commodity prices rise. Insurance is discretionary for large operators who self-insure with mid- to small-size operators the primary players paying for coverage. Gathering and transportation fees are volume-based and may increase or decrease with time. If a hurricane enters the GoM and damages infrastructure, operators without insurance will see a larger cost in cleanup and repair cost relative to operators with insurance cost.

18.2.4 Regional Cost Comparison

Various organizations have prepared operating cost estimates as shown in Figure R.6 by Deutsche Bank, Figure R.7 by Booz Allen Hamilton, and more recently, Figure R.8 by Wood MacKenzie. In Figure R.6, operating cost plus royalties per barrel are depicted by country in 2009 dollars and range from <$2/bbl in UAE, Kuwait, and Saudi Arabia, up to about $10/bbl for the GoM and $15/bbl for China and the UK. In Figure R.7, analysts assumed a 10% return for conventional and 13% return for unconventional technologies after severance and production taxes, and assume average costs. In Figure R.8, the UK North Sea data is from the UK Oil & Gas Authority survey and baselines the other offshore regions.

Regional comparisons give a sense of the different ranges of cost involved per basin/region but need to be interpreted with an understanding of the source data and the uncertainty and variability involved, since most organizations do not normally specify their data sources, methodology, uncertainty, or limitations of analysis. The best aspect of these graphs are their ability to consolidate and present at a glance a large amount of information, but the reader should understand that the graphs – while not hypothetical – are also usually not empirically derived and should not be considered at the same level of accuracy of cost accounting. Error/uncertainty bars across each country are expected to be of the same magnitude or larger than the average data reported.

18.2.5 Comparison to Mining

Mining operations provide a useful point of comparison to conventional oil and gas wells. In mining operations such as coal and oil sands, operating cost usually range from 40 to 50% or more of the commodity sales price and then increase after the cut-off reserves threshold is achieved.

Mining operations are labor and equipment intensive as anyone visiting a mining operation knows. Large amounts of dirt/rock must be moved and processed over a large geographic area which is energy intensive, and all mechanical things and moving equipment (trucks, conveyor belts, grinders, etc.) require large numbers of operators and breakdown with use and require frequent repair and/or replacement because of the abrasive nature of solids and the requirements of processing (Hustrulid and Kuchta 2006).

Each truck requires an operator and a repair crew for the fleet and additional personnel are required for surveying, drilling, blasting, processing, and refining. Overburden must be removed to access the reserves unless underground entry is made which is even more expensive to provide safe access and operating conditions, ventilation, equipment and material transfer (Hartman and Mutmansky 2002). Rock is physically extracted and crushed and minerals separated using energy-intensive and chemical methods with waste streams collected in pits which may require remediation. All energy for operational activity must be imported.

Oil and gas by comparison use wells to make contact with reservoir sands and the fluids flow from the reservoir into the wellbores to a central facility for processing and export to market. No rock is removed except in drilling. Flowing fluids are significantly easier to process, handle, and transport than solids. Changes in temperature and pressure between the well and surface facilities are used for processing and provide a significant percentage of the energy[29] needed, and only near the end of primary production, where the reservoir energy has been 'used up', do operating cost start to increase. At the end of life of most offshore operations, unit production cost would still be cheaper than most initial mining operations.

18.2.6 Apply Cost Indices Cautiously

How does production cost for an offshore facility or region change over time? For a facility, the answer needs to be gathered from operator data, while on a regional basis cost indices are a common approach. Can an inflationary index reliably capture changes in operating cost at a property/field or regional level? Caution should always be exercised when applying cost indices to adjust or otherwise normalize operating cost data.

No evidence has ever been reported that shows inflationary indices are useful for LOE adjustment or that they accurately reflect changes that occur, except for specific cost categories such as

[29] As a percentage of energy consumed vs. exported, BP reported GoM shelf operations at 2-3% and deepwater GoM operations at 1-2% (Edwards 2004).

chemicals that usually only contribute a small proportion of the total cost of LOE. The manner in which specific categories of cost change provides important clues to what cost indices can accomplish. LOE may increase, decrease, or stay the same from year-to-year depending on the decisions of the operator and behavior of cost components. The age of an item is a proxy for the wear and tear that occurs on equipment and structures or declining production levels associated with wells. The age of infrastructure, market changes, and operator reaction impact the individual components of operating cost in different ways confounding the ability of a cost index to reliably reflect.

18.3. Operating Cost Factors

Offshore structures were categorized in Part 1 according to structure type, manned status, number of wells, water depth, complex association, production type, and well type. All of these factors play a role in the economic limits computed in Chapters 8-10 and are also important in operating cost considerations. In this section we enumerate additional factors to provide a more detailed and nuanced view. The direction in which factors impact cost are easy to understand qualitatively (Figure R.9), but the relative impacts and data needed to quantify and generalize the relationships are much more complicated.

18.3.1 Labor

The number of personnel required for offshore operations represents a significant fixed cost associated with offshore production and influence many other cost components. Once staffing requirements are defined, other associated costs such as personnel logistics and catering can be estimated. To determine labor costs, staffing and job classification levels need to be defined. Personnel may be organized into different groups such as field management, production crew, multi-skill personnel such as mechanics and electricians, roustabouts, housekeeping and catering personnel (Steube and Albaugh 1999). In the GoM, catering services that provide housekeeping and food is usually quoted on a dollar per person per day basis. Contracts on a cost plus basis may also be used.

All deepwater producing facilities in the GoM are manned 24 hours a day while about one-third of shallow water structures circa 2018 are continuously manned. In shallow water, a manned facility is often responsible for several facilities in the area, but in deepwater crews are generally responsible for just one facility. If a manned platform and crew are responsible for other facilities, the labor cost for the other platforms that are serviced are allocated according to man hours at site or similar metric.

Example. Deepwater bed count

For the largest deepwater floaters in the GoM bed counts range from 150 to 200, while for smaller floaters without drilling capacity bed counts range from 20 to 40. For example, Thunder Horse, Perdido and Mad Dog report quarters of 186, 170, and 150, respectively, whereas Boomvang, Devils Tower, and Lucius report bed counts of 20, 26, and 44 (Figure R.10). ■

18.3.2 Dry vs. Wet Trees

Dry tree and wet tree wells have significantly different operating cost. Dry tree wells are produced from lines tied back to the rig floor, whereas subsea wells are frequently tied into a manifold and is connected to the production facility by a riser. Wet wellheads are located on the seabed and are more expensive to operate, more expensive to maintain, more expensive to repair, and more expensive to abandon than dry tree wells. Record water depths and tieback distances for subsea wells circa 2017 are shown in Table R.3. Flow assurance requires energy or chemicals or both and regular pigging operations (Bai and Bai 2012). Harsh operating environments, long tieback distances, and low product quality will result in high operating cost. Subsea processing technologies are still in their infancy (Kondapi et al. 2017) and thus production needs to be sent to a host facility for processing prior to injection into an export line.

Subsea processing is an emerging technology that treats produced fluids at or below the seabed to improve recovery rates. Subsea processing technologies include multiphase pumping, subsea separation, gas compression, and seawater injection. Circa 2017, there were only 25 subsea boosting systems and six subsea separation systems installed or awarded worldwide. In the GoM, Perdido employs a subsea separation system, and Cascade, Chinook, Stones, and Julia host subsea boosting. On the King development, the subsea boosting system is no longer operational.

For platform (dry tree) wells, well intervention is normally straightforward and cheap. If the intervention can be performed without a rig (rigless), costs are reduced further and interruptions to drilling schedules avoided. Subsea well interventions on the other hand are rarely easy or cheap and carries significant risk. They require mobilization of a rig or multipurpose service vessel which have high day rates and significant lead time for equipment and planning is required. If a subsea well fails it may be shut-in for a long period of time and as a result there tend to be fewer well interventions on subsea wells.

18.3.3 Flow Assurance

Flow assurance issues are generally not a concern with shallow water and with dry tree or direct vertical access wells, but are primary problems in deepwater development and subsea systems (Jamaluddin et al. 2002). Wax, asphaltenes and hydrates in the hydrocarbon streams have the potential to disrupt production due to deposition in the production system (Figure R.11). Hydrates are the most common problem facing all developers (Cochran 2003). Hydrocarbon solids have the potential to deposit anywhere from the near wellbore and perforations to the flowline, topsides surface facilities and export pipeline. Pigging is a common procedure to remove build-up in pipelines (Figure R.12) but flow assurance issues governing design are more complex as illustrated with two examples.

Example. Gemini hydrate management strategy

The Gemini field is located in Mississippi Canyon 292 in 3400 ft water depth and is tied back 27.5 miles to the Viosca Knoll 900 platform. The initial development consists of three subsea wells tied into a 4-slot cluster manifold connected together via a pigging loop (Figure R.13). Dual 12-inch uninsulated flowlines transport the produced fluids to the host platform. Gemini's fluid consist of 96% methane with 3.5% light ends (C_2–C_5) and 1.5% of C_{6+} fraction. The condensate to gas ratio was predicted to be about 16 bbl/MMcf and peak production rates of 80 MMcf/d were expected per well.

Reservoir modeling predicted limited water production throughout field life and continuous methanol injection was selected to control hydrate formation (Kashou et al. 2001). Both flowlines enter the hydrate formation region less than 1000 feet from the manifold and remain in the hydrate region for the next 27.5 miles (Figure R.14). Low operating temperatures, high operating pressures, the long tieback and presence of water create a high risk environment for hydrate plug formation. ■

Example. 'Wax-on, wax off' strategy at Coulomb

The Coulomb field is a gas/condensate development in 7500 ft water depth tied back to the Na Kika semisubmersible via a single 27-mile, 8-inch flowline (Manfield et al. 2007). MEG is injected at the tubing head of each well to provide continuous hydrate inhibition so that solids accumulation would not constrain production. The MEG/condensate ratio for the two wells were 1:55 and 1:230 and describe MEG usage requirements.

The two wells produce fluids with significantly different condensate-gas ratios, 65 bbl/MMcf and 200 bbl/MMcf, and fluids from one well were significantly waxier than the design basis and caused the well to be temporarily shut-in shortly after first production due to a rapid increase in pressure drop in the flowline. The deterioration in flowline performance was believed to be due to accumulation of a highly viscous material, either a wax/glycol/condensate emulsion or a wax slurry. Engineers determined that burying the flowline 6 to 8 ft with backfill would improve heat retention and mitigate the phenomenon.

The flowline burial operation was executed over several days while one well was flowing. After completion of the first burial pass operators reported a rapid change in the measured pressure drop across the line, and within hours a large slug of liquid and wax began to arrive at the platform. Approximately 3000 bbl of liquid inventory was unloaded from the flowline after burial, about 40% of the total volume of the line. Prior to burial, well C-2 was producing at 68 MMcf/d and the flowline pressure drop ΔP was 3900 psi. After burial, well C-2 production reached 102 MMcf/d with ΔP of 2700 psi. The C-3 well was returned to production and achieved 110 MMcf/d. ■

18.3.4 Well Configuration

GoM wells on the continental shelf are predominately low angle dry tree directional wells that are generally cased and perforated. Deepwater wells are a combination of dry tree, direct vertical access and subsea wells. Deepwater wells are a mixture of moderate to high angle wells, most with open holes gravel packs and open hole frac packs, a completion technique that merges hydraulic fracturing and gravel packing. Unconsolidated sands require sand control, and in the deepwater GoM, frac packing is the most common completion technique, followed by high-rate water pack and openhole gravel pack (Weirich et al. 2013).

A larger percentage of dry tree wells will be high angle wells with longer completion intervals than subsea wells which are likely to be near vertical with shorter step cuts. Single completion shallow depth wells that are near vertical allow for relatively simple wireline operations, but deep boreholes with multiple completions and deviated or complex boreholes are more complicated to re-enter and perform remediation efforts. Workover and repair cost on complex well configurations are expected to be more expensive than on simple wells for all other things equal.

18.3.5 Old vs. New

New wells have higher production and lower unit cost, less problems after start-up, and fewer repairs and maintenance compared to old wells. For all things equal, older structures will require greater repair and maintenance cost than younger structures. Offshore, platform space and load capacity represent restrictions, and so low cost operating and maintenance options for mature field production may not be as viable as onshore. For example, in mature oil fields, increasing volumes of produced water may restrict production because of equipment capacity limitations. In some cases, the operating cost of large processing facilities may simply be too much to be carried by production from a smaller field.

18.3.6 Materials and Supplies

Materials and supplies are an important component of operating cost and depend on product type (oil, gas, condensate) and quality (e.g., sour, paraffinic, corrosive, water cut) of production. The cost to handle produced water and the scale and corrosion that results typically increases over field life (Cavaliaro et al. 2016). When seawater for injection is mixed with fresher aquifer water scale may develop which will require inhibitor to manage. Gas compression is typically required on mature properties which require a prime driver (e.g., diesel engine, gas turbine) and a fuel source, and if adequate space is not available, a new platform structure. The prime driver, being equipment and long-lasting is depreciated, while the fuel source, if gas is produced at site, is free. If fuel has to be transported and stored at site or on a nearby lease, operating cost will increase.

Example. Eugene Island 11 complex upgrade

The Eugene Island 11 platform was designed with a capacity of 500 MMcfd and 6000 bopd to service production from five Dutch field wells in federal waters and five Mary Rose field wells in Louisiana state waters (Steube 2000). In September 2010, Contango installed a companion platform (Figure R.15) and two pipelines to access alternative markets to enhance economics, either the Eugene Island 63 platform and then onward to shore via an ANR pipeline or to the American Midstream pipeline. In July 2014, Contango reported investing $12 million to build and install a turbine type compressor to serve all ten Dutch and Mary Rose wells.

18.3.7 Development Tradeoffs

Development tradeoffs are important to recognize since they impact operating cost on an as-built basis. There are always tradeoffs between capital and operating expense that engineers make in design but are unusually hard to disentangle after development is complete. At the design stage, these tradeoffs can have a large impact on where and how cost are allocated over the lifecycle of production, and so comparisons between developments need to be made carefully since not all factors will be observable.

The selection of dry trees vs wet trees, for example, will have a significant impact on future operating costs, but the manner flow assurance is designed is more subtle. In systems with gas and condensate or oil and gas, hydrates often form as free particles and then aggregate. Prevention of hydrate can be undertaken by using insulation or heating to maintain temperature high enough to operate within the hydrate-free zone, a high capital low operating cost option, or MEG may be continuously employed, a low capital high operating cost option.

Example. Ukpokiti operating strategies

Conoco's first offshore development in Nigeria was the Ukpokiti field developed using a converted FPSO designed to process 20,000 bopd, 40,000 bbl/d water injection, 25 MMcfd produced gas, and 14,000 bbl/d of produced water. Four operating strategies were considered in development selection (Table R.4). Each strategy had a specific objective and a rationale was developed to support each objective. For example, strategy B's objective was to balance downtime risk and volume while managing market value. Strategy C was eliminated due to the risk of increased downtime and strategy D, in which Conoco shared logistical support services for personnel and materials with another operator located 16 miles away (CanOxy at the Ejulebe field), was eventually selected over strategy B. ■

18.3.8 Produced Water

As reservoirs mature, especially if secondary recovery methods are used, the quantity of water increases and often exceed the volume of the hydrocarbons before wells are shut-in. Initially, water represents a small percentage of produced fluids, but over the life of the well the water-to-hydrocarbon ratio increases. The cost of producing, handling and disposing of the produced water defines the economic life of some fields.

Most offshore platforms dispose of produced water directly into the ocean but have to meet stringent regulations on the entrained and dissolved oil and other chemicals in the produced water. The wide variation in the concentration and type of constituents sometimes make produced water challenging to treat and discharge (Usher et al. 2015). The physical and chemical properties of produced water vary depending on the geographic location of the field, the geologic formation, and the type of hydrocarbon produced (Veil and Clark 2011). The major constituents of concern are salt content (expressed as salinity, conductivity, or total dissolved solids), oil and grease (various organic compounds captured through an n-hexane extraction procedure), inorganic and organic compounds introduced as chemical additives to improve drilling and production operations, and naturally occurring radioactive material. In the GoM, produced water discharge specifications are based on oil content of 29 parts per million (ppm). Some deepwater GoM operators self-impose more stringent discharge requirements of 10 ppm to safeguard against oil sheen in the overboard discharge (Wiggett 2014).

Changes in produced water due to pressure and temperature changes that occur from producing oil and gas can have serious impacts through precipitation of scales and corrosion which must be treated and mitigated (Jordan and Feasey 2008). The main detrimental effects encountered during handling are deposition of insoluble scales and corrosion of metal surfaces, which may lead to leaks and costly repairs if not inhibited and monitored. Inhibition of most scales is through application of organic compounds which act to poison (prevent) the growth sites of the crystals. Corrosion mitigation typically takes investment in corrosion-resistant alloys and/or a chemical corrosion-inhibition/monitoring program.

18.3.9 Water Injection

Water may be injected into oil reservoirs to supplement recovery. Water will generally require treatment and the type of treatment and cost depends on the source and issues identified. If operators inject water into reservoirs to maintain pressure, they typically use seawater with some chemicals since this is the lowest cost option (McClure 1982). In some cases, subsurface water may be processed if seawater causes injection problems (Ogletree and Overly 1977). To inject produced water, suspended solids and oil must be removed to an appropriate degree to avoid plugging and other precautions taken to avoid fouling the reservoir. Between 5 to 10% of the produced water in the GoM is injected for pressure maintenance (Veil and Clark 2011).

The operational requirements for seawater injection generally require filtration, de-oxygenation, and corrosion control. The details of the treatment steps are specific to each project. For example, some projects may require injected water to be filtered to 1 micron (1 μm) while other systems may require 10 μm. Deoxygenation in some systems may be achieved by chemical addition, other systems may require gas stripping and chemical treatment, and each process will have its own capital and operating cost requirement.

18.3.10 Gas Injection

Gas can be injected into reservoirs to supplement recovery by maintaining reservoir pressure or as a means of disposing of gas which cannot be flared. Generally, there is no need to control hydrocarbon dew point as in export gas since injected gas will get hotter not cooler, but it may be attractive to remove heavy hydrocarbons for economic reasons (Jahn et al. 2008). Dehydration is always required to avoid water dropout and corrosion problems. Gas injection is rarely used in the GoM except to enhance oil recovery in a few reservoirs since an extensive pipeline network exists for industrial and consumer use, and offshore gas is always in demand as a fuel source and for gas lift operations.

18.3.11 Artificial Lift

The most common types of artificial lift for offshore oil production in the GoM are gas lift and downhole pumping. In gas lift systems, gas is injected directly into the wellbore to lower the hydrostatic head. Gas compression depends on the source pressure, and since gas lift is essentially a closed-loop system except at start-up where another source of gas (e.g., nitrogen) may be required, little gas is consumed in operations. For downhole pumping power generation is required to drive the electric pumps.

18.3.12 Well Intervention

Well interventions (aka workovers) are performed throughout the life of a well to protect value (e.g., by repairing or preventing corrosion or scale, maintaining gas lift systems) or to create value (e.g., shutting off water or adding gas lift to accelerate production), and are a primary means of protecting or increasing reserves and production. There is a wide variation among operators on their production surveillance and the frequency of intervention is dependent on many factors – well vintage, production type, well type, operations policies, production level, oil and gas prices, corporate budget, etc. Some operations apply sophisticated methods in evaluation, others use simple well reviews. The best stimulation candidates with the greatest business value are usually high production, high recovery wells.

18.3.13 Work Priority and Operating Budget

During production, the surface facilities are managed to maximize system capacity and availability. There are many pieces of equipment involved in separation and treatment and the equipment is monitored for performance and periodically inspected and tested. The production crew is responsible to monitor well constraints which may limit the reservoir potential and remediation options. If the cost of action is significant (e.g., sidetrack), an economic evaluation may be performed; otherwise, these activities are part of the annual operating budget and are prioritized. If the operating budget for the year does not allow all activities to be performed they are postponed. Since the properties of the reservoir and produced fluids change over the life of the field (e.g., pressure, temperature, composition), the feed conditions change and need to be properly managed to optimize performance. De-bottlenecking is performed to maximize production. Equipment needs to be periodically inspected for corrosion, wear, etc. and may need to be tested.

18.3.14 Market Conditions

GoM offshore markets are epitomized by supply and demand and these conditions are often proxied by oil and gas prices. When oil and gas prices are high, demand for services, chemicals, service boats, etc. are usually high, which places upward pressure on dayrates and chemical prices. Similarly, when oil and gas prices are low (weak markets), prices for services and chemicals are reduced. Operators continually make operational decisions on workover and maintenance schedules, insurance requirements, shut-in, etc. in response to the changes which will impact LOE.

18.3.15 Equipment Maintenance and Maintenance Budget

Maintenance refers to how the equipment is maintained to ensure that it is capable of performing the tasks for which it was designed. Since mechanical performance deteriorates with use due to normal wear and tear, corrosion, vibration, contamination, etc. which may lead to failure and safety issues, the maintenance department plays an important role to achieve production objectives. Maintenance strategy may be proactive or reactive and maintenance budgets will vary with the annual operating budget. Different equipment will be maintained in different ways depending on their criticality and failure mode (Logan et al. 1984). Preventative maintenance work is usually based on a schedule of planning cycles within the year. Non-planned work includes all maintenance jobs that are not from the planned maintenance system.

CHAPTER 19. FINANCIAL STATEMENTS & OTHER METHODS

Public oil and gas companies listed on U.S. stock exchanges are required to disclose operating expense in their financial statements, but because cost data are consolidated over many different assets and broad geographic regions, its ability to inform operating cost in a specific region, field or asset is limited except in special circumstances. We examine the operating cost of ten public oil and gas companies with the majority of their production and reserves in the GoM to avoid some of these limitations. The strengths and weaknesses of lease operating statements, surveys, software tools and computer methods are also reviewed. The UK North Sea operating cost survey is the best publicly available offshore data in the world and main results are highlighted.

19.1. FINANCIAL STATEMENTS

Companies maintain detailed production cost for their properties but this information is not reported unless required by regulation. The amount and quality of operating cost data available for analysis is therefore tightly constrained and many misconceptions may arise from the lack of transparency and misunderstanding operational requirements. As a corollary, it is fair to say that many companies do not understand the value of their operating cost data nor the manner in which it can be utilized to improve operations, both because of its opaque connection with accounting and financial departments, as well as the difficulty to organize and interpret the information in a useful manner. Benchmarking studies attempt to address these shortcomings by collecting and analyzing lease operating statements for participating companies, but are often limited by the small number of participants and difficulties associated with normalization (Table S.1).

19.1.1. Regulatory Requirements

Exploration and production companies are required to present certain information about their oil and gas producing activities specified in Financial Accounting Standards Board Accounting Standards Certification (FASB ASC) Topic 932 – Extractive Industries – Oil and Gas (Gallun et al. 2001). FASB ASC 932-235-50-5, for example, requires a tabular presentation of the year-to-year changes in the net quantities of proved reserves.

According to Item 1204 of Regulation S-K, public companies are required to disclose operating expense according to direct, other, and indirect cost categories. Direct expenses primarily includes labor cost, chemicals, services, repair and maintenance, and rentals. Other lease operating expenses include production and severance taxes, insurance, gathering and transportation fees. Indirect operating expenses normally refer to overhead, general and administrative expenses.

19.1.2. Direct Lease Operating Expenses

Direct lease operating expenses LOE are the costs associated with the recovery of produced hydrocarbons from wells and usually include:

1. Labor to operate equipment and facilities and to provide service for production;
2. Materials, supplies, and fuel consumed and services utilized in operating the wells and related equipment and facilities;

3. Services used in daily operations, storage, handling, transportation, processing, and measurement;
4. Repair and maintenance;
5. Rental of special and heavy tools and equipment;
6. Equipment and facilities with a life of less than one year;
7. All technical costs other than those specifically classified as capital costs.

Labor

Labor costs is one of the more significant offshore operating expenses. Labor costs include the salary of employees who are directly involved in production activities, services (such as general repairs and maintenance performance), and supervision. Payroll and benefits for corporate staff are not included. Employee benefits, such as insurance and medical service, may be included. Some benefits are required by local laws and employee benefit packages usually varies by company.

Example. Delta House

Delta House is a deepwater semisubmersible facility located in Mississippi Canyon 254 that has a 48 person living quarters with permanent crew requirements for 24 person working in a 2 week on/off basis (Figure S.1). Subsea wells is the development strategy (Figure S.2). Supply boat trips to Fourchon shore base near Grand Isle, Louisiana takes about 6 hours and a helicopter ride to the Galliano bases takes about an hour. ■

Materials and Supplies

Materials and supplies refer to equipment, tools, and other supplies that are used in production activity and repair and maintenance. Materials and supplies are usually held in inventory and charged to costs at the time they are sent to operations. The net costs of materials and supplies purchased or furnished include not only the cost of the materials and supplies themselves, but also all costs associated with acquiring and transporting the materials and supplies. These associated costs may include broker's fee, loading and unloading fees, license fees, and in-transit losses not covered by insurance. Fuel, power and water consumed in operating the wells and related equipment is sometimes considered a subcategory of materials and supplies and reported in a separate fuel, power, and water account.

Services, Logistics, and Transportation

Services refer to activities required for daily operations and to maintain production and include catering as well as personnel transportation and workover operations. Logistics refers to the organization of people and supply and storage of materials. The transport of people is related to the mode of manning the operation. For a typical GoM shelf operation, the transport of personnel to and from facilities is by helicopter or crew boat and is commonly shared among several operations or operators, while for a deepwater facility crew transport is always by helicopter because of the greater distance and sharing is not common. Material transport is by supply boat. Transportation cost include all expense involved in shipping materials and supplies and staff to site.

Repair and Maintenance

Repair and maintenance refer to normal activities to maintain safe and continued production, and include maintenance of wells (e.g., when corrosion has made it necessary to replace downhole production equipment), related equipment and facilities (e.g., repairing a generator and lubricating a pump), as well as the maintenance and repair of the structure (e.g., inspecting and replacing corroded or pitted braces and joints).

The performance of equipment deteriorates with use and maintenance is required is ensure that the equipment and offshore structure are capable of safely performing the tasks for which it was designed. Wells and equipment breakdown and require intervention, and all offshore structures requires periodic inspection and maintenance to provide a safe working environment. The cost to repair system failures includes the additional service company personnel and logistics expenses incurred, while the cost of the replacement equipment will be depreciated. Different maintenance strategies are employed by operators depending on the design of the system and criticality of the equipment. For example, an operator may employ a spare export pump, run to failure, and then switch to the spare pump during repair.

Repair and maintenance are often divided into ordinary repair and maintenance, and major repair. Ordinary repair and maintenance, which repairs or maintains the asset to its original operating condition, is generally expensed when incurred and included in direct lease operating expenses. In contrast, major repair (e.g., overhaul), which materially increases the useful life or the productivity of an asset should be capitalized and amortized in subsequent fiscal periods. The duration and the distribution of the amortization are regulated by US GAAP based on the type of asset. Although the one-time spending amount of major repair could be much greater than that of ordinary repair and maintenance, amortization tends to smooth out the spending incurred through major repair.

Example. Hurricane damage at Mars

In 1996, Shell brought the giant Mars field into production using a tension leg platform, and through 2017 the field has produced over 750 MMboe and is estimated to hold about 4 Bboe hydrocarbons in place. In 2005, the Mars TLP was directly in the path of Hurricane Katrina and suffered extensive damage when a drilling rig on the platform was toppled by the storm and shattered the upper decks and living quarters (Figure S.3). Two export pipelines were also damaged by a dragged anchor from a semisubmersible (Paganie and Buschee 2005). Shell chartered a six-story flotel (floating hotel) from the North Sea and linked it to Mars via a pontoon during repairs that required eight months to complete and one million man-hours estimated to cost between \$250 and \$300 million (Paganie 2006).

The Mars field is so large that practically any loss – even complete destruction - would have been repaired/replaced and there was never any question that the field would return to production. The field is so large that in 2015 a second TLP (Olympus, or Mars B) was installed on an adjacent lease about a mile southwest of Mars at a cost of \$7.5 billion to continue to develop the field (Newberry 2014). At capacity, Mars can produce 140,000 bopd and on a full production basis, hurricane repairs and maintenance is estimated as \$5.4 per barrel capacity:

$$\frac{\$275\,\text{million}}{140{,}000\,\text{bbl/d}\cdot 365\,\text{d}} = \$5.4/\text{bbl}.$$

The operator also incurred approximately \$10 million loss per day business interruption since all production ceased during the repair. ■

Repairs and maintenance are usually referred to as workovers when wells are involved. Typically, workover refers to operations on a producing or inactive well to restore or increase production, and such costs are expensed. If the workover adds new proved reserves, however, costs are capitalized. Repairs and maintenance are also performed on structures, equipment, pipeline, and subsea hardware.

It is not unusual for a company to build up a separate account outside lease operating expenses for amortizing major repair cost, such as would occur with significant and long-lasting hurricane damage. Separated accounts will carve out all expenses related to major repair from direct operating expense, including labor, transportation, material and service, rental tools and equipment. For companies that build separate accounts, the major repair cost does not affect lease operating expense but will increase the final total expense.

19.1.3 Other Lease Operating Expenses

Production and Severance Taxes

Property tax for producing properties depends on location and ad valorem taxes are levied and administrated by local tax districts. In the U.S., oil and gas production books for tax purposes must be kept on an individual property basis. Production and severance taxes can be revenue- or volume-based and are normally a small part of production cost. In federal waters, there are no production taxes, while onshore and state water operations are subject to production and severance taxes.

Gathering and Transportation Fees

Gathering and transportation refer to the cost to gather and transport the raw fluids to the processing facility and the cost to transport the processed oil and gas to shore. These costs are usually not broken out and they may or may not be reported separate from direct LOE. Export fees are often reported separately when the export pipeline owner is a third-party, but large variation on reporting practices exist. If the export pipeline owner is a subsidiary of the structure owner or an affiliate exports fees may be included within other LOE or allocated and accounted for differently. Gathering and transportation costs are directly related to the location of the platform and the volume and type of fluid that flows through the system. Most pipeline tariffs in the GoM are proportional rates and on a per barrel or cubic foot basis are usually no more than 3 to 5% commodity prices.

Example. Energy XXI Pipeline, LLC South Timbalier tariffs

The cost to transport crude from South Timbalier block 27 to Fourchon terminal, Lafourche Parish, Louisiana is 77.79 cents per barrel, and from South Timbalier block 63 to Fourchon terminal is 155.56 cents per barrel effective July 1, 2016. ■

Insurance

Companies maintain insurance for some, but not all, of the potential risks and liabilities associated with production. Most larger companies are self-insured, but many smaller and mid-size companies rely on coverage as a condition to access capital markets. Offshore, the major risks are property damage due to hurricanes and severe weather, and companies may purchase coverage for removal of wreck, control of well, and business interruption. The oil and gas industry suffered significant damage from Hurricanes Ivan, Katrina, and Rita in 2004-2005 and Gustav and Ike in 2008, and as a result insurance costs increased in the immediate aftermath of the storms. Since 2008, there has been no major hurricane to hit the GoM oil patch and the insurance market has considerably weakened. Due to market conditions, premiums and deductibles for certain insurance policies may be economically unavailable or available only for reduced amounts of coverage. If a company cannot obtain insurance or believe the cost is excessive relative to the risks presented, then insurance coverage (and LOE) may decrease.

Technically, the basic function of offshore property/casualty insurance is the transfer of risk, to reduce financial uncertainty, and to make loss manageable. It does this by substituting payment of a small fee – an insurance premium – to a professional insurer (underwriter[30]) in exchange for the assumption of the risk of a large loss (property damage limit) with a small and uncertain probability, and the promise to pay in the event of such loss. Insurance companies collect premiums from payers and invest the funds, so that as events arise in the future they have the funds to pay policyholders. To remain a going concern payouts have to be less than funds collected and invested.

There are several types of coverage in the offshore oil and gas industry, the most common types being (Sharp 2000):

- Business Interruption
- Wind Damage
- Physical Damage
- Removal of Wreck
- Control of Well
- Operators Extra Expense
- Pollution Liabilities

Generally, the larger the number of premium payers (premium pool), the lower the premiums per policyholder, but as the premium pool shrinks, or if the loss incidence increases above expected values, insurers will charge more premium and provide less coverage to remain a viable business enterprise. In theory, the more accurate insurers are able to estimate probable losses the lower the amount of premium that will need to be collected, but this is most valid when events are common (e.g., car accidents) as opposed to the infrequent events (e.g., blowouts, hurricane destruction) that occur in the oil and gas industry.

In the GoM, there were no major hurricanes that impacted the offshore industry from 2008-2017, and since significant decommissioning activity has occurred during the same period, there is much less exposure and one would expect a 'soft' insurance market to develop for windstorm and removal of wreck coverage, price reductions, and broadening terms and conditions offered by the industry to attract business due to a reduced premium pool. If premiums pools are reduced too much, however, coverage may become increasingly difficult for operators to obtain at affordable rates.

It is difficult to give any sort of pricing guidelines or premium estimates for insurance products in the GoM due to the unique makeup of each operator's business and dynamic market conditions. Historically, most property damage and removal of wreck includes a deductible, usually a few

[30] Underwriter got their name from the practice in 17th century England of investors signing their names as guarantors, for a fee, under posted listings of marine voyages and cargoes.

percent (e.g., 5%) of the structure replacement value or expected cost to remove, and premiums are usually priced at a few percent of the replacement value. The limit of liability equals the total coverage purchased; e.g., the insured pays a $10 million premium for $150 million wind storm damage limit. In soft markets the insurer may reduce the damage limit, increase deductibles, increase premiums, or aggregate events.

Example. Stone Energy wind storm insurance, 2005 to 2013

In 2005, Stone Energy's wind storm insurance for all of their GoM platforms was covered under $150 million property damage limit per named storm and a $1 million deductible per storm. The annual premium for this coverage was reported as $6.5 million, or about 4% of the damage limit (Siems 2014). In 2005, Hurricane Rita toppled eight Stone Energy platforms with 29 wells and the following year insurance cost in the GoM soared as underwriters adjusted loss calculations and operators dropped out of the premium pool.

In 2006, Stone Energy held insurance for windstorm damage for one-third of their platform inventory under a $100 million property damage for the season and a $25 million deductible per storm. The annual premium for coverage was $55 million, an astonishing 55% of the damage limit. Deductibles increased 25 times from the previous year, premiums increased 8.5 times, and the coverage limit was broadened to storm season rather than storm event.

In 2008, after six structures and 34 wells were toppled by Hurricane Ike, Stone Energy accelerated decommissioning activity to reduce exposure and potential future liability. From 2008-2011, they plugged 419 wells and in 2012-2014 decommissioned 102 idle structures. In 2013, Stone Energy completely eliminated their wind storm insurance. ■

19.1.4 Indirect Operating Expenses

The general rule for charging costs directly to an operation is that those charges must be for work physically performed at the project site, or if not on-site, they must be performed specifically and exclusively for that operation (Seba 2003). All other cost which may be incurred at a distant location for a number of different operations are considered indirect operating costs or overhead and need to be allocated. Supervisory and administrative expenses which are shared with other properties are often pro-rationed.

Indirect operating expenses include the expenses that are not directly related to production activities but provide a benefit to operations. General and administrative expenses are costs incurred for overhead, including payroll and benefits for corporate staff, costs of maintaining headquarters, costs of managing production and development operations, audit and other fees for professional services and legal compliance. The major component (sometimes the only component) of indirect operating expenses is operating overhead expense. Operating overhead expense refers to expense which, although incurred in a firm's day to day operations, cannot be directly assigned to a specific department or product.

The specific method for allocating indirect expenses is arbitrary but specific rules should be developed to maintain uniformity. A common rule is to charge a percentage on top of certain direct costs. The percentage is often determined as a percent of direct operating costs plus a percent of capital expenditures required for the project when capital is spent.

19.2. Lifting and Production Cost

Lifting cost, production cost, and total expense per unit of production are ratios that measure how much a company spends to produce (lift) one unit of hydrocarbon out of the ground and to make ready for transport. Generally speaking, the smaller the lifting and production cost, the greater the ability of the company to profit from its production and the more efficient it can extract hydrocarbons. Production cost and total expense do not have the same meaning as lifting cost (in an accounting sense) and include more terms. Lifting cost is the most visible metric directly related to LOE and it is important to understand what the metric includes and how it is computed since there is no universal definition and regulatory agencies do not require reporting.

Lifting cost usually includes the cost to operate and maintain wells and related equipment and facilities and may or may not include indirect operating expense (Table S.2). Production cost is usually defined as lifting cost plus gathering and transportation costs and may include production taxes, or these may be reported separately. Since gathering and transportation costs are often small on a unit basis their inclusion in lifting costs will usually not significantly impact the metric. If lifting cost is computed based on total expense, it will be greater than a ratio that does not include other expense and major repairs.

Example. Energy XXI GOM operating expense, 2012-2014

Lifting cost, production cost, and total operating expenses per boe as reported by Energy XXI GOM from 2012-2014 is shown in Table S.3. Total lease operating expense include direct LOE, insurance, and workover and maintenance. Production taxes and gathering and transportation were reported separately. Depreciation, depletion and amortization (DD&A) of capital expenditures and overhead and management salary company-wide via general and administrative (G&A) expenses contribute to total operating expenses. Note that DD&A account for more than half of total operating expense. ■

Companies normally identify their production as "primarily oil" or "primarily gas" using total aggregate oil and gas production volumes via the gas oil ratio GOR, expressed in cubic feet natural gas per barrel crude oil. Condensate from natural gas production is often included in the liquids reporting unless it exceeds 10 to 15% crude volumes in which case it is broken out separately. If GOR < 10,000 cf/bbl the company can be considered an "oil" company; otherwise, the company is classified as a "gas" company. An operator will usually report lifting cost as $/boe if production is primarily oil and $/Mcfe if primarily gas, but this is not a requirement and operators may prefer reporting production in units that differ from their primary product. In other words, an oil company/property may report lifting cost in terms of $/Mcfe and a gas company/property in terms of $/boe.

Lifting cost is a popular measure, used internally within companies as a means of measuring operating efficiency, and is frequently used by business analyst and bond rating agencies to compare operating performance across companies (e.g., Moody's 2009). However, since lifting cost is not required to be released in financial statements, the ratios are often calculated based on different accounting treatments and will vary from company to company. Comparisons need to be made cautiously. Except in special situations, lifting cost is measured over all properties within a company's reporting divisions and fiscal period, and so the ability to extract useful information for a specific region or property is rare. For operators that only operate regionally, offshore in the GoM for example, or have a dominant offshore focus useful data may be obtained.

19.3. Company Financial Statements

19.3.1 Sample

Ten public oil and gas companies with the majority of their production and reserves in the federal waters of the GoM were identified and LOE data tabulated from 2006-2015 (Table S.4). All the companies are independents, primarily regional players, except Freeport-McMoRan Oil and Gas, which is a subsidiary of Freeport-McMoRan, a mining company, and Energy Resources Technology, a subsidiary of Helix Energy Solutions Group, Inc., an international offshore service company. Four companies of the sample went bankrupt during the evaluation period (ATP Oil and Gas Corporation, Energy XXI GOM, RAAM Global Energy, Stone Energy), two companies sold off their assets and left the region (Callon, Freeport-McMoRan Oil & Gas), and two companies were purchased outright (EPL by Energy XXI and Energy Resource Technology by Talos). Energy XXI GOM is entirely a shelf Gulf player, whereas Stone Energy, W&T Offshore and ATP are primarily deepwater operators.

The sample was roughly split between oil and gas producers and all company fiscal years ended December 31 except Energy XXI GOM which ended June 30. Companies report consolidated information on their operations, net production, average sales prices, impact of derivatives and average production cost. Average production cost are usually broken out by category for direct LOE, DD&A, accretion, taxes, and G&A expenses. LOE may include maintenance expenses or these may be reported separately, but excludes transportation tariffs. Four companies report direct LOE as a single cost category as per the U.S. SEC Regulation S-X Section 210.4-10(a), whereas all other companies present some variation. Cost are presented in nominal (unadjusted) money-of-the-day dollars in the tabulation.

Companies with a significant portion of their production and/or reserves onshore cannot be employed because of the significant differences between onshore and offshore regions. Companies with a significant presence in the GoM and internationally such as Anadarko, Apache, Chevron, Newfield, and Shell do not breakout LOE for the GoM and could not be used in the evaluation. Private companies with a significant presence in the GoM such as Fieldwood and Bennu Oil and Gas do not report data.

19.3.2 Direct LOE

Direct LOE is the largest and most important cost category for all companies all years and in most cases includes chemicals, fuel, insurance (if purchased), labor, logistics, repairs and maintenance (workovers). In some cases, companies breakout one or more subcategories such as workovers, repair and maintenance, and insurance. Transportation and gathering is usually considered a separate category but in a few cases is included within the direct LOE category.

Direct LOE may decrease from one year to the next if high cost fields are divested, operating efficiencies are improved, and/or low commodity prices allow cost reductions during contract negotiation, say for transportation services. Conversely, older less prolific properties with greater water cuts and maintenance expense, sour crude service, and an increasing commodity price environment will usually act to increase service cost and unit operating cost from one year to the next. Declining production from suspension of drilling and intervention activities will act to increase unit operating cost because of reduced production relative to fixed costs. Property acquisitions may act to increase or decrease direct LOE.

It is important to understand that a combination of factors determine operating expense. For example, old, low production, low quality crude oil wells with large produced water volumes that require pressure maintenance and are isolated and far from port will cost more on a unit basis relative to new, high producing, high quality wells that do not require pressure support and are produced near shore. Breaking out the contribution of individual attributes is usually problematic.

19.3.3 Workover and Maintenance

Workover and maintenance expense are reported separately for half of the sample and range from \$1.9-\$5.8/boe and \$0.1-\$0.8/Mcfe from 2010-2012. When commodity prices rise workover activity usually increases since it accelerates production. Direct LOE will increase if the marginal cost exceeds the incremental production. In low commodity price environments, workovers may not return the investment and are therefore postponed. For wet wells, workover costs are significantly greater than dry tree wells because of the need to mobilize a MODU.

Workover and maintenance cost depends on the nature and age of operations, level of production, well type, oil and gas prices. Workovers often require installing smaller tubing, recompletion into a higher zone, re-stimulation, replacing corroded tubing, etc. Workover and maintenance expense are discretionary, meaning the operator decides if it wants to perform the activities and incur the cost. High producing wells in high price environments have a greater chance of returning the investment and workovers are more likely to be performed relative to marginal producers.

Repairs and maintenance costs will be higher for remote mature properties, and in low price environments will be postponed, except for emergencies and as long as it does not involve a safety hazard. Repair and maintenance work is expected to be positively related to commodity prices to the extent that increasing prices provide budgets that allow work to be performed, and in high price environments operators want to accelerate production.

19.3.4 Hurricane Impacts

Significant hurricane impacts to infrastructure can reduce and/or defer future production and revenues, increase lease operating expenses for evacuations and repairs, and increase and/or accelerate plugging and abandonment costs (Kaiser 2014). Assets damaged or destroyed by hurricanes will require greater budgets for longer durations to repair or decommission than undamaged or standing structures. McMoRan was the only company in the sample that reported hurricane related repairs as a separate category, averaging \$0.14/Mcfe from 2006-2012.

19.3.5 Insurance

Insurance cost depends on a company's structure and well inventory, type of coverage (property damage, repair of wreck, business interruption), and market conditions. To understand coverage, it is necessary to enumerate the number, location, type as well as replacement value of infrastructure, and the type and nature of coverage. Affordable coverage in the years after a significant event may be difficult to obtain and companies may choose to eliminate or reduce hurricane insurance coverage, which will reduce short-term operating expense but may increase expenses later. Energy XXI and McMoRan Oil & Gas reported insurance cost as a separate cost category that averaged \$2.36/boe at Energy XXI and \$0.30/Mcfe at McMoRan over the reporting period. For companies that purchase insurance coverage, insurance cost often range from 5% to 10% LOE but in some cases may be greater.

19.3.6 Transportation and Gathering

Transportation and gathering cost depend on the location of the property, volumes and distance transported, pipeline ownership and regulation, product transported, age of the pipeline(s), and capital investment. The reservation rate is paid to reserve firm capacity regardless of usage. The commodity rate is paid based on volumes committed and shipped. Interruptible service is sometimes offered on a discounted basis. Since gas is usually produced in association with oil, there must be a gas transportation outlet on oil structures to prevent curtailment of oil production.

Old, partially full pipelines generally require more maintenance than new full lines, and if line volumes are low tariff rates will often be higher than on packed lines unless the capital cost are fully depreciated. Generally, transportation and gathering costs to deliver oil and gas to onshore markets are a small part of overall operating cost (< $1-2/bbl, < $0.50/Mcf) but exceptions exist. Typically, because transportation and gathering costs are volume-based, fees will change in proportion to production changes and will usually vary less than other cost categories and in smaller proportion to the total expense.

19.4. LEASE OPERATING STATEMENTS

Lease operating statements represent the accounting records of operating expenses on a property or lease basis for tax purposes and are used for internal management review and cost control. They are by far the best and most accurate source of data on the cost to operate oil and gas properties since they are a complete and faithful record of all operational expenses. Lease operating statements are not part of financial statements that are regulated and required to be disclosed to the public periodically, and hence, they are not available for review except to property owners.

Companies typically employ accrual-based accounting which recognize expense and revenue as economic events occur, regardless of when cash transactions are recorded (Gallun et al 2001). Accrual accounting is the standard accounting practice for most oil and gas companies but the expenses and revenue depicted on the lease operating statement may not exactly match the (actual) cash flows in the same fiscal period.

Service companies in the GoM have on occasion formed subsidiaries to acquire working interest in mature oil and gas properties to provide additional opportunities for their well intervention services and platform management businesses during periods of market downturn. When companies acquire a working interest position they take title to reserves and assume their share of well abandonment and decommissioning liabilities. In 1999, TETRA Technologies, Inc., a well service and construction company, formed Maritech Resources, Inc. in part to grow opportunities for its well intervention and decommissioning businesses.

Example. Maritech Resources

Thirty three lease operating statements and 46 LOE accounts at Maritech were examined in 2005 as part of an internal review of its GoM operations. Lease operating statements are for individual leases and typically include one or more structures per lease and dozens of wells. Average leasehold expense circa 2005 was $556,000 per lease and contract services transportation and labor represent the largest cost categories (Table S.5). Average unit production cost was $2.20/Mcfe and average total expense was $3.65/Mcfe. No economies of production were found indicating the mostly uniform nature of marginal operations (Table S.6), but increasing GOR exhibited decreasing unit cost (Table S.7). In 2008, Maritech began to divest its GoM assets after significant hurricane destruction impacted cash flows and no longer operates in the region. ■

19.5. SURVEY METHODS

Survey methods are a common means to evaluate lease operating cost and over the years various operators, consulting companies, and the federal government have all performed studies. The UK Oil and Gas Authority is currently the gold standard and is the source of the best publicly available operating cost data in the world.

19.5.1 Oryx Energy GoM Survey

In 1990, Oryx Energy Company conducted surveys with 13 shallow water GoM operators to quantify the various practices, philosophies and techniques with a view to benchmarking operations (Bolin et al. 1990). Operating cost per boe was the most widely used measure of operational performance and for the sample ranged from $0.7 to $2.8/boe and $110,000 to $430,000 per well per year in 1990 dollars. There were 6.1 employees per platform and 14.3 employees per manned platform for structures with full production capacity. Personnel and transportation accounted for slightly more than half of field expenses, excluding workovers. Cost variation was attributed to the nature of production and density of operations, number of manned/unmanned platforms and degree of automation.

19.5.2 Energy Information Administration

From 1994-2009, the U.S. Energy Information Administration (EIA) conducted a survey of domestic oil and gas well equipment in several regions of the U.S. (EIA 2009). Individual items of equipment were priced using price lists and by communicating with the manufacturers of the items in each region. The survey data on equipment and usage were combined with a factor model to reflect the direct cost incident to assumed production levels. The EIA survey was discontinued in 2010.

Operating costs for the Gulf of Mexico were estimated for 12- and 18-well slot fixed platforms assumed to be 50, 100 and 125 miles from shore corresponding approximately to water depths of 100, 300 and 600 ft. Crude oil production was assumed to total 11,000 bbl per day (4 MMbbl per year) and associated gas production was assumed to be 40 MMcf per day (14.6 Bcf per year).

Meals, platform and well maintenance, helicopter and boat transportation of personnel and supplies, communication costs, insurance, and administrative expenses were included in the cost estimate. Export cost to shore and water disposal cost, depreciation and ad valorem and severance taxes were not considered. Year 2009 estimates are shown in Table S.8. According to the EIA survey method, the implied LOE for a platform in 300 ft water depth producing 11,000 bopd crude and 40 MMcfpd natural gas would be $1.5/boe:

$$\text{Implied LOE: } \frac{\$9.6\text{MM}}{(17{,}667\text{boed})(365\text{d/yr})} = \$1.5/\text{boe}.$$

19.5.3 IHS Upstream Operating Cost Index

The IHS Upstream Operating Cost Index measures quarterly changes in the cost of oil and gas upstream operations on a regional basis (Figure S.4). Introduced in 2000, the index is calculated by examining equipment and supply and service cost by vendors via survey for specific types of properties and operations in different regions in the world. The index is meant to be similar to the consumer price index (CPI) in providing a transparent benchmark for forecasting and as a commercial product provides greater levels of detail to subscribers.

19.5.4 Benchmarking

Benchmarking studies collect and analyze lease operating statements for participating companies and summarize the results and best practices using a common set of categories. Since oil and gas assets are unique and companies report and aggregate cost differently, the first step in all benchmarking studies is to normalize and account for the different factors to make comparisons. Wide participation help to ensure surveys are representative. Benchmarking studies are not released to the public or otherwise reported except in the occasional press release. Participation is the means to gain access in client studies.

In 2002, Ziff Energy Group surveyed 312 GoM shelf fields for 24 companies amounting to over $1 billion in annual operating expenses. The field weighted average operating cost for gas assets was reported to be $0.29/Mcfe and for oil assets $2.3/boe. In deepwater, 10 companies producing from 30 fields and representing about 80% of deepwater production had an average operating cost below $2/boe.

In 2009, 125 GoM fields in water depth less than 1000 ft were evaluated (66 gas fields producing over 1 Bcfpd and 52 oil fields producing over 200,000 boepd). The unit operating cost almost tripled to $0.84/Mcfe for gas fields and $7.83/boe for oil fields (Alba 2008, Ziff Energy Group 2009). The single largest cost component for shelf operations was reported as labor and field supervision accounting for about a quarter of operating expenses, followed by transportation for gas fields and repairs and maintenance for oil fields. Well servicing amounted to about a fifth of offshore expenses.

19.5.5 UK North Sea

The UK North Sea has the best publicly available offshore operating cost data in the world. The UK Oil & Gas Authority collects cost data on an annual basis using a survey instrument and presents data driven analysis on an operator, field, and structure basis (Oil & Gas Authority 2017). In 2016, unit operating cost was reported at $16/boe with the largest producers generally having the lowest unit cost and the Northern North Sea – with its late life fields, harsh weather conditions, larger infrastructure, and more onerous logistical requirements – having the highest regional cost.

In Figure S.5, operators producing >50 MMboe during 2016 had operating cost ranging between $4 to $15/boe, while for operators with production between 15-50 MMboe, operating cost ranged from $8 to $35/boe. There is a 12-fold difference between the highest and lowest unit operating cost across operators in the region (Figure S.6). In Figure S.7, operating cost by field for the South North Sea, Central North Sea and North North Sea shows the wide variation between and within regions. Another interesting graph shows manned platform operating cost per topside weight quartile performance by location (Figure S.8).

The average operating cost for manned platforms and floating facilities of similar liquid processing capacity (100,000 bopd) was $61 million per year and $80 million per year, respectively, and on a production volume basis was $22/boe and $14/boe reflecting the higher production rates of floating facilities. Topsides weight had the strongest correlative index for operating cost and for manned platforms the top quartile performance had an operating cost <$3.5 million per 1000 tons of topside weight. ■

19.6. Software Tools

There are three main software tools used by industry to estimate capital and operating costs: Aries Petroleum (Field Plan) from Halliburton, Questar from IHS, and Merak Peep from Schlumberger. There are more similarities with the software than differences. In each, data is collected from industry, media reports, direct contact with operators and other sources annually and algorithms applied using field characteristics and other relevant information to normalize and estimate cost at various levels of granularity. These tools have been developed over a long period of time (25-30 years) and are generally considered accurate to +/- 40% in conceptual development studies.

19.7. Computer Methods

Four computer/software technologies have been used in the petroleum industry for operating cost estimation – expert systems, fuzzy logic systems, neural networks, and genetic algorithms. Applications have been produced with each technique but only a handful of papers over the past half century have been published. Operations that are most amenable to sophisticated computer analysis include high revenue generation assets with pressure maintenance via waterflood or gas injection, gas lift operations, and subsea gas developments from multiple fields (Harvey et al. 2000).

An expert system is a computer program that provides expert advice (MacAllister et al. 1996). The program usually contains a data structure that represents a subset of human expert's knowledge, algorithms to manipulate the data structure, and an interface for inputs and results. An example of an expert system developed specifically for operating expense modeling was described in Greffioz et al. 1993), but such systems have not gained widespread interest. In recent years, SAP systems have been applied (Taylor 2016).

Neural networks are used to mimic the pattern-recognition capabilities that humans use in analysis and interpretation problems. Neural networks develop solutions implicitly through exposure to information about the problem domain. Usually the "exposure" takes the form of several different examples of solutions to the general problem class being solved. The neural network uses these examples to create a solution in a manner analogous to learning via trial-and-error. An example of a neural network model of lease operating cost has been built (Boomer 1995). A useful review of the field is available in Saputelli et al. (2002).

Fuzzy set theory deals with the generalization of binary logic to include imprecise, vague, and ambiguous concepts to include a spectrum of possible states. Genetic algorithms provide a technology for solving optimization problems that cannot be handled using conventional linearprogramming approaches. Using the idea of ‘fitness’ of each ‘offspring’ generation, a population of solutions is generated and only the ‘strongest’ members survive.

CHAPTER 20. FIELD EXAMPLES

Public companies listed on U.S. stock exchanges are required to provide separate disclosure of reserves, production and production cost for each country that controls more than 15% of a company's total proved reserves and each field for production. Field information is useful because it provides granular cost data at an asset level, but the field units applied in financial reports do not necessarily correspond to those adopted by regulators, and multiple companies may operate across a field and combine two or more fields in reporting. The field is the lowest aggregation unit for production cost that is publicly available and all known GoM fields reporting operating cost data from 2010-2016 are described.

20.1. West Delta 73

The West Delta 73 field is an oil producing sandstone with bottom waterdrive and is one of the top 10 producing oil fields on the Gulf shelf circa 2017. The field was discovered in 1962 by Humble Oil and Refining about 28 miles offshore of Grand Isle, Louisiana in approximately 175 ft of water. The field is a large low relief faulted anticline that produces from Pleistocene through Upper Miocene aged sands trapped structurally from 1500 ft to 13,000 ft below the mudline (Ogletree and Overly 1977).

Energy XXI is the operator and 100% working interest owner in the West Delta 73 field which covers seven lease blocks WD 73-75, 89-92 (Figure T.1). At the end of 1975, cumulative oil production was 128 MMbbl oil and 170 Bcf natural gas. Through September 2017 the field has produced 277 MMbbl oil and 686 Bcf gas from 305 wells, and remaining reserves are estimated at 5.4 MMbbl oil and 17.3 Bcf gas (Figure T.2).

In 2011, over $100 million was spent to identify, plan and drill 21 horizontal wells with associated infrastructure improvement, and by 2016 production expanded from 1800 boepd to 7000 boepd (Iqbal et al. 2016). Circa 2016, there were six production platforms with 27 active wells and 46 shut-in wells (Figure T.3). From 2012-2014, production costs ranged between $18.54 to $21.30 per boe (Table T.1).

20.2. Main Pass 61 Complex

The Main Pass 61 complex is located in approximately 100 ft of water near the mouth of the Mississippi River and operated by Energy XXI (Figure T.1). The Main Pass 61 complex consolidates the Main Pass 61, 73 and 311 fields and portions thereof that were acquired from EPL Oil & Gas.

Main Pass 61 field was discovered by POGO in 2000 and has been producing from the Upper Miocene sands since 2002. Main Pass 73 field was discovered in 1976 by Mobil and began producing in 1979. In 2012, the last year in which data is reported, daily production from the complex totaled 6.5 Mbopd crude and 4.1 MMcfpd natural gas with unit production cost of $9.77/boe (Table T.2).

There were 23 producing wells and three production platforms in operation circa 2016, one of which is shown in Figure T.4. Cumulative production through September 2017 from the three fields was 224 MMbbl oil and 953 Bcf gas.

20.3. SOUTH TIMBALIER 21

The South Timbalier 21 field was discovered by Gulf Oil in 1957 on the south flank of the giant Timbalier Bay field six miles south of Lafourche Parish, Louisiana, in approximately 50 ft water depth (Lipari 1962). Circa 2017, the field includes acreage in South Timbalier blocks 21, 22, 27 and 28, as well as two state leases. The field is bounded on the north by a major Miocene expansion fault. Miocene sands are trapped structurally and stratigraphically from 7000-15,000 ft in depth.

There are 10 major production platforms two of which are shown in Figures T.5 and T.6, and 61 smaller structures located throughout the field (Figure T.7). In 2010, the last year of reported data, crude production was 3.8 Mbopd and natural gas was 4.6 MMcfpd with production cost of $27.21/boe (Table T.3).

Through 1975, the field produced 150 MMbbl oil and 231 Bcf natural gas. Cumulative production through September 2017 from federal leases totaled 259 MMbbl oil and 426 Bcf natural gas (Figure T.8). Remaining reserves circa September 2017 are estimated at 1.5 MMbbl oil and 3.1 Bcf gas.

20.4. SHIP SHOAL 349 (MAHOGANY)

The Ship Shoal 349 field known as Mahogany covers Ship Shoal blocks 349 and 359 and was the first shelf subsalt development in the GoM (Montgomery and Moore 1997). Phillips Petroleum Company along with partners Anadarko Petroleum and Amoco discovered the field in 1993 in 375 ft of water and W&T Offshore, Inc. holds 100% working interest in the field circa 2017.

The discovery was positioned beneath a salt sheet displaying high variable thickness and geometry (Figure T.9). The discovery well penetrated 3825 ft of salt and logged as many as 14 sandstone zones between depths of 12,300 and 16,300 ft (Voss et al. 2010). Below the salt there was a noncompetent zone ('gumbo') approximately 1000 ft thick before entering the flank of the anticline with three-way dip closure. A production complex was installed above the field (Figures T.10, T.11).

Total reserves at the time of discovery were estimated at more than 100 MMbbl but production has been slow to achieve these levels. Cumulative production through September 2017 was 34.4 MMbbl oil and 69.2 Bcf gas, and since 2011 the operator has drilled and completed several new challenging wells resulting in a significant production increase (Figure T.12). From 2013-2015, production costs ranged between $3.30 to $4.12 per boe (Table T.4). Remaining reserves circa 2017 are estimated at 7.4 MMbbl oil and 14.4 Bcf gas.

20.5. VIOSCA KNOLL 990 (POMPANO)

The Pompano field was developed by BP with a fixed platform in 1994 in 1290 ft water depth in the southeast corner of Viosca Knoll block 989 (Figure T.13). The development included a 10-well subsea tieback located about 4.5 miles away from the platform in Mississippi Canyon 28 in 1850 ft water depth producing from Pliocene and Miocene reserves (Figure T.14). Cumulative field production through September 2017 is 143.9 MMbbl oil and 268.6 Bcf natural gas, and remaining reserves are estimated at 15.1 MMbbl oil and 17.1 Bcf gas (Figure T.15). Several tiebacks are hosted at the platform.

Reservoir geometry at Pompano is a series of stacked and connected composite sand bodies of moderate to high quality which were deposited in varying thickness (Willson et al. 2003). Pliocene reserves are all located within reach of the platform and some of the offset Miocene reserves can also be reached from the platform using extended reach drilling (Figure T.16). Miocene reserves that can't be efficiently drilled from the platform were developed with subsea wells. One of the first long distance tiebacks was the Mica field in 4350 ft water depth 29 miles away in Mississippi Canyon block 211 (Ballard 2006).

In 1999, Pompano's production peaked at about 65,000 boepd. By July 2007, field production was approximately 11,500 bopd. Stone Energy acquired a working interest in 2006 for $168 million and later became the sole working interest operator. In 2016, the Cardona and Amethyst subsea tiebacks were installed and production has nearly doubled since 2013 (Figure T.18).

In 2013-2014, lease operating cost including major maintenance expense ranged from $1.98 to $2.75/Mcfe, but in 2015 with the doubling in production at the facility, unit cost was effectively cut in half to $0.96/Mcf (Table T.5). Transportation, processing and gathering expenses were reported at $0.1/Mcfe. In 2016, LOE was reported to be $4.85/boe = $0.81/Mcfe and with future tiebacks from Derbio and Rampart planned, LOE will likely remain within its current range.

20.6. MISSISSIPPI CANYON 109 (AMBERJACK)

The Amberjack field is located on Mississippi Canyon blocks 108, 109 and 110 in water depths from 850 to 1050 ft (Figure T.19). Field development started in 1984 and by 1992 38 wells had been completed and were producing oil and gas from various sand packages from a platform in a water depth of 1030 ft (Figure T.20).

The majority of the reserves in the Amberjack field are contained in the Green G-sand, an unconsolidated Pliocene reservoir deposited by a shelf edge delta system which laid down the sediments as a series of shingled mouth bar sands separated by dipping silt beds, referred to as clinoforms (Johnston et al. 1993). Reservoir compartmentalization required the use of a large number of wells (Figure T.21).

Early in production there were persistent problems with gravel packs to control sand production (Hannah et al. 1993). Horizontal wells were drilled in the early-1990s to improve productivity and drain several clinoforms. For example, well A-5 was oriented perpendicular to the clinoform depositional axes with the completion interval draining all three packages saving on well cost (Figure T.21).

In 1999 a redevelopment program was initiated with two sidetrack wells. Both wells experienced problems to reach the planned target depth but contributed to production increase (Figure T.22). One lost hole, one unplanned sidetrack and persistent non-productive operating time caused significant cost overruns. In 2003, one of the sidetracks was re-entered but problems again arose due to difficult circumstances that included depletion, reduced fracture gradient, and wellbore instability.

In 2001, a gas lift automation and optimization project was initiated which resulted in production peaking at around 5 MMbbl oil. Of the 34 wells, 27 utilized gas lift injection to facilitate flow but daily operations were challenging because the system was not automated or optimized (Reeves et al. 2003). Following Hurricane Katrina in August 2005, the Amberjack platform required repairs and rerouting of a damaged oil pipeline, and from 2007-2010, Stone invested in a seven well drill program (Fredericks et al. 2011).

From 2008-2010, Amberjack field production expense ranged between $0.86 to $2.19/Mcfe (Table T.6). Through September 2017 the field has produced 84.7 MMbbl oil and 83.6 Bcf gas. Remaining reserves are estimated at 3.4 MMbbl oil and 6.1 Bcf gas.

20.7. MOBILE BAY 113 (FAIRWAY)

The Fairway field is comprised of Mobile Bay blocks 113 and 132 and is located in 25 ft of water, approximately 35 mi south of Mobile, Alabama, in state waters (Figure T.11). The field was discovered by Shell in 1985 and is a Norphlet sand dune trend with one production horizon at about 21,300 ft. Development drilling began in 1990 and included four wells drilled from separate surface locations. W&T Offshore, Inc. acquired a 64.3% working interest along with operatorship in August 2011 and acquired the remaining working interest from Shell in 2014.

In 2016, cumulative field production was approximately 129 MMboe (776 Bcfe) with an average production rate of 6.1 Mboepd. In 2015, the Fairway field generated about $28 million on net sales of 10,250 MMcfe and had production cost of $15 million, leaving about $13 million net revenue. Four platforms and numerous wells are currently used in production and operating expense are quite high.

From 2013-2015, unit production costs ranged between $1.49 to $2.08 per Mcfe (Table T.7). In 2016, cumulative field production was approximately 129 MMboe (776 Bcfe) with an average production rate of 6.1 Mboepd. As of December 31, 2015, the operator reported 84 Bcfe reserves.

20.8. MAIN PASS 299

The Main Pass 299 field was discovered in 1962 on the periphery of a salt dome and production began in 1967 from four lease blocks at Main Pass 142, 298, 299 and 300. In 1988, Freeport-McMoRan Oil & Gas Co. acquired a portion of block MP 299 on top of the salt dome and discovered a large accumulation of sulfur (67 million tons) and recoverable oil (39 MMbbl out of 99 MMbbl oil in place) in the caprock 2000 ft below sea level (Figure T.23). A large development was planned with sulfur mining as a primary objective (Figure T.24).

Freeport-McMoRan's development plan called for a simultaneous thermal enhanced oil recovery project and sulfur mining operation (Lewis and Taylor 1992). Pressurized hot water heated to 325°F injected into the sulfur zone would liquefy the sulfur where it was to be artificially lifted to the surface and offloaded using barges. The hot water injection for mining was expected to add 18 MMbbl to recoverable oil.

Produced crude is heavy and sour (22°API and 2.5%wt sulfur) and the solution gas and gas cap gas has an H_2S content of 14.9 mole% and 2.5 mole%, respectively. Electric submersible pumps were utilized to lift the crude and of the 18 initial development wells 11 were drilled horizontal and placed high above the oil-water contact to eliminate water coning (Figure T.25).

Fifteen platforms make up the Main Pass complex and include one power plant, one living quarters and warehouse and storage facilities (Figure T.26). Five of the six major platforms are connected via bridges spanning about a mile and supported by nine bridge platforms. There are two drilling and production platforms. Eight wells were drilled on the "A" platform, five horizontal and two deviated oil wells, and one gas cap depletion well. Ten wells were drilled on the "B" platform, six horizontal and three deviated oil wells, and one gas well.

Through September 2017, the MP 299 field produced more than 169 MMbbl of oil and 116 Bcf of gas (Figure T.27). Freeport-McMoRan's MP 299 lease block above the salt dome was highly prolific and produced about a third of the field's oil production (51.7 MMbbl of oil and 8.4 Bcf gas). Sulfur operations were problematic from the beginning and relatively small quantities were produced before operations were shut-down and large portions of the complex reefed-in-place.

From 2010-2012, McMoRan Exploration Co. reported MP 299 lease oil production from 348 to 376 Mbbl and average sales prices from \$73 to \$104/bbl. In 2012, \$63/bbl lifting cost was attributed to the difficulty of producing sour crude reservoirs (Table T.8). Workover expenses were reported as \$1.9 million in 2010 (or \$5.2/bbl of the \$52/bbl total production cost), \$16.2 million in 2011 (\$46.6 per barrel), and \$3.2 million in 2012 (\$9 per barrel). From 2005-2009, production cost ranged between \$31/bbl to \$69/bbl.

Freeport-McMoRan's lease was terminated in 2016 but the field still produces. Circa 2017, Cantium LLC operates four leases covering Main Pass blocks 142, 298, 299, and 300. Remaining reserves are estimated at 5.5 MMbbl oil and 4.3 Bcf gas.

20.9. DISCUSSION

In 2014, production from the West Delta 73 field was 5500 boe per day, 75% from crude oil and NGLs: 4100 bbl crude oil, 100 bbl NGLs and 7.5 MMcf gas per day, and generated approximately \$170 million in gross revenue during the year:

$$4100 \text{ bopd crude} \left(\frac{365d}{\text{yr}}\right)\left(\frac{\$105}{\text{bbl}}\right) + 7.5 \text{ MMcfd gas} \left(\frac{365d}{\text{yr}}\right)\left(\frac{\$4.22}{\text{Mcf}}\right) = \$168.8 \text{ million}$$

Crude oil is responsible for about 91% of revenue, 7% is due to gas sales, and 1% is due to NGLs. Production costs in 2014 totaled about \$40 million:

$$(5500 \text{ boepd})(365\text{d/yr})(\$19.8/\text{boe}) = \$39.7 \text{ million},$$

about one-quarter of the total revenue, indicating the mature, high-cost nature of field production. Production weighted average sales price was \$85.1/boe and LOE as a percent of the sales price is 23%. Net revenues in 2014 was \$129 million.

Main Pass 61 and South Timbalier 21 fields no longer contribute more than 15% of Energy XXI's reserves and have not been reported in recent years. In 2010, the sales prices received for crude oil and natural gas were about the same in the two fields, with Main Pass crude and natural gas receiving slightly higher prices than from South Timbalier. These differences can be attributed to the quality of the crude oil and amount of hydrocarbon liquids (NGLs) present in the gas streams which were not reported. On the cost side there is a large difference in production cost, \$11.4/boe at MP 61 versus \$27.2/boe at ST 21. ST 21 is a much older field and has many more platforms which partially accounts for the difference.

The Mahogany field reported proved reserves of 22 MMboe in 2015. If a barrel of oil in the ground is assumed to be worth \$20/bbl, Mahogany's reserves are worth about \$440 million. Unit production cost is about one-third the level of MP 61 and one-fourth the level of WD 73 and ST 21 production because volumes are much greater and rely on only one platform, well counts are smaller, and vintage is younger. Net revenue from Mahogany in 2015 was approximately \$102 million:

$$3037 \text{ Mboe } ((\$36.8 - \$3.3)/\text{boe}) = \$102 \text{ million.}$$

West Delta 73 and Mahogany are classified as oil fields since their GORs are less than 10,000 cf/bbl. The NGL content of the associated gas for the two fields are 13 and 25 bbl/MMcf, respectively, typical medium-rich gas streams due to their association with crude production, but neither make a material contribution to revenue as the reader can readily verify.

The Pompano field is primarily oil producing and it is odd that the operator choose to use natural gas equivalents in its early presentations (it has since reverted to boe). Pompano produces from both wet and dry trees and uses a "through flowline" technique to clean out paraffin deposits in the subsea wells. In 2015, gross revenue from crude oil was \$139 million and \$7.4 million from natural gas, while production cost totaled about \$22.7 million, leaving \$116 million net revenue. Production cost at Pompano at 16% gross revenue is higher than at Mahogany where it is 9% gross revenue because the field is in deep water and employs a large number of subsea wells which are expensive to operate relative to dry tree wells. As subsea wells bring additional production back to the host, unit production cost are expected to stabilize or decline.

CHAPTER 21. FACTOR MODELS & PRODUCTION HANDLING AGREEMENTS

Factor models are popular in operating cost modeling because they are easy to implement in spreadsheets and allow for versatile and efficient implementation. Unfortunately, the reliability of factor models is often poor because users typically assume model parameters without any attempt to validate and/or calibrate with empirical data. In this chapter, factor models for lease operating cost, workovers and gathering and transportation services are illustrated and their limitations are discussed. Production Handling Agreements are a special type of factor model negotiated between infrastructure owners and third-party producers who wish to use the facility for production operations. The terms and conditions of Production Handling Agreements are illustrated using numerical examples and the manner risk is allocated between parties is highlighted.

21.1. LEASE OPERATING EXPENSE

21.1.1 Model Specification

Operating cost models are typically described in terms of a fixed and variable component at a given organizational level such as a structure, lease, or field. Fixed cost arises from the level of maintenance required to sustain production, overhead and administrative cost, workforce salary, and related factors. Very few properties can be operated without overhead costs because of accounting and reporting requirements, and occasionally overhead costs may exceed direct costs. In modeling, fixed operating cost is frequently assumed proportional to the capital costs of the items to be operated and based on a percentage of CAPEX or cumulative CAPEX over time.

Variable cost may be reported for each production stream and water and gas injection or several components may be consolidated. Variable cost depend upon chemicals, energy/electricity used in production and water handling, disposal of waste, maintenance requirements, etc. In modeling, variable operating cost is usually assumed proportional to the throughput of the primary or composite production fluids oil, oil and water, gas, oil and gas, oil and gas and water.

The simplest OPEX factor model is configured as a combination of fixed and variable cost components as:

$$OPEX_t = A \cdot CAPEX_t + B \cdot Production_t,$$

where $CAPEX_t$ and $Production_t$ in year t is known or estimated and A and B are user-defined model parameters. $CAPEX_t$ and $Production_t$ are described in units of dollars and volume, respectively, usually on an annual basis. Capital expenditures may include topsides only, topsides and structure (i.e., the 'facility'), or the facility and subsea system, if applicable. For offshore GoM platforms, the value of A is typically assumed to range between 1 to 5% and B between \$3 to \$15/boe or \$0.5-\$2.5/Mcfe. Ideally, the value of B would be obtained from an evaluation of the production cost or direct LOE of the operator or properties in the region, but this is not always possible.

An OPEX model that breaks production cost into individual streams would be written as:

$$OPEX_t = C_{oil}\, NP_t + C_{gas}\, GP_t + C_{water}\, WP_t + C_{water\_inj}\, WI_t,$$

where NP_t, GP_t, and WP_t are the cumulative production of oil, gas, and water for each year; WI_t is the cumulative injection of water during the year; and C_{oil}, C_{gas}, C_{water}, C_{water_inj} are the variable operating expense for each unit of oil, gas, water produced and water injected, respectively. This model requires more detailed input from the user but is an improvement over the two-factor version if suitable data is available. For the deepwater GoM, C_{oil} = \$10/bbl, C_{gas} = \$1/Mcf, C_{water} = \$10/bbl, C_{water_inj} = \$8/bbl might apply.

Example. Average production cost at Energy XXI GOM, 2012-2014

Energy XXI reported average production cost from 2012-2014 for their shallow water GoM properties as $15.2/boe direct LOE, $3.8/boe for workovers and maintenance, and $2/boe for insurance (Table U.1). ■

21.1.2. Limitations

There are obvious structural flaws in these models since they predict operating expense will decline over time as production declines, which is the opposite of what is commonly experienced! Applying an inflationary factor to increase cost with time is not a good strategy to resolve the issue since costs are increasing because of wear and tear and reservoir issues, which are independent of inflation, not the result of inflation. In the real world, LOE are not linearly related to anything and models that specify a linear relationship are usually capturing gross characteristics of the system. Lease operating expense are not just dependent on the number of producing wells or the volume of oil. It takes energy to produce water or operate a water/gas injection plant at a given pressure. It takes money for gas lift operations and for production crew and workover expenses. As wells age operating cost normally increase significantly.

To understand the cost to produce a barrel of oil it is necessary to understand the primary operational variables and their interrelationships over time. These relationships are generally complex, poorly understood, and difficult to model. Only rarely have such relations been examined. In many companies it is laborious to establish a clear and effective link between cost drivers and the bottom line because of the complexity of financial reporting and transactional processes.

The most popular operating cost models typically relate operating expenses to (producing) well count, oil/gas volume or rate, water volume or rate, or time. Each summary statistic provides a different perspective. The dollars per oil volume metric, for example, assumes that changes in well counts or produced fluids do not impact cost (Boomer 1995). The dollars per well metric assumes that increasing production volume does not increase operating expense. The dollars per month model assumes expenses will remain the same regardless of well count, fluid volumes, injection volumes, or injection pressure.

Example. Capital and operating expense for minimal structures

Chevron carried out a study in 2000 to identify and select platforms for shallow water GoM oil field development (Botelho et al. 2000). The locations considered were Eugene Island block 238 in 130 ft of water and Main Pass block 133 in 200 ft of water. Platform designs were based on maximizing the expected net present value over a range of production scenarios envisioned for a structure capable of supporting: (1) five wells, (2) a small deck with enough space to handle a coiled tubing unit or wireline unit; (3) a test separator and well header; (4) a small crane; (5) boat landing; and (6) a minimum helideck. Fabrication cost was estimated to range from $1.5 to $2 million per structure and installation was assumed to cost $750,000. Operating cost was assumed to be $725,000 per year on average for all concepts and $1 million for normal abandonment. ■

21.1.3. Model Parameters

Oil is inherently more expensive to produce than natural gas and dry tree wells are significantly cheaper to operate than wet tree wells, and thus model parameters should depend on the number and type of wells and type of production at the facility. Fields that require multiple platforms or platforms developing multiple fields, platforms with more wells, or wells with more complex configurations will usually have larger production cost than fields with one platform or platforms with fewer and simpler wells, for all other things equal. Unmanned and automated facilities are cheaper to operate than manned platforms but unit production cost may be higher or lower.

Trends with commodity price levels are difficult to establish empirically since they impact operating cost components both directly and indirectly. Changes in commodity prices directly impact costs such as fuel and chemicals which tend to be contractually tied to prices. Other items such as labor, boats, helicopters and materials are indirectly impacted since as prices increase industry activity and demand increase, and thus, costs, which enter the negotiation stage at contract renewal. Workover expenses are variable and insurance expense depends on operator preferences, size, and asset values.

Example. One- and two-factor operating cost models

If the operating cost for the GoM shallow water asset described in Chapter 18 (Table R.1, Figure R.3) were specified using the factor model $OPEX_t = A + B \cdot Production_t$ the model parameters will yield A = $2.6 million and B = $0.26/bbl.

The average production cost from the regression is smaller than the $1.21/bbl lifecycle cost because of the inclusion of the fixed term which provides additional information about operations. If the fixed term of the regression model is divided by the total capital expenditures of $57 million previously reported the result is 4.6% (= 2.6/57), providing an empirical basis for the selection of model parameters.

For the two-factor model $OPEX_t = A \cdot CAPEX_t + B \cdot Production_t$, the model parameters range over a larger solution space. For A = 3% the fixed term becomes smaller at 1.71 (=0.03*57) with larger B = $0.46/bbl. For A = 5% the fixed term increases to 2.85 (=0.05*57) while the variable term decreases to B = $0.21/bbl. ■

21.2. Workover Expense

Workovers are performed to maintain production and produce at the highest possible rates. When commodity prices rise operators seek to increase production and the number of workovers performed typically increase. Workovers are a discretionary budget item and a part of the annual operating budget is often allocated toward workovers. Assuming an average well workover cost C_t ($/well) and frequency of operation f_t (number of operations per year), the workover expense factor model is described as the product of the expense, frequency of intervention, and well inventory:

$$WO_t = C_t \cdot f_t \cdot NW_t ,$$

where the number of producing wells NW_t in year t is known or estimated and the workover cost and frequency of workovers is user-defined. A common assumption in the shallow water GoM is to require a workover every three years but this will obviously vary widely. Workover cost also range broadly from tens of thousands of dollars per operation to several hundred thousand dollars to a million dollars or more. Companies maintain records of their well activities and cost but rarely publicize results.

Example. Shell's GoM deepwater portfolio

Shell's deepwater GoM portfolio circa 2012 consisted of about 120 wells, two thirds direct vertical access and one third subsea, 80% oil wells and 20% gas wells. From 2002-2011, Morgenthaler and Fry (2012) reported that 128 stimulations were performed, on average about one stimulation per well per decade, while the total number of stimulations per year varied from 6 to 22 (5% to 20% well portfolio per year). During the early, high rate production period, depletion fines migration was the primary damage mechanism and acid treatments accounted for >80% jobs. As reservoirs depleted closer to bubble point asphaltenes deposition became more prevalent, and as wells started to produce water scale deposition became a problem. In 2012, half of treatments were for fines migration, 40% for asphaltenes deposits, and 10% for scale. Each stimulation treatment for scale, solvent and acid have separate workover expense and different outcomes. ■

21.3. Transportation and Gathering

When a pipeline is installed, the tariff is used to recover the investment, operating and maintenance expense, and various other secondary costs. The investment and owner of the line and the manner in which it is regulated are the most important factors that determine tariffs, but the age of the line and the number of customers and volume throughput and special circumstances (e.g., hurricane damage) are also important in determining rates at different times in the lifecycle of the pipeline. The underlying principal of cost recovery is the universal theme in ratemaking.

Age-related factors can act in favor or against the operator. After the pipeline is fully depreciated, for example, and assuming the pipeline is well maintained with adequate flow, tariffs may decline after the investment cost are fully depreciated. If the number of customers and amount of product transported through the pipeline at this time is low, however, then the operator may have to increase rates on remaining subscribers to generate adequate revenue to cover operations and maintenance. When volumes in the line decline, corrosion usually increases and maintenance becomes more difficult and expensive. The conditions governing each system is unique and therefore many factors potentially impact tariffs.

Historically, ownership of export pipelines in the GoM, especially gas trunklines, has seen significant activity from gas transmission companies. Producers contract for export services for oil and gas with an affiliated company or third-party. The transportation agreements set forth the terms and schedules. If gas pipelines are regulated by FERC, the agreements are in the public domain, otherwise, the agreements are generally confidential.

The monthly bill for deliveries usually include a reservation and commodity charge and other charges as applicable:

- Reservation charge – Equal to the product of the reservation rate multiplied by the Maximum Daily Quantity (MDQ) specified in the service agreement, multiplied by the shipper specific heating value and the number of days in the month.
- Commodity charge – Equal to the commodity rate multiplied by the quantity of gas allocated to the delivery point in the month.
- Other charges – Any applicable surcharges, new facilities charges, repair charges, and any incidental expenses.

The sum of the charges is equal to the transportation fee for a particular segment of line. If product is delivered using two or more segments a separate tariff will apply to each segment.

The heat or energy content of natural gas is dependent upon the composition of the gas and independent of the temperature and pressure. A thermie (th) is a metric unit of heat energy, and is equivalent to the amount of energy required to raise the temperature of one tonne (or 1000 kilograms) of water by one degree Celsius. A Btu or British thermal unit is the amount of energy needed to heat or cool one pound of water by one degree Fahrenheit. In North America, the heat value or energy content of a fuel is often expressed in BTUs. When dealing with larger quantities of energy, larger standards of measure are often used. In many natural gas pipelines energy content is measured in decatherms (Dth). A decatherm equals ten therms, or 1,000,000 Btu (or 1 MMBtu).

Example. Destin Pipeline firm transportation rate FT-1

A traditional firm service with fixed maximum daily quantity and reservation charge (FT-1 service) is depicted in Table U.2 for the Destin Pipeline (Figure U.1). For a shipper reserving 50 MMcf/d capacity with a heat content of 1000 Btu/cf, the monthly reservation rate is computed as:

$$\frac{\$7.19}{\text{Dth/mo}} \cdot \frac{50\,\text{MMcf}}{\text{d}} \cdot \frac{1000\,\text{Btu}}{\text{cf}} \cdot 30\ \text{d/mo} = \$10.785\ \text{million}.$$

If the actual average amount of gas delivered to the pipeline was 48 MMcf/d for the month, the commodity rate is computed as:

$$\frac{\$0.237}{\text{Dth}} \cdot \frac{48\,\text{MMcf}}{\text{d}} \cdot \frac{1000\,\text{Btu}}{\text{cf}} \cdot 30\ \text{d} = \$341{,}280.$$

The transportation rate 0.3¢/Dth = \$0.03/Dth is computed based on volumes delivered and being more than an order-of-magnitude smaller than the commodity rate is negligible in this case. The fuel retention percentage 0.3% represents a percentage of the quantity of gas delivered for transportation and used by the pipeline company for compressor fuel and gas otherwise used, lost, or unaccounted for and is also negligible in this case. The total cost for service for the month is \$11.126 million, 3% of which is due to the variable cost and 97% for the reservation rate. ■

Example. Mars pipeline tariffs

The Mars platform in Mississippi Canyon block 801 was one of the first regional hubs in the GoM and currently serves as a central processing facility for several fields (Figure U.2). The Mars pipeline is a 163-mi line originating approximately 130 miles offshore and delivers crude to salt dome caverns in Clovelly, Louisiana (Figure O.36).

Crude production from Mars A is transported to a service platform at West Delta 143 at the rate of \$2.61/bbl and then onward to Bay Marchand block 4 at \$1.16/bbl if <30,000 bbl/mo was delivered and \$0.70/bbl if >30,000 bbl/mo was transported (Table U.3). A discounted rate applies because greater volumes for the pipeline means greater revenue for the transporter to cover fixed cost. From Bay Marchard product is delivered to Fourchon and into storage at Clovelly/Caverns.

Crude production from Mars B (Olympus) to WD 143 is delivered in a newly constructed pipeline and because the line is new and the capital cost of construction greater than the Mars A pipeline, the tariff rate for the first segment will be higher. ■

21.4. Production Handling Agreements

21.4.1 General Considerations

In the deepwater GoM, there are several developments where an unaffiliated third-party owns the processing structure rather than the owner of the reserves. Canyon Express, Prince, Marco Polo, Independence Hub, Devils Tower, Tubular Bells (Gulfstar), Thunder Hawk, and more recently, Who Dat, Delta House and Stones are examples of deepwater projects where third-parties (e.g., gas transmission companies, private equity, conglomerates) without interest in the hydrocarbons own the host structure and lease it to the producers under negotiated terms referred to as Production Handling Agreements (PHAs).

Majors typically have the capital budgets and preference to own and operate all/most of the infrastructure in field development and believe they derive value from ownership, while independents in the GoM have sought various means to reduce capital outlays via third-party ownership to free-up capital for exploration and production (Huff and Heijermans 2003). In these transactions, the infrastructure owner provides the upfront capital and then collects monthly fixed fees and additional fees for demand and capacity based on the amount of production processed through the infrastructure. The downside for the reserves owner is less development freedom and higher production cost.

Infrastructure owners will seek recompense from third-party satellite (tieback) owners for operating expenses relating to processing production and a return on capital expenditures at a minimum, as well as a reservation of capacity for existing and other upstream projects in which they hold an interest. Generally speaking, the price parameters of PHAs are constrained on the upper end by the next best alternative available to the producer and on the lower end by the cost to upgrade equipment and process additional production (Thompson 2009).

Conversely, an infrastructure owner might not allow access for third party production for any number of reasons, including lack of capacity, disagreement on the legal and economic terms on which access is granted, inability to handle the type of production for which access is proposed, and the desire not to enrich a competitor (Sweeney 2016). The use, or increased use, of a facility may also bring greater risks of liability and damage and faster rates of depreciation and mechanical breakdown which need to be considered by the infrastructure owner.

Example. FPSO operating cost, rent vs. own

For a \$600 million FPSO with daily process operational cost of \$150,000, the difference between renting the FPSO on a 20-year lease and owning/depreciating the capital expenditures will be about \$100,000 per day. A quick back-of-the-envelope calculation illustrates the numbers. The owner of the FPSO will amortize the capital investment over the 20-yr lease-period, which using straight-line depreciation amounts to:

$$\$600 \text{ million}/20\text{yr} = \$30 \text{ million/yr} = \$82{,}200/\text{day}.$$

The FPSO owner is assumed responsible for all costs associated with vessel and process operations, maintenance and repairs. A production crew of 15 and a marine crew of 10 on a two week on/off schedule and annual average salary of $100,000 per person equates to $5 million/yr, or $13,700/day. Combined, the owner of the FPSO will need to charge the operator at least $100,000 per day to cover crew and depreciation cost. ■

21.4.2 Model Contracts

Several standard contracts for PHAs have been used for many years in the GoM and the American Association of Petroleum Landmen (AAPL) was one of the first organizations to develop model contracts in the industry in the 1950s. Model contracts such the AAPL Deepwater Model Form PHA and Shelf Model Form PHA are available through the AAPL website, and a few contracts are publicly accessible with the negotiated terms redacted. The contract arrangements and agreements are complex and consume time and resources in evaluation and negotiations. Contracts may exceed 100+ pages in length.

21.4.3 Contract Sections

The main sections of PHAs cover Infrastructure and Facilities, Services, Fees and Expenses, Capacity, Metering and Allocation, Gathering and Transportation, Suspension of Operations, Term, Liability and Indemnification (Table U.4). The Fees and Expenses section of contracts are the most important to understand for economic evaluations.

In the Infrastructure and Facilities section, the host and receiving facilities and the satellite production system are defined, including the host entry point (e.g., boarding valve) where satellite production enters host, and the delivery point (e.g., export pipeline) where satellite production departs host. In the Services section, the production handling and operating functions are described.

In the Fees and Expenses section, an infrastructure access fee is charged on a monthly basis for utilizing the host and its associated facilities. In consideration for access to the host and utilization of facilities, including risers, porches and boarding facilities; utilization of deck and riser space for satellite components; utilization of deck space for receiving facilities; and for the services provided, the producer pays a monthly infrastructure access fee. Minimum monthly fees and suspension of fees in the event the host is incapable of processing and handling satellite production are common features.

The producer pays for its pro-rata share of certain host operating and maintenance expenses based on the quantity of oil, gas, and water delivered on a monthly basis. These expenses are subject to allocation charges if mechanical or operational problems occur with satellite or non-satellite production. Deferred production compensates the host for deferment of host production during hook-up of the satellite system. A typical formula applies the average daily oil and gas volume of the host during the first 14 days of the 21 days immediately preceding the shutdown, multiplied by the duration of the shutdown, the average prevailing oil and gas price during the duration of the shutdown, and a negotiated discount factor that multiples the expression (such as 0.22 or 0.35).

In the Capacity section, the host capacity defines baseline processing and handling capacity, while the satellite capacity establishes the maximum production rates by product (oil, gas, produced water) on host. Production prioritization establishes constraint types and priority utilization principles in the event of curtailment due to operational issues of host and export pipelines. Fluid limits and operating parameters of satellite provides baseline specifications to determine conformance and establishes rights, obligations and responsibilities.

21.5. Thunder Hawk PHA

Netherlands-based SBM Offshore, owner of the Thunder Hawk semisubmersible, signed a PHA with Noble Energy to produce the Big Bend and Dantzler fields as subsea tiebacks. Big Bend is located about 18 miles from the Thunder Hawk facility in MC 698 in 7200 ft water depth and Dantzler is about seven miles away in 6580 ft in MC 782 (Figure P.16). In a 2016 press release, SBM Offshore announced production fees from the PHA were projected to generate $400 million in revenue over the 10-year primary contract period.

Denote the fixed and variable cost components of the PHA by A ($/yr) and B ($/bbl) and assume the total fixed and variable cost over the duration of the contract are allocated according to the percentage p and $1\text{-}p$, respectively. For field reserves of X MMbbl and contract duration D years, the total revenue R generated by the contract expressed in dollars is given by: $R = D{\cdot}A + X{\cdot}B$. The assumption of the cost recovery split allows the total revenue to be decoupled into fixed and variable cost components:

Fixed cost = $pR = A{\cdot}D$

Variable cost = $(1 - p)R = B{\cdot}X$

For values of R, D, X, and p given or estimated there are two equations and two unknowns to solve for A and B. For public companies, R is required to be reported if it is material to a companies operations and D is usually described in an accompanying press release. Reserves X may be reported by the producer or elsewhere in the trade literature and if not are readily estimated. The cost split p usually varies between 40 to 60%, and although it is a negotiated (confidential) term, it is unlikely to deviate too far outside this range. In some cases, A and B may be structured to be time-dependent with an inflationary adjustment.

In the Thunder Hawk PHA, the revenue and duration of the contract are reported as R = $400 million and D = 10 years, while the field reserves X = 50 MMbbl and the cost split p = 50% are assumed. Using this input data, the cost equations are solved to yield A = $20 million per year and B = $4/bbl, the inferred terms of the PHA. These contract terms are used to allocate revenue to the infrastructure owners based on field production and approximates annual production cost for the producer as:

$$OPEX_t\ (\$/\text{yr}) = \$20\ \text{million/yr} + \$4/\text{bbl} \cdot Production_t\ (\text{bbl/yr}).$$

For PHAs, the terms A and B determine operating cost via formula and contract specification in a form structurally equivalent to OPEX factor models. PHAs do not represent the full operating cost the reserves owners, however, since workover expense to maintain production and other exceptional events are not included.

21.6. Independence Project PHA

The Independence Project consists of ten natural gas fields in water depths from 7800 to 9000 ft in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas (Figure U.3). No field by itself was large enough to support the capital investment but combined and with third-party platform and export pipeline ownership a commercial solution was found (Burman et al 2007, Holley and Abendschein 2007). The Independence Hub semisubmersible is located in Mississippi Canyon 920 and was reported to cost $385 million and the cost of the Independence Trail pipeline was reported as $280 million.

Under the terms of the PHA, each producer pays a monthly demand charge to the owners of the platform for a portion of its investment and the remainder is recovered through a processing charge based on actual production. Each producer's capacity commitment determines its share of the total demand payment and has an allocated firm reserved capacity on the processing facility and pipeline for the first five years and a reduced reserve capacity in subsequent years.

The platform owners are responsible for all costs associated with platform operations, maintenance and repairs. The demand charge is assumed to be recovered over five years and the commodity charge is assumed to be recovered using proved reserves of 1 Tcf. The $385 million investment is split according to a 60% demand charge ($231 million) over five years and a 40% commodity charge ($154 million) is spread over 1 Tcf reserves. The fixed cost for the first five years is therefore $46.1 million/yr and variable cost throughout production is $154/MMcf.

Processing capacity at the facility was designed for 1 Bcf/d, so if the first year of production achieved design capacity then (1,000 MMcf/d)(365d/yr) = 365,000 MMcf natural gas would be processed at a cost of (365,000 MMcf)($154/MMcf) = $56.2 million. As production declines, the variable cost component will decline and once the entire reserves base has been recovered the full investment will have been returned.

The pipeline owner is responsible for all costs associated with export pipeline operations, maintenance and repairs (Al-Sharif 2007). The export tariff recovers the investment cost on an annualized basis similar to the platform access fees. Assuming 2P reserves of 2 Tcf, the $280 million is recovered by exporting 2 Tcf over its design life of 15 years: ($280 million)/(2 Tcf) = $140 MMcf.

In February 2016, production at Independence Hub ceased and all the wells were permanently abandoned. Total production was 1.26 Tcf and 326 Mbbl condensate, meaning that an export tariff based on 2P reserves would not have recovered the full cost of the investment. Who Dat gas export currently flows through the Independence Trail pipeline which provides some relief to the infrastructure owners.

21.7. PHA Risk Allocation

There are risks to the infrastructure owner if the reserves are not achieved in full since this is the cost basis used to recover their investment. If the commodity fee was based on 2P (proved and probable) reserves, for example, the infrastructure owner would have a greater exposure since the larger reserves both reduces and delays the cash flows received, and 2P reserves may or may not be achieved over the lifetime of the field. If 2P reserves are used to determine the commodity charge and only P1 reserves are recovered, the infrastructure owners will probably not have reached their investment goals. To secure the investment, the investor will prefer discounting P1 reserves but may have to agree to a larger reserve base (to lower the tariffs) when negotiating with the producer group. Many factors are involved in negotiation, including the members of the producer group and their affiliation with the infrastructure owners, the time of development and outlook for the future, the nature of the geologic prospectivity in the region and reserves committed to the asset.

Allocation of the fixed and variable cost attempt to account for the degree of risk involved between the two parties but the remedy is far from perfect. Two hypothetical scenarios for Thunder Hawk illustrate how risk enters PHAs for the different parties and why parties may seek to renegotiate contract terms.

Example. Big Bend & Dantzler hypothetical futures

<u>Scenario A: Fully depreciated asset by 2030</u>

The year is 2030 and Big Bend & Dantzler have exceeded their 50 MMbbl initial reserves estimates with 65 MMbbl cumulative production. In 2026, the terms of the PHA were renegotiated. The fixed cost term *A* was set to zero since the capital expenditures of the investor were fully depreciated and the variable cost term was raised to *B* = $10/bbl to handle SBM's higher operating cost and aging infrastructure. In 2026, Big Bend & Dantzler production was 3 MMbbl oil and commodity prices were relatively high, but by 2030 crude prices fell to $50/bbl and production was 0.5 MMbbl. With a royalty rate of 18.75% the producers net revenue in 2030 was about $20 million.

The processing fee to board/use Thunder Hawk is $5 million and Big Bend & Dantzler's operating cost is about $15 million/yr, so the operator will either need to shut-in the field, attempt to renegotiate the terms of the PHA (say aiming to reduce *B* in the range $5-$7/bbl), or try to sell the asset to another company. SBM Offshore may be willing to lower the terms of the PHA to keep the asset profitable for the operator, but they will not reduce the contract terms below their direct operating expense and insurance cost unless they have a clear strategic reason for doing so, say to keep the structure in place as nearby well results from other companies become known.

<u>Scenario B: Reservoir problems in 2020</u>

The year is 2020, just four years after the PHA was signed and first production was delivered. The operator has experienced numerous well failures, sand control problems and compartmentalization far worse than anticipated and the cost to remedy will yield much lower returns than originally expected. The operator does not anticipate recompletion or sidetracking additional wells and will run the existing wells until they no longer produce commercial quantities which is expected within two years. Low oil prices have made the decision to drill new wells and workover existing wells uneconomic and the operator will exit the field.

The production profile from Big Bend & Dantzler under this scenario yields revenue for SBM Offshore shown in Table U.5. After five years, SBM Offshore has received $240 million of its $400 million investment. There have been no announced discoveries and only a handful of exploration wells drilled within 25 miles of the asset and it is considered unlikely that new regional production activities from 2020-2025 will be supported at Thunder Hawk. A contingency fee on the fixed cost may require Noble Energy to pay some portion of the remaining $100 million to get out of the contract, but the variable cost are not included and SBM Offshore will incur at least a $60 million loss on its investment but thereafter is free to relocate and contract out its asset to other companies. ■

CHAPTER 22. ACTIVITY-BASED COSTING

Activity-based cost models apply work decomposition methods with knowledge of engineering and market conditions to estimate operating cost. They are the most detailed and transparent method that can be applied in operating cost estimation and require a higher level of expertise to successfully apply. In this final chapter, bottom-up activity-based approaches are described to illustrate how the operating cost components of labor, logistics and transportation, materials and supplies, repairs and maintenance are estimated. Numerous examples are provided to develop analytic skills and intuition regarding cost components and their relative importance. Diving, helicopter, and marine vessel contracts and service markets are reviewed as part of this discussion.

22.1. Operating Cost Categories

The primary cost categories for offshore oil and gas operations include:

- Salaries of operating personnel
- Transportation of products and people
- Materials and supply services
- Repair and maintenance of wells and flowlines
- Repair, maintenance, and inspection of equipment and structure

These are the on-going cost required to produce oil and gas and are expensed. Cost may be incurred daily, monthly or annually, be volume based, capacity based, or per person (Table V.1).

All cost estimates are performed at a specific point in time and are site, location, and operator specific. In activity-based costing, the tasks required to be performed are identified and the time and duration to perform each task is estimated using the best available information. If only a small number of facilities are evaluated a detailed approach is feasible, but for more than a few structures the resources required to complete an activity-based cost study is significant. The experience and time/resources available to the analyst is an important factor in the reliability of cost estimates.

22.2. Labor

In the GoM, facilities which are manned 24-hr report a bed count for the number of individuals that can be accommodated overnight (Figure V.1). Beds are required for production crew as well as service personnel, drilling and workover crew, supervisors, visitors, etc., and bed capacity does not necessarily reflect the number of permanent crew required for operations. Drilling and temporary beds are also sometimes counted separately from permanent beds. Permanent crew requirements may be considered to range between one-third to one-half of the reported number of permanent beds.

Hourly wage rates for offshore production and drilling crew are about the same as onshore, but for offshore operations the crew live onboard the platform which requires logistics planning, transportation, catering, safety process planning and support staff, which makes the total expenses far greater than for onshore operations. Direct salary expense for permanent crew usually ranges between \$100 to \$150 thousand per year and there are many different personnel rates (e.g., annual salaries or hourly contractors for different grades and occupations).

Example. Production crew salary

Offshore crew in the GoM typically work two weeks on and two weeks off, so a facility that requires a permanent crew of 16 such as Independence Hub when it was in production would require an annual labor cost of 2 × 16 personnel × \$125,000/person per yr = \$4 million per year assuming an average base salary of \$125,000 per person. A shallow water facility such as a gas receiving platform may only require a four-man crew at \$1 million per year. ■

Example. Catering expense

Catering requirements are usually contracted on a dollar per person per day basis and includes food service, cleaning, and laundry. Vendors can be contacted for the most up-to-date quotes but values are easy to bound. It would be difficult for a GoM contractor to stay in business charging less than say \$10/day per person to feed personnel three meals a day while \$50/day per person is an approximate upper bound. Actual values will depend on market competition and other conditions. Services such as cleaning linen and waste disposal may be added separately or included as part of the per person cost. The caterer is provided transportation to-from an onshore service base by a logistic firm paid for by the operator, unless the caterer contracts and charges for this service as part of its price. ■

22.3. Logistics and Transportation

Crews, supplies and equipment must be transported to the offshore platform, and so the further from shore base the operation the greater the cost for fuel and vessel/helicopter rentals, and the more frequent the visits the greater the expense. Larger vessels and helicopters usually charge a premium relative to smaller vehicles, and services with a shorter notice period and contract duration will also be more expensive, for all other things equal. All manned platforms in the GoM have helidecks and all deepwater facilities are serviced using helicopters for crew, while closer to shore, both marine vessels and helicopters are utilized for crew change. Material transport for water, chemicals, mud, fuel, equipment, etc. is via supply vessel.

22.3.1 Marine Vessels

Vessel charters are the product of either direct negotiation or a competitive process that evaluates vessel capability and price. The dayrate is the primary bid variable in contract negotiation and selection, but other factors such as safety record, history with the firm, and vessel specifications are also important.

Marine vessels are leased primarily on "term" or "spot" charters, although "time" and "bareboat" charters are also used occasionally. Term charters are generally three months to three years in duration and are typical for drilling or production support. Contract terms may be indexed to market conditions. Spot charters are a short-term agreement (one day to three months) to provide offshore services for a specific job. Spot charters are commonly employed for unscheduled or non-recurring support, as in decommissioning, well work, or incident response. Under a time charter, the operator provides a vessel to a customer and is responsible for all operating expense including crew costs, but typically excluding fuel. Under a bareboat charter, the operator provides a vessel to a customer and the customer assumes responsibility for all operating expenses and associated risks.

Average monthly dayrates for crew boats and offshore supply vessels (OSVs) in the GoM are published in Workboat Magazine based on contractor surveys and can be found on an annual consolidated basis in financial statements for public companies. Several consulting firms also provide dayrate indices based on market intelligence, including contract evaluation. As a general proxy, market dayrates and/or company data can often be used to infer fleet vessel rates because to a large extent the ships and services – at least in shallow water – are relatively homogeneous and commodity-like (Kaiser 2015). High levels of competition in the region mean that dayrates are unlikely to deviate significantly among operators unless differentiated by technology or vintage.

Example. Shallow vs. deepwater transportation charters

In December 2016, the average dayrates in the GoM for crewboats <170 ft in length and OSVs < 2000 dead weight ton DWT (Figure V.2) were reported in Workboat Magazine to be \$3230/day and \$7800/day, respectively. Assuming one day per trip for OSVs and 6 hr per trip for crew, two week on/off schedule for crew and a weekly OSV visit to the platform, and an assumed 80% discount to the average OSV spot rates yields the following annual cost estimate for crew and material transportation:

$$\text{Crewboat: } \$3230/\text{day} \cdot 0.25 \text{ day/trip} \cdot 26 \text{ trips/yr} = \$21{,}000/\text{yr}$$

$$\text{OSV: } 0.80 \cdot \$7800/\text{day} \cdot 1 \text{ day/trip} \cdot 52 \text{ trips/yr} = \$324{,}000/\text{yr.}$$

The average dayrates for OSVs >5000 DWT were \$30,662/day in December 2016 and helicopter spot rates are assumed to be \$2500/hr. If a round trip to a deepwater facility takes two days by boat and five hours by helicopter, then for a weekly OSV visit and biweekly crew change the annual crew and logistics cost are estimated as:

$$\text{Helicopter: } \$2500/\text{hr} \cdot 5 \text{ hr/trip} \cdot 26 \text{ trips/yr} = \$325{,}000/\text{yr}$$

$$\text{OSV: } \$30{,}662/\text{day} \cdot 2 \text{ day/trip} \cdot 52 \text{ trips/yr} = \$3.19 \text{ million/yr.}$$

Structures in deepwater are farther from shore bases and require larger crew than shallow water structures which translate into higher labor, catering, transportation, and logistics cost. ■

Example. Shallow vs. deepwater labor and transportation cost

In Table V.2, labor, subsistence and transportation cost for a manned platform in shallow water with five permanent crew and a deepwater facility with 30 permanent crew are estimated circa 2016. Annual labor and transportation cost for a five man shallow water platform is estimated at \$1.7 million versus \$11.6 million/yr for a 30 man deepwater facility. Note that deepwater labor and transportation costs in this example are about an order-of-magnitude larger than for a shallow water platform. ■

22.3.2 Helicopters

The majority of helicopters in the GoM are chartered through master service agreements, subscription agreements, and day-to-day charter arrangements. Master service agreements and subscription agreement typically require a fixed monthly fee plus incremental payments based on flight hours. These agreements have fixed terms ranging from one month to three years and contain terms that index fuel costs to market rates so the helicopter operator is not exposed to fuel price variation. Contracts are cancellable by the client with a notice period ranging from 30 to 180 days. In the U.S., short-term contracts for 12 months or less are common. "Ad-hoc" (spot, or term charter) services usually entail a shorter notice period and shorter contract duration and are based on an hourly rate, or a daily or monthly fixed fee plus additional fees for each hour flown. Generally, ad-hoc services have a higher margin than other helicopter contracts due to supply and demand conditions.

Helicopters range in size from small to large. Single engine and light-twin helicopters perform multiple takeoff/landings to shelf platforms and have a typical passenger capacity of five to nine. Single engine helicopters are the largest population of helicopters in the GoM and most are single pilot and use aviation gasoline and reciprocating engines, which are cheaper to operate and build than turbine engines but also provide less performance. Medium and heavy helicopters have twin turbine engines and a typical passenger capacity of 16 to 19, can fly in a wider variety of operating conditions using instrument flight rules, travel longer distances, and carry larger payloads than light helicopters. Medium and heavy aircraft are required for crew changes on large production facilities and drilling rigs and all deepwater facilities.

When an aircraft company purchases a helicopter, direct cost is an important feature since it shows the revenue a company must receive to recover its cost and stay in business. The fixed cost and hourly flight cost serve as the primary point of negotiation between operator and customer. Terms depend on the age and type of aircraft, as well as market conditions at the time of negotiation and safety record of the operator. If flight activity is less than anticipated then the revenue rate may not cover the actual cost per hour and operators balance this risk through a combination of fixed and variable components, similar to the PHAs described in Chapter 21. Helicopter operators report that they typically receive about half of their revenue from the fixed cost.

Example. Master Service Agreement for Eurocopter 135/145

Direct cost calculations for a light twin Eurocopter 135/145 (Figure V.3) at a purchase price of $700,000 is considered (Table V.3). To break even a 5-year depreciation period with a 30% residual value per year is applied. Operators buy hull and liability insurance to protect against damage to aircraft and related liabilities and hull insurance is assumed to be 10% of the purchase cost. One pilot with annual salary of $90,000 is assumed. Fuel rates are taken from the EC 145 spec sheet and the oil and lubricants, maintenance labor, spare parts, and engine overhaul to maintain safe and reliable operations are additional cost terms. Fuel costs are assumed to be $2/gal for Jet A.

The fixed cost for the 5-year depreciation period is $263,000 per year. The hourly costs for flying are estimated at $240.50/hr and are computed for different flight hours. To recover the cost of operations, an operator will need to negotiate a monthly rate of $263,000/12 = $21,900/mo and an hourly rate of $504/hr flight time if the flight hours are expected to be 1000 hours. If the flight hours are expected to be 500 hours a minimum hourly rate of $767/hr would need to be negotiated to breakeven. ■

22.4. MATERIALS AND SUPPLIES

Materials and supplies are usually not a significant cost in conventional operations until late-in-life since after the equipment is purchased and installed, the primary energy for their operation derives from the reservoir itself and from separated production gas. Facilities which support production from the reservoir, such as gas and water injection, and fields with low quality crude which exhaust their reservoir energy require more equipment and greater material and energy use relative to young fields with lighter crudes and strong reservoir drives. Facilities which support subsea wells require greater utilities and chemical usage relative to dry tree wells.

Chemicals are used for controlling corrosion, emulsions, foaming, mineral scales, paraffins (waxes), asphaltenes, gas hydrates, hydrogen sulfide and water quality. Before any treatment is applied, it is important to conduct a thorough investigation of the problems, their root causes, and any implications of the treatment. Chemical cost should be considered from a life-cycle perspective and compared against methods where the problem is managed in a different way. Chemical cost is usually not the overriding driver in chemical selection, but rather, the technical performance must be able to manage the risk.

22.4.1 Chemicals for Water Treatment

Water may be injected into the reservoir to supplement oil recovery or to dispose of produced water. In either case, water will require treatment and the type of treatment depends on the source and issues identified (Table V.4).

Example. FPSO seawater injection cost

For an FPSO with a \$100,000 daily operating facility cost, water treatment cost per barrel based on seawater injection and produced water treatment at \$4/L chemical cost is shown in Table V.5 (Wigget 2014). ■

22.4.2 Chemicals for Corrosion

Highly corrosive fluids (e.g., sour >10,000 ppm H_2S; heavy oil >25 °API; gas oil ratio < 500 cf/bbl; high water cut >80%) will require greater chemical spending for corrosion control and account for a higher percent of operating expense than non-corrosive fluids. There are many chemical corrosion treatments, including hydrogen sulfide scavenging chemicals, combo treatment chemicals, single purpose inhibitors, biocides, etc. that can be applied. Pilot studies are often performed to determine the best treatment before implementation.

Production chemicals are typically injected directly into the wellbore's tubing-casing annulus, wellhead, flowlines and throughout the separation train to treat for corrosion, emulsions, scale and H_2S content. Tubing failures are a common impact of corrosion. Reducing chemical spend can lead to mechanical integrity issues that are more costly to remediate than to prevent (Cavaliaro et al. 2016).

Example. Corrosion inhibitors

Natural gas with impurities such as H_2S and CO_2 are highly corrosive and are commonly treated with chemical inhibitors. Typical corrosion inhibitor concentrations are 5-50 ppm for continuous addition and up to 250 ppm for batch dosing. Inhibitor use increases in proportion to flowrate and at higher flow inhibitor use increases. Gas inhibitor dosage rates are typically in the range of 0.25-0.75 L/MMcf of gas and at \$10/L chemical cost translates into an annual chemical cost of \$1825 and \$91,250 for flowrates of 1 and 50 MMcfd (Table V.6). ■

In moderately corrosive environments, batch chemical treatments can provide sufficient protection to downhole equipment and flowlines. In highly corrosive environments and larger produced volumes, chemical treatment may be uneconomic. When flowrates are high, turbulence in the pipelines help ensure that the full interior of the line is inhibited with chemical, but as flow velocities decline and turn laminar, untreated areas are more likely to arise.

22.4.3 Chemicals for Flow Assurance

In general, the greater the change in temperature and pressure that produced fluids experience in traveling from the reservoir to the host, the greater the number of flow assurance problems and chemical treating needs (Figure V.4). Flow assurance issues are generally not a concern in shallow water and with dry tree and direct vertical access wells. The list of chemicals utilized in subsea developments may be substantial to avoid problems with solids deposition and to ensure safe and reliable operations. They include: methanol, low dosage hydrate inhibitors, asphaltene inhibitor, paraffin inhibitor, pour-point depressant, corrosion inhibitor, and scale inhibitor (Bomba et al. 2018).

Strategies to reduce the magnitude of the changes occurring, especially in temperature which drives wax and hydrate formation and to a lesser extent scale formation, require capital. Flow assurance strategies typically involve a combination of equipment design/selection, operational methodologies, and chemical treatments (Table V.7). The overall objective of flow assurance is the keep the flow-path open.

Example. Methanol hydrate inhibitor cost

A well produces 1000 bpd water and 0.5 bbl of methanol per barrel of water is used to prevent hydrate formation. In the GoM, methanol cost varies with market conditions and transportation, and historically has ranged from \$25 to \$75/bbl. For \$50/bbl (=\$1.2/gal) methanol, hydrate inhibitor cost will be \$25,000 per day or \$9 million per year. For some fields, the methanol delivery system may define the abandonment conditions of the well. ■

Methanol and LDHI (low density hydrate inhibitors) are commonly employed in oil wells and are usually consumed (i.e., not recovered) in the process. Gas dominated systems typically use MEG rather than methanol because of the lower amounts required and MEG offers the advantage of being recyclable. Selection is normally based on the lowest cost per volume produced basis but other factors may also play a role. For example, the presence of methanol in crude oil negatively impacts the price received since it causes catalyst poisoning in refineries and may limit its application. Topside storage volume constraints may also play a role in chemical selection.

Example. Methanol vs. LDHI cost comparison

For a subsea well producing a 39 °API condensate application costs for methanol at \$1/gal and 35% water flow are compared to LDHI at \$30/gal and 0.5% water flow (Swanson et al. 2005). If there is no recovery of the chemical, then the monthly chemical cost to inhibit hydrates for a water flow rate of 1300 bpd is:

$$\text{Methanol cost} = 0.35(1300\ \text{b/d})(42\ \text{gal/bbl})(\$1/\text{gal})(30\ \text{d/mo}) = \$573{,}300/\text{mo}$$

$$\text{LDHI cost} = 0.005(1300\ \text{b/d})(42\ \text{gal/bbl})(\$30/\text{gal})(30\ \text{d/mo}) = \$246{,}300/\text{mo}.$$

Hydrate inhibitors treat the aqueous phase and therefore the higher the water rate the higher the dosage. Hydrate prevention costs vary with the water flow rate, chemical cost, and prevention mechanism. ■

Example. K2 chemical injection system

The K2 field is a three-well subsea development in 4200 ft water depth tied back 6.9 miles to its host at the Marco Polo TLP. Pipe-in-pipe flowlines and insulated risers with a chemical injection system for each well was selected in development. LDHI was selected as the main hydrate inhibitor and methanol was used as a backup system. At startup after a shutdown it is necessary to inject wax inhibitor to prevent wax formation while the flowrates are low and the temperature is below the WAT. Once the flowline temperature is greater than WAT, which is expected at flowrates >5000 bpd of produced fluid, the paraffin inhibitor is stopped. Modeling indicated that asphaltenes deposit occur around the bubble point where vaporization takes place and might stick to themselves or to the pipe wall causing a flowline restriction. Chemical injection to control asphaltenes is used when needed and varies with each well.

The injection points are shown schematically in Figure V.5 and the umbilical assembly for chemical delivery is shown in Figure V.6. Two deep-set chemical injection mandrels are located above the production packer approximately 18,000 ft below the mudline, and one shallow-set mandrel is located above the downhole safety valve which is 3900 ft below the mudline. The deep-set mandrels are used for asphaltenes and wax inhibitor injection to protect the wellbore as well as pipeline. LDHI is injected downhole for better mixing and methanol is injected at the tree for startup. ■

22.4.4 Fuel, Water and Utilities

"Fuel is free" is a common adage in the oilfield, and indeed, as long as wells are not producing highly viscous, black crude (GOR < 500 cf/bbl), most wells produce enough (associated) gas to use at site to satisfy a significant portion of fuel usage and export the surplus. Back-up fuels are always required during start-up and after shut-down operations since process systems will be off-line during these times and the gas from processing will not be available.

If a structure produces gas from its lease it is used free-of-charge to provide electricity, heat, cooling (via pumping seawater for example) and related power requirements. Of course, gas use will reduce sales revenue and operators have incentive to operate efficiently, but from a cost perspective unless purchased fuel cost is not considered in evaluation, and so electricity generated from gas produced at site has no fuel cost. If gas is not available at site, fuel will need to be purchased and delivered to the platform. For start-up operations and as a back-up power, diesel is commonly used offshore and stored in bulk or in tanks. Gas supply may be provided by a nearby platform by running a flowline to the facility and installing a metering system with standard market rates applying.

Utilities systems support production operations and include the power system (fuel gas and diesel), seawater and potable water treatment system, chemical and lubricating oils, alarm and shutdown systems, fire and protection and fire-fighting system, instrumentation and utility air system. Power generation and electrical systems are required for large or complex facilities and manned platforms. Water needs to be transported to manned facilities for personnel use.

Example. Power generation at Appomattox

Dresser-Rand delivered power generation equipment for a combined cycle power plant for Shell's deepwater Appomattox development. The 150 MW power plant features four 27 MW gas turbine-driven generator sets equipped with heat recovery systems and a 40 MW steam turbine generator. ■

22.5. REPAIRS AND MAINTENANCE – WELLS & FLOWLINE

22.5.1 Maintenance

Pigging is performed as part of regular operations to facilitate flow and reduce corrosion and buildup in pipelines.

Example. Paraffin cutting at Pompano

In the Pompano development in Viosca Knoll 989 and Mississippi Canyon 28, subsea wells are maintained using a TFL (through flowline) system to transport (simple) tools and chemicals to the wellbores through the manifold/template (Figure V.7). TFL systems were introduced in the late 1960s to provide a low cost wellbore re-entry capability for mechanical removal of paraffin deposits but many early systems were plagued by operational problems and equipment failures (Keptra 1976). Circulating pressure moves the tool through the looped system. Because of the waxy nature of the crude (3.2 wt% paraffin content, 95 °F cloud point, -6 °F pour point) and the distance between the subsea wells and host facility, frequent paraffin cutting of the service lines was expected (Kleinhans and Cordner 1999).

A base case and a worst case scenario in the types of TFL operations required and their expected frequencies were estimated by engineers to understand the downtime and operating cost requirements (Table V.8). Operations require different tools to be employed and contractor cost for equipment and crew will depend upon requirements. Production will normally be shut-in during operations and dead oil used for circulation. When wells are producing at high rates (>2000 bopd) downhole cutting is not expected, but as the well rates diminish routine paraffin cutting is required. As reservoirs deplete and fluid chemistry changes, the worst case scenario was considered more likely to arise. ■

22.5.2 Stimulation

Wells need to be maintained for maximum productivity, and in the event that a well stops producing a decision has to be made on the merits of attempting to bring the well back on-line. Well constraints are categorized as completion interval constraints and production tubing constraints (Table V.9). The type and frequency of activities vary significantly as well as the success of action.

The three primary causes of well impairment include the movement and rearrangement of reservoir fines, deposition of solids from produced crudes, and deposition of mineral scales from produced water (Table V.10). Scale formation may occur in the reservoir and inside the production tubing and may be removed chemically or mechanically. A well producing at high water cut may be choked back or a change of perforation interval may be considered to shut-off unwanted fluids. Skin problems may be resolved by acidizing or additional perforations.

Tubing corrosion requires monitoring and if a leak develops the tubing needs to be replaced or the well shut-in. As reservoir pressure declines, the tubing may need to be reduced in diameter to maintain maximum flow. When the natural drive energy of the reservoir has reduced, artificial lift may be justified which will increase both capital and operating expense. Sand production from loosely consolidated formations may erode tubulars and valves and cause problems at the surface separators and necessitate recompletion. Paraffin cutting is a common maintenance requirement for high wax crude.

Personnel separate from the production crew are required for operations and are performed by a service crew that require transportation and logistics support. Because the well is shut-in during operations, logistics coordination and efficiency is critical and timing is of the essence. Stimulation of subsea wells is more challenging and costly than dry tree and direct access wells but may be highly profitable if technology solutions have been developed and outcomes are successful.

22.5.3 Well Failure

When wells stop producing, the probable cause of the shut-in is determined and options are identified such as

- Sidetrack the well
- Perform a workover to remediate problem
- Leave the well shut-in

The decision to invest capital in an attempt to bring the well back on-line depends on many factors. The price of oil/gas and equipment/rig dayrates play an important role in decision making as well as the uncertainty associated with the problem and remaining reserves. New wells that fail have a much greater chance of getting a workover than an old well that has already drained most of the reservoir. Workover decisions in old wells are risky since the operator may not get their investment back, and so once an older well stops producing a workover may not even be contemplated if production rates are low. Decisions may also be based on maintaining a lease position.

Example. Troika well TA-6

The Troika field in Green Canyon 201 is a subsea development tied back to the Bullwinkle platform in GC 65 (Bednar 1998). Well TA-6 was brought online in November 2000 and produced 3.9 MMbbl oil and 4.48 Bcf of gas for 14 months before a gravel pack failure occurred (Gillespie et al. 2005). Sidetracking was not considered the best option due to low oil price forecasts and the uncertainty of the remaining reserves caused by increasing water production. It was decided to clean out the well and run a screen insert inside the failed screen. If this option failed the well would be shut-in.

The workover was completed in one week at a cost of about $8 million. The well was returned to production in January 2003 and the post workover production was 1.95 MMbbl oil and 2.7 Bcf through June 2005, an obvious success since the post workover revenue far exceeded the cost of the intervention. Operators seek workovers with strong positive results but cannot always control or predict the outcome of operations. ■

22.5.4 Flowline and Export Repairs

Hydrates, wax, and asphaltenes in the hydrocarbon streams have the potential to disrupt production due to deposition in the production system and is a primary issue in subsea systems.

Example. Stuck pig at Marlin

The Marlin TLP is located in Viosca Knoll 915 in 3250 ft water depth and is host to several dry tree and wet tree wells (Fung et al. 2006). Oil export is via a 22 mile non-insulated 10-inch line to facilities at Main Pass 225 in 200 ft water depth. The oil export management plan used a regular single trip pigging technique to remove the wax build up every 14 days and was selected over continuous wax inhibition because of the high operating expense of the chemical treatment.

Oil leaves the Marlin TLP at a temperature of approximately 120 °F and drops to 40 °F over the first 7300 ft (1.4 miles) of flowline and then warms to about 65 °F at the MP 225 location (Figure V.8). Since the pipeline does not have any insulation higher flowrate fluids will retain heat for longer distance. The WAT of the co-mingled oil streams is approximately 95 to 100 °F. Heavy molecular weight paraffinic hydrocarbons begin to solidify and deposit on the pipe wall over time and give rise to an increasing pressure drop due to reduction in the flow diameter and increase in the pipe roughness.

Equipment failure stopped the 14-day pigging cycle and resulted in a stuck pig. The stuck pig was estimated to be approximately nine miles from the MP 225 facility in approximately 1200 ft water depth (Figure V.9). Pumping equipment at MP 225 was used to pump the pig back to Marlin using buyback crude with 5000 gallons of wax solvent and 300 ppm of wax inhibitor. ■

22.6. Repairs and Maintenance – Equipment and Structure

Offshore platforms generally have longer useful lives than the underlying reserves for which they were installed, but since the platform resides in an environment subject to the stresses of operation, temperature changes, corrosive chemistry, storm waves and possible collision, structure inspections are performed on a periodic basis dictated by company practices and regulatory requirements. The scope of maintenance painting and inspection operations vary by operator and structure type.

22.6.1 Regulatory Requirements

The OCS Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and periodic unscheduled (unannounced) inspection of all oil and gas operations on the OCS. In addition to examining all safety equipment designed to prevent blowouts, fires, spills, or other major accidents, the inspections focus on pollution, drilling operations, completions, workovers, production, and pipeline safety.

Upon detecting a violation, the inspector issues an Incident of Noncompliance ("INC") to the operator and uses one of two main enforcement actions (warning or shut-in), depending on the severity of the violation. If the violation is not severe or threatening a warning INC is issued. The warning INC must be corrected within a reasonable amount of time specified on the INC. The shut-in INC may be for a single component (a portion of the facility) or the entire facility and must be corrected before the operator is allowed to resume operations.

The BSEE can also assess a civil penalty of up to $40,000 per violation per day if: (i) the operator fails to correct the violation in the time specified on the INC; or (ii) the violation resulted in a threat of serious harm or damage to human life or the environment. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

BSEE regulations require operators perform in-service inspection intervals for fixed platforms according to API Recommended Practice 2A-WSD (NTL 2009-G32). Section 14 of API RP-2A-WSD describes the inspection program survey levels and frequencies to monitor periodically the adequacy of the corrosion protection system and determine the condition of the platform.

22.6.2 Inspection Schedules

The time interval between platform inspections depend upon structure exposure category (L-1, L-2 or L-3), survey level (Level I, Level II, Level III), and manned status (Table V.11).

Exposure Category

Two classes of risk are used to define exposure category, those associated with life safety and those associated with consequences of failure (Ward et al. 2000a, b). The three levels of exposure to life safety are manned and non-evacuated, manned and evacuated, and unmanned (Table V.12). Consequences of failure encompass damage to the environment, economic losses to the operator and the government, and public concerns. Economic losses to the operator can include the costs to replace, repair and/or remove destroyed or damaged facilities, costs to mitigate environmental damages due to released oil, and lost revenue. Economic losses to the government include lost royalty revenues. Consequences of failure are categorized as high, medium and low.

Level Surveys

A Level I survey is required to be conducted for each platform at least annually and a grade assigned to the coating system as A, B, or C. Grade A indicates the coating system is in good condition with no maintenance needed within three years. Grades B and C refer to fair and poor coating system conditions requiring maintenance within three years or twelve months, respectively.

A Level II survey is required for each platform at the minimum survey interval for each exposure category, at least every three years for L-1 platforms and at least every five years for L-2 and L-3 platforms.

A Level III survey is required for each platform at the minimum survey interval for each specified exposure category, at least every six years for L-1 platforms and at least every 11 years for L-2 platforms.

For unmanned platforms, BSEE may approve an increased interval for Level II and Level III inspections if the operator is in compliance with all structural inspection requirements and the platform is in good structural condition according to previous Level I and Level II surveys.

Inspection Levels

Level I inspections are topside inspections performed annually. Topside maintenance is relatively easy to perform as long as equipment is accessible and paint schedules are followed. Flare towers, crane booms, and lower deck levels present more complicated regions because of access. Level I inspections are normally performed by an operator's maintenance personnel or staff personnel.

Level II inspections are underwater inspections performed every three to five years to check for debris, gross damage, measure cathodic potential readings, and verify anode connections. On large shelf structures anode connections may number in the hundreds, and on deepwater structures in the thousands[31]. Level II inspections generally do not involving cleaning and marine growth

[31] For example, the cathodic protection system on the Bullwinkle jacket in 1350 ft (411 m) water depth consists of approximately 6300 aluminum-zinc-mercury anodes totaling about 2400 tons of anode material (Wolfson and Kenney 1989).

removal for weld inspections and fractures and one or two days per platform is considered adequate for inspection.

Level III inspections are underwater inspections required to be performed on a six to 11-year interval in compliance with BSEE regulations. Typically, Level III inspections include the cleaning and inspection of select member ends, conductor areas near the bell guides, and connection points of anodes. Member ends with lower fatigue life are selected for inspection, and if damage is detected, the inspection scope is likely to be extended. Level III inspections will usually take several days to a week or longer per platform.

22.6.3 Three Zones

There are three separate zones in platform corrosion control: the immersed zone, the splash zone, and the atmosphere. Corrosion rates for each zone are broadly similar throughout the world but site-specific factors lead to differences. Tides, water temperature and velocity, salinity, humidity, and wave forces all affect corrosion rates and the design of the corrosion control system.

The bulk of the platform is immersed and this portion is also the simplest to protect with cathodic protection being the most common method. The process typically involves welding sacrificial nodes throughout the structure before installation to supply protective current to the steel members. The splash zone is the most critical area with the highest corrosion rates due to the alternate submergence and aeration. Splash zone protection in the GoM is often installed a few feet below the waterline to several feet above (e.g., -3 ft to 7 ft). Steel members in the splash zone are also normally designed with a greater wall thickness to account for greater corrosion. The atmospheric zone includes structural steel, equipment, piping, vessels and valves and has the least corrosion rate but the most surface area and is the most expensive to maintain (Figure V.10).

Structures and piping in the splash zone are painted to protect the steel from aggressive corrosion due to wave action and continuous wetness. Structures are painted above the splash zone to assure that equipment will remain functional. Bare flanges, valves and rotating equipment will quickly become inoperable and pressure equipment may become too thin to hold pressure creating safety hazards if not properly maintained. Below the splash zone, some operators may paint the entire jacket but cathodic protection systems is the principal means of corrosion control.

22.6.4 Painting

Objective

The primary objective of painting platforms and equipment is to protect offshore structures to ensure integrity and that the structure will last for its intended design life (Choate and Kochanczyk 1991, Knudson 2013). The selection of a coating system is a design choice made by engineers based on the tradeoffs between steel thickness and the corrosion allowance that the coating system is engineered to protect (Taekker et al 2006, Kattan et al. 2013).

During the fabrication of offshore structures, surfaces are painted and treated to the operator's specification, and assuming activities are performed according to requirements, will provide protection against salt water corrosion, ultraviolet radiation, rust, splash zones, changing temperatures, and related deterioration for several years. After a period of time, however, depending on the specifications and materials used, environmental conditions, and other factors the coating will need to replaced according to the level of deterioration. Coatings are monitored and treatment performed before major interventions are needed. Regular maintenance extends the structure life integrity and lowers repair frequency.

Paints & Standards

Most of the early GoM platforms installed in the 1950s used coating systems based on polyvinyl acetate copolymers and later epoxy amine systems (Mitchell 2004). The vinyl copolymer systems were low solids (20% volume solids) which meant that thick films could not be applied in a single coat. Maximum dry film thickness (DFT) for low solids systems were around 50 microns (2 mils) per coat but had good durability and long term stability. To achieve DFT of 250-300 microns (10-12 mils) multi-coat systems expensive to apply were required.

An improvement to the system was the application of inorganic zinc silicate as a primer. Primers contain inhibitors to suppress corrosion processes while top coats are a barrier product. By the late 1970s GoM systems comprised zinc-rich epoxies which became the precursors to those used today (Hanson 1969). Typically, steel is painted with zinc-rich epoxy primer to a specification thickness (e.g., 50 μm, 2 mils), and then a primer finish is applied in one or more coats (e.g., 125 μm, polysiloxane primer). Different areas of construction often require different coating systems. When applying a coating on a large and complex installation, it is almost impossible to control film thickness on every part of the structure. In a three-coat system, the chance for thin areas in the coat are less likely than for two-coat applications.

In the 1990s higher solids coating systems were employed to reduce solvent emissions and number of coats. Over the last 20 years, regulations have created changes in coating chemistry for health and safety reasons (e.g., ban on use of coal tar epoxies) and environmental concerns (VOC emissions).

There are design standards for offshore coating systems (ISO 20340, NORSOK M-501, NACE TM 0104) and the qualification of products, procedures, companies and (inspection) personnel. The primary aim of standards is to provide optimum surface protection with a minimum need for maintenance. Each standard describes different coating systems for application on various parts of an offshore structure. Each coating system is described with requirements to surface preparation, number of coats, and requirements for pre-qualification testing.

There are five categories relating to atmospheric corrosion per ISO 20340 and the C5-M category refers to marine corrosivity in offshore areas of high salinity. IM2 describes the immersion category of sea or brackish water. Surface preparation is defined by increasingly thorough abrasive blasting methods Sa1, Sa2, Sa2½, and Sa3 that leave the surface free from visible oil, grease and dirt and from scale, rust, paint coatings, and foreign matter. Standard preparation grades also exist for hand and power tool cleaning (St2, St3) and water jetting (Wa1, Wa2, Wa2½). The more corrosive the environment the more thorough the surface preparation required.

Maintenance Painting Schedule

There are several methods of conducting maintenance painting and determining which method to use is a philosophical and technical decision. Maintenance implies sustaining a particular level of coating integrity and performance, while repair implies restoring a coating to a previously higher level of integrity and performance. Operators with small maintenance budgets or that delay or reduce maintenance activities will often face higher repair costs than operators with a constant painting budget. For low cost equipment and with a short operation life, corrective maintenance is the common approach (i.e., fix it when it breaks). For high capital cost structures and equipment, preventative and predictive monitoring is standard (Witte and Ribeiro 2012).

Normally, coating systems are selected to meet design criteria and at lowest cost and are carried out at construction yards. Repainting is then required at 5-8 year intervals with surface preparation such as water jetting, grinding or sand blasting. After original painting, spot touch up and repair are expected to occur at the "Practical Life (PL)" (or service life) of the coating system listed in Table V.13 for different coating systems for offshore atmospheric and immersion service. The time until "Maintenance Repaint (MRP)," which includes spot prime and full overcoat, is estimated to occur at Practical Life plus 33% (1.33PL). A "Full Repaint (FRP)" involving total coating removal and replacement is expected to occur at the year of "Maintenance Repaint" plus 50% of the Practical Life (MRP + 0.5PL). Table V.14 summarizes the schedule.

Example. Levelized annual maintenance cost

If the practical life of a paint system for a platform is 10 years, touch-up would occur at year 10, with an overcoat at year 13 and full replacement at year 18. If the costs of these activities are denoted as C_{PL}, C_{MRP}, and C_{FRP}, respectively, then the total maintenance cost on an annualized (non-discounted) life cycle basis beginning at touch-up through FRP is $(C_{PL} + C_{MRP} + C_{FRP})/(FRP - PL + 1)$. ■

Structures are often separated by horizontal and vertical zones and the condition of the coating determined for each zone. One example of zones might include below the spider deck, spider deck to bottom of cellar deck, top of cellar deck to bottom of production deck, production deck and above. Component groupings may also be based on where abrasive blasting is not permitted. The structure and decks are usually evaluated separately from equipment and piping.

Paint and Coating Cost

In Table V.15, typical material costs of paints and protective coatings are depicted based on 2016 survey data from U.S. paint and coating suppliers (Helsel and Lanterman 2016). Costs are expressed in cost per square foot at typical DFT and assume 30% spray painting losses and 10% brush/roll losses.

There are many factors that impact the volume of paint required to protect steel surfaces. The theoretical spreading rate of paint for a given dry film thickness on a smooth surface is calculated as (Hempel 2016):

$$\frac{\text{Volume solids (\%)}\times 10}{\text{Dry film thickness (μm)}} = \frac{10 \cdot VS\text{ (\%)}}{\text{DFT (μm)}} = \text{m}^2\text{/liter},$$

where volume solids (VS) expresses the ratio of dry film thickness (after drying) to wet film thickness (as applied). The practical consumption is estimated by multiplying the theoretical consumption with a relevant consumption factor. Consumption factor is not given in painting specifications since it depends on several site-specific conditions such as the size and shape of the surface (small and complex area vs. square and flat area), application method (hand/brush vs. spray), surface roughness of the substrate (rough vs. smooth), physical losses, experience of the painters, atmospheric conditions, etc.

The maintenance and repair cost for an offshore structure depends on the size and location of the project, type and volume of paints used, scope of work, and contracts applied. Work can range from a full blast to repair. Painting may be required at night (Judice 2007).

Example. Auger TLP painting cost estimation

Shell's Auger TLP in 2860 ft water depth is comprised of four 74 ft diameter by 159 ft high columns connected by four 35 ft wide by 28 ft high pontoons, a drilling rig, production facility, associated power plants and living accommodations for 142 people (Figure V.11). Hull weight is 20,000 tons (Bourgeois 1994). The deck section measures 290 ft x 330 ft x 20 ft high and steel weight is 10,500 tons. The TLP is held in position with 12-26 inch diameter tendons, three per corner, attached to a foundation template anchored to the seafloor (Figure V.12). There is also an 8 point lateral mooring system. First oil was in April 1994.

Shell reported performing 75,000 square feet blasting and painting activities at Auger TLP each year, which is approximately 4% of the total surface area of 1.8 million square feet (Satterlee et al. 2009). Using work decomposition methods, Auger's annual maintenance painting is estimated to cost \$1.9 million per year, or about \$25 per square foot serviced (Table V.16).

Shell reported employing a 6-man blasting and painting crew with a foreman and inspector. Assuming \$150,000 annual salary for foreman and inspector and \$100,000 for paint contractors and blasting crew, the total annual labor budget for blasting and painting is \$1.2 million per year.

Inspections are performed to survey the coatings and develop an annual plan and to ensure quality control during application. The blasting crew prepares the surface by hand, power tools and abrasive wet jets to remove contaminants such as oil, grease and soluble salts, as well as paint chips and metal debris. Garnet and equipment (air compressors, blasting hoses, spray assemblies, paint mixing equipment) must be transported and stored at the facility and blasting generates waste which must be collected, bagged, and transported off the structure and disposed or recycled in dedicated sites associated with industrial (hazardous and non-hazardous) waste.

Garnet costs about \$500/ton and can be reused up to eight times, although there are issues regarding recycle and performance that often limit reuse. In surface preparation, 2-4 lbs of garnet are assumed to be used per square foot steel surface[32] and reused once in operations and then disposed onshore.

For 75,000 ft^2 steel surface requiring blasting, the annual garnet budget is estimated at

$$\frac{1}{2} \cdot 75{,}000 \text{ ft}^2 \cdot 3 \text{ lbs/ft}^2 \cdot \$500\text{/ton} \cdot \frac{\text{ton}}{2200 \text{ lbs}} = \$26{,}000$$

or \$0.35/ft^2. For high-solids sprayed paint expenditures of \$1.5/ft^2, a similar calculation yields \$112,500 paint cost per year.

Disposal of spent abrasive material is assumed to cost \$50/ton for non-hazardous material and \$300/ton for hazardous material. Most spent abrasive material is non-hazardous but Shell reported about 10% hazardous due to cadmium-coated bolts that were blasted or older areas containing lead paint. Assuming 5 lbs waste per square foot arise from the spent abrasive, corrosion and paints removed from the steel and 10% is hazardous, annual disposal cost is estimated as

$$\text{Nonhazardous disposal cost} = 0.9 \cdot 170 \text{ ton/yr} \cdot \$50\text{/ton} = \$7670$$

$$\text{Hazardous disposal cost} = 0.1 \cdot 170 \text{ ton/yr} \cdot \$300\text{/ton} = \$5100.$$

[32] For comparison, the amount of garnet used in ship conversion operations typically requires 10-15 lbs of garnet per square foot steel surface because of the intensive surface preparation requirements (Azevedo 2011).

Indirect cost associated with operations include logistics, catering, and travel for the paint crew and equipment, downtime and weather delays. A 40% indirect rate is assumed to cover these costs.

Painting and blasting interfere with other activities and since they do not generate revenue fall low in the work queue and are scheduled around other activities and rarely (never) take precedence over drilling or production. Downtime may arise that delay operations and environmental conditions[33] may prevent activity from being performed, but since crews are available year round these potential impacts are easily handled by shifting schedules and work windows. ■

Square Footage Conversion

Since total square footage of a structure is rarely reported in public documents approximations are required to estimate painting areas. Useful conversions based on deck and topsides weight are shown in Table V.17.

Example. Steel footage estimation

The Enchilada platform was installed in 1997 and sits in 705 ft water depth with a total topsides operating weight of 9000 tons. The Prince TLP was installed in 2001 in 1490 ft water depth and consists of a three-level deck capable of carrying topsides payload of 6100 tons. The Mars TLP was installed in 1997 in 2933 ft water depth and has topsides operating weight of about 23,000 tons. Assuming 4% of the total area of a deepwater structure requires treatment per year after the service life is reached, and using a topsides weight-to-square foot conversion of 200 ft^2/ton, topsides painting areas for Enchilada, Prince, and Mars are estimated at 1.8, 1.2, and 4.6 million square feet, respectively. ■

In the deepwater GoM about two thirds of the floater platforms circa 2017 have topside operating weight greater than 5000 ton (D’Souza et al. 2016). Defining a medium topsides weight category as 5000 to 12,000 ton and large topsides weight categories as greater than 12,000 ton, Table V.18 summarizes structure counts by type and mean topsides weight. Within each weight class, the mean topsides operating weight is approximately the same across structure type, while across the weight classes mean topsides weight increases about two-fold.

One-Point Cost Extrapolation

Since maintenance program data is limited and private, a one-point cost estimate can be extrapolated based on a square foot normalization. If more data is available, cost ranges can be improved and the statistics will be more robust.

Example. Painting cost estimation at Enchilada, Prince, and Mars

Assuming 4% of the total area of a deepwater structure is treated per year after its service life is reached and normalizing by Auger’s unit cost estimate previously computed ($1.2 million for 75,000 ft^2 treatment per year), annual painting and blasting cost at Enchilada, Prince, and Mars based on their steel footage estimates is $1.2 million, $770,000, and $2.9 million, respectively. The structures are all deepwater facilities and approximately the same age as Auger, serve similar functions, and are of similar complexity. Assuming similar original coat systems and degradation, maintenance cost would likely be similar. Enchilada and Mars are also Shell operated which will likely have similar maintenance programs in place. ■

[33] For example, no blast cleaning or coating applications are allowed if the relative humidity is more than 85% and when the steel temperature is less than 3°C above the dew point.

Example. South Pass 52 platform painting cost estimate

The South Pass 52 platform was installed in 1992 in 531 ft water depth, last produced in 2011, and was decommissioned in 2016. The 548 foot jacket weighed 2700 t and had an 800 t deck and 275 t module (Allen et al. 1992). Assuming a 250 ft^2/ton conversion for the module and 400 ft^2/ton conversion for the deck, 10% of the total area treatment per year after the service life was reached, and Auger's normalized one-point cost data ($1.2 million for 75,000 ft^2 treatment per year) yields an estimated annual paint budget of about $600 thousand:

$$\left(275 \text{ ton} \cdot \frac{250 \text{ ft}^2}{\text{ton}} + 800 \text{ ton} \cdot \frac{400 \text{ ft}^2}{\text{ton}}\right) \cdot \frac{0.10}{\text{yr}} \cdot \frac{\$1.2 \text{ MM}}{75{,}000 \text{ ft}^2} = \$622{,}000/\text{yr}. \blacksquare$$

22.6.5 Underwater Maintenance

Operators deploy underwater inspection schedules according to regulatory requirements and base decisions on the cost-benefit of maintenance. In the 1970s many operators learned that underfunded structural maintenance budgets can lead to expensive long-term costs (Hughes 1972, Hughes et al. 1975) and adjusted their underwater maintenance programs accordingly.

Cleaning is the most time consuming task. A good cleaning will remove marine growth down to black oxide one or two inches on each side of welds at various positions and cleaned to bright metal. High-pressure water blasters are used for cleaning and need to be set-up and properly positioned. Gross damage around the circumference of members (e.g., wide cracks) and fractures are identified, if any, and video and photo documentation performed.

Remotely operated vehicles (ROVs), divers, and supporting equipment may be based on the platform or workboat, but usually workboats are preferred for economic, safety, and logistical reasons. In shallow water <200 ft divers are typically used exclusively, in 200-400 ft water depth divers and/or ROVs are employed, and in >400 ft ROVs are primarily employed with divers employed in the top water section.

Example. Level II & III inspection cost at Cognac

Shell conducted time studies during Level II and III inspection at Cognac about 12 years after first installation and documented that it took on average six hours per member for cleaning and inspection (Miller and Hennegan 1990). Half of this time was spent on cleaning with the set-up time, positioning and video documentation time comprising the remainder. On average, 1.5 member ends were cleaned and inspected in a 12-hr workday.

In 1990, Level II and III inspection at Cognac were reported to cost $480,000, about $293,000 for the Level III inspection and $175,000 for the Level II inspection (Table V.19). The top 200 ft of the structure was inspected by divers. The inferred ROV dayrate was $227,000/15 days = $15,133/day, or $275/ft structure. The inferred Level III diver dayrate was $23,000/200ft, or $115/ft. The inferred Level II cost was $161,000/825 ft = $195/ft. Cost exclude mob/demob fee. ■

Diving

The underwater service industry in the GoM is highly competitive. In deepwater, several companies compete worldwide, while in the shallow water numerous small companies that operate locally offer services. For services that require less sophisticated equipment, small companies are able to bid for contracts at prices that are uneconomical to larger companies, and this is reflected in the gross margins reported by large contractors for inspection services (asset integrity, repair and maintenance), which are typically the smallest among their business segments. In shallow water high levels of competition, low dayrates, and low technological requirements constrain profits.

Manned diving operations utilize traditional diving techniques of air, mixed gas and saturation diving, all of which are surface-supplied breathing gas. In water depths greater than 1000 ft, traditional diving techniques are not used and instead ROVs are employed (Figure V.13). ROVs are tethered submersible vehicles remotely operated from the surface, usually a specially outfitted vessel, either owned or chartered (leased) by the company.

Divers provide high quality fast cleaning rates and can adapt to difficult positioning and changing conditions, but safety is always a concern with saturation diving as water depths increase. ROVs are advanced and significantly more reliable than models in the early 1990s, but are expensive and may be difficult to maintain position in high currents or reach difficult areas between conductors, within the structure interior, and at the mudline.

ROV

Service for ROV contracts are typically awarded on a competitive bid on a dayrate basis for contracts less than one year in duration, although multi-year contracts may also be awarded for significant work campaigns. Under dayrate contracts, the contractor provides the ROV, vessel or equipment and the required personnel to operate the unit, and compensation is based on a rate per day for each day the unit is used. Lower dayrates often apply when a unit is moving to a new site (or a separate mobilization fee is applied), or when operations are interrupted or restricted by equipment breakdowns, adverse weather or water conditions or other conditions beyond the contractor's control. Contracts often specify a 12-hr workday and an ROV downtime allowance (e.g., 30 hr downtime per month).

Dayrates depend on market conditions, the nature of the operations to be performed, the duration of the work, the equipment and services to be provided, the geographic areas involved, and other variables. Inspection speed depends on the coordinated movement of the ROV and support vessel. Video inspections include wellheads, valve positions, pipeline end terminations and manifolds, flowlines, jumpers, moorings, risers, and associated cabling (Kros 2011). This equipment is often spaced over many square kilometers requiring the support vessel to maneuver in DP mode for days.

Example. Oceaneering International Inc. ROV dayrates, 2008-2016

Oceaneering is one of the largest underwater services contractors in the world, and as of December 31, 2016 owned over 300 work-class ROVs, the largest fleet in the world. The average revenue per day on hire from 2008-2016 was reported to range from $8500 to $11,000 per day. Revenue per day on hire is not the same as dayrate but provides an indication of dayrate ranges. ■

AUV

Autonomous Underwater Vehicles (AUV) inspection technologies for the offshore oil and gas industry is in its infancy but promise to reduce the cost of inspecting subsea facilities for a range of activities, including pre/post-hurricane inspection, decommissioning structure surveys, pipeline and riser inspection (Table V.20). In diving and ROV operations, support vessels are required with large crews to collect relatively simple visual inspecting records. AUVs use advanced technology to reduce costs but are not proven technology. The technology is advancing and is likely to play a future role in inspection.

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APPENDIX A

CHAPTER 1 TABLES AND FIGURES

Table A.1. Active Gulf of Mexico inventory circa 2017

Water Depth (ft)	Installed	Removed	Active
< 400	6933	5024	1909
> 400	120	23	97
Total	7053	5048	2005

Source: BOEM, February 2018

Table A.2. Active shallow water structures by type and water depth circa 2017

Water Depth (ft)	Caisson/WP	Fixed Platform	Total (%)
≤ 100	563	724	1287 (67%)
101-150	17	181	198 (10%)
151-200	10	152	162 (8%)
201-400	11	251	262 (14%)
Total	601	1308	1909 (100%)

Source: BOEM, February 2018

Table A.3. Active inventory and stock changes, 2008-2017

Year	Installed	Decommissioned	Active	Decline Rate (%)
2008	78	154	3755	
2009	32	234	3553	5.4
2010	30	220	3363	5.3
2011	18	294	3087	8.2
2012	11	286	2812	8.9
2013	17	223	2606	7.3
2014	21	203	2424	7.0
2015	4	128	2300	5.1
2016	2	200	2102	8.6
2017E	2	99	2005	4.6

Source: BOEM, February 2018

Table A.4. Shallow water structures by type and production status circa 2017

	Caisson/WP	Fixed Platform	Total (%)
Idle (1-3 yr)	85	134	219 (11%)
Idle (>3 yr)	212	229	441 (23%)
Auxiliary	43	318	361 (19%)
Producing	257	630	887 (46%)
Total	597	1311	1908

Source: BOEM, February 2018

Table A.5. Fixed platform and compliant tower inventory in the Gulf of Mexico circa 2017

Complex	Operator	Area Block	Name	Water Depth (ft)	Install Year
70	Manta Ray Gathering	EC373		443	1998
113	W & T Energy VI	VK823	Virgo	1130	1999
147	W & T Offshore	EW910		557	1998
1052	Chevron U.S.A.	HI582	Cyrus	440	2002
1076	Renaissance Offshore	ST317		460	2002
1165	Tarpon Operating & Development	WC661		484	2002
1279	W & T Offshore	ST316	South Timbalier	447	2003
1320	ATP Oil & Gas	GB142		542	2003
1482	Ankor Energy	MC21	Simba	667	2005
1500	Fieldwood Energy	ST308	Tarantula	484	2004
2027	Bennu Oil & Gas	HI589		477	2007
2606	Walter Oil & Gas	EW834	Coelacanth	1186	2015
10178	Fieldwood SD Offshore	EB160	Cerveza	935	1981
10192	W & T Offshore	HI389		410	1981
10212	Fieldwood SD Offshore	EB159	Ligera	924	1982
10242	Fieldwood SD Offshore	EB110	Tequila	660	1984
10297	Fieldwood SD Offshore	EB165	Snapper	863	1985
22172	Energy XXI GOM	SP93		446	1978
22178	EnVen Energy Ventures	MC194	Cognac	1023	1978
22224	Fieldwood Energy	MC311	Bourbon	428	1978
22662	Fieldwood Energy	SP89		422	1982
22685	Energy XXI GOM	SP49		400	1981
22840	Exxon Mobil	MC280	Lena(CT)	1000	1983
23051	Taylor Energy	MC20		475	1984
23151	Energy XXI GOM	SP93		450	1985
23212	Manta Ray Gathering	SS332		438	1985
23277	Shell Oil	GC19	Boxer	750	1988
23353	Poseidon Oil Pipeline	SM205		457	1989
23503	Whistler Energy II	GC18	Boxer	750	1986
23552	Fieldwood Energy Offshore	GC65	Bullwinkle	1353	1988
23567_1	MC Offshore Petroleum	GC52	Marquette	604	1989
23567_2	MC Offshore Petroleum	GC52	Marquette	604	1989
23760	Chevron U.S.A.	GB189	Tick	720	1991
23788	Triton Gathering	GB191	Pimento	721	1993
23800	Fieldwood Energy	EW826		483	1988
23848	Arena Offshore LP	SP83		467	1990
23875	Eni US	MC365	Corrla	619	1992
23883	Stone Energy Corporation	MC109	Amberjack	1100	1991
23893	Energy XXI GOM	MC397	Alabaster	476	1991
23925	McMoRan Oil & Gas	EW947		477	1990
24129	EnVen Energy Ventures	EW873	Lobster	775	1994
24130	Stone Energy	VK989	Pompano	1290	1994
24201	Flextrend Development	VK817	Phar Lap Shallo	673	1995
27032	Flextrend Development	GB72	Spectacular Bid	541	1995
27056	Shell Offshore	GB128	Enchilada	705	1997
33039	Hess	GB260	Baldpate(CT)	1648	1998
70012	Chevron U.S.A.	VK786	Petronius(CT)	1754	2000
70016	Fieldwood Energy	VK780	Spirit	722	1998
80015	Fieldwood Energy	SS354		464	1997
90014	Shell Offshore	GB172	Salsa	693	1998
90028	Energy Resource Technology	EC381		446	1997

Source: BOEM, June 2017

Table A.6. Floating structure inventory in the Gulf of Mexico circa 2017

Complex	Operator	Area Block	Name	Type	Water Depth (ft)	Install Year
67	Chevron U.S.A.	GC205	Genesis	SPAR	2590	1998
183	Exxon Mobil	AC25	Hoover	SPAR	4825	2000
235	Anadarko Petroleum	VK915	Marlin	TLP	3236	1999
251	Eni US	GC254	Allegheny	MTLP	3294	1999
420	Shell Offshore	GC158	Brutus	TLP	2900	2001
811	EnVen Energy Ventures	EW1003	Prince	TLP	1500	2001
821	Anadarko Petroleum	EB602	Nansen	SPAR	3675	2001
822	Anadarko Petroleum	EB643	Boomvang	SPAR	3650	2002
876	Anadarko Petroleum	MC127	Horn Mountain	SPAR	5400	2002
1001	BP E&P	MC474	Na Kika	SEMI	6340	2003
1035	Anadarko Petroleum	GC645	Holsten	SPAR	4340	2004
1088	W & T Energy VI	MC243	Matterhorn	MTLP	2850	2003
1090	Murphy E&P	MC582	Medusa	SPAR	2223	2003
1101	BP E&P	MC778	Thunder Horse	SEMI	6200	2005
1175	Eni US	MC773	Devils Tower	SPAR	5610	2004
1215	BP E&P	GC782	Mad Dog	SPAR	4420	2004
1218	ConocoPhillips	GB783	Magnolia	TLP	4670	2004
1223	BP E&P	GC787	Atlantis	SEMI	7050	2007
1288	Anadarko Petroleum	GB668	Gunnison	SPAR	3150	2003
1290	Murphy E&P	GC338	Front Runner	SPAR	3330	2004
1323	Anadarko Petroleum	GC608	Marco Polo	TLP	4300	2004
1665	Anadarko Petroleum	GC680	Constitution	SPAR	4970	2005
1766	Anadarko Petroleum	MC920	Independence Hub	SEMI	8000	2007
1799	BHP Billiton Petroleum	GC613	Neptune	MTLP	4250	2007
1819	Chevron U.S.A.	GC641	Tahiti	SPAR	4000	2008
1899	BHP Billiton Petroleum	GC653	Shenzi	TLP	4375	2008
1930	Chevron U.S.A.	MC650	Blind Faith	SEMI	6480	2008
2008	Shell Offshore	AC857	Perdido	SPAR	7835	2009
2045	Murphy E&P	MC736	Thunder Hawk	SEMI	6050	2009
2089	Bennu Oil & Gas	MC941	Mirage/Titan	SEMI	4050	2010
2133	Energy Resource Technology	GC237	Helix	MOPU	2200	2009
2229	Petrobras America	WR249	Cascade&Chinook	FPSO	8300	2011
2385	Shell Offshore	MC807	Olympus	TLP	3028	2013
2424	LLOG Exploration Offshore	MC547	Who Dat	SEMI	3280	2011
2440	Chevron U.S.A.	WR718	Jack St. Malo	SEMI	6950	2014
2498	Hess	MC724	Gulfstar	SPAR	4600	2014
2503	Shell Offshore	WR551	Stones	FPSO	9560	2016
2513	LLOG Exploration Offshore	MC254	Delta House	SEMI	4400	2014
2576	Anadarko Petroleum	KC875	Lucius	SPAR	7000	2014
2597	Anadarko Petroleum	GC860	Heidelberg	SPAR	5300	2016
23583	MC Offshore	GC184	Jolliet	TLP	1760	1989
24080	Shell Offshore	GB426	Auger	TLP	2860	1994
24199	Shell Offshore	MC807	Mars	TLP	2933	1996
24229	Shell Offshore	VK956	Ram Powell	TLP	3216	1997
24235	Noble Energy	VK826	Neptune	SPAR	1930	1996
70004	Shell Offshore	MC809	Ursa	TLP	3970	1998
70020	Eni US	EW921	Morpeth	MTLP	1700	1998

Source: BOEM, June 2017

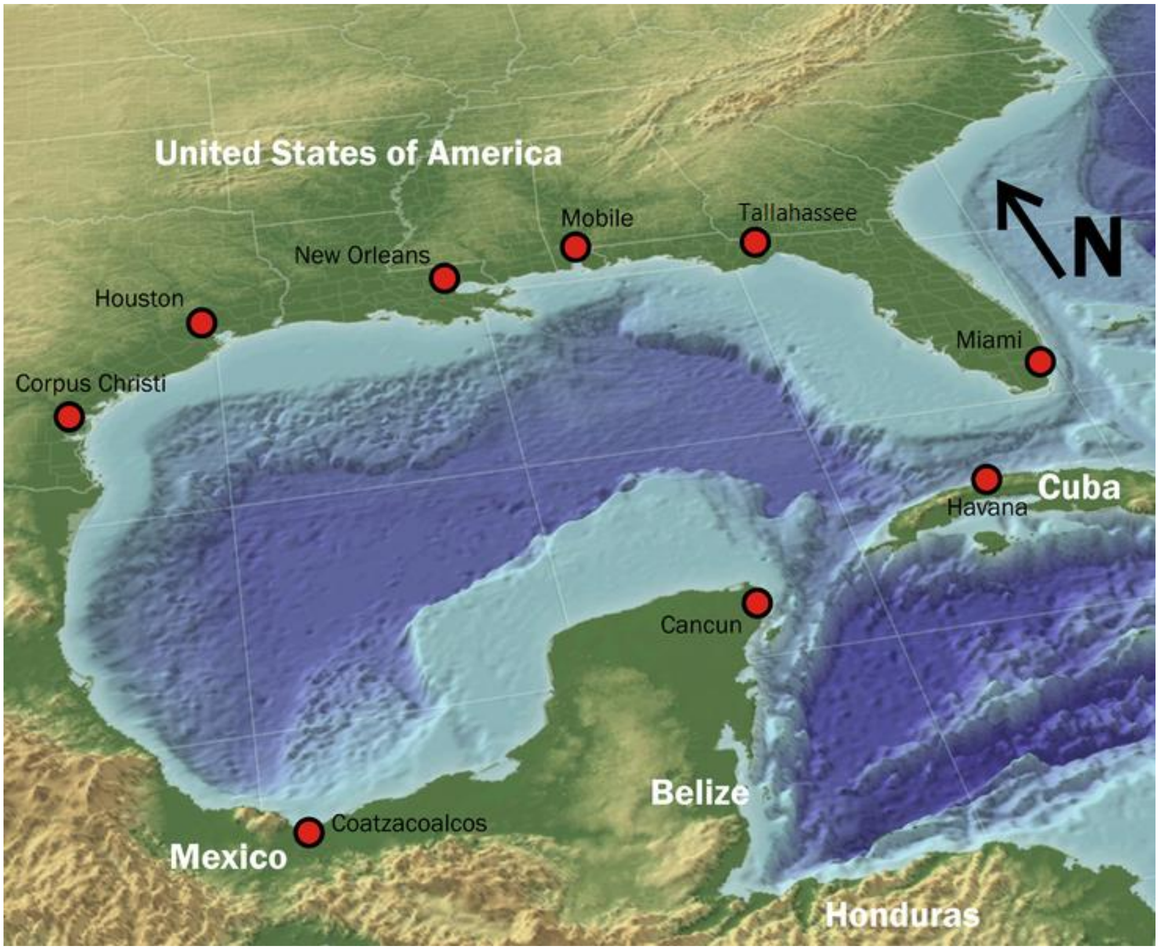


Figure A.1. The Gulf of Mexico basin with seawater removed reveal shelf and slope features
Source: Wikipedia

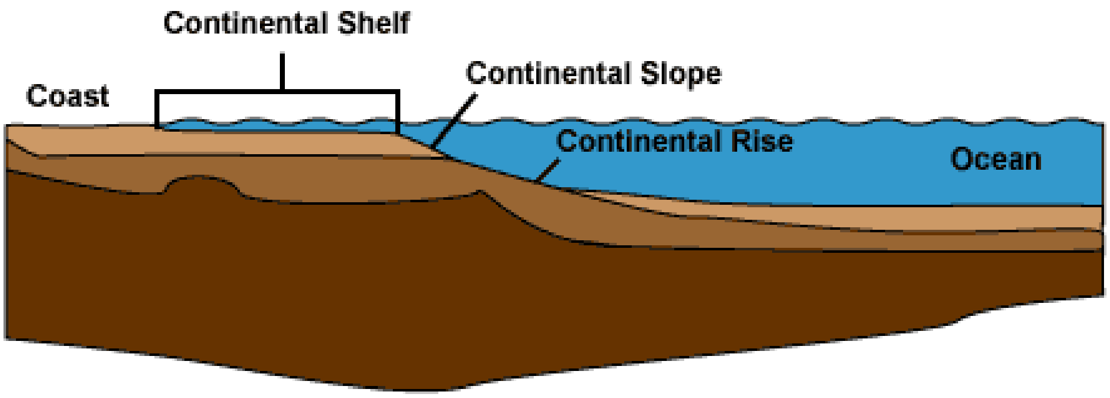


Figure A.2. Schematic representation of continental shelf, slope and rise.
Source: Office of Naval Research

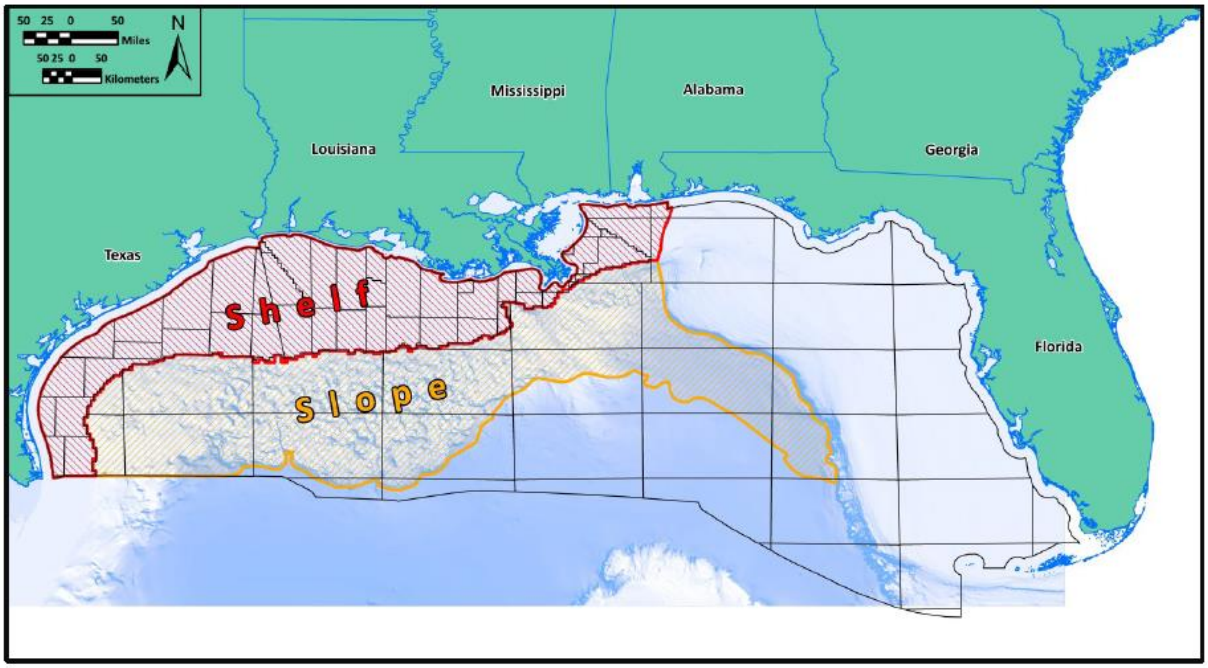


Figure A.3. Location of the shelf and slope in the Gulf of Mexico
Source: BOEM

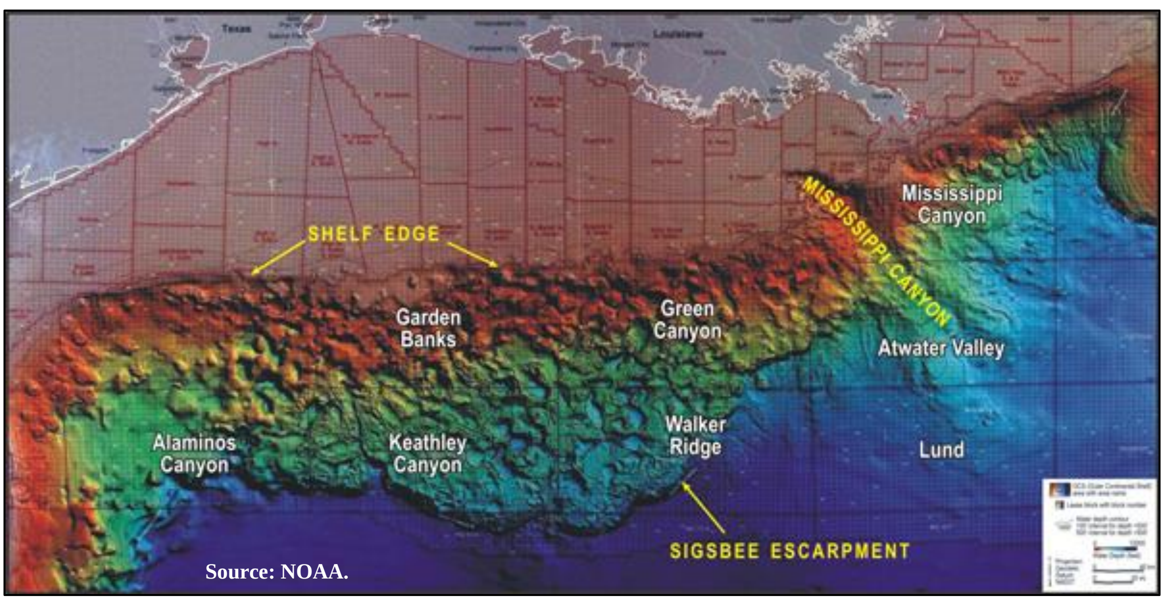


Figure A.4. Bathymetry of the northern Gulf of Mexico and Sigsbee Escarpment
Source: NOAA

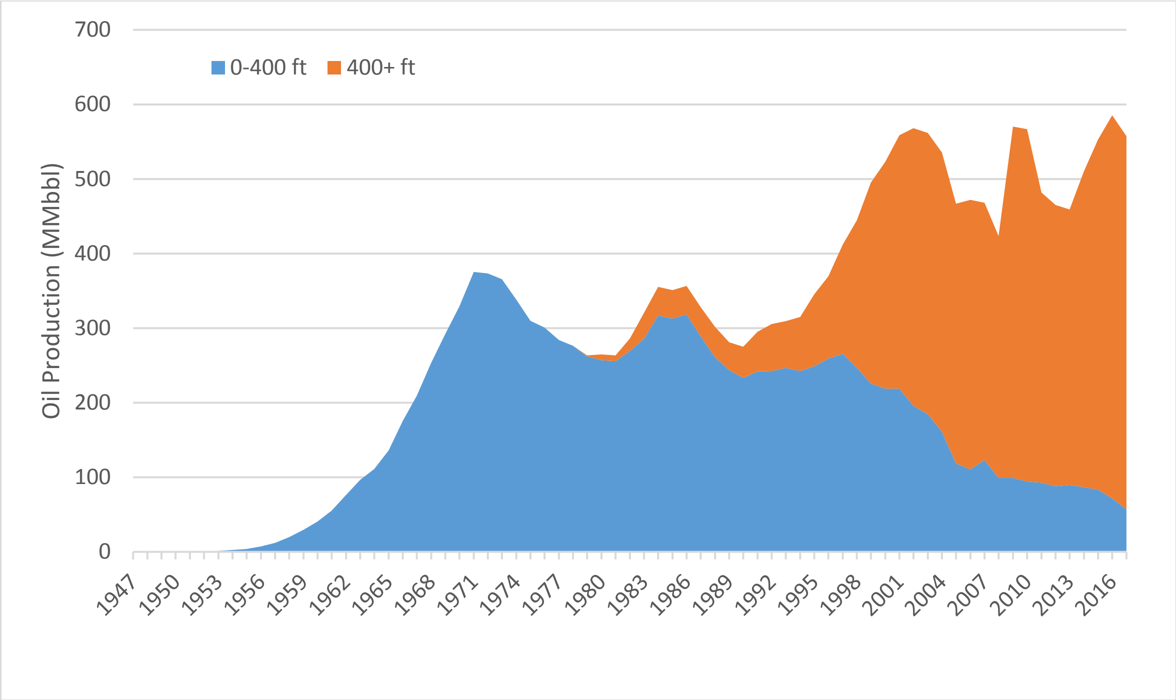


Figure A.5. Gulf of Mexico Outer Continental Shelf oil production, 1947-2017
Source: BOEM, February 2018

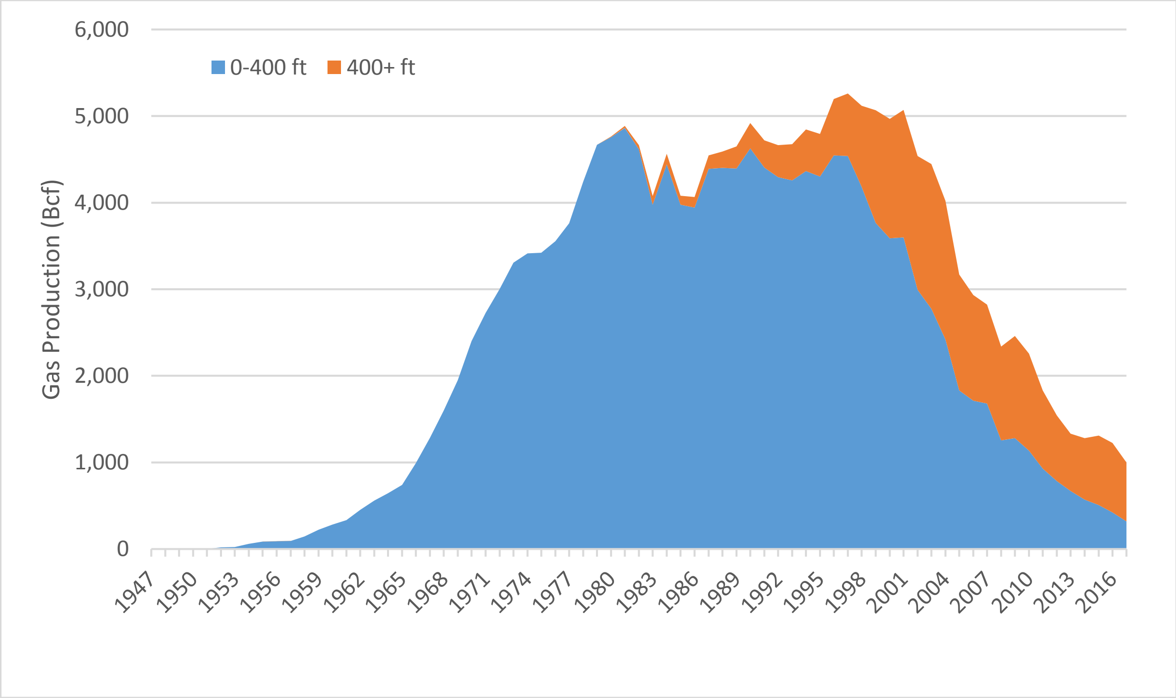


Figure A.6. Gulf of Mexico Outer Continental Shelf natural gas production, 1947-2017
Source: BOEM, February 2018

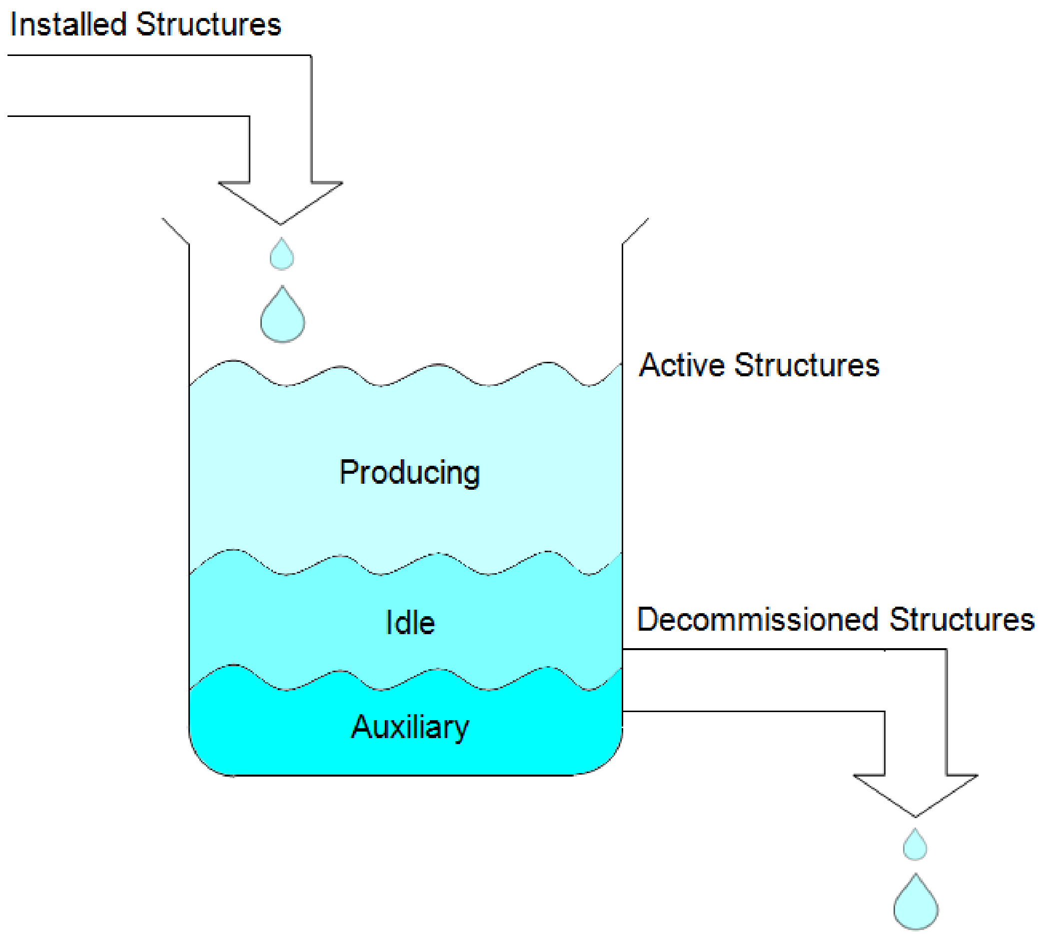


Figure A.7. Bath-tub analogy for active inventory

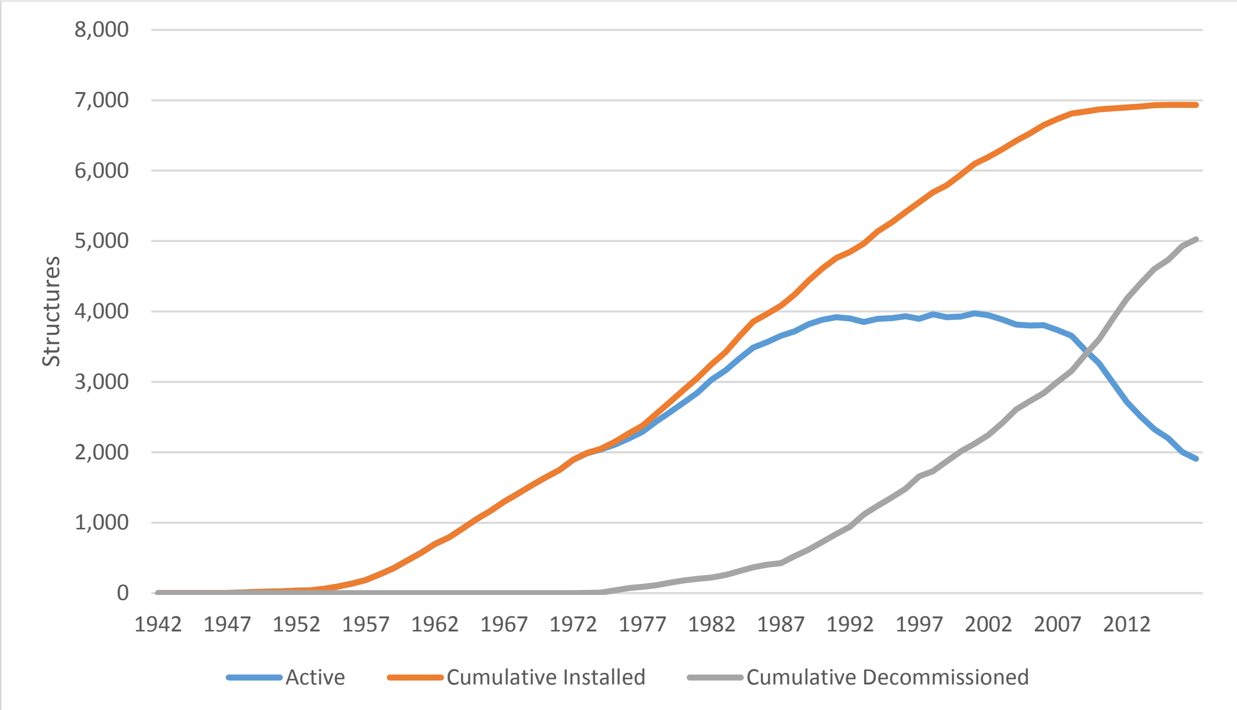


Figure A.8. Active structures in water depth less than 400 ft, 1942-2017

Source: BOEM, February 2018

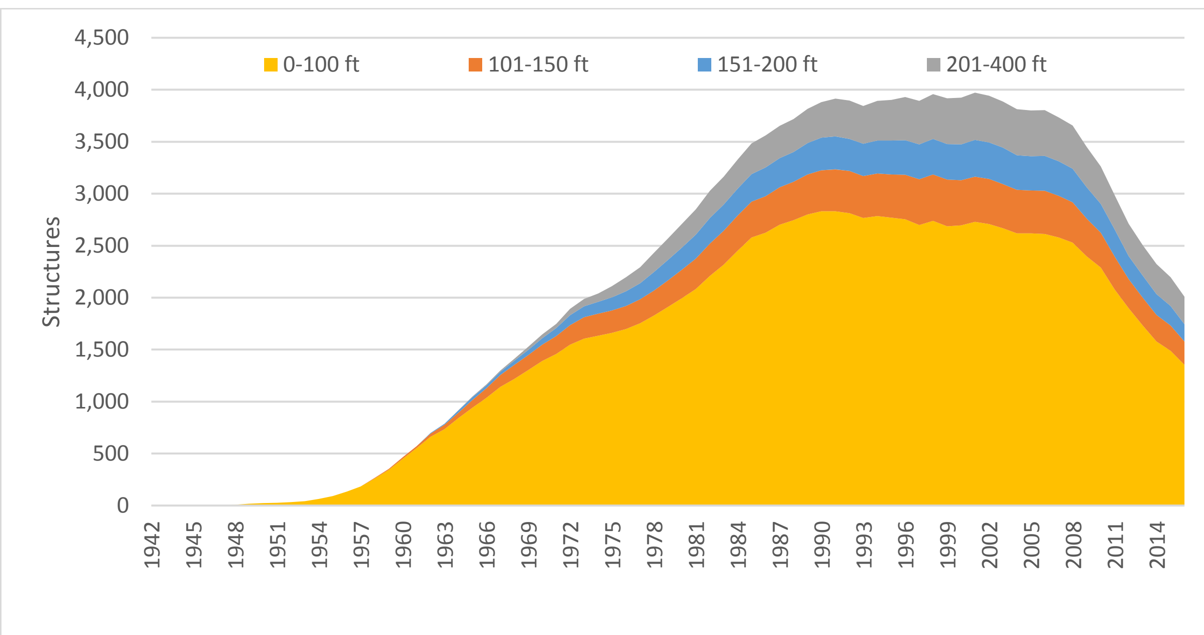


Figure A.9. Active shallow water structures by water depth category circa 2017

Source: BOEM, February 2018

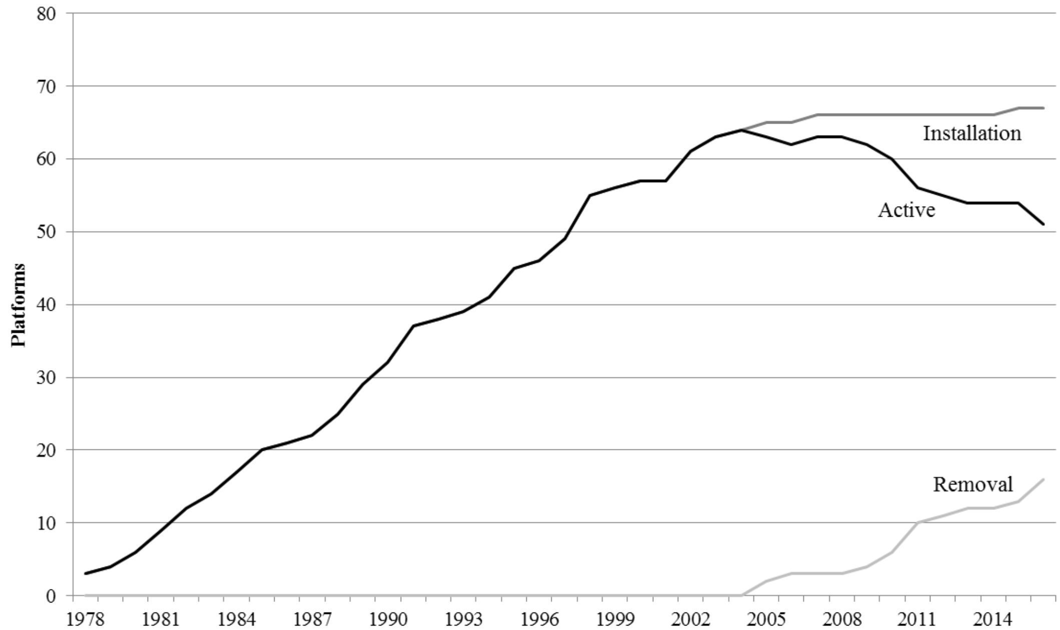


Figure A.10. Deepwater fixed platform installation and removal in water depth greater than 400 ft
Source: BOEM, June 2016

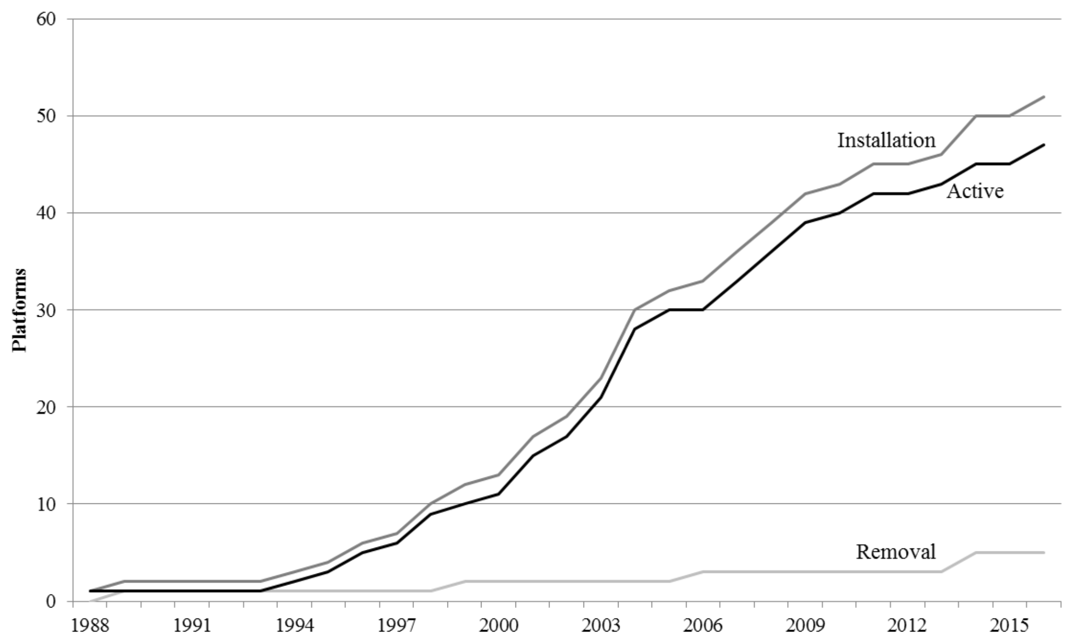


Figure A.11. Deepwater floater installation and removal in water depth greater than 400 ft
Source: BOEM, June 2016

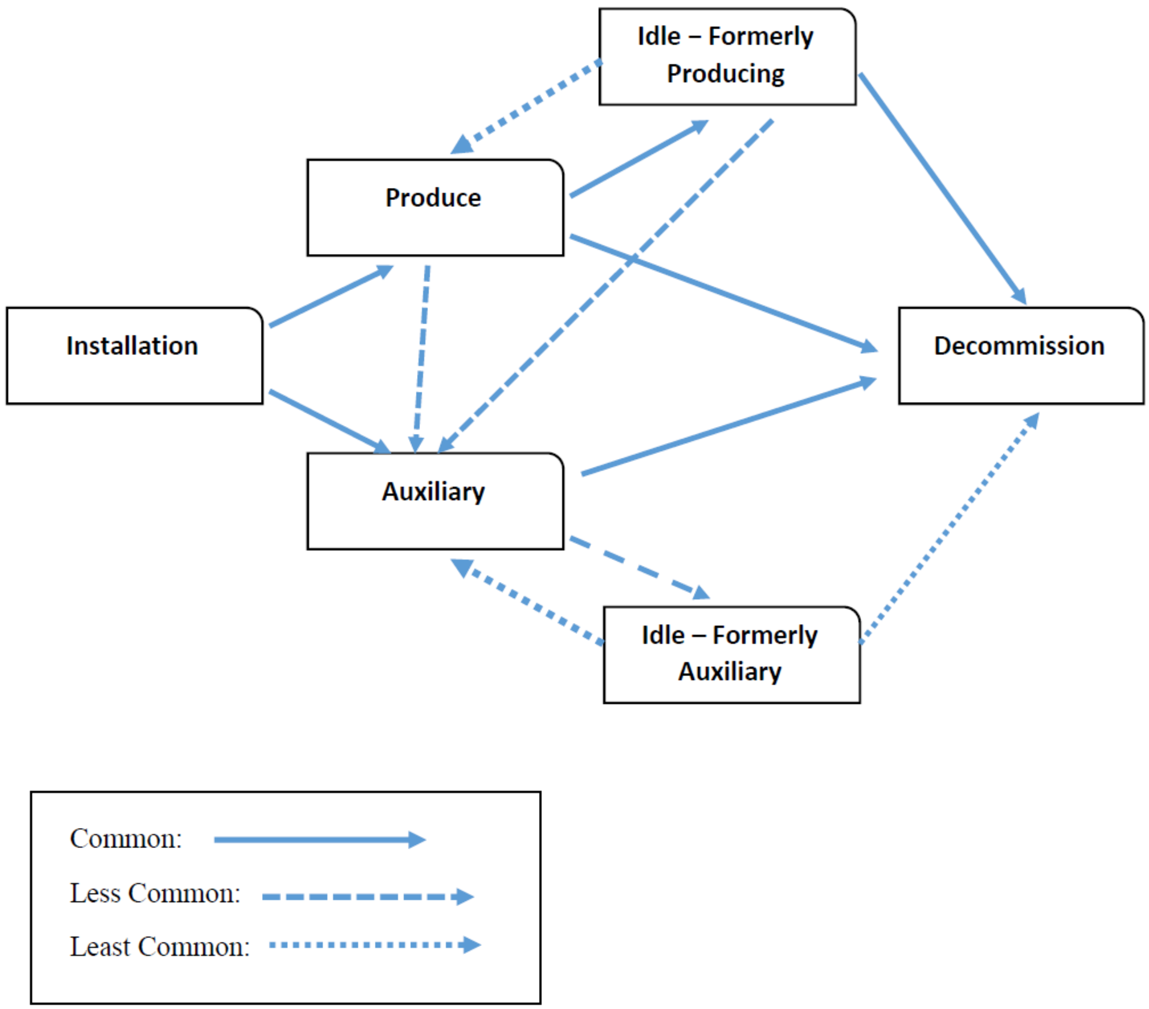


Figure A.12. Structure classifications and transition pathways over time

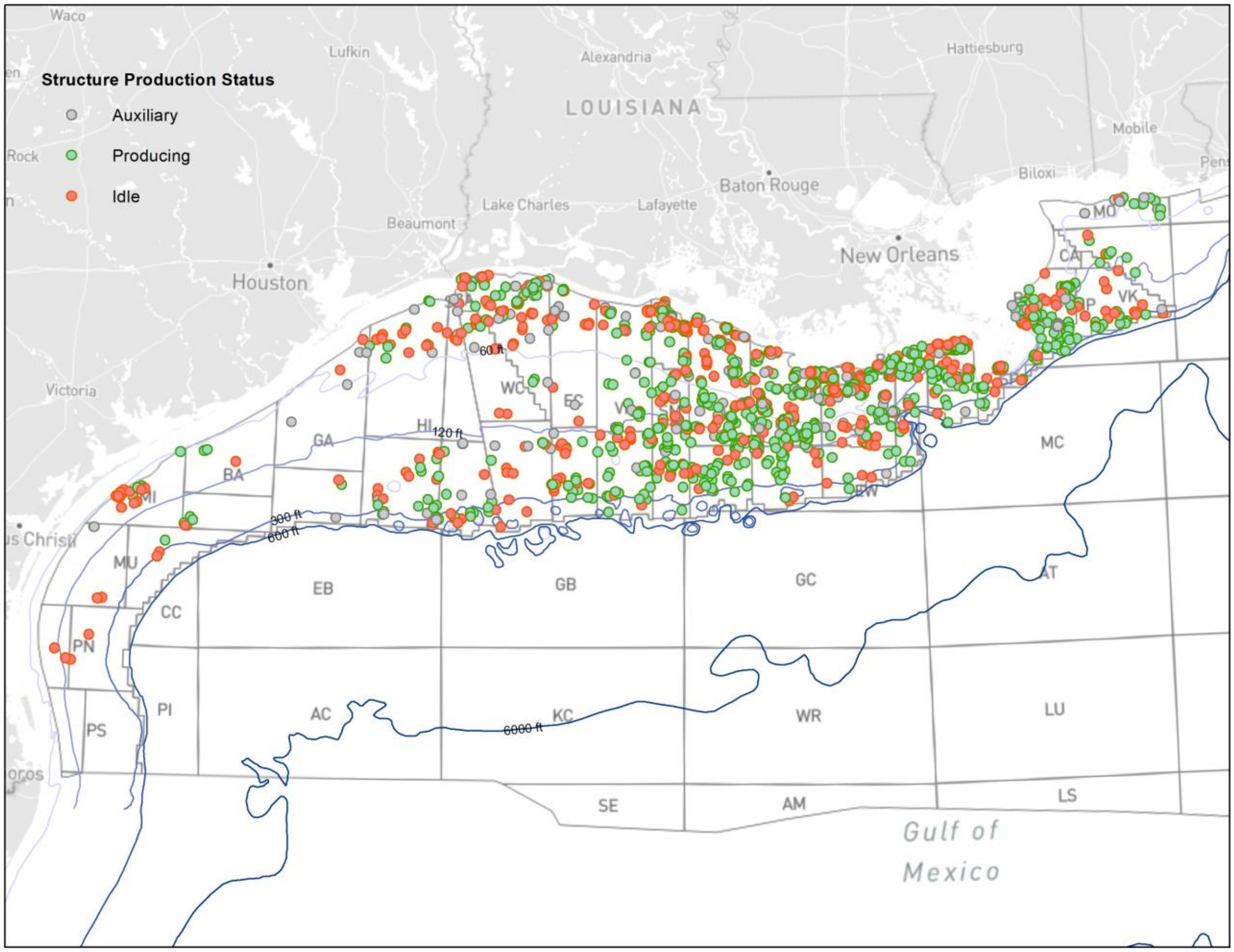


Figure A.13. Producing, idle and auxiliary structures in shallow water circa 2017
Source: BOEM, February 2018

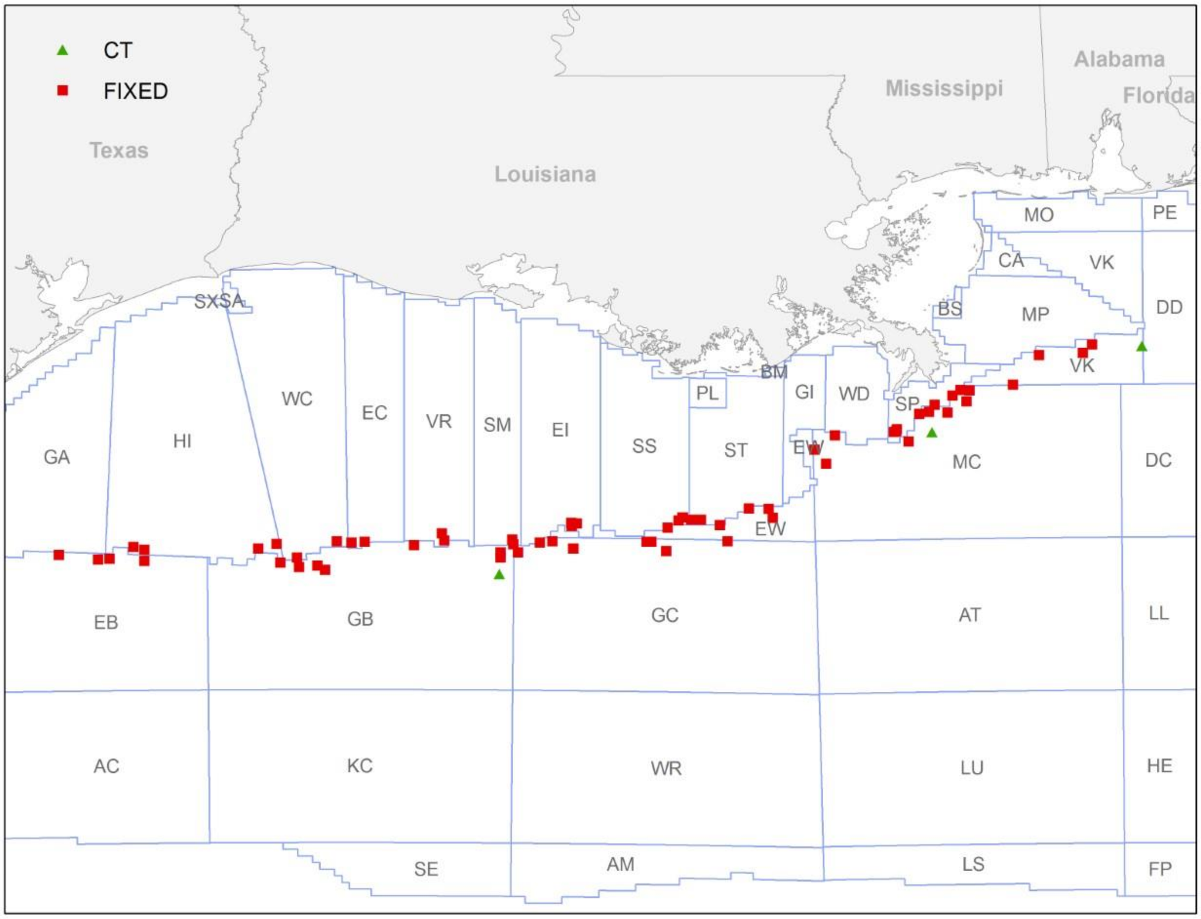


Figure A.14. Deepwater fixed platforms and compliant towers in the Gulf of Mexico circa 2017
Source: BOEM, June 2017

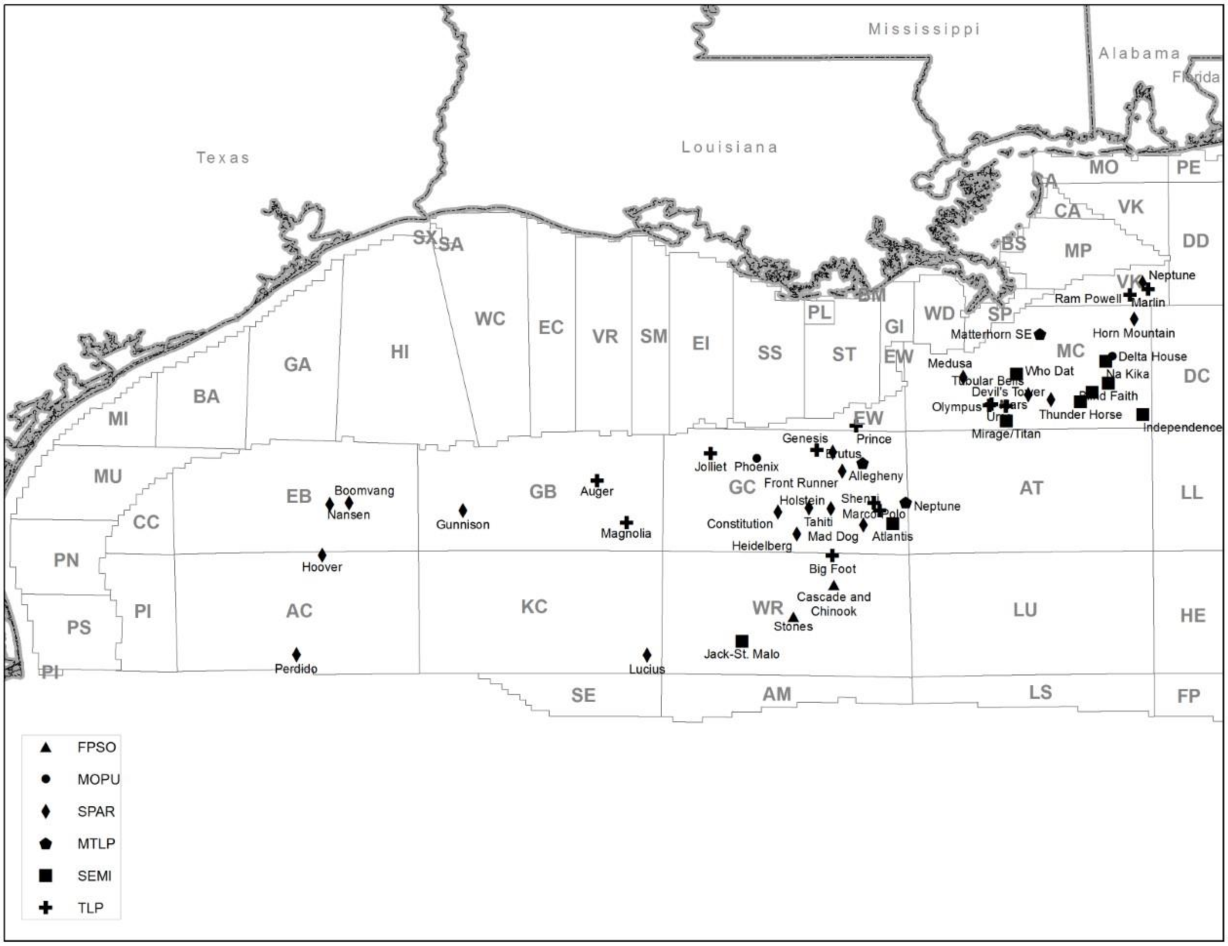


Figure A.15. Floaters in the Gulf of Mexico circa 2017

Source: BOEM, June 2017

APPENDIX B

CHAPTER 2 TABLES AND FIGURES

Table B.1. Gulf of Mexico floaters circa 2017

FPSO	2
MOPU	1
MTLP	4
Semi	11
Spar	18
TLP	12
Total	48

Source: BOEM, February 2018

Table B.2. Active structure counts per complex excluding compliant towers and floaters circa 2017

Structures per Complex	Caisson	Fixed Platform	Mixed Platform	Well Protector	Structure Total
1	347	862	0	139	1348
2	13	86	31	1	262
3	2	38	11		153
4		12	8	1	84
5		8	1		45
6		3	1		24
7		1	1		14
9			1		9
15		1	0		15
Total	362	1011	54	141	1954

Source: BOEM, February 2018

Note: Three compliant towers and 48 floaters are excluded from the first row.

Figure B.1. Caisson, well protector, and fixed platform structures in the Gulf of Mexico
Source: BOEM

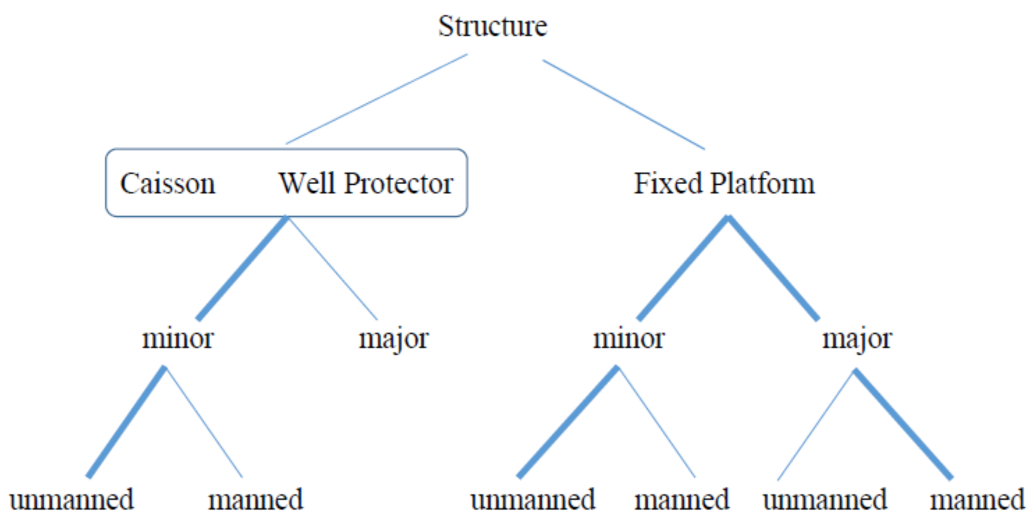


Figure B.2. Structure classification with dominant categories denoted with thick lines

Figure B.3. Sailaway of the Coelacanth platform offshore Texas on October 15, 2015
Source: Walter Oil and Gas

Figure B.4. Cognac platform in Mississippi Canyon 194
Source: Shell

Figure B.5. Bullwinkle platform in Green Canyon 65
Source: Shell


SEMI – Jack/St. Malo
SPAR – Perdido
FPSO – Stones
TLP – Olympus

Figure B.6. Main floater classes in the Gulf of Mexico
Source: Chevron, Shell

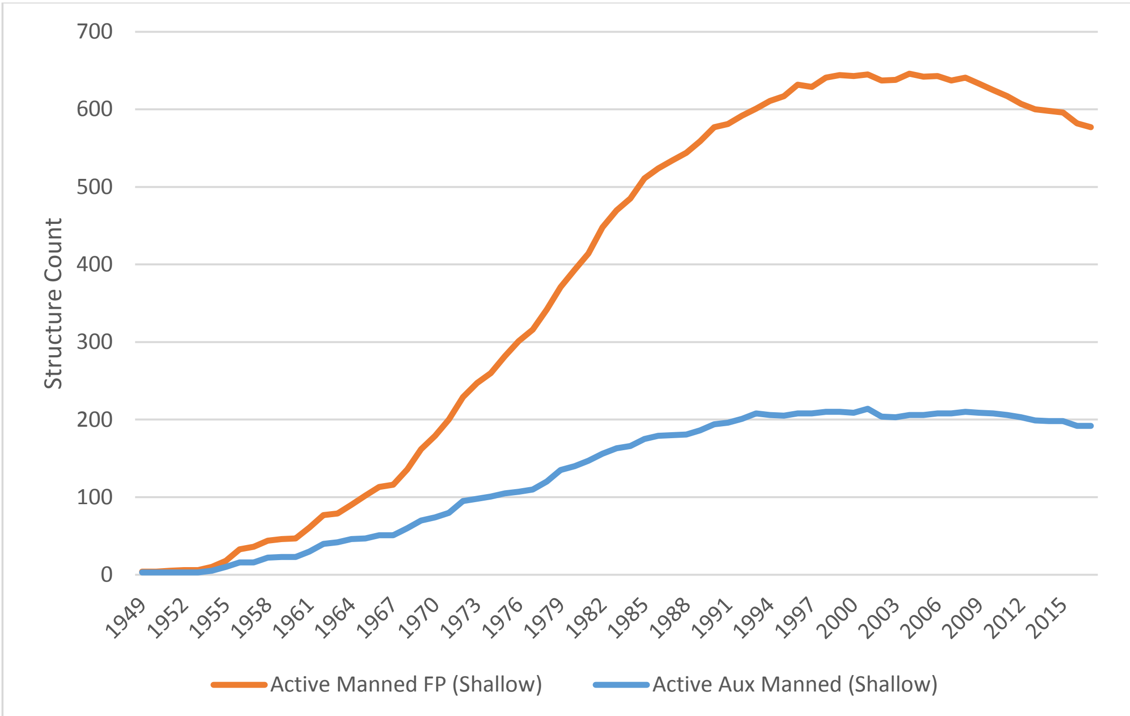


Figure B.7. Active manned fixed platform and auxiliary structures in water depth less than 400 ft, 1949-2017

Source: BOEM, February 2018

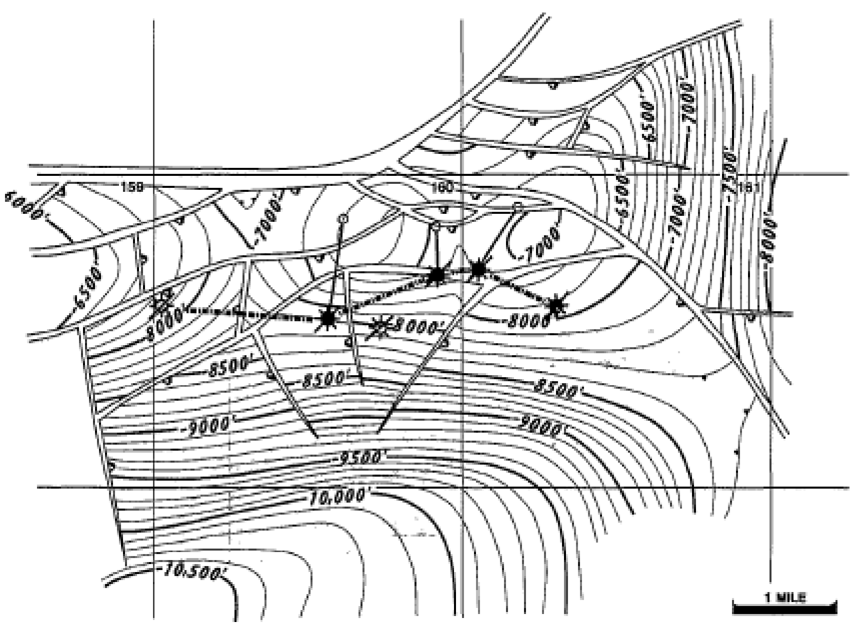


Figure B.8. East Breaks blocks 160-161 structure map with line of cross section

Source: Schanck et al. 1988

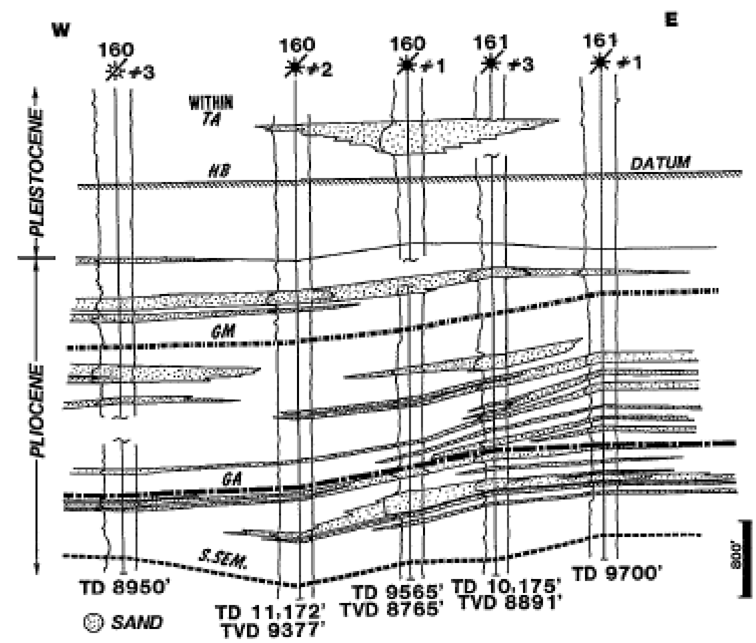


Figure B.9. East Breaks blocks 160-161 stratigraphic cross section
Source: Schanck et al. 1988

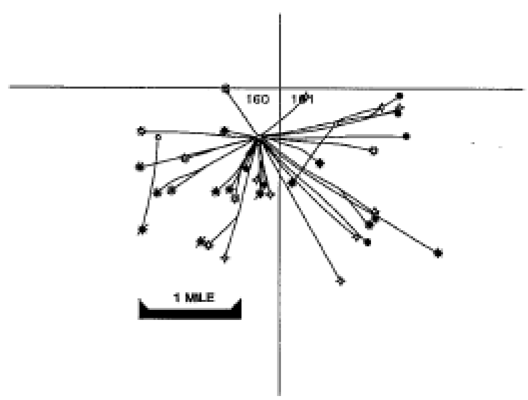


Figure B.10. East Breaks 160 (Cerveza) structure spider diagram
Source: Schanck et al. 1988

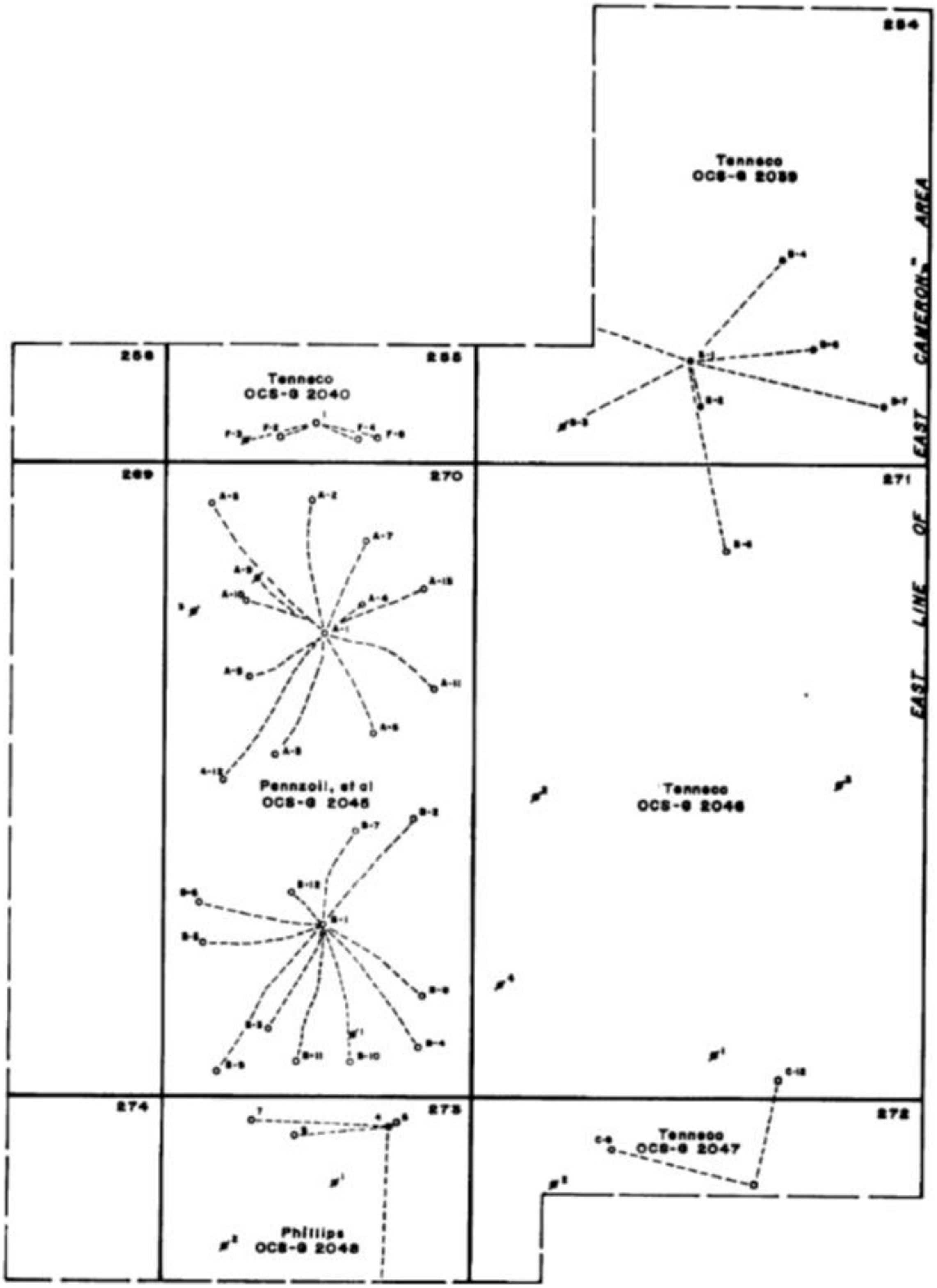


Figure B.11. East Cameron block 270 field development
Source: Holland et al. 1975

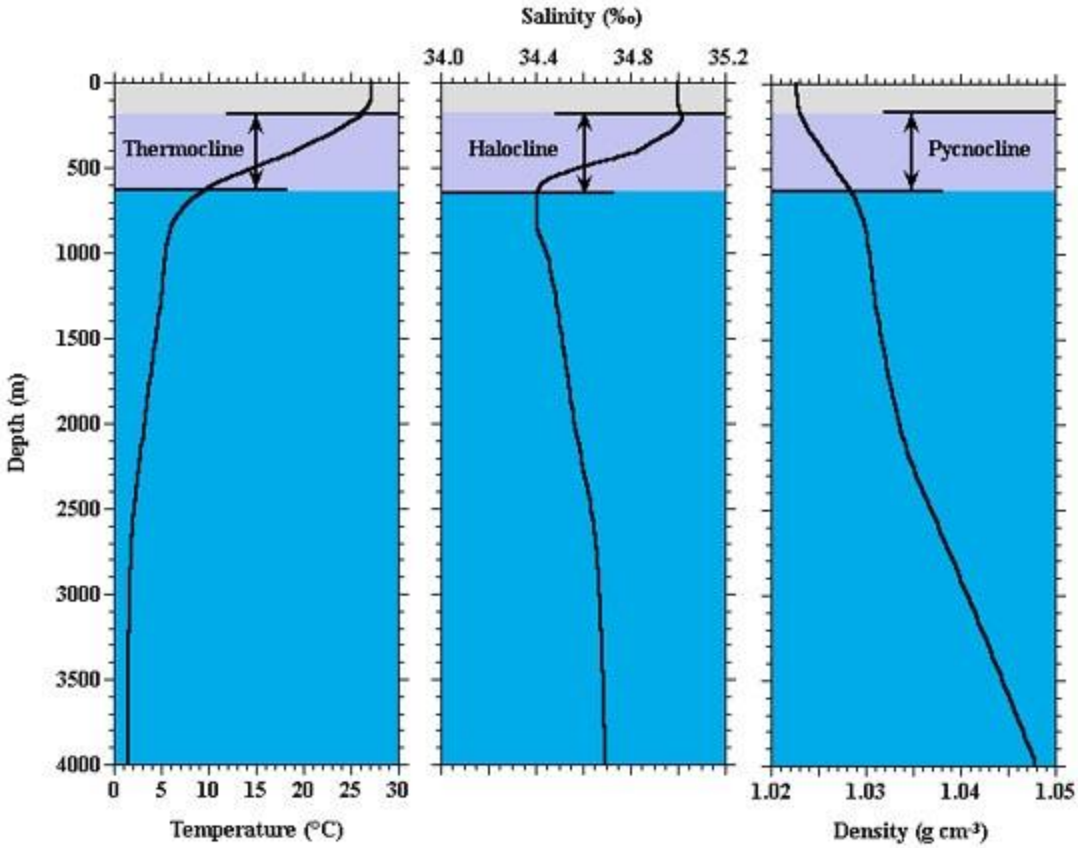


Figure B.12. Representation of the temperature, saline and density changes in the water column
Source: ldeo.columbia.edu

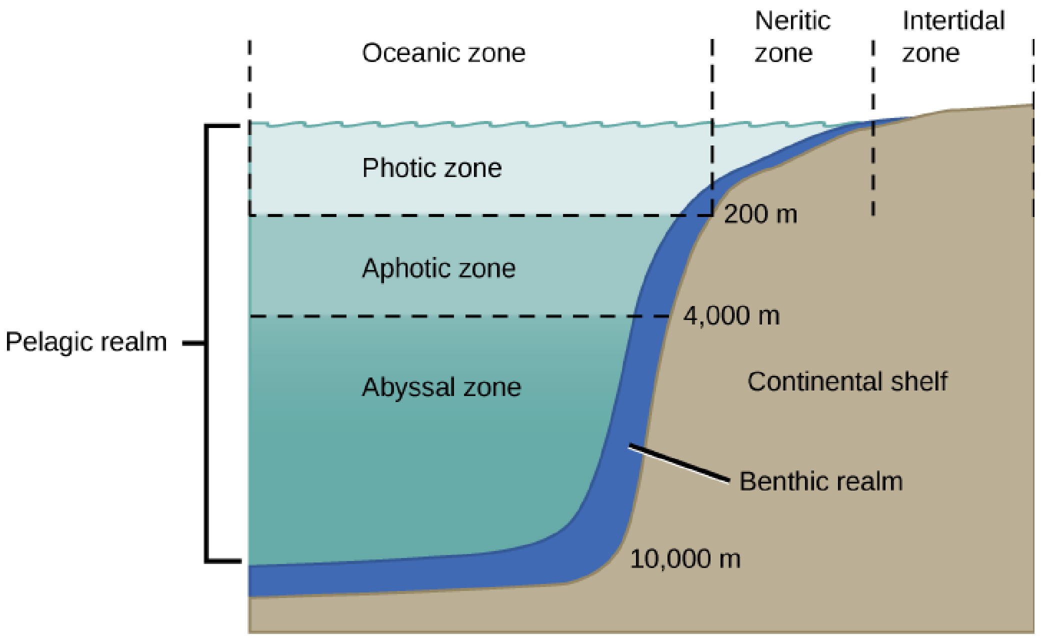


Figure B.13. Photic (sunlight), aphotic (twilight), and abyssal (midnight) water depth zones

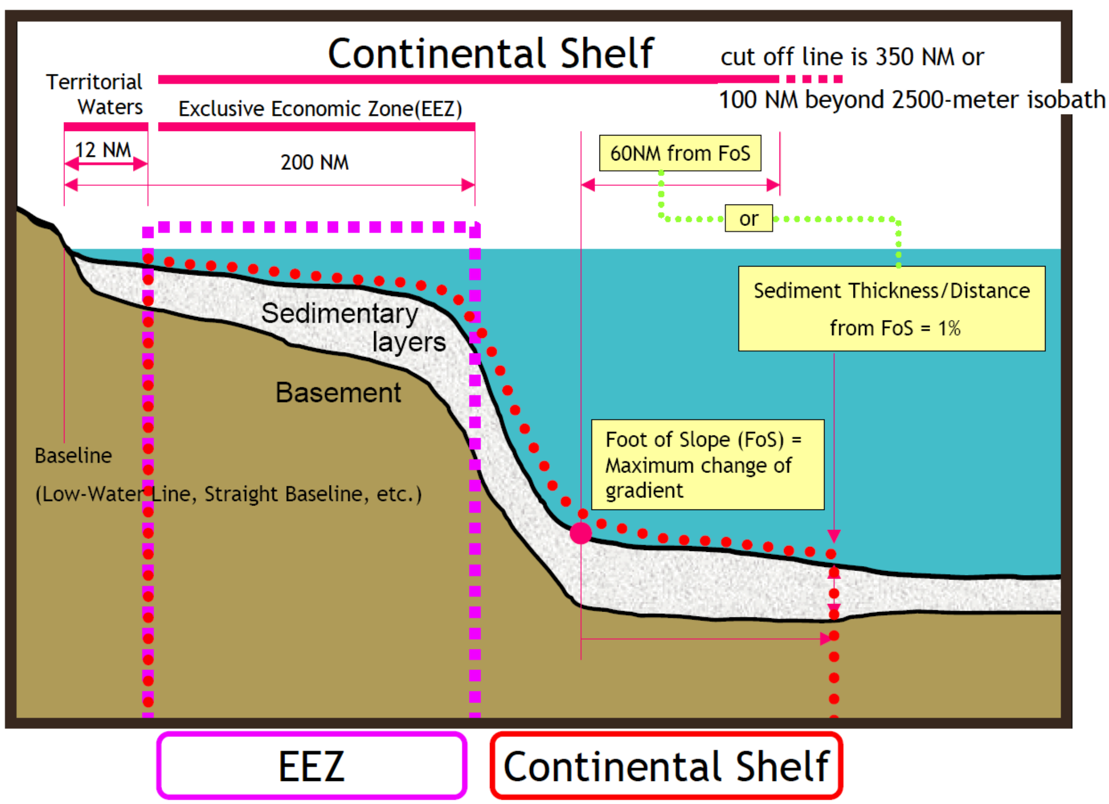


Figure B.14. Continental shelf extension formula
Source: tunnel2funnel.com

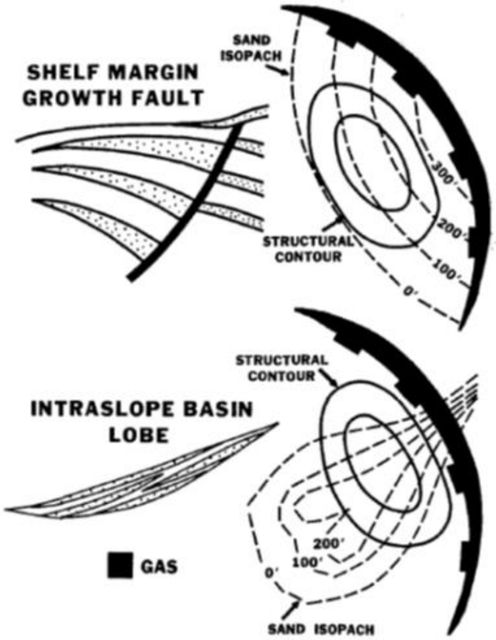


Figure B.15. Depositional models for reservoir sands on shelf margin and intraslope basin
Source: Braithwaite et al. 1988

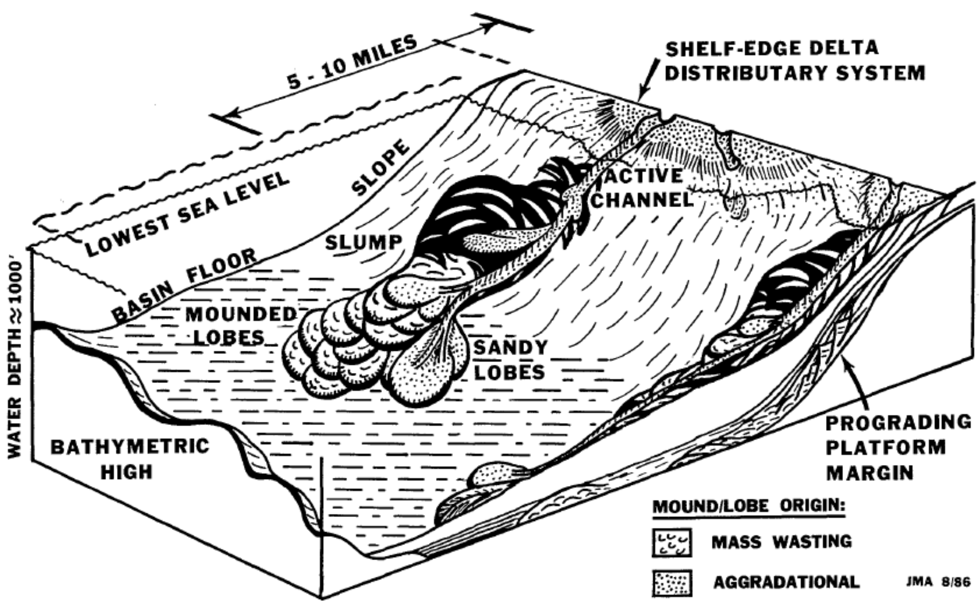


Figure B.16. Conceptual model for East Breaks 160 field primary reservoir interval
Source: Braithwaite et al. 1988

APPENDIX C

CHAPTER 3 TABLES AND FIGURES

Table C.1. Installed structures by type and water depth, 1942-2017

Water Depth (ft)	C/WP	FP	Floater	All	(%)
≤100	3010	2011	3	5024	(71.2%)
101-150	182	553	0	735	(10.4%)
151-200	98	452	0	550	(7.8%)
201-400	40	584	0	624	(8.9%)
>400	0	65	55	120	(1.7%)
All	3330	3665	58	7053	

Source: BOEM, February 2018

Table C.2. Decommissioned structures by type and water depth, 1973-2017

Water Depth (ft)	C/WP	FP	Floater	All	(%)
≤100	2447	1284	3	3734	(74.0%)
101-150	165	372	0	537	(10.6%)
151-200	88	300	0	388	(7.7%)
201-400	33	333	0	366	(7.3%)
>400	0	19	4	23	(0.5%)
All	2733	2308	7	5048	

Source: BOEM, February 2018

Table C.3. Structures decommissioned in the Gulf of Mexico in water depth >400 ft

Operator	Complex	Type	Water Depth (ft)	First Production	Last Production	Decommissioned Year
Apache	85	FP	670	1998	2012	2016
Chevron U.S.A.	735	MTLP	2107	2001	2004	2006
W & T Offshore	1055	FP	472	2002	2008	2012
ATP Oil & Gas	1320	FP	542	2003	2012	2017
Anadarko Petroleum	1384	SPAR	5300	2004	2008	2014
ATP Oil & Gas	1771	SEMI	2975	2006	2013	2014
Fieldwood SD Offshore	10242	FP	660	1985	2009	2017
Louisiana Land and Exploration	22274	FP	431	1981	2001	2005
Chevron U.S.A.	22372	FP	685	1980	2003	2010
Apache	22583	FP	651	1981	2005	2015
Apache	22705	FP	432	1989	2008	2016
Chevron U.S.A.	22846	FP	480	1984	2003	2011
EP Energy E&P	23004	FP	414	1986	2017	2011
W & T Offshore	23308	FP	415	1989	2008	2013
Placid Oil	23543	SEMI	1540	1988	1989	1989
Chevron U.S.A.	23581	FP	620	1990	2005	2011
Sojitz Energy Venture	23859	FP	582	1990	2008	2010
Apache	23891	FP	531	1992	2011	2016
W & T Offshore	24021	FP	467	1992	2004	2006
Newfield Exploration	24079	SEMI	2097	1991	1999	1999
Louisiana Land and Exploration	24087	FP	420	1995	2001	2005
BP E&P	27014	FP	530	1995	2002	2009
W & T Offshore	28033	FP	430	1996	2008	2011

Source: BOEM, February 2018

Table C.4. Shallow water installation by decade

Decade	C/WP	FP	Total	(%)
1944-1956	30	104	134	(2%)
1957-1966	607	425	1032	(15%)
1967-1976	441	659	1100	(16%)
1977-1986	775	924	1699	(25%)
1987-1996	708	738	1446	(21%)
1997-2006	627	606	1233	(18%)
2007-2016	142	143	285	(4%)
2017-	0	1	1	
Total	3330	3600	6930	

Source: BOEM, February 2018

Table C.5. Shallow water decommissioning by decade

Decade	C/WP	FP	Total (%)
1973-1976	65	5	70 (1%)
1977-1986	248	83	331 (7%)
1987-1996	636	443	1079 (21%)
1997-2006	783	578	1361 (27%)
2007-2016	963	1121	2084 (42%)
2017-	38	59	97 (2%)
Total	2733	2289	5022

Source: BOEM, February 2018

Table C.6. Deepwater structure installation by decade

	Fixed Platform	Floater
1977-1986	19	1
1987-1996	26	5
1997-2006	18	29
2007-2016	2	19
2017-	0	1
Total	65	55

Source: BOEM, February 2018

Table C.7. Deepwater structures decommissioned in the Gulf of Mexico, 1989-2017

Water Depth	1989	1999	2005	2006	2009	2010	2011	2012	2013	2014	2015	2016	2017
400-500			2	1			3	1	1			1	
500-1500					1	2	1				1	2	2
>1500	1	1		1						2			
Total	1	1	2	2	1	2	4	1	1	2	1	3	2

Source: BOEM, February 2018

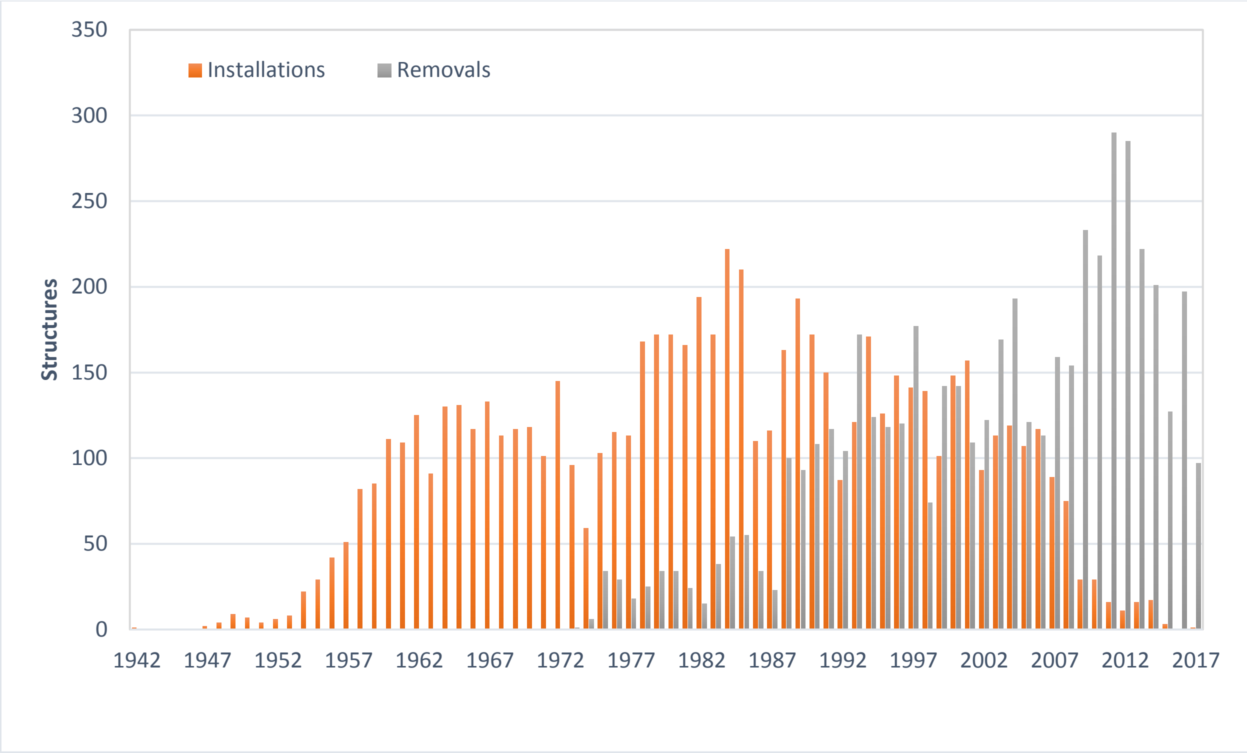


Figure C.1. Gulf of Mexico structures installed and removed in water depth <400 ft, 1942-2017.
Source: BOEM, February 2018

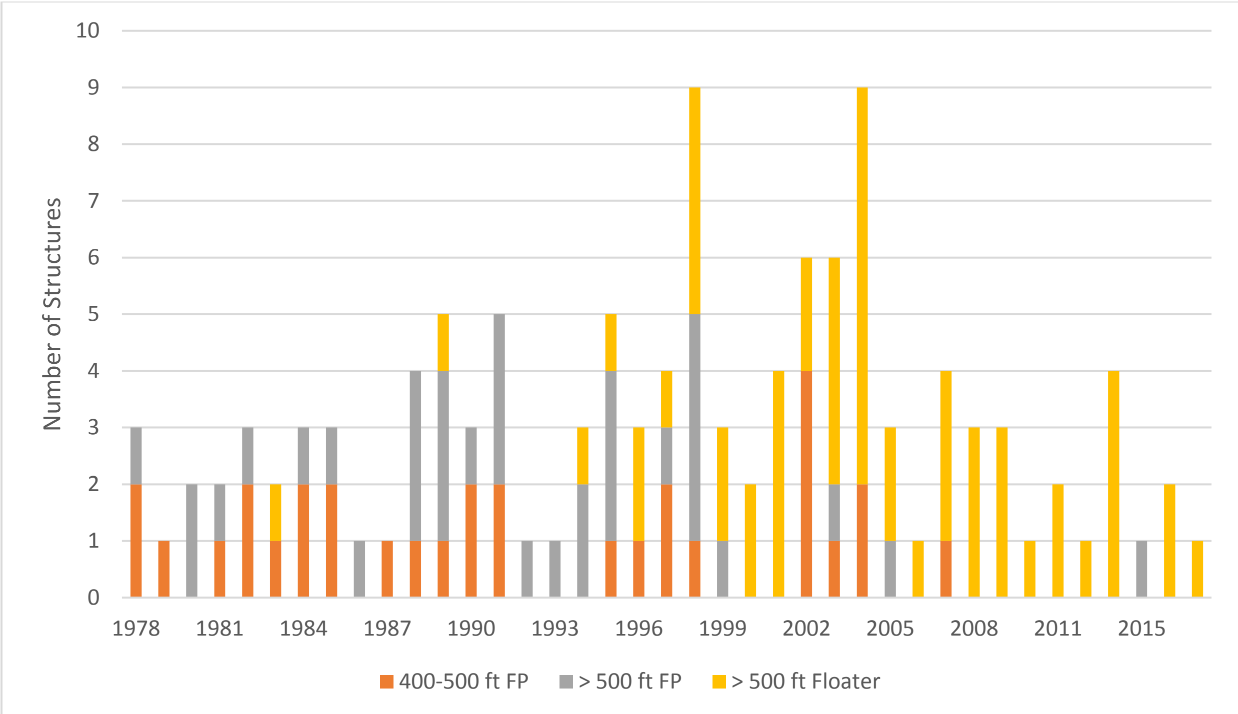


Figure C.2. Deepwater structure installation in the Gulf of Mexico in water depth >400 ft, 1978-2017.
Source: BOEM, February 2018

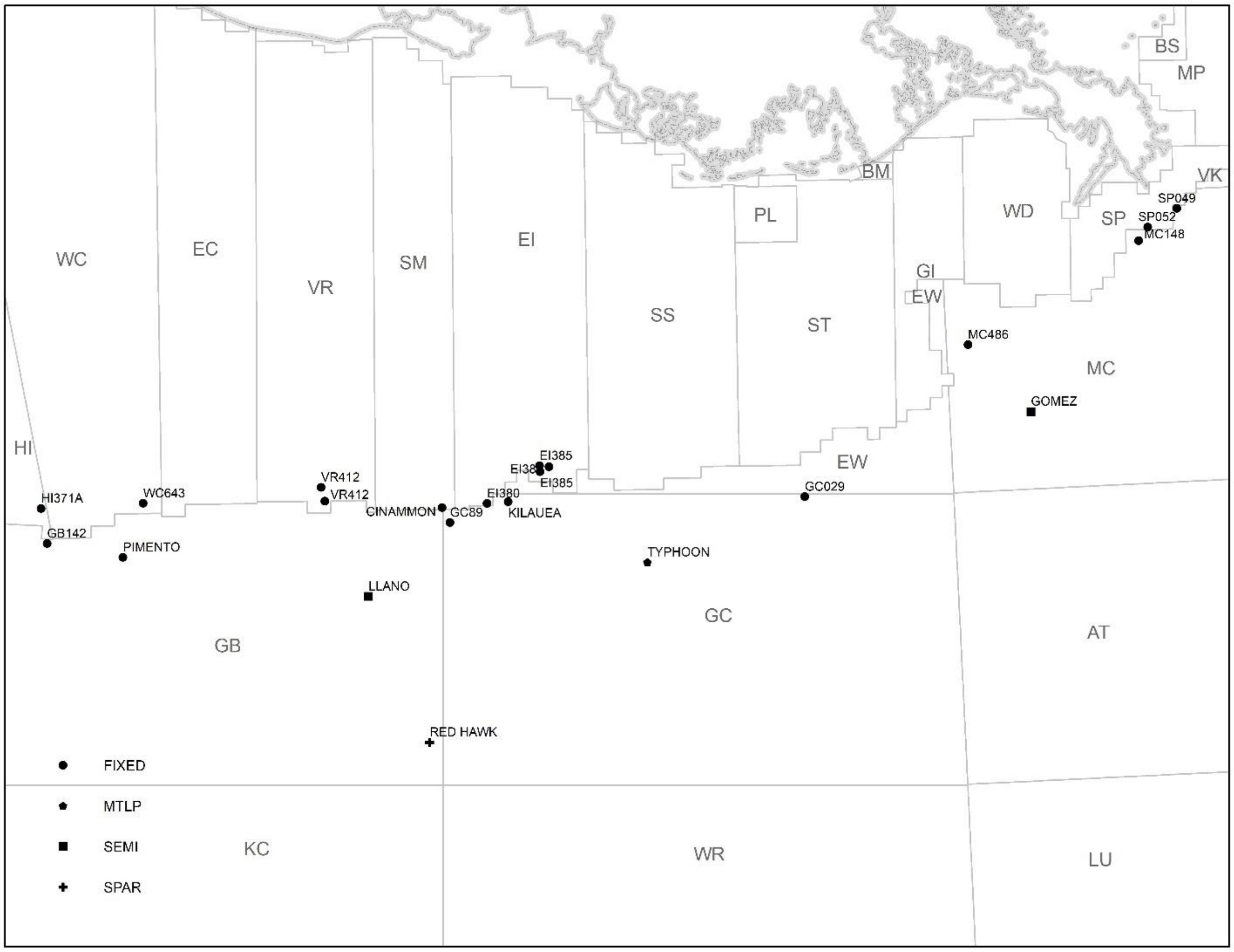


Figure C.3. Deepwater structures decommissioned in the Gulf of Mexico circa 2017.
Source: BOEM, February 2018

APPENDIX D
CHAPTER 4 TABLES AND FIGURES

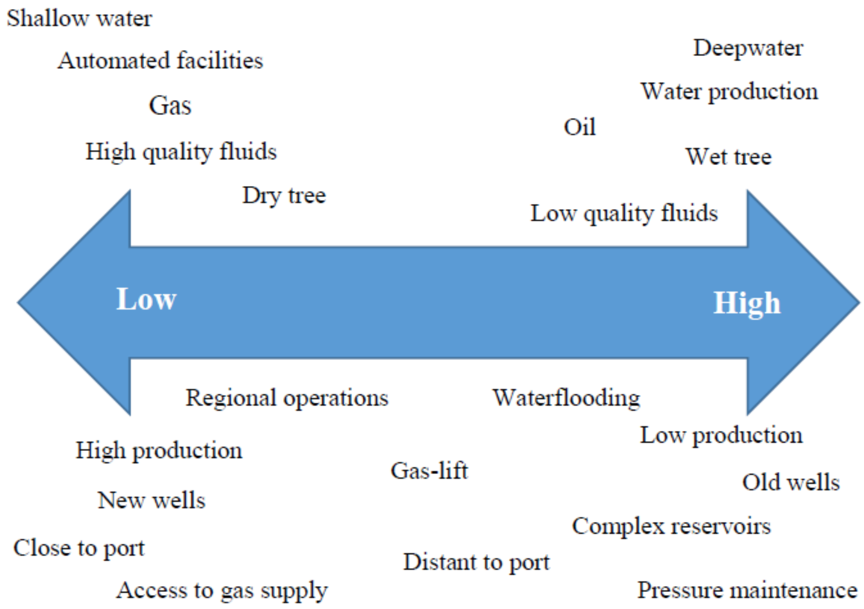


Figure D.1. Operating cost spectrum

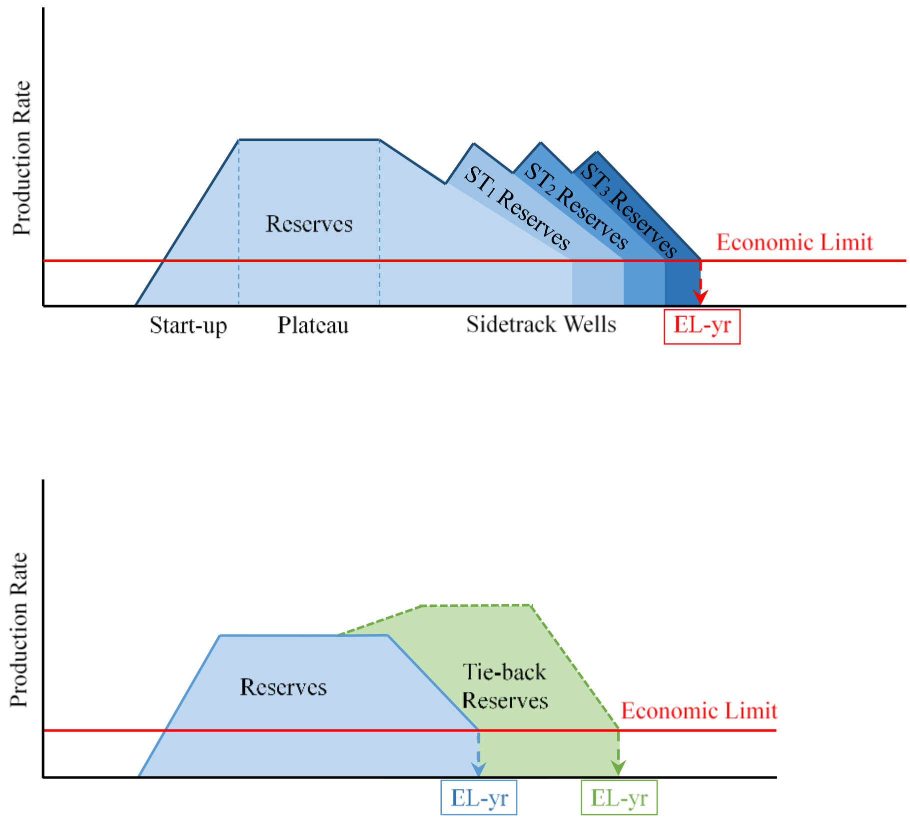


Figure D.2. Decommissioning timing is impacted by sidetrack drilling and tieback opportunities

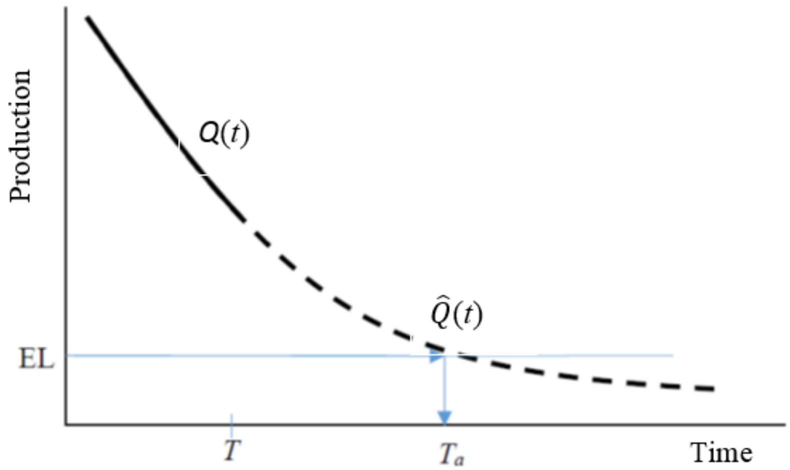


Figure D.3. Predicted abandonment time for a producing well using the economic limit cutoff

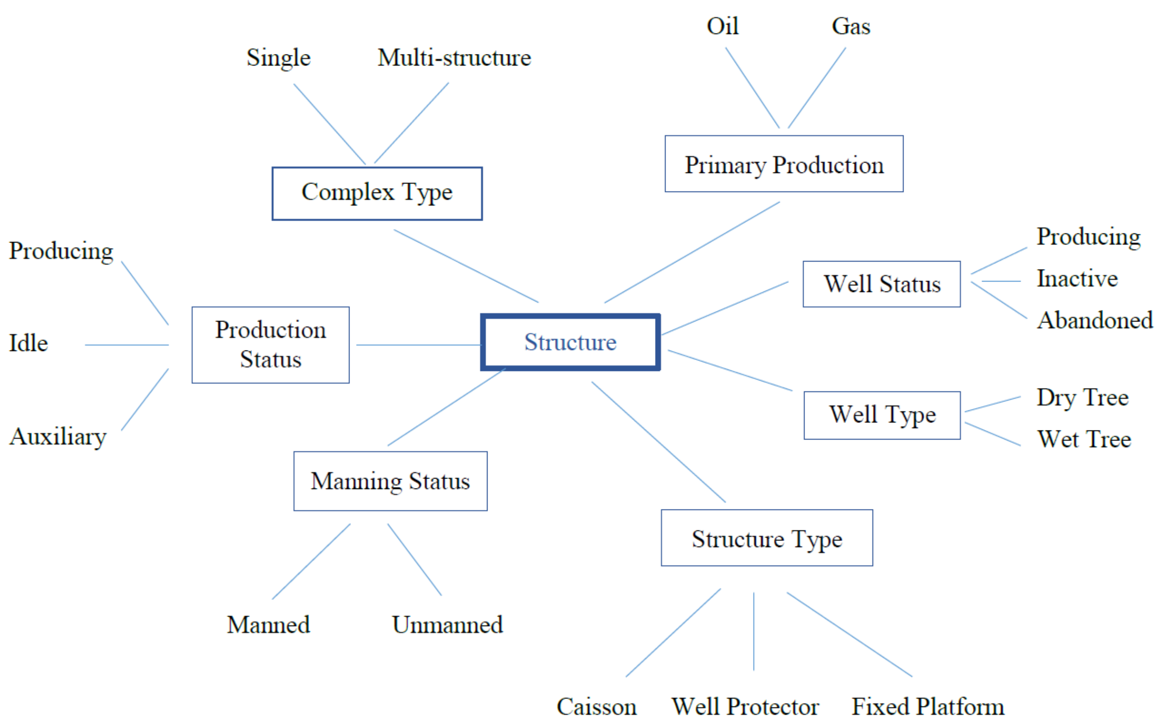


Figure D.4. Primary structure classification categories

APPENDIX E

CHAPTER 5 TABLES AND FIGURES

Table E.1. Bullwinkle and subsea field tieback production through September 2017

Project	Field Name	Lease Blocks	Discovery Year, First Production	Original Reserves (MMbbl)	(Bcf)	Cum. Oil (MMbbl)	Cum. Gas (Bcf)
Bullwinkle	GC 065	GC 65, GC 109, GC 108, GC 64	1983, 1989	122.3	208.7	122.1	207.5
Rocky	GC 110	GC 110, GC 155, GC 199	1987, 1995	29.1	45.2	29.1	45.5
Troika	GC 244	GC 244, GC 200, GC 201	1994, 1996	192.9	378.6	180.1	343.5
Angus	GC 112	GC 112, GC 113	1997, 1998	41.4	62.9	41.2	62.5
Aspen	GC 243	GC 243	2001, 2002	36.5	44.3	33.8	33.8

Source: BOEM 2017

Table E.2. Geological time scale

Era	Period	Epoch	Age
Cenozoic	Quaternary	Holocene	0-10 ka
		Pleistocene	0.01-2 Ma
	Tertiary	Pliocene	2-5.3 Ma
		Miocene	5.3-38 Ma
		Eocene	28-55 Ma
		Paleocene	55-65 Ma
Mesozoic	Cretaceous		65-140 Ma
	Jurassic		140-200 Ma
	Triassic		200-250 Ma
Paleozoic	Permian		250-290 Ma
	Pennsylvanian		290-320 Ma
	Mississippian		320-365 Ma
	Deconian		365-405 Ma
	Silurian		405-425 Ma
	Ordovician		425-500 Ma
	Cambrian		500-570 Ma
Precambrian			0.57-4.5 Ga

Table E.3. Gulf of Mexico cumulative production and reserves by water depth circa 2016

Water Depth Range (ft)	Number of Fields	Cumulative Production (MMboe)	Reserves (MMboe)
< 500	1082	41,331	899
500-999	54	1260	33
1000-1499	26	1388	98
1500-4999	97	6431	1993
5000-7499	35	1883	1403
≥ 7500	18	483	353
Total	1312	52,776	4779

Source: Burgess et al. 2016

Table E.4. Top 20 shallow water fields based on original barrels oil equivalent circa 2016

Rank	Field name	Disc. (yr)	Original reserves (MMboe)	Cumulative production (MMboe)	Reserves Oil (MMbbl)	Reserves Gas (Bcf)	Reserves BOE (MMboe)
2	EI 330	1971	798.6	782.9	11.7	22.6	15.7
3	WD 30	1949	796.5	758.9	6.8	21.3	10.6
4	GI 43	1956	711.1	669.8	22.4	106.0	41.3
5	TS 000	1958	710.6	681.7	2.7	146.8	28.9
7	BM 002	1949	649.7	642.9	5.6	6.8	6.8
8	VR 14	1956	604.2	604.2	0	0	0
9	MP 41	1956	550.0	543.8	3.2	17.1	6.2
10	VR 39	1948	496.3	495.3	0.3	3.9	1.0
11	SS 208	1960	484.6	472.2	6.0	35.8	12.4
14	WD 73	1962	403.0	395.2	5.4	17.3	8.4
15	WI 238	1964	383.4	365.6	8.2	54.0	17.8
16	GI 16	1948	380.4	376.4	2.8	6.5	4.0
17	SP 61	1967	378.8	365.1	10.1	20.4	13.7
18	SP 89	1969	353.0	350.5	1.9	3.6	2.5
19	ST 172	1962	349.9	349.9	0	0	0
20	WC 180	1961	342.2	341.7	0	2.5	0.5
21	ST 21	1957	335.7	333.6	1.5	3.1	2.1
22	SS 169	1960	334.0	326.0	5.3	14.8	8.0
23	ST 176	1963	322.0	314.6	3.4	22.3	7.4
24	EI 292	1964	319.9	316.0	2.7	7.2	4.0

Source: BOEM 2016

Note: Cumulative production through 2015.

Table E.5. Top 20 deepwater fields based on original barrels oil equivalent circa 2016

Rank	Field	Disc. (yr)	Original reserves (MMboe)	Cumulative production (MMboe)	Reserves Oil (MMbbl)	Reserves Gas (Bcf)	Reserves BOE (MMbbl)
1	Mars-Ursa	1989	1851.0	1504.5	260.8	481.6	346.5
6	Tahiti/Caesar/Tonga	2002	660.5	265.0	363.7	178.8	395.5
12	Auger	1987	432.4	410.4	13.7	46.7	22.0
13	Atlantis	1998	411.6	279.2	113.7	105.0	132.4
25	N. Thunder Horse	2000	319.5	227.8	78.3	75.1	91.7
26	Cognac	1975	319.3	315.2	3.1	5.4	4.1
30	King/Horn Mt.	1993	309.1	262.1	34.7	69.0	47.0
32	Shenzi	2002	303.2	254.4	45.6	18.1	48.8
35	Great White	2002	285.6	126.2	134.9	137.6	159.4
42	Salsa	1984	264.7	222.7	25.6	92.0	42.0
44	Holstein	1999	261.7	107.9	124.4	165.3	153.8
45	Troika	1994	260.3	240.5	13.4	36.0	19.8
46	Ram-Powell	1985	257.9	255.2	2.2	3.1	2.7
47	Thunder Horse	1999	251.2	124.7	111.4	84.8	126.5
55	Stampede	2006	229.0	0.0	214.3	82.7	229.0
63	Pompano	1981	206.8	188.6	15.1	17.1	18.2
68	Baldpate	1991	198.1	181.3	8.8	45.2	16.8
69	Petronius	1995	197.9	186.2	8.8	16.5	11.7
74	Genesis	1988	191.8	175.5	13.1	17.8	16.3
80	Mad Dog	1998	183.7	155.5	17.9	57.4	28.2

Source: BOEM 2016
Note: Cumulative production through 2015.

Table E.6. Undiscovered technically recoverable resources in the Gulf of Mexico circa 2015

Planning Area	Oil (Bbbl) 95%	Oil (Bbbl) mean	Oil (Bbbl) 5%	Gas (Tcf) 95%	Gas (Tcf) mean	Gas (Tcf) 5%	BOE (Bboe) 95%	BOE (Bboe) mean	BOE (Bboe) 5%
Western GoM (<200 m)	0.51	0.75	0.98	15.8	24.9	35.7	3.3	5.2	7.3
Central GoM (<200 m)	1.04	1.36	1.71	23.6	36.0	52.5	5.2	7.8	11.0
Total GoM	39.5	48.5	58.5	124	141.8	159.6	61.5	73.7	86.9

Source: BOEM 2017

Table E.7. Geologic provinces and number of fields in northern deepwater Gulf of Mexico

Province	Description	Number
Basins	Thick Neogene suprasalt sediments that overlie shallow allochthonous salt or welded to strata that once underlaid the welded-out basins.	149
Subsalt	Subsalt prospects imaged below allochthonous salt bodies most of which have bathymetric expression. Considerable variation in salt thickness, styles and timing of formation. Boundary marked by the edge of the Sigsbee Escarpment.	50
Fold Belt	Three subregional fold belts have been identified: Perdido, Keathley-Walker, and the Mississippi Fan, each with different structural styles, timing of deformation, ages of reservoirs, and natures of salt.	19
Abyssal Plain	Rests outboard (south) of the Subsalt, Fold Belt and Basins provinces and subdivided into areas underlain by Louann salt and areas that are salt free. Distinguishing feature is the lack of bathymetric expression of the structures and few exploration wells.	7

Source: Weimer et al. 2017

Table E.8. Blind Faith fluid properties in the Pink and Peach reservoir sands

	Upper Pink	Lower Pink	Upper Peach	Lower Peach
Reservoir pressure (psia)	~13,500		~17,000	
Reservoir temperature (°F)	216-230		255-267	
Bubble point (psia)	4200-6500		1800-2000	
Density (°API)	28.3	29	28.5	33.3
Gas oil ratio (scf/bbl)	500-1200		350-550	
Viscosity (cP) @ 15 psia, 70°F	33.6	19.5	32	6.6
Wax content, C20+ n-paraffin (wt%)	2.59	-	2.17	2.51
Asphaltenes (wt%)	1.4	2.9	5.8	2.4

Source: Subramanian et al. 2009

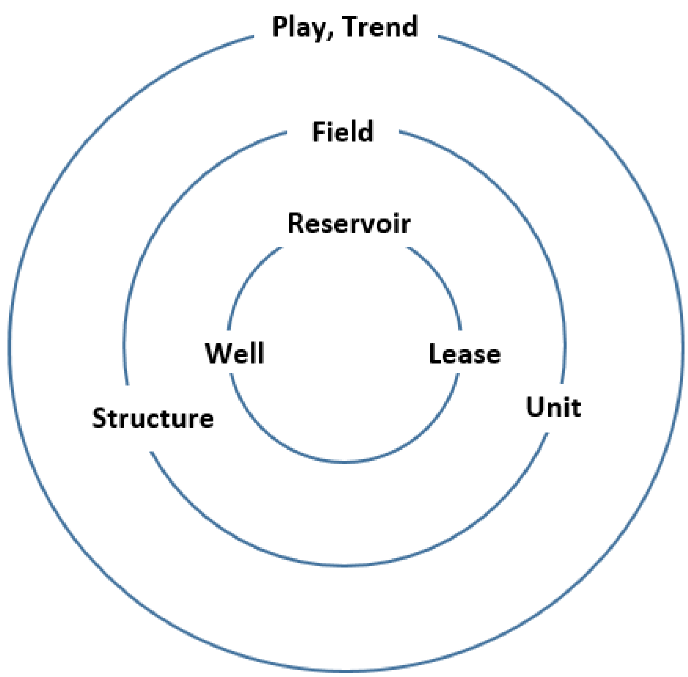


Figure E.1. Organizational layers with reservoir, lease and well as base units

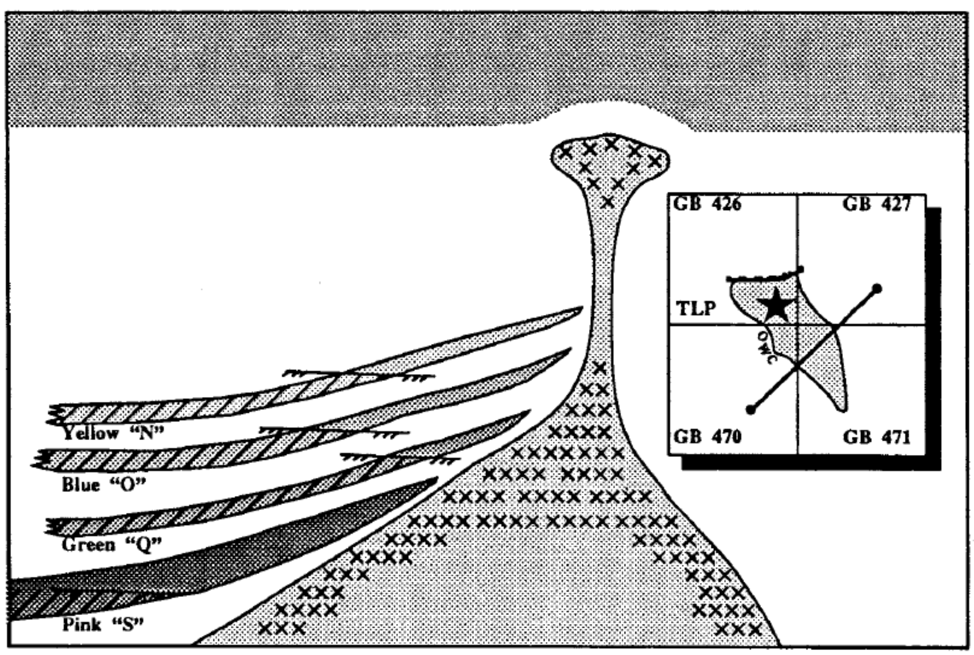


Figure E.2. Auger geologic structure and main reservoirs
Source: Bourgeois 1994

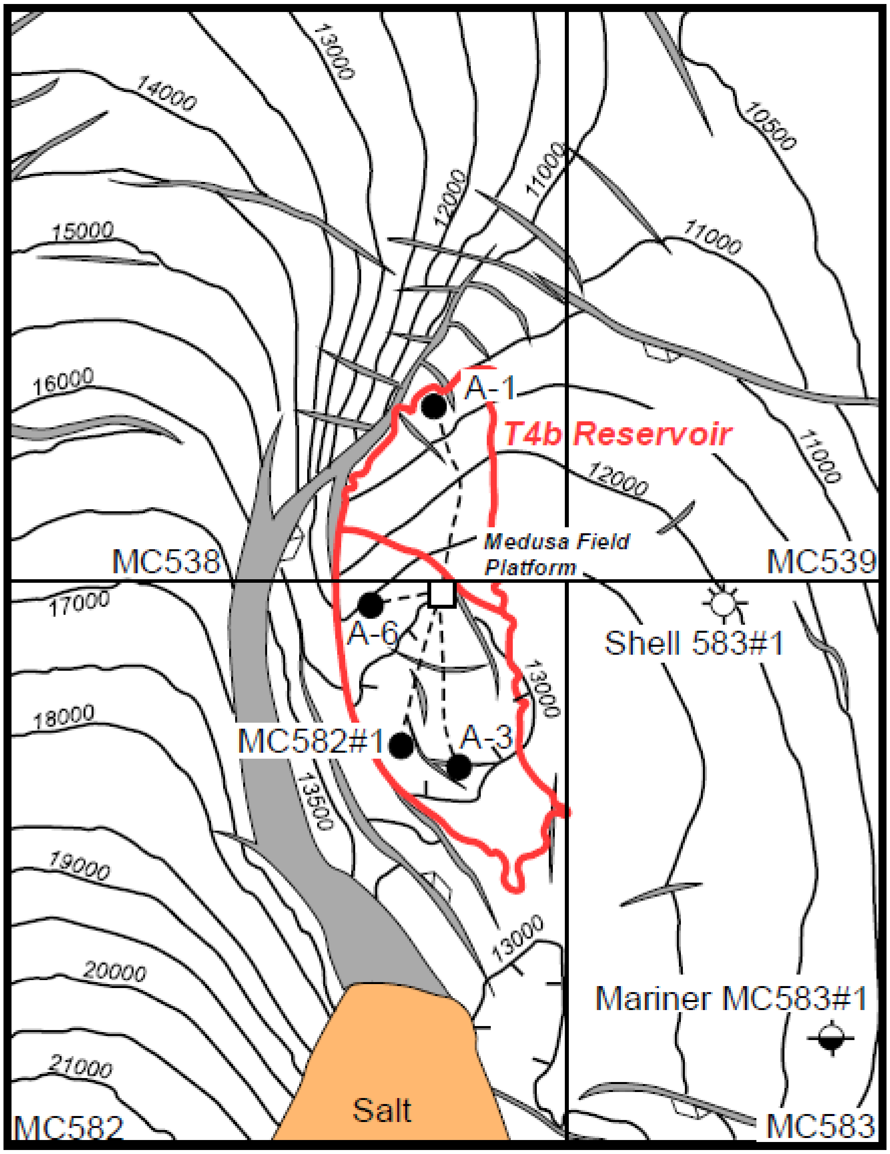


Figure E.3. Structural map of the T4b sand formation in the Medusa field
Source: Lach et al. 2005

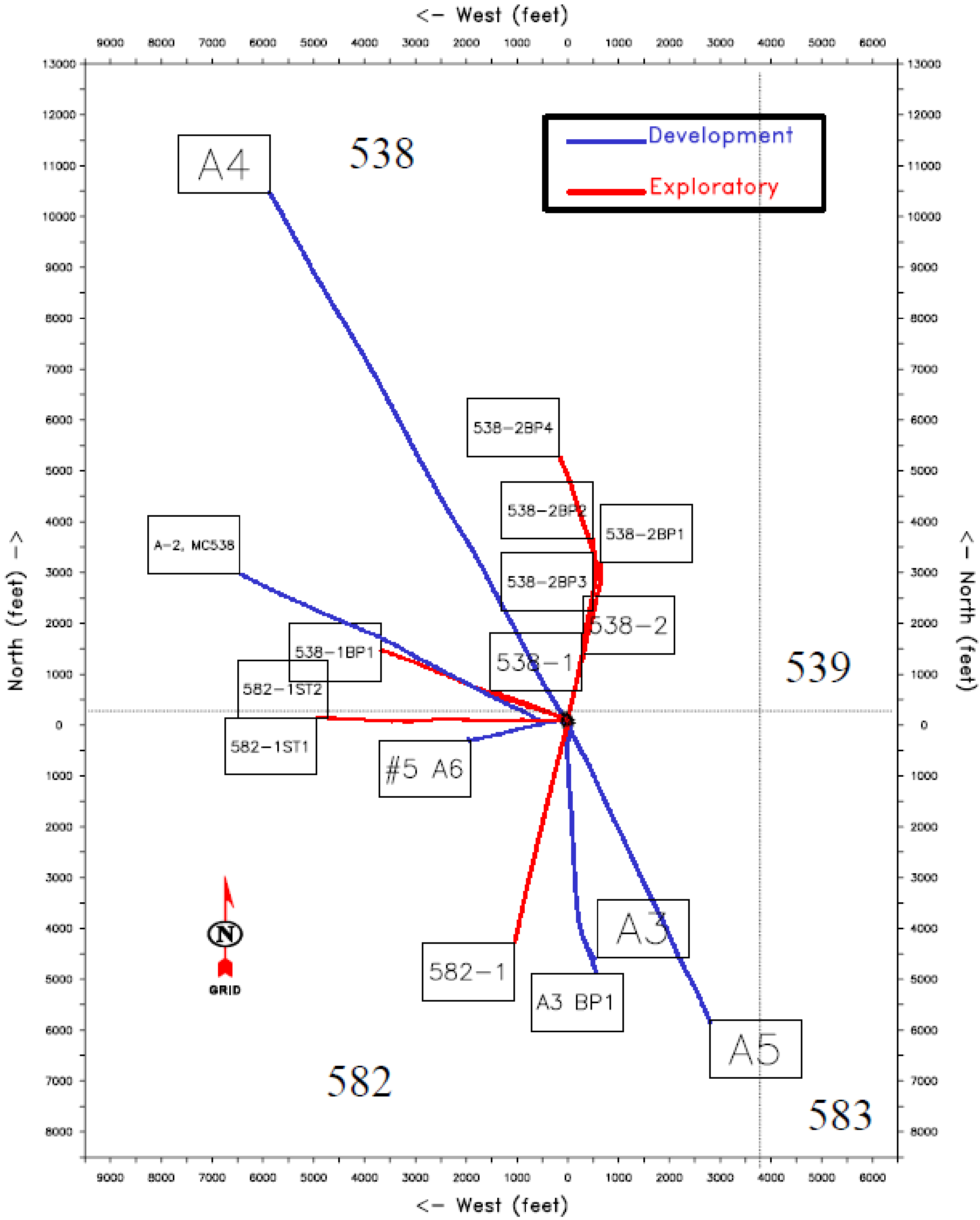


Figure E.4. Exploration and development wells drilled on blocks GC 538/582 in the Medusa field
Source: Chhajlani et al. 2002

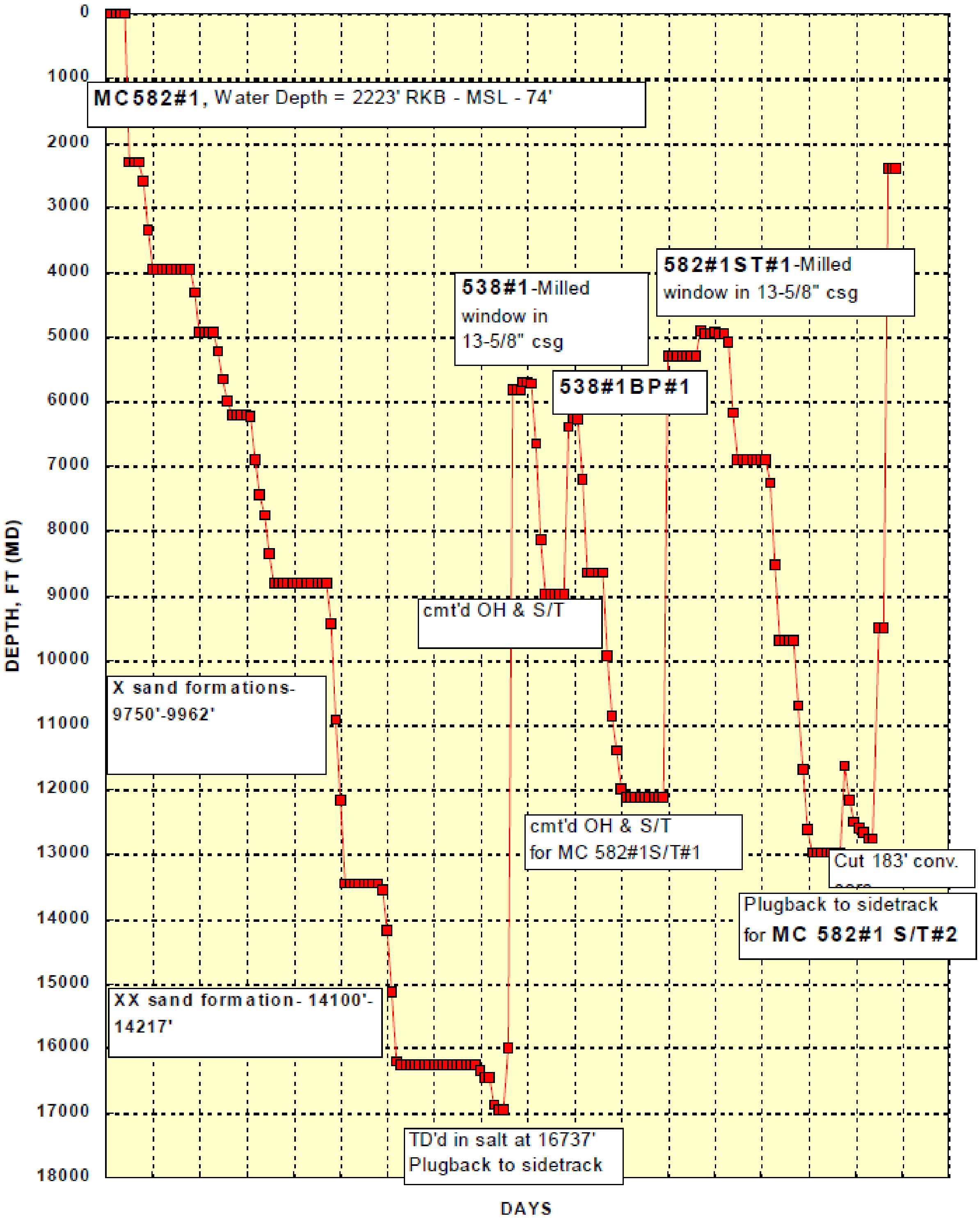


Figure E.5. Days vs. depth plot for the Medusa discovery well on MC 582#1 and its sidetracks.
Source: Chhajlani et al. 2002

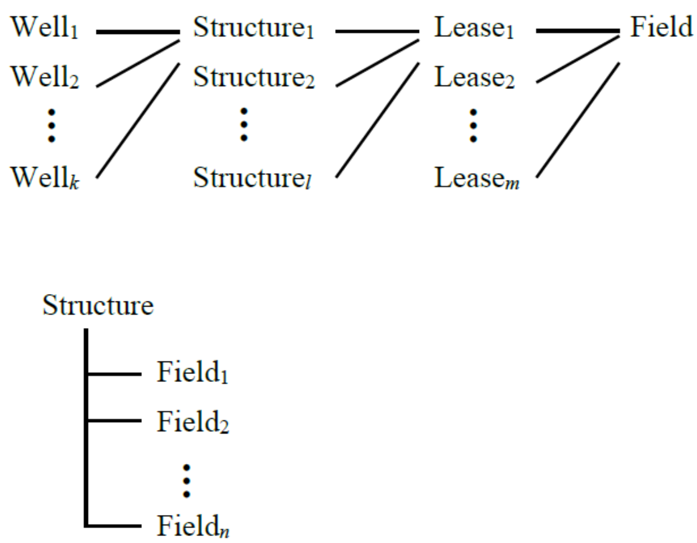


Figure E.6. Levels of aggregation and field-structure correspondences

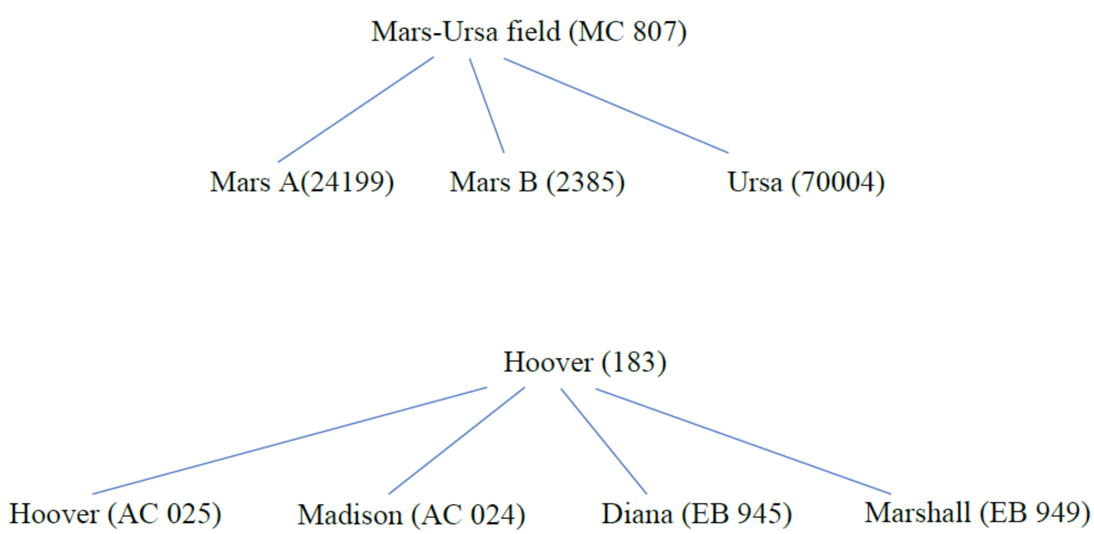


Figure E.7. Deepwater field-structure associations
Source: BOEM 2017

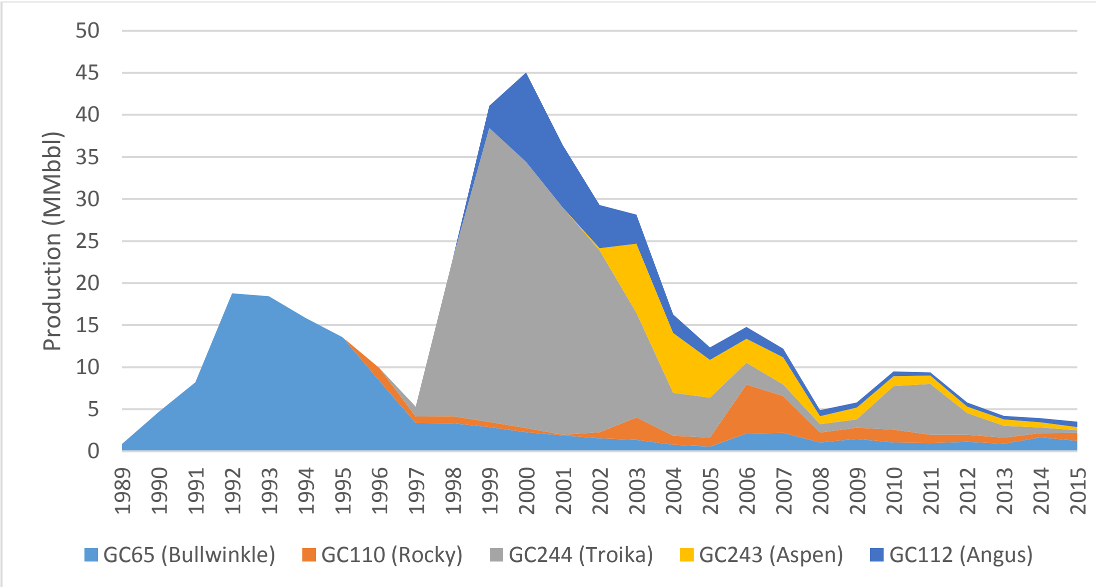


Figure E.8. Green Canyon 65 (Bullwinkle) field production and subsea tiebacks Rocky, Troika, Angus and Aspen

Source: BOEM 2017

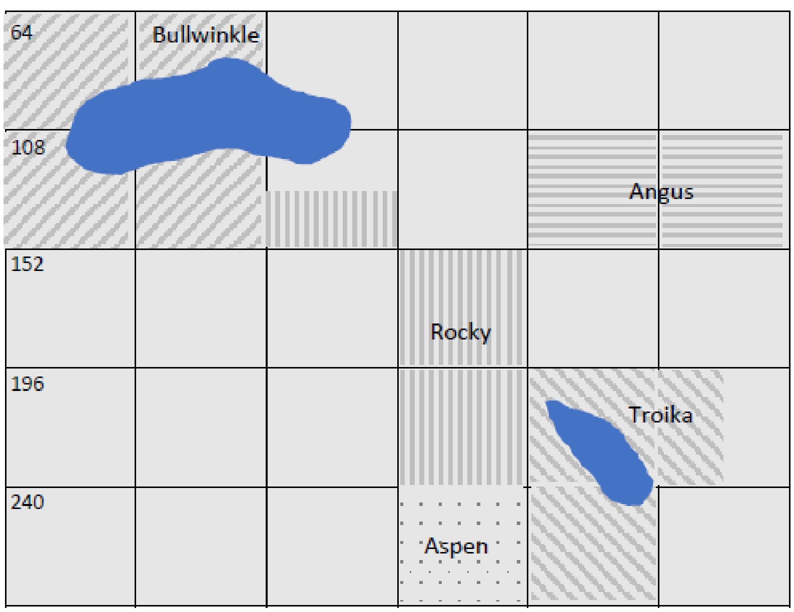


Figure E.9. Subsea fields indicated by producing leases that tieback to Bullwinkle's fixed platform

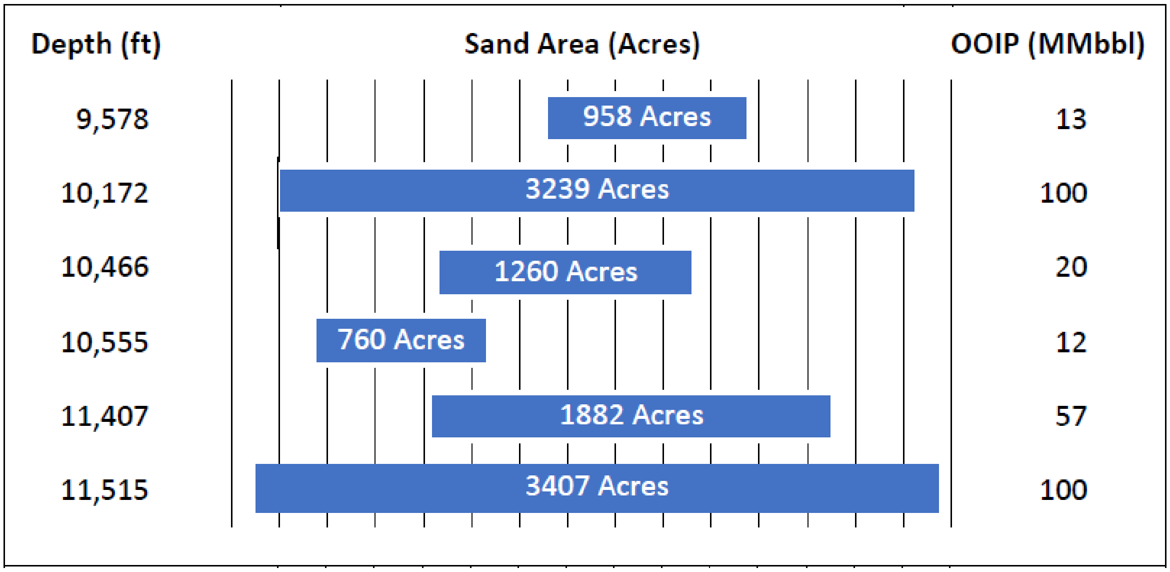


Figure E.10. Stacked sands at South Timbalier 21 field

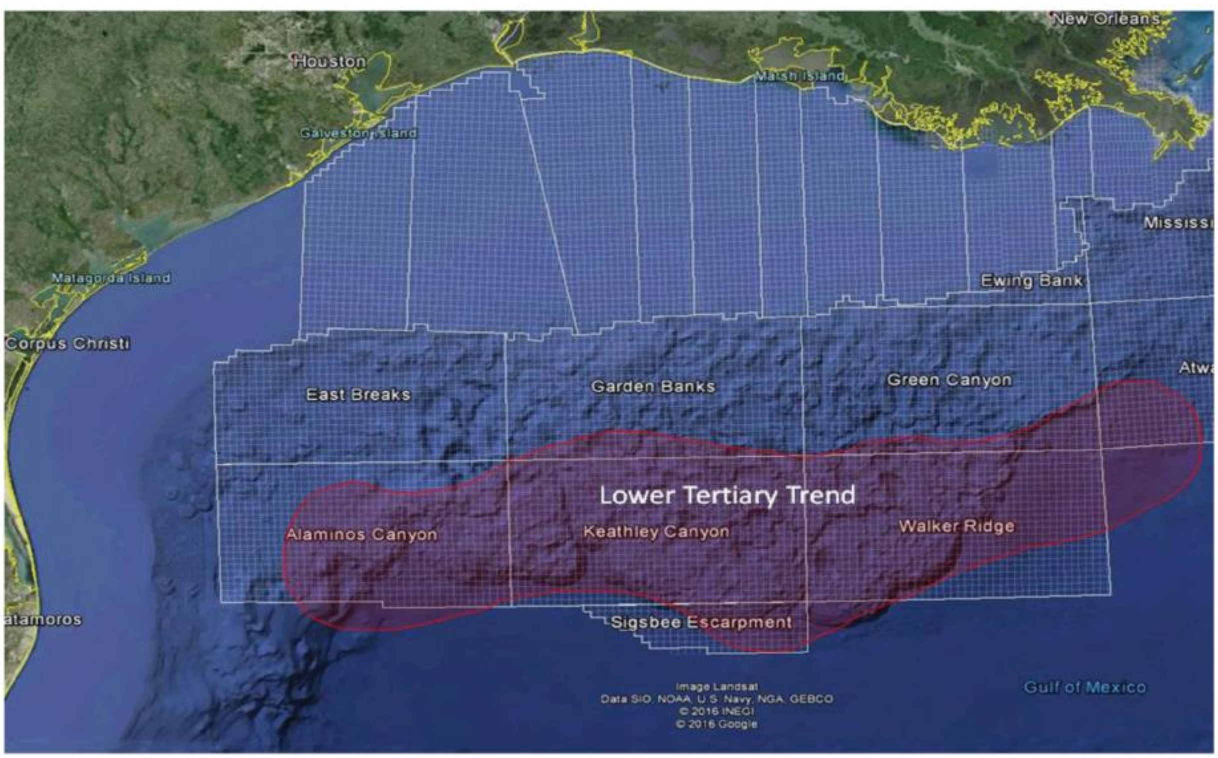


Figure E.11. Approximate outline of the Lower Tertiary trend in the Gulf of Mexico

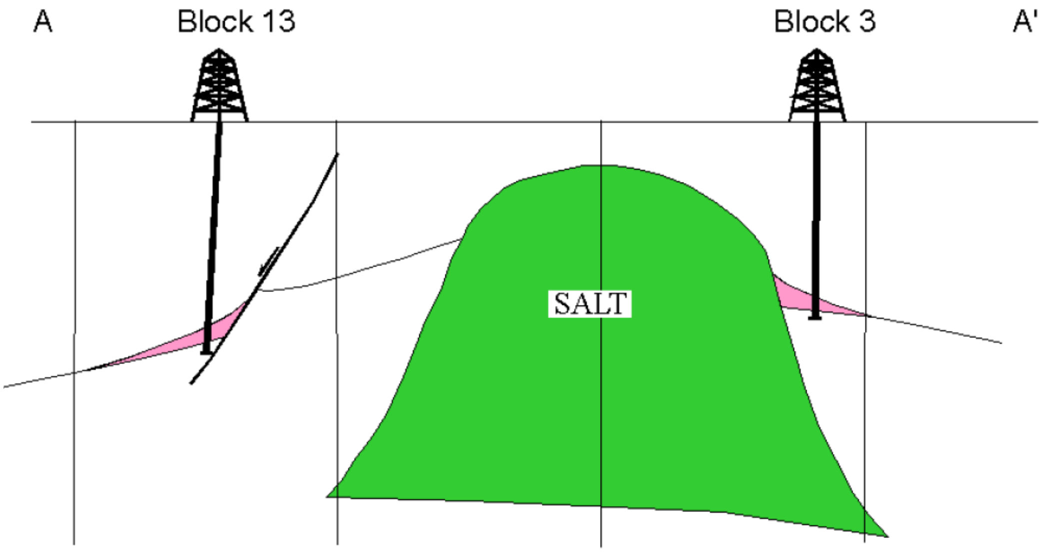


Figure E.12. Salt dome with fault trap downdip on the domal structure
Source: BOEM 1996

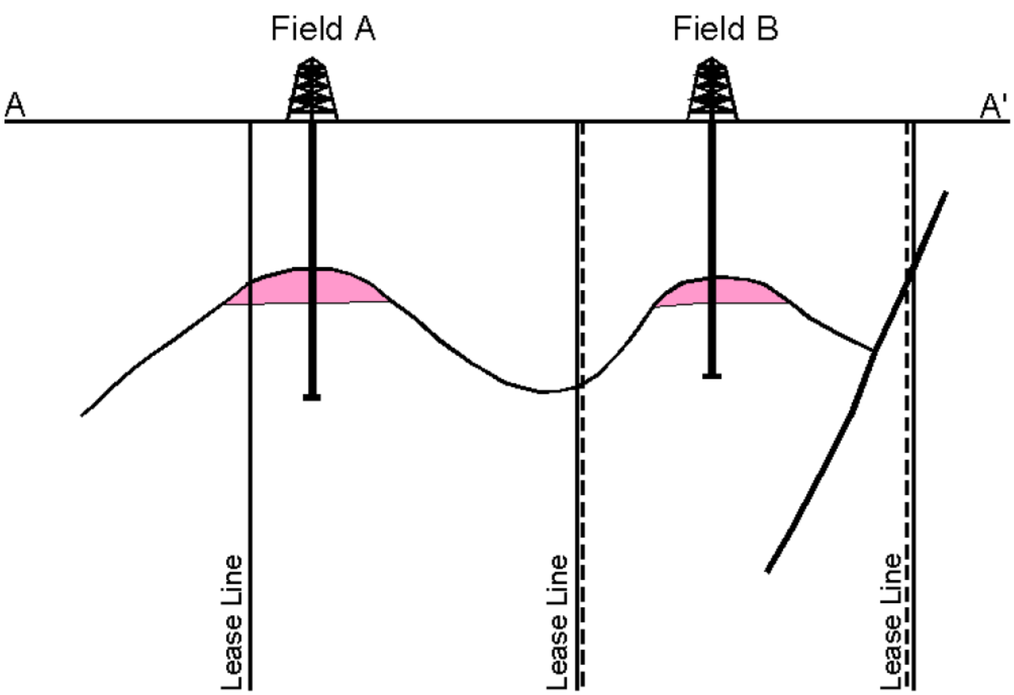


Figure E.13. Two structural highs with a separating structural low
Source: BOEM 1996

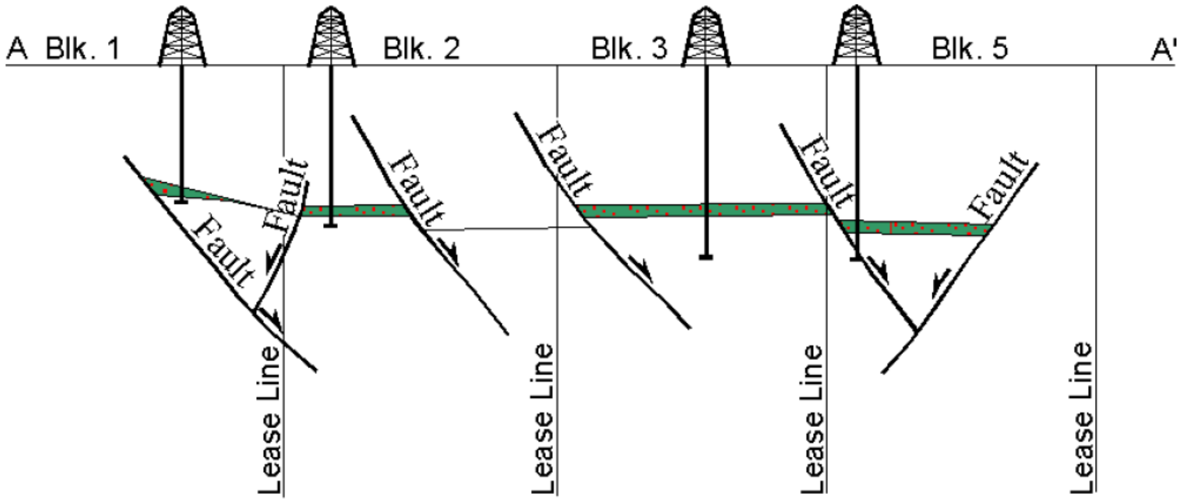


Figure E.14. Series of traps against a large fault without separating structural lows
Source: BOEM 1996

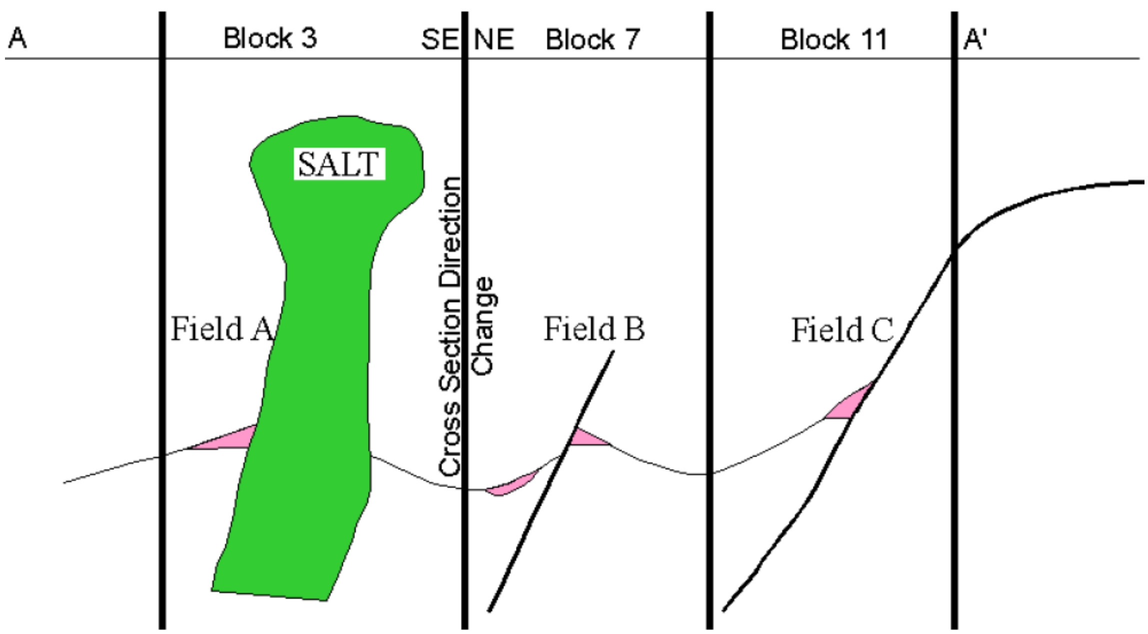


Figure E.15. Multiple accumulations with different structural styles in a salt-bounded mini-basin
Source: BOEM 1996

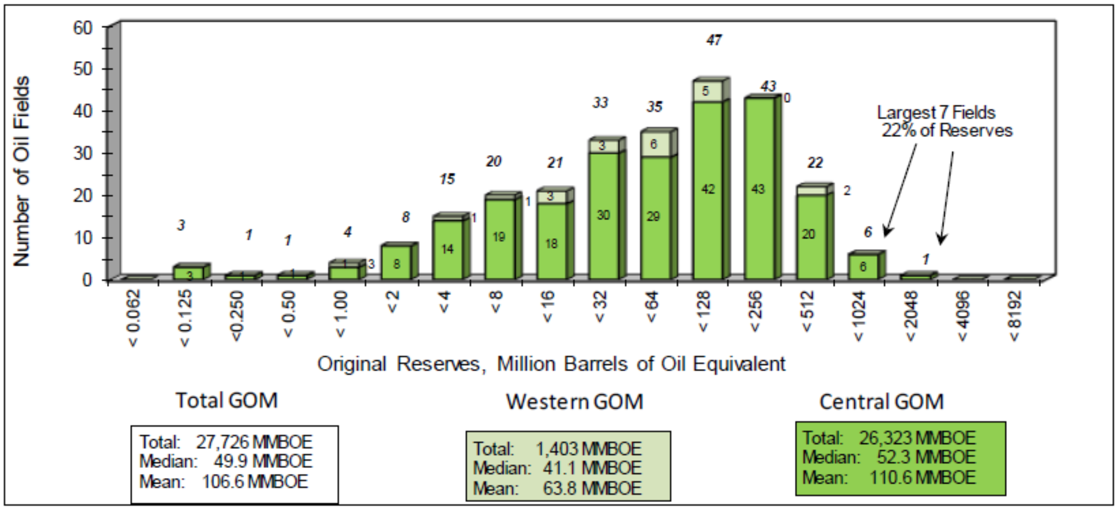


Figure E.16. Original reserves in oil fields in the Gulf of Mexico (MMboe)
Source: Burgess et al. 2016

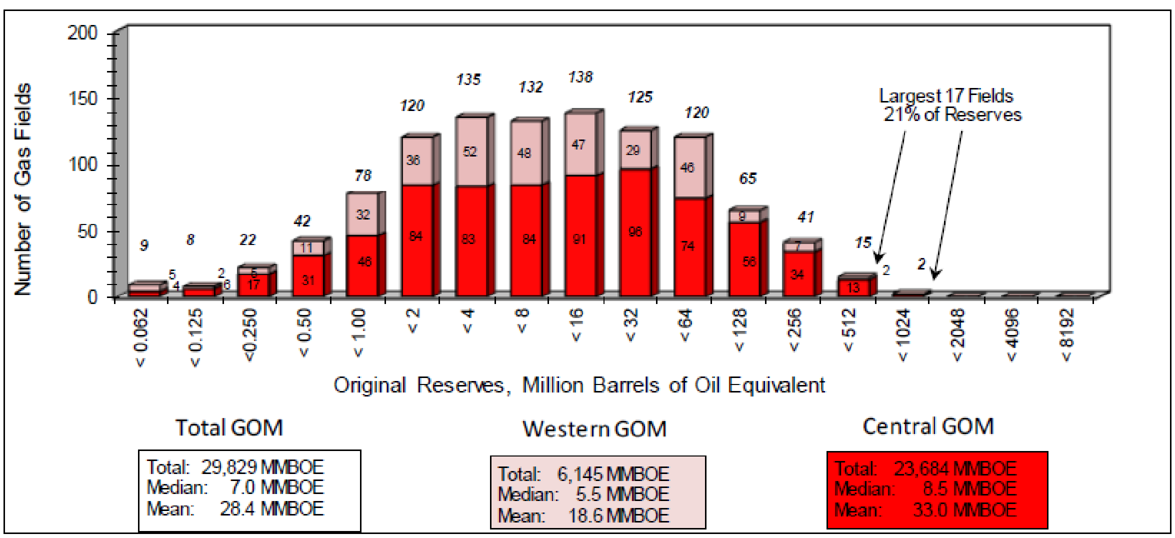


Figure E.17. Original reserves in gas fields in the Gulf of Mexico (MMboe)
Source: Burgess et al. 2016

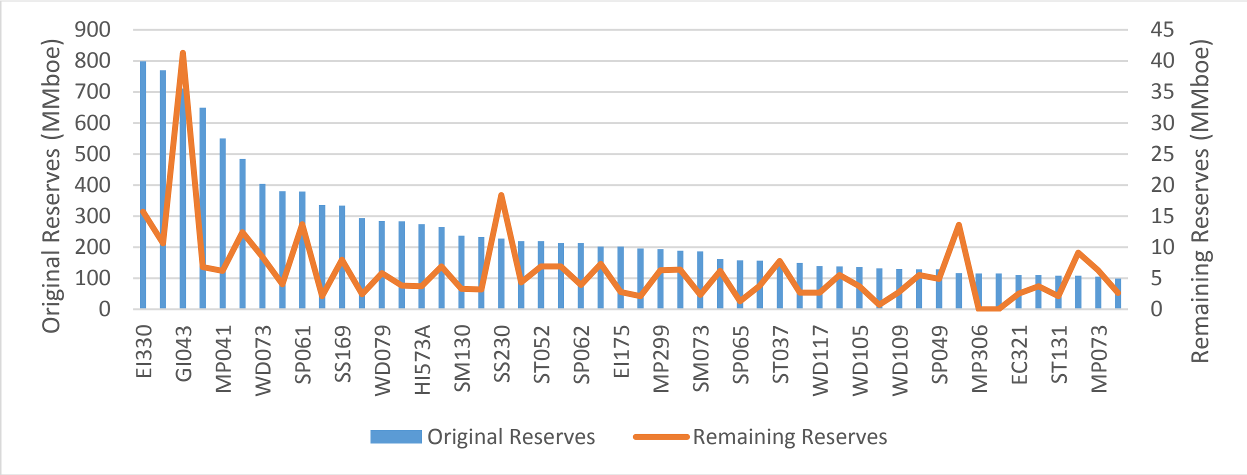


Figure E.18. Original reserves and remaining reserves in the top 50 shallow water Gulf of Mexico fields
Source: BOEM 2016

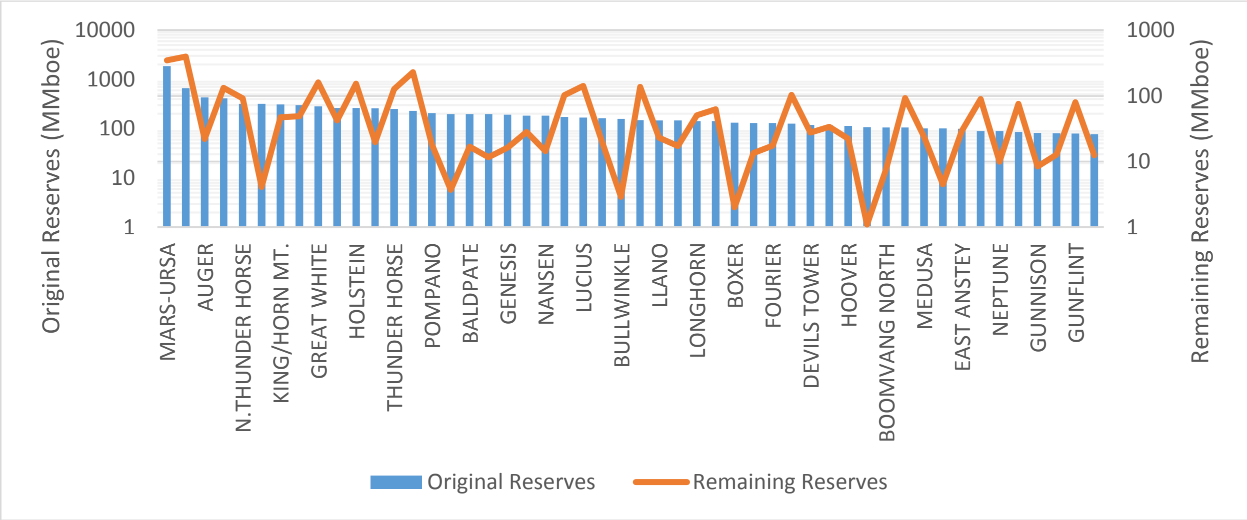


Figure E.19. Original reserves and remaining reserves in the top 50 deepwater Gulf of Mexico fields
Source: BOEM 2016

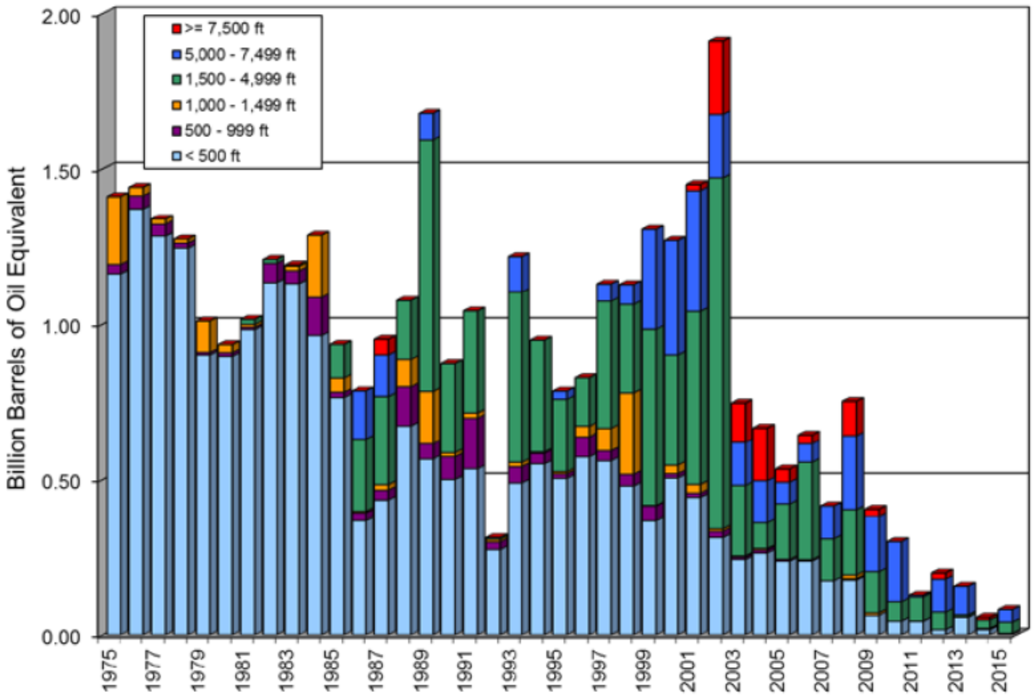


Figure E.20. Field discoveries and reserves by year of discovery and water depth
Source: Burgess et al. 2016

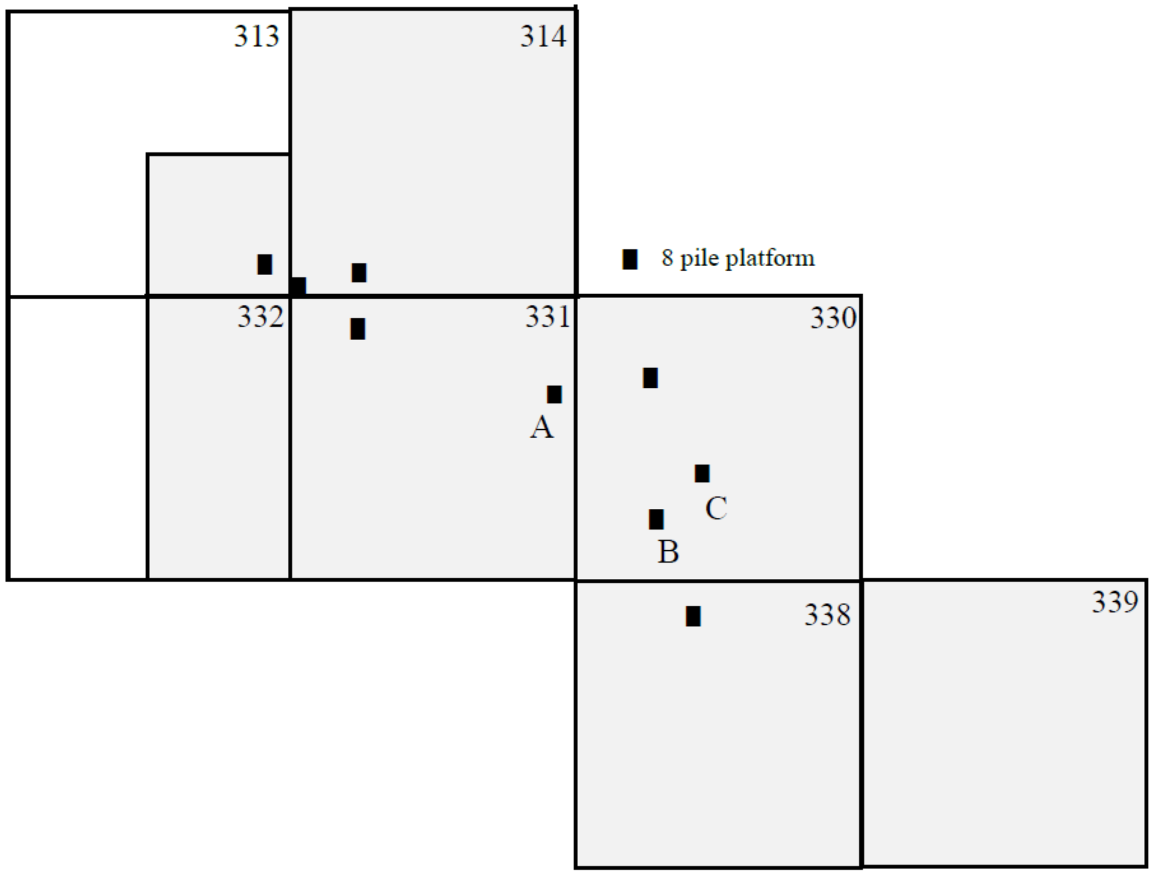


Figure E.21. Eugene Island 330 field lease position circa 1984

Source: Holland et al. 1990, BOEM 2017

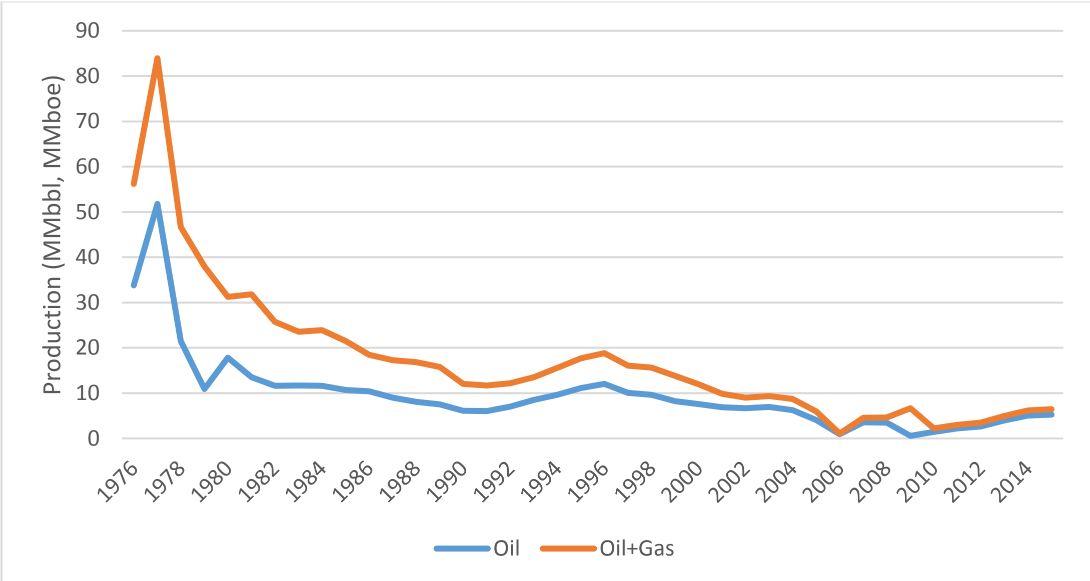


Figure E.22. Eugene Island 330 field oil and gas production plot, 1976-2015
Source: BOEM 2017

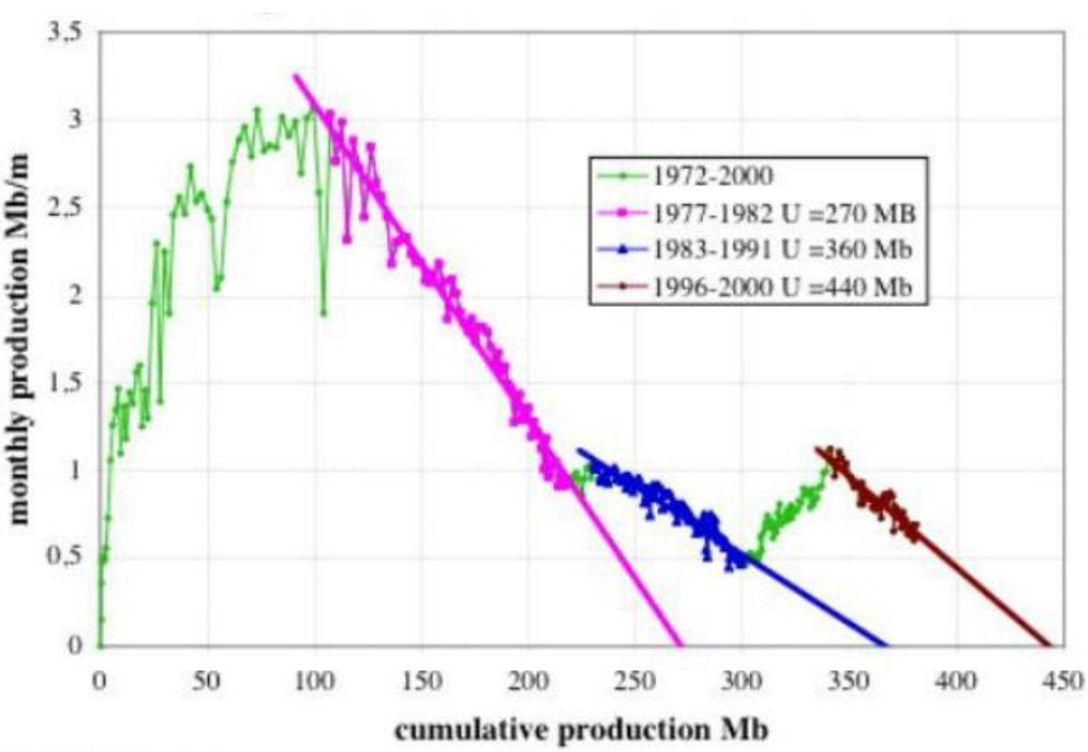


Figure E.23. Eugene Island 330 field monthly production versus cumulative production, 1972-2000
Source: Laherrere 2002

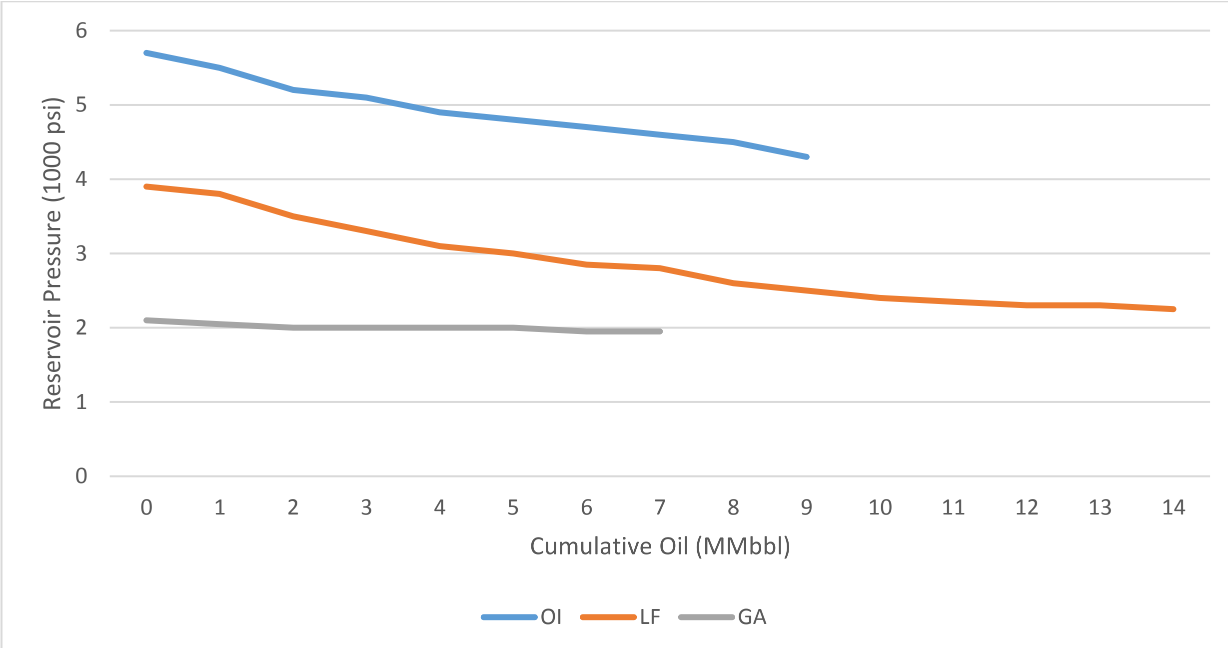


Figure E.24. Pressure history of three reservoirs in the Eugene Island 330 field
Source: Adapted from Holland et al. 1990

Figure E.25. Eugene Island 331A jacket tow using Versabar
Source: Abadie 2010

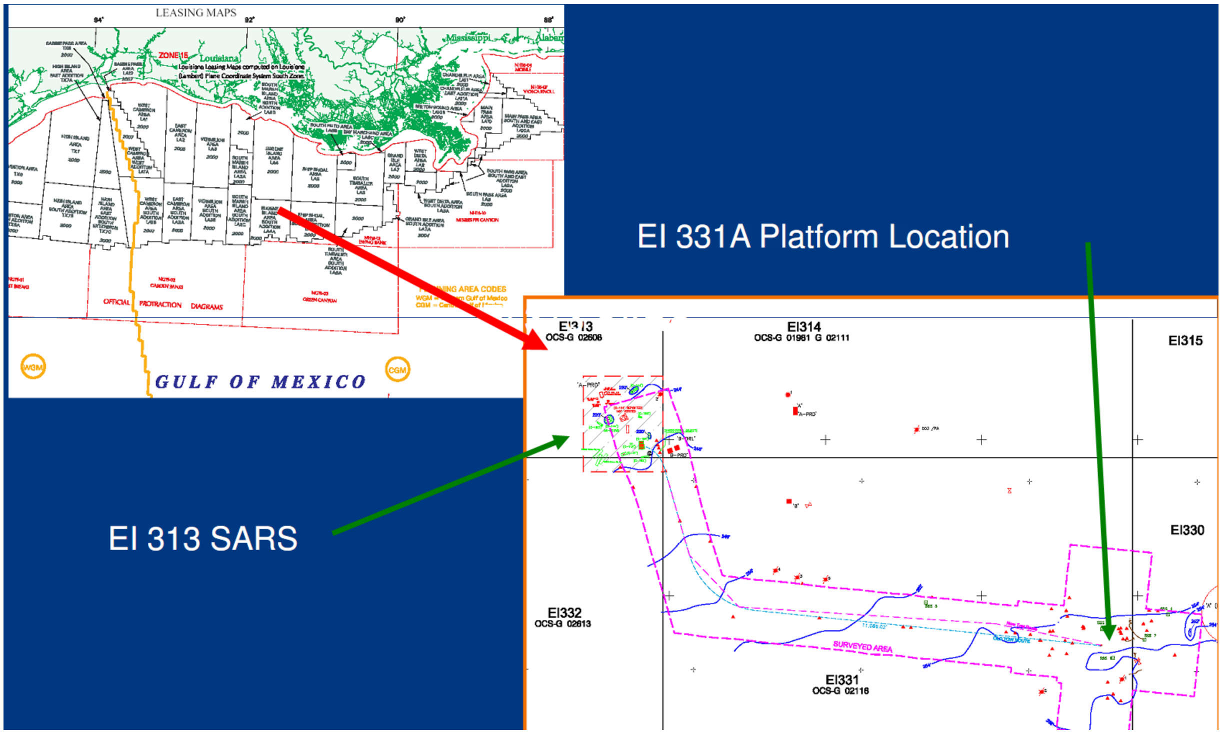


Figure E.26. Eugene Island 331A jacket tow route to reef site in EI 313 Special Artificial Reef Site
Source: Abadie 2010

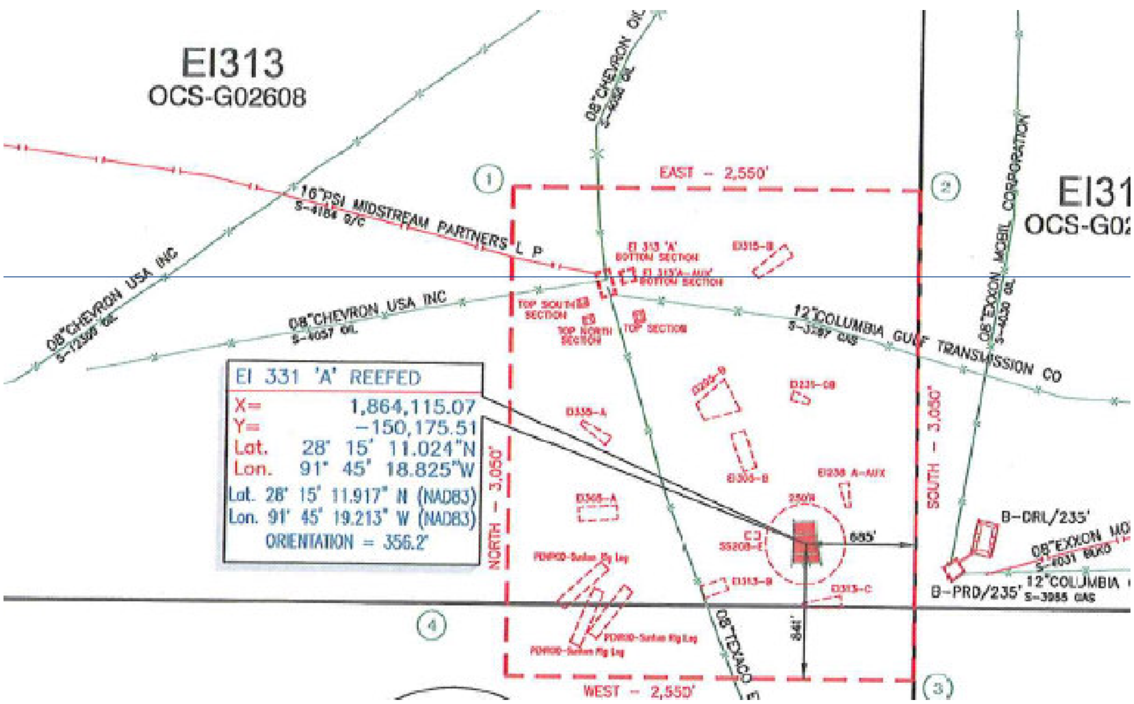


Figure E.27. Eugene Island block 313 Special Artificial Reef Site reefing survey
Source: Abadie et al. 2011

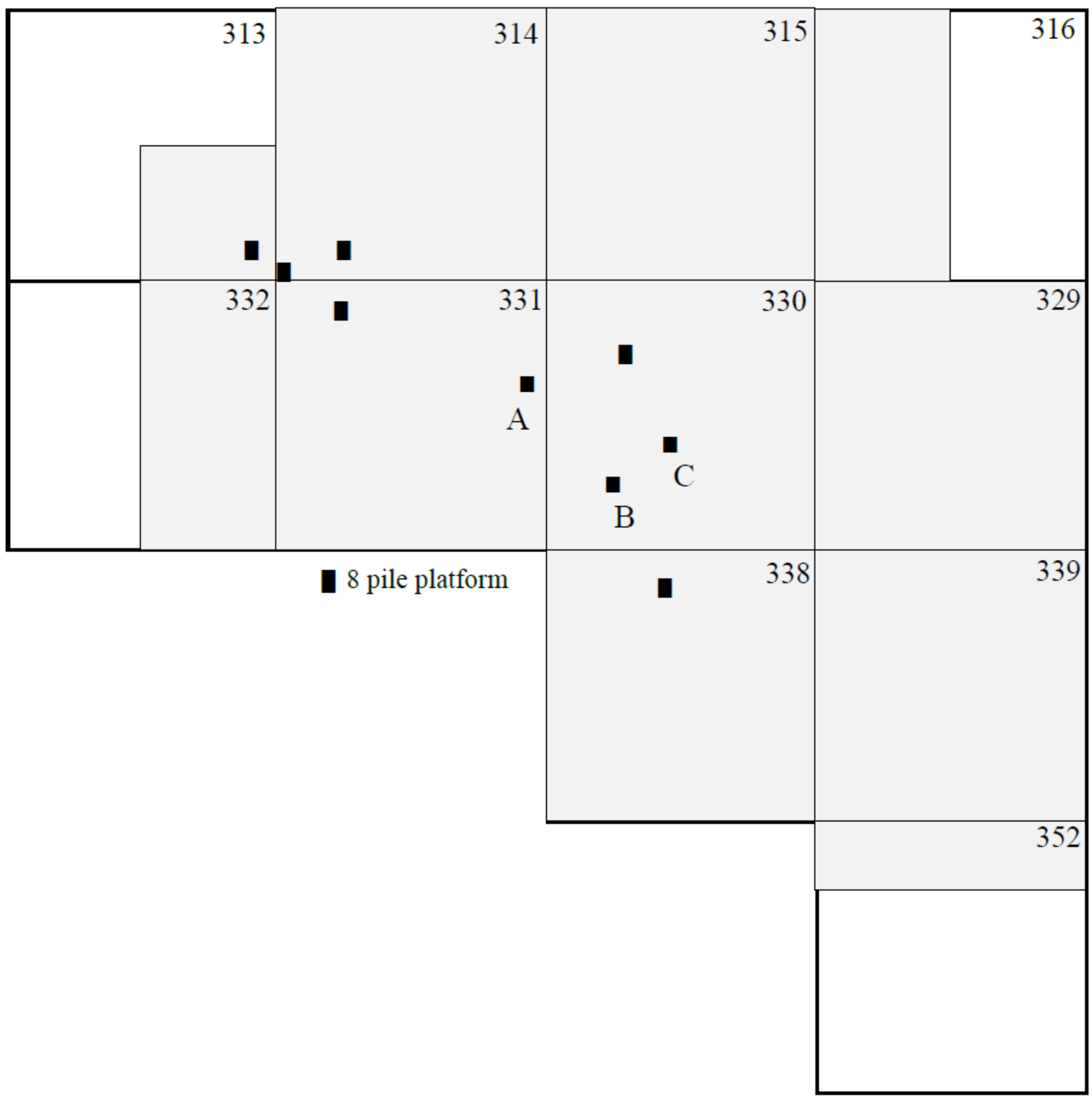


Figure E.28. Eugene Island 330 field lease position circa 1990
Source: BOEM 2017

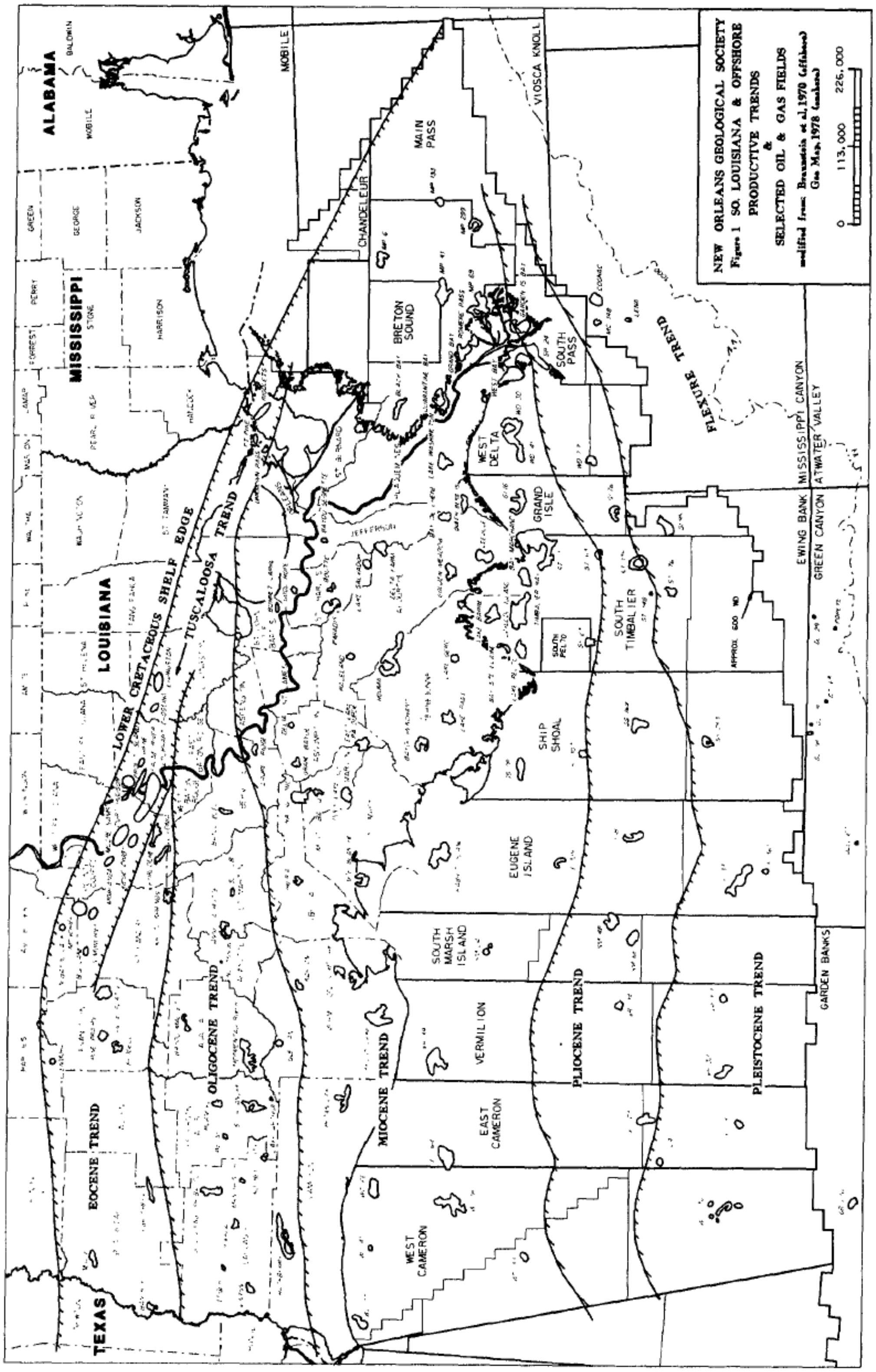


Figure E.29. South Louisiana and offshore productive trends
Source: Branson 1986

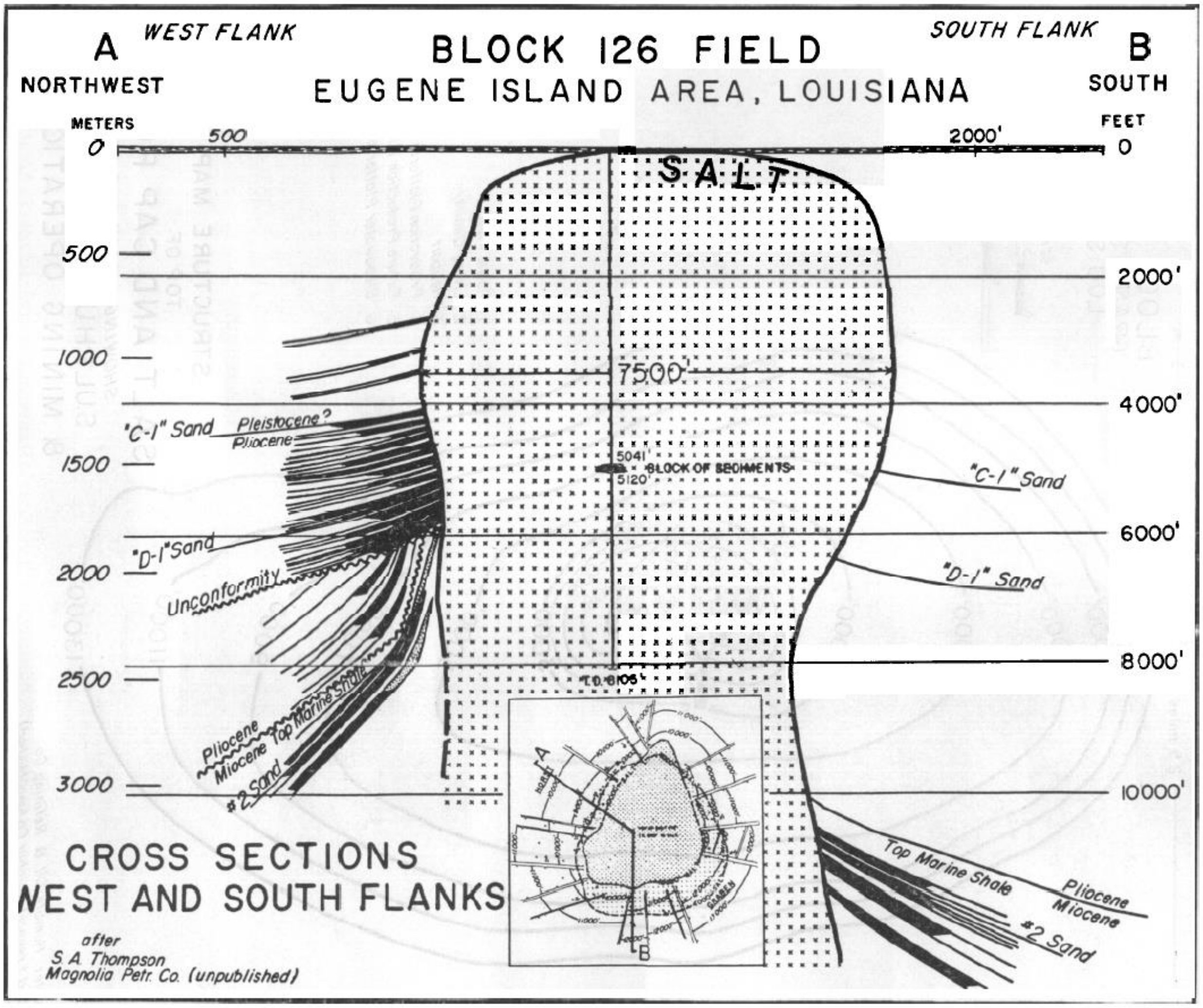


Figure E.30. Eugene Island block 126 field cross sections
Source: Atwater 1959

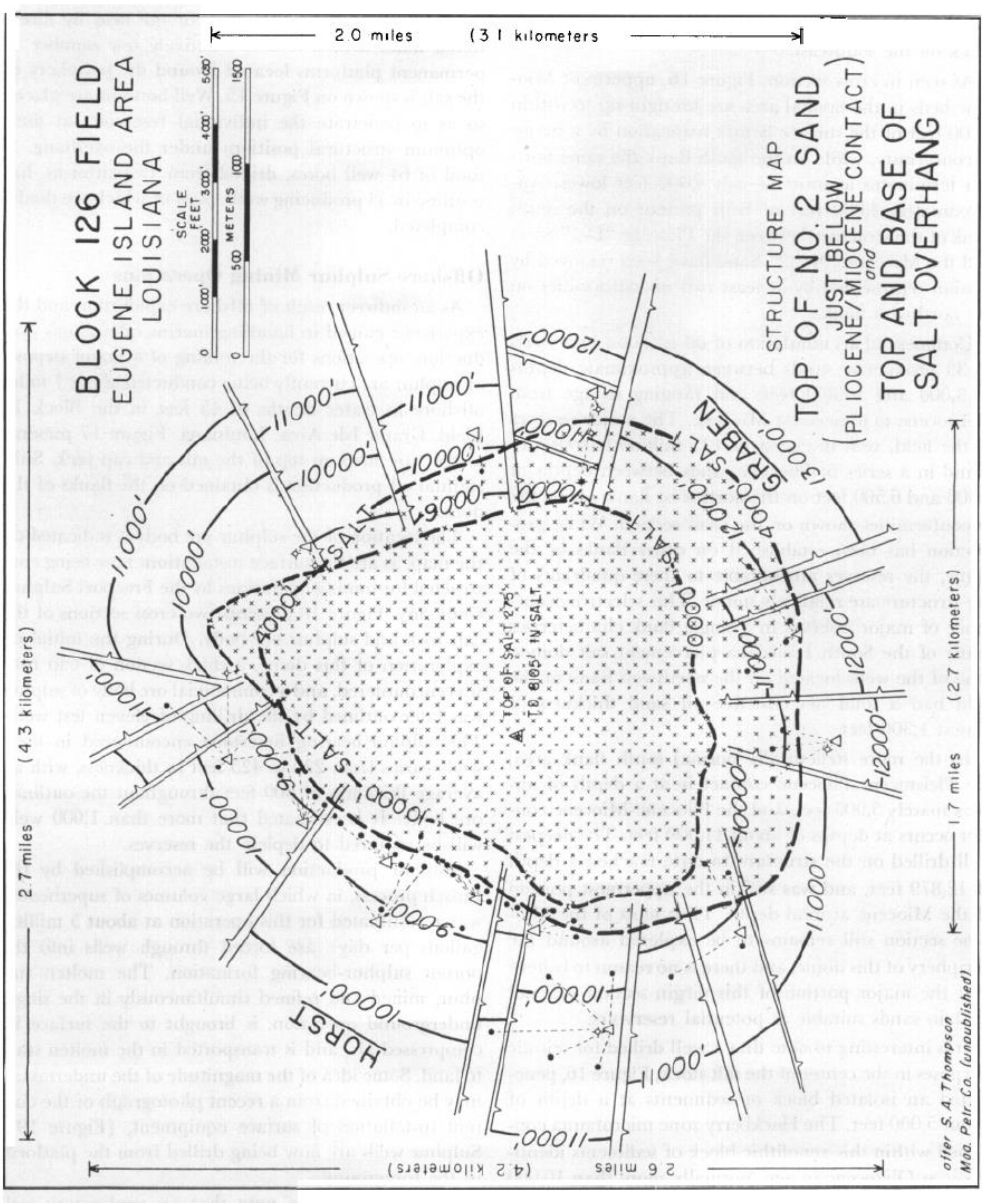


Figure E.31. Eugene Island block 126 field top and base of salt overhang

Source: Atwater 1959

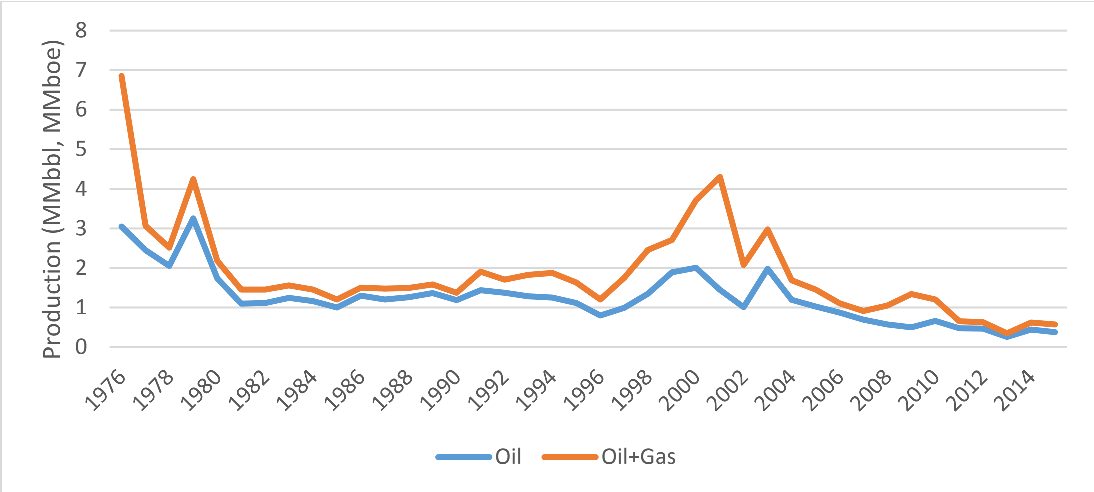


Figure E.32. Eugene Island 126 field oil and gas production plot, 1976-2015

Source: BOEM 2017

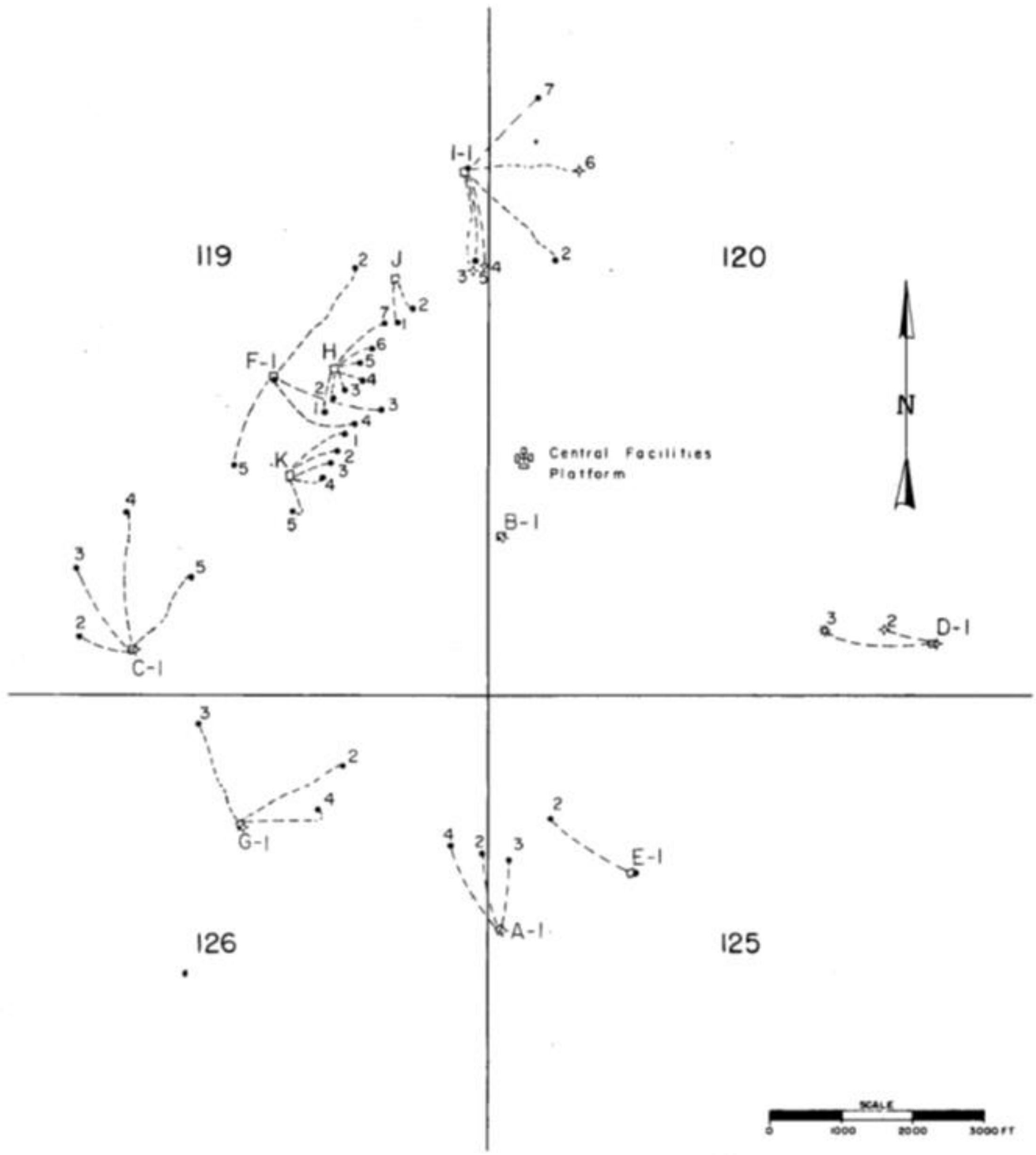


Figure E.33. Well platforms and production facilities at the Eugene Island 126 field circa 1956
Source: Massad and Pela 1956

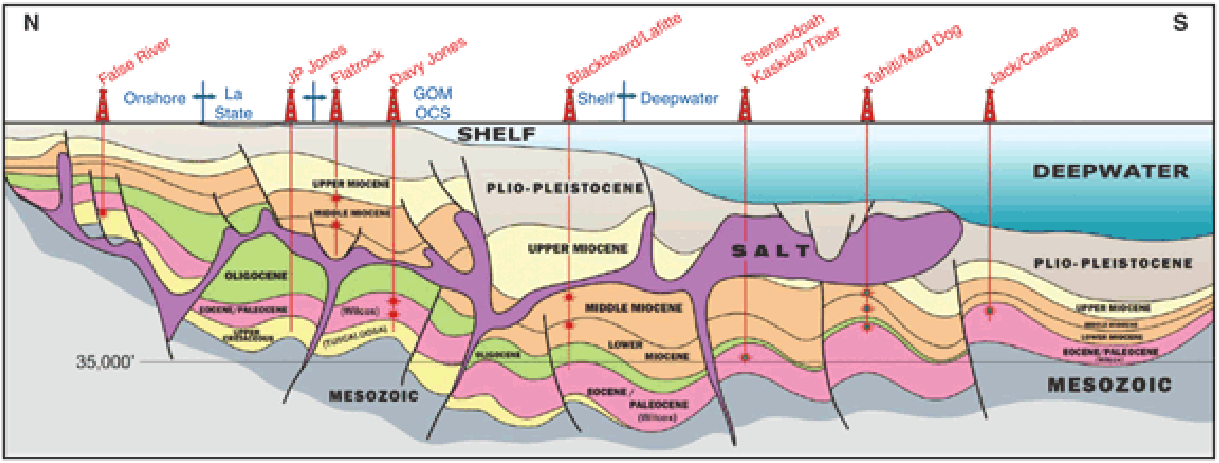


Figure E.34. Generalized Gulf of Mexico cross section from the deepwater Jack field to onshore Louisiana
Source: McMoRan 2010

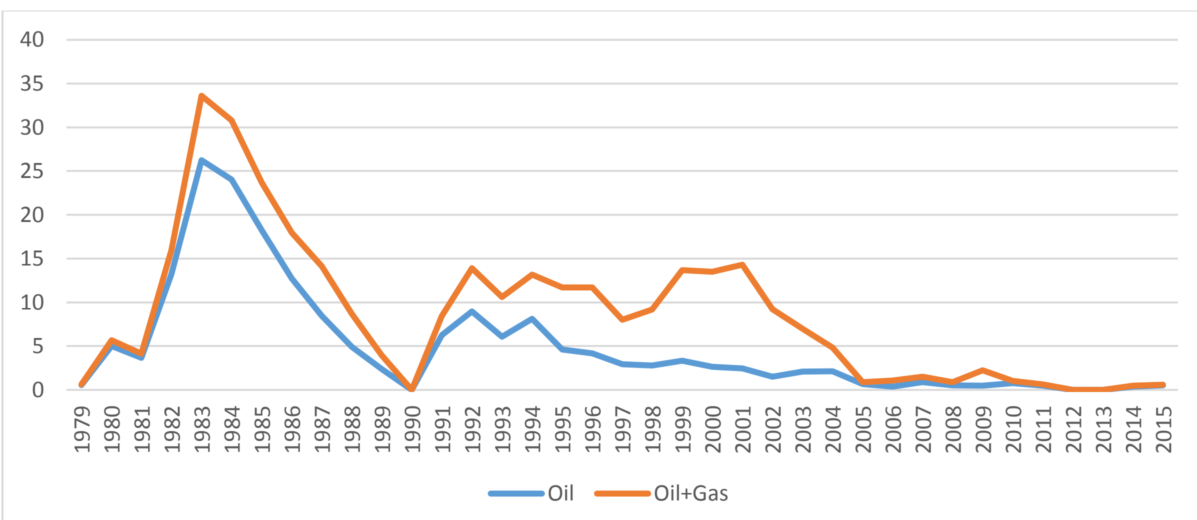


Figure E.35. Mississippi Canyon 194 (Cognac) field oil and gas production, 1979-2015
Source: BOEM 2017

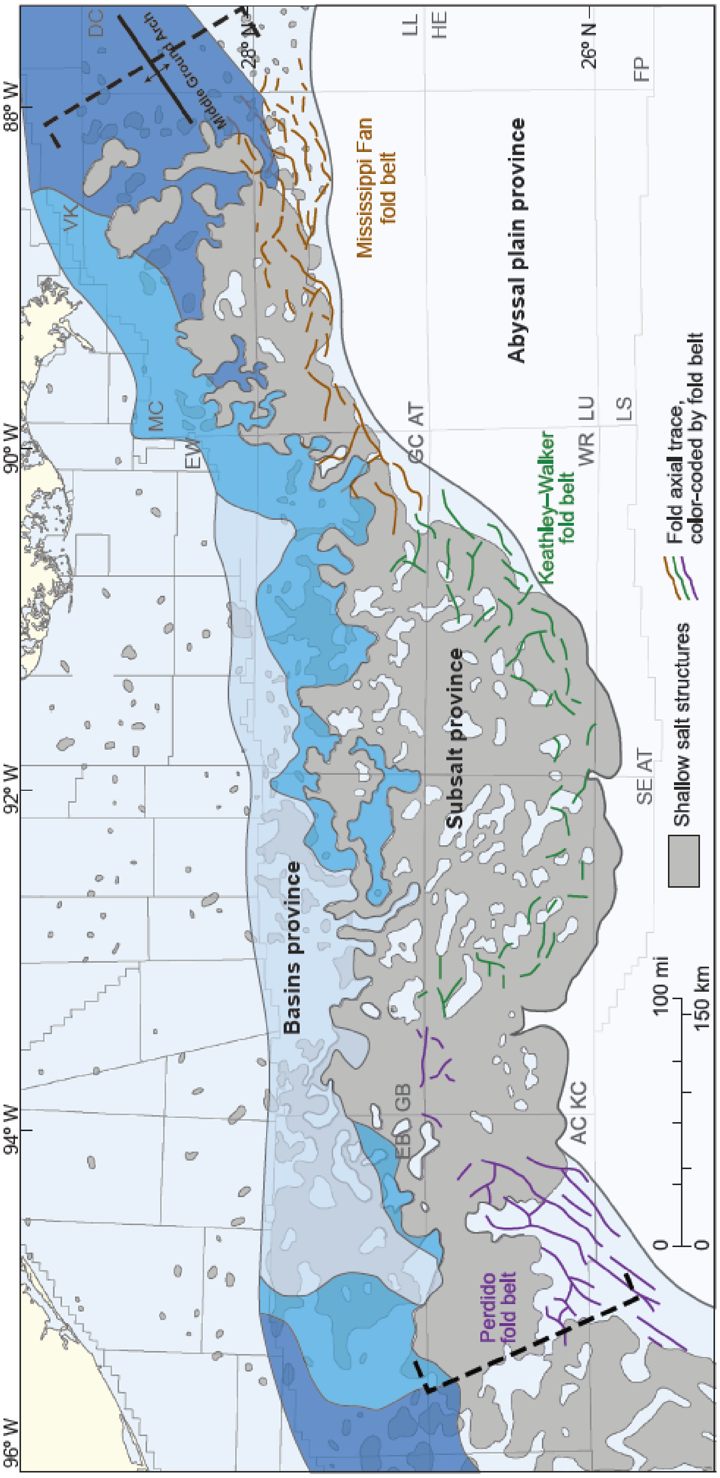


Figure E.36. Major structural features. of the northern deepwater Gulf of Mexico
Source: Weimer et al. 2017

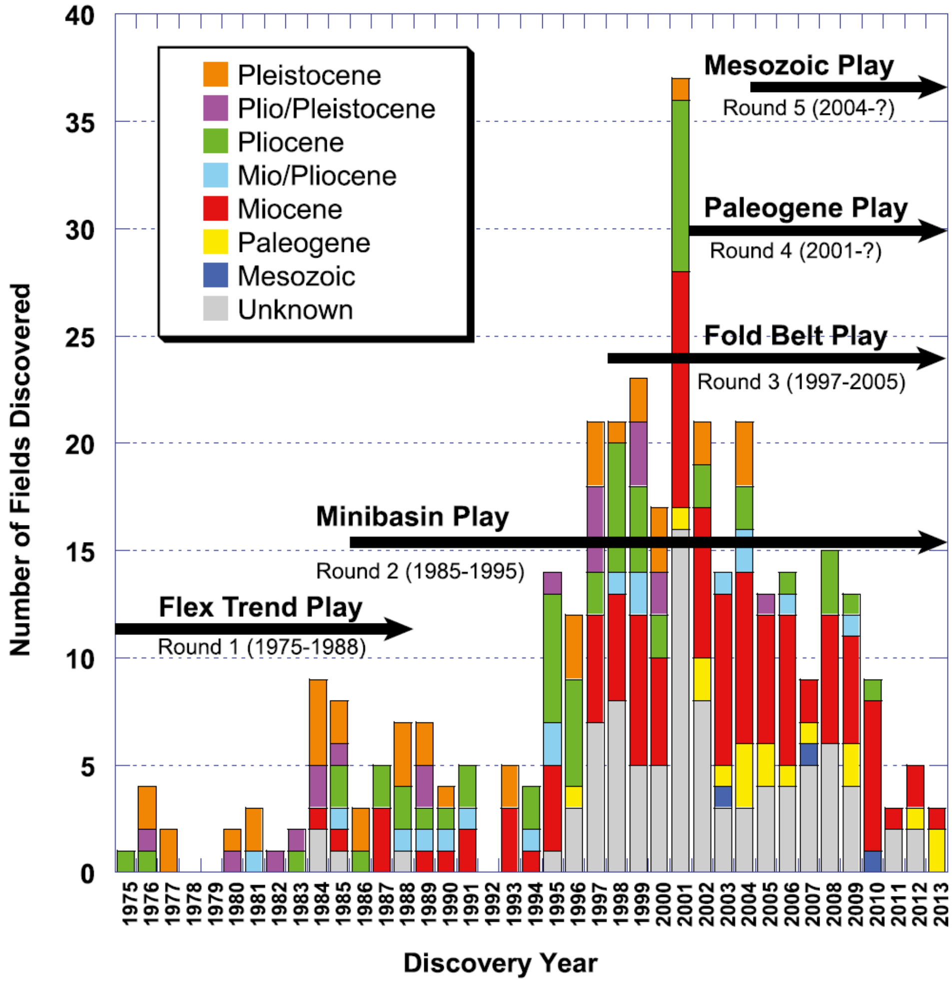


Figure E.37. Field discoveries in the deepwater Gulf of Mexico and major exploration plays
Source: Weimer et al. 2017

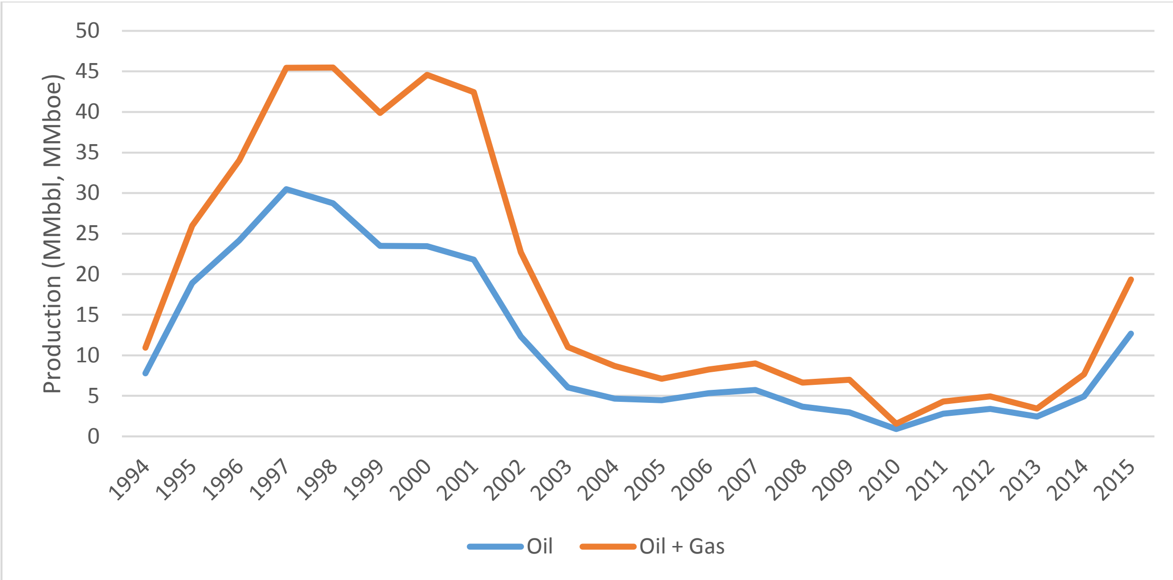


Figure E.38. Garden Bank 426 (Auger) field oil and gas production, 1994-2015
Source: BOEM 2017

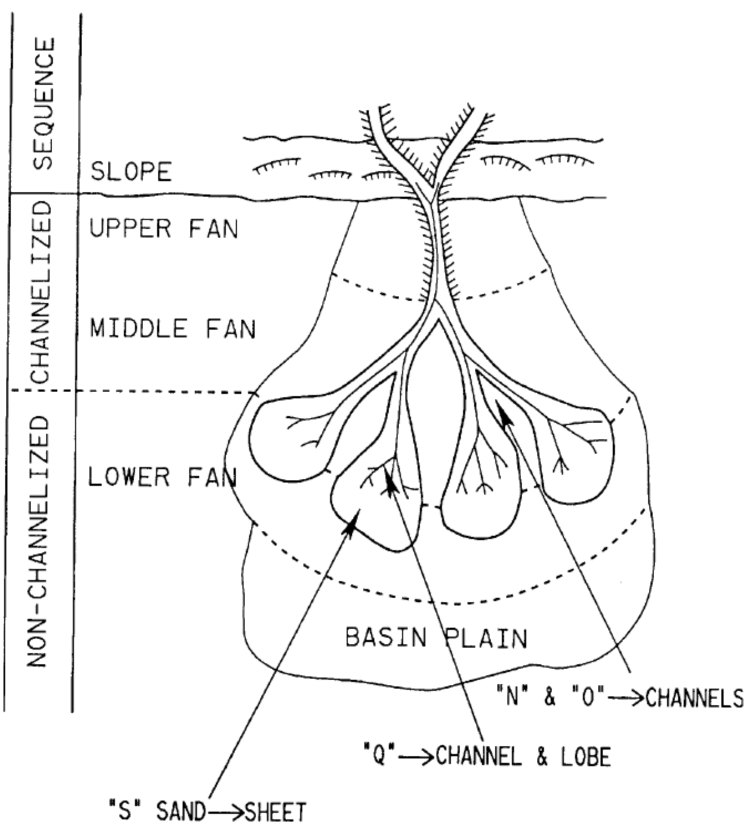


Figure E.39. Garden Banks 426 (Auger) submarine fan deposition model
Source: Bilinski et al. 1992

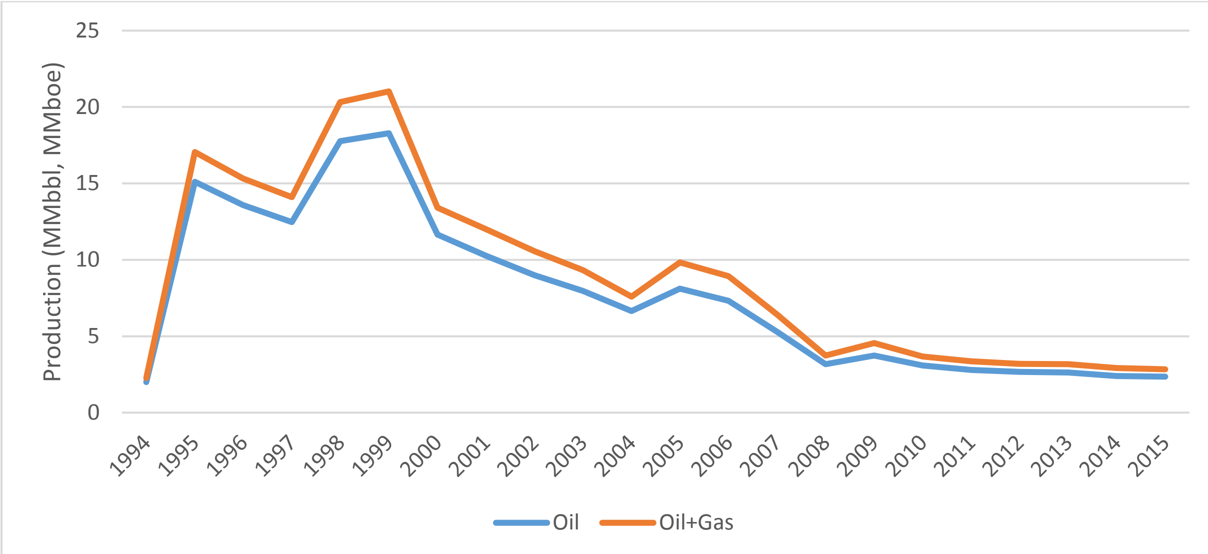


Figure E.40. Ewing Bank 873 (Lobster) field oil and gas production, 1994-2015
Source: BOEM 2017

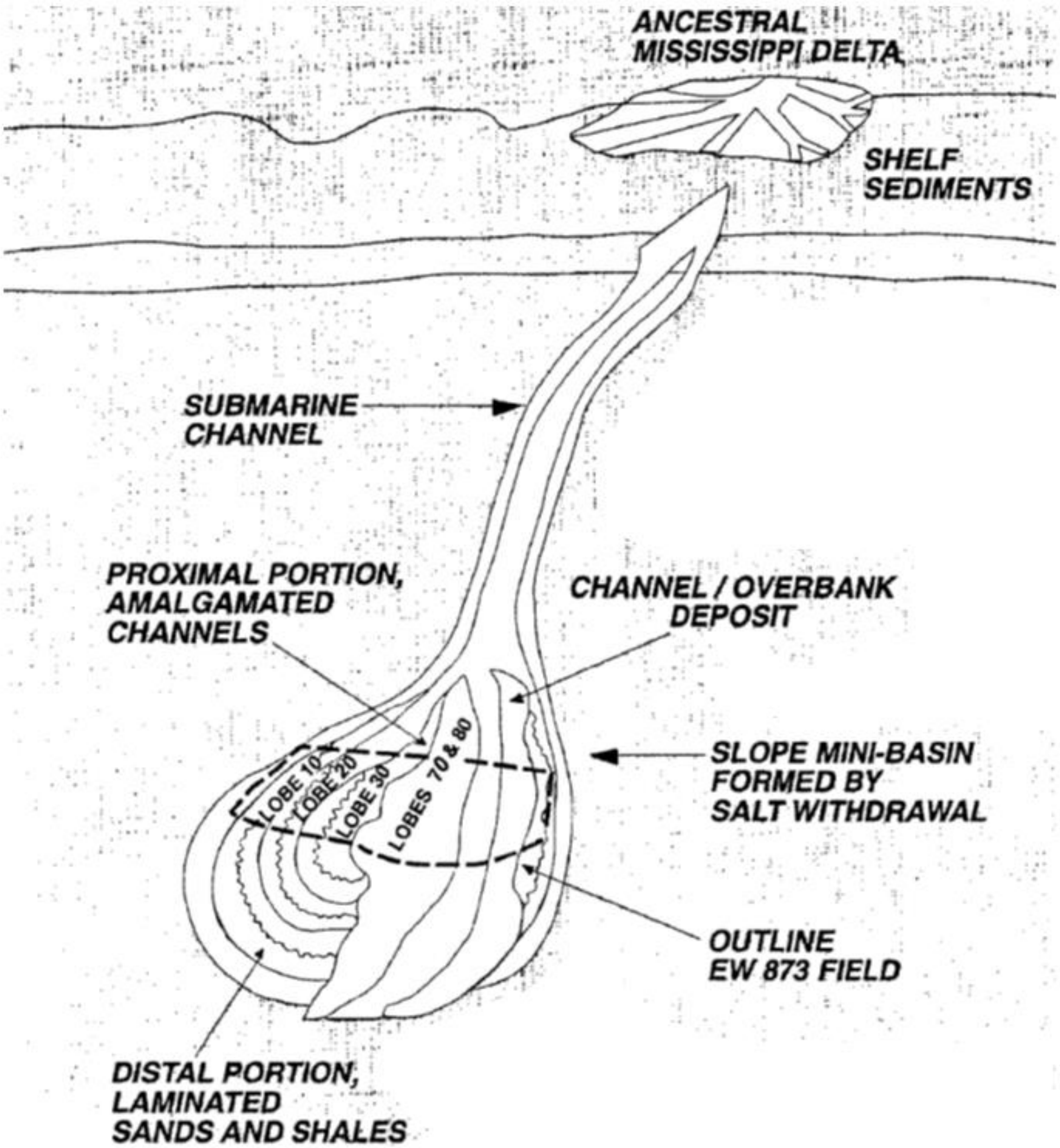


Figure E.41. Ewing Bank 873 (Lobster) field deposition model
Source: Edman and Burk 1998

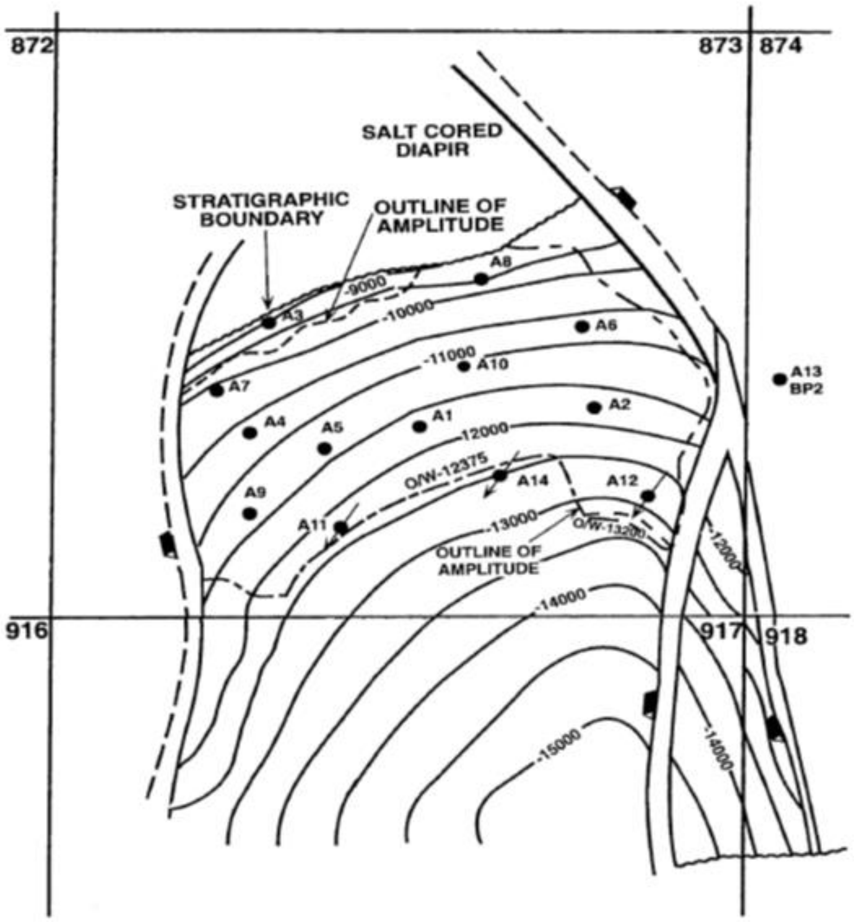


Figure E.42. Ewing Bank 873 (Lobster) field boundary and producing and injection wells
Source: Edman and Burk 1998

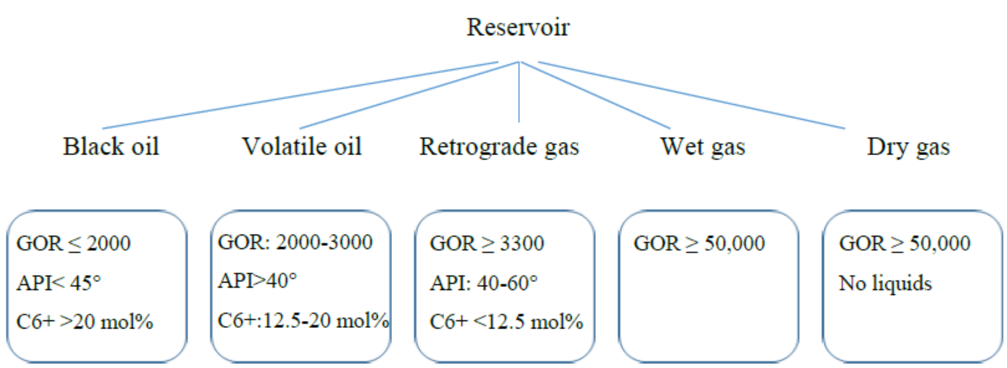


Figure E.43. The five reservoir fluids and their classification

APPENDIX F

CHAPTER 6 TABLES AND FIGURES

Table F.1. Exploration and development wells by water depth including sidetracks circa 2017

Water depth (ft)	Exploration	Development	Total
< 400	14,978	31,148	46,126
> 400	3792	3046	6838
Total	18,770	34,196	52,964

Source: BOEM, March 2018

Table F.2. Gulf of Mexico well Inventory circa 2017

	<400 ft	>400 ft	Total
Drilled	46,243	6733	52,964
Permanently abandoned	25,254	2151	27,405
Remaining	20,989	4582	25,559
Producing	2644	819	3463

Source: BOEM, March 2018

Table F.3. Subsea well inventory circa 2017

	<400 ft	>400 ft	Total
Drilled	112	1331	1443
Permanently abandoned	73	178	251
Remaining	39	1153	1192
Producing	8	375	383

Source: BOEM, March 2018

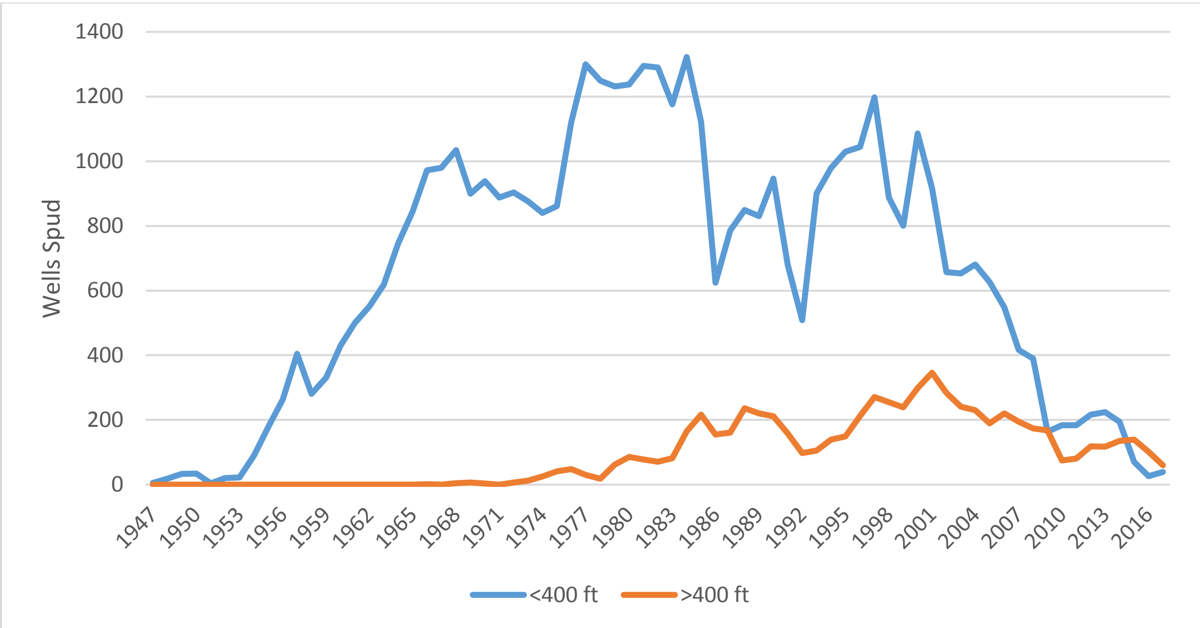


Figure F.1. Shallow water and deepwater wells drilled in the Gulf of Mexico
Source: BOEM, March 2018

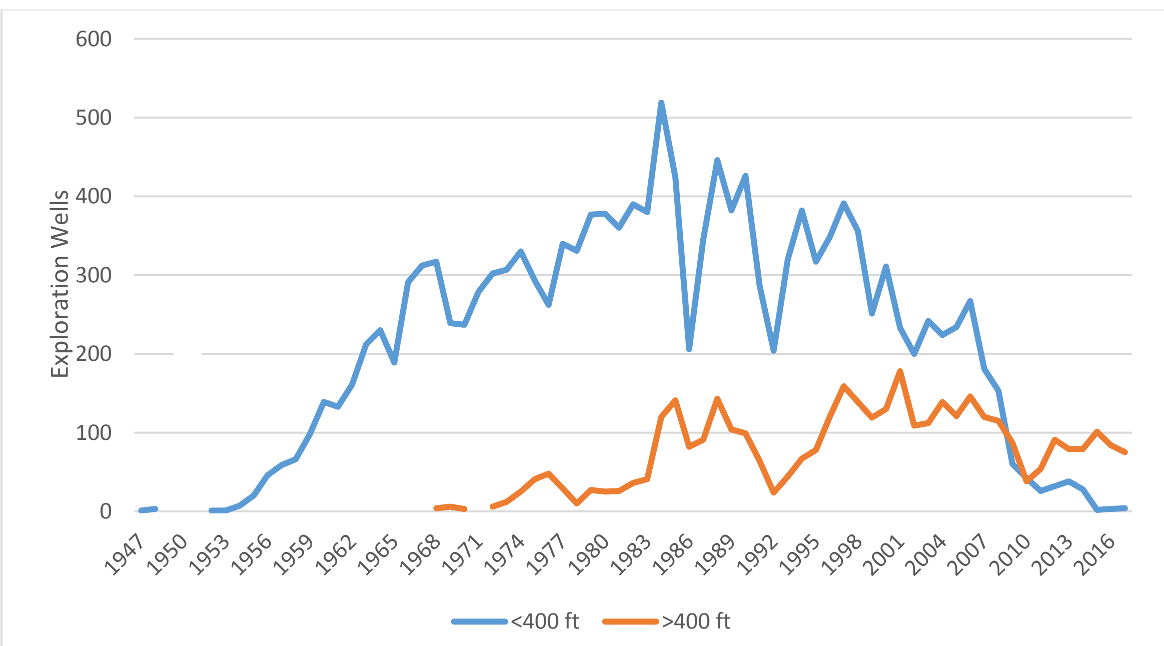


Figure F.2. Shallow water and deepwater exploration wells drilled in the Gulf of Mexico
Source: BOEM, March 2018

Figure F.3. Shallow water and deepwater development wells drilled in the Gulf of Mexico
Source: BOEM, March 2018

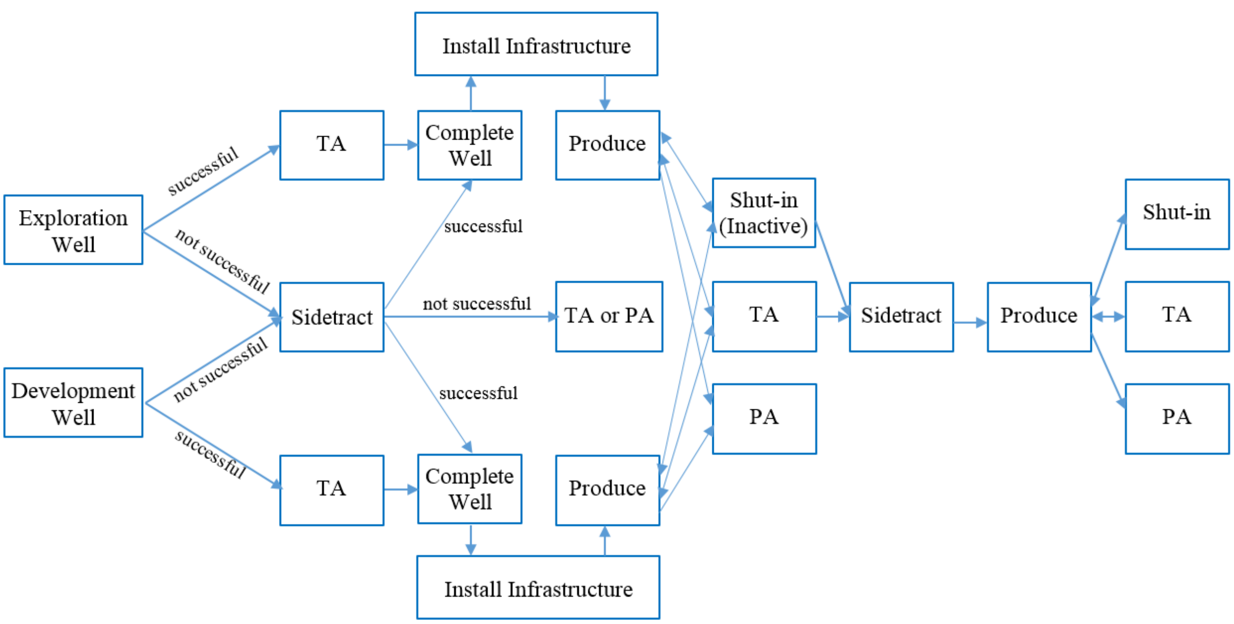


Figure F.4. Well life-cycle pathways from spud to abandonment

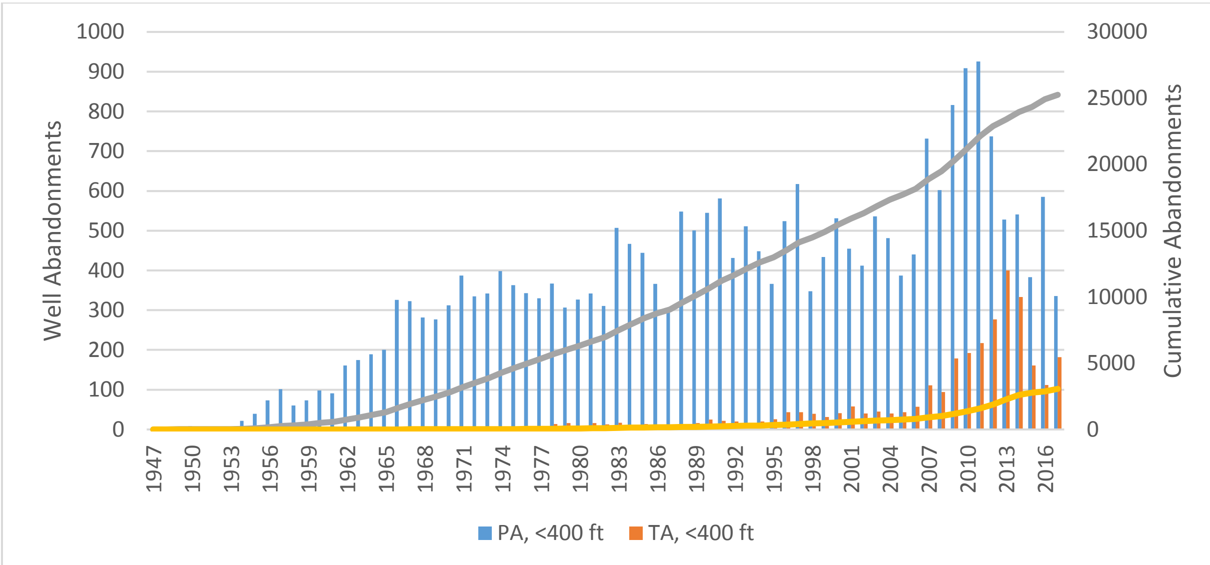


Figure F.5. Shallow water permanent and temporary well abandonments in the Gulf of Mexico
Source: BOEM, March 2018

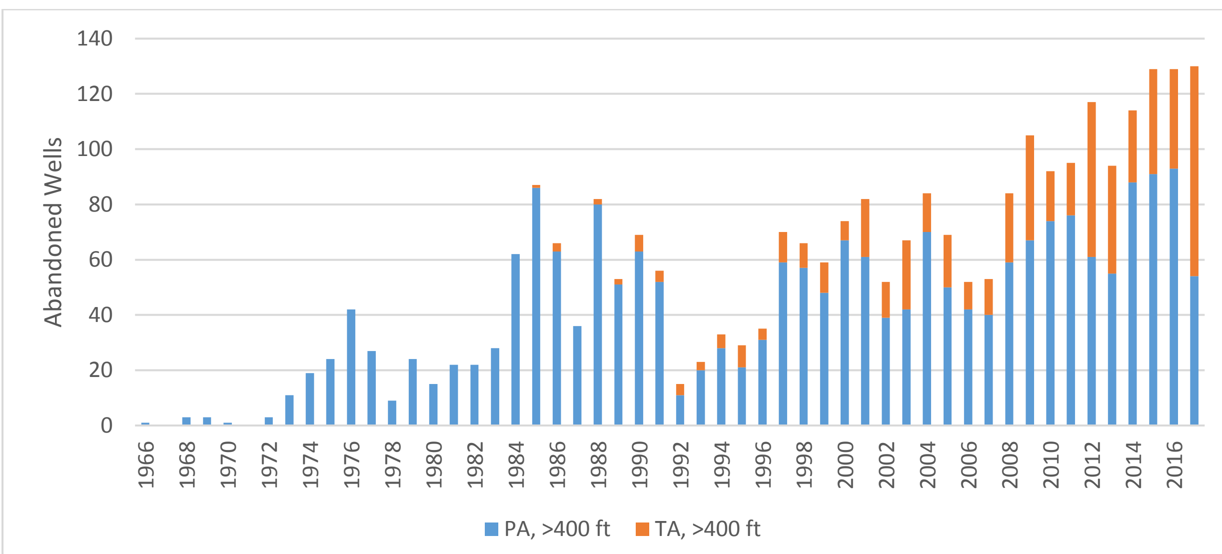


Figure F.6. Deepwater permanent and temporary well abandonments in the Gulf of Mexico
Source: BOEM, March 2018

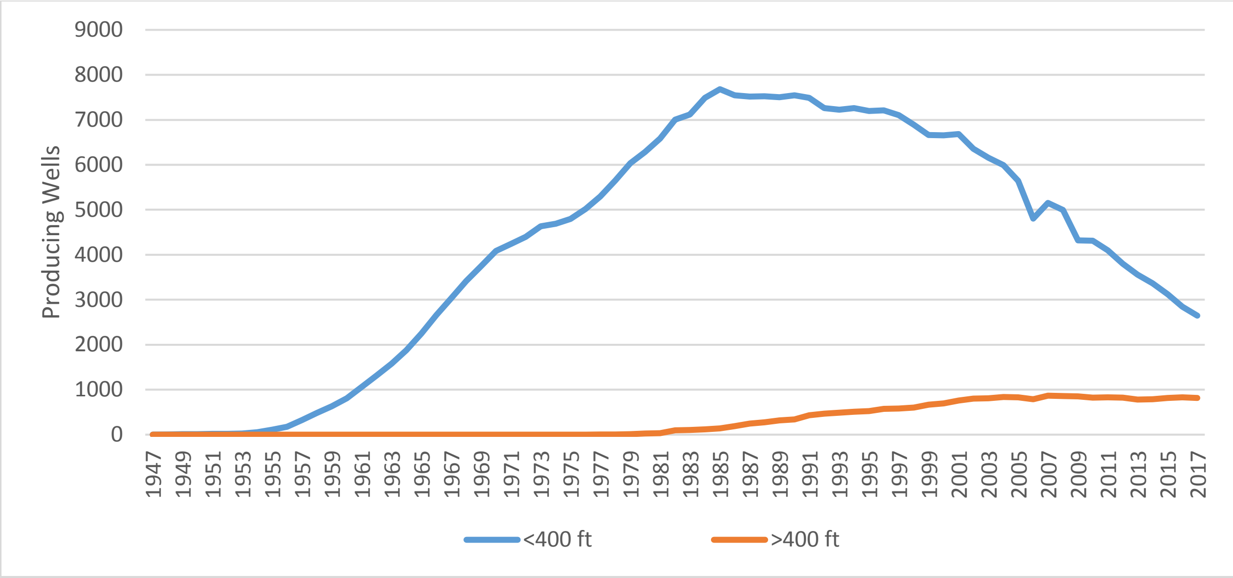


Figure F.7. Producing well inventories in the shallow and deepwater Gulf of Mexico
Source: BOEM, March 2018

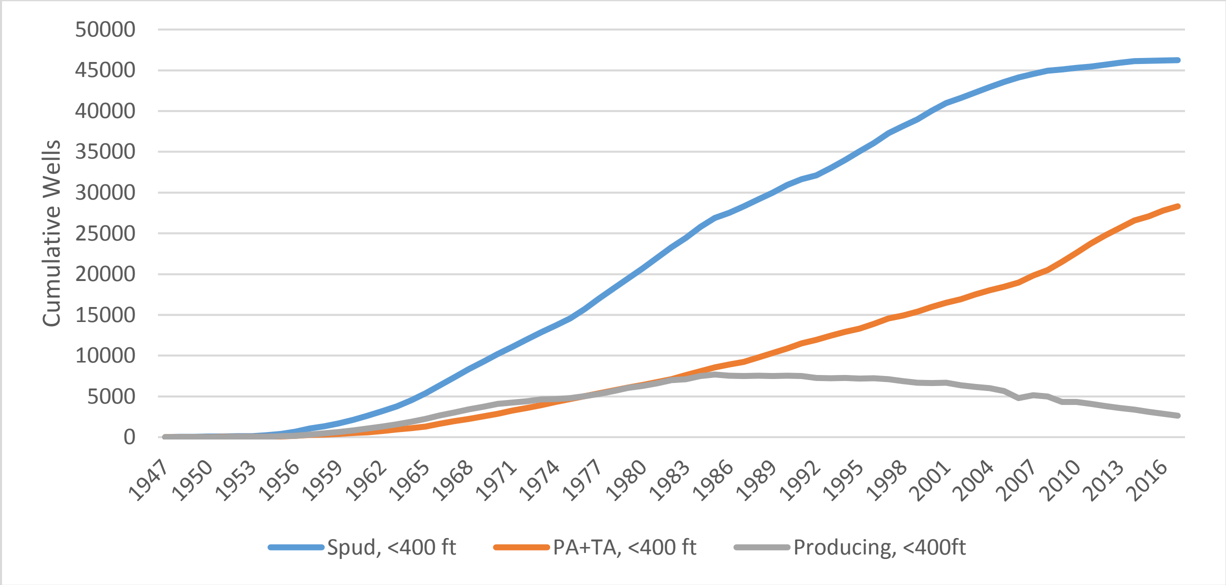


Figure F.8. Drilled, abandoned and producing wells in the shallow water Gulf of Mexico
Source: BOEM, March 2018

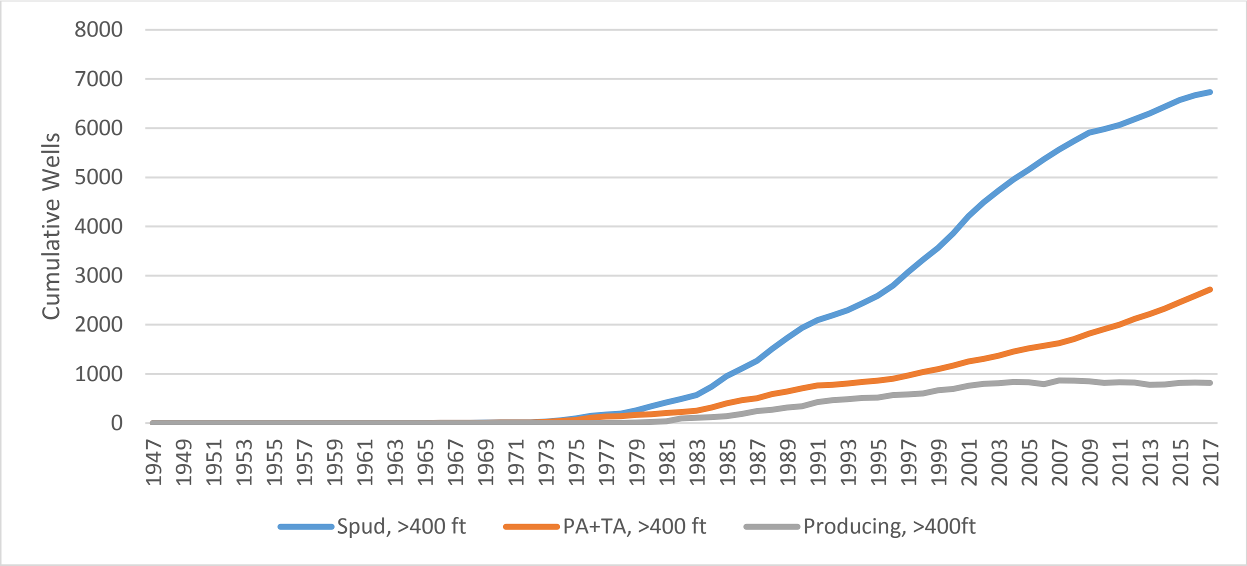


Figure F.9. Drilled, abandoned and producing wells in the deepwater Gulf of Mexico
Source: BOEM, March 2018

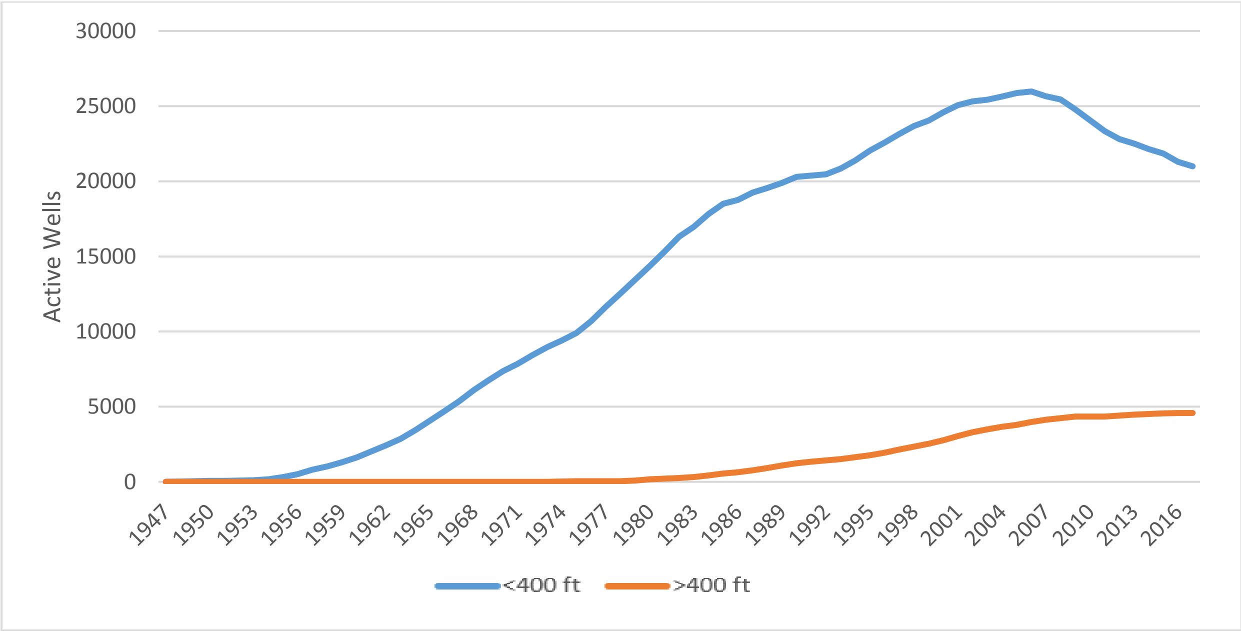


Figure F.10. Active well inventories in the shallow water and deepwater Gulf of Mexico
Source: BOEM, March 2018

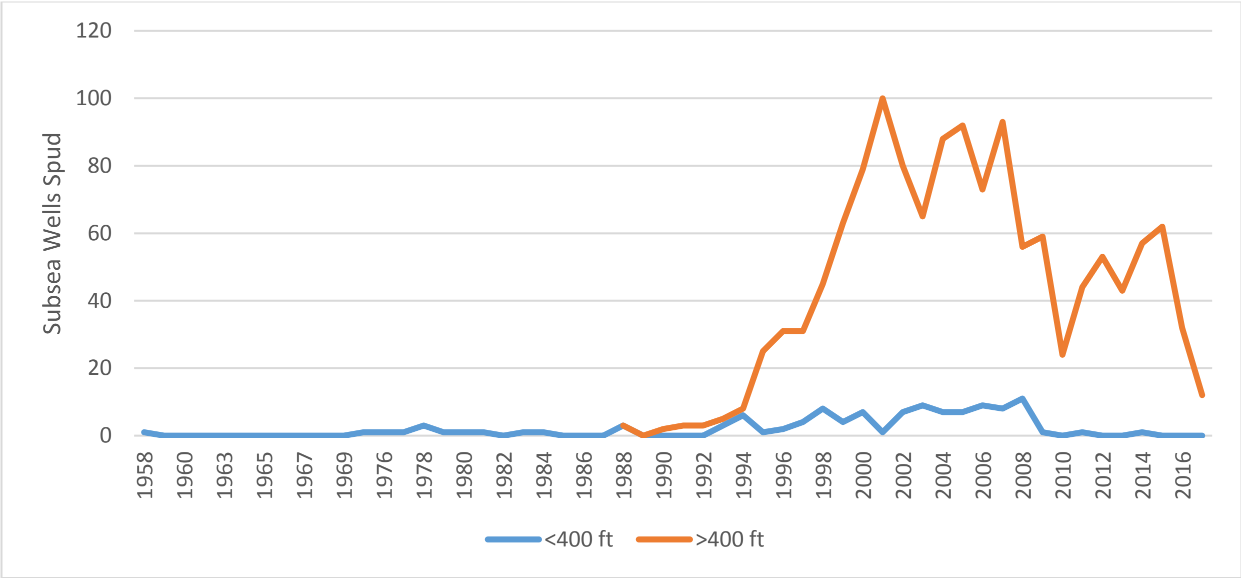


Figure F.11. Subsea wells spud in the shallow water and deepwater Gulf of Mexico
Source: BOEM, March 2018

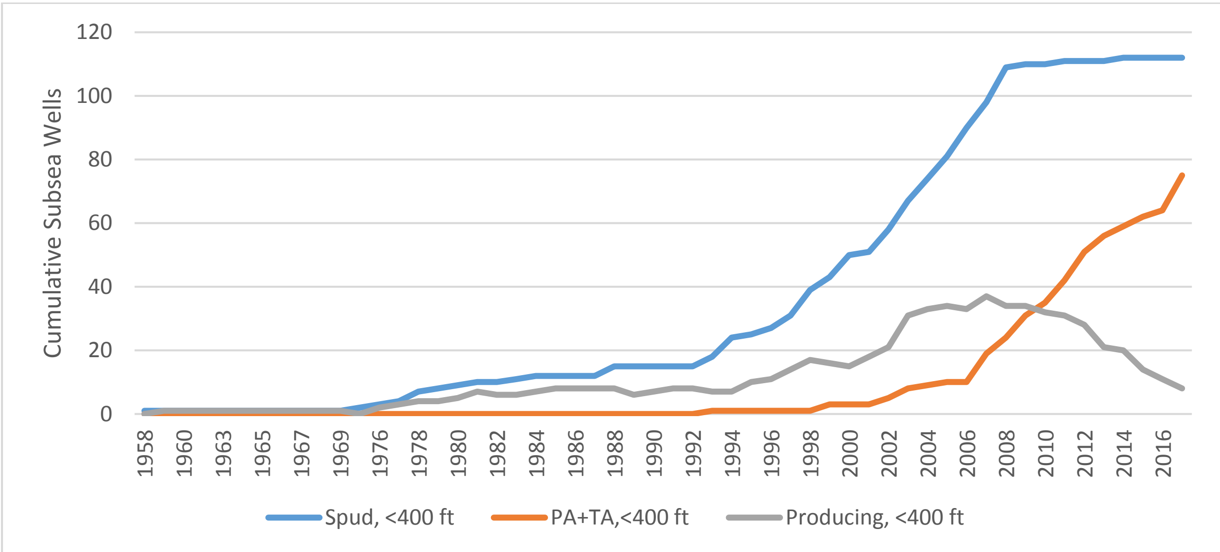


Figure F.12. Subsea wells spud, producing and abandoned in the shallow water Gulf of Mexico
Source: BOEM, March 2018

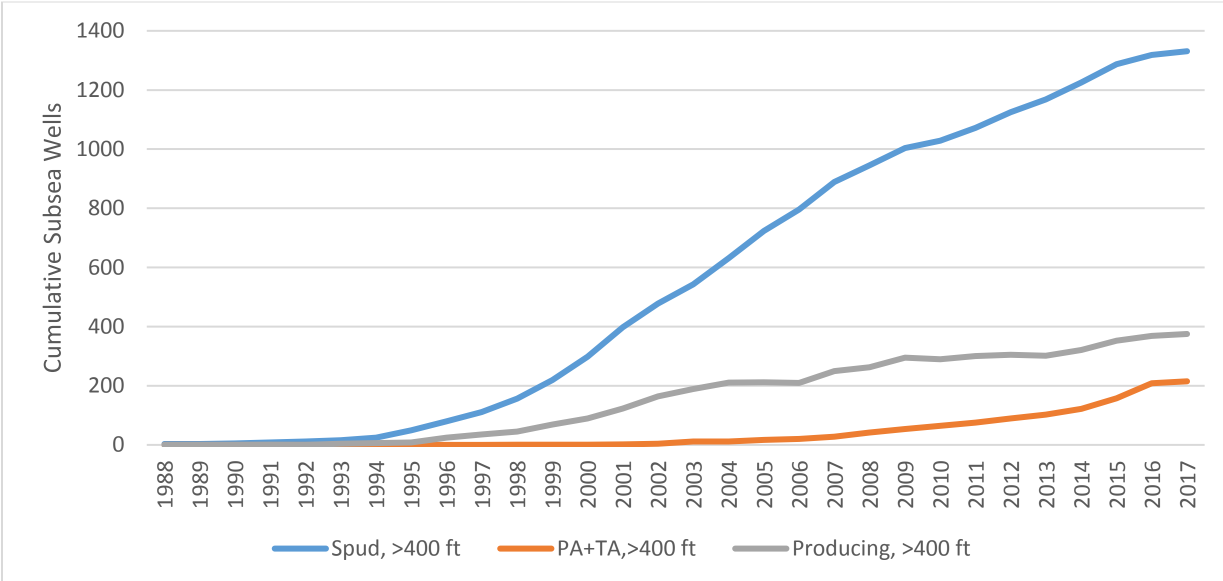


Figure F.13. Subsea wells spud, producing and abandoned in the deepwater Gulf of Mexico
Source: BOEM, March 2018

APPENDIX G
CHAPTER 7 TABLES AND FIGURES

Table G.1. Shallow water producing structures circa 2017

	Primarily Oil	Primarily Gas
Inventory (#)	563	323
Revenue		
from liquids ($ million)	2522	380
from gas ($ million)	276	708
Total revenue ($ million)	2797	1088

Source: BOEM, February 2018

Table G.2. Production comparison by structure class circa 2017

	Primarily Oil	Primarily Gas
Producing Inventory (#)	563	323
Total Production circa 2017	6182 MMbbl	23.1 Tcf
Average Production	11.0 MMbbl/structure	71.9 Bcf/structure
Idle Inventory (#)	237	425
Total Production	1074 MMbbl	22.0 Tcf
Average Production	4.5 MMbbl/structure	51.7 Bcf/structure
Decommissioned Inventory (#)	968	3335
Total Production	2834 MMbbl	89.3 Tcf
Average Production	2.9 MMbbl/structure	26.8 Bcf/structure

Source: BOEM, February 2018

Table G.3. Idle inventory in the shallow water Gulf of Mexico

Year	Number
1990	505
1995	578
2000	734
2005	896
2010	995
2015	740

Source: BOEM, February 2018

Table G.4. Idle age for shallow water idle inventory circa 2017

Idle Age (yr)	Caisson/WP	Fixed Platform	Total
1-2	33	49	82
2-3	29	46	75
3-4	22	37	59
4-5	18	24	42
5-6	21	26	47
6-7	16	14	30
7-8	21	12	33
8-9	10	14	24
9-10	9	9	18
>10	121	131	252
Total	300	362	662

Source: BOEM, February 2018

Table G.5. Structure count and class contribution at time of decommissioning by idle status

	0-1 yr	2-5 yr	6-10 yr	10+ yr	Total
1973-1976	17	22	12	3	54
1977-1986	75	110	36	32	253
1987-1996	374	230	105	146	855
1997-2006	483	386	150	178	1197
2007-2016	536	660	320	362	1878
2017-	15	45	16	13	89
Total	1500	1453	639	734	4326
1973-1976	31%	41%	22%	6%	100%
1977-1986	30%	43%	14%	13%	100%
1987-1996	44%	27%	12%	17%	100%
1997-2006	41%	32%	12%	15%	100%
2007-2016	29%	35%	17%	19%	100%
2017-	17%	51%	18%	15%	100%
Average	35%	33%	15%	17%	100%

Source: BOEM, February 2018

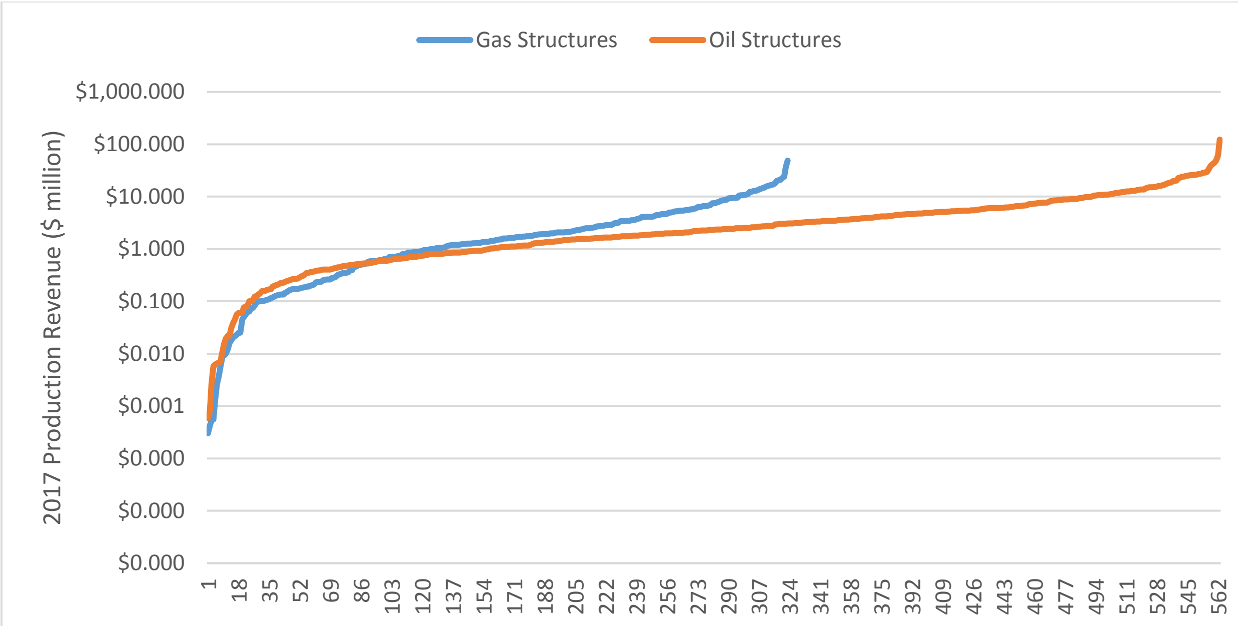


Figure G.1. Revenue generated by shallow water structures in 2017
Source: BOEM, February 2018

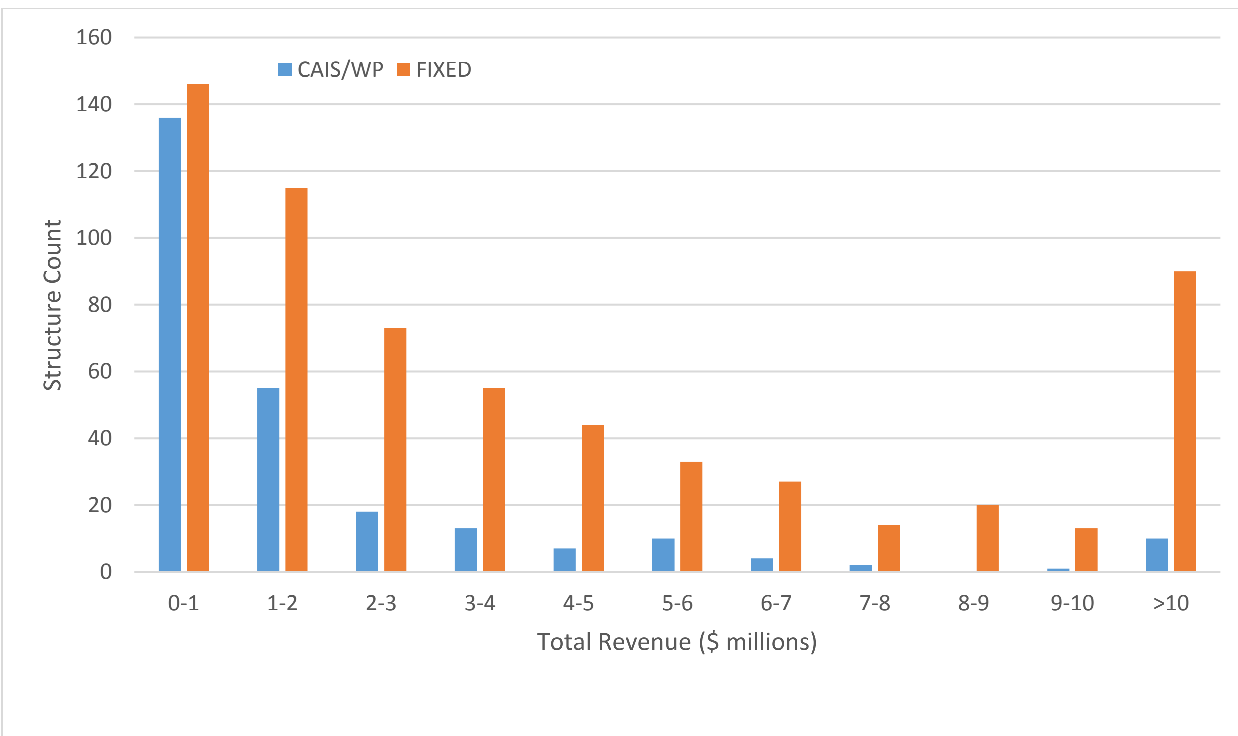


Figure G.2. Revenue distribution by shallow water structures in 2017
Source: BOEM, February 2018

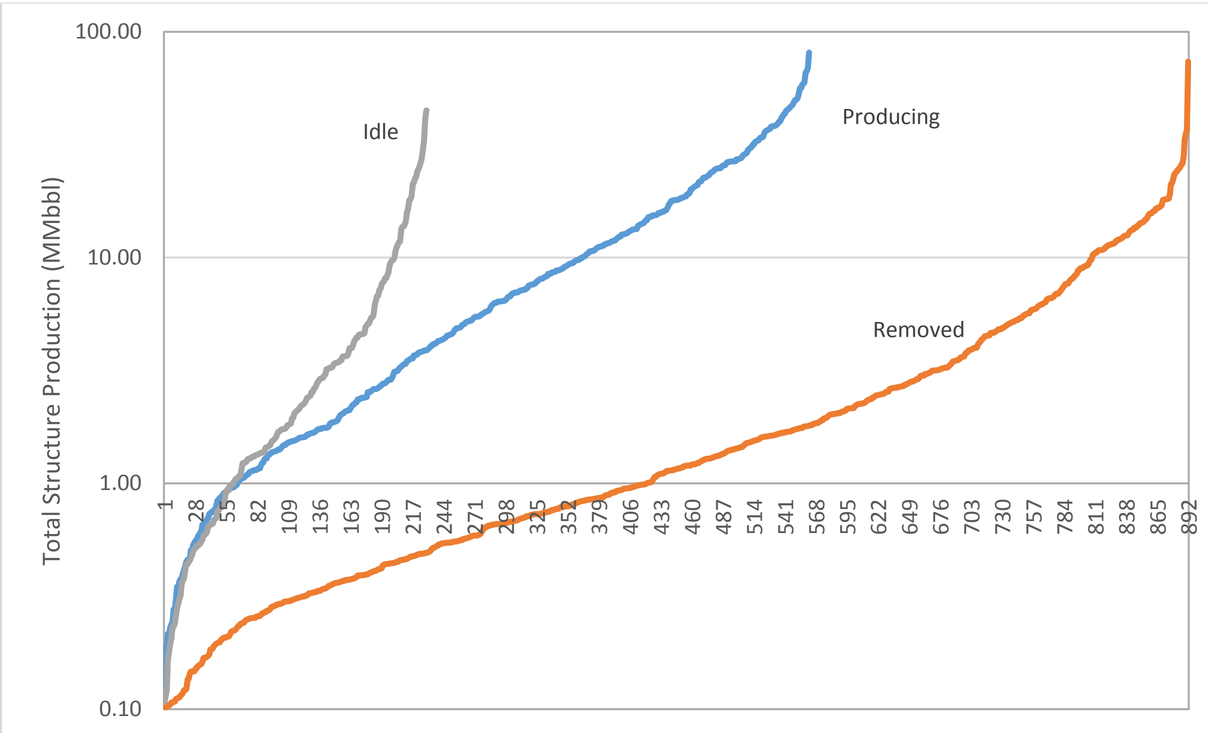


Figure G.3. Producing, idle and decommissioned oil structures <400 ft water depth circa 2017
Source: BOEM, February 2018

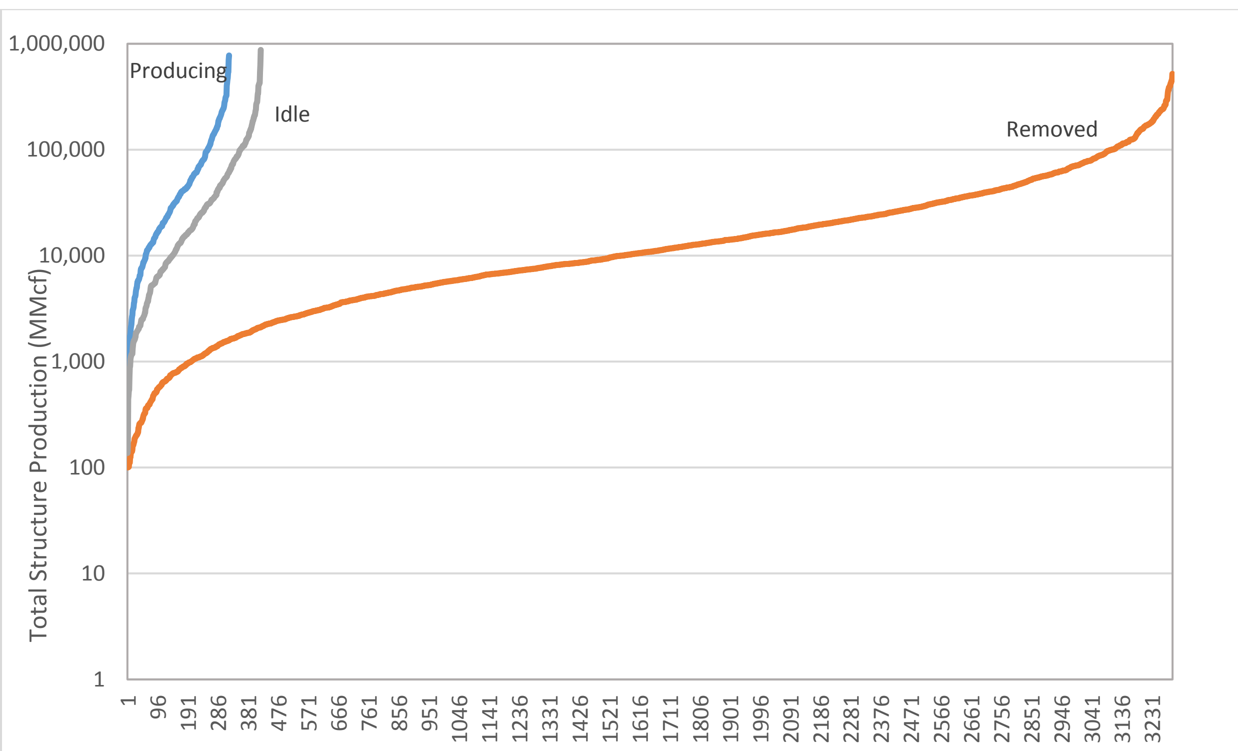


Figure G.4. Producing, idle and decommissioned gas structures <400 ft water depth circa 2017
Source: BOEM, February 2018.

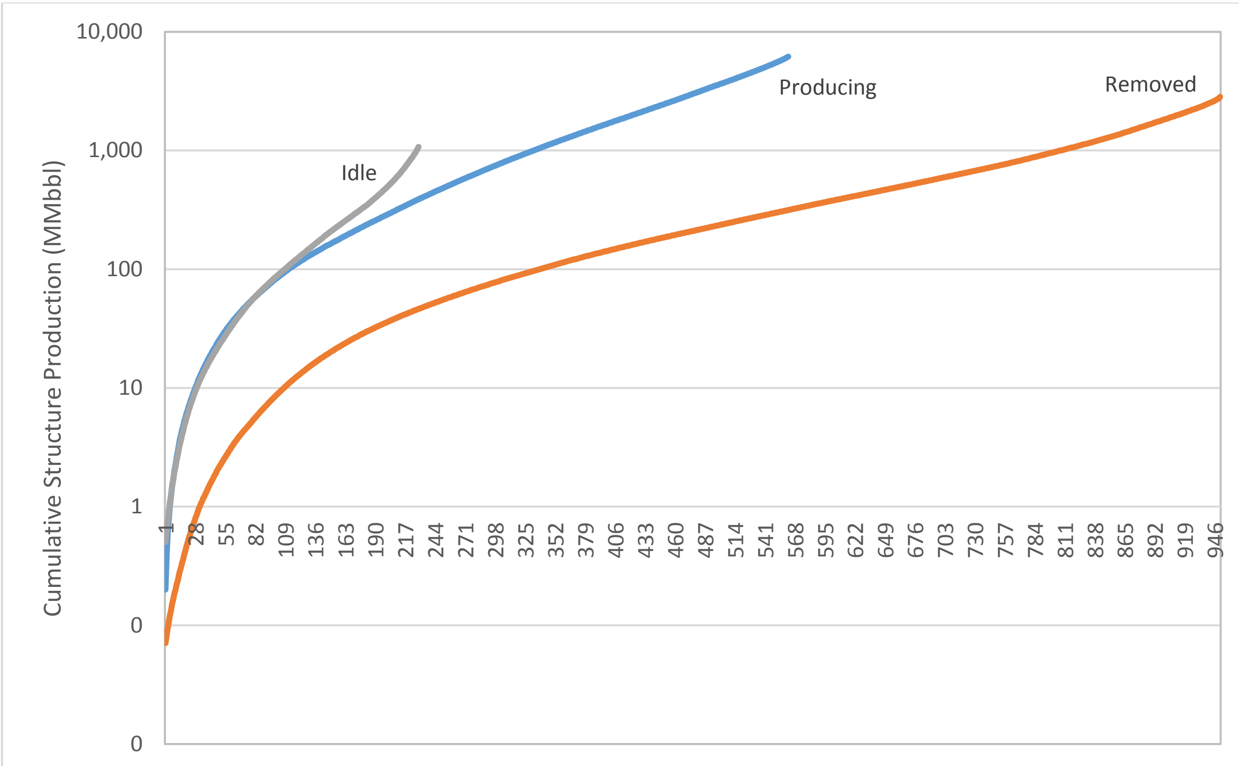


Figure G.5. Cumulative production for producing, idle and decommissioned oil structures <400 ft circa 2017
Source: BOEM, February 2018

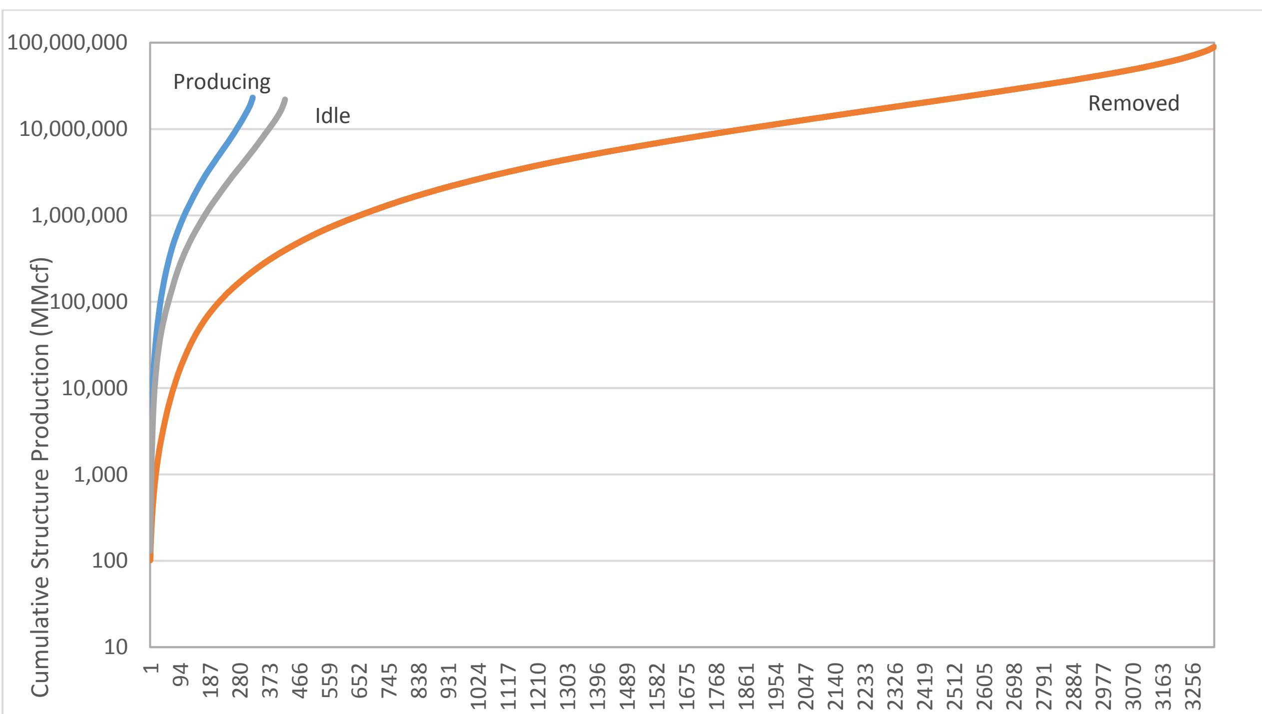


Figure G.6. Cumulative production for producing, idle and decommissioned gas structures <400 ft circa 2017
Source: BOEM, February 2018

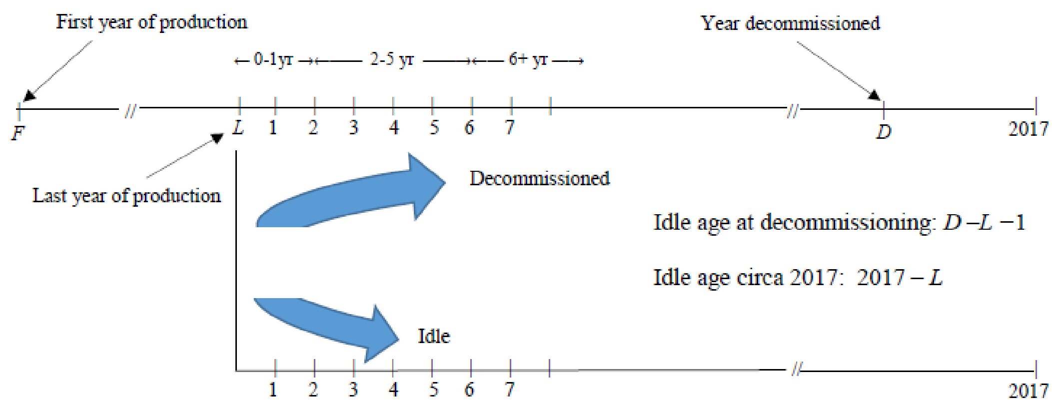


Figure G.7. Idle age of a structure at decommissioning and in active inventory circa 2017

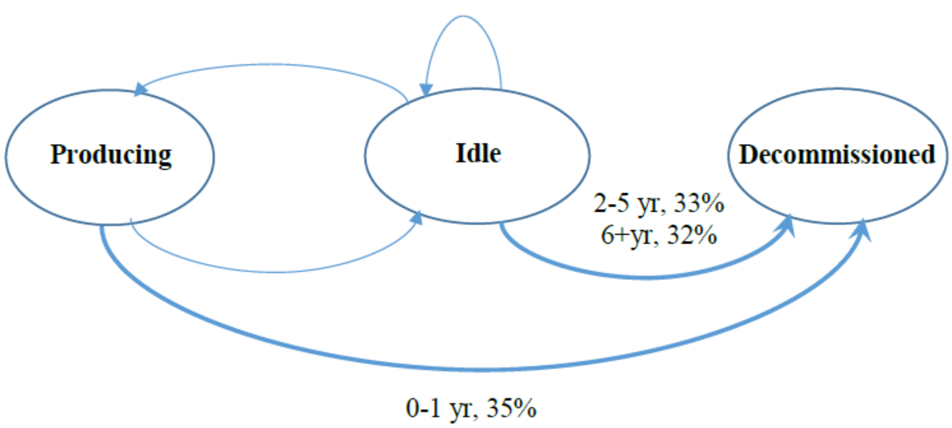


Figure G.8. Percentage of structures producing and idle at time of decommissioning, 1973-2017

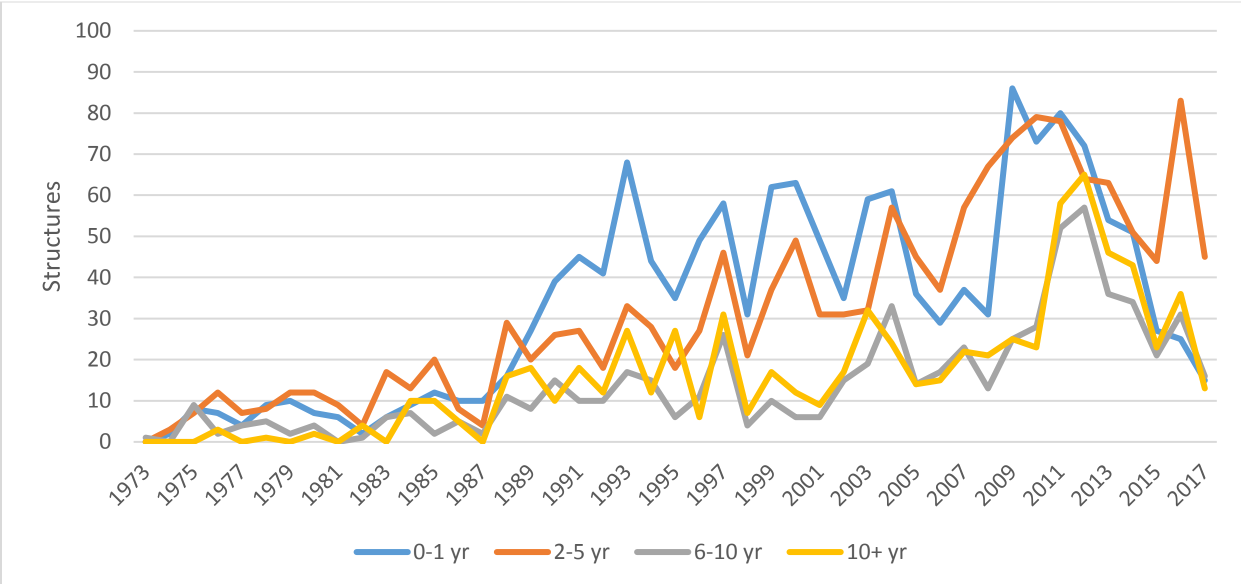


Figure G.9. Structures decommissioned by idle age group, 1973-2017

Source: BOEM, February 2018

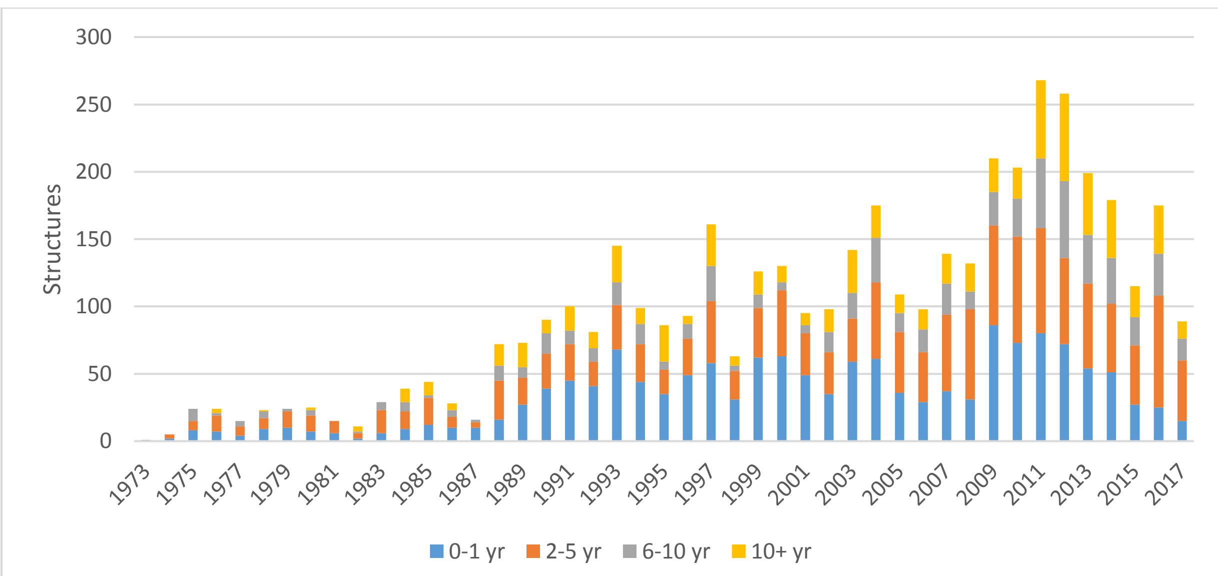


Figure G.10. Structures decommissioned by idle age group - stacked, 1973-2017

Source: BOEM, February 2018

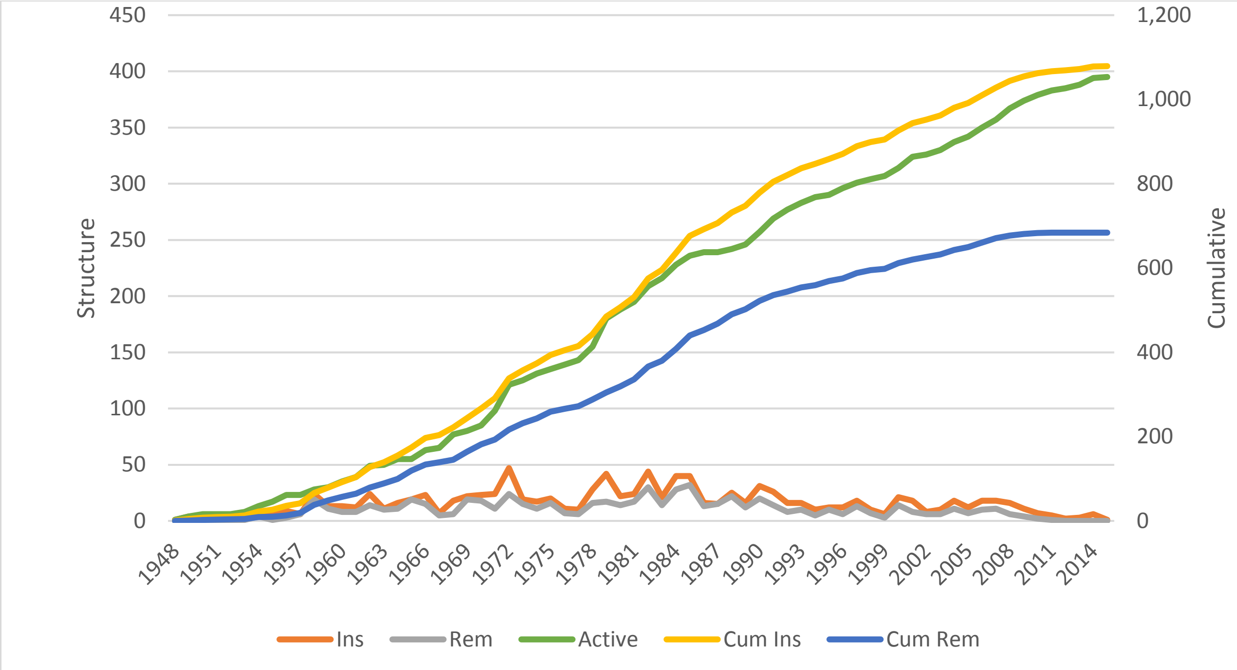


Figure G.11. Shallow water auxiliary structure trends, 1948-2017
Source: BOEM, February 2018

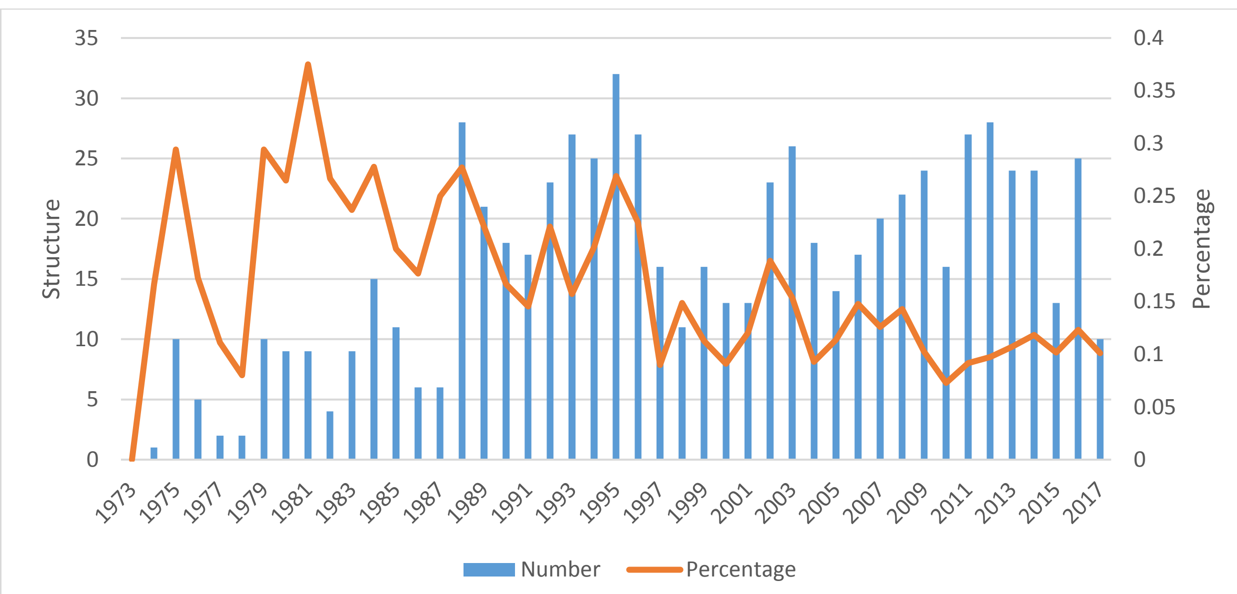


Figure G.12. Shallow water auxiliary structures decommissioned and percentage of total, 1948-2017
Source: BOEM, February 2018

APPENDIX H

CHAPTER 8 TABLES AND FIGURES

Table H.1. Economic limit statistics by structure type and manning status, 1990-2017 (thousand 2016$)

	Gas Structure			Oil Structure		
	P20	P50	P80	P20	P50	P80
C/WP	235	1118	3815	81	469	1441
FP	326	1296	4013	297	1017	3348
Manned	651	2045	5379	439	1080	3583
Unmanned	275	1190	3852	122	590	1926
All	282	1220	3970	135	627	2010

Table H.2. Labor and transportation cost allocation for regional operations

	Annual Man Hours	Flight Hours	Production (Mboe)	Labor Cost ($1000)	Transportation Cost ($1000)	$\frac{\text{TotalCost}}{\text{Production}}$ ($/boe)
C (P1/P2)	47,152	104	200	1076	208	6.42
P3	3744	78	97	86	156	2.49
P4	832	52	50	19	104	2.84
P5	832	52	3	19	104	41.00
Total	52,560	286	350	1200	572	5.06

Note: See Section 8.2.3 example for model assumptions

Table H.3. Average gross revenues for oil and gas structures by decade, 1990-2017 (million 2016$)

Structure Type	1990-2017	1990-1999	2000-2009	2010-2017
Gas	2.68 (1.11)	2.94 (0.77)	3.23 (1.12)	1.51 (0.20)
Oil	1.91 (2.07)	1.14 (0.58)	1.85 (1.22)	2.93 (3.31)

Note: Standard deviation in parenthesis.

Table H.4. Economic limit regression models in the shallow water Gulf of Mexico (million 2016$)

Variable	Model A	Model B	Model C
Fixed Term	1.22 (6.0)	1.07 (5.1)	1.08 (5.2)
Type	0.11 (0.7)	0.17 (1.0)	0.16 (1.0)
Oil/Gas	1.32 (6.2)	1.37 (6.4)	1.37 (6.4)
Water Depth	1.18 (4.0)	1.20 (4.2)	1.20 (4.2)
Manned	1.00 (2.3)	1.00 (2.3)	1.02 (2.3)
Major		0.82 (3.0)	0.82 (3.0)
Complex			-0.31 (-0.8)

Note: t-statistics denoted in parenthesis.

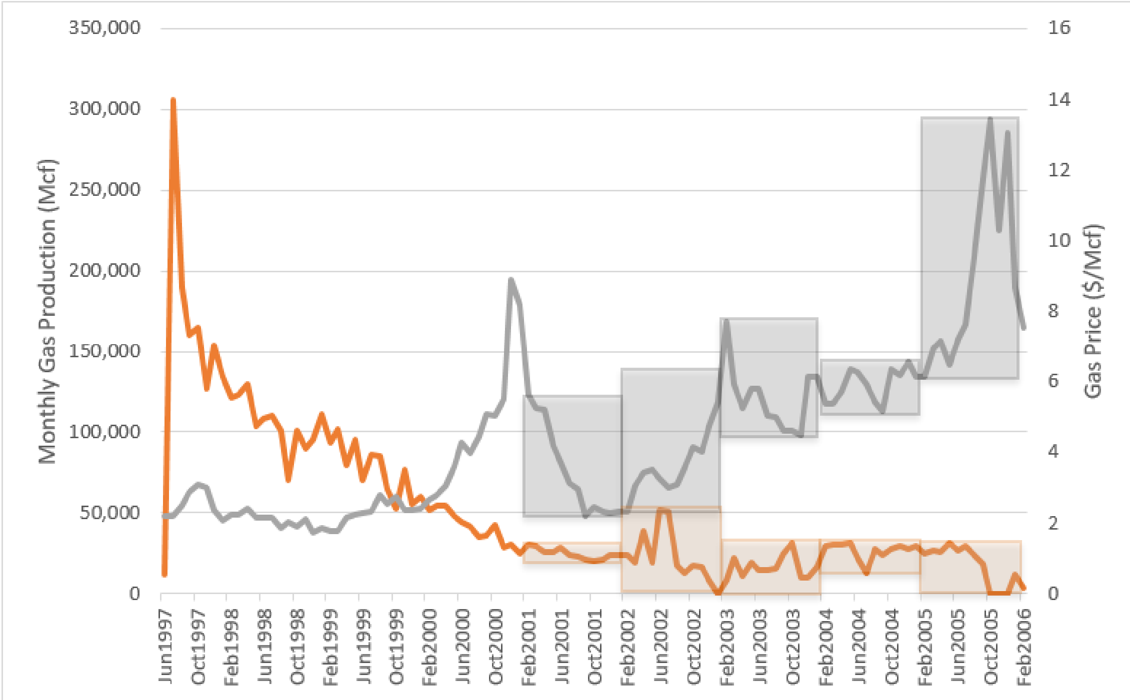


Figure H.1a. Gas production and prices for structure 90026 and one-year time windows
Source: BOEM, June 2017

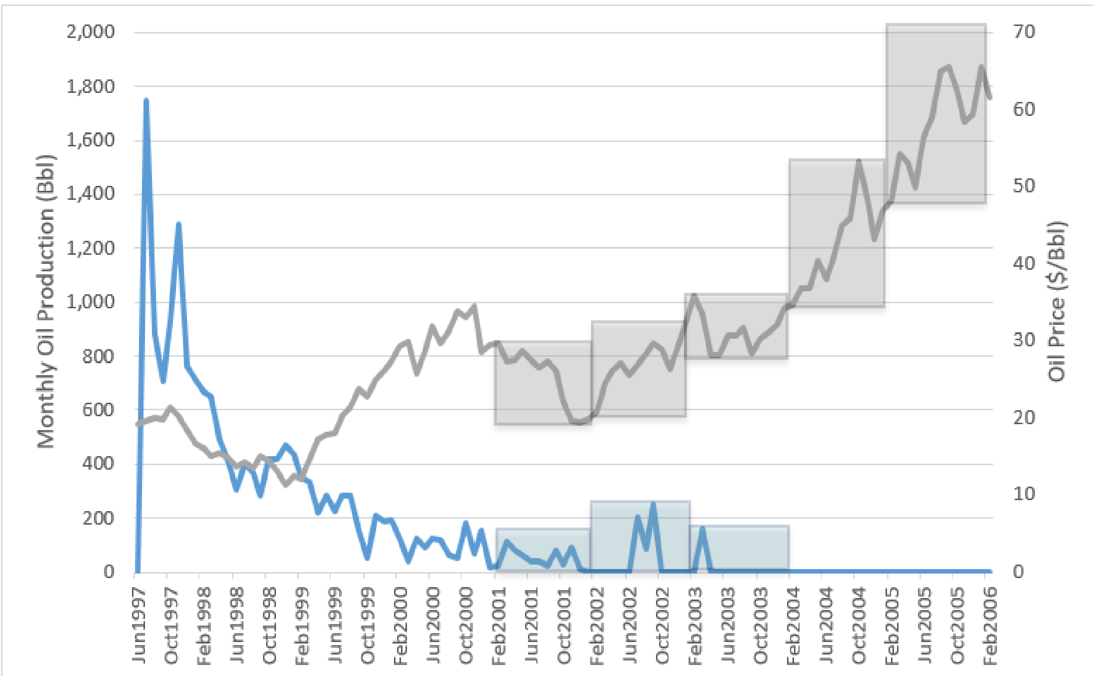


Figure H.1b. Condensate production and oil prices for structure 90026 and one-year time windows
Source: BOEM, June 2017

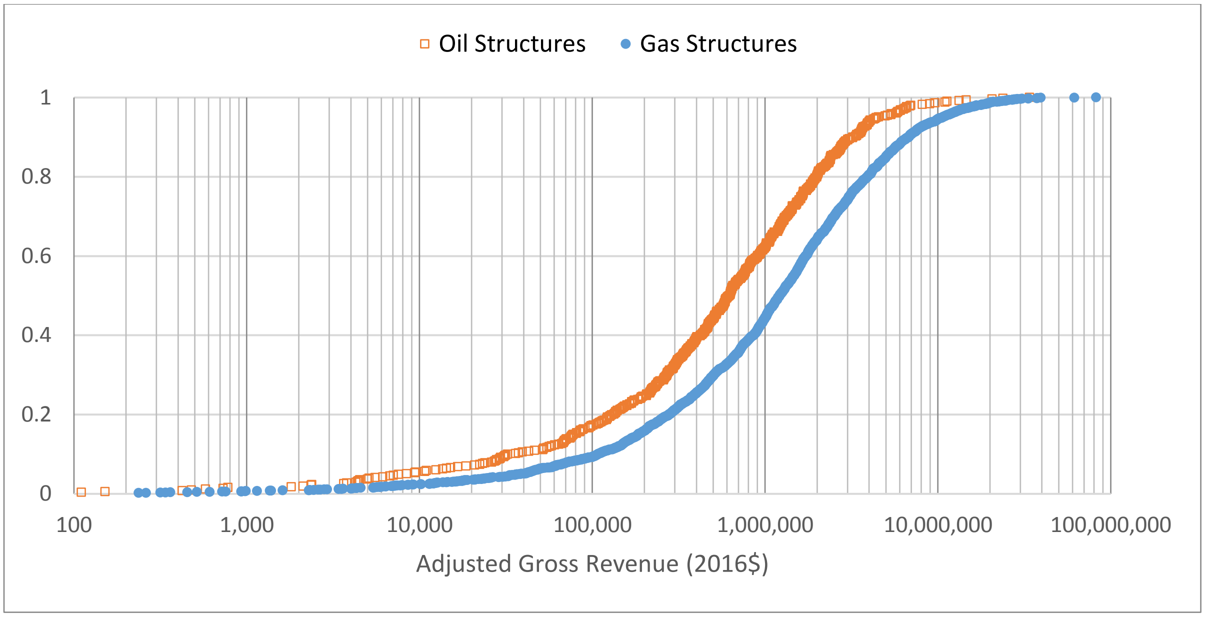


Figure H.2. Gross revenues for oil and gas structures the last year of production, 1990-2017 (2016$)
Source: BOEM, June 2017

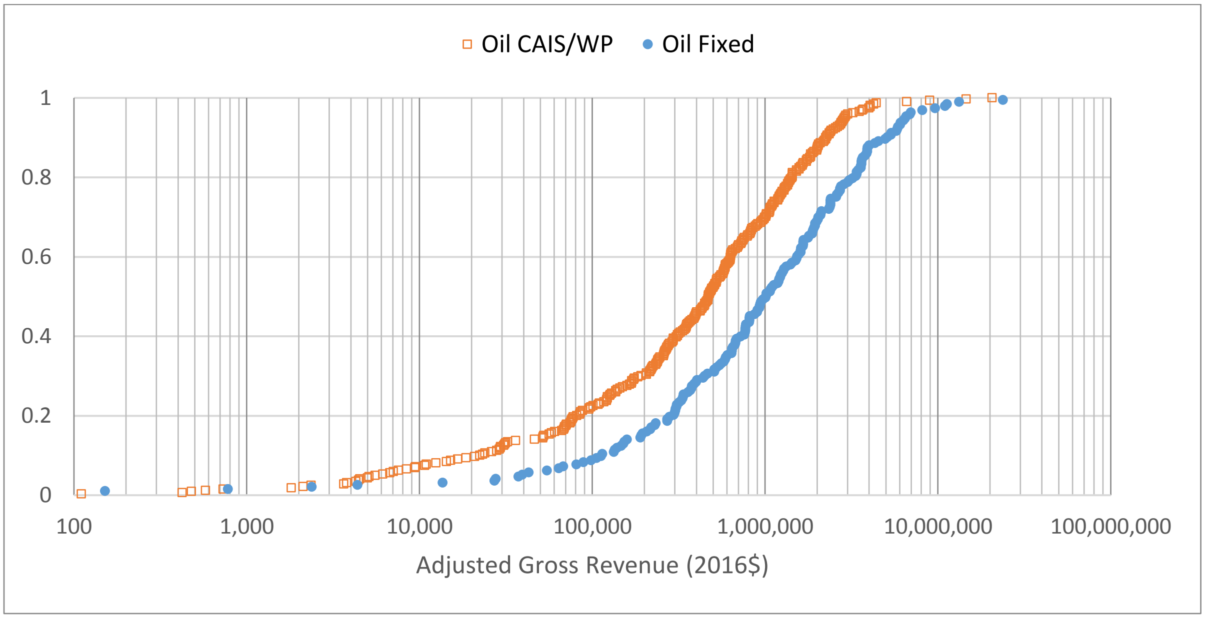


Figure H.3. Gross revenues for oil structures last producing year by structure type, 1990-2017 (2016$)
Source: BOEM, June 2017

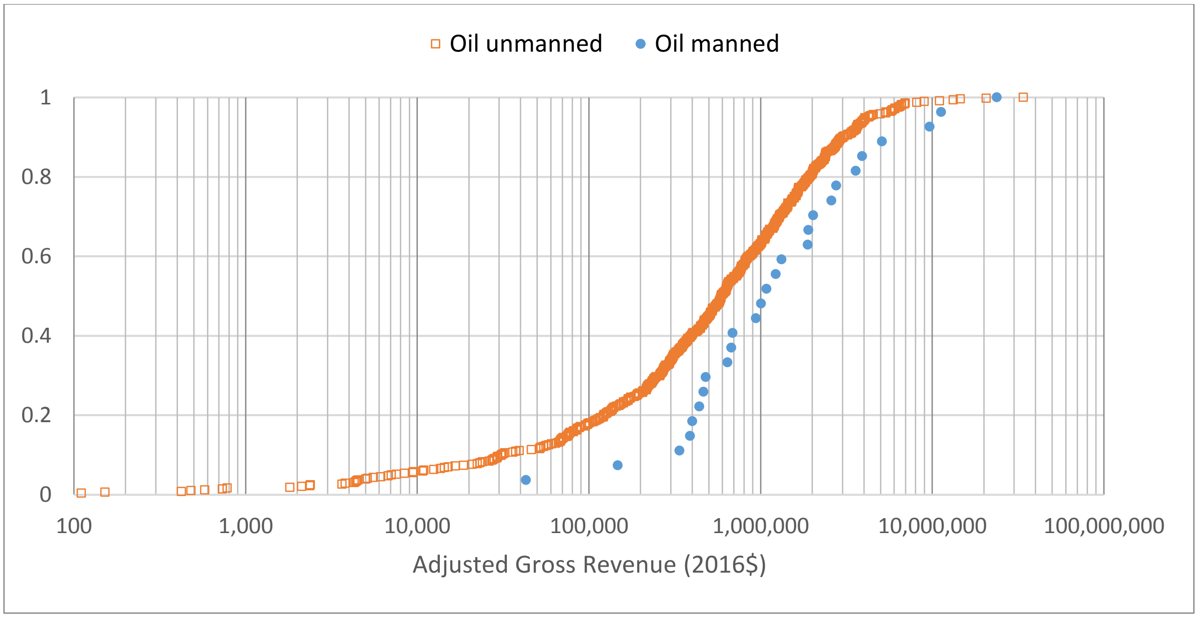


Figure H.4. Gross revenues for oil structures last producing year by manning status, 1990-2017 (2016$)
Source: BOEM, June 2017

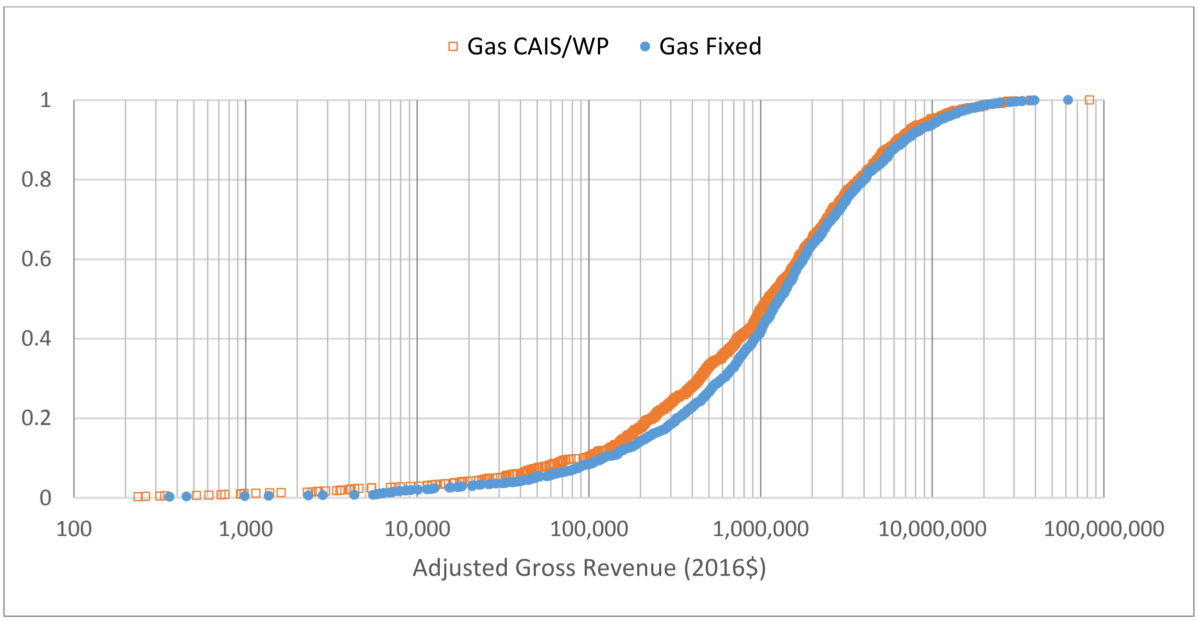


Figure H.5. Gross revenues for gas structures last producing year by structure type, 1990-2017 (2016$)
Source: BOEM, June 2017

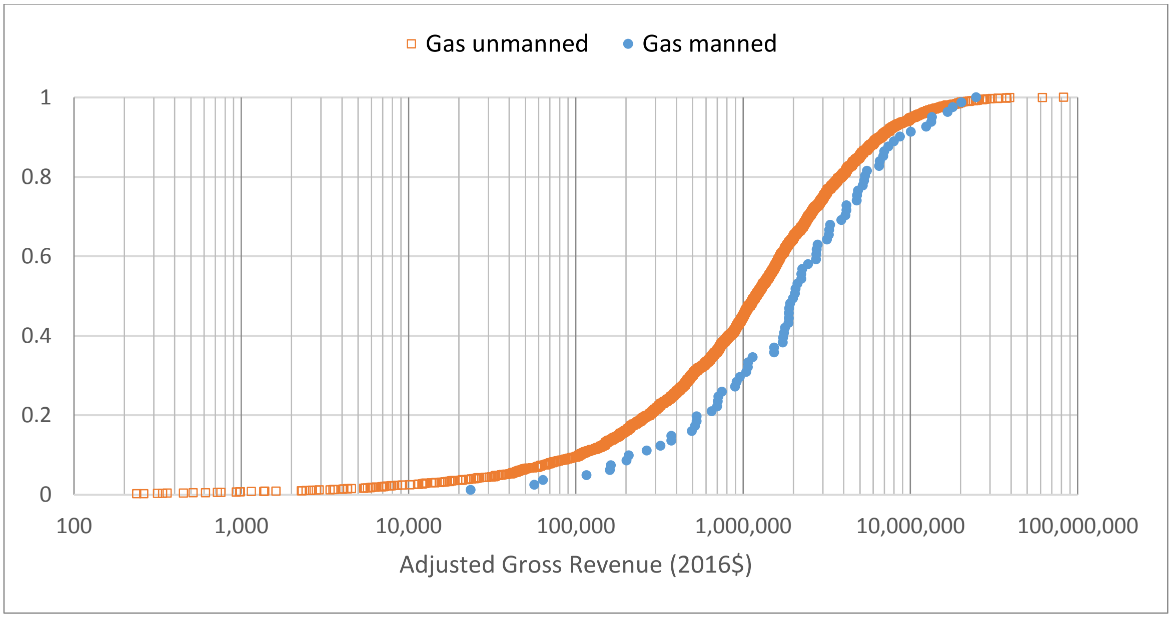


Figure H.6. Gross revenues for gas structures last producing year by manning status, 1990-2017 (2016$)
Source: BOEM, June 2017

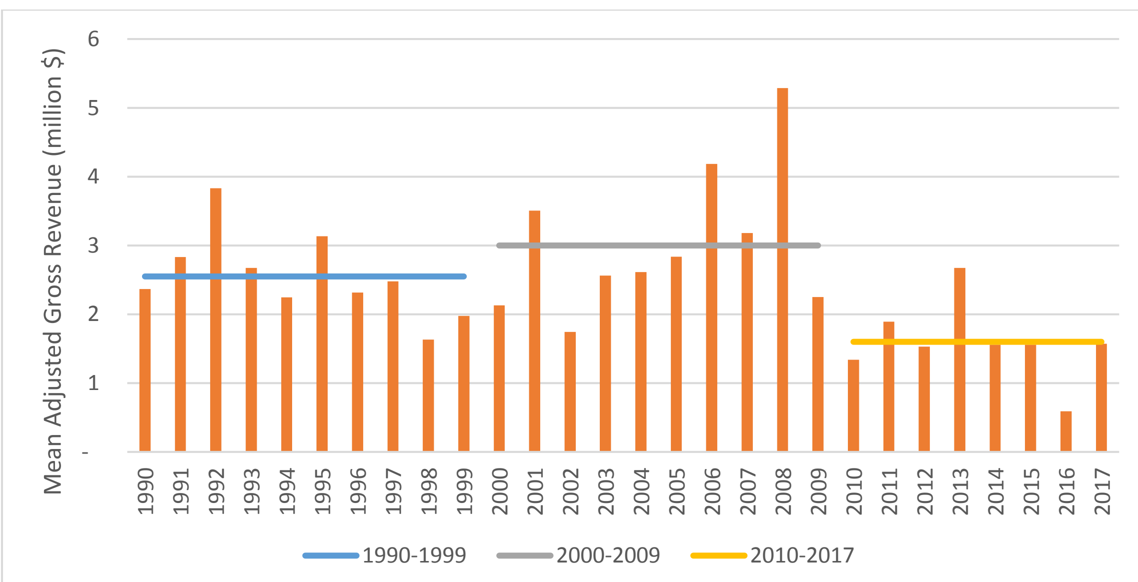


Figure H.7. Average gross revenue last year of production, 1990-2017 (million 2016$)
Source: BOEM, June 2017

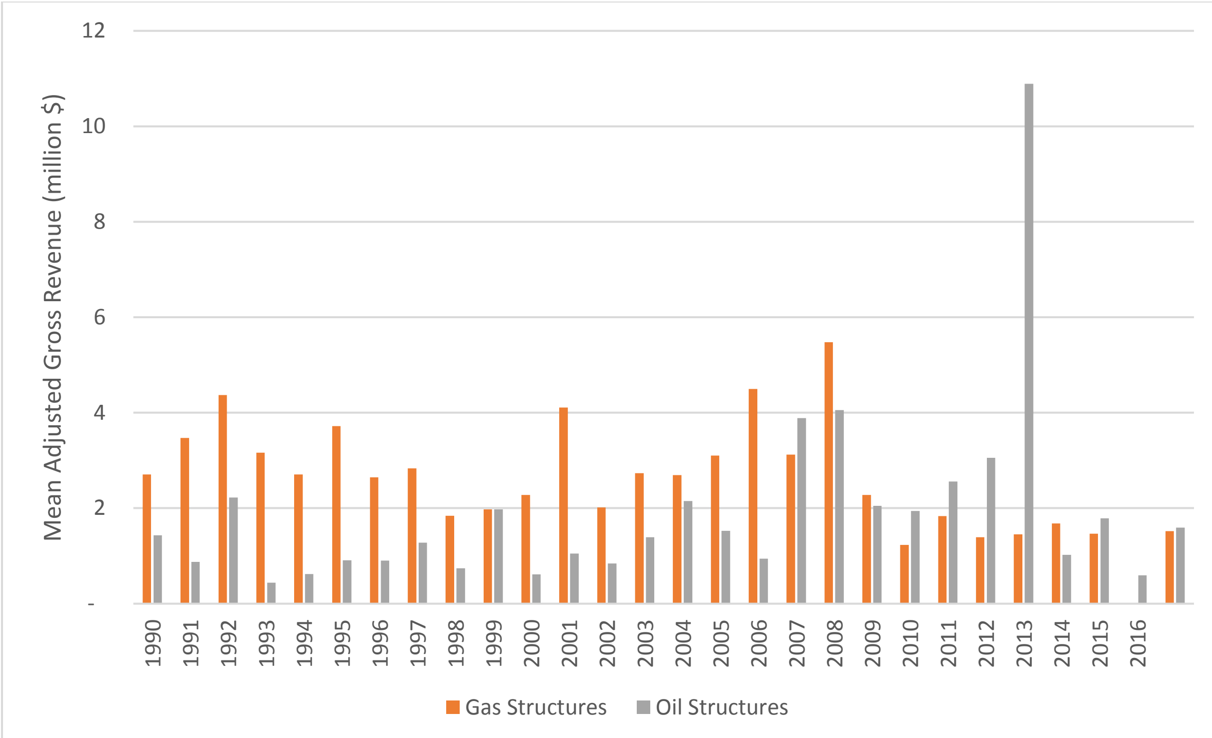


Figure H.8. Average gross revenue last year of production for structures (million 2016$)
Source: BOEM, June 2017

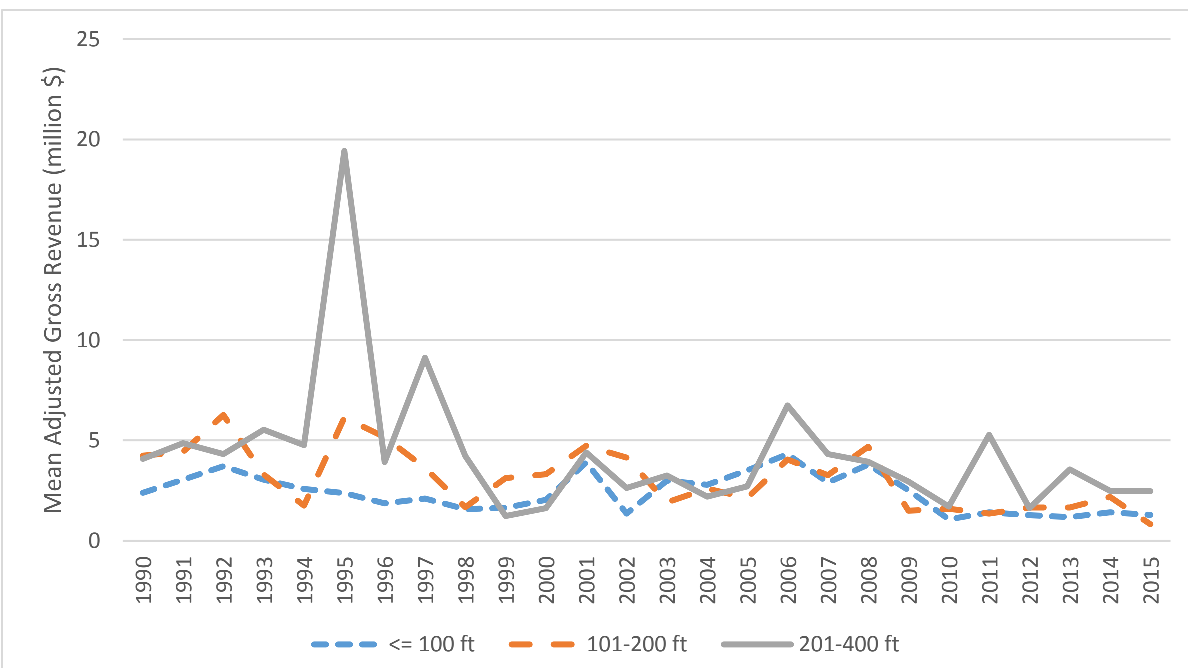


Figure H.9. Average gross revenue the last year of production for gas structures, 1990-2017 (million 2016$)
Source: BOEM, June 2017

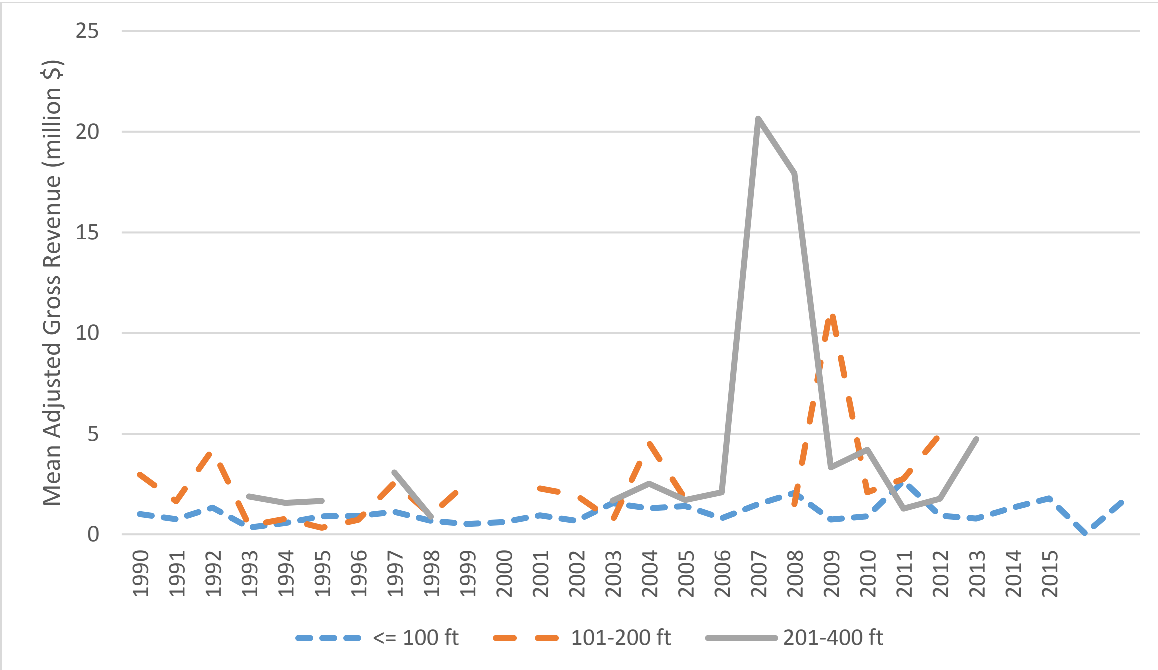


Figure H.10. Average gross revenue the last year of production for oil structures, 1990-2017 (million 2016$)
Source: BOEM, June 2017

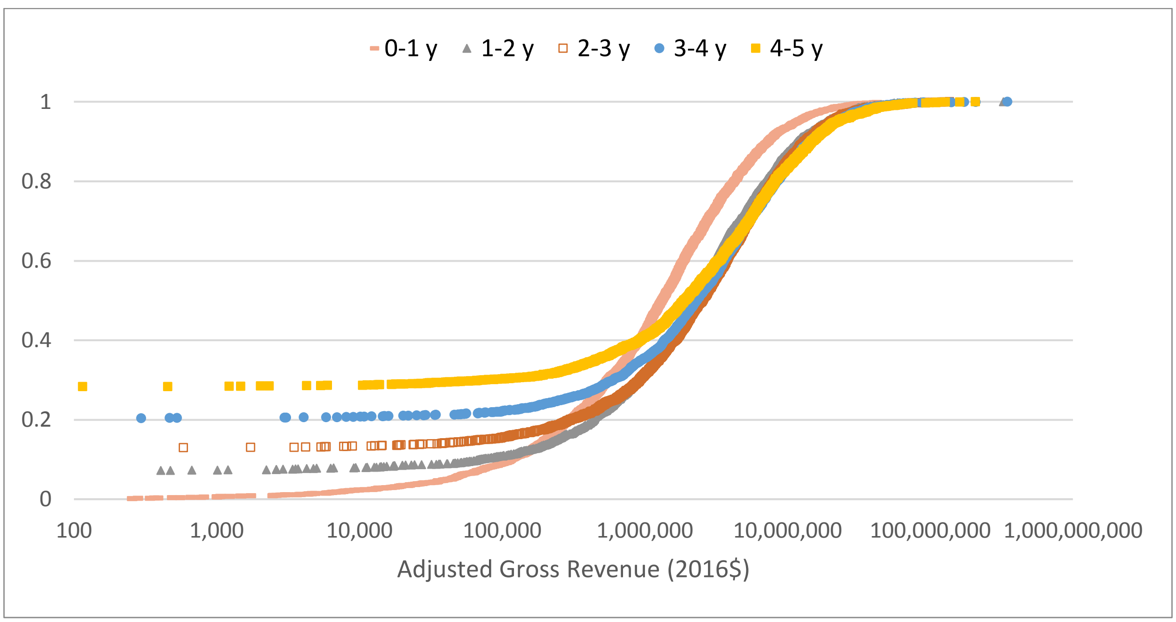


Figure H.11. Average gross revenue last five years of production for gas structures, 1990-2017
Source: BOEM, June 2017

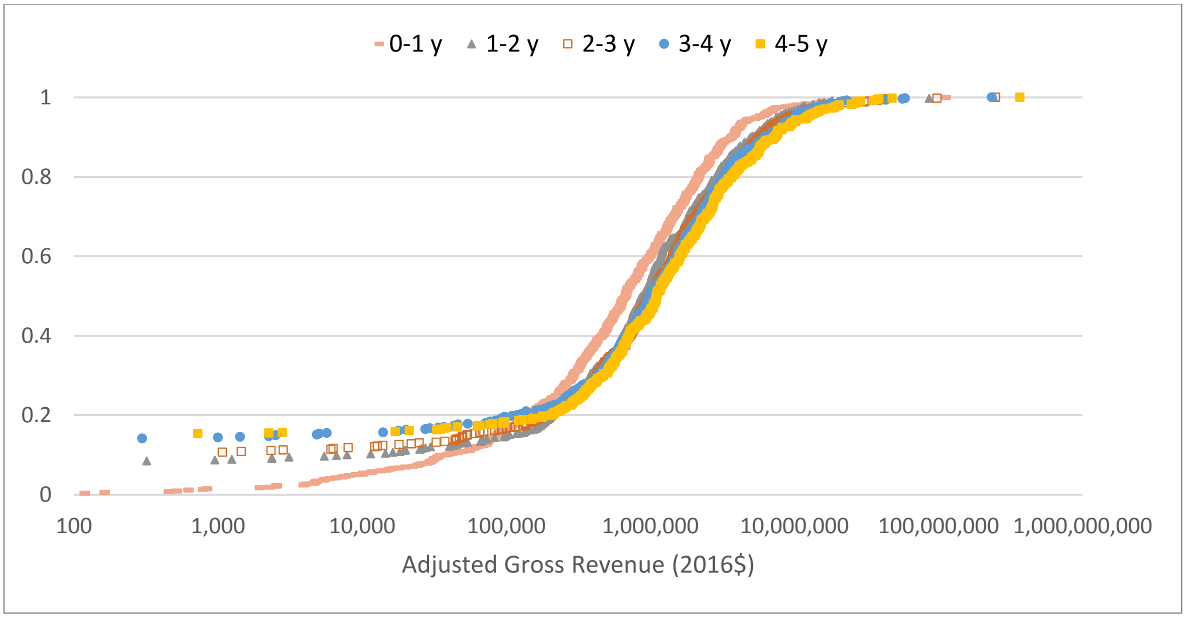


Figure H.12. Average gross revenue last five years of production for oil structures, 1990-2017
Source: BOEM, June 2017

APPENDIX I

CHAPTER 9 TABLES AND FIGURES

Table I.1. Gulf of Mexico deepwater inventory statistics circa 2016

	Fixed Platforms 400-500 ft	FPs/CTs > 500 ft	Floaters
Structures			
Oil (#)	14	20	46
Gas (#)	8	9	1
Cumulative Production			
Oil (MMbbl)	360	1838	5732
Gas (Bcf)	3058	6379	11,777
2016 Production			
Oil (MMbbl)	2.5	37	469
Gas (Bcf)	10.5	119	651
Gross Revenue ($ million)	129	1781	20,657
Proved Reserves			
Oil (MMbbl)	4.3	135	1826
Gas (Bcf)	16.5	447	2312
PV-10 ($ billion)	0.16	4.14	51.3
Wells			
Dry Tree (#)	485	906	648
Wet Tree (#)	52	210	746
Producing (#)	82	256	464

Source: BOEM, July 2017

Note: PV-10 value assumes $60/bbl crude oil and $3/Mcf natural gas price, 16.67% royalty rate, and $7/boe operating cost

Table I.2. Deepwater structure cumulative production in the Gulf of Mexico circa 2016

Cumulative Production – Primarily Oil (MMboe)	Fixed Platforms	Compliant Towers	Floaters
<25	13(3)	0	5
25-50	5	0	4
50-100	5(1)	0	13
100-150	3	1	9
150-200	0	1	4
200-500	4	1	8
>500	1	0	3
Total	31(4)	3	46
Cumulative Production – Primarily Gas (Bcfe)	**Fixed Platforms**	**Compliant Towers**	**Floaters**
<50	1(1)	0	0
50-100	3(3)	0	0
100-200	4(1)	0	0
200-300	5(3)	0	0
300-400	1	0	0
400-500	1	0	0
>500	2	0	1
Total	17(8)	0	1

Source: BOEM, July 2017

Note: Numbers in parenthesis represent structures that did not produce in 2016.

Table I.3. Deepwater structure revenue in the Gulf of Mexico circa 2016

Gross Revenue (million $)	Fixed Platforms	Compliant Towers	Floaters
No Production	12		
<5	11		1
5-30	14	1	3
30-100	7		13
100-500	4	2	14
500-1000			8
1000-2000			8
Total	48	3	47

Source: BOEM, July 2017

Table I.4. Deepwater structure PV-10 in the Gulf of Mexico circa 2016

PV-10 (million $)	Fixed Platforms	Compliant Towers	Floaters
<10	18	0	2
10-50	7	1	1
50-100	5	0	5
100-200	2	0	7
200-500	2	2	13
>500	2	0	18
Total	36	3	47

Source: BOEM, July 2017

Note: PV-10 calculations assume constant oil price of $60/bbl and gas price of $3/Mcf, 16.67% royalty rate, and $7/boe operating cost.

Table I.5. Production and gross revenue for fixed platforms in 400-500 ft circa 2016

Operator	Complex	Producing Well	2016 Production		Cumulative Production		Gross Revenue (MM $)
			Oil(MMbbl)	Gas(Bcf)	Oil(MMbbl)	Gas(Bcf)	
Arena Offshore LP	23848	11	0.0	3.4	0.3	201.7	8.6
Bennu Oil & Gas	2027	1	0.0	0.1	0.9	2.8	1.0
Chevron U.S.A.	1052	3	0.1	0.1	14.1	120.0	2.3
Energy Resource Technology	90028	3	0.1	0.2	7.8	87.9	4.7
Energy XXI GOM	22172	11	0.2	0.4	73.3	353.8	7.7
Energy XXI GOM	22685	-			16.4	29.8	-
Energy XXI GOM	23151	6	0.1	0.1	36.9	109.4	3.2
Energy XXI GOM	23893	1	0.1	0.0	8.9	649.6	2.3
Fieldwood Energy	1500	7	0.6	1.3	17.0	33.6	27.6
Fieldwood Energy	22224	5	0.1	0.2	32.7	305.6	6.5
Fieldwood Energy	22662	4	0.1	0.2	65.0	241.9	6.3
Fieldwood Energy	23800	16	0.6	1.9	30.0	91.0	27.6
Fieldwood Energy	80015	1	0.0	0.0	3.7	34.1	0.0
Manta Ray Gathering	70	4	0.4	2.5	8.4	373.6	23.1
Manta Ray Gathering	23212	-	-	-	3.3	75.4	-
McMoRan Oil & Gas	23925	-	-	-	5.9	114.7	-
Poseidon Oil Pipeline	23353	-	-	-	0.0	88.7	-
Renaissance Offshore	1076	2	0.0	0.0	1.0	1.2	0.6
Tarpon Operating & Development	1165	2	0.1	0.0	5.2	3.6	3.3
Taylor Energy	23051	-	-	-	13.8	40.8	-
W & T Offshore	1279	5	0.1	0.1	14.7	38.7	4.4
W & T Offshore	10192	-	-	-	0.3	60.6	-

Source: BOEM, July 2017
Note: Structures 1076 and 80015 had oil production less than 10,000 bbls and gas production less than 100 MMcf in 2016.

Table I.6. Fixed platform revenue status in water depth 400-500 ft circa 2016

Operator	No Production (Last Year)	Gross Revenue (million $)	
		<5	5-30
Arena Offshore			23848
Bennu Oil & Gas		2027	
Chevron U.S.A.		1052	
Energy Resource Technology		90028	
Energy XXI GOM	22685 (2004)	23151, 23893	22172
Fieldwood Energy		80015	1500, 22224, 22662, 23800
Manta Ray Gathering	23212 (1992)		70
McMoRan Oil & Gas	23925 (2008)		
Poseidon Oil Pipeline	23353 (2007)		
Renaissance Offshore		1076	
Tarpon		1165	
Taylor Energy	23051 (2004)		
W & T Offshore	10192 (2012)	1279	
Total	6	9	7

Source: BOEM, July 2017

Table I.7. Production and gross revenue for fixed platforms in water depth >500 ft circa 2016

Operator	Complex	Producing Well	2016 Production		Cumulative Production		Gross Revenue (MM $)
			Oil (MMbbl)	Gas (Bcf)	Oil (MMbbl)	Gas (Bcf)	
Ankor Energy	1482	15	0.7	1.4	9.1	21.0	30.2
ATP Oil & Gas	1320	-	-	-	0.1	8.6	-
Chevron U.S.A.	23760	-	-	-	29.0	263.0	-
Chevron U.S.A.	70012	18	4.1	8.0	162.1	261.8	188.1
Eni US	23875	5	2.0	22.2	17.9	419.7	138.3
EnVen Energy	22178	12	0.7	6.1	181.4	808.0	43.1
EnVen Energy	24129	21	2.2	1.9	193.0	172.6	95.9
Exxon Mobil	22840	21	0.4	0.3	63.6	237.4	17.7
Fieldwood Energy	23552	21	3.1	6.7	404.1	686.8	141.5
Fieldwood Energy	70016	-	-	-	3.8	204.8	-
Fieldwood SD	10178	5	0.1	0.2	16.4	88.3	4.0
Fieldwood SD	10212	9	0.1	1.2	15.2	186.4	6.7
Fieldwood SD	10242	-	-	-	3.6	190.3	-
Fieldwood SD	10297	10	0.4	0.5	38.4	117.2	17.9
Flextrend Dev.	24201	4	0.7	0.5	16.4	125.2	31.6
Flextrend Dev.	27032	7	0.1	6.4	16.5	201.9	21.4
Hess	33039	7	3.1	10.5	124.0	450.5	153.0
MC Offshore	23567_1	3	0.5	2.7	10.9	48.6	28.3
MC Offshore	23567_2	7	0.1	0.1	15.9	16.7	5.9
Shell Offshore	27056	4	0.1	0.5	7.8	135.4	3.5
Shell Offshore	90014	6	8.1	28.4	138.0	553.7	401.2
Shell Oil	23277	-	-	-	9.3	59.6	-
Stone Energy	23883	31	1.5	1.7	83.7	95.9	64.5
Stone Energy	24130	25	5.8	11.7	159.8	493.0	264.4
Triton Gathering	23788	-	-	-	0.0	248.5	-
W & T Energy VI	113	7	0.1	3.0	4.0	119.0	12.1
W & T Offshore	147	6	1.1	3.5	18.0	43.0	53.4
Walter Oil & Gas	2606	2	0.7	0.5	0.7	0.5	31.4
Whistler Energy II	23503	10	0.6	0.7	95.4	121.2	26.5

Source: BOEM, July 2017.

Note: Complex 2606 was installed in 2016.

Table I.8. Fixed platform and compliant tower revenue status in water depth >500 ft circa 2016

Operator	No Production (Last Year)	Gross Revenue (million $)			
		<5	5-30	30-100	100-500
Ankor Energy				1482	
ATP Oil & Gas	1320(2012)				
Chevron U.S.A.	23760(2015)				70012
Eni US					23875
EnVen Energy Ventures				22178, 24129	
Exxon Mobil			22840		
Fieldwood Energy	70016(2013)				23552
Fieldwood SD Offshore	10242(2009)	10178	10212, 10297		
Flextrend Development			27032	24201	
Hess					33039
MC Offshore Petroleum			23567-1, 23567-2		
Shell Offshore		27056			90014
Shell Oil	23277(2013)				
Stone Energy				23883	24130
Triton Gathering	23788(2003)				
W & T Energy VI			113		
W & T Offshore				147	
Walter Oil & Gas				2606	
Whistler Energy II			23503		
Total	6	2	8	7	6

Source: BOEM, July 2017

Table I.9. Production and gross revenue for floating structures circa 2016

Operator	Complex	Type	Producing Well	2016 Production		Cumulative Production		Gross Rev. (MM$)
				Oil(MMbbl)	Gas(Bcf)	Oil(MMbbl)	Gas(Bcf)	
Anadarko Petroleum	821	SPAR	5	0.8	9.5	74.0	547.9	57.4
Anadarko Petroleum	822	SPAR	11	1.5	2.0	88.0	255.9	66.2
Anadarko Petroleum	1288	SPAR	7	0.6	1.7	36.1	214.8	30.0
Anadarko Petroleum	1323	TLP	15	7.8	5.6	97.5	77.5	331.6
Anadarko Petroleum	1665	SPAR	15	17.5	17.4	108.5	108.6	752.6
Anadarko Petroleum	1766	SEMI	3	-	0.0	0.3	1,263.4	0.0
Anadarko Petroleum	2576	SPAR	9	27.6	135.9	50.4	239.9	1461.4
Anadarko Petroleum	2597	SPAR	4	4.7	2.2	4.7	2.2	195.6
Bennu Oil & Gas	2089	SEMI	4	1.1	1.1	13.4	14.3	46.7
BHP Billiton Petroleum	1799	MTLP	7	2.9	2.2	36.0	29.0	121.2
BHP Billiton Petroleum	1899	TLP	18	26.3	10.7	251.7	100.5	1092.5
BP E&P	1001	SEMI	18	16.8	27.1	309.2	786.6	749.6
BP E&P	1101	SEMI	16	34.1	30.7	314.3	273.1	1461.5
BP E&P	1215	SPAR	8	20.2	5.6	167.7	50.0	831.7
BP E&P	1223	SEMI	20	37.3	25.0	287.7	187.0	1575.4
Chevron U.S.A.	67	SPAR	11	1.3	1.7	117.6	184.5	56.3
Chevron U.S.A.	1819	SPAR	12	20.1	11.3	218.7	118.4	842.7
Chevron U.S.A.	1930	SEMI	4	1.8	1.5	72.7	56.0	76.2
Chevron U.S.A.	2440	SEMI	11	36.0	8.4	58.0	13.9	1481.8
ConocoPhillips	1218	TLP	5	1.1	2.1	37.1	100.9	48.4
Energy Resource Technology	2133	MOPU	8	3.3	5.3	61.9	95.7	147.4
Eni US	251	MTLP	6	1.8	2.5	62.4	285.0	77.7
Eni US	1175	SPAR	10	5.4	4.6	84.6	201.6	230.9
Eni US	70020	MTLP	4	0.7	0.5	44.6	39.4	29.6
EnVen Energy Ventures	811	TLP	4	0.7	1.2	10.1	11.2	31.2
Exxon Mobil	183	SPAR	9	2.4	2.1	116.1	580.8	101.5
Freeport McMoRan Oil & Gas	235	TLP	11	8.8	12.5	181.1	546.5	389.7
Freeport McMoRan Oil & Gas	876	SPAR	8	3.6	5.1	114.3	100.9	159.5
Freeport McMoRan Oil & Gas	1035	SPAR	14	4.9	3.5	96.8	93.8	208.9
Hess	2498	SPAR	6	7.4	14.4	17.1	35.6	337.7
LLOG Exploration Offshore	2424	SEMI	10	9.3	18.5	44.7	81.1	424.9
LLOG Exploration Offshore	2513	SEMI	11	24.8	62.1	37.5	90.0	1161.1
MC Offshore	23583	TLP	11	0.2	0.4	36.0	136.5	9.7
Murphy E&P	1090	SPAR	11	3.0	3.2	67.5	74.9	130.9
Murphy E&P	1290	SPAR	10	2.0	2.1	47.7	59.7	87.7
Murphy E&P	2045	SEMI	7	12.9	10.6	39.4	39.9	550.2
Noble Energy	24235	SPAR	3	1.7	2.1	91.8	245.2	75.0
Petrobras America	2229	FPSO	4	4.4	0.7	28.7	4.8	181.9
Shell Offshore	420	TLP	12	6.3	5.5	143.9	182.4	271.1
Shell Offshore	2008	SPAR	15	23.2	52.8	138.8	245.2	1071.9
Shell Offshore	2385	TLP	6	15.0	18.7	42.9	49.8	654.1
Shell Offshore	2503	FPSO	2	0.7	0.1	0.7	0.1	30.1
Shell Offshore	24080	TLP	17	19.2	48.6	401.8	1,253.0	902.5
Shell Offshore	24199	TLP	25	19.8	28.6	801.6	918.7	876.8
Shell Offshore	24229	TLP	9	1.0	6.2	98.4	897.2	56.7
Shell Offshore	70004	TLP	19	25.9	35.3	550.6	831.9	1139.0
W & T Energy VI	1088	MTLP	9	0.9	2.1	27.5	51.7	40.7

Source: BOEM, July 2017. Note: Complex 2503 was installed in 2016.

Table I.10. Floating structure revenue status circa 2016

Operator	Gross Revenue (million $)					
	<5	5-30	30-100	100-500	500-1000	1000-2000
Anadarko Petroleum	1766	1288	821, 822	1323, 2597	1665	2576
Bennu Oil & Gas			2089			
BHP Billiton Petroleum				1799		1899
BP E&P					1001, 1215	1101, 1223
Chevron U.S.A.			67, 1930		1819	2440
ConocoPhillips			1218			
Energy Resource Technology				2133		
Eni US		70020	251	1175		
EnVen Energy Ventures			811			
Exxon Mobil				183		
Freeport McMoRan Oil & Gas				235, 876, 1035		
Hess				2498		
LLOG Exploration Offshore				2424		2513
MC Offshore		23583				
Murphy E&P			1290	1090	2045	
Noble Energy Inc			24235			
Petrobras America				2229		
Shell Offshore			24229, 2503	420	2385, 24080, 24199	2008, 7004
W & T Energy VI			1088			
Total	1	3	13	14	8	8

Source: BOEM, July 2017.

Note: Complex 2503 was installed in 2016.

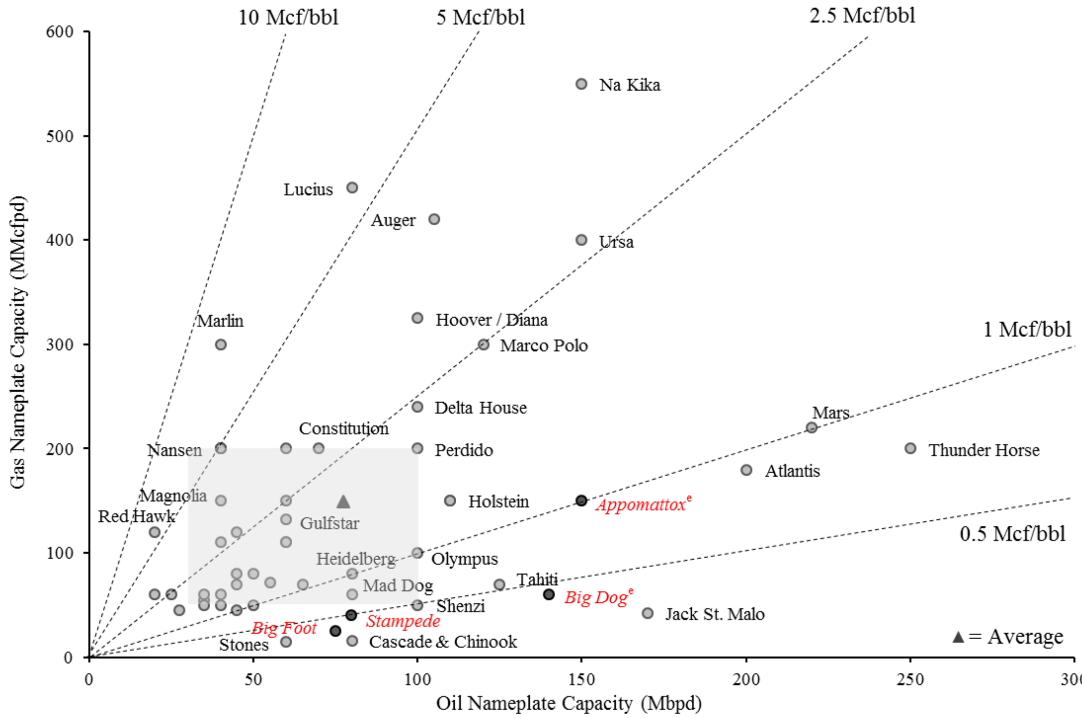


Figure I.1. Gulf of Mexico floater nameplate oil and gas processing capacity circa 2016

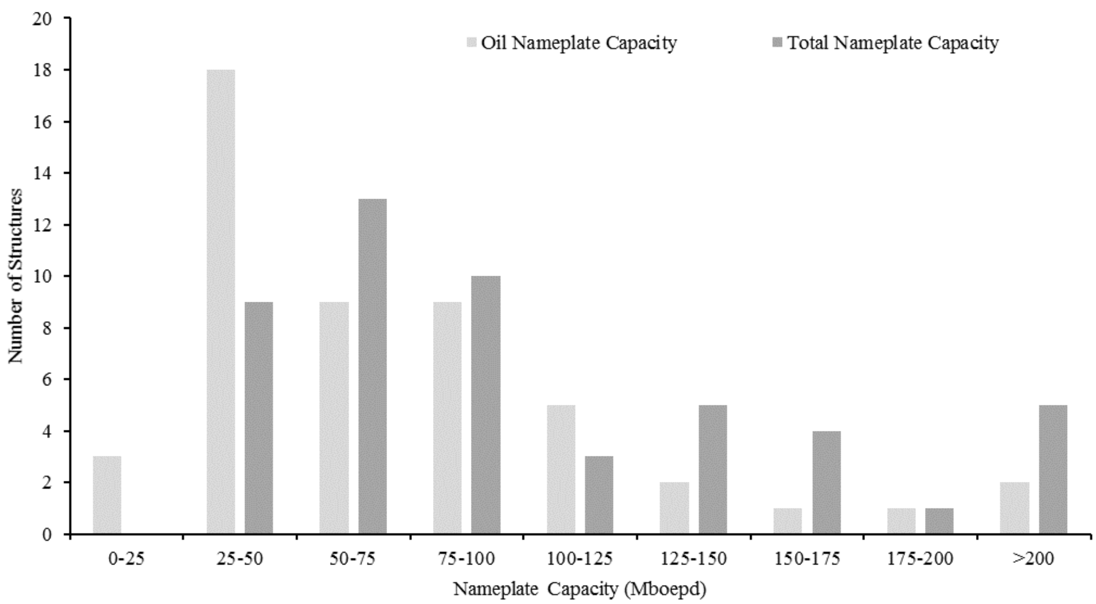


Figure I.2. Gulf of Mexico floater nameplate oil and gas processing distribution circa 2016

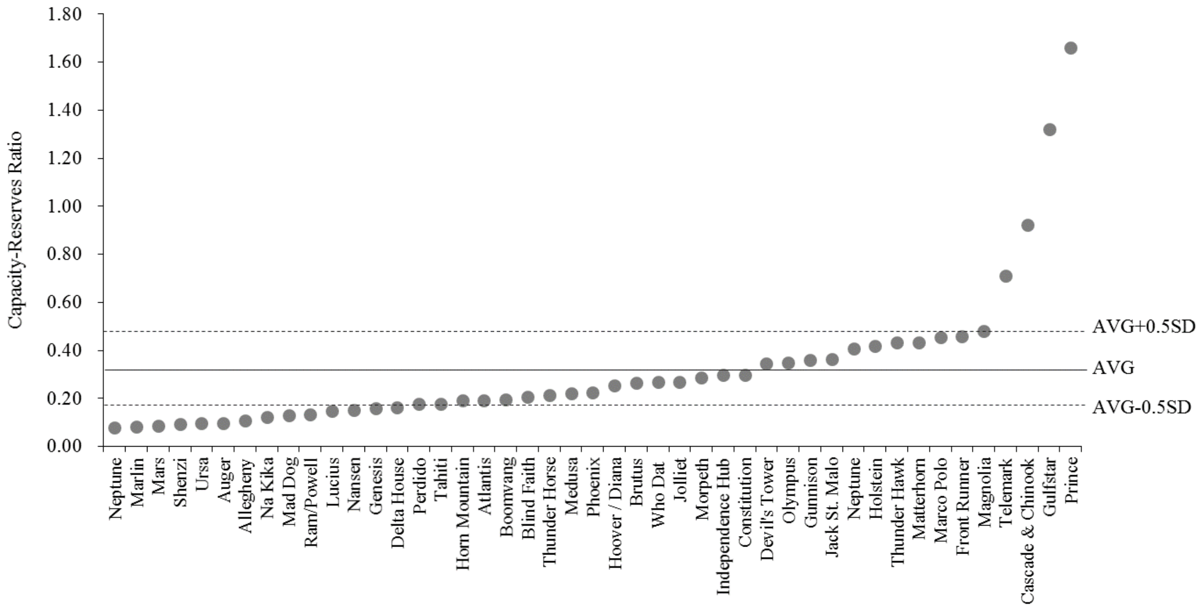


Figure I.3. Gulf of Mexico floater capacity-to-reserves estimates circa 2016

APPENDIX J

CHAPTER 10 TABLES AND FIGURES

Table J.1. Gross revenue statistics for deepwater decommissioned structures the last two years of production

Complex	Structure Type	Cumulative Oil (Mbbl)	Cumulative Gas (MMcf)	CGOR (Mcf/bbl)	Last Year			Second to the Last Year		
					Oil (Mbbl)	Gas (MMcf)	Revenue (MM$)	Oil (Mbbl)	Gas (MMcf)	Revenue (MM$)
85	FP	3779	6436	1.7	33.8	96.8	3.9	122	331	14.1
735	MTLP	2244	3016	1.3	64.5	113	3.7	1003	1476	50.8
1055	FP	4675	22,745	4.9	322	2058	63.9	400	4,246.	68.7
1320	FP	76	8605	114	0.04	11.9	0.04	20.4	148	2.9
1384	SPAR	137	125,094	915	3.0	8293	87.8	39.6	37,654	314
1771	SEMI	19,877	64,313	3.2	305	584.	32.2	1,248	4557	139
10242	FP	3605	190,272	52.8	16.6	461	3.0	62.4	4662	59.6
22274	FP	1001	158,194	158	0.0	1.4	0.01	0.0	13.7	0.1
22372	FP	290	304,770	1053	0.0	511	4.1	2.6	2186	9.2
22583	FP	1267	316,731	250	1.5	356	3.6	0.0	338.	2.5
22705	FP	209	77,913	3712	14.3	5813	67.6	42.4	10,422	88.9
22846	FP	1737	33,297	19.2	0.0	39.5	0.3	0.6	335	1.3
23004	FP	3457	61,043	17.7	41.3	63.5	2.2	45.8	88.5	2.1
23308	FP	3251	80,186	24.7	28.0	351	7.7	40.9	670	9.0
23543	SEMI	532	4979	9.4	14.2	344.	2.5	452	4259	42.6
23581	FP	11,538	196,131	17.0	3.4	157	1.4	50.3	2611	22.1
23859	FP	1548	136,441	88.1	5.1	681	8.1	12.7	1744	15.4
23891	FP	1133	72,371	63.9	0.0	0.1	0.0	0.0	1500	7.9
24021	FP	2967	41,941	14.1	4.0	12.3	0.3	15.9	728	5.8
24079	SEMI	7711	12,582	1.6	427	565	11.1	1823	2888	49.2
24087	FP	0.05	27,207	555,240	0.0	109	0.9	0.0	985	4.2
27014	FP	1102	16,377	14.9	3.5	18.3	0.2	22.3	308	2.2
28033	FP	454	76,087	168	6.1	203	3.1	12.3	342	3.8

Note: Gross revenues adjusted to 2017 dollars.

Table J.2. Permanently abandoned subsea well statistics the last year of production, 2000-2015

Primary	Distance	------------------ Altitude ------------------			
Product	(miles)	> 500^- ft	<500 ft	> 500^+ ft	All
Oil (MMboe)	0-5	73(86)[a]	68(-)	210(-)	92(88)
	5-10	16(-)	308(-)	0.85(-)	109(173)
	≥10	-	-	64(90)	64(90)
	All	63(80)	188(170)	85(103)	91(103)
Gas (Bcfe)	0-5	0.45(0.56)	0.54(1.1)	1.6(-)	0.53(0.94)
	5-10	0.42(0.42)	1.3(1.7)	0.89(1)	1.1(1.5)
	≥10	3.3(7.9)	1.0(1.5)	3.7(6.7)	3.4(6.5)
	All	1.1(3.7)	0.83(1.4)	3.2(6.1)	1.5(3.8)
Oil ($ Million)	0-5	3.7(3.8)	3.5(-)	11(-)	4.7(4.2)
	5-10	1.0(-)	20(-)	0.087(-)	7.0(11)
	≥10	-	-	2.9(4.1)	2.9(4.1)
	All	3.2(3.6)	12(12)	4.3(5.3)	5.0(6.0)
Gas ($ Million)	0-5	3.5(4.2)	4.7(10)	17(-)	4.5(9)
	5-10	3.0(3.2)	8.9(11)	6.4(7.5)	7.6(9.9)
	≥10	16(38)	4.9(6.2)	28(58)	24(52)
	All	6.2(18)	6.1(11)	24(53)	11(30)

Note: Standard deviation denoted in parenthesis.

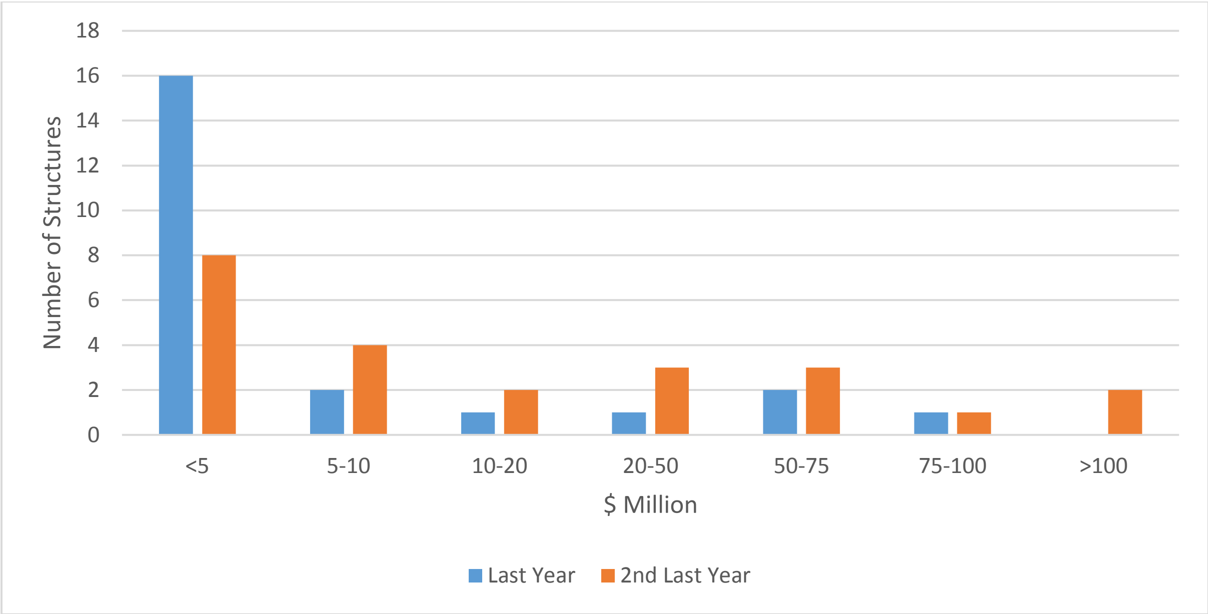


Figure J.1. Deepwater decommissioned structures gross revenue near the end of production (Million 2017$)
Source: BOEM 2018

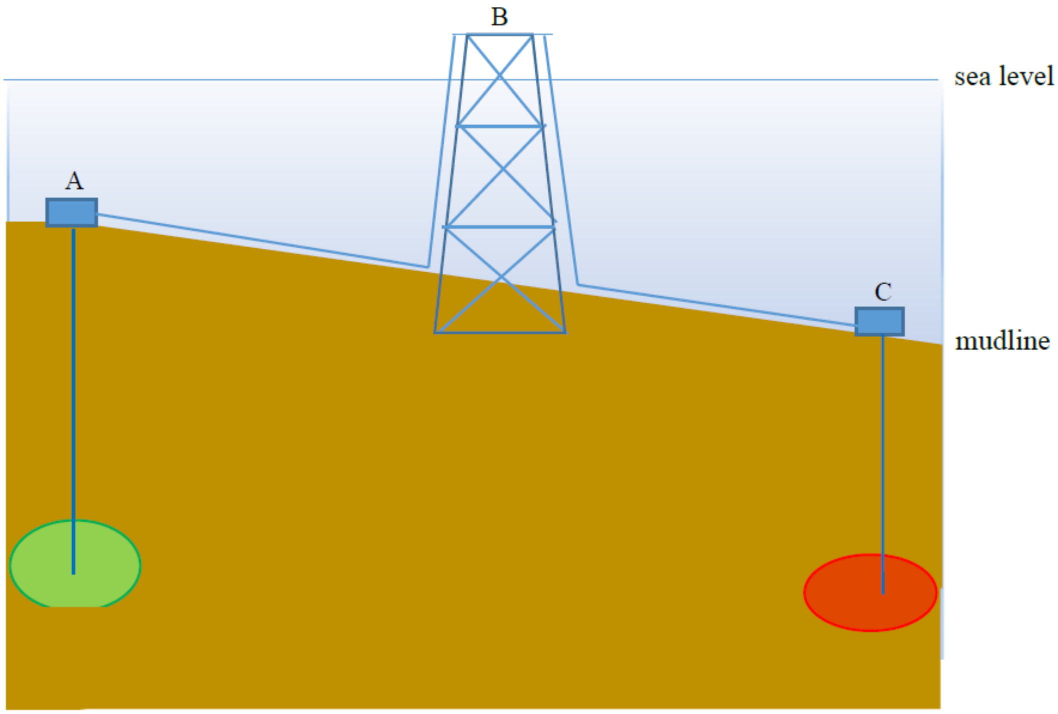


Figure J.2. Subsea development illustrating differences in tieback distance and altitude

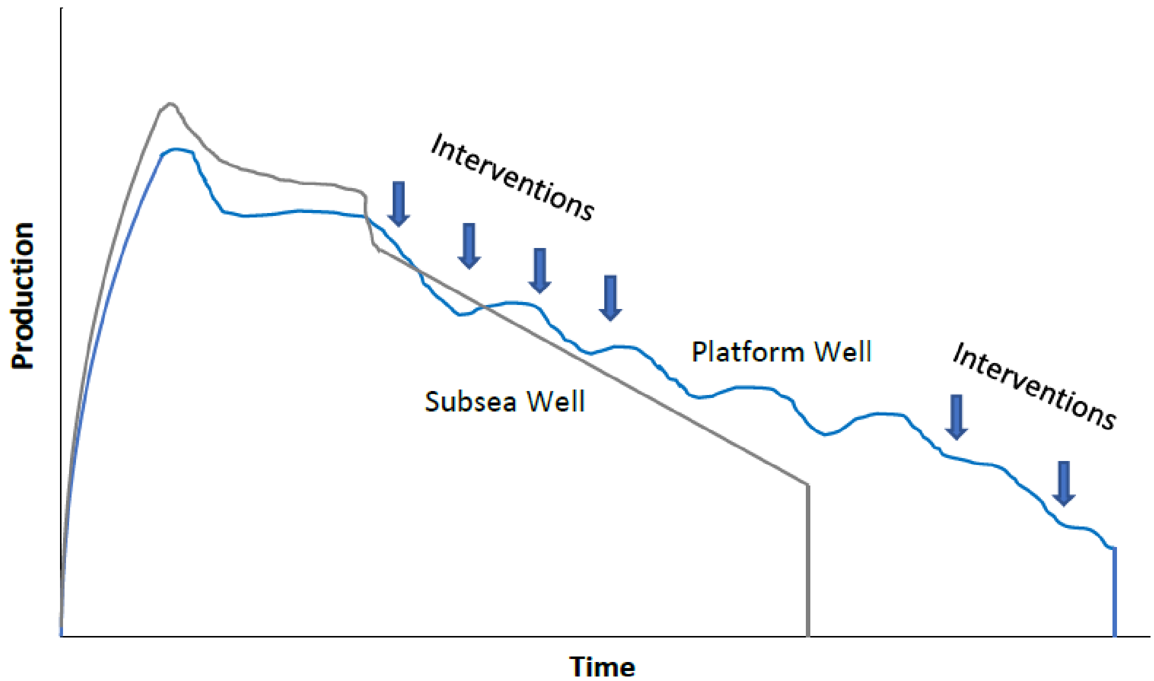


Figure J.3. Schematic of platform well production with regular interventions vs. subsea wells without intervention

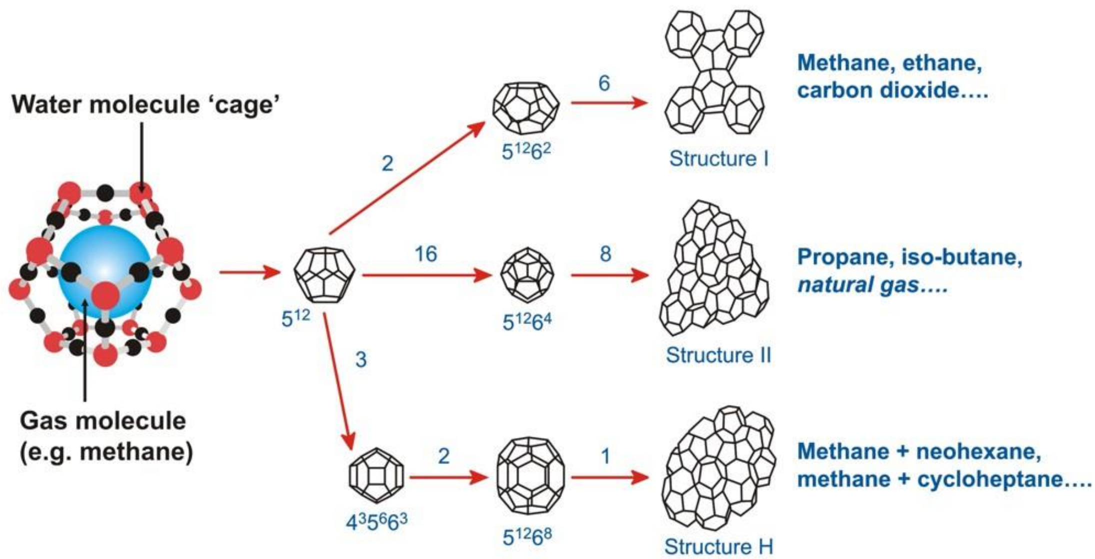


Figure J.4. Molecular representation of hydrate cages for different captive species
Source: Institute of Petroleum Engineering, Heriot Watt University

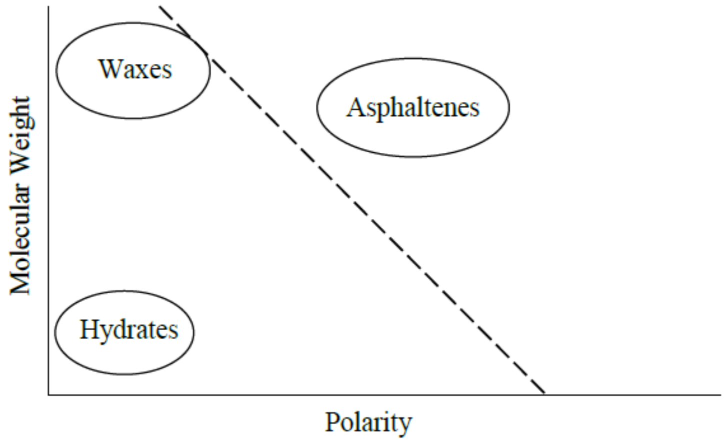


Figure J.5. Hydrocarbon molecular weight and polarity define the presence of asphaltenes

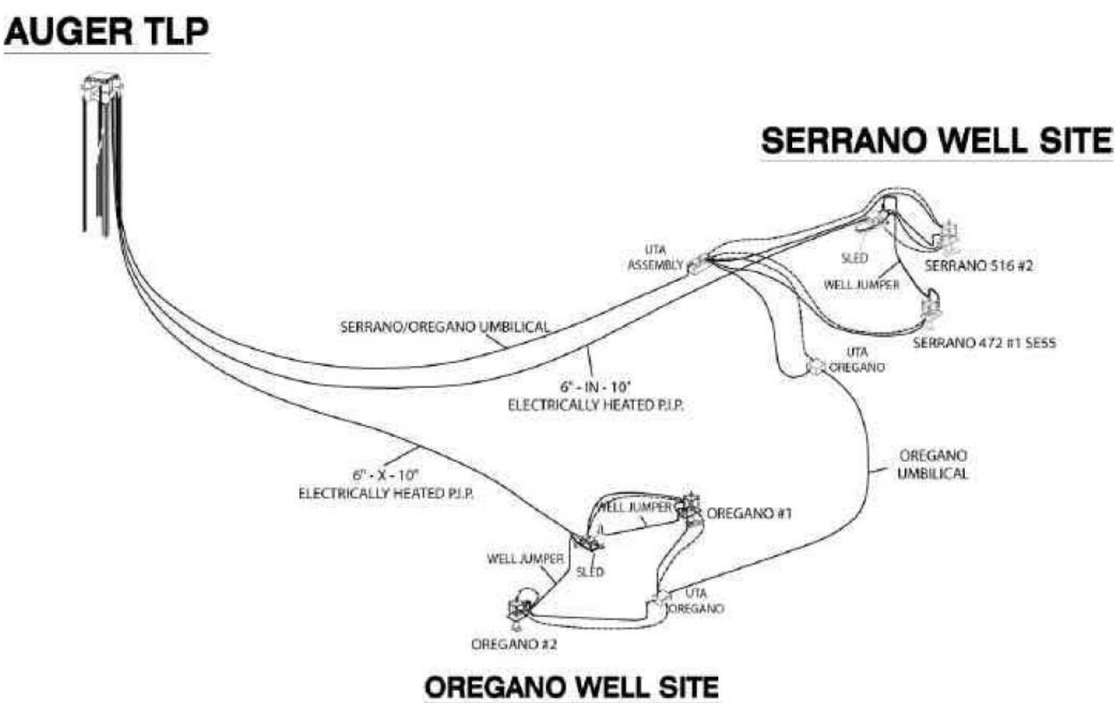


Figure J.6. Serrano and Oregano field layout
Source: Hale and Clegg 2001

APPENDIX K

CHAPTER 11 TABLES AND FIGURES

Table K.1. Structure inventories by production class circa 2016

Class	Shallow (%)	Deepwater (%)
Producing	960 (48%)	86 (88%)
Idle	675 (34%)	7 (7%)
Auxiliary	374 (19%)	5 (5%)

Source: BOEM July 2017

Table K.2. Producing structure decommissioning forecast model parameters

Parameter	Notation	Range, Type or Value
Decline model	$q(b, D)$	Exponential (D), Hyperbolic (b, D)
Commodity price	P^{oil}, P^{cond}; P^{gas}, P^{ass}	\$40, \$60, \$80/bbl; \$2, \$3, \$4/Mcf
Economic limit	EL	\$200, \$300, \$400, \$500, \$1000 M
Regulatory	τ ; roy	1 yr; 16.67%

Table K.3. Oil and gas structure hydrocarbon liquid and gas prices and typical relationships

	Oil Structure	Gas Structure	Relation	Typical Range
Crude (\$/bbl)	P^{oil}	P^{cond}	$P^{oil} > P^{cond}$	$P^{cond} = (0.4\text{-}0.6)\ P^{oil}$
Gas (\$/Mcf)	P^{ass}	P^{gas}	$P^{ass} > P^{gas}$	$P^{ass} = (1.2\text{-}1.5)\ P^{gas}$

Table K.4. Idle inventory in the shallow water Gulf of Mexico by idle age circa 2016

Idle Age (yr)	Idle Structures	p	$I(\leq p)$	$I(> p)$
1-2	111	2	111	564
2-3	84	3	195	480
3-4	49	4	244	431
4-5	51	5	295	380
5-6	33	6	328	347
6-7	35	7	363	312
7-8	25	8	388	287
8-9	21	9	409	266
9-10	22	10	431	244
>10	244		675	

Source: BOEM April 2017

Table K.5. Normalization of two scenarios for idle schedule

Scenario	1	2	3	4	5	6	7	8	9	10	RowSum
(10, 10, 5)	91.9	91.9	91.9	91.9	91.9	43.1	43.1	43.1	43.1	43.1	675
(7, 5, 3)	176.6	176.6	176.6	72.6	72.6						675
Column Sum	268.5	268.5	268.5	164.5	164.5	43.1	43.1	43.1	43.1	43.1	1350
% Activity	0.20	0.20	0.20	0.12	0.12	0.03	0.03	0.03	0.03	0.03	1.00

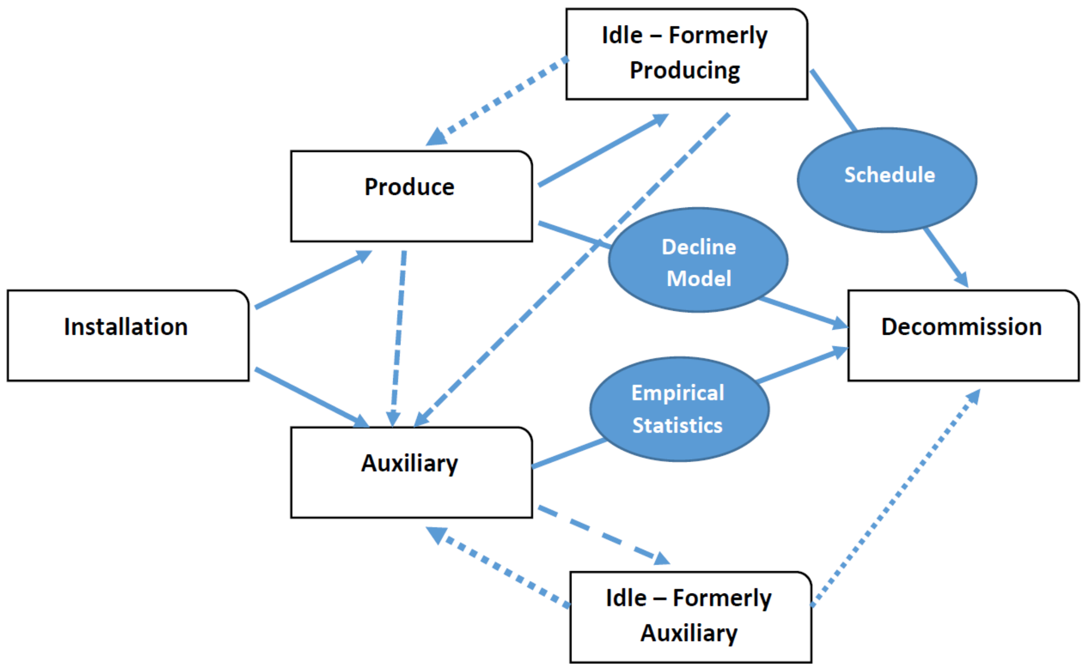


Figure K.1. Decommissioning forecast and schedule models in shallow water

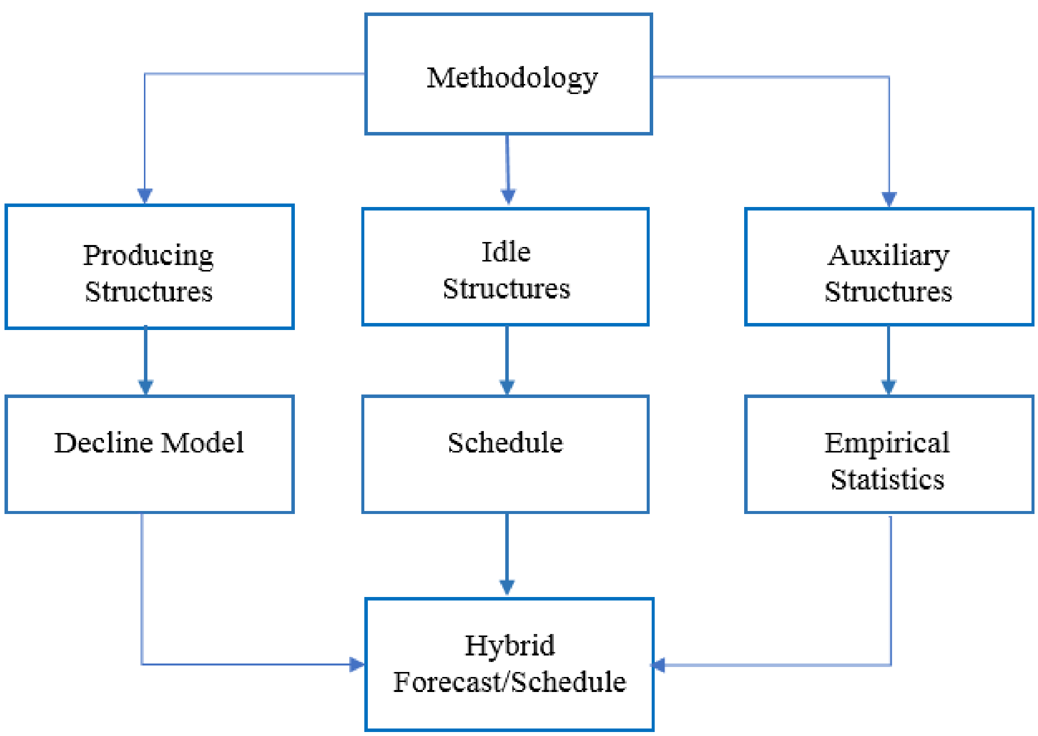


Figure K.2. Flowchart for shallow water structure decommissioning forecast

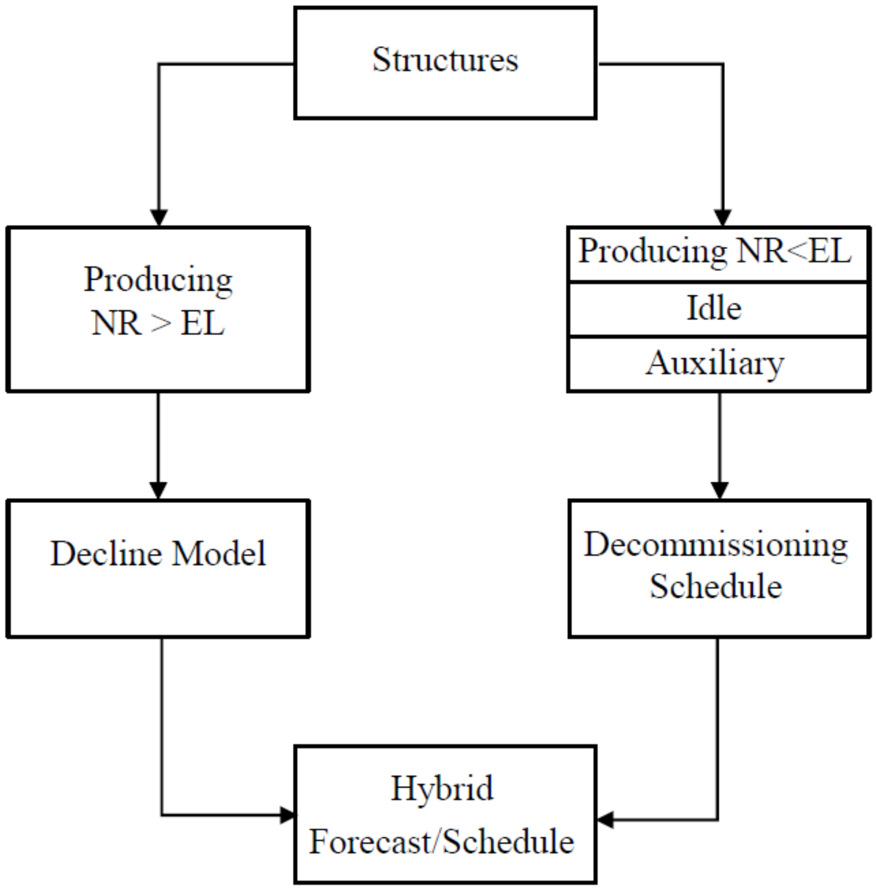


Figure K.3. Flowchart for deepwater structure decommissioning forecast

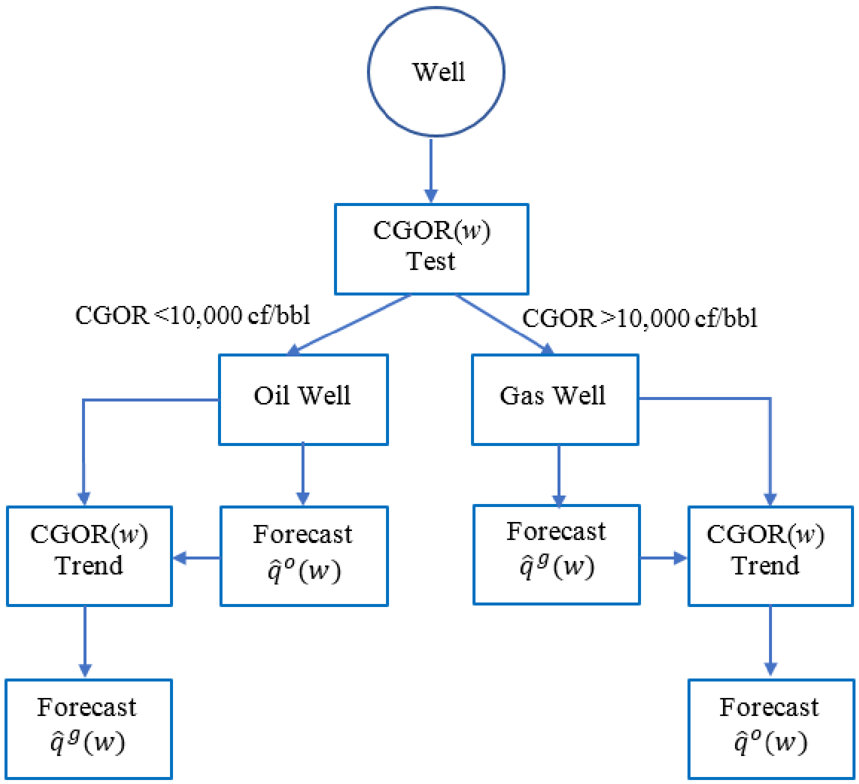


Figure K.4. Well forecast methodology using the primary forecast and CGOR trends

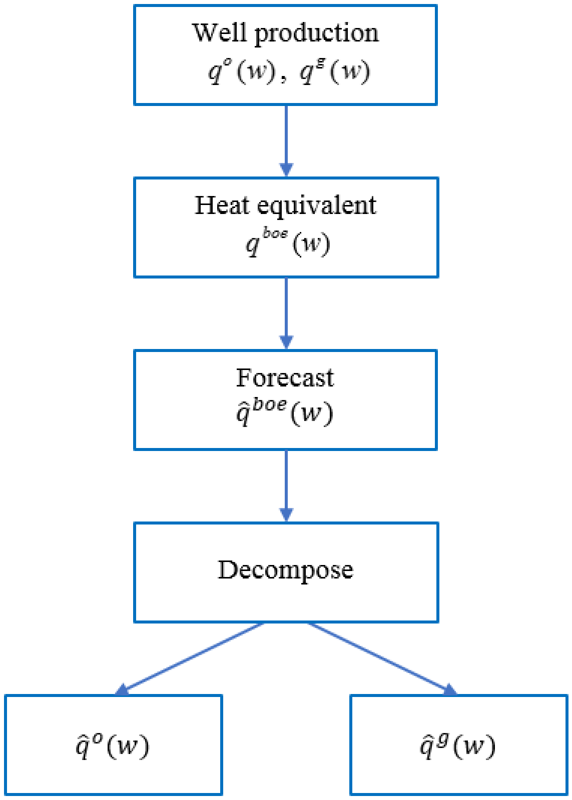


Figure K.5. Well forecast methodology using the composite heat-equivalent stream and decomposition

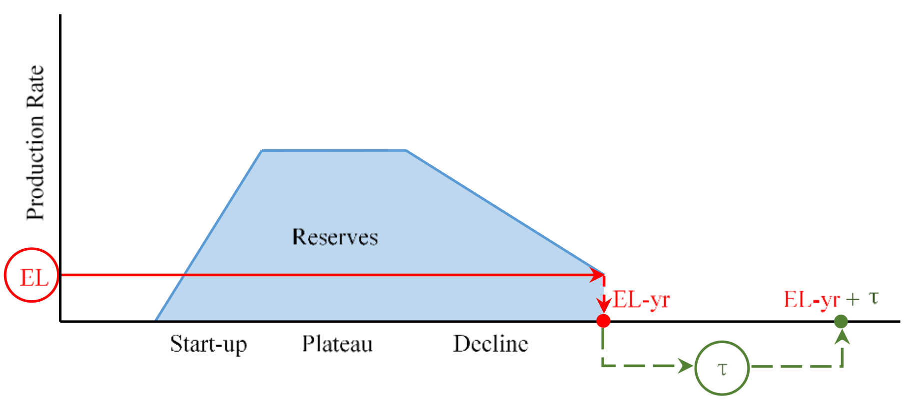


Figure K.6. Decommissioning forecast showing input and model parameters

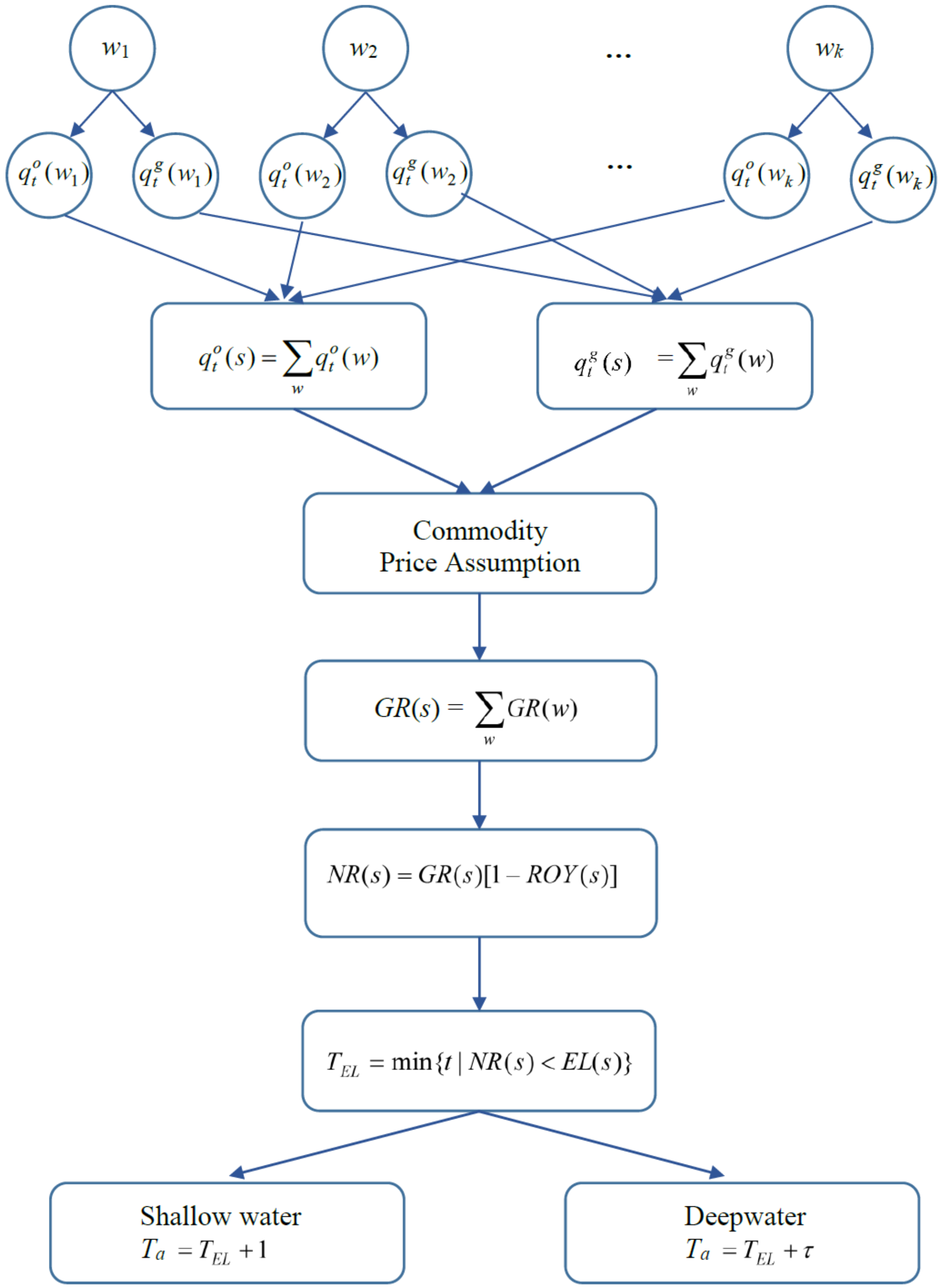


Figure K.7. Flowchart of structure decommissioning forecast procedure

APPENDIX L

CHAPTER 12 TABLES AND FIGURES

Table L.1. Tick well inventory circa January 2013

API Number	First Production	Status/Wet	Cumulative Production Oil (Mbbl)	Cumulative Production Gas (MMcf)	GOR (Mcf/bbl)
608074005100	1992	Idle	683	1905	3
608074005500		Dry hole	-	-	
608074005501	1998	Idle	29	14,009	486
608074005900		Dry hole	-	-	
608074005901	1992	Idle	165	2091	13
608074005902	1997	Idle	139	2714	20
608074009200	1992	Idle	250	2189	9
608074009201	1994	Producing	266	38,076	143
608074009500		TA	-	-	
608074009501	1992	TA	493	6255	13
608074009600		Dry hole	-	-	
608074009601	1992	Idle	0	10,824	69,829
608074010700	1992	Idle	2317	19,036	8
608074010800	1992	Producing	4887	16,498	3
608074010900	1992	Idle	2430	10,607	4
608074011000	1992	Idle	660	12,002	18
608074011100	1992	Idle	540	18,057	33
608074011200	1993	Idle	75	5144	69
608074011400	1993	Idle	303	24,040	79
608074011500	1993	Producing	187	16,975	91
608074011600	1993	Idle	100	23,632	236
608074012000		Dry hole			
608074012001	1993	Idle	1658	6700	4
608074012400	1993	Idle	188	933	5
608074012600	1994	Idle	1187	1801	2
608074012700		Dry hole	-	-	
608074012701	1994	Idle	911	14,043	15
608074016300	2001	Producing/wet	6912	7303	1
608074063500	1997	Idle/wet	1632	1453	1
608074063501	2007	Producing/wet	2634	3126	1
Total	-	-	28,648	259,414	9

Source: BOEM, June 2013

Table L.2. Tick's producing wells and estimated reserves circa 2012

API Number	Best-fit Parameter			Remaining Production			Total Production		
	b	D	R^2	Oil (Mbbl)	Gas (MMcf)	Boe (Mboe)	Oil (Mbbl)	Gas (MMcf)	Boe (Mboe)
608074009201	0.13	0.19	0.96	5	1350	230	271	39,426	6842
608074010800	0.00	0.23	0.94	35	121	56	4923	16,619	7692
608074011500	1.00	0.35	0.88	5	453	81	192	17,428	3097
608074016300	0.39	0.45	0.89	15	16	18	6927	7319	8147
608074063501	0.00	0.40	0.97	208	248	249	2842	3374	3405
Total				269	2188	633	15,155	84,167	29,183

Note: Remaining production estimates are based on $100/bbl oil price and $4/Mcf gas price.

Table L.3. Tick primary product stream forecast circa 2012

Well	09201	10800	11500	16300	63501	Structure	
Primary	Gas	Oil	Gas	Oil	Oil	Oil	Gas
Unit	MMcf	Mbbl	MMcf	Mbbl	Mbbl	Mbbl	MMcf
1992	-	235	-	-	-	235	-
1993	-	530	24	-	-	530	24
1994	1264	447	46	-	-	447	1310
1995	2179	627	168	-	-	627	2347
1996	3377	649	129	-	-	649	3506
1997	4187	616	134	-	-	616	4321
1998	4571	585	241	-	-	585	4812
1999	4182	430	2083	-	-	430	6266
2000	3529	198	2641	-	-	198	6170
2001	2724	160	2111	526	-	686	4835
2002	2081	108	1641	1789	-	1897	3722
2003	1612	82	1290	1551	-	1633	2902
2004	1578	68	889	700	-	768	2466
2005	1172	41	722	396	-	436	1894
2006	1031	39	950	220	-	259	1981
2007	1006	12	798	463	973	1448	1804
2008	773	2	527	350	616	968	1300
2009	164	0	121	230	490	721	286
2010	1067	7	974	445	349	801	2041
2011	809	22	765	225	157	404	1574
2012	770	30	720	17	49	96	1490
2013	409	12	308	9	86	108	716
2014	356	10	146	6	58	73	502
2015	311	8	-	-	38	46	311
2016	273	6	-	-	26	32	273
Cumulative	38,076	4887	16,975	6912	2634	14,433	55,052
Remaining	1350	35	453	15	208	258	1803
Total	39,426	4923	17,428	6927	2842	14,692	56,854

Source: BOEM, June 2013
Note: Oil price = $100/bbl, gas price = $4/Mcf.

Table L.4. Tick secondary product stream forecast circa 2012

Well	09201	10800	11500	16300	63501	Structure	
Secondary	Oil	Gas	Oil	Gas	Gas	Oil	Gas
Unit	Mbbl	MMcf	Mbbl	MMcf	MMcf	Mbbl	MMcf
1992	-	257	-	-	-	-	257
1993	-	1181	12	-	-	12	1181
1994	23	1147	17	-	-	40	1147
1995	34	2057	31	-	-	65	2057
1996	46	1883	33	-	-	79	1883
1997	54	1572	32	-	-	86	1572
1998	40	1653	14	-	-	54	1653
1999	28	1203	17	-	-	45	1203
2000	16	801	14	-	-	30	801
2001	9	1735	9	476	-	18	2211
2002	5	1359	4	2194	-	9	3553
2003	3	793	1	1773	-	4	2566
2004	3	438	0	733	-	3	1171
2005	1	84	0	466	-	1	550
2006	1	130	0	266	-	1	396
2007	1	53	0	335	1090	1	1478
2008	1	24	1	192	742	1	958
2009	0	4	0	182	546	0	732
2010	1	12	0	414	517	1	942
2011	0	41	0	242	155	1	438
2012	0	74	0	31	75	0	179
2013	2	42	3	10	103	5	154
2014	1	33	2	6	69	3	108
2015	1	26	-	-	46	1	72
2016	1	21	-	-	31	1	51
Cumulative	266	16,498	187	7303	3126	453	26,927
Remaining	5	121	5	16	248	10	386
Total	271	16,619	192	7319	3374	463	27,313

Source: BOEM, June 2013

Note: Oil price = \$100/bbl, gas price = \$4/Mcf.

Table L.5. Tick revenue forecast per wellbore circa 2012 (million $)

Well	09201	10800	11500	16300	63501	Total
Unit	million $	million $	million $	million $	million $	million $
1992	-	5.3	-	-	-	5.3
1993	-	12.3	0.3	-	-	12.6
1994	2.8	9.9	0.4	-	-	13.1
1995	4.3	15.0	0.8	-	-	20.2
1996	10.3	19.6	1.1	-	-	31.0
1997	11.7	16.7	1.0	-	-	29.4
1998	10.1	11.9	0.7	-	-	22.7
1999	10.0	11.0	5.0	-	-	26.1
2000	15.4	9.4	11.6	-	-	36.4
2001	11.3	11.2	8.8	15.6	-	46.9
2002	7.1	7.3	5.6	54.1	-	74.1
2003	9.1	7.0	7.3	58.2	-	81.6
2004	9.3	5.3	5.2	32.5	-	52.3
2005	10.3	2.9	6.3	24.6	-	44.2
2006	7.0	3.4	6.4	15.9	-	32.7
2007	7.0	1.2	5.6	36.1	78.5	128.5
2008	6.9	0.4	4.7	38.2	70.9	121.2
2009	0.6	0.0	0.5	14.8	32.2	48.1
2010	4.7	0.6	4.3	37.1	29.9	76.7
2011	3.3	2.6	3.1	25.3	17.6	52.0
2012	2.1	3.4	2.0	1.9	5.5	15.0
2013	1.8	1.4	1.6	1.0	9.0	14.8
2014	1.6	1.1	0.7	0.6	6.0	10.0
2015	1.4	0.9	-	-	4.0	6.3
2016	1.2	0.7	-	-	2.7	4.6
Cumulative	143.7	156.4	80.8	354.3	234.7	969.9
Remaining	5.9	4.0	2.3	1.6	21.8	35.6
Total	149.6	160.4	83.1	355.9	256.5	1005.5

Source: BOEM, June 2013
Note: Oil price = $100/bbl, gas price = $4/Mcf.

Table L.6. Economic limit sensitivity analysis circa 2012 (T_{EL})

Oil Price ($/bbl)	Gas Price ($/Mcf)			
	2	4	6	8
60	2015	2015	2016	2016
80	2015	2016	2016	2017
100	2016	2016	2017	2017
120	2016	2017	2017	2017

Table L.7. Proved reserves sensitivity analysis circa 2012 (Mboe)

Oil Price ($/bbl)	Gas Price ($/Mcf)			
	2	4	6	8
60	528	528	630	630
80	546	624	647	708
100	587	633	708	715
120	633	715	715	715

Table L.8. Reserves valuation sensitivity analysis circa 2012 (million $)

Oil Price ($/bbl)	Gas Price ($/Mcf)			
	2	4	6	8
60	7	10	14	18
80	11	15	19	24
100	16	20	25	29
120	21	26	30	34

Note: Assumes 10% discount rate, 16.7% royalty rate, and $15/boe operating cost.

Table L.9. Horn Mountain well inventory circa 2016

API Number	First Production	Status	Well Type	Cumulative Production		GOR (Mcf/bbl)
				Oil (MMbbl)	Gas (Bcf)	
608174092700	2003	Producing	Oil	17.6	16.0	0.91
608174093000	2002	Idle	Oil	7.6	6.3	0.83
608174093100		Dry hole				
608174093101	2003	Producing	Oil	8.2	7.9	0.97
608174093200	2003	Producing	Oil	15.1	12.0	0.79
608174093300	2003	Producing	Oil	9.7	11.1	1.14
608174093400	2003	Idle	Oil	8.7	8.1	0.92
608174093500		Dry hole				
608174093600	2002	Producing	Oil	22.6	17.4	0.77
608174093700	2003	Producing	Oil	24.0	19.4	0.81
608174095200		Dry hole				
608174130600	2016	Producing	Oil	0.2	1.1	4.64
608174131100	2016	Producing	Oil	0.6	1.6	2.76
608174131900		Dry hole				

Source: BOEM, June 2017

Table L.10. Summary of best-fit parameters, remaining and total production for producing wells circa 2016

API Well Number	Best-fit Parameter			Remaining Production			Total Production		
	b	D	R^2	Oil (MMbbl)	Gas (Bcf)	Boe (MMboe)	Oil (Mbbl)	Gas (MMcf)	Boe (Mboe)
608174092700	0.78	0.40	0.96	0.67	0.56	0.76	18.23	16.56	20.99
608174093101	0.48	0.57	0.98	0.91	0.86	1.05	9.07	8.73	10.52
608174093200	0.00	0.32	0.96	0.18	0.13	0.20	15.26	12.11	17.27
608174093300	1.00	0.66	0.97	2.34	2.79	2.81	12.05	13.89	14.36
608174093600	0.00	0.12	0.86	6.73	4.97	7.56	29.35	22.42	33.09
608174093700	0.24	0.12	0.95	6.70	5.25	7.57	30.70	24.65	34.81
608174130600	0.35	0.47		0.59	2.73	1.04	0.83	3.85	1.47
608174131100	0.35	0.47		1.46	4.02	2.13	2.02	5.58	2.95
Total				19.58	21.31	23.13	117.51	107.79	135.47

Note: Best-fit parameters for subsea wells 608174130600 and 608174131100 apply average b and D parameters from dry tree wells.

Table L.11. Horn Mountain primary product stream forecast circa 2016

Well	92700	93101	93200	93300	93600	93700	30600	31100	Structure
Primary	Oil	Oil	Oil	Oil	Oil	Oil	Oil	Oil	Oil
Unit	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
2002	0	0	0	0	67	0	0	0	67
2003	2229	1335	2553	1479	3088	3092	0	0	13,777
2004	3286	2068	3522	2071	2499	3046	0	0	16,492
2005	2348	1421	2822	984	2109	2486	0	0	12,170
2006	1974	812	2662	972	2292	2387	0	0	11,100
2007	1313	389	1397	763	2101	2047	0	0	8010
2008	1095	368	692	591	2250	1701	0	0	6697
2009	1054	353	554	529	1940	1542	0	0	5973
2010	771	365	171	418	1305	1449	0	0	4479
2011	464	212	260	265	625	942	0	0	2768
2012	298	199	178	311	693	1021	0	0	2701
2013	717	129	26	363	1056	1137	0	0	3427
2014	713	175	109	317	999	1181	0	0	3493
2015	698	174	100	363	822	1004	0	0	3162
2016	602	156	32	276	777	963	242	566	3615
2017	150	87	57	223	695	700	156	366	2433
2018	118	77	41	187	626	630	107	250	2036
2019	93	68	30	161	564	567	77	179	1739
2020	74	61	22	141	508	510	57	133	1505
2021	58	55	16	126	458	458	43	101	1315
2022	46	50	12	113	412	412	34	79	1158
2023	36	46		103	371	371	27	63	1017
2024	28	42		95	334	333	22	51	906
2025	22	38		88	301	300	18	42	809
2026	18	35		81	271	270	15	35	725
2027	14	32		76	245	242	13	29	651
2028	11	30		71	220	218	11	25	586
2029		28		67	198	196	9	21	520
2030		26		63	179	176		19	463
2031		24		60	161	159		16	420
2032		23		57	145	143		14	382
2033		21		54	131	128		12	347
2034		20		52	118	115		11	316
2035		19		50	106	104		10	288
2036		18		48	96	93			254
2037		17		46	86	84			233
2038		16		44	78	75			213
2039		15		42	70	68			195
2040		14		41	63	61			179
2041		13		40	57	55			165
2042		13		38	51	49			151
2043		12		37	46	44			140
2044		12		36	42	40			129
2045				35	37	36			108
2046				34	34	32			100
2047				33	30	29			92
Cumulative	17,562	8157	15,078	9704	22,622	23,998	242	566	97,930
Remaining	669	911	177	2342	6733	6700	588	1457	19,576
Total	18,231	9068	15,255	12,046	29,355	30,698	830	2023	117,506

Source: BOEM, June 2017

Note: Oil price = $60/bbl, gas price = $3/Mcf.

Table L.12. Horn Mountain secondary product stream forecast circa 2016

Well	92700	93101	93200	93300	93600	93700	30600	31100	Structure
Secondary	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Unit	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf
2002	0	0	0	0	54	0	0	0	54
2003	2253	1254	2037	1605	2525	2607	0	0	12,282
2004	3165	1905	2805	2331	2017	2530	0	0	14,753
2005	2051	1243	2139	1200	1647	1994	0	0	10,273
2006	1640	833	1943	1340	1683	1826	0	0	9266
2007	1114	480	1117	948	1517	1622	0	0	6798
2008	912	390	555	773	1542	1325	0	0	5497
2009	890	398	490	638	1328	1188	0	0	4931
2010	676	362	126	428	1067	1251	0	0	3909
2011	409	228	246	263	502	774	0	0	2422
2012	291	170	101	282	550	805	0	0	2199
2013	706	93	2	348	895	952	0	0	2995
2014	658	194	200	327	820	987	0	0	3187
2015	617	172	181	333	663	828	0	0	2794
2016	611	149	35	289	634	711	1125	1561	5115
2017	127	82	43	265	515	550	726	1008	3315
2018	100	73	31	222	464	495	497	690	2570
2019	79	65	23	191	417	445	356	494	2068
2020	62	58	17	168	376	400	264	366	1709
2021	49	52	12	149	338	359	201	279	1440
2022	39	47	9	135	305	323	157	218	1232
2023	30	43		123	274	290	125	174	1060
2024	24	39		113	247	261	101	141	926
2025	19	36		104	222	235	83	116	815
2026	15	33		97	200	211	69	96	722
2027	12	31		90	180	190	58	81	642
2028	9	28		85	162	171	50	69	574
2029		26		80	146	153	43	59	508
2030		25		76	132	138		51	421
2031		23		72	119	124		44	382
2032		21		68	107	112		39	347
2033		20		65	96	100		34	316
2034		19		62	87	90		30	288
2035		18		59	78	81		27	263
2036		17		57	70	73			217
2037		16		55	63	66			199
2038		15		52	57	59			183
2039		14		51	51	53			169
2040		13		49	46	48			156
2041		13		47	42	43			144
2042		12		46	38	39			134
2043		11		44	34	35			124
2044		11		43	31	31			115
2045				41	28	28			97
2046				40	25	25			90
2047				39	22	23			84
Cumulative	15,994	7871	11,975	11,104	17,444	19,400	1125	1561	86,474
Remaining	563	861	134	2785	4973	5249	2730	4016	21,313
Total	16,557	8733	12,110	13,889	22,418	24,649	3854	5577	107,787

Source: BOEM, June 2017

Note: Oil price = $60/bbl, gas price = $3/Mcf.

Table L.13. Horn Mountain revenue forecast per wellbore (million $)

Well	92700	93101	93200	93300	93600	93700	30600	31100	Structure
Primary	Oil	Oil	Oil	Oil	Oil	Oil	Oil	Oil	Oil
Unit	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
2002	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	1.9
2003	81.9	48.5	90.8	55.0	110.1	110.7	0.0	0.0	497.1
2004	150.7	94.3	158.2	97.0	112.4	137.4	0.0	0.0	749.9
2005	140.0	84.8	165.4	61.7	124.0	146.7	0.0	0.0	722.5
2006	137.5	57.6	183.6	71.3	158.2	165.2	0.0	0.0	773.5
2007	103.5	31.7	109.6	62.2	163.8	160.6	0.0	0.0	631.4
2008	122.5	41.9	77.2	68.6	248.8	189.5	0.0	0.0	748.5
2009	68.1	23.2	35.8	34.9	124.0	99.1	0.0	0.0	385.1
2010	64.1	30.5	14.1	35.0	108.1	120.4	0.0	0.0	372.2
2011	52.0	24.0	29.1	29.8	69.8	105.2	0.0	0.0	310.0
2012	32.8	21.9	19.5	34.3	76.0	112.0	0.0	0.0	296.4
2013	78.9	14.0	2.8	39.9	115.6	124.4	0.0	0.0	375.5
2014	70.2	17.3	11.2	31.3	97.9	115.8	0.0	0.0	343.6
2015	35.1	8.8	5.3	18.3	41.1	50.3	0.0	0.0	158.8
2016	26.0	6.7	1.4	11.9	33.1	40.8	12.7	26.9	159.5
2017	9.4	5.5	3.5	14.2	43.2	43.7	11.6	25.0	156.0
2018	7.4	4.8	2.6	11.9	38.9	39.3	7.9	17.1	129.9
2019	5.8	4.3	1.9	10.2	35.1	35.3	5.7	12.2	110.5
2020	4.6	3.9	1.4	9.0	31.6	31.8	4.2	9.1	95.4
2021	3.6	3.5	1.0	8.0	28.5	28.6	3.2	6.9	83.2
2022	2.9	3.1	0.7	7.2	25.6	25.7	2.5	5.4	73.2
2023	2.3	2.9		6.6	23.1	23.1	2.0	4.3	64.2
2024	1.8	2.6		6.0	20.8	20.8	1.6	3.5	57.1
2025	1.4	2.4		5.6	18.7	18.7	1.3	2.9	51.0
2026	1.1	2.2		5.2	16.9	16.8	1.1	2.4	45.7
2027	0.9	2.0		4.8	15.2	15.1	0.9	2.0	41.0
2028	0.7	1.9		4.5	13.7	13.6	0.8	1.7	36.9
2029		1.8		4.3	12.3	12.2	0.7	1.5	32.7
2030		1.6		4.0	11.1	11.0		1.3	29.0
2031		1.5		3.8	10.0	9.9		1.1	26.4
2032		1.4		3.6	9.0	8.9		1.0	23.9
2033		1.3		3.5	8.1	8.0		0.9	21.8
2034		1.3		3.3	7.3	7.2		0.8	19.8
2035		1.2		3.2	6.6	6.5		0.7	18.1
2036		1.1		3.0	5.9	5.8			15.9
2037		1.0		2.9	5.4	5.2			14.5
2038		1.0		2.8	4.8	4.7			13.3
2039		0.9		2.7	4.3	4.2			12.2
2040		0.9		2.6	3.9	3.8			11.2
2041		0.8		2.5	3.5	3.4			10.3
2042		0.8		2.4	3.2	3.1			9.5
2043		0.8		2.4	2.9	2.8			8.7
2044		0.7		2.3	2.6	2.5			8.1
2045				2.2	2.3	2.2			6.8
2046				2.1	2.1	2.0			6.3
2047				2.1	1.9	1.8			5.8
Cumulative	1163	505	904	651	1585	1678	13	27	6526
Remaining	42	57	11	149	419	418	43	99	1239
Total	1205	563	915	800	2004	2096	56	126	7764

Note: Oil price = $60/bbl, gas price = $3/Mcf.

Table L.14. Economic limit sensitivity analysis (T_{EL})

Oil Price ($/bbl)	Gas Price ($/Mcf)			
	2	3	4	5
40	2042	2042	2043	2043
60	2047	2047	2047	2047
80	2051	2051	2051	2051
100	2056	2056	2056	2056

Table L.15. Proved reserves sensitivity analysis (Mboe)

Oil Price ($/bbl)	Gas Price ($/Mcf)			
	2	3	4	5
40	22,205	22,283	22,429	22,466
60	23,098	23,128	23,128	23,142
80	23,609	23,609	23,621	23,621
100	24,038	24,038	24,038	24,046

Table L.16. Reserves valuation sensitivity analysis (million $)

Oil Price ($/bbl)	Gas Price ($/Mcf)			
	2	3	4	5
40	199	211	222	233
60	393	405	416	427
80	588	599	610	621
100	782	793	805	816

Note: Assumes 10% discount rate, 16.67% royalty rate, and $15/boe operating cost.

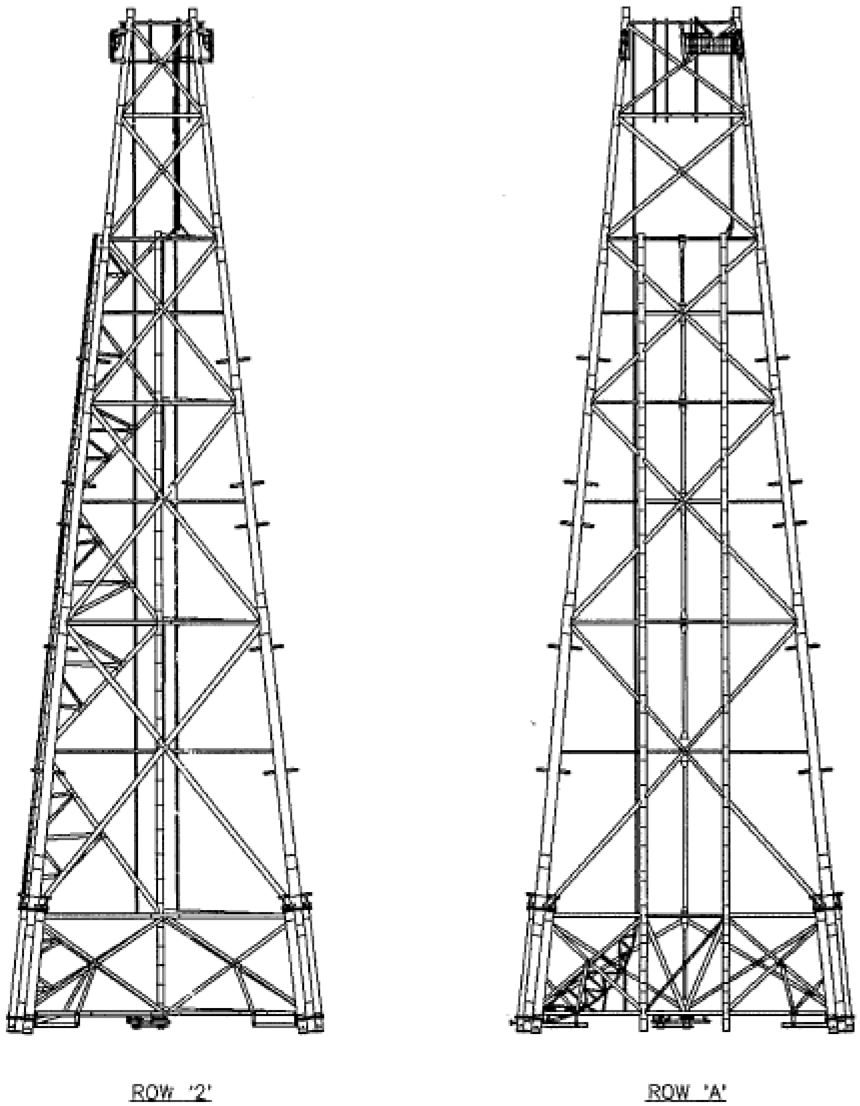


Figure L.1. Garden Banks 189 (Tick) platform was installed in 1991 in 720 ft water depth
Source: Chevron

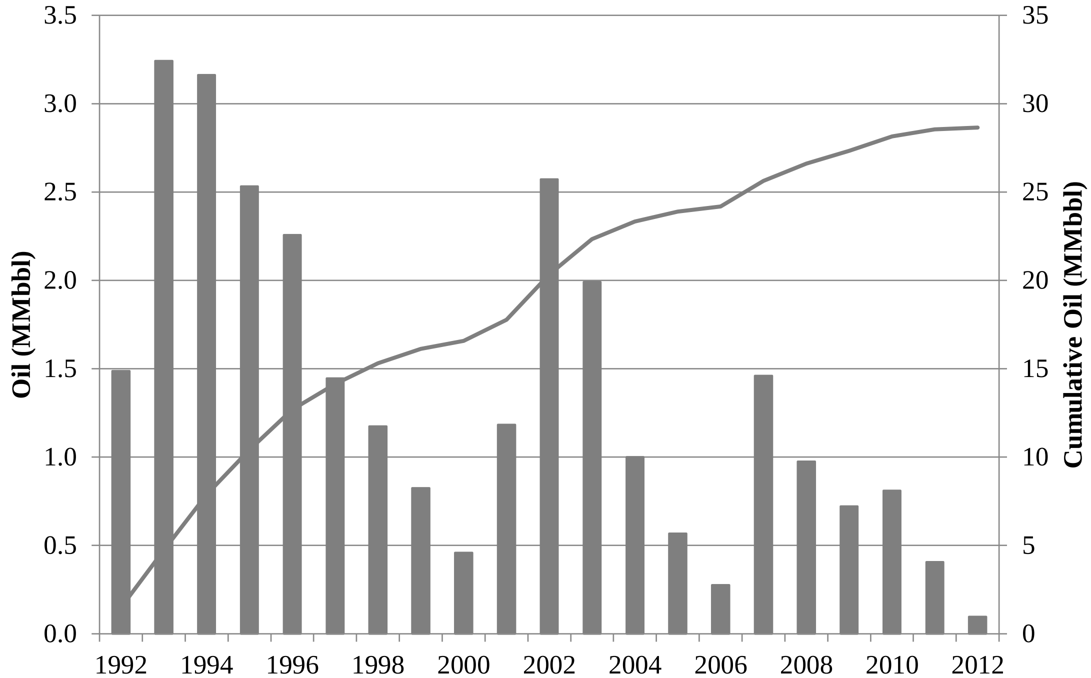


Figure L.2. Tick oil production, 1992-2012
Source: BOEM, June 2013

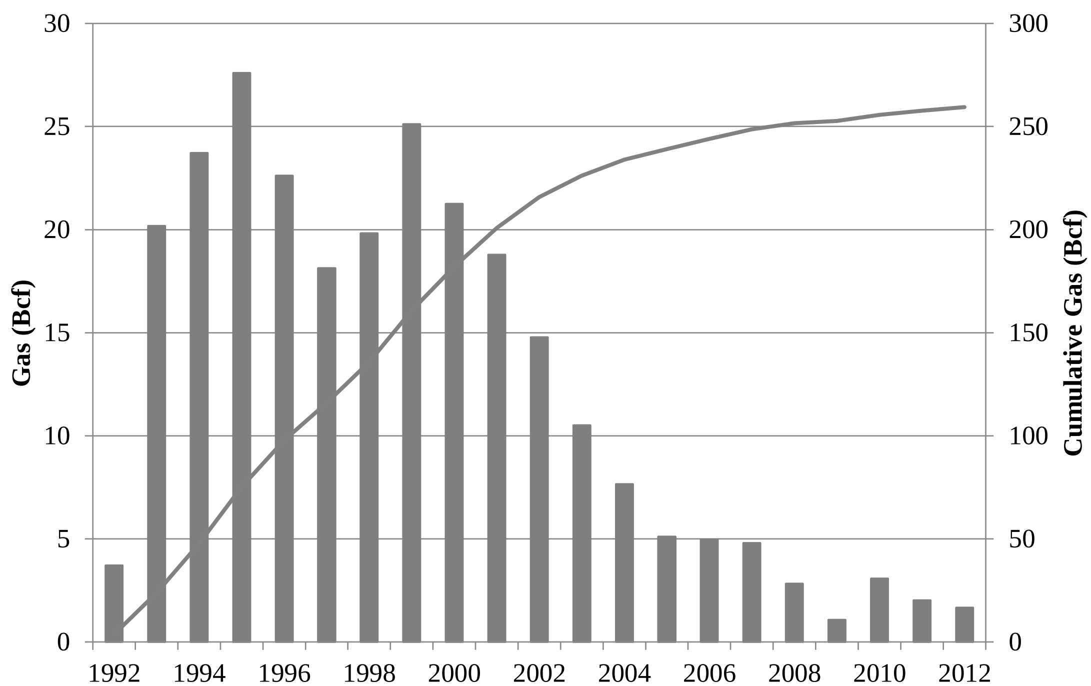


Figure L.3. Tick gas production, 1992-2012
Source: BOEM, June 2013

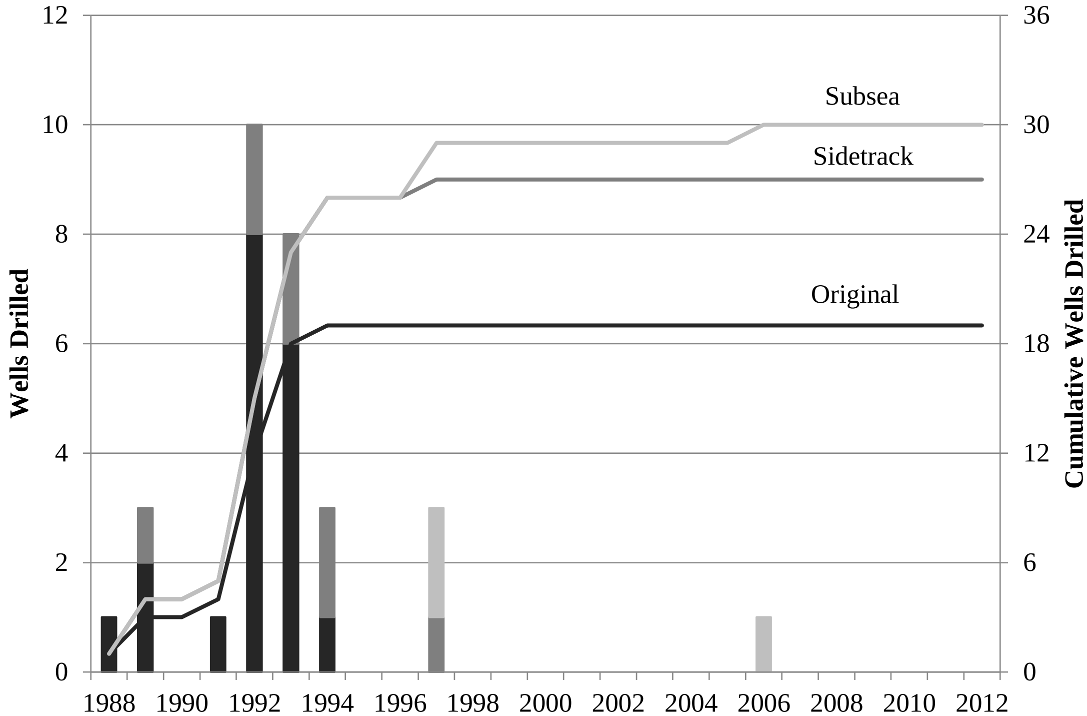
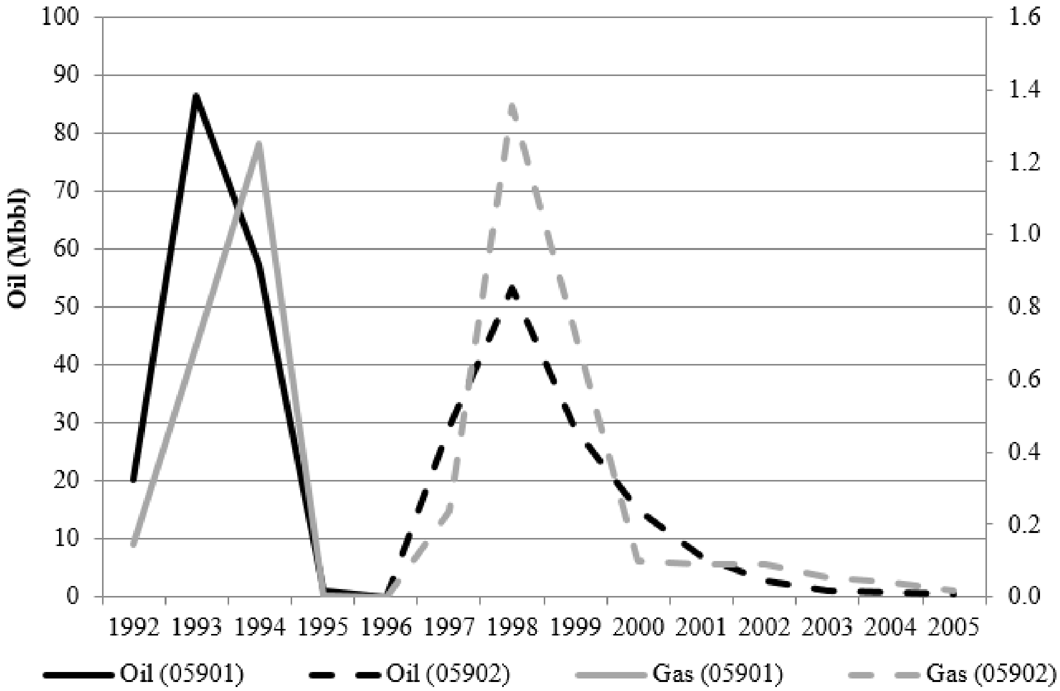


Figure L.4. Tick drilling and subsea tieback schedule
Source: BOEM, June 2013



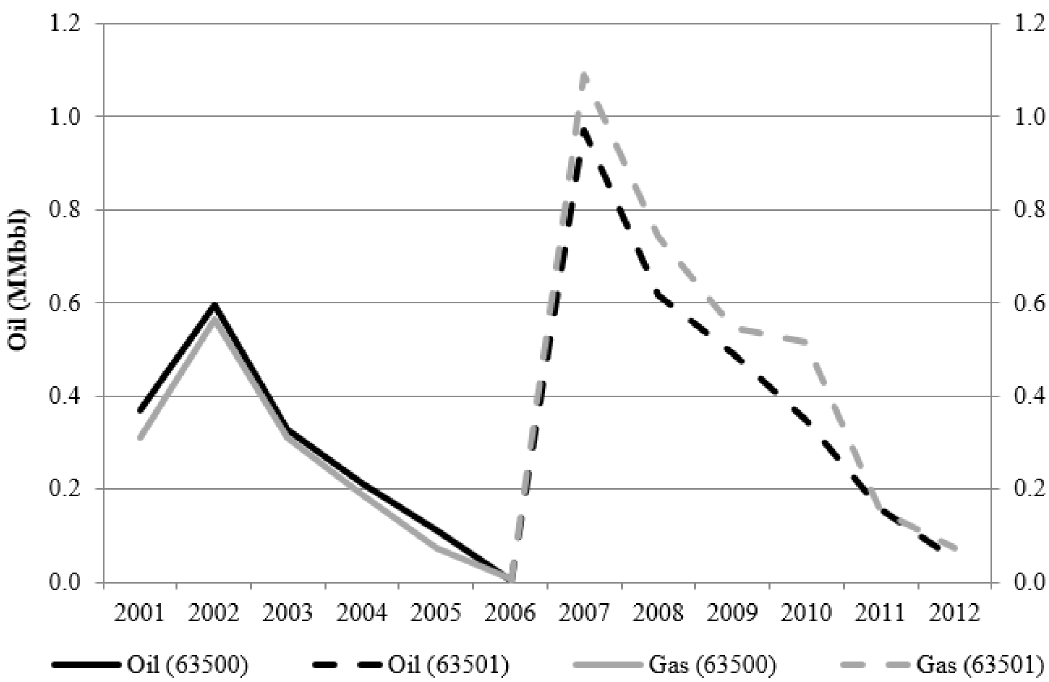


Figure L.5. Tick production profiles for wells 05901 and 63500 and sidetracks 05902 and 63501
Source: BOEM, June 2013

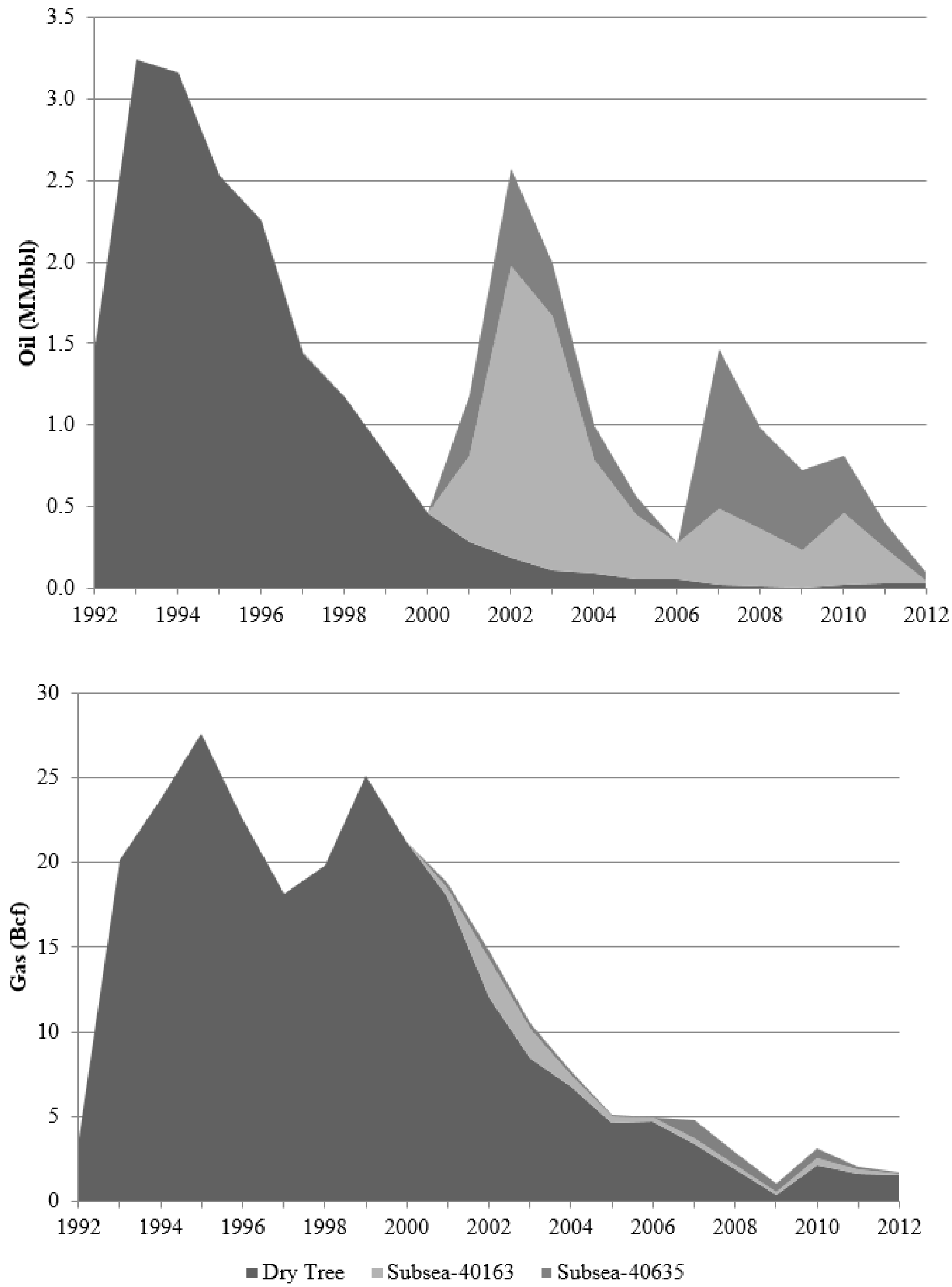


Figure L.6. Tick and Ladybug subsea well production profile
Source: BOEM, June 2013

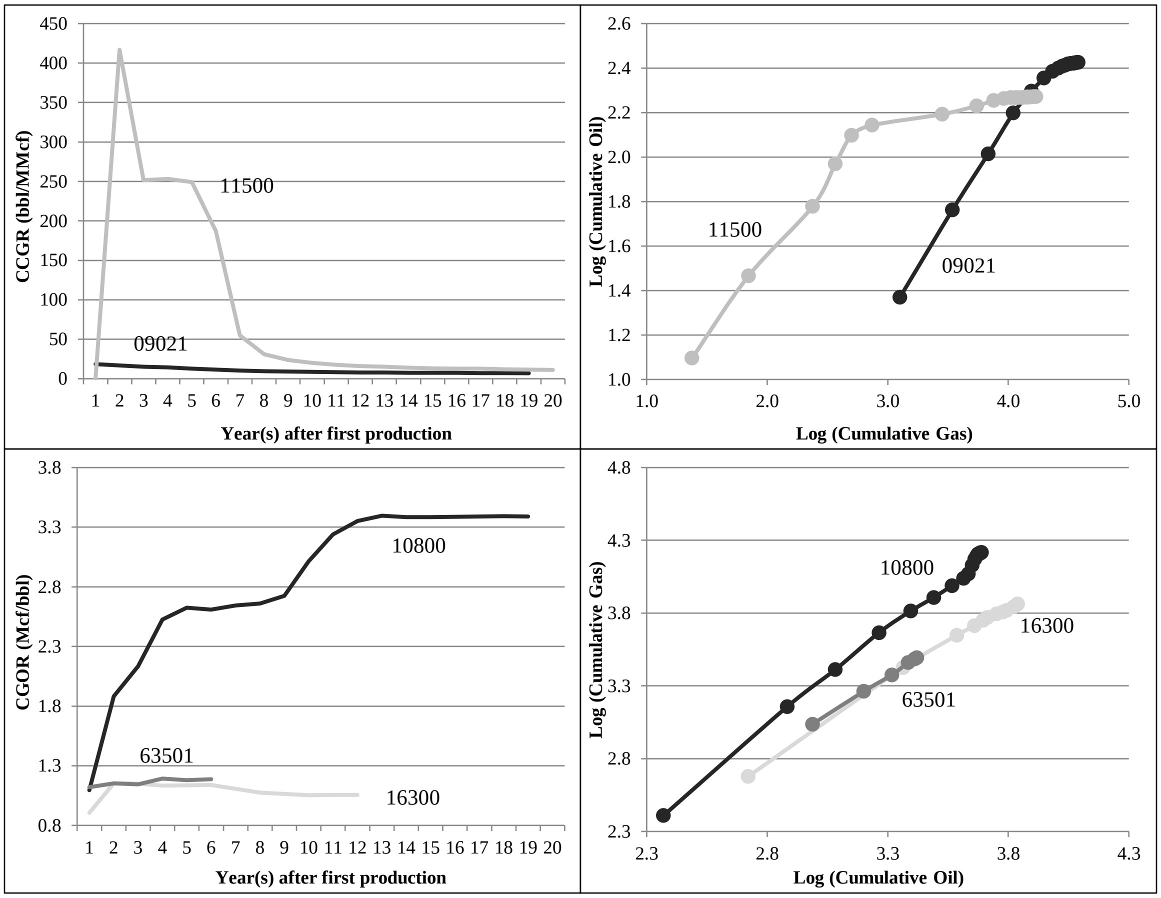


Figure L.7. Cumulative gas-oil and condensate-gas ratios for Tick's five producing wells circa 2012.
Source: BOEM, June 2013

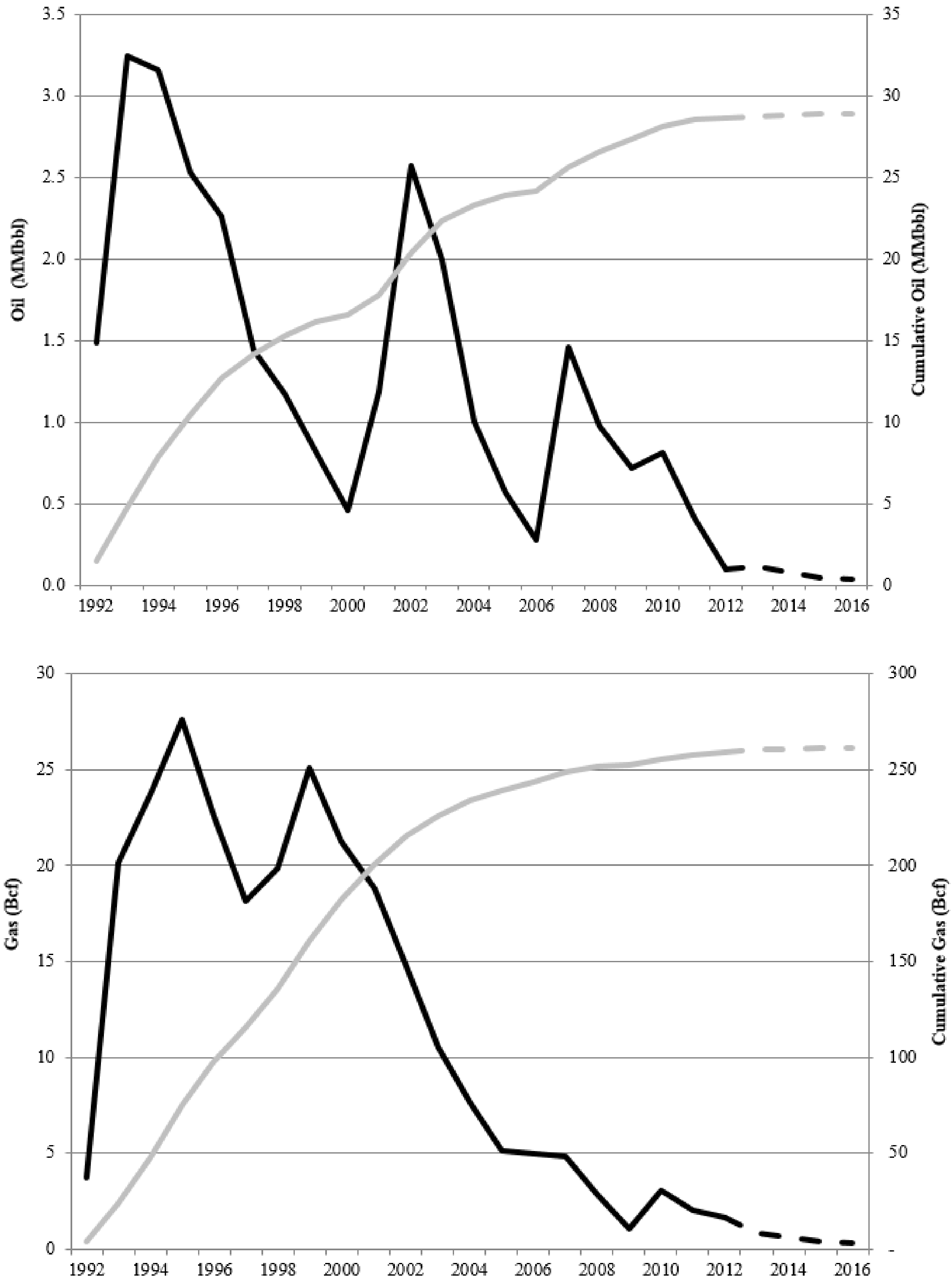


Figure L.8. Tick oil and gas production forecast, 2012-2016

Figure L.9. Horn Mountain was installed in 2002 in Mississippi Canyon 126 in 5400 ft water depth
Source: BP

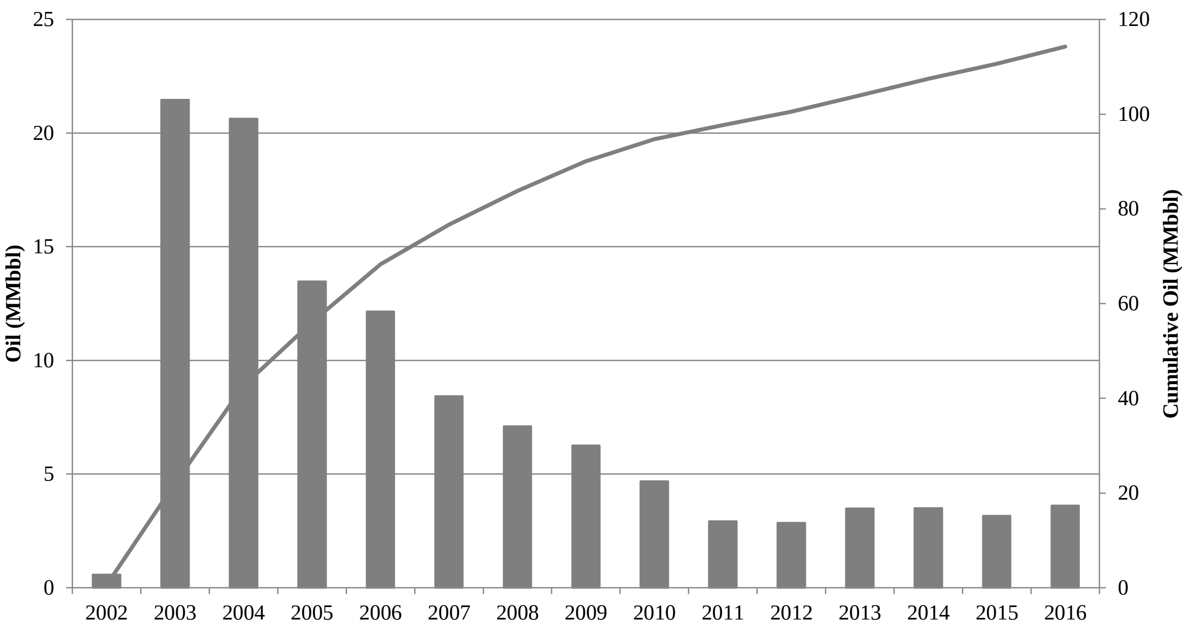


Figure L.10. Horn Mountain oil production, 2002-2016
Source: BOEM, June 2017

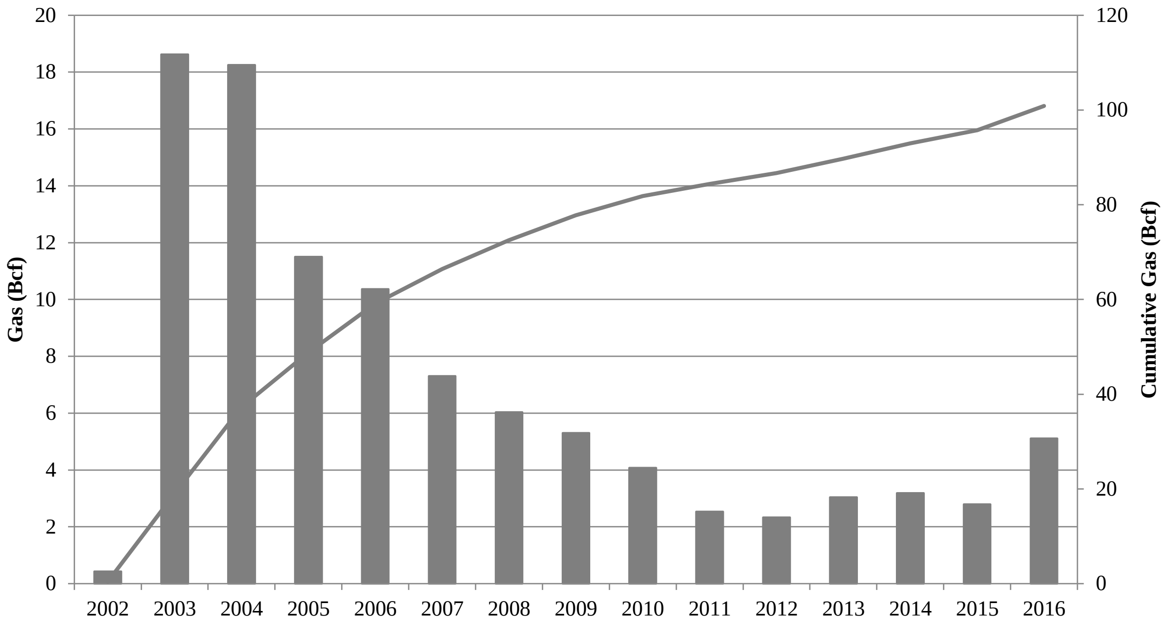


Figure L.11. Horn Mountain gas production, 2002-2016
Source: BOEM, June 2017

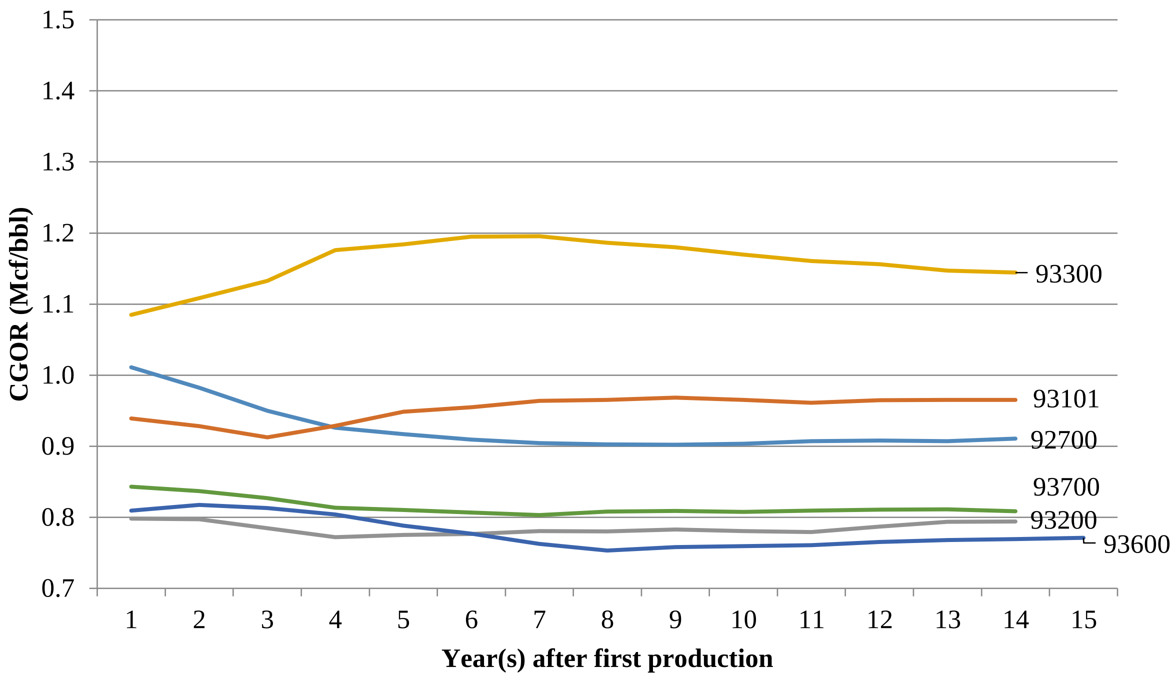


Figure L.12. Cumulative gas-oil ratio trends for the producing wells on Horn Mountain circa 2016
Source: BOEM, June 2017

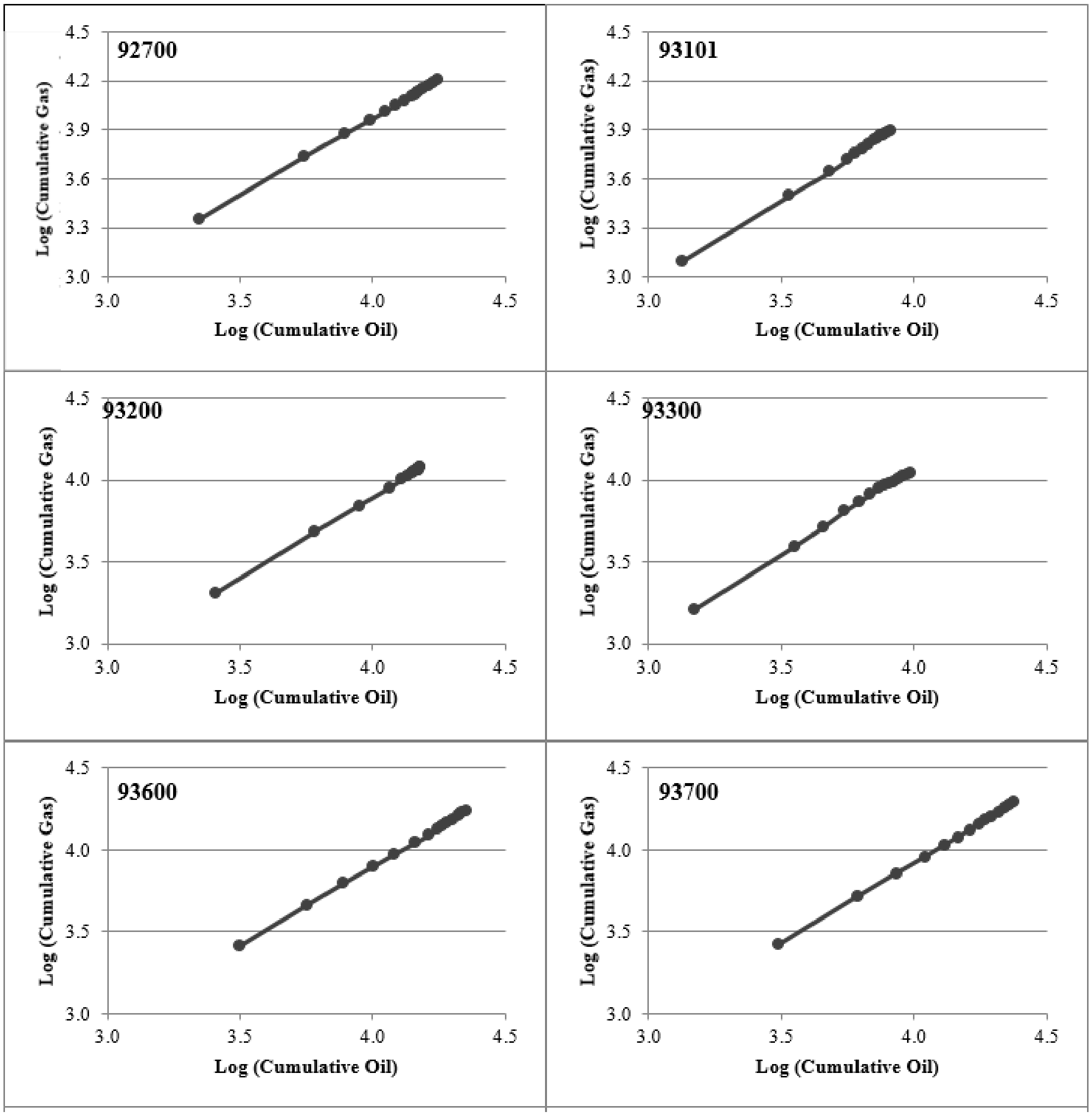


Figure L.13. Gas-oil ratio trends for producing wells at Horn Mountain circa 2016
Source: BOEM, June 2017

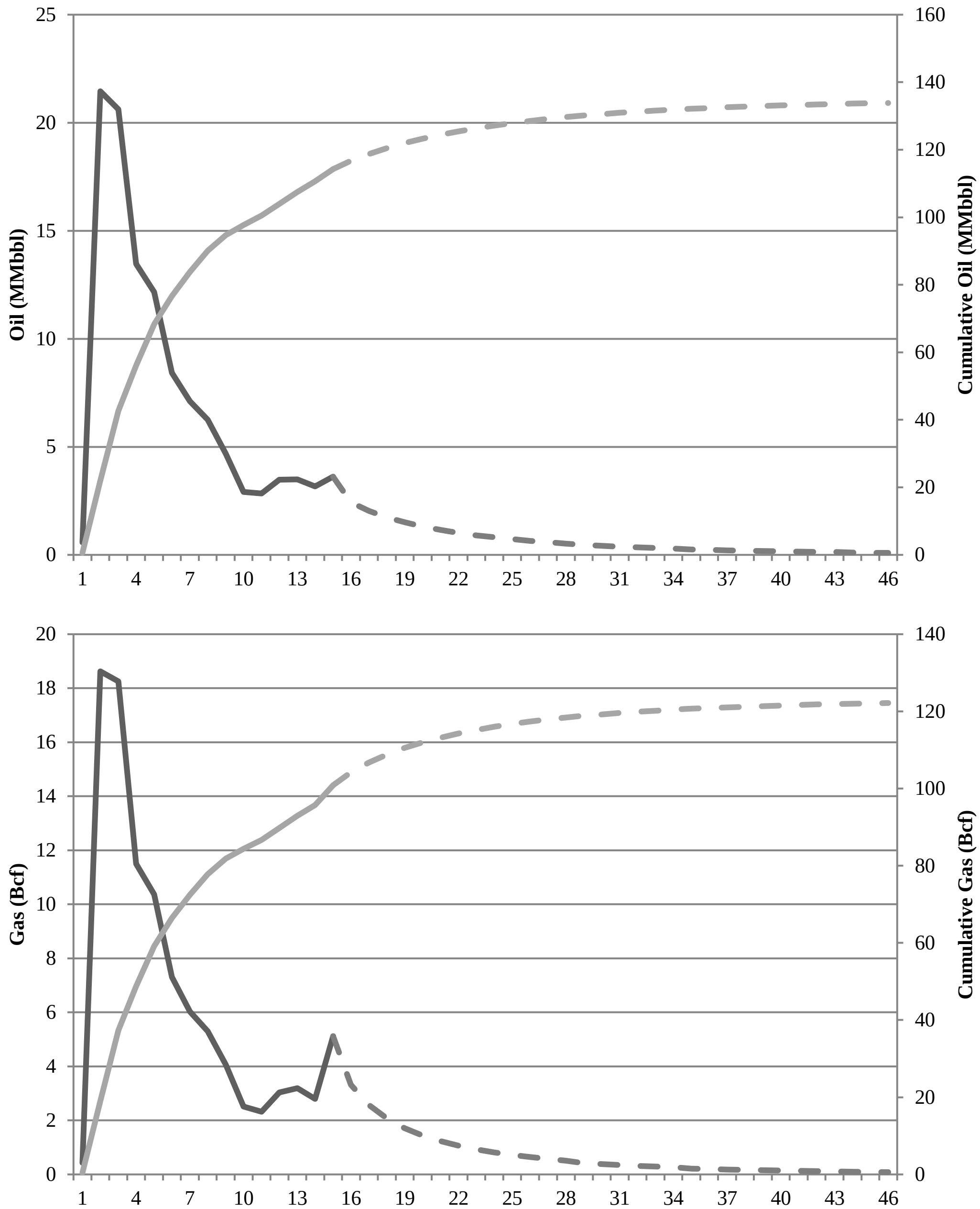


Figure L.14. Horn Mountain production forecast
Source: BOEM, June 2017

APPENDIX M

CHAPTER 13 TABLES AND FIGURES

Table M.1. Shallow water decommissioning model parameter summary

Class	Model Parameters	2016 Inventory
Producing	$q(b, D)$, P^o, P^g, EL, ROY	960
Idle	(p, T_1, T_2); $\{(p_L, p_U), (T_{1L}, T_{1U}), (T_{2L}, T_{2U})\}$	675
Auxiliary	Average, standard deviation	374

Table M.2. Hyperbolic vs. exponential cumulative decommissioned structures – oil price variation circa 2016

Year	\$40/bbl, \$3/Mcf	\$60/bbl, \$3/Mcf	\$80/bbl, \$3/Mcf
2027	177, 555	148, 517	121, 478
2037	282, 738	231, 700	202, 670
2047	360, 843	301, 812	263, 789

Note: *EL* = \$300,000. In table entries, the first element of the pair is the hyperbolic model results followed by the exponential model results.

Table M.3. Hyperbolic vs. exponential cumulative decommissioned structures – gas price variation circa 2016

Year	\$60/bbl, \$2/Mcf	\$60/bbl, \$3/Mcf	\$60/bbl, \$4/Mcf
2027	172, 533	148, 517	136, 501
2037	257, 719	231, 700	212, 685
2047	327, 823	301, 812	284, 807

Note: *EL* = \$300,000. In table entries, the first element of the pair is the hyperbolic model results followed by the exponential model results.

Table M.4. Oil and gas structure cumulative decommissioning count – exp. decline, oil price variation circa 2016

Year	\$40/bbl, \$3/Mcf	\$60/bbl, \$3/Mcf	\$80/bbl, \$3/Mcf
2027	228, 327	227, 290	219, 259
2037	288, 450	282, 418	277, 393
2047	318, 525	314, 498	312, 477

Note: Exponential model, \$3/Mcf gas, *EL* = \$300,000. In table entries, the first element of the pair is the gas structure count followed by the oil structure count.

Table M.5. Oil and gas structure cumulative decommissioning count – exp. decline, gas price variation circa 2016

Year	\$60/bbl, \$2/Mcf	\$60/bbl, \$3/Mcf	\$60/bbl, \$4/Mcf
2027	238, 295	227, 290	217, 284
2037	291, 428	282, 418	272, 413
2047	323, 500	314, 498	310, 497

Note: Exponential model, \$60/bbl oil, *EL* = \$300,000. In table entries, the first element of the pair is the gas structure count followed by the oil structure count

Table M.6. Increase in decommissioning count for a reduced condensate price

Economic Limit (\$)	2027	2037	2047
200,000	36	15	4
300,000	28	22	5
400,000	24	19	4
500,000	26	23	2
1,000,000	42	16	0
Average	31	19	3

Note: Assumes crude price of \$60/bbl for oil structures and a condensate price of \$36/bbl (= 60% crude) for gas structures. Gas price is \$3/Mcf for both oil and gas structures.

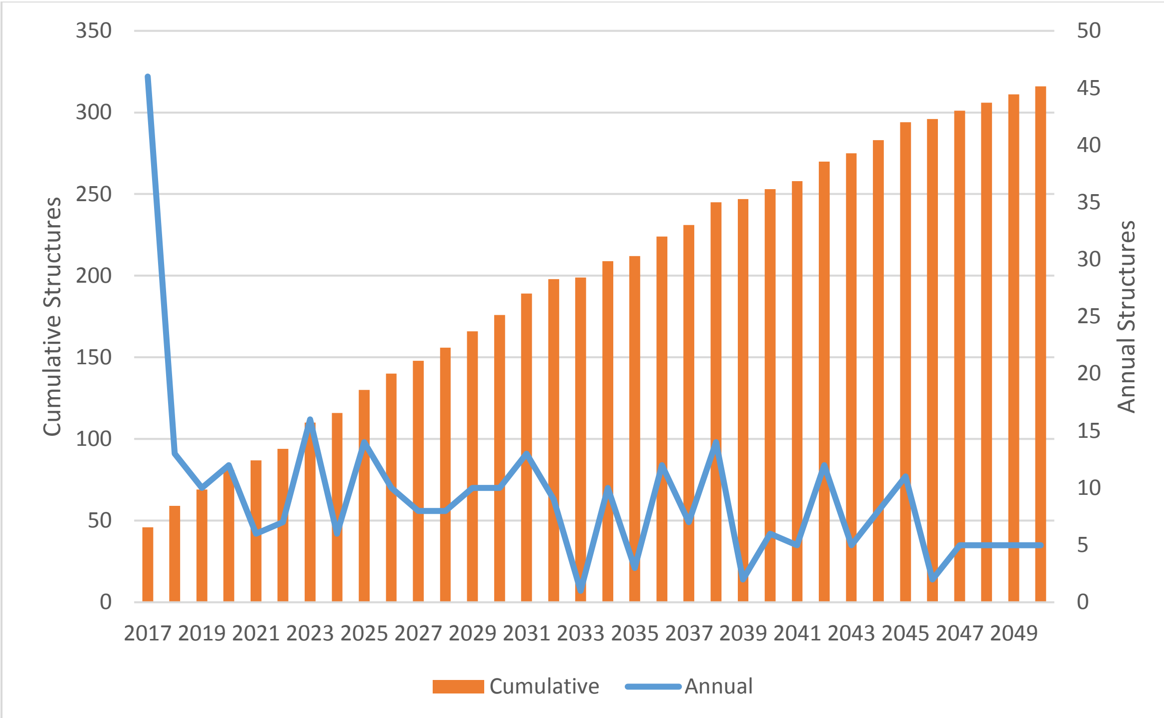


Figure M.1. Reference case, hyperbolic decline model decommissioning forecast

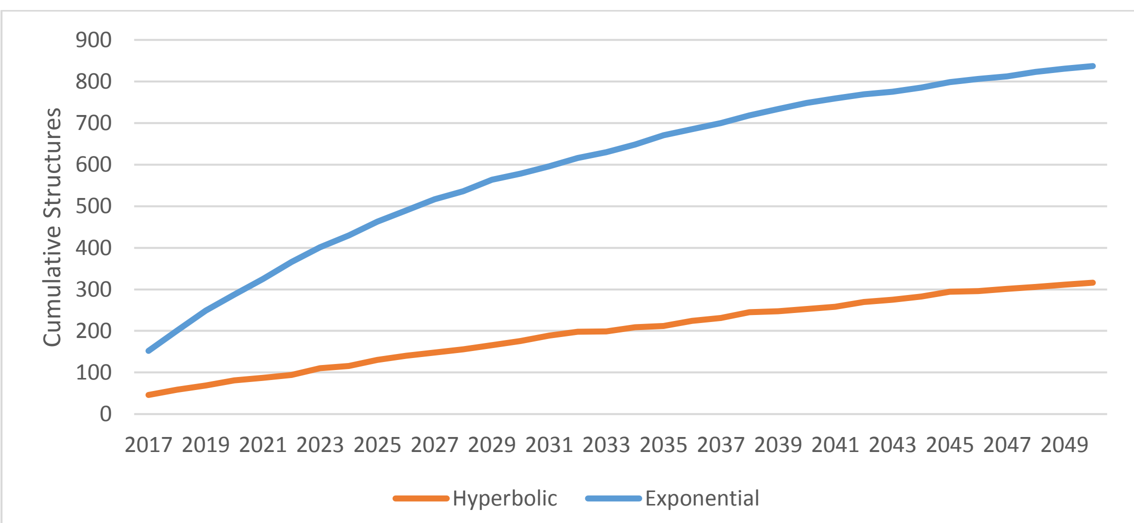


Figure M.2. Hyperbolic versus exponential decline cumulative structure decommissioning forecast

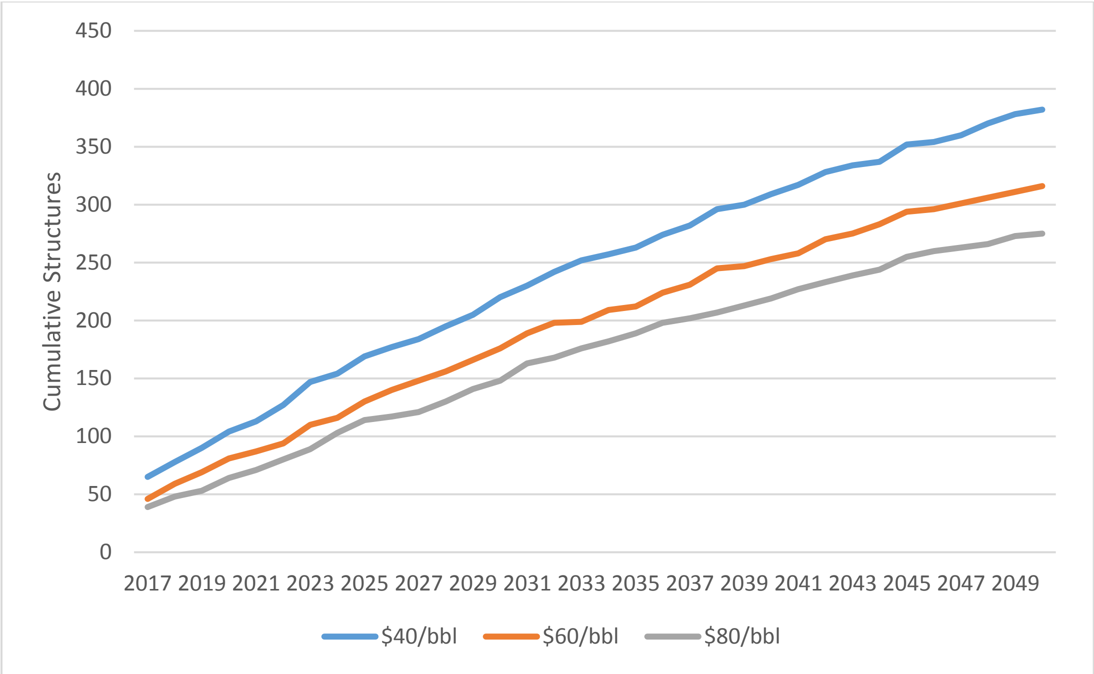


Figure M.3. Oil price variation on hyperbolic decline decommissioning forecast

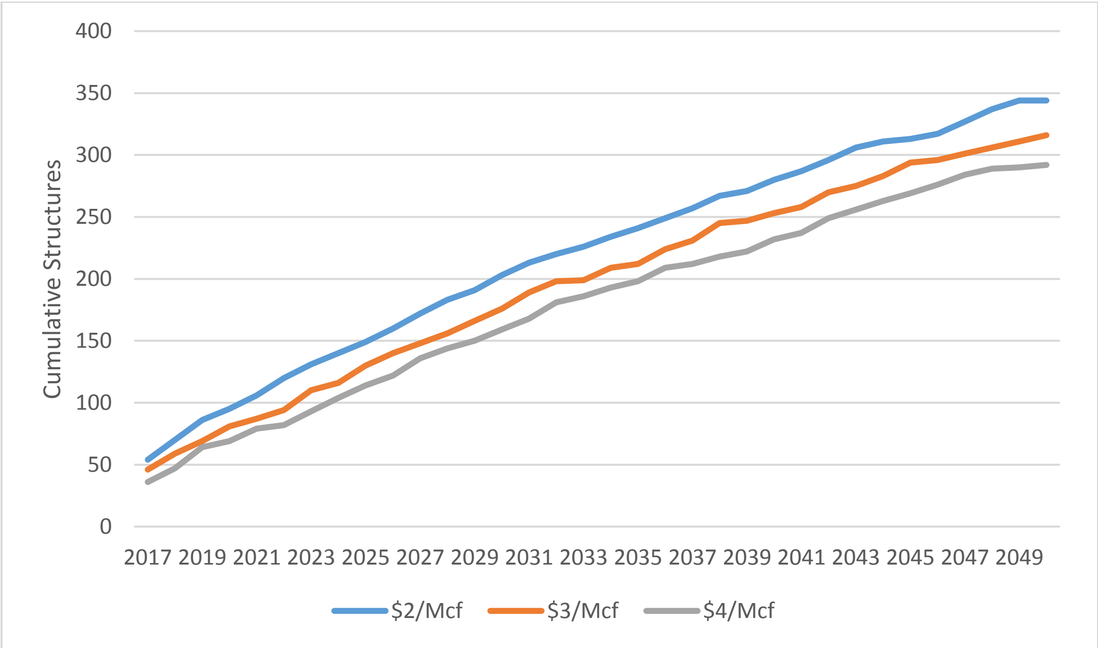


Figure M.4. Gas price variation on hyperbolic decline decommissioning forecast

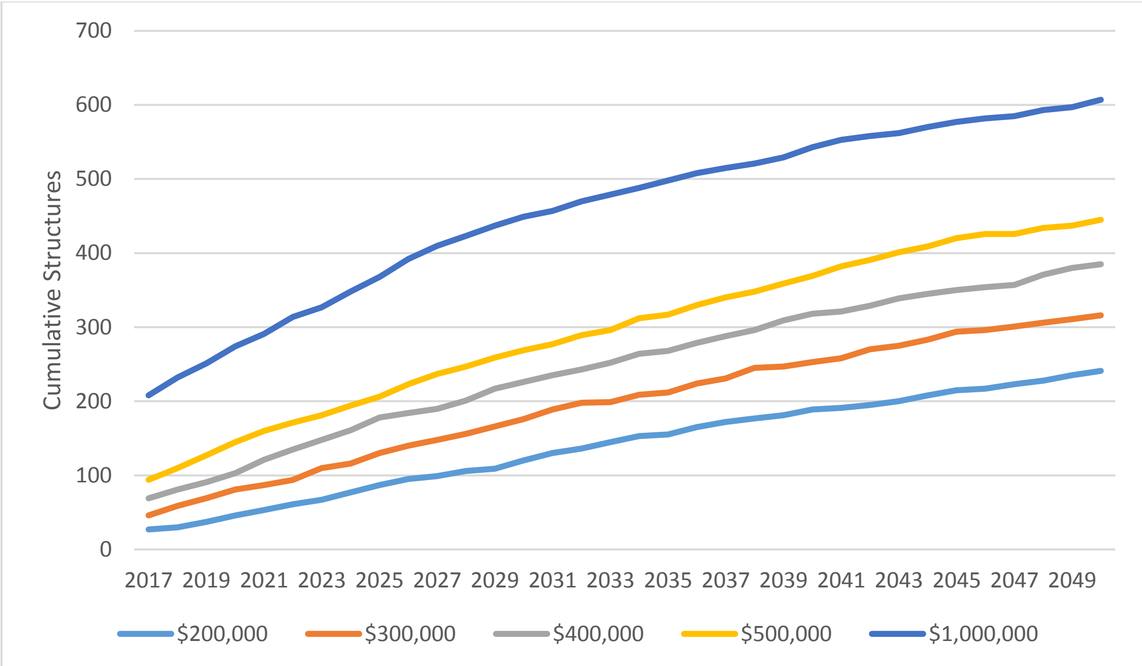


Figure M.5. Economic limit variation on hyperbolic decline decommissioning forecast

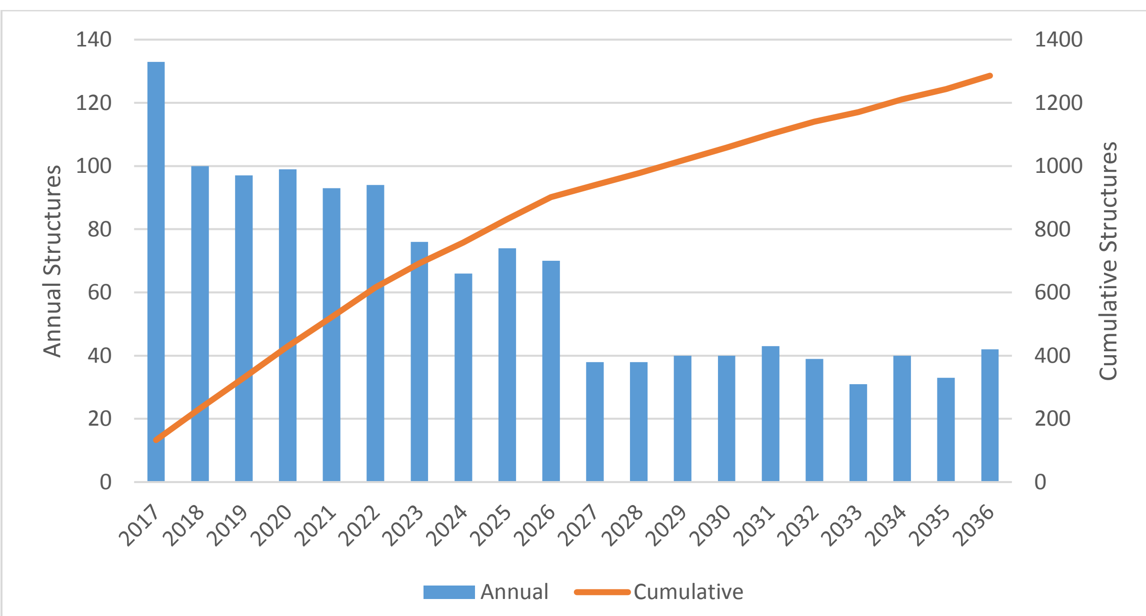


Figure M.6. Shallow water Gulf of Mexico decommissioning forecast, 2017-2036

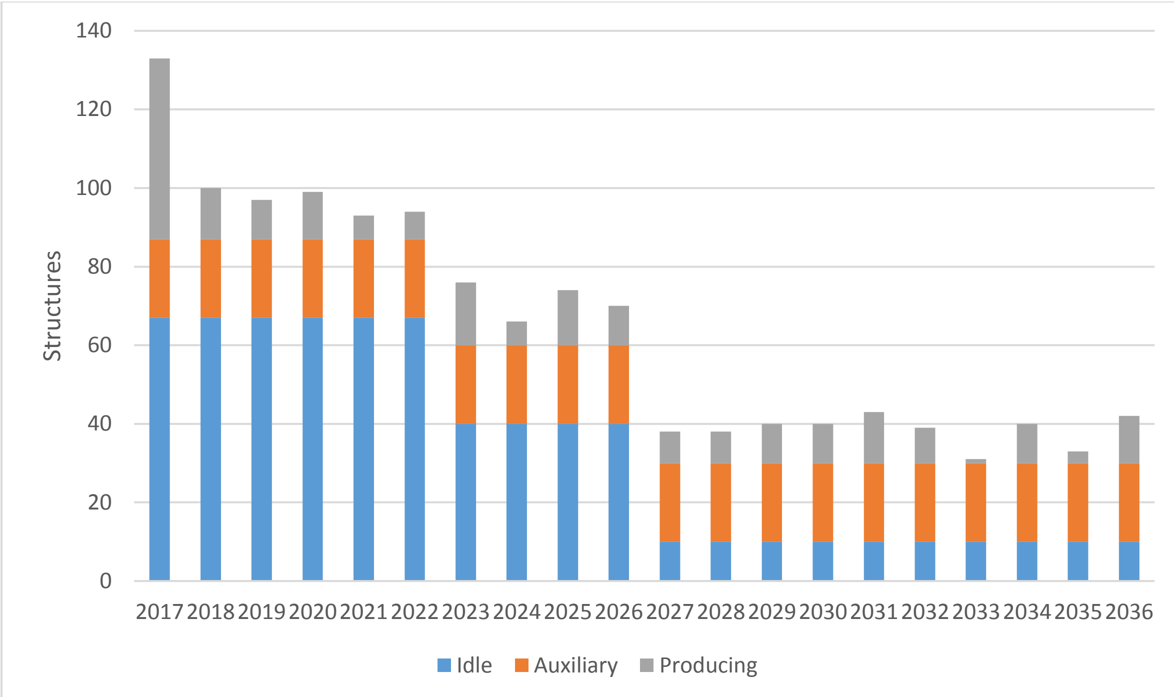


Figure M.7. Shallow water decommissioning forecast by structure class, 2017-2036

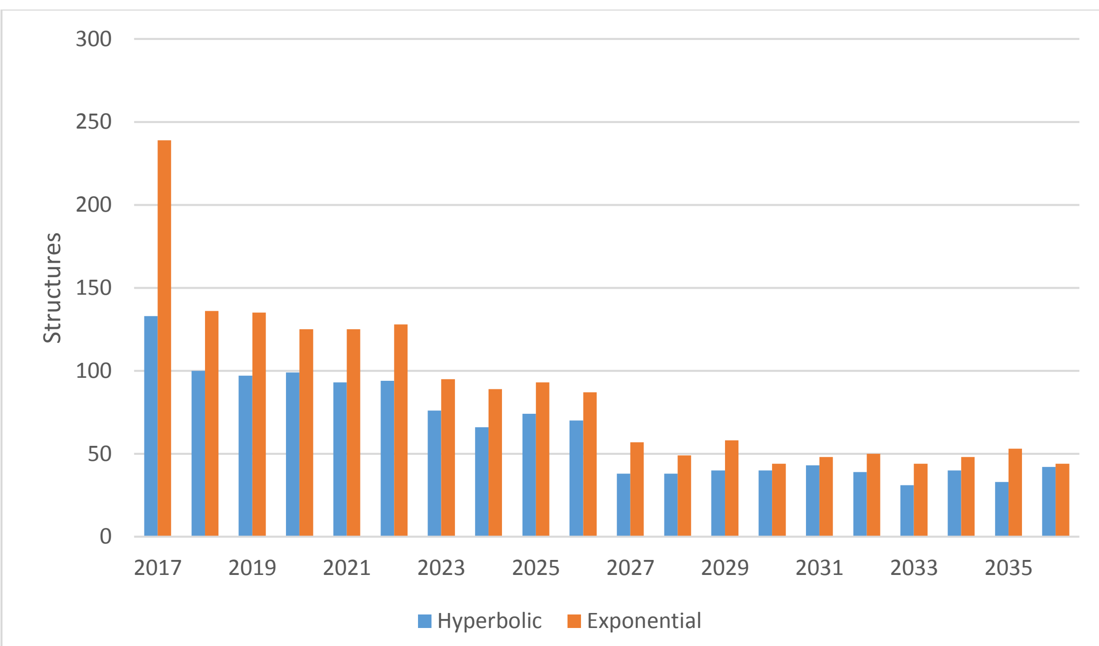


Figure M.8. Hyperbolic vs exponential decline decommissioning forecast, 2017-2036

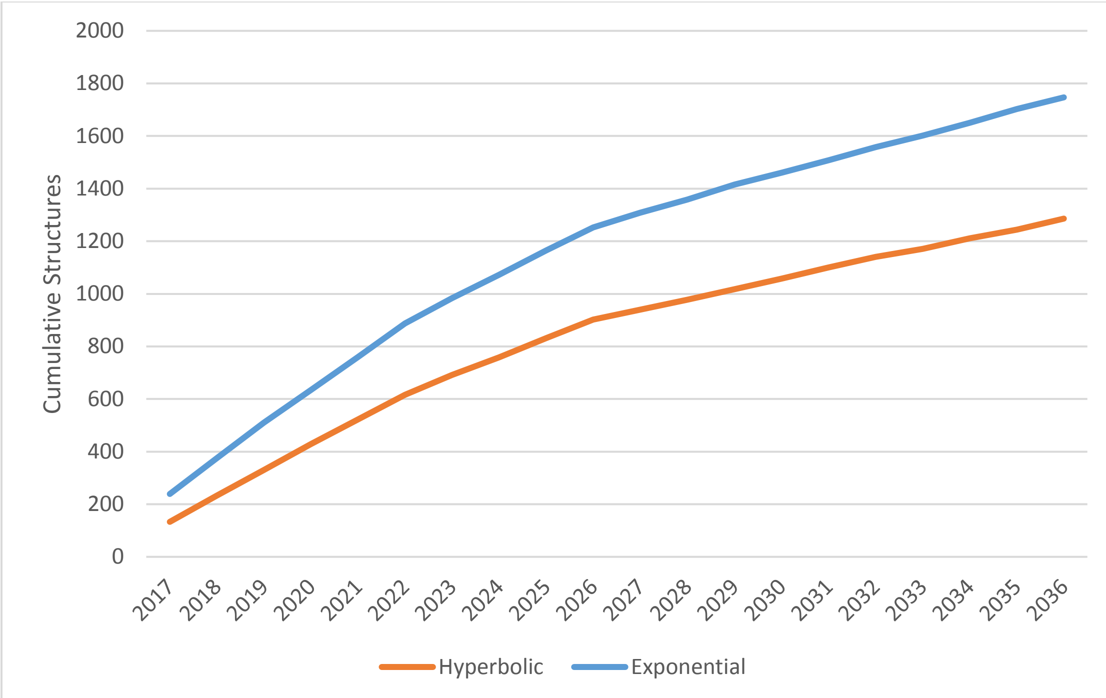


Figure M.9. Hyperbolic vs exponential decline cumulative decommissioning forecast, 2017-2036

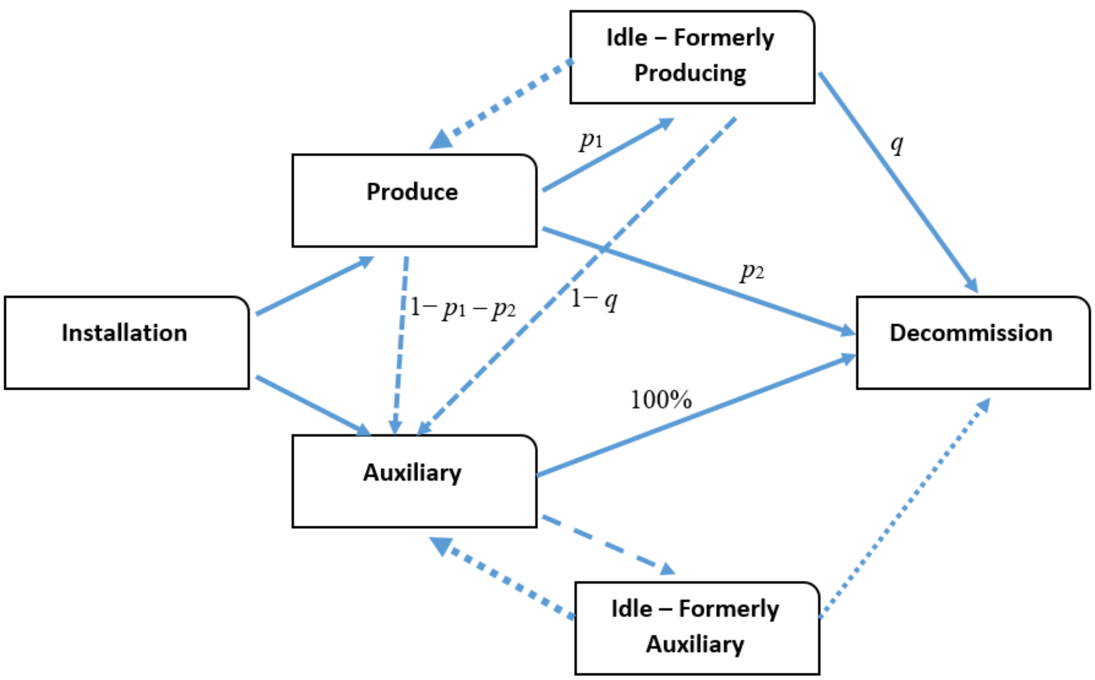


Figure M.10. Transition probabilities defined for the structure classes

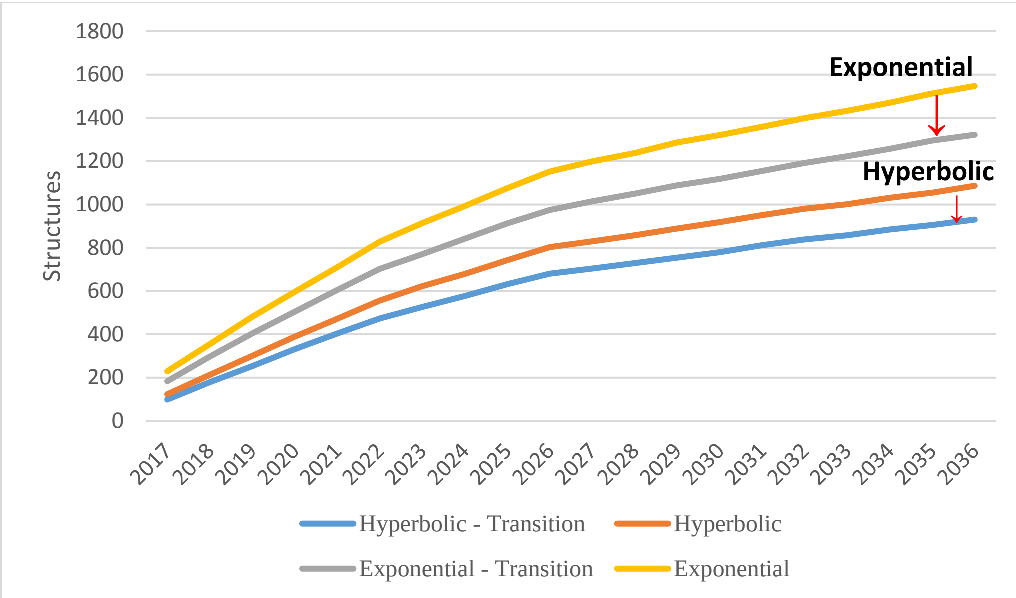


Figure M.11. Cumulative decommissioning forecast with and without transition probabilities, 2017-2036

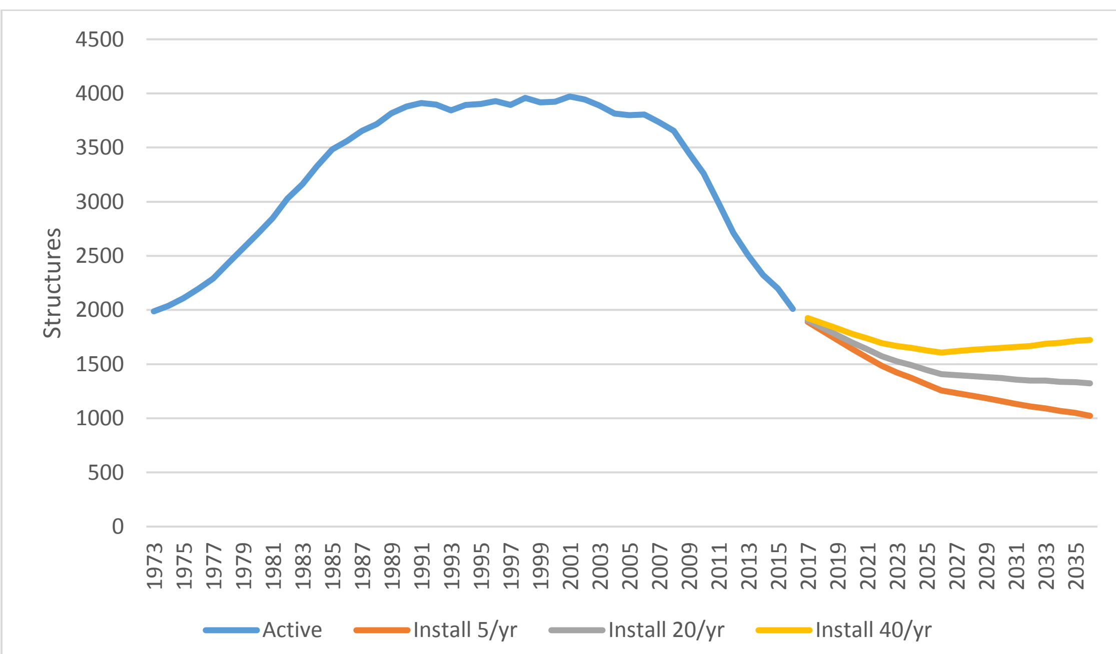


Figure M.12. Active shallow water Gulf of Mexico inventory forecast, 2017-2036

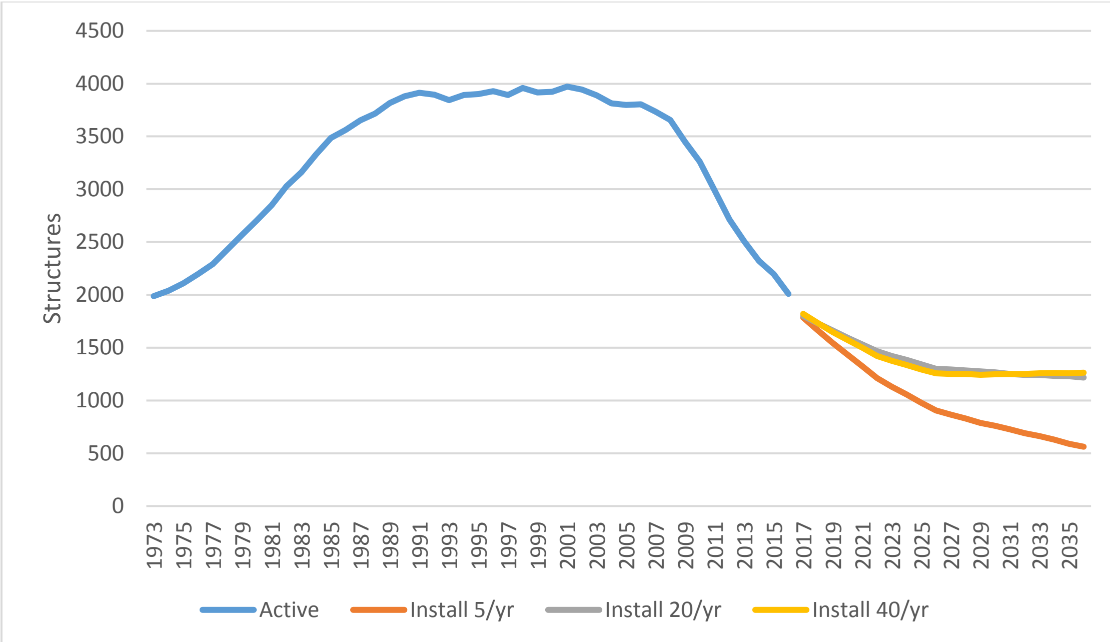


Figure M.13. Active shallow water Gulf of Mexico inventory forecast, 2017-2036

APPENDIX N

CHAPTER 14 TABLES AND FIGURES

Table N.1. Structure class scenarios and model assumptions

	Base	Slow/Low	Fast/High
Idle structure removal rate	U(5)	U(10)	U(3)
Platforms with $NR < EL$	U(5)	U(10)	U(3)
Platforms with $NR > EL$	$EL-yr+5$	$EL-yr+10$	$EL-yr+3$
Floaters with $NR > EL$	$EL-yr+2$	$EL-yr+2$	$EL-yr+2$
EL ($ million)	2.7	0.5	0.5
Oil Price ($/bbl)	60	80	40
Gas Price ($/Mcf)	3	4	2
Roy (%)	16.67	16.67	16.67

Note: U(T) represents uniform removal of inventory over T years.

Table N.2. Expected last year of production for fixed platform in water depth 400-500 ft

Complex	$40/bbl	$60/bbl	$80/bbl
1052	2016	2016	2016
1076	2016	2016	2016
1165	2016	2018	2024
1279	2016	2016	2016
1500	2022	2026	2039
2027	2016	2016	2016
22172	2017	2018	2026
22224	2017	2018	2028
22662	2017	2019	2025
23151	2016	2016	2016
23800	2021	2026	2035
80015	2016	2016	2016
Complex	$2/Mcf	$3/Mcf	$4/Mcf
70	2021	2023	2036
23848	2017	2020	2026
23893	2016	2016	2016
90028	2016	2016	2016

Note: For oil structures, gas price assumed constant at $3/Mcf for all oil price scenarios. For gas structures, oil price assumed at $60/bbl for all gas price scenarios.

Table N.3. Expected last year of production for fixed platforms and compliant towers in water depth >500 ft

Complex	$40/bbl	$60/bbl	$80/bbl
147	2019	2021	2025
1482	2021	2027	2037
10178	2016	2016	2016
10297	2018	2022	2029
22178	2025	2034	2050
22840	2017	2022	2035
23503	2018	2021	2025
23552	2032	2039	2055
23883	2024	2030	2040
24129	2027	2030	2038
24130	2033	2040	2063
24201	2025	2031	2043
33039	2032	2038	2049
70012	2028	2034	2043
90014	2056	2065	2084
23567-1	2020	2023	2028
23567-2	2016	2016	2016
Complex	**$2/Mcf**	**$3/Mcf**	**$4/Mcf**
113	2019	2024	2036
10212	2017	2018	2034
23875	2028	2031	2037
27032	2021	2025	2057
27056	2016	2016	2016

Note: For oil structures, gas price assumed constant at $3/Mcf for all oil price scenarios. For gas structures, oil price assumed constant at $60/bbl for all gas price scenarios.

Table N.4. Expected last year of production for floaters

Complex	$40/bbl	$60/bbl	$80/bbl
67	2026	2036	2088
183	2029	2037	2058
235	2052	2061	2067
251	2028	2034	2062
420	2027	2031	2036
811	2021	2028	2039
821	2030	2036	2047
822	2027	2034	2067
876	2038	2048	2090
1001	2046	2055	2070
1035	2027	2034	2046
1088	2020	2022	2034
1090	2033	2041	2082
1101	2069	2086	2090
1175	2031	2038	2076
1215	2053	2067	2090
1218	2023	2028	2045
1223	2053	2069	2090
1288	2022	2024	2028
1290	2023	2027	2031
1323	2039	2046	2059
1665	2028	2030	2041
1766	2016	2016	2016
1799	2031	2036	2045
1819	2040	2046	2056
1899	2062	2076	2090
1930	2029	2033	2041
2008	2041	2046	2053
2045	2030	2048	2090
2089	2021	2025	2035
2133	2036	2045	2063
2229	2023	2024	2029
2385	2038	2043	2049
2424	2043	2051	2090
2440	2049	2057	2076
2498	2021	2026	2044
2513	2090	2090	2090
2576	2069	2078	2089
2597	2047	2057	2071
23583	2016	2018	2021
24080	2031	2035	2042
24199	2052	2060	2073
24229	2025	2029	2035
24235	2029	2036	2060
70004	2058	2077	2090
70020	2023	2029	2041

Note: For oil structures, gas price assumed constant at $3/Mcf for all price scenarios.
For gas structure 1766, oil price constant at $60/bbl for all gas price scenarios.

Table N.5. Expected decommissioning schedule for fixed platforms in water depth 400-500 ft

Complex	High	Base	Low
1052	2017-2019	2017-2021	2017-2026
1076	2017-2019	2017-2021	2017-2026
1165	2019	2023	2034
1279	2017-2019	2017-2021	2017-2026
1500	2025	2031	2049
2027	2017-2019	2017-2021	2017-2026
22172	2020	2023	2036
22224	2020	2023	2038
22662	2020	2024	2035
22685	2017-2019	2017-2021	2017-2026
23051	2017-2019	2017-2021	2017-2026
23151	2017-2019	2017-2021	2017-2026
23800	2024	2031	2045
80015	2017-2019	2017-2021	2017-2026
Complex	High	Base	Low
70	2024	2028	2046
10192	2017-2019	2017-2021	2017-2026
23212	2017-2019	2017-2021	2017-2026
23353	2017-2019	2017-2021	2017-2026
23848	2020	2025	2036
23893	2017-2019	2017-2021	2017-2026
23925	2017-2019	2017-2021	2017-2026
90028	2017-2019	2017-2021	2017-2026

Table N.6. Expected decommissioning schedule for fixed platforms and compliant towers in water depth >500 ft

Complex	High	Base	Low
147	2022	2026	2035
1482	2024	2032	2047
2606	-	-	-
10178	2017-2019	2017-2021	2017-2026
10297	2021	2027	2039
22178	2028	2039	2060
22840	2020	2027	2045
23277	2017-2019	2017-2021	2017-2026
23503	2021	2026	2035
23552	2035	2044	2065
23760	2017-2019	2017-2021	2017-2026
23883	2027	2035	2050
24129	2030	2035	2048
24130	2036	2045	2073
24201	2028	2036	2053
33039	2035	2043	2059
70012	2031	2039	2053
90014	2059	2070	2094
235671	2023	2028	2038
235672	2017-2019	2017-2021	2017-2026
Complex	High	Base	Low
113	2022	2029	2046
1320	2017-2019	2017-2021	2017-2026
10212	2020	2023	2044
10242	2017-2019	2017-2021	2017-2026
23788	2017-2019	2017-2021	2017-2026
23875	2031	2036	2047
27032	2024	2030	2067
27056	2017-2019	2017-2021	2017-2026
70016	2017-2019	2017-2021	2017-2026

Table N.7. Expected decommissioning schedule for floaters

Complex	High	Base	Low
67	2028	2038	2090
183	2031	2039	2060
235	2054	2063	2069
251	2030	2036	2064
420	2029	2033	2038
811	2023	2030	2041
821	2032	2038	2049
822	2029	2036	2069
876	2040	2050	2092
1001	2048	2057	2072
1035	2029	2036	2048
1088	2022	2024	2036
1090	2035	2043	2084
1101	2071	2088	2092
1175	2033	2040	2078
1215	2055	2069	2092
1218	2025	2030	2047
1223	2055	2071	2092
1288	2024	2026	2030
1290	2025	2029	2033
1323	2041	2048	2061
1665	2030	2032	2043
1766	2017-2019	2017-2021	2017-2026
1799	2033	2038	2047
1819	2042	2048	2058
1899	2064	2078	2092
1930	2031	2035	2043
2008	2043	2048	2055
2045	2032	2050	2092
2089	2023	2027	2037
2133	2038	2047	2065
2229	2025	2026	2031
2385	2040	2045	2051
2424	2045	2053	2092
2440	2051	2059	2078
2498	2023	2028	2046
2513	2092	2092	2092
2576	2071	2080	2091
2597	2049	2059	2073
23583	2018	2020	2023
24080	2033	2037	2044
24199	2054	2062	2075
24229	2027	2031	2037
24235	2031	2038	2062
70004	2060	2079	2092
70020	2025	2031	2043

Table N.8. Deepwater decommissioning forecast in the Gulf of Mexico under base scenario

Water Depth (ft)	2017-2021	2022-2026	2027-2031	2032-2036	2037-2041	2042-2046	2047-2051	2052-2056	2056+	Total
400-500	14	5	3	0	0	0	0	0	0	22
500-1500	9	3	6	5	1	3	0	0	1	28
>1500	2	3	6	6	8	3	6	1	13	48
Total	25	11	15	11	9	6	6	1	14	98

Table N.9. Deepwater decommissioning forecast in the Gulf of Mexico under low scenario

Water Depth (ft)	2017-2022	2022-2026	2027-2031	2032-2036	2037-2041	2042-2046	2047-2051	2052-2056	2056+	Total
400-500	7	7	0	4	1	2	1	0	0	22
500-1500	4	5	0	2	3	4	4	1	5	28
>1500	1	1	2	2	3	5	5	2	27	48
Total	12	13	2	8	7	11	10	3	32	98

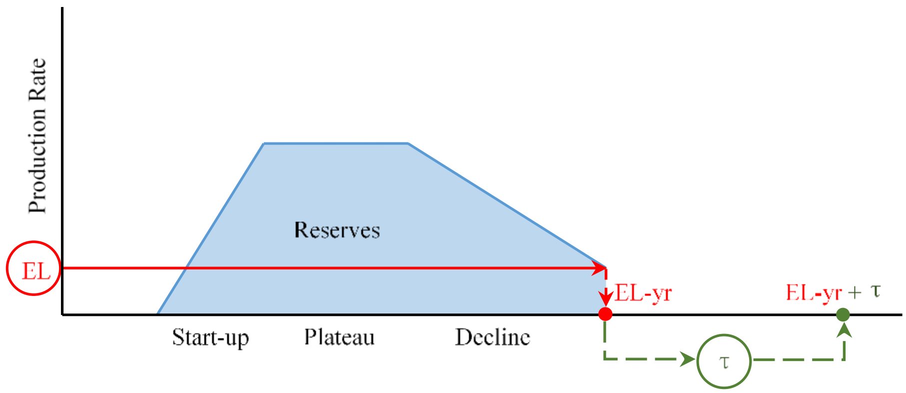


Figure N.1. Decommissioning forecast showing input and model parameters

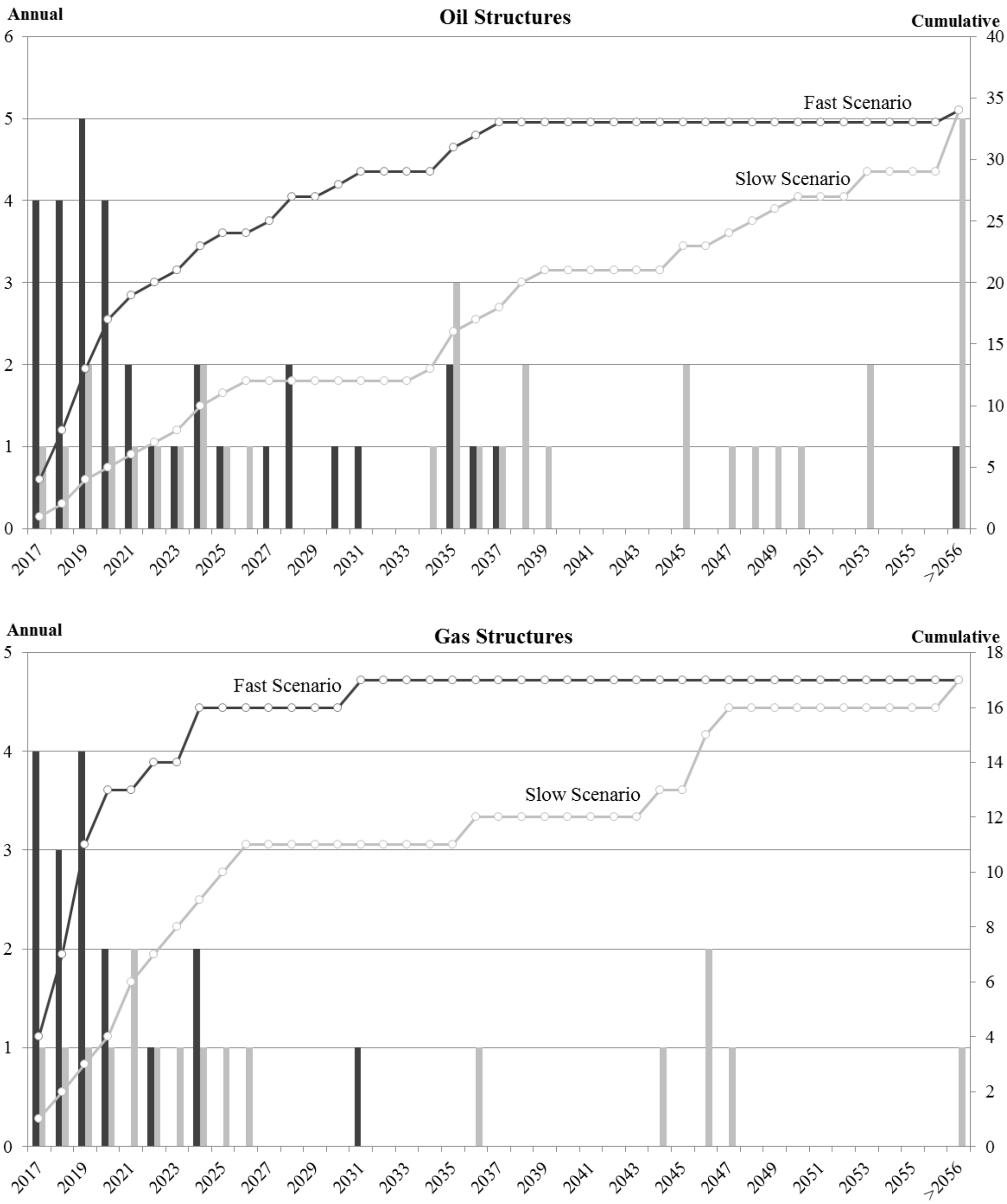


Figure N.2. Decommissioning schedules for deepwater fixed platforms − slow and fast scenarios

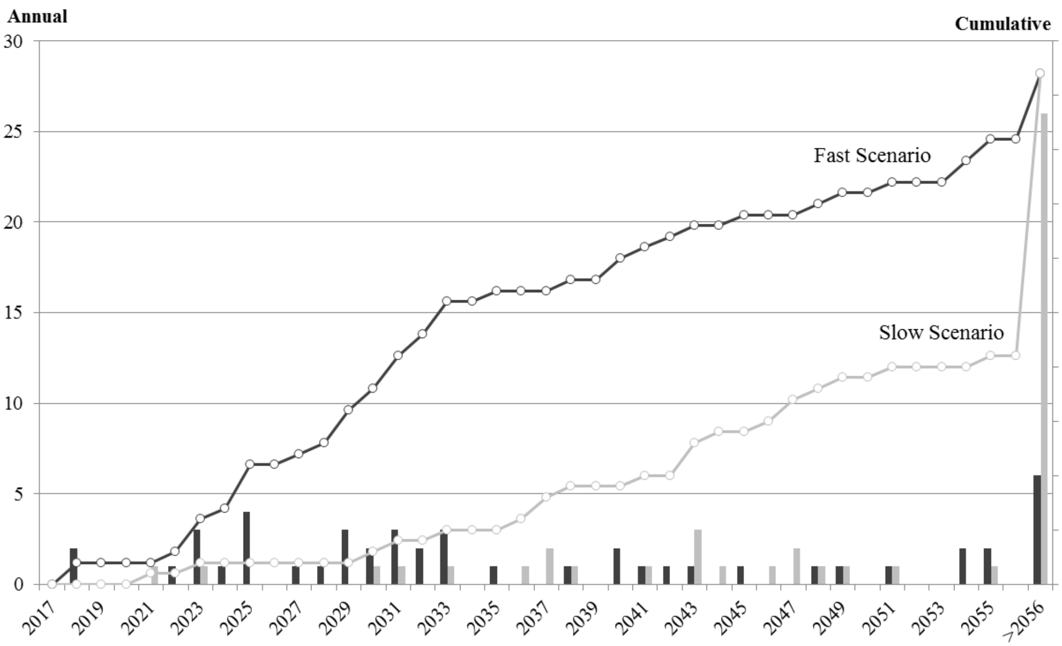


Figure N.3. Decommissioning schedule for floating structures − slow and fast scenarios

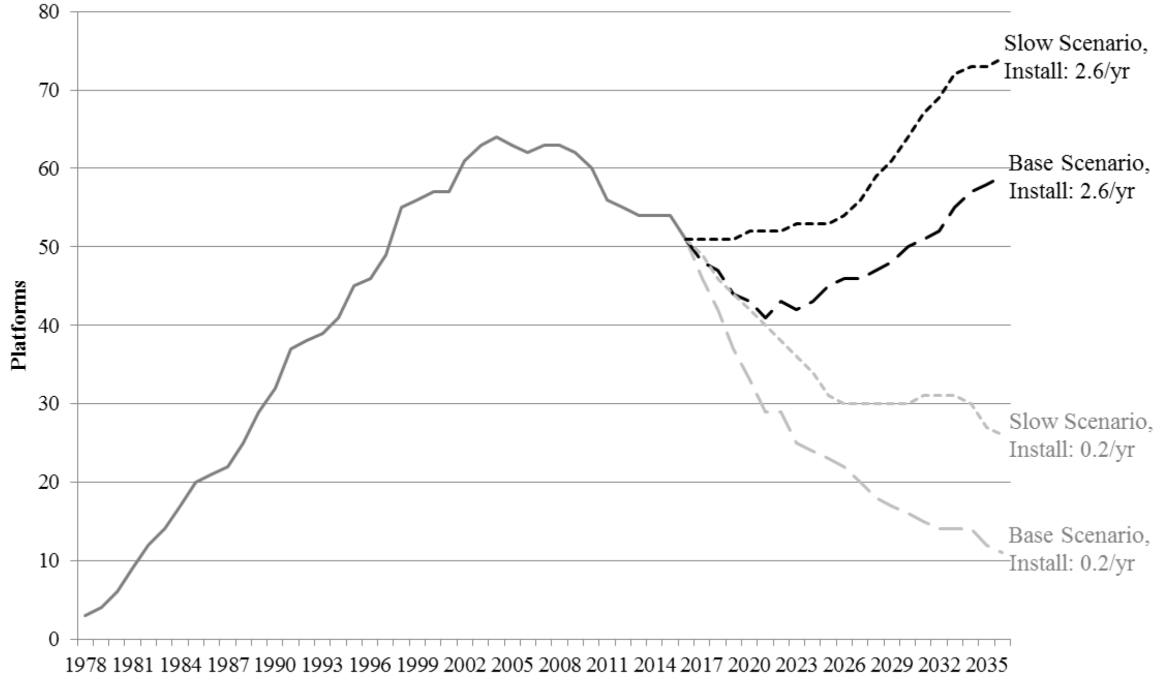


Figure N.4. Active inventory of deepwater fixed platforms − slow and base scenarios

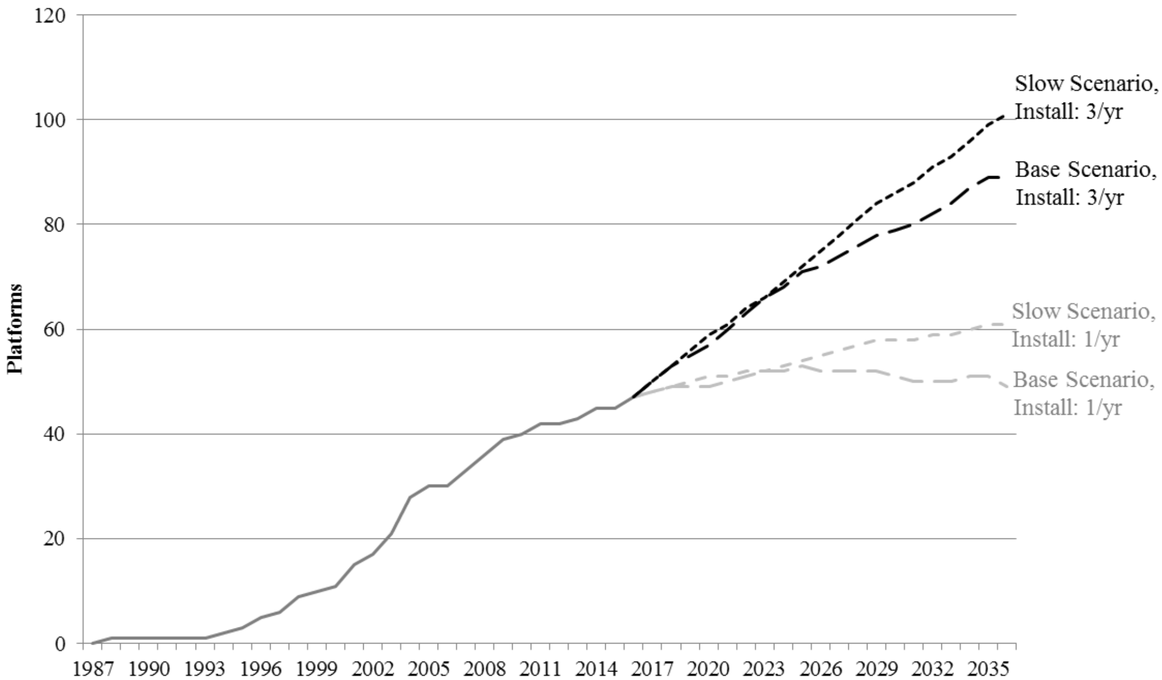


Figure N.5. Active inventory of floaters under slow and base scenarios

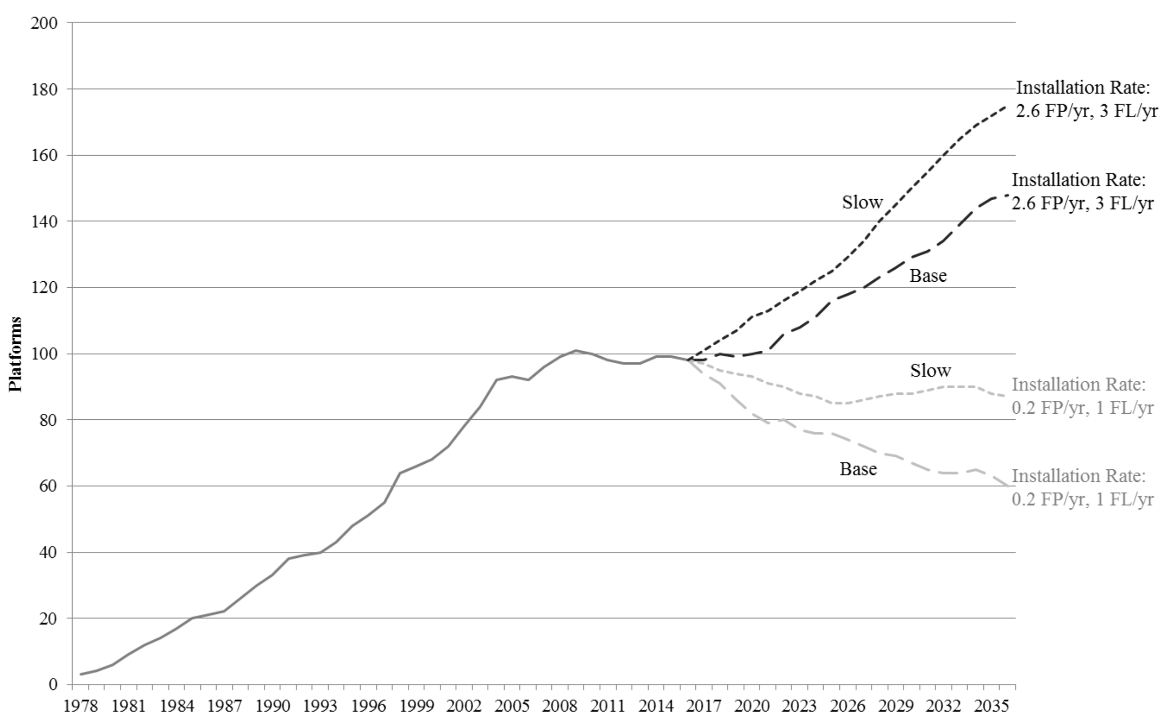


Figure N.6. Composite active inventory of deepwater structures under slow and base scenarios

APPENDIX O

CHAPTER 15 TABLES AND FIGURES

Table O.1. Opportunities within and outside field developments

Within Field Opportunities	
	Workover
	Redevelopment
	Secondary Production
	Tertiary Production
Outside Field Opportunities	
	Satellite Development – Full
	Satellite Development – Partial
	Transport Hub
	Other

Table O.2. Hypothetical economic thresholds between reserves size and tieback distance

Size	Tieback Distance			
(MMboe)	< 5 mi	5-30 mi	30-60 mi	> 60 mi
< 1	-	--	---	---
1-5	?	-	--	---
5-10	+	?	-	---
10-50	++	+	?	--
50-100	+++	+++	++	++

Note: Plus sign indicates likely economic, minus sign indicates likely uneconomic. The number of signs translates into higher confidence/probability levels.

Table O.3. Auger and subsea tieback cumulative production circa September 2017

Name	Field	First Production	Garden Bank Lease Blocks	Cum. Oil (MMbbl)	Cum. Gas (Bcf)
Auger	GB 426	1994	426, 427, 470, 471	267	935
Macaroni	GB 602	1999	602	13.4	24.9
Oregano	GB 559	2001	559	33.1	49.5
Serrano	GB 516	2001	515, 516, 472	3.9	47
Llano	GB 387	2002	341, 385-387	94.7	223
Total				412	1279

Source: BOEM 2017

Table O.4. Oil pipeline capacity for deepwater Gulf of Mexico

Pipeline Name	Capacity (Mbopd)
1. Mars	400
2. Amberjack	
3. Poseidon	350
4. Eugene Island	65
5. Auger & Bonito	200
7. Caesar	450
8. LOOP	
9. Cameron Highway (CHOPS)	600
10. Odyssey	200
11. Proteus/Endymion	580/750
14. Constitution	
15. Allegheny	
16. Mountaineer	
17. Hoover (HOOPS)	100
18. Na Kika	

Table O.5. Shell pipeline network scale-free parameter illustration

Model: $P(k) = 1/(k+a)^p$				
	Model 1		Model 2	
a	*p*	*SSE*	*p*	*SSE*
0	2.9	0.11	2.4	0.15
0.5	1.7	0.06	1.6	0.03
1.0	1.3	0.13	1.2	0.07
1.5	1.2	0.17	1.0	0.10

Note: Model 1 refers to pipeline network in Figure O.32. Model 2 refers to pipeline network in Figure O.30.

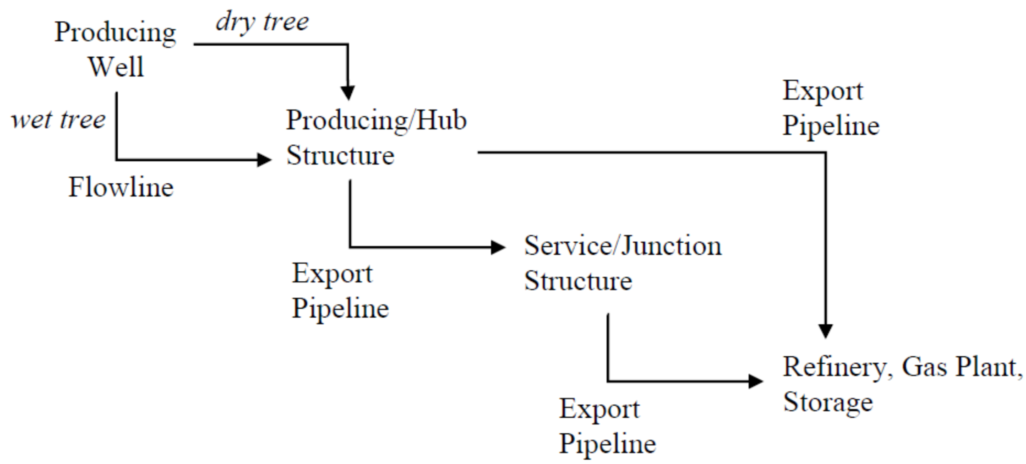


Figure O.1. Processing hierarchy from well to end consumer

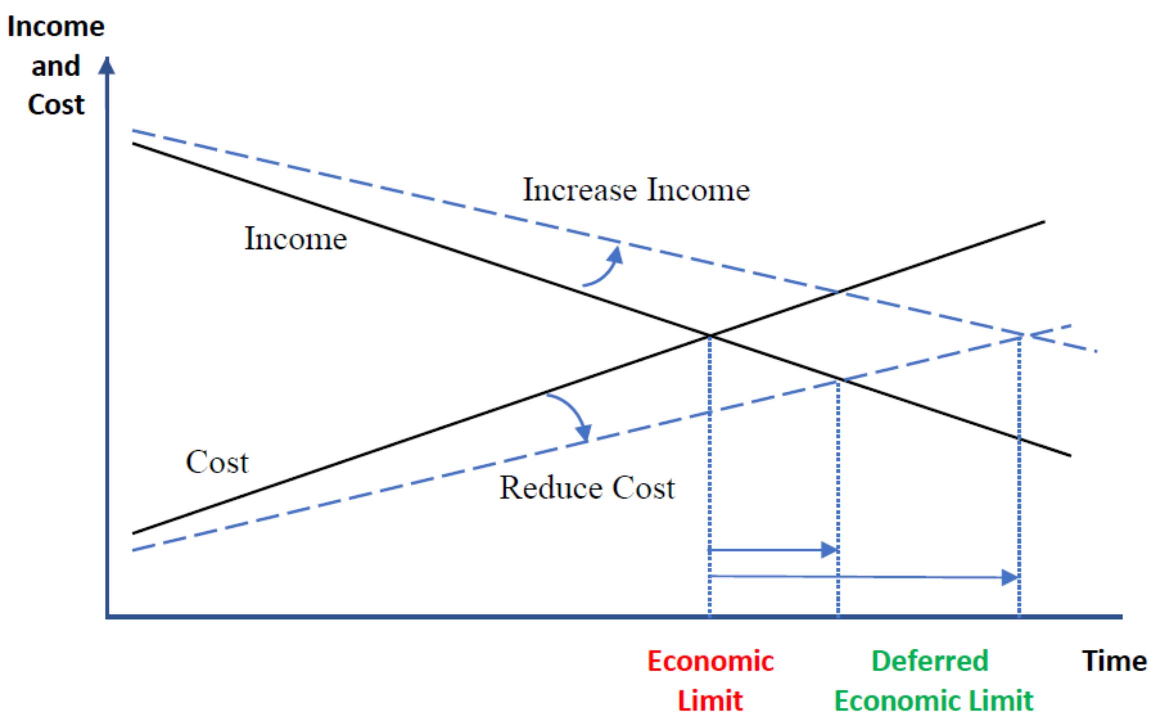


Figure O.2. Economic limit and means to defer economic lifetime

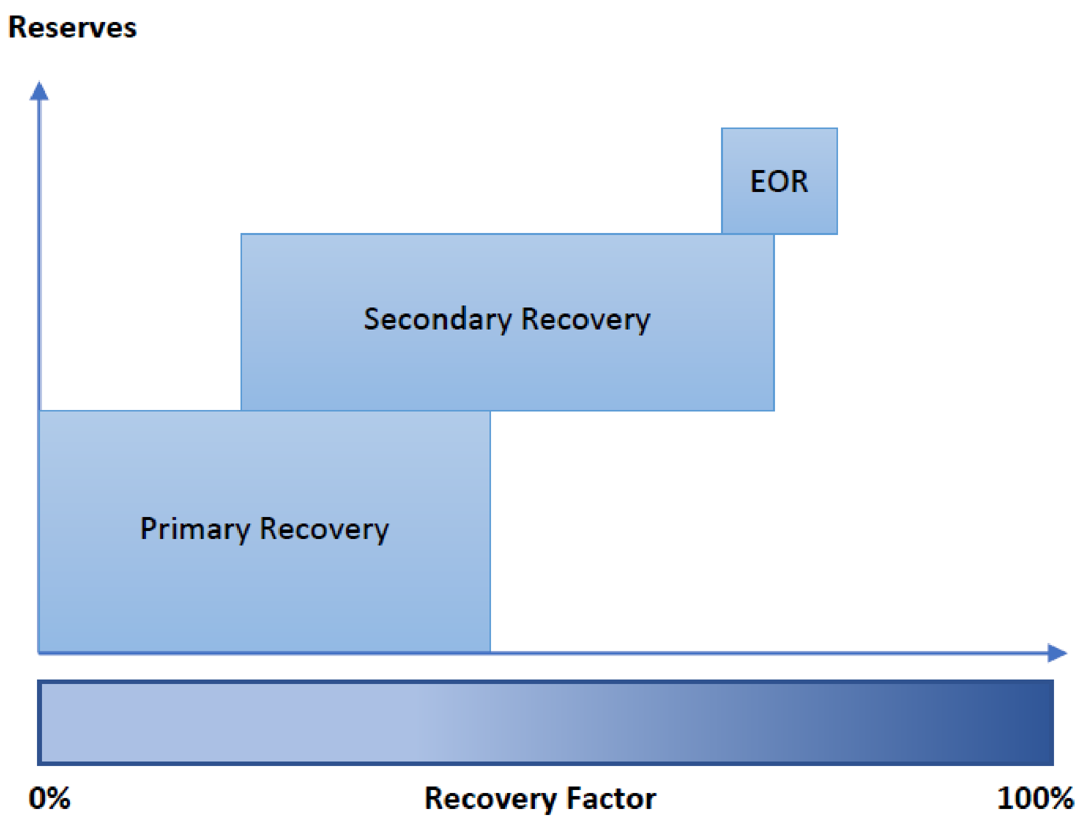


Figure O.3. Schematic of recovery factor and production volumes across life cycle stages of development

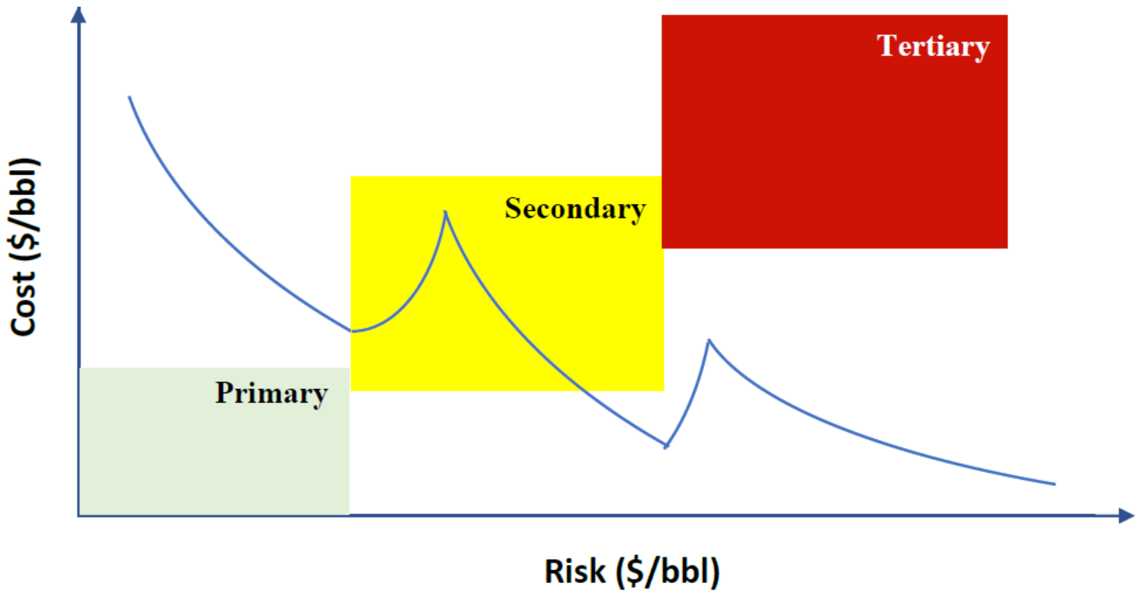


Figure O.4. Schematic of the cost and risk across the life cycle stages of production

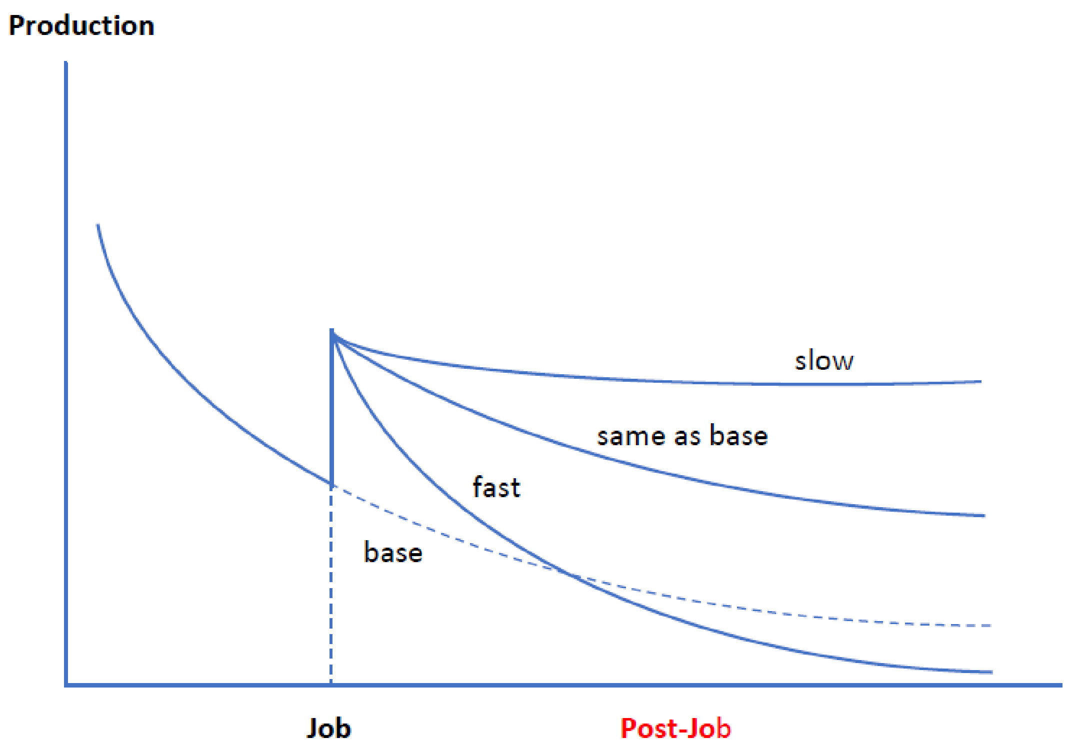


Figure O.5. Redevelopment requires investment and are accompanied by uncertain outcomes

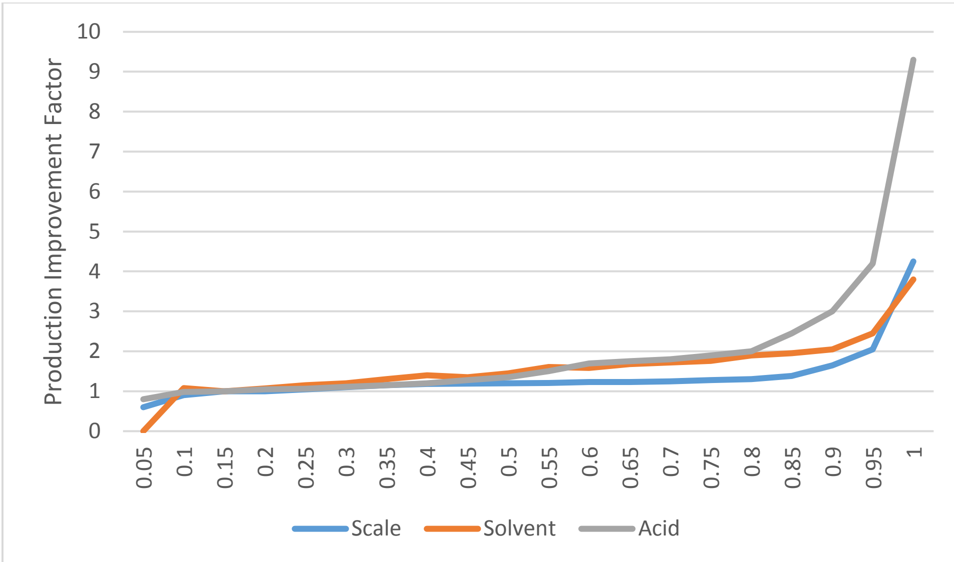


Figure O.6. Production improvement factor distribution for 128 deepwater well stimulations, 2002-2011
Source: Morgenthaler and Fry 2012

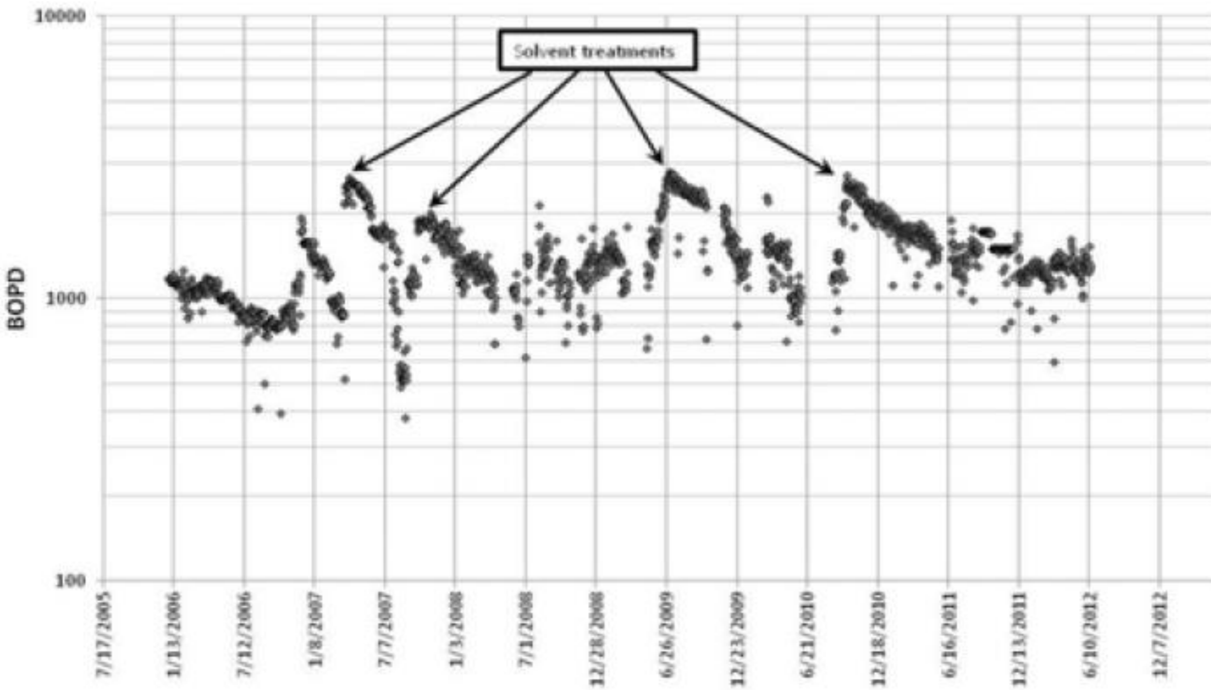


Figure O.7. Typical response for solvent treatments
Source: Morgenthaler and Fry 2012

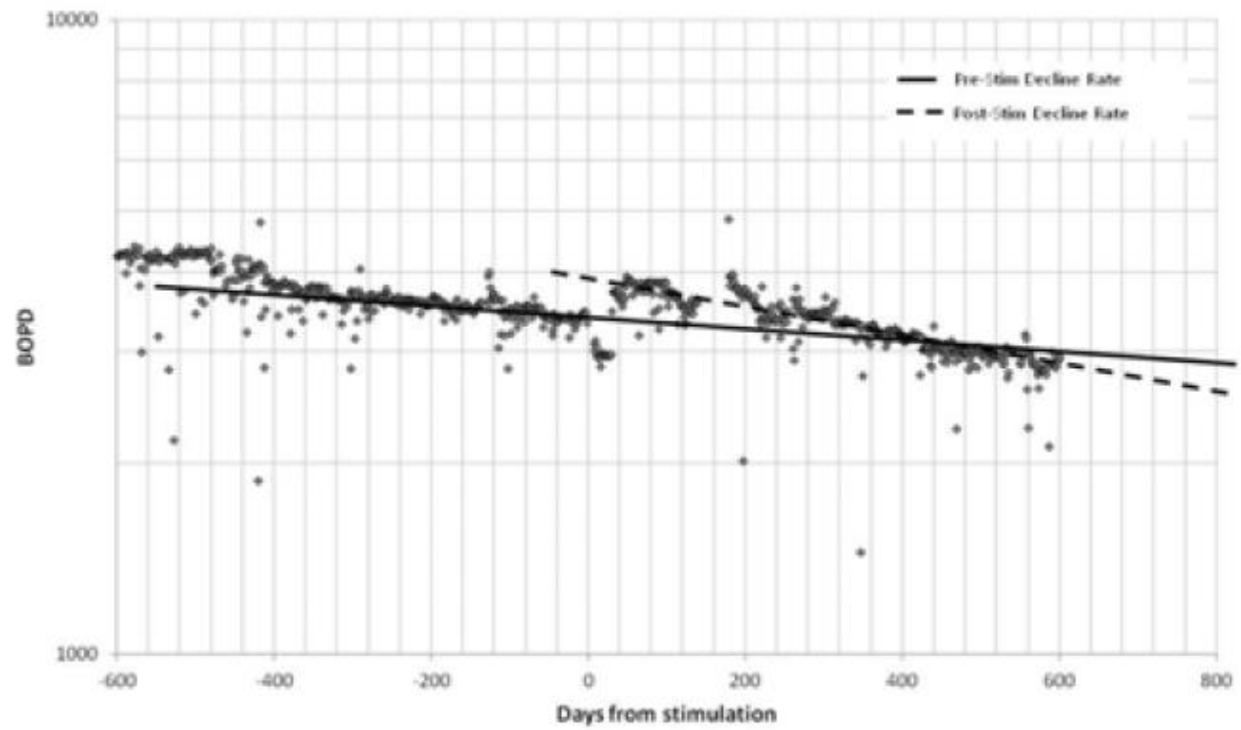


Figure O.8. Typical accelerated production response
Source: Morgenthaler and Fry 2012

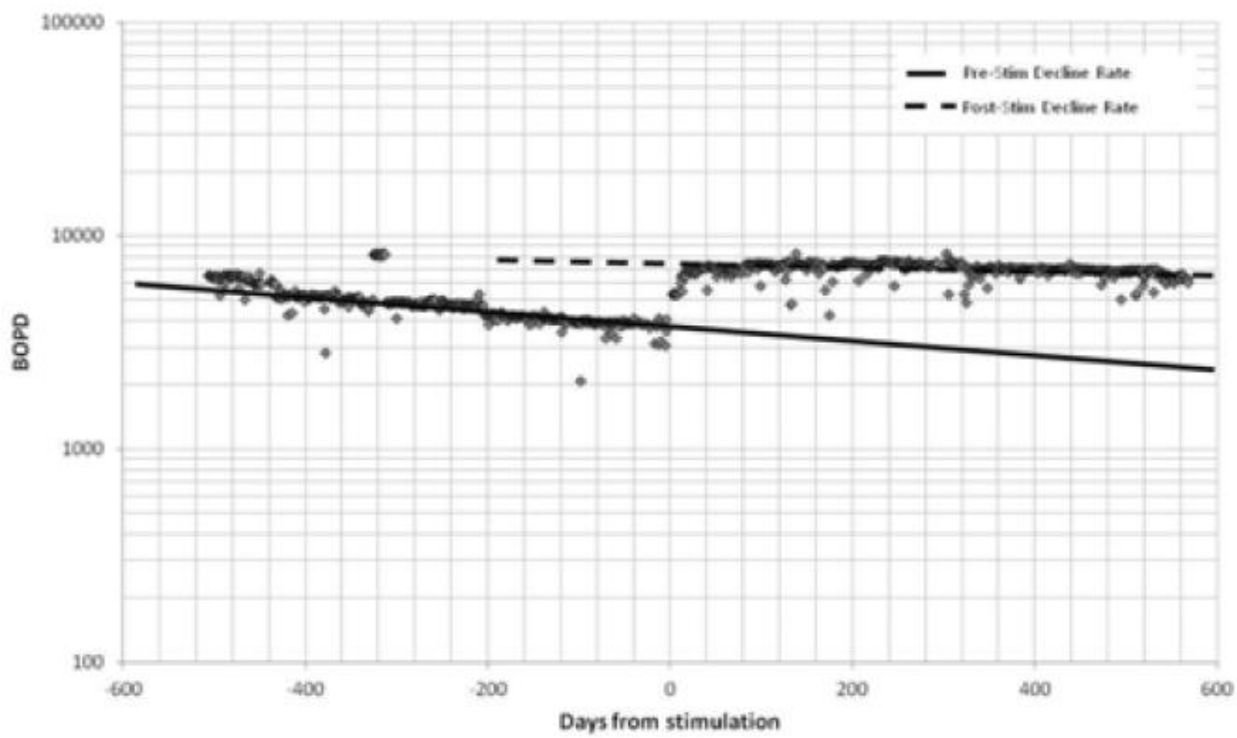


Figure O.9. Production response with shallower decline and increased volume recovery
Source: Morgenthaler and Fry 2012

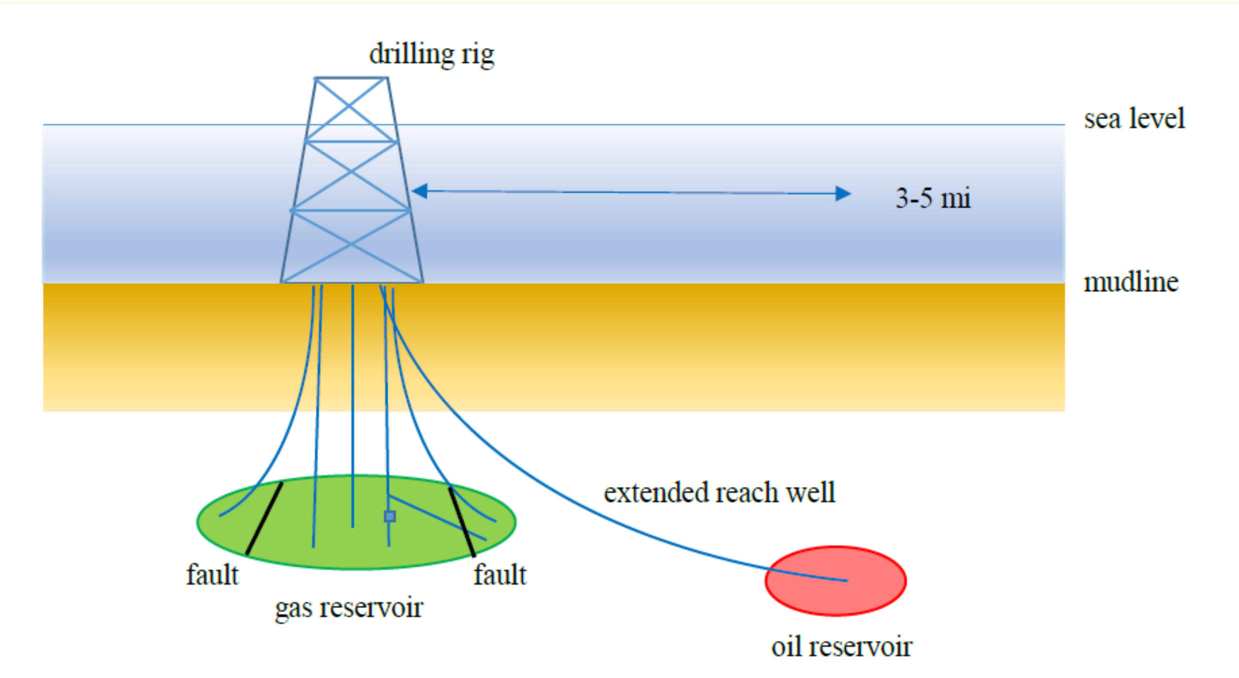


Figure O.10. Anchor field development and extended reach drilling

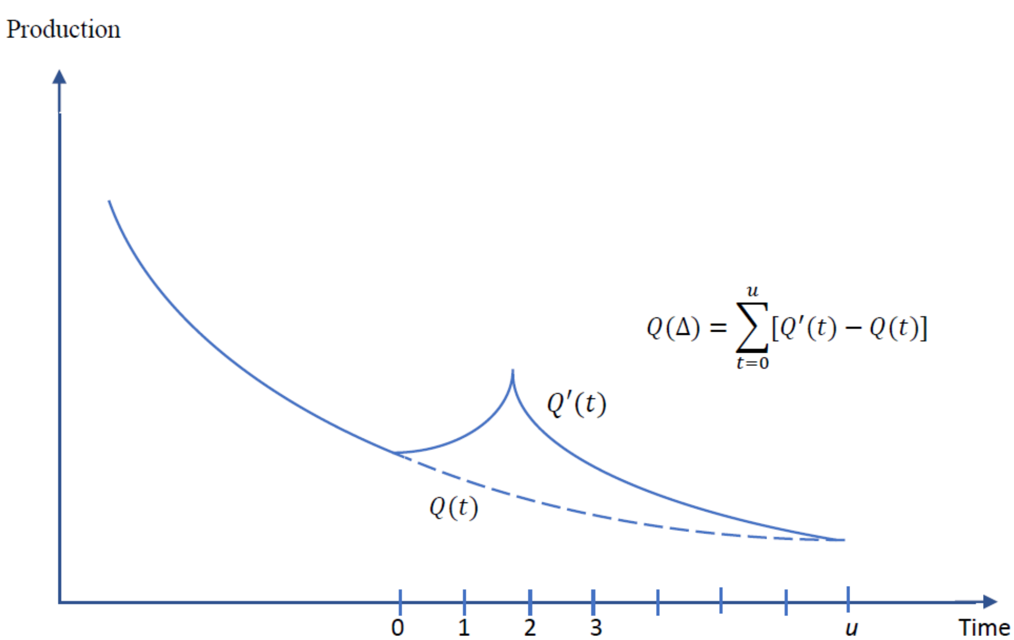


Figure O.11. Incremental production is estimated and after valuation compared against capital investment

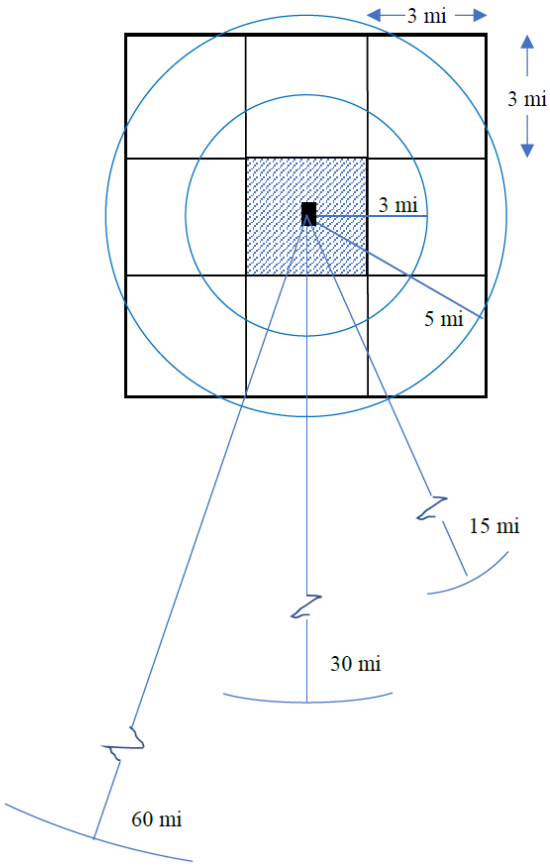


Figure O.12. Drilling zones and subsea tiebacks

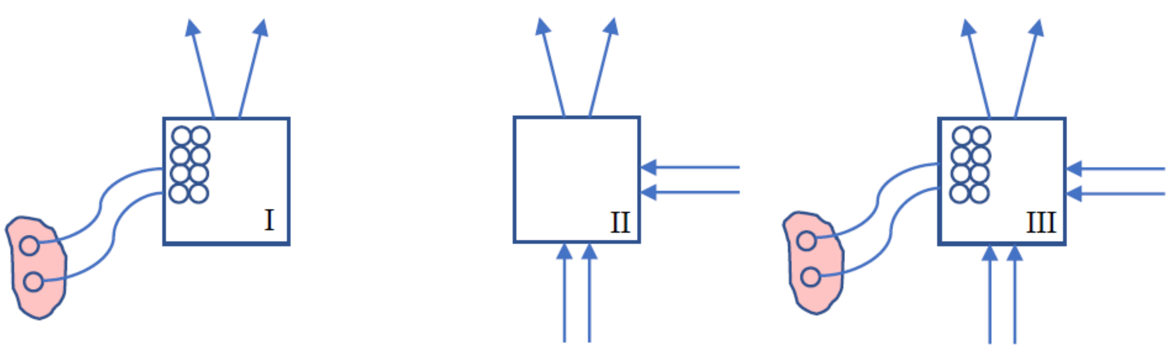


Figure O.13. Hub platform classes: field development (I), transportation (II), and combined services (III)

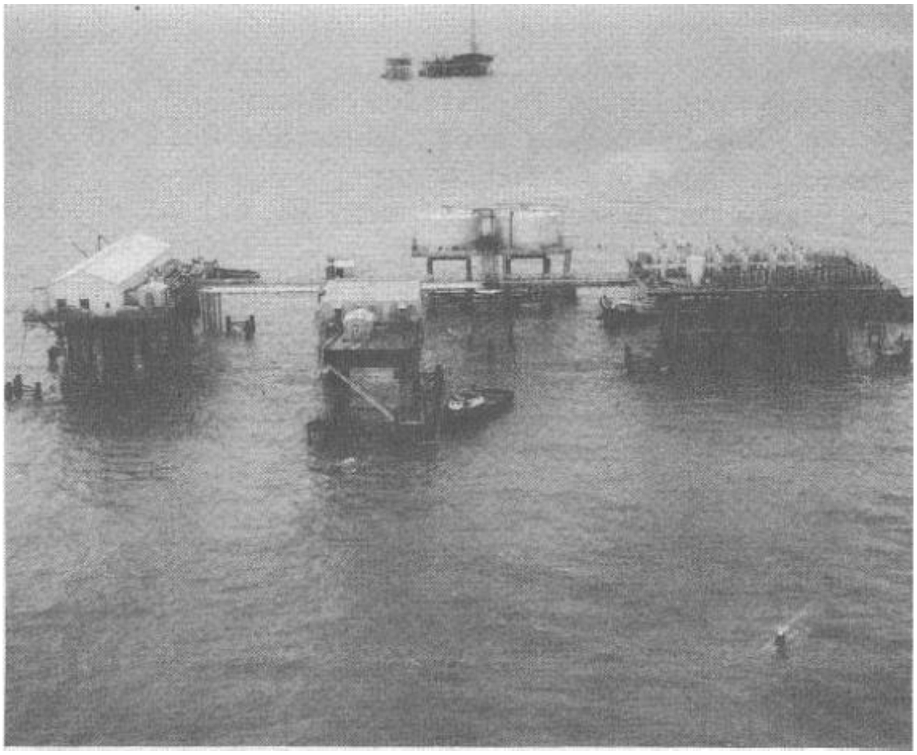


Figure O.14. Central production facility at the Eugene Island 126 field circa 1956
Source: Massad and Pela 1956

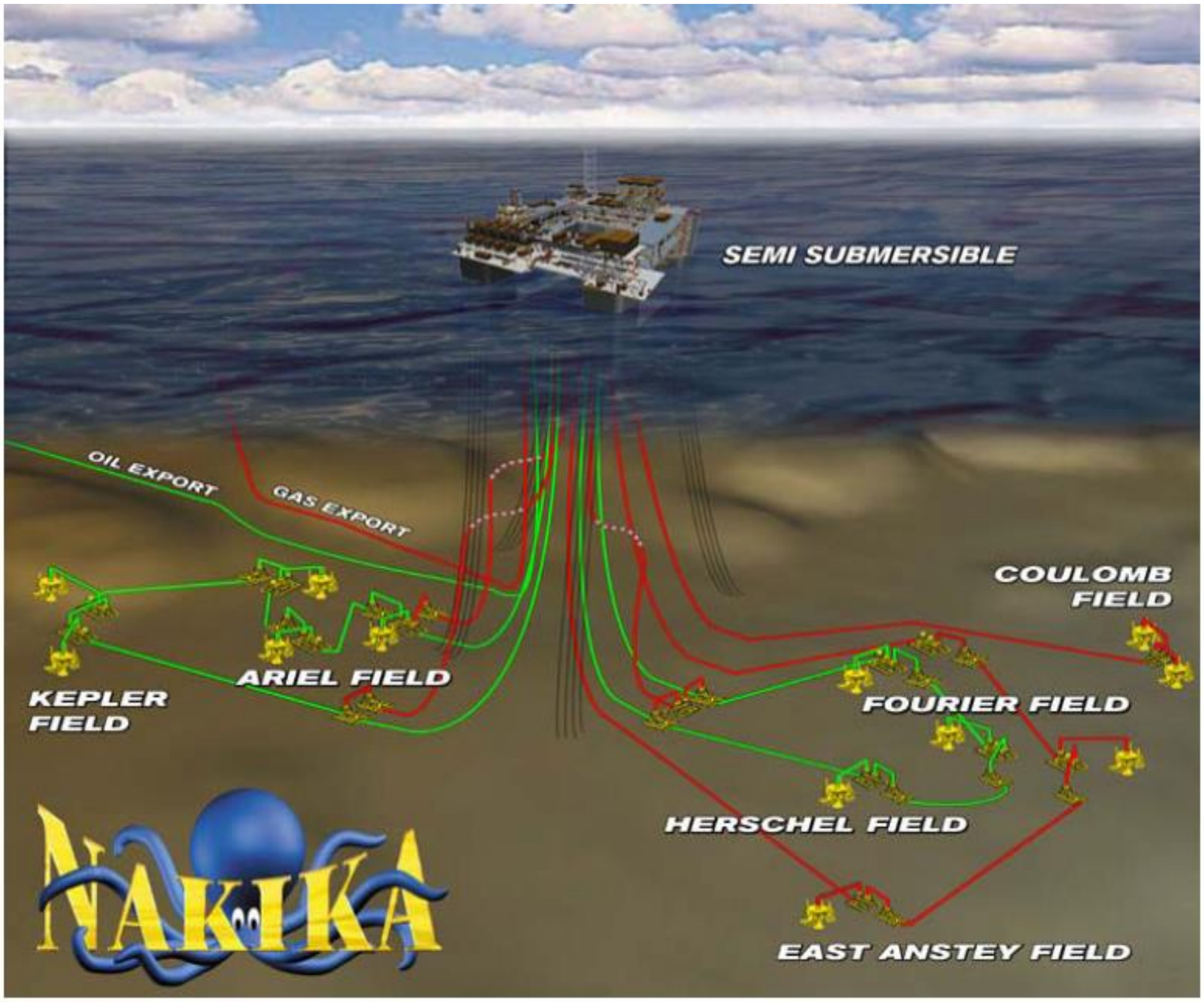


Figure O.15. Schematic of Na Kika host and subsea layout
Source: Kopp et al. 2004

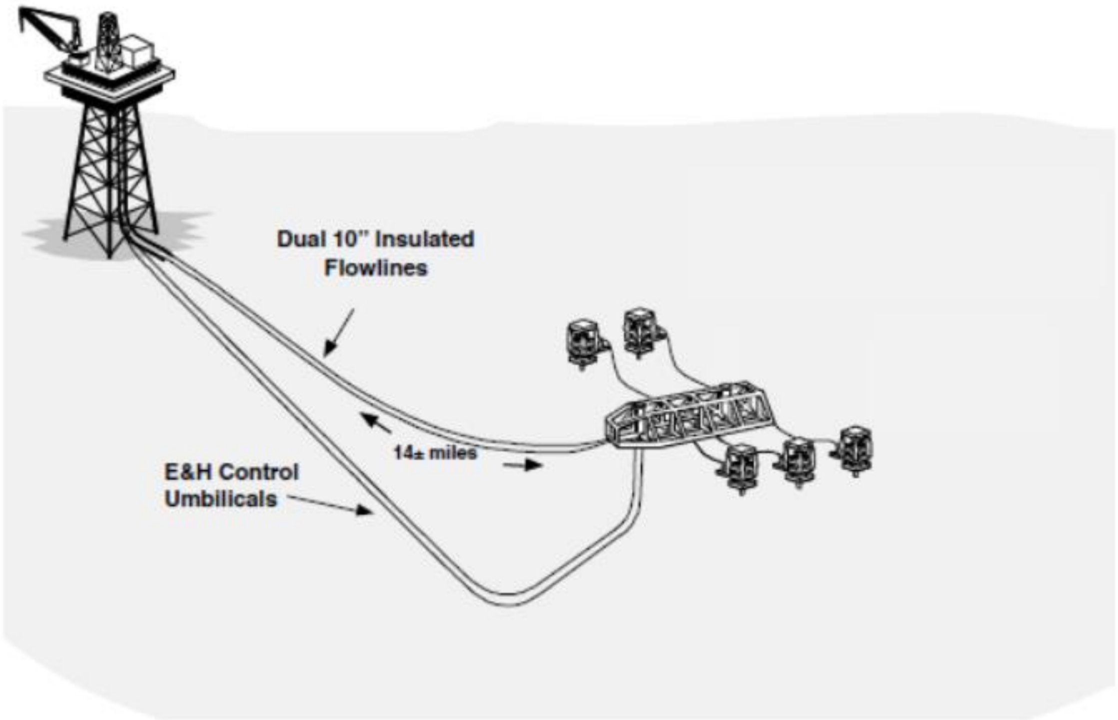


Figure O.16. Troika subsea system layout and tieback to host platform Bullwinkle
Source: Berger and McMullen 2001

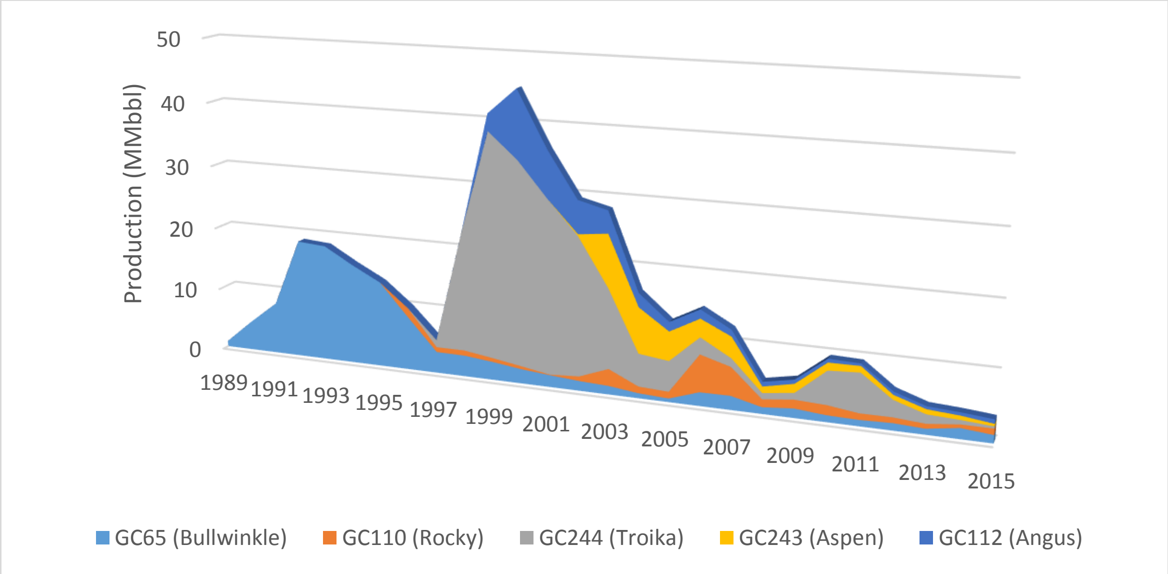


Figure O.17. Bullwinkle oil field production and subsea tiebacks Rocky, Troika, Angus and Aspen
Source: BOEM 2017

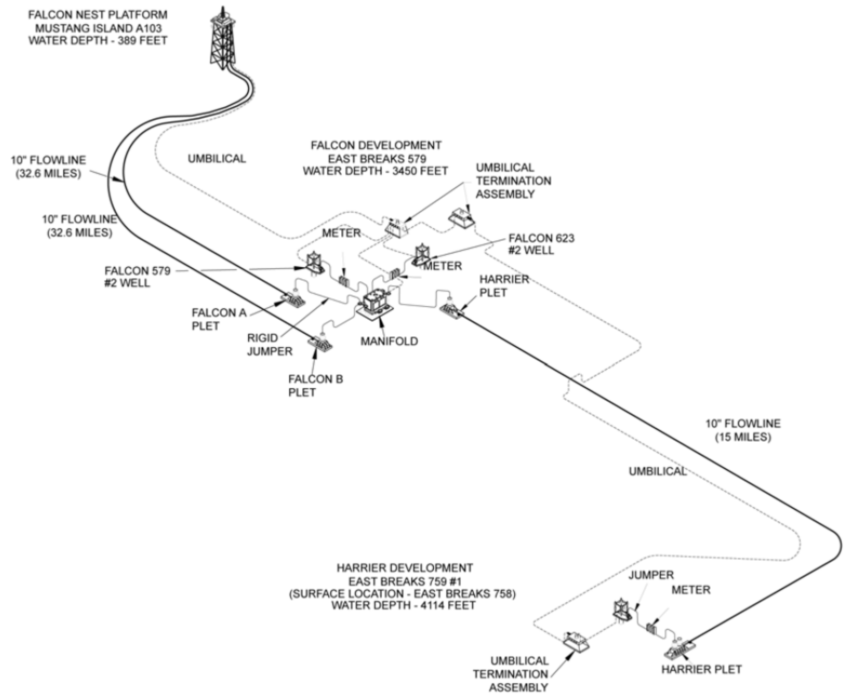


Figure O.18. Falcon Nest and Harrier field development schematic
Source: Hall et al. 2004

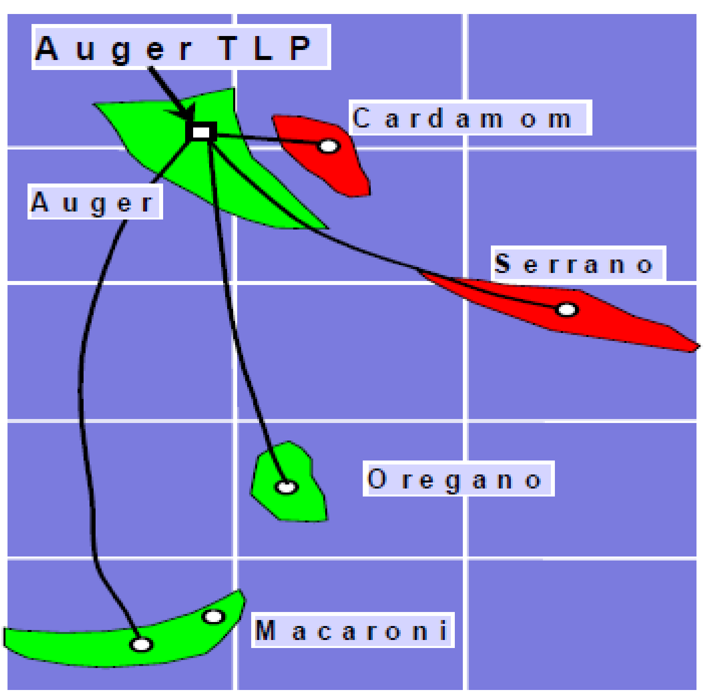


Figure O.19. Auger TLP subsea tiebacks Macaroni, Oregano and Serrano
Source: Brock 2000.

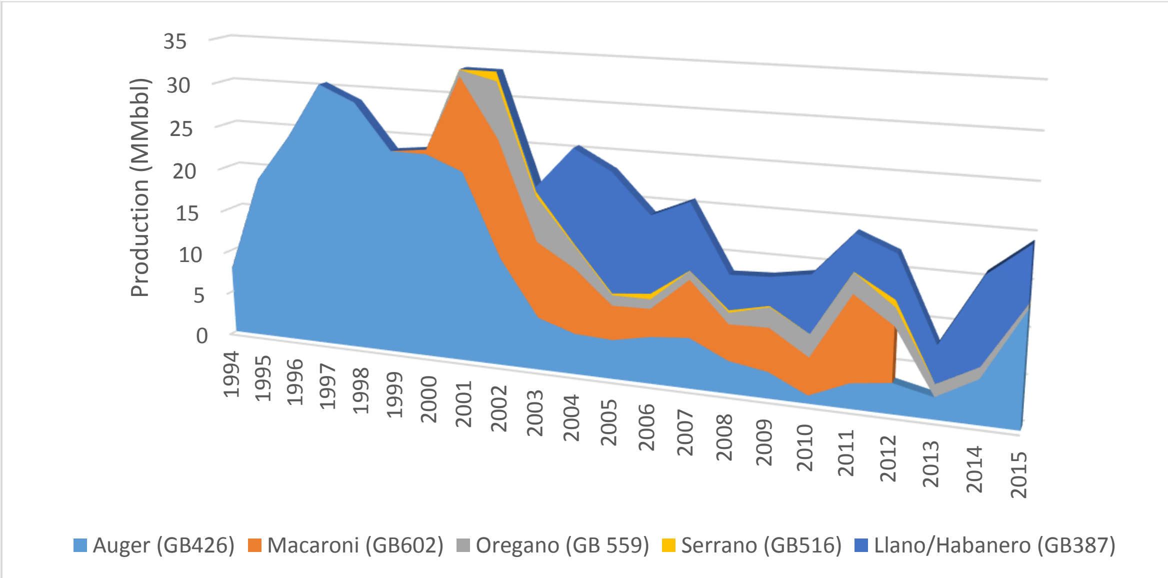


Figure O.20. Auger field production and subsea tiebacks Macaroni, Oregano, Serrano, and Llano
Source: BOEM 2017

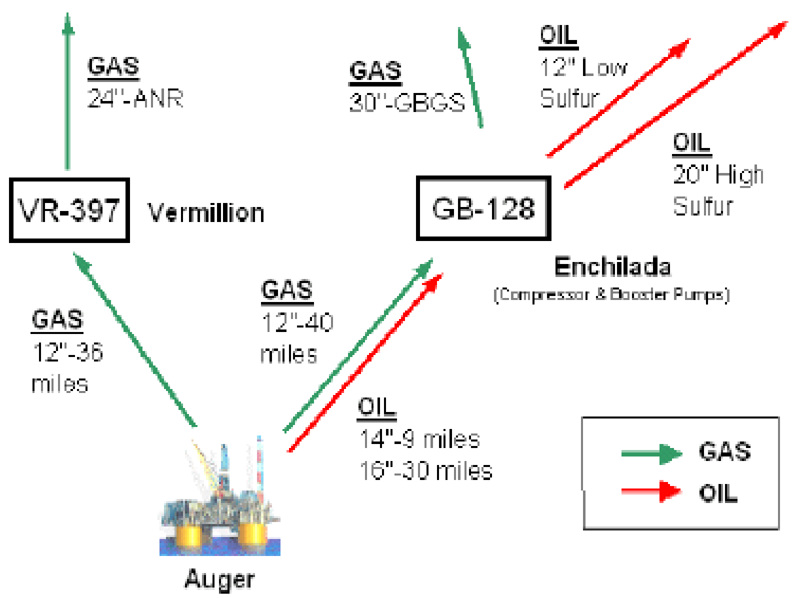


Figure O.21. Auger oil and gas export pipelines
Source: Brock 2000.

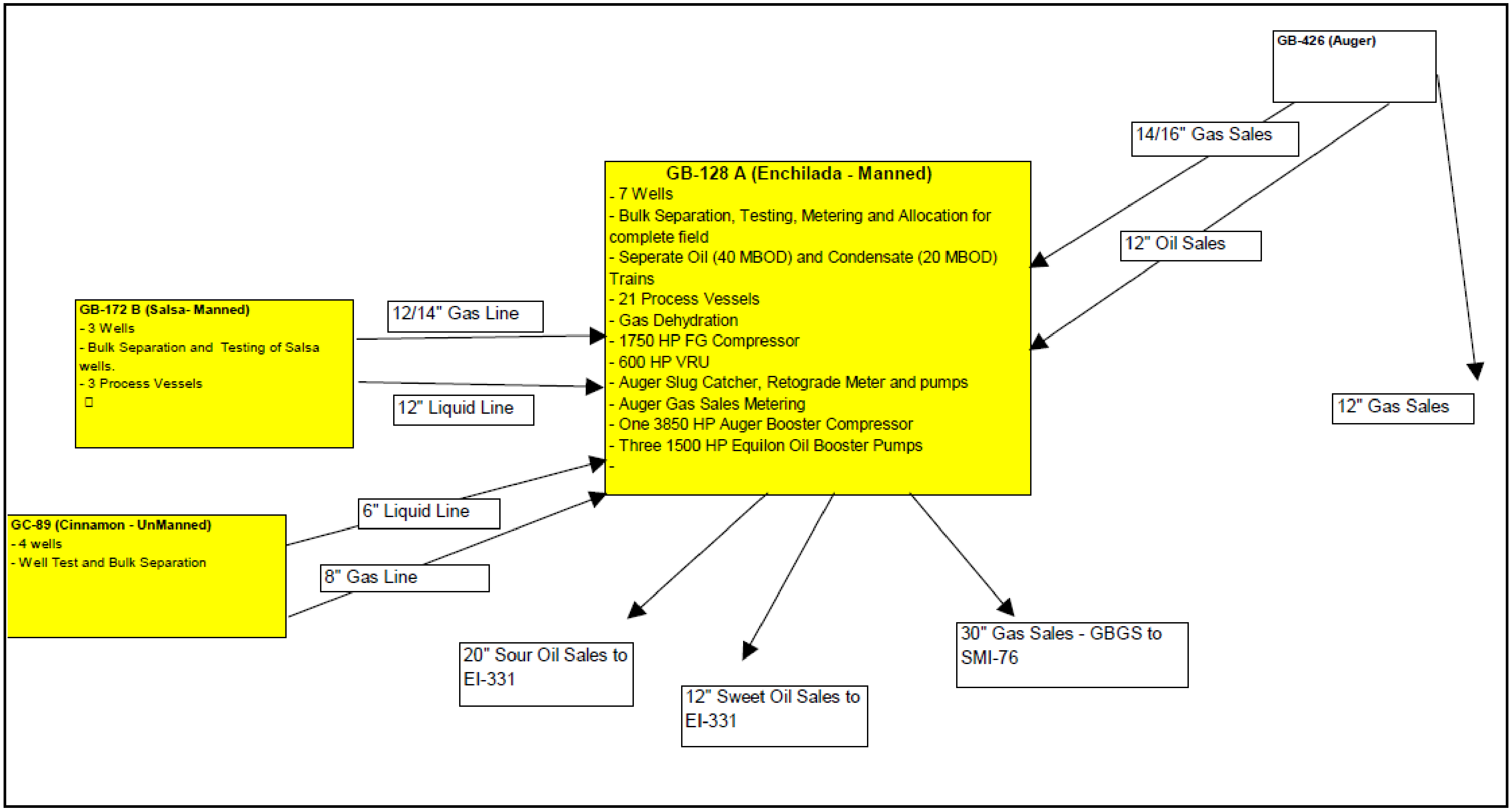


Figure O.22. Enchilada field layout circa 2000

Source: Smith and Pilney 2003

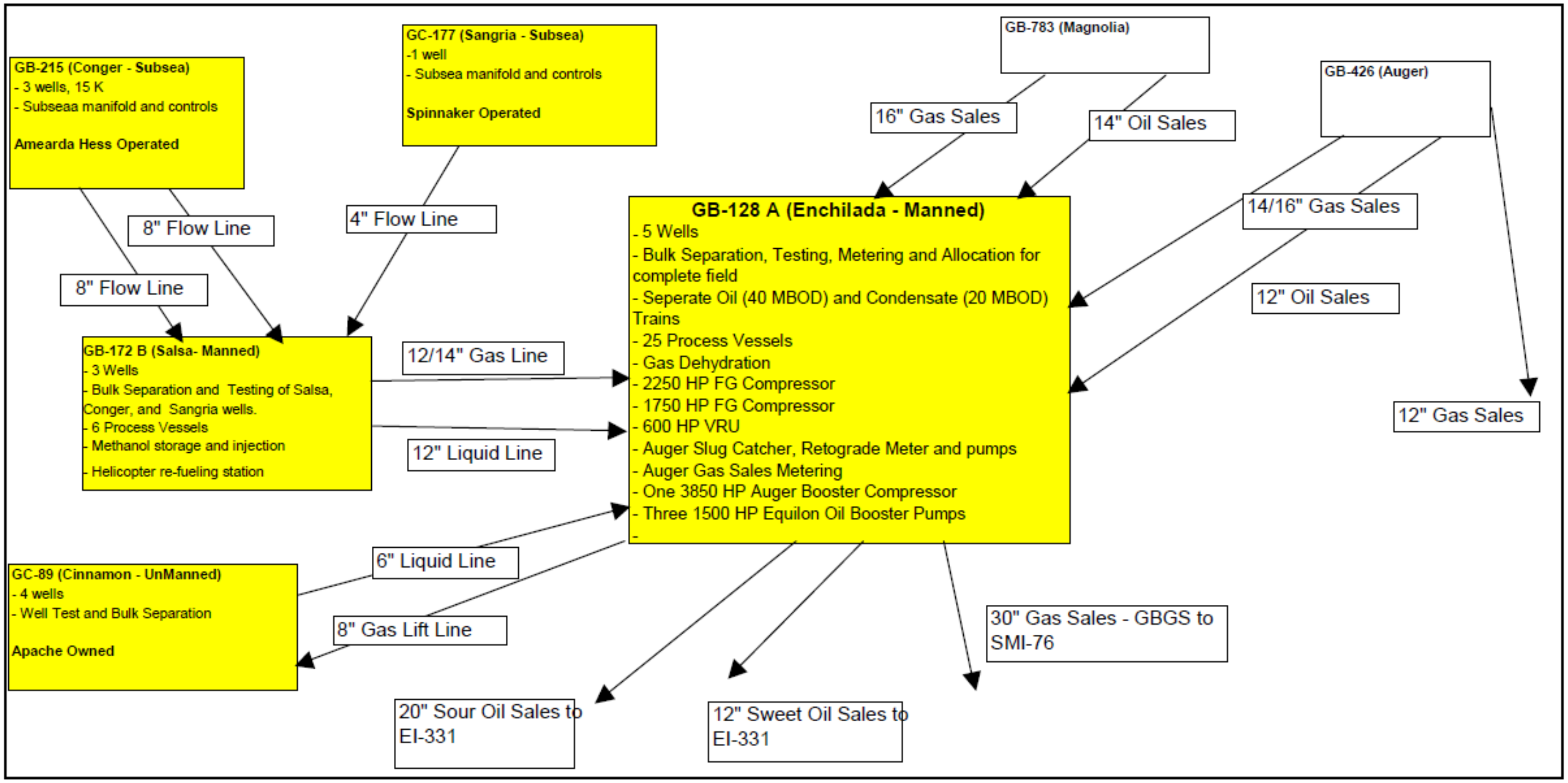


Figure O.23. Enchilada hub layout circa 2005

Source: Smith and Pilney 2003

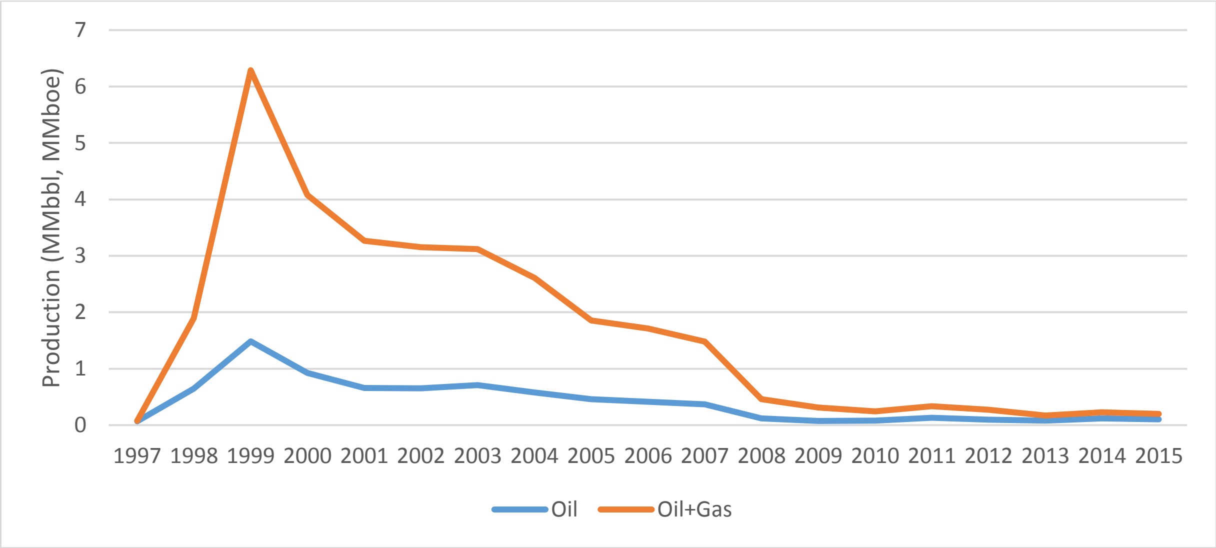


Figure O.24. Garden Bank 83 (Enchilada) field oil and gas production profile, 1997-2015

Source: BOEM 2017

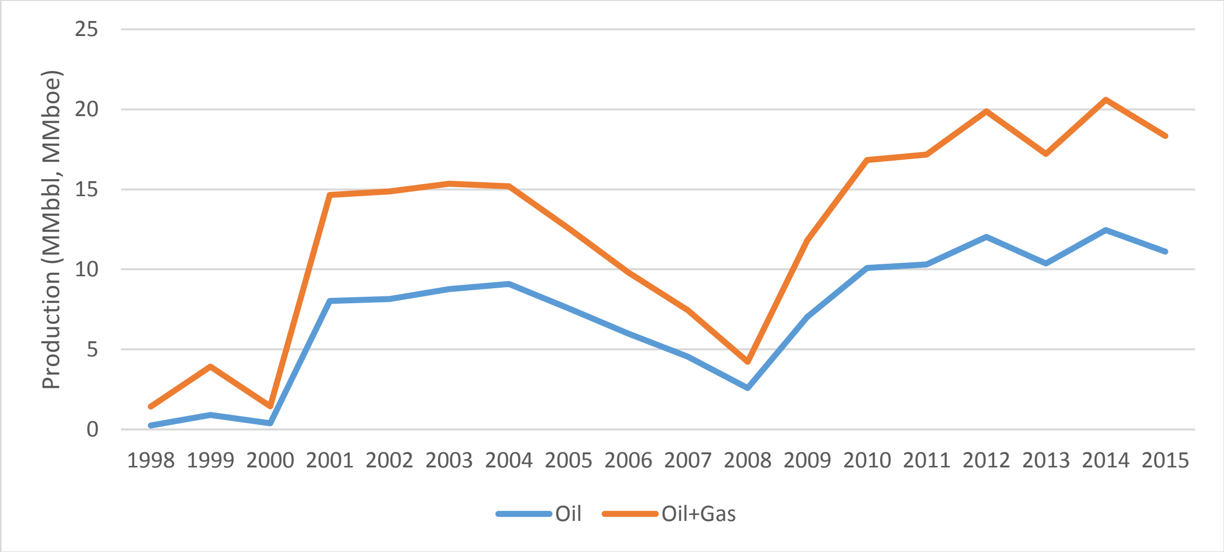


Figure O.25. Garden Bank 171 (Salsa) field oil and gas production profile, 1998-2015

Source: BOEM 2017

Figure O.26. Garden Bank 72 (Spectacular Bid) platform
Source: Huff and Heijermans 2003

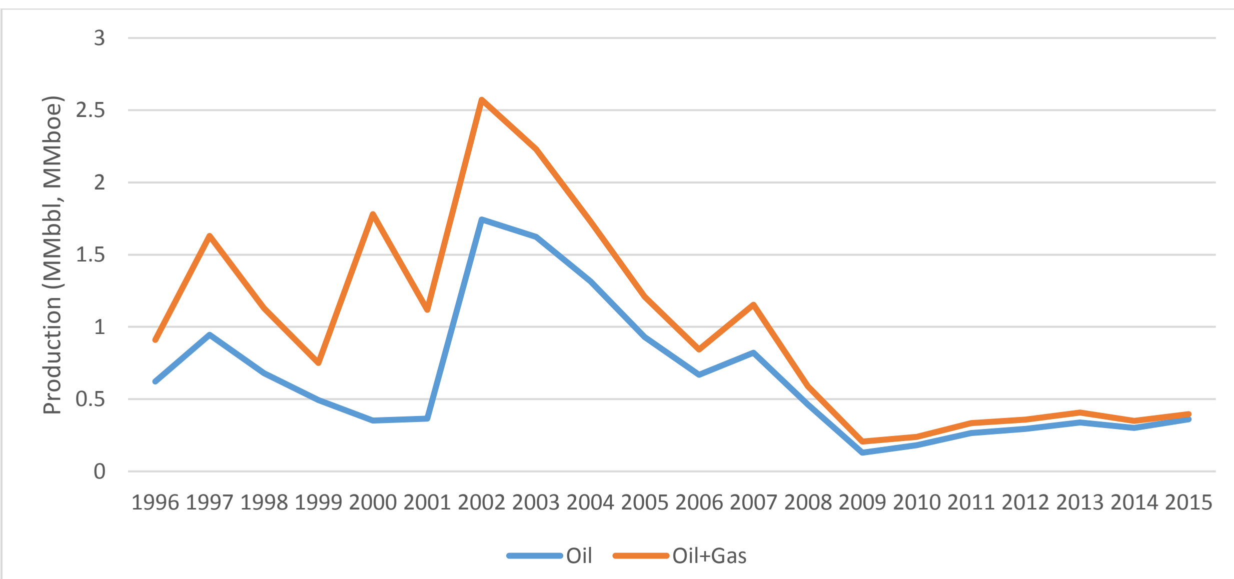


Figure O.27. Garden Bank 72 (Spectacular Bid) field oil and gas production profile, 1996-2015
Source: BOEM 2017

Figure O.28. Ship Shoal 332 A&B platform hub for the Cameron highway pipeline system and close-up of SS 332A

Source: Genesis Energy 2017, Huff and Heijermans 2003

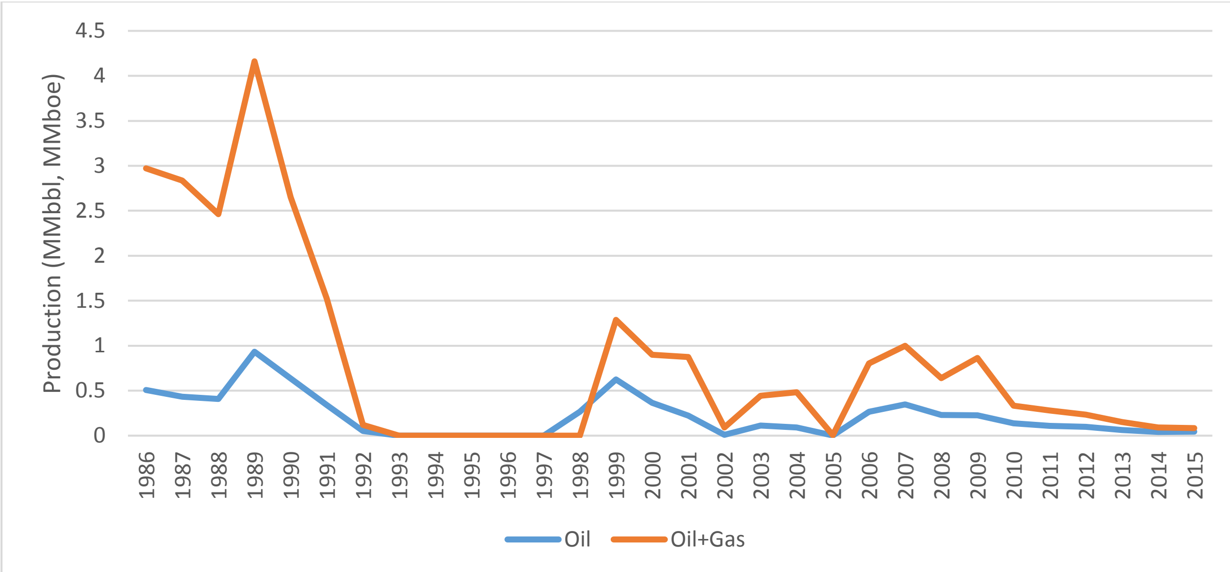


Figure O.29. Ship Shoal 332 field oil and gas production profile, 1986-2015
Source: BOEM 2017

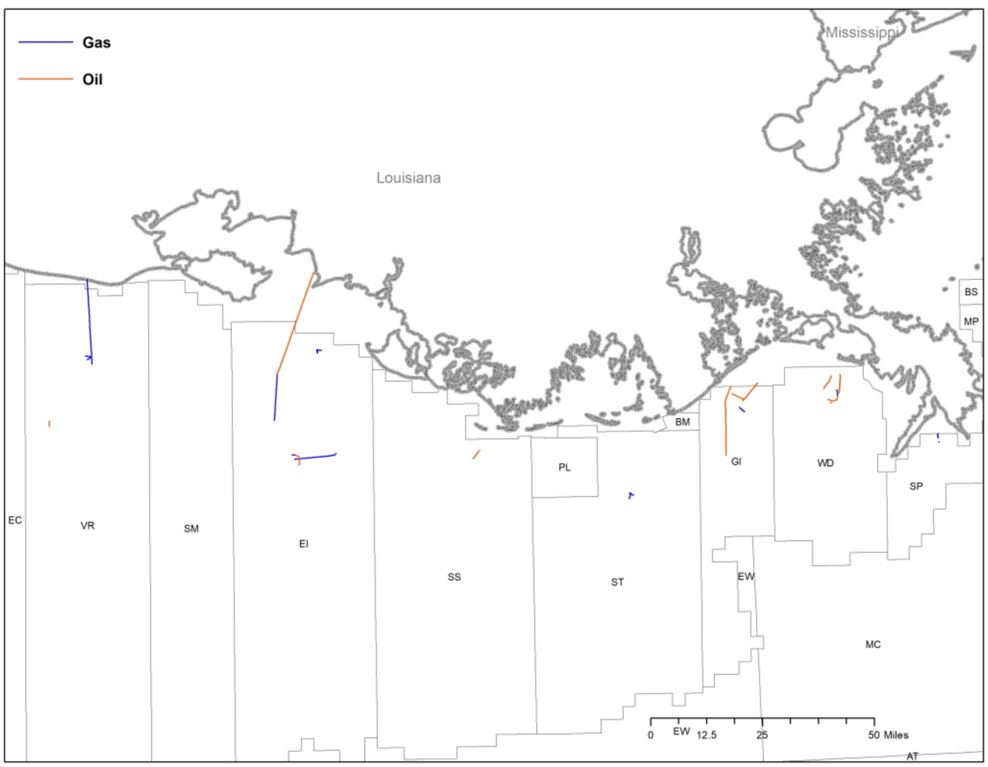


Figure O.30a. Oil and gas export pipeline installed in the Gulf of Mexico in the 1950s
Source: BOEM 2018

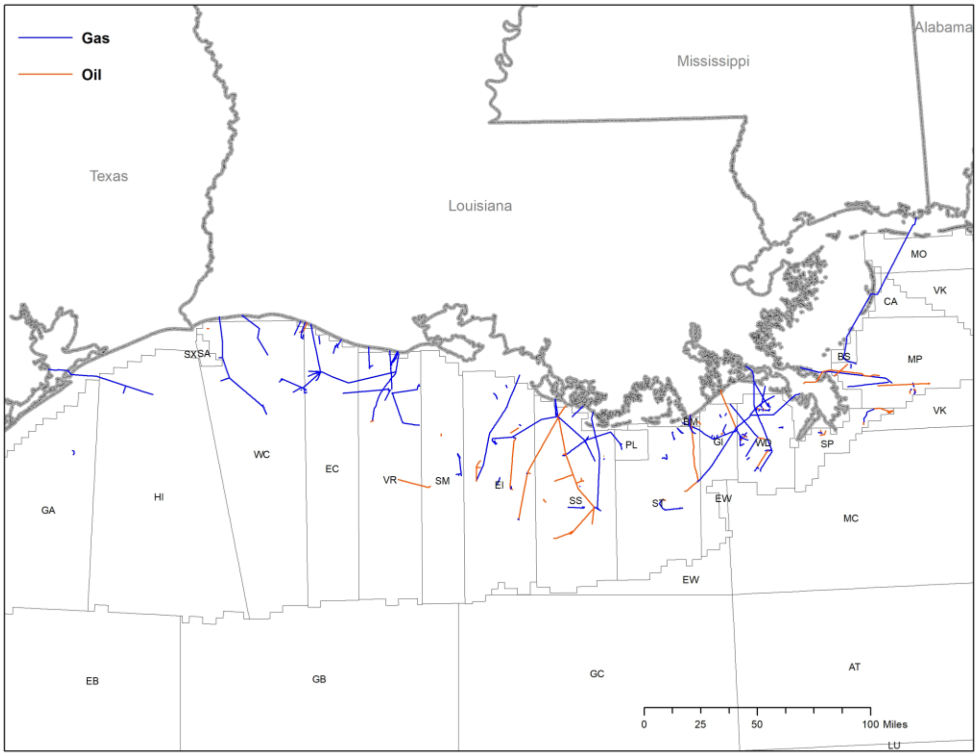


Figure O.30b. Oil and gas export pipeline installed in the Gulf of Mexico in the 1960s
Source: BOEM 2018

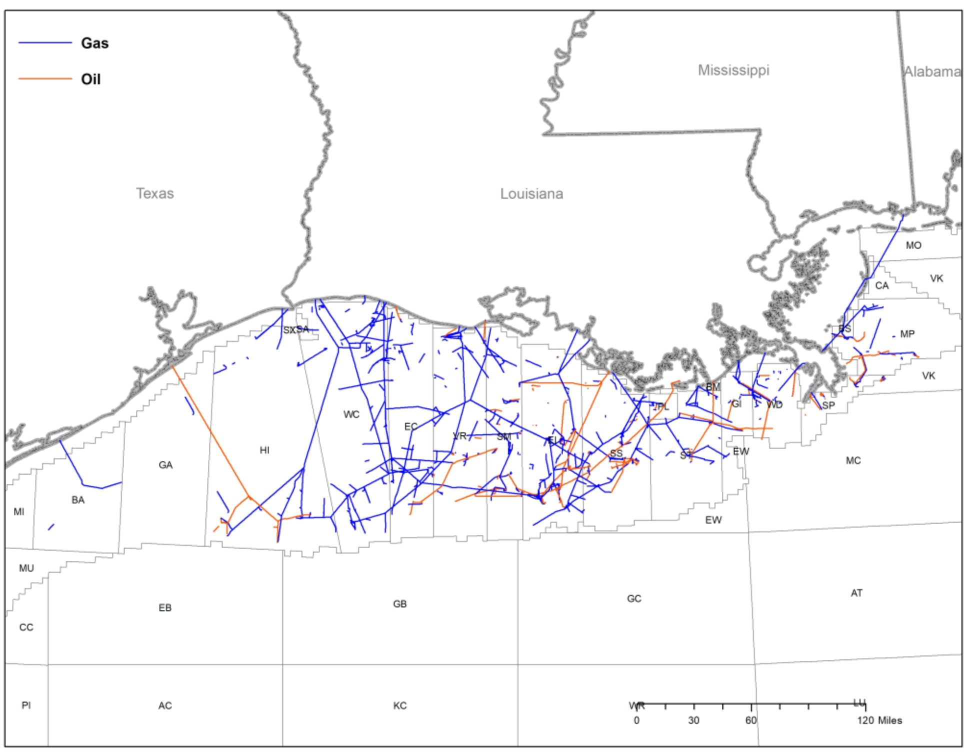


Figure O.30c. Oil and gas export pipeline installed in the Gulf of Mexico in the 1970s
Source: BOEM 2018

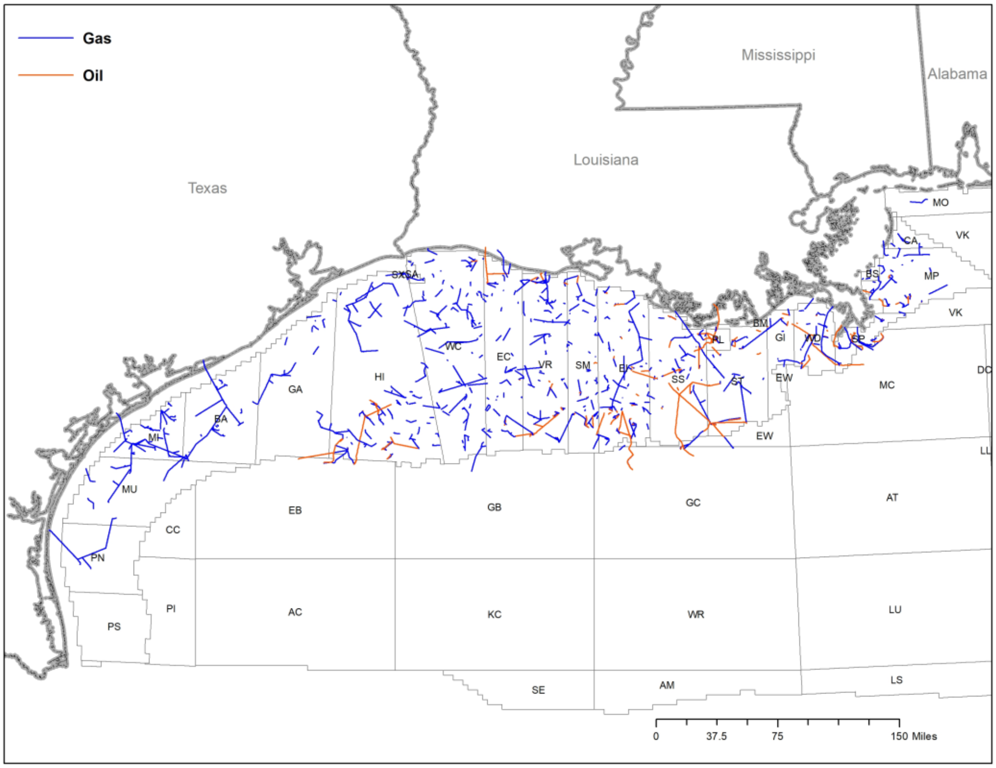


Figure O.30d. Oil and gas export pipeline installed in the Gulf of Mexico in the 1980s
Source: BOEM 2018

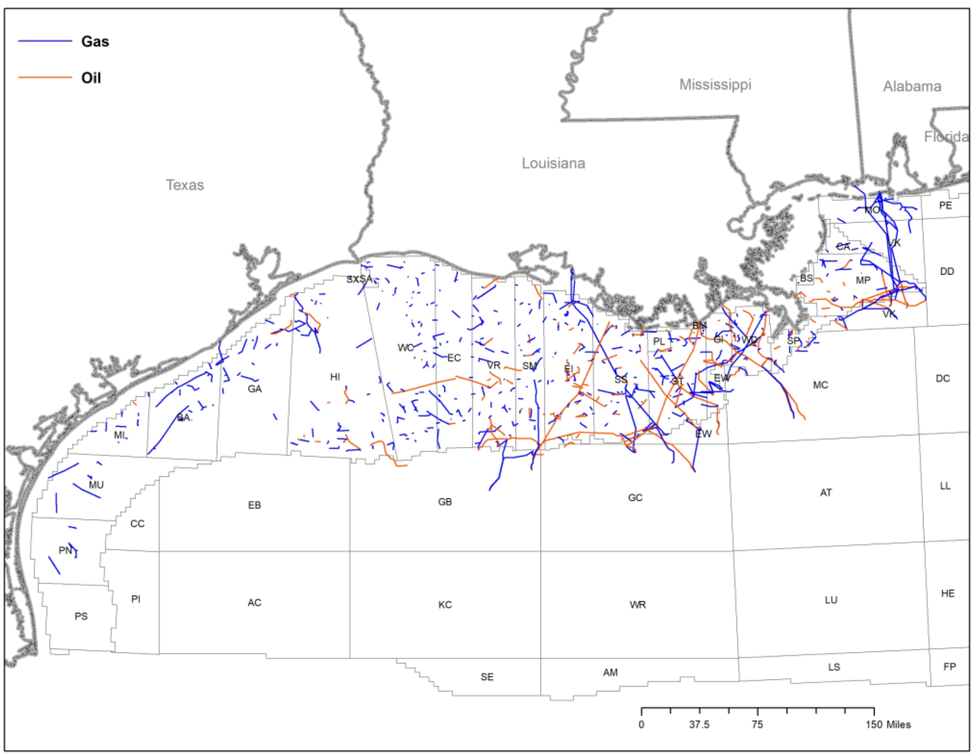


Figure O.30e. Oil and gas export pipeline installed in the Gulf of Mexico in the 1990s
Source: BOEM 2018

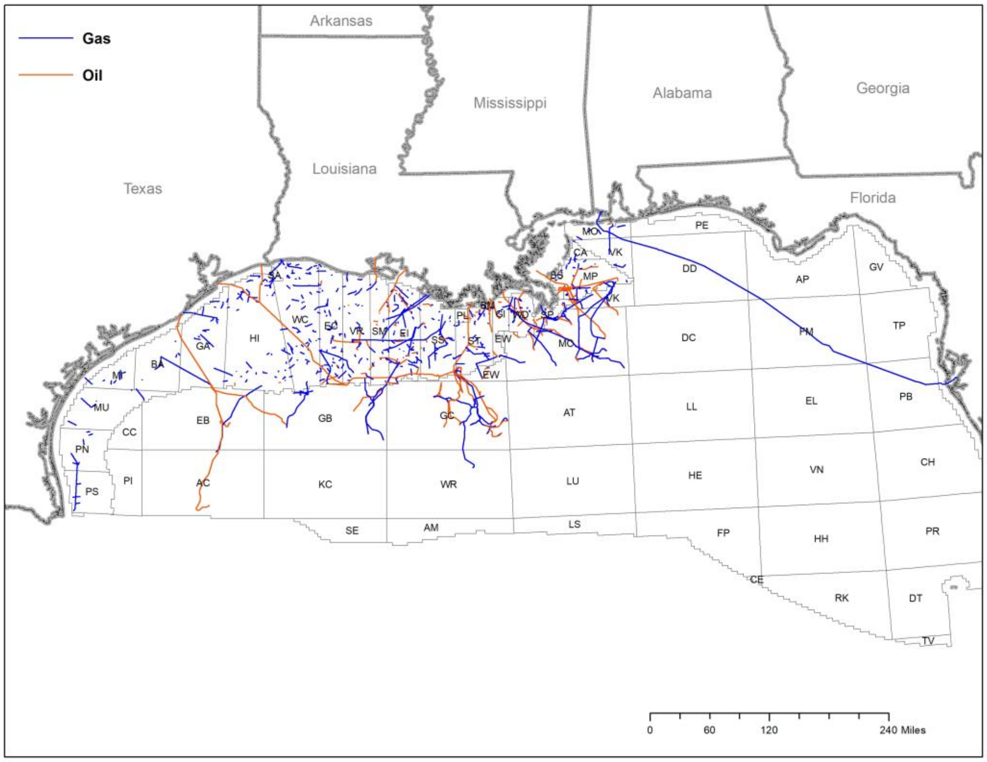


Figure O.30f. Oil and gas export pipeline installed in the Gulf of Mexico in the 2000s
Source: BOEM 2018

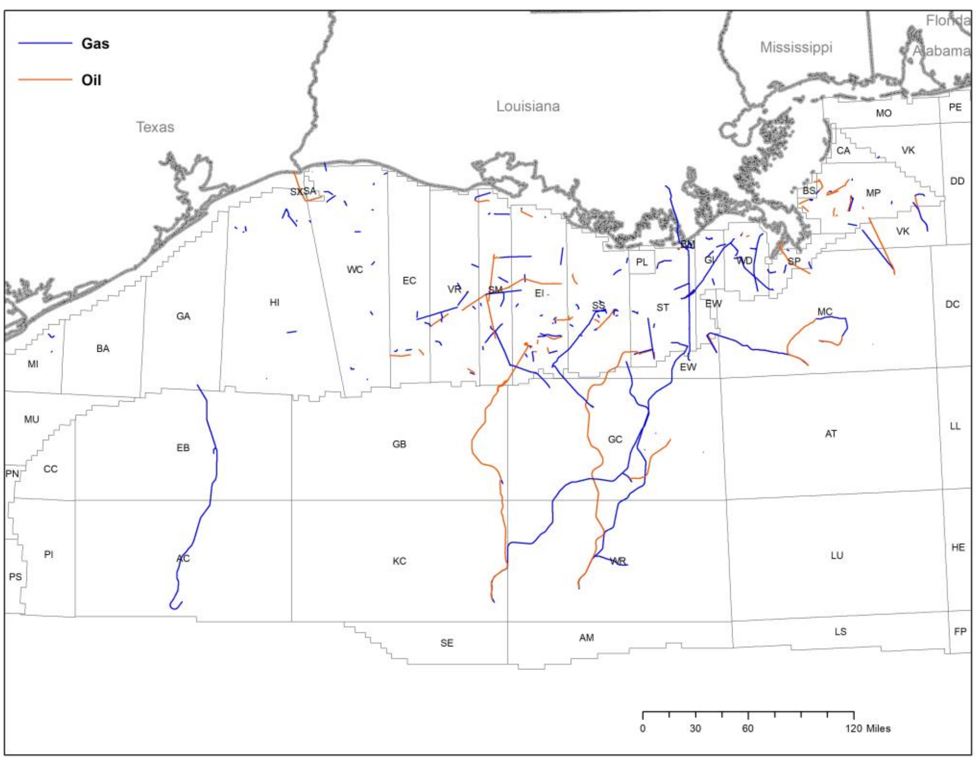


Figure O.30g. Oil and gas export pipeline installed in the Gulf of Mexico in the 2010s
Source: BOEM 2018

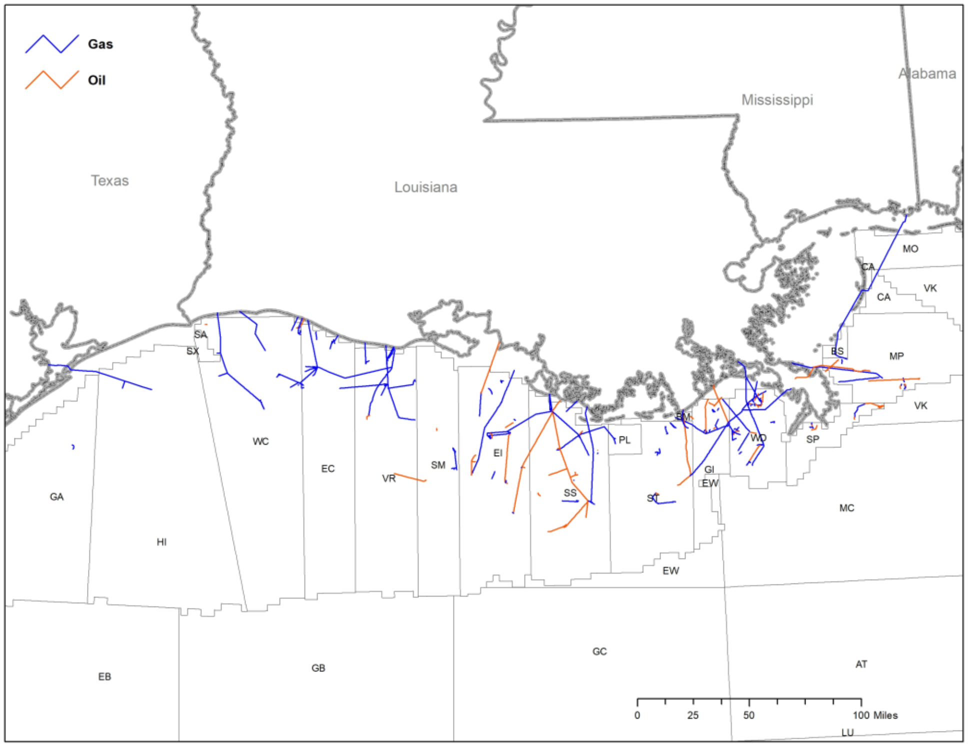


Figure O.31a. Active oil and gas export pipeline in the Gulf of Mexico circa 1969
Source: BOEM 2018

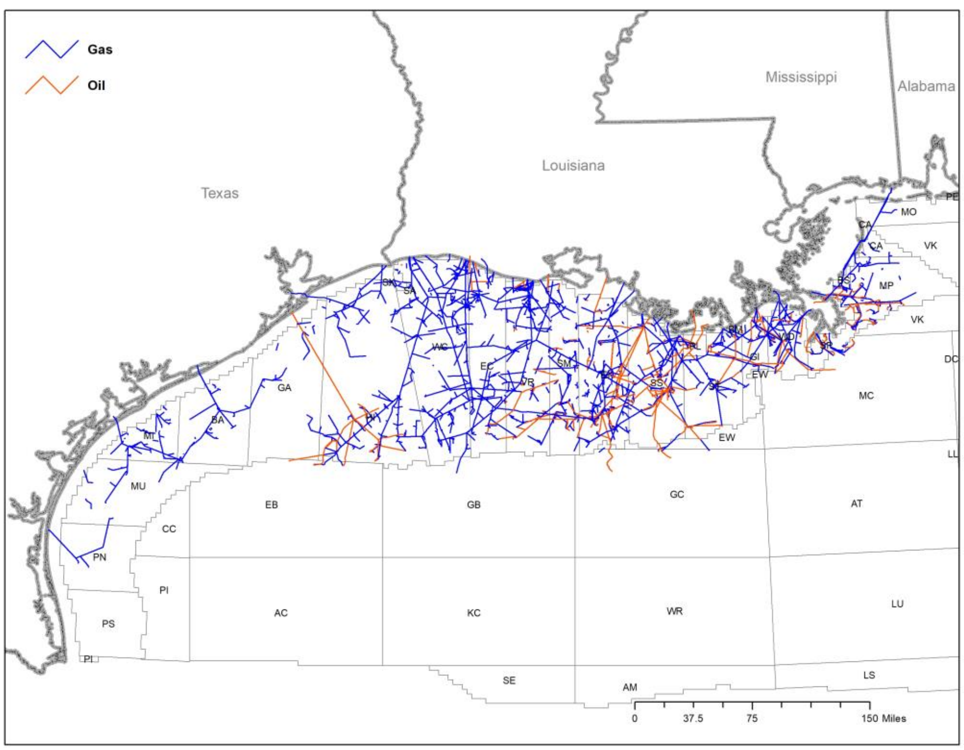


Figure O.31b. Active oil and gas export pipeline in the Gulf of Mexico circa 1989
Source: BOEM 2018

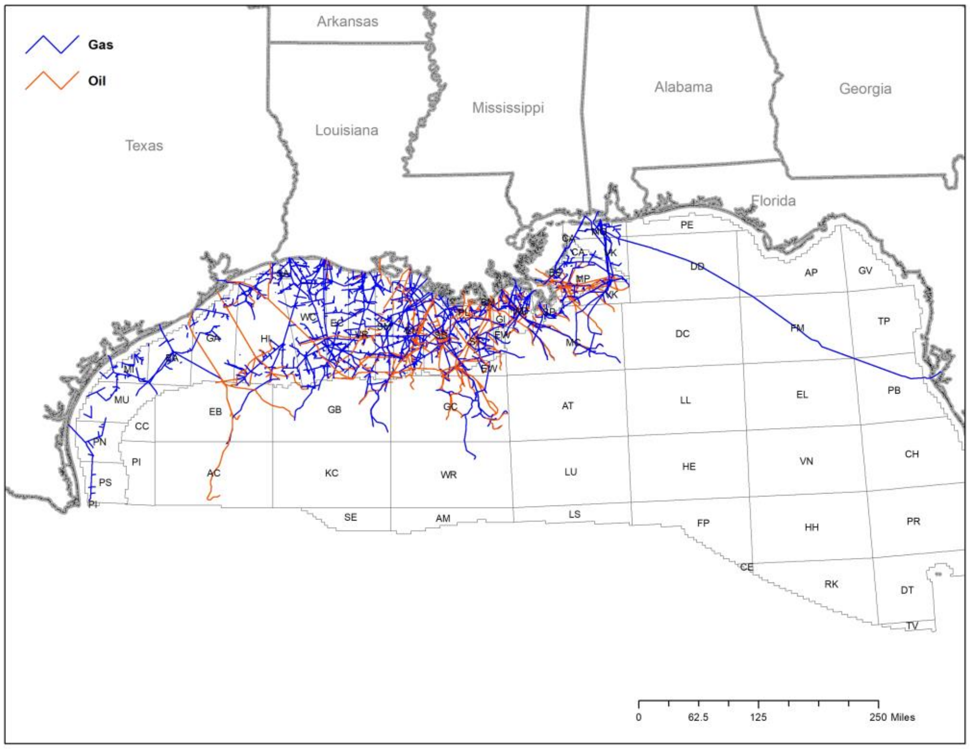


Figure O.31c. Active oil and gas export pipeline in the Gulf of Mexico circa 2009
Source: BOEM 2018

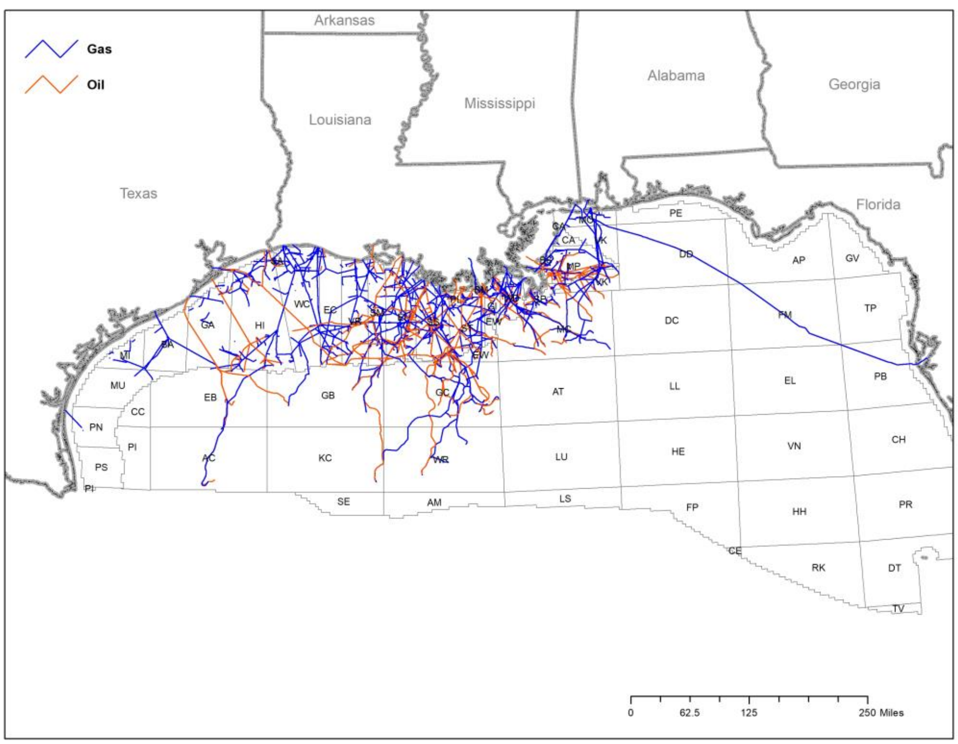


Figure O.31d. Active oil and gas export pipeline in the Gulf of Mexico circa 2018
Source: BOEM 2018

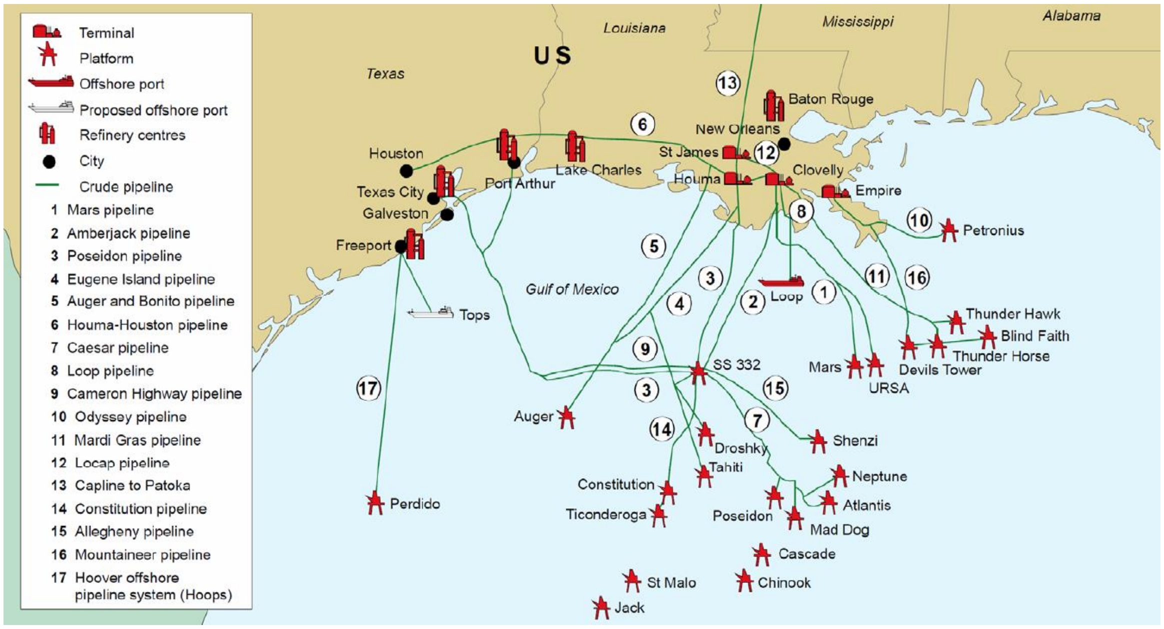


Figure O.32. Gulf of Mexico major oil pipelines

Source: Massey 2005

Figure O.33. Poseidon oil pipeline network and South Marsh Island 205A junction platform
Source: Poseidon Oil Pipeline Company

Figure O.34. Shell's oil pipeline network and transportation platforms in yellow

Figure O.35. El Paso's oil pipeline network and platforms circa 2003
Source: Huff and Heijermans 2003

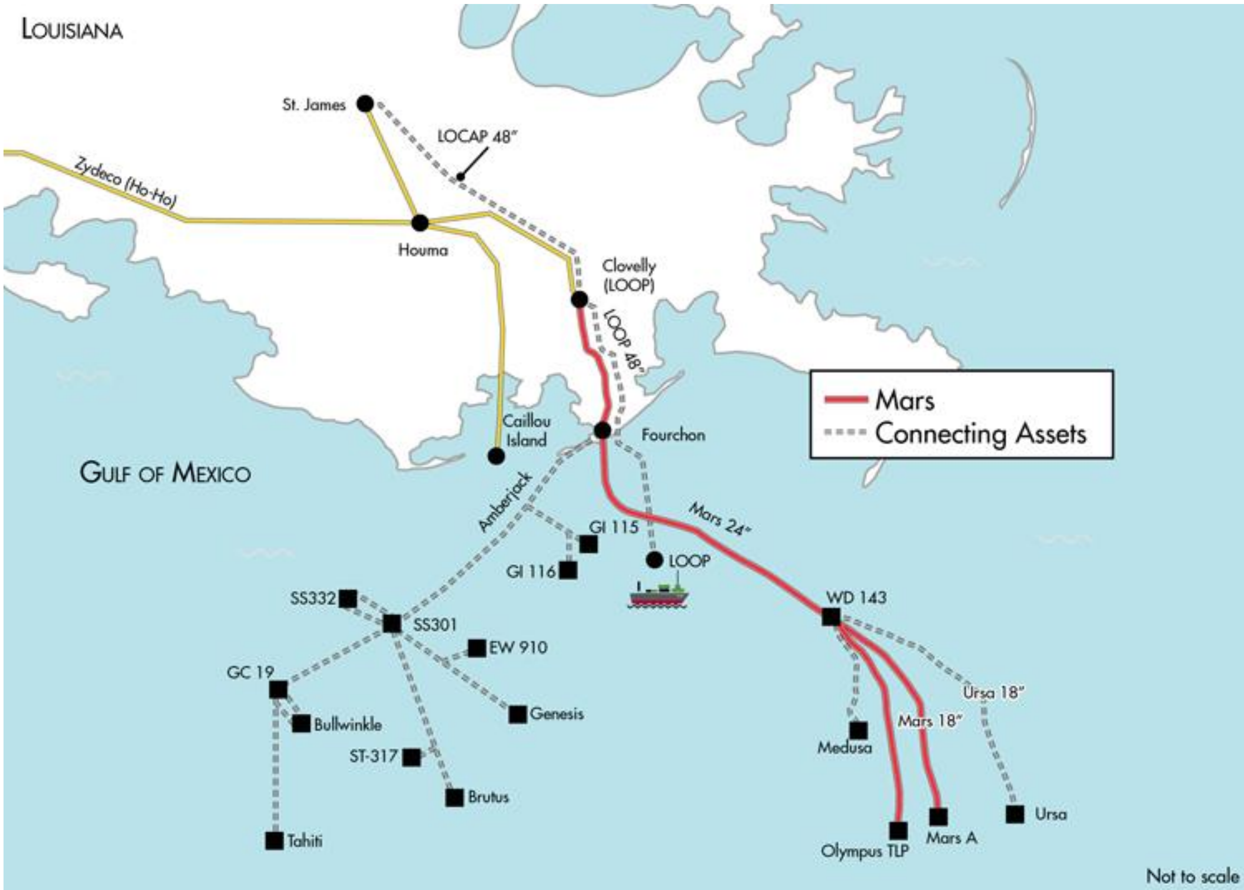


Figure O.36. Shell's central Gulf of Mexico oil pipeline network
Source: Shell Midstream Partners

APPENDIX P

CHAPTER 16 TABLES AND FIGURES

Table P.1. Lobster and subsea tieback cumulative production circa September 2017

Name	Field	Operator	Lease Blocks	Cumul. Oil (MMbbl)	Cumul. Gas (Bcf)
Lobster	EW 873	EnVen Energy Fieldwood	EW 873, 874, 914; ST 308	172	157.7
Seattle Slew	EW 914	Walter Oil & Gas	EW 914, 915, 871	13.4	17.0
Arnold	EW 963	EnVen Energy	EW 963	22.7	20.0
Manta Ray	EW 1006	Marathon Oil Walter Oil & Gas	EW 1006	4.7	12.4

Source: BOEM 2017

Table P.2. Corporate bankruptcies with significant Gulf of Mexico presence, 2015-2017

Filing Date	Debtor	Total ($million)
08/11/2015	Black Elk Energy Offshore	145
10/26/2015	RAAM Global Energy Company	304
03/24/2016	Whister Energy II, LLC	192
04/14/2016	Energy XXI, Ltd	2750
05/16/2016	SandRidge Energy, Inc	8260
08/11/2016	Bennu Titan, LLC	192
08/12/2016	Northstar Offshore Group, LLC	132
11/30/2016	Bennu Oil & Gas, LLC	724
12/14/2016	Stone Energy Corporation	1445
06/02/2017	Rooster Energy, LLC	52
06/08/2017	Deep Operating, LLC	1.5
06/29/2017	King’s Peak Energy, LLC	23

Source: Haynes and Boone LLP, July 2017

Table P.3. In-service inspection intervals for fixed, manned, and unmanned platforms

Level	Exposure Category		
	L-1	L-2	L-3
I	1 yr	1 yr	1 yr
II	3 yr (5 yr)	5 yr (10 yr)	5 yr (10 yr)
III	6 yr (6 yr)	11 yr (11 yr)	

Source: NTL 2009-G32

Note: Unmanned platform inspection intervals denoted in parenthesis.

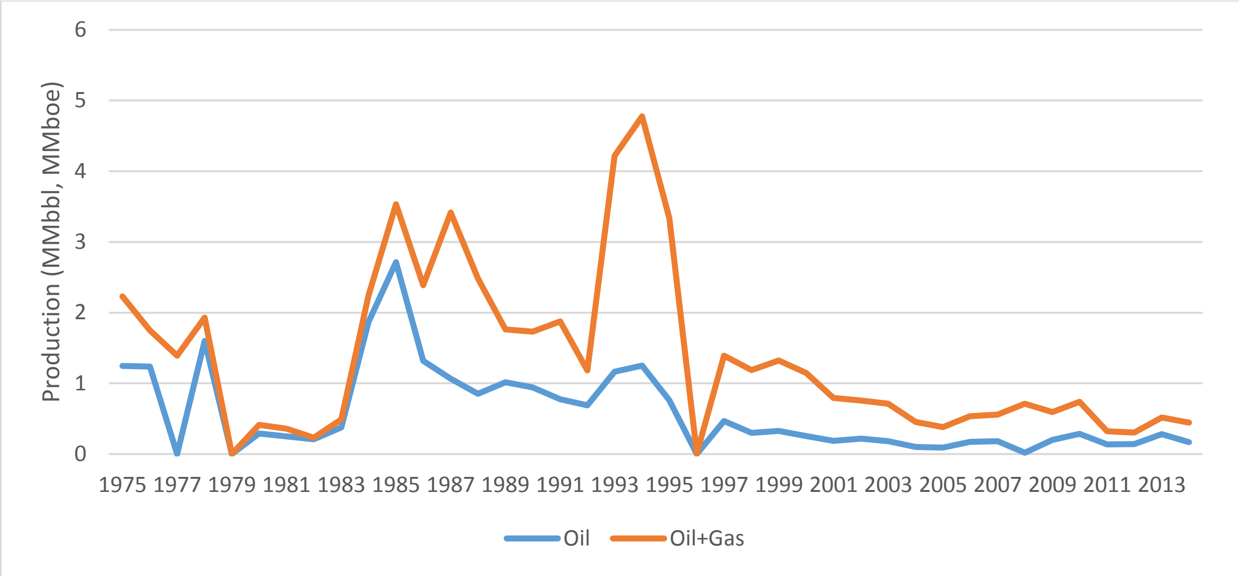


Figure P.1. Eugene Island 188 field oil and gas production plot, 1975-2015
Source: BOEM 2017

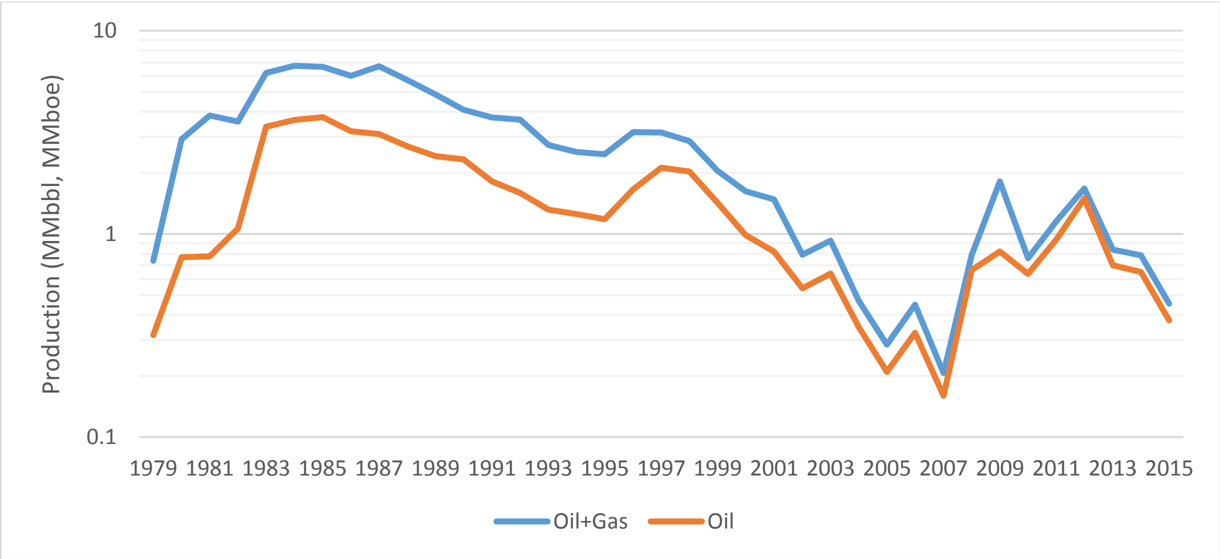


Figure P.2. Main Pass 73 field oil and gas production plot, 1979-2015
Source: BOEM 2017

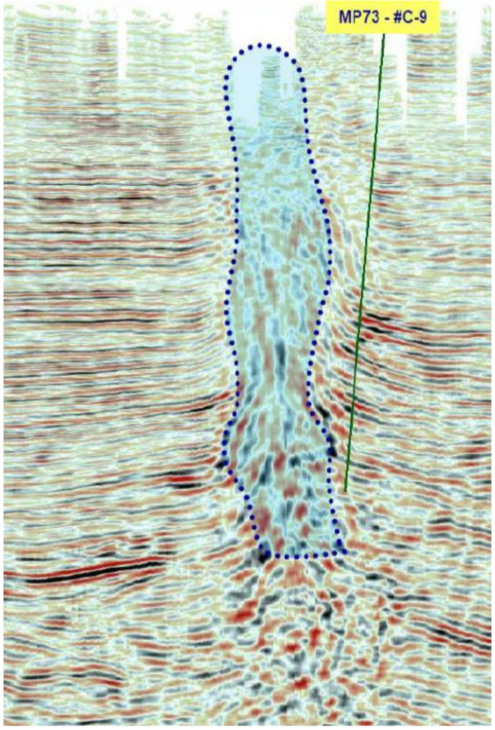


Figure P.3. Salt body image at Main Pass 73 field circa 2007
Source: Ammar et al. 2015

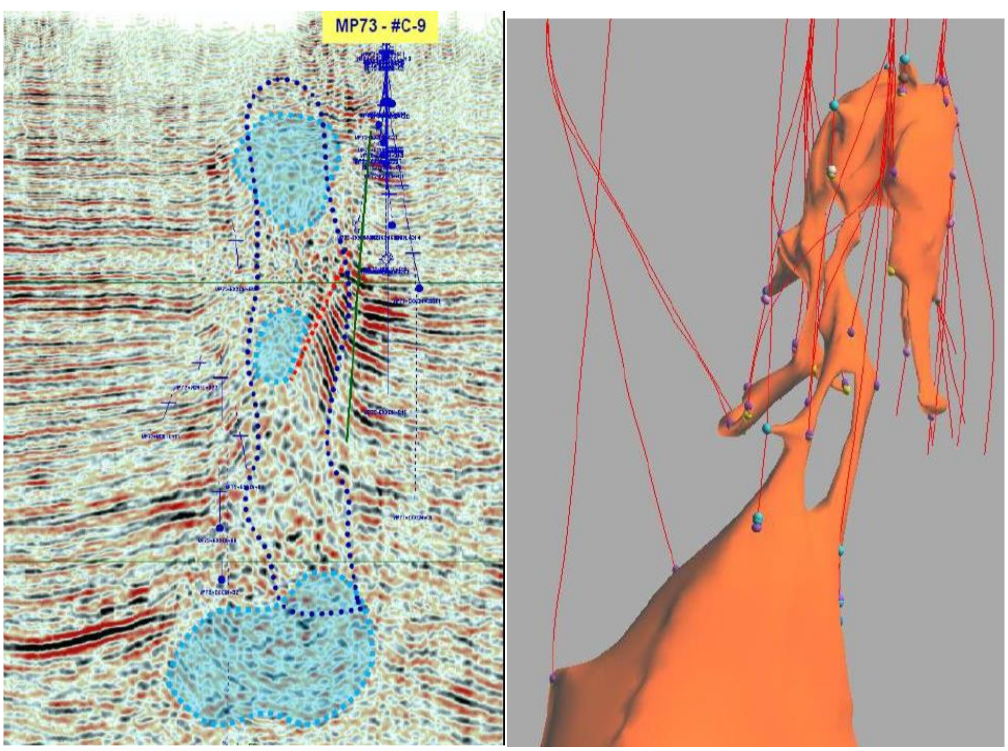


Figure P.4. Salt body image at Main Pass 73 field and model reconstruction circa 2011
Source: Ammar et al. 2015

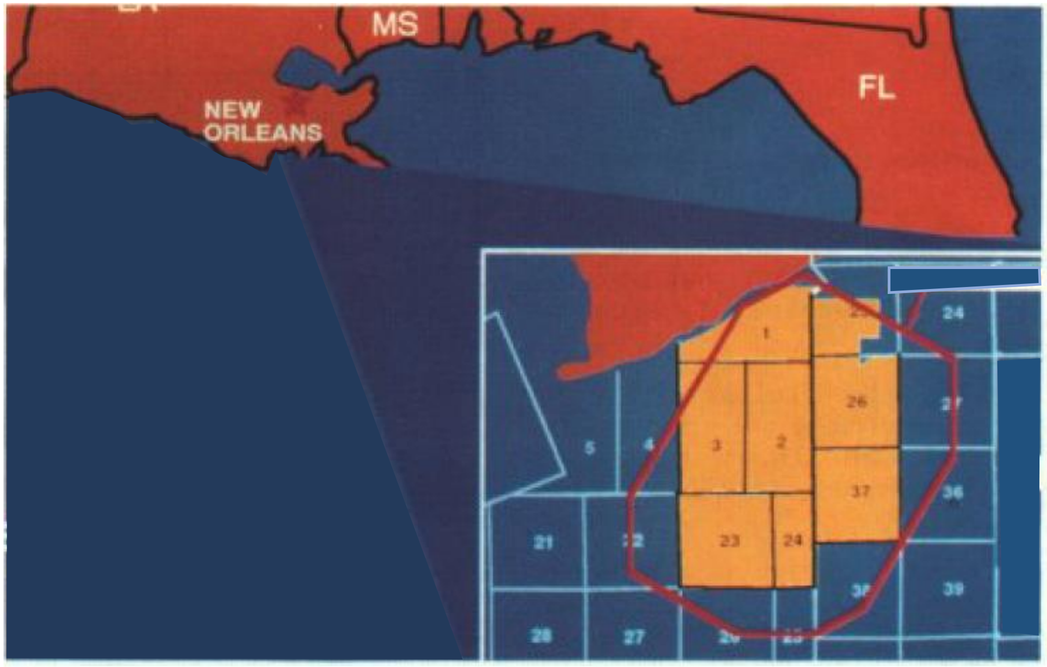


Figure P.5. Bay Marchand area outline circa 2009
Source: Abriel 1991

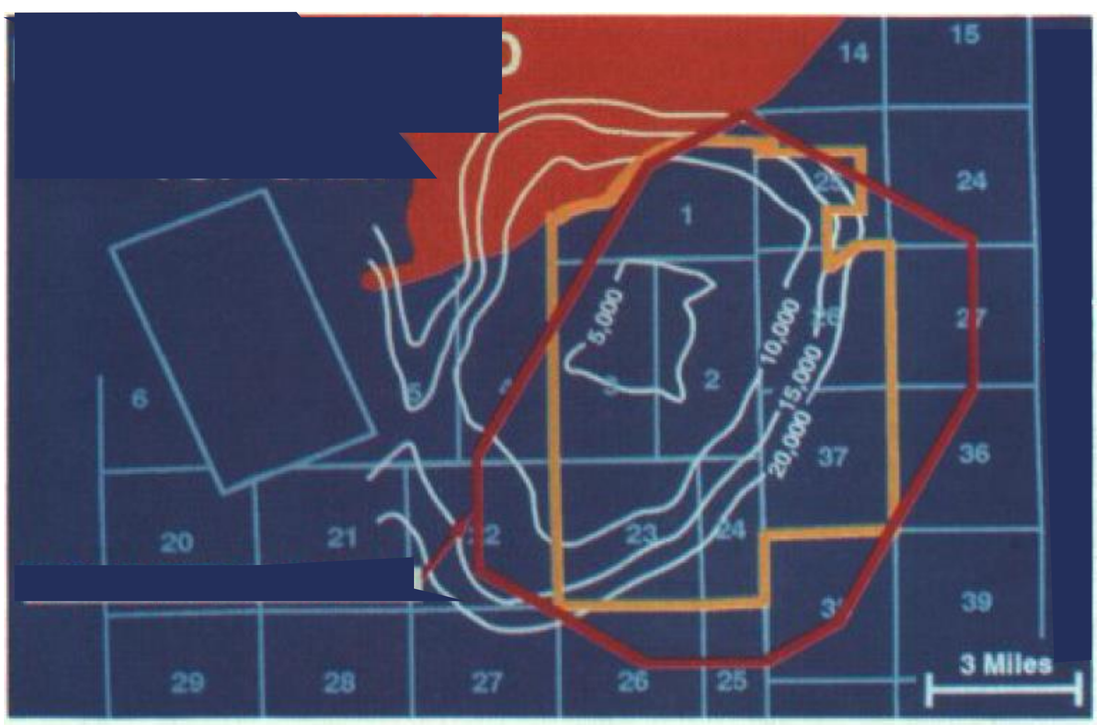


Figure P.6. Bay Marchand structure top salt
Source: Abriel 1991

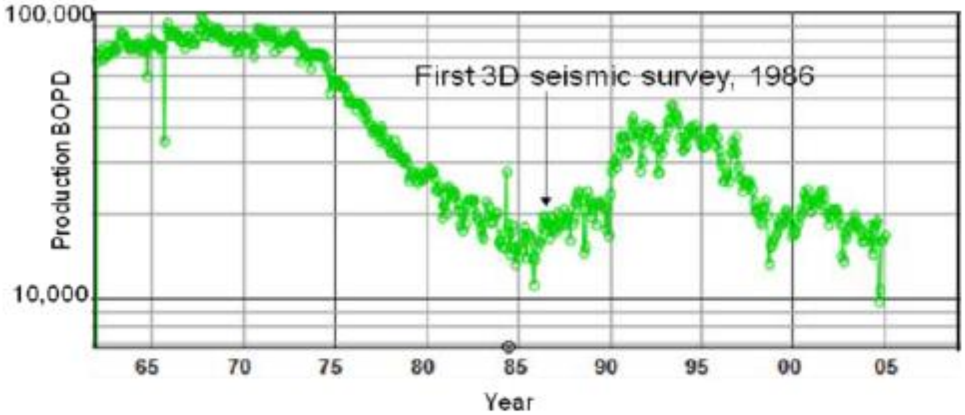


Figure P.7. Bay Marchand average daily production rate, 1960-2005 (state and federal waters)
Source: Abriel 2009

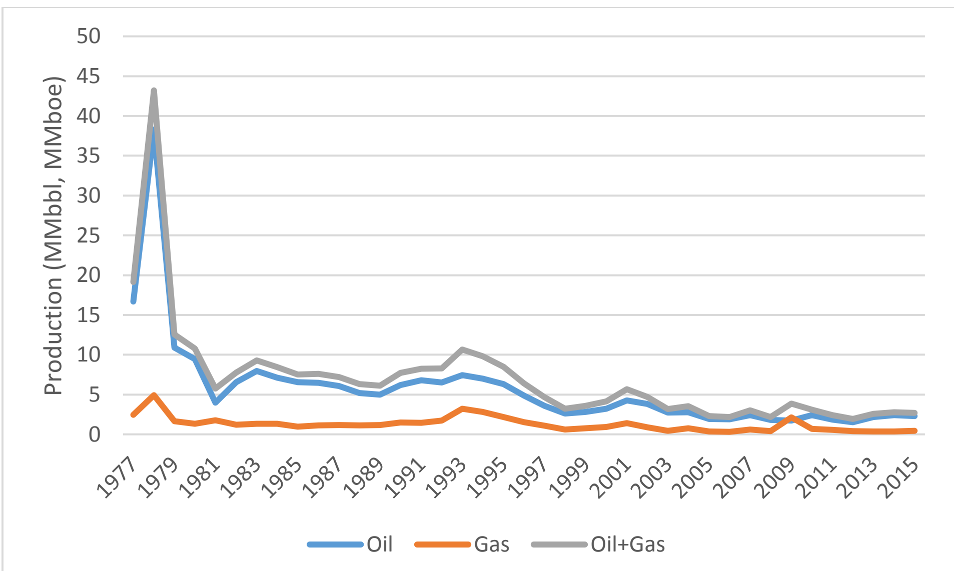


Figure P.8. Bay Marchand field oil and gas production plot, 1977-2015 (federal waters only)
Source: BOEM 2017

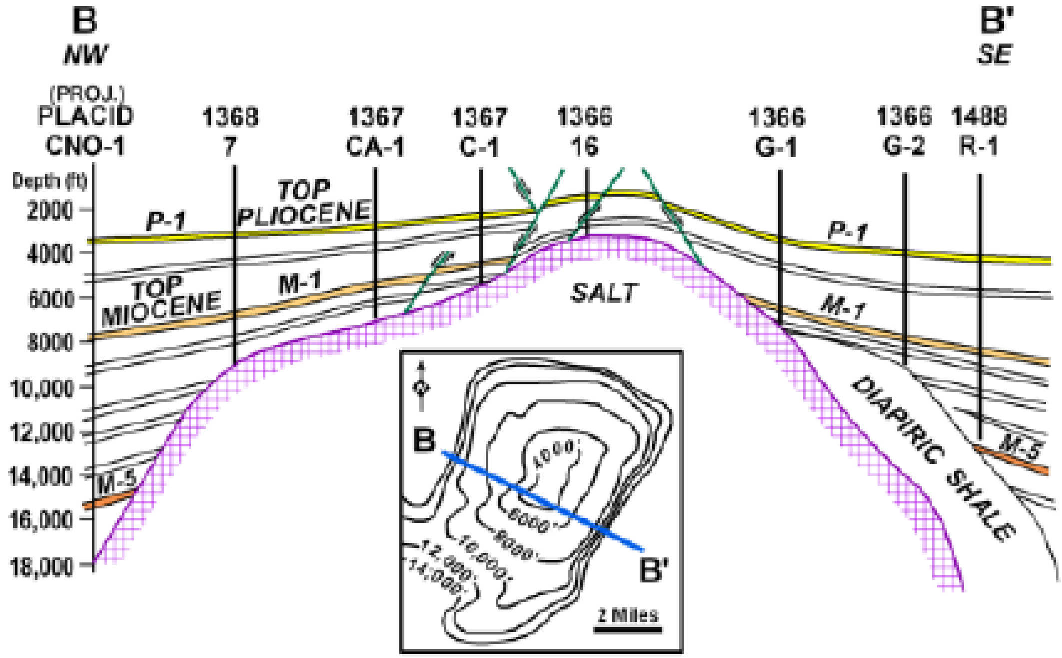


Figure P.9. Bay Marchand cross sectional profile
Source: Abriel 2009

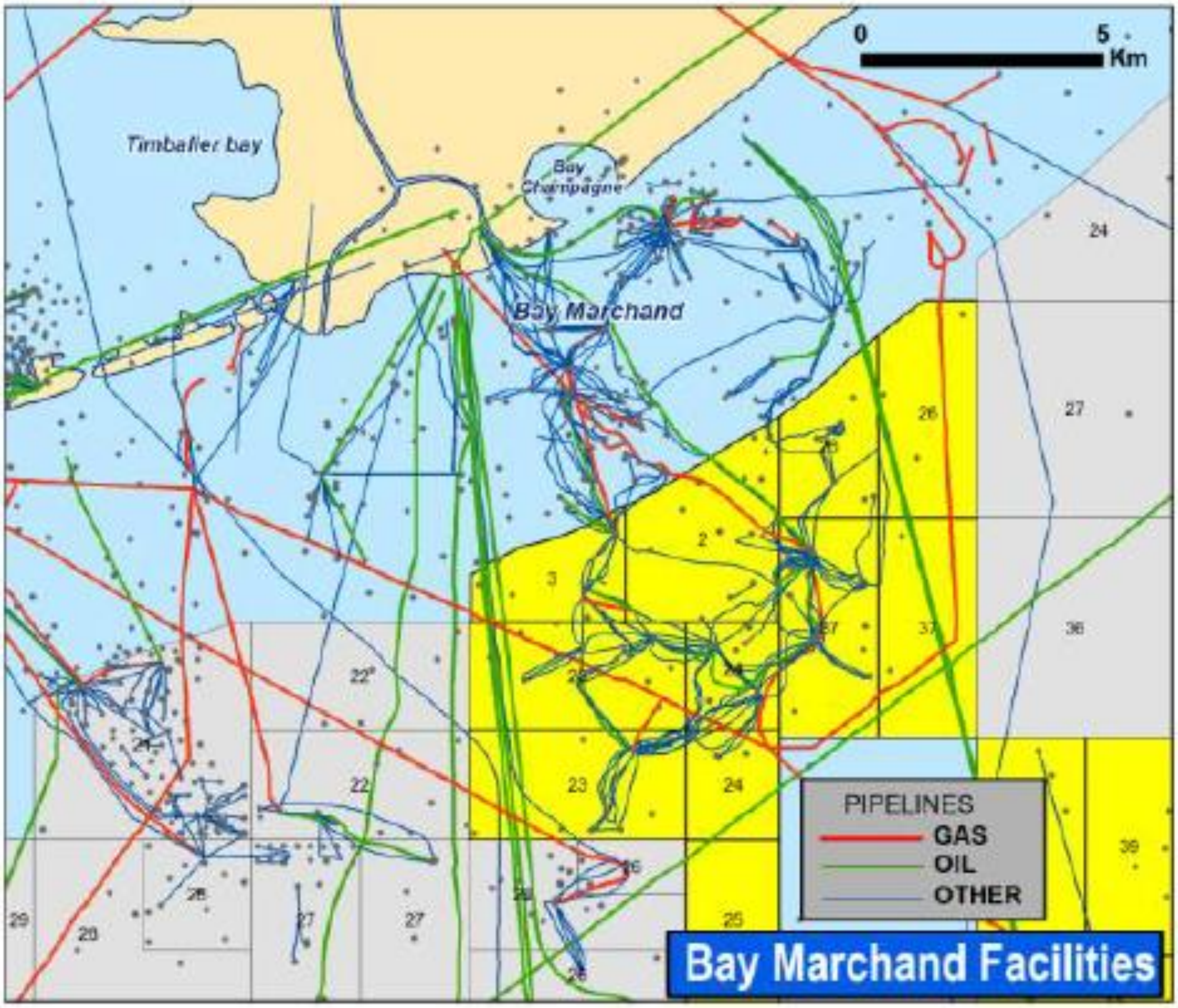


Figure P.10. Bay Marchand facilities circa 2009
Source: Abriel 2009

Figure P.11. Bay Marchand 8200 ft Miocene sand interpretation based on 1/4 to 1/2 mi seismic spacing resolution
Source: Abriel 1991

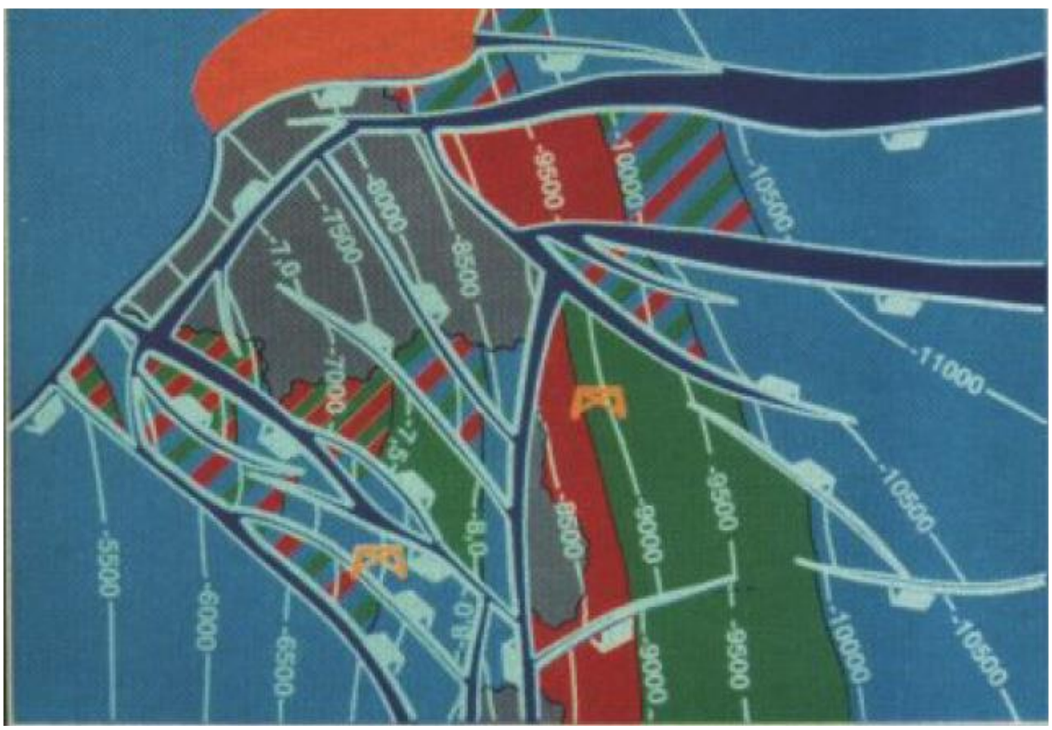


Figure P.12. Bay Marchand 8200 ft Miocene sand interpretation based on 35 ft seismic spacing resolution
Source: Abriel 1991

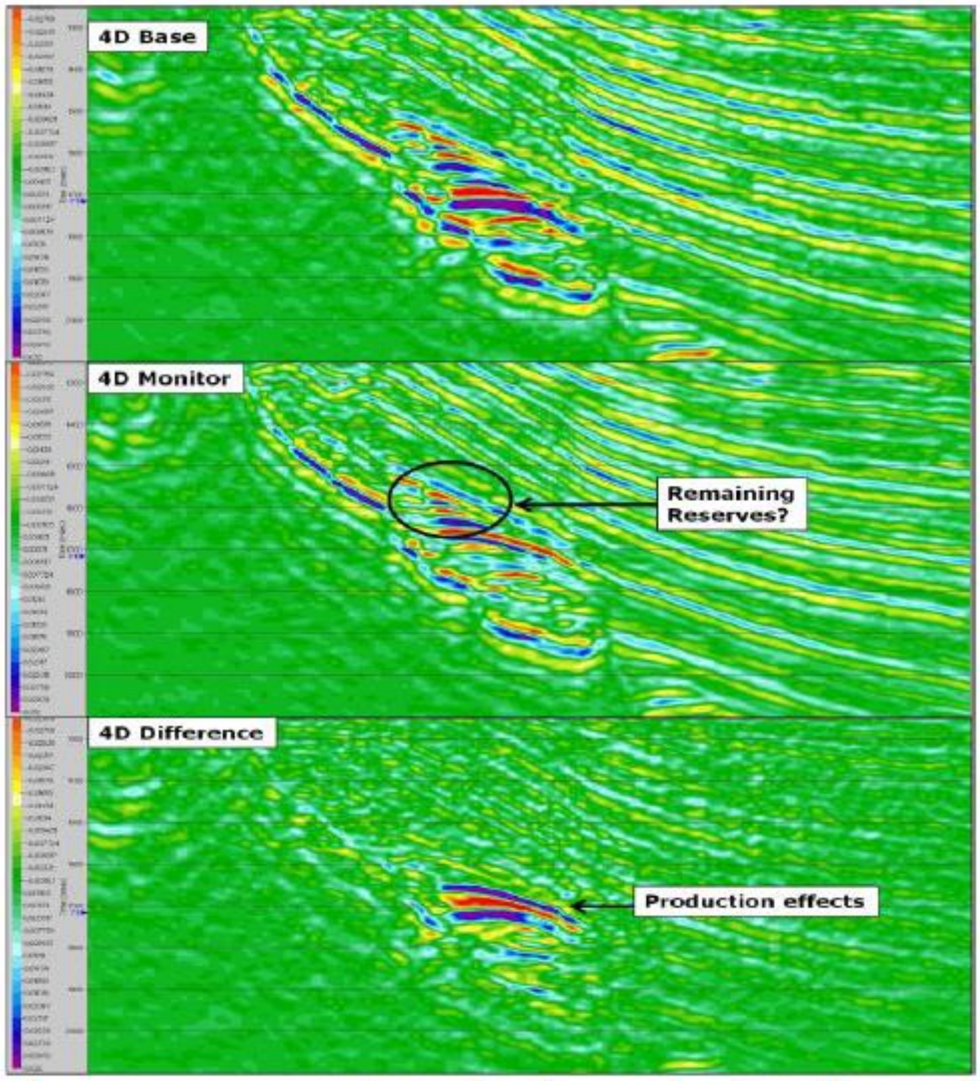


Figure P.13. Seismic plots over time shows oil movement from production and help identify new prospects
Source: Shank et al. 2014

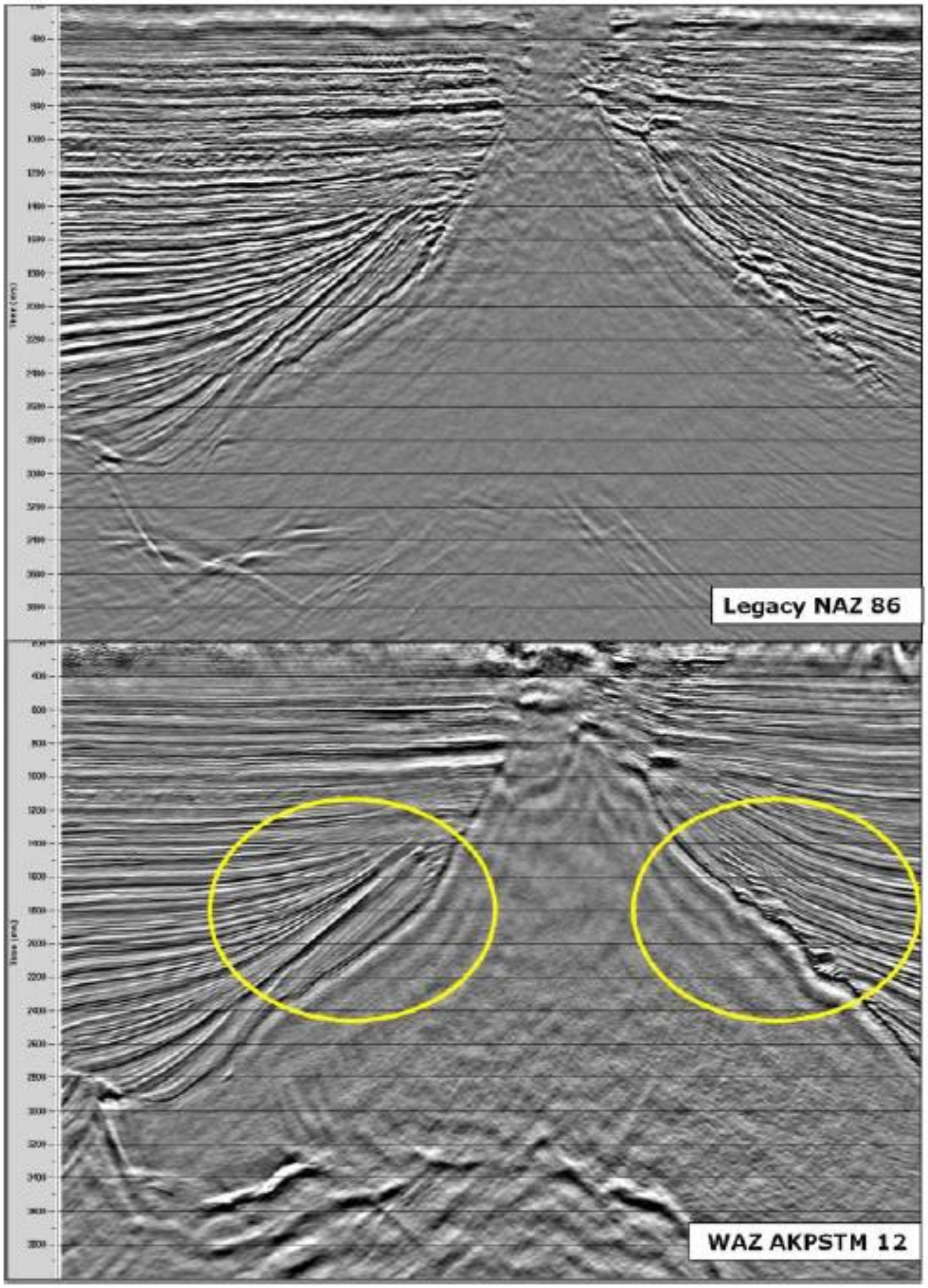


Figure P.14. Bay Marchand WAZ data yields better interpretation at salt flanks
Source: Shank et al. 2014

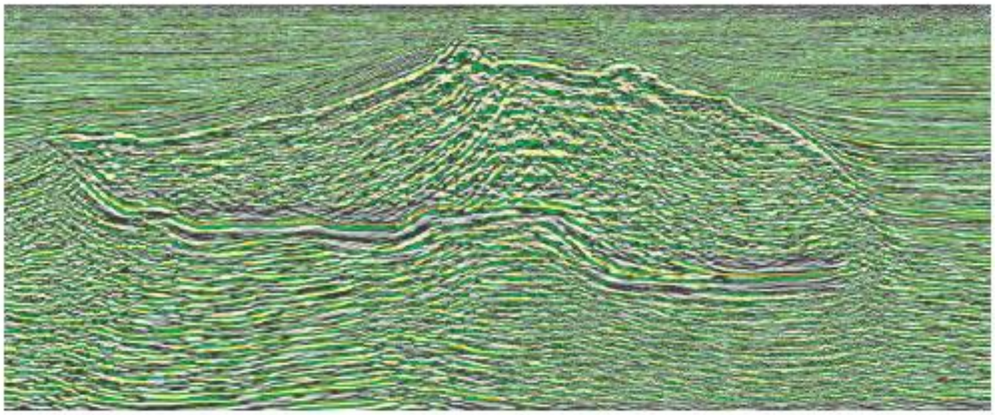


Figure P.15. Bay Marchand below salt might yield future prospects
Source: Abriel 2009

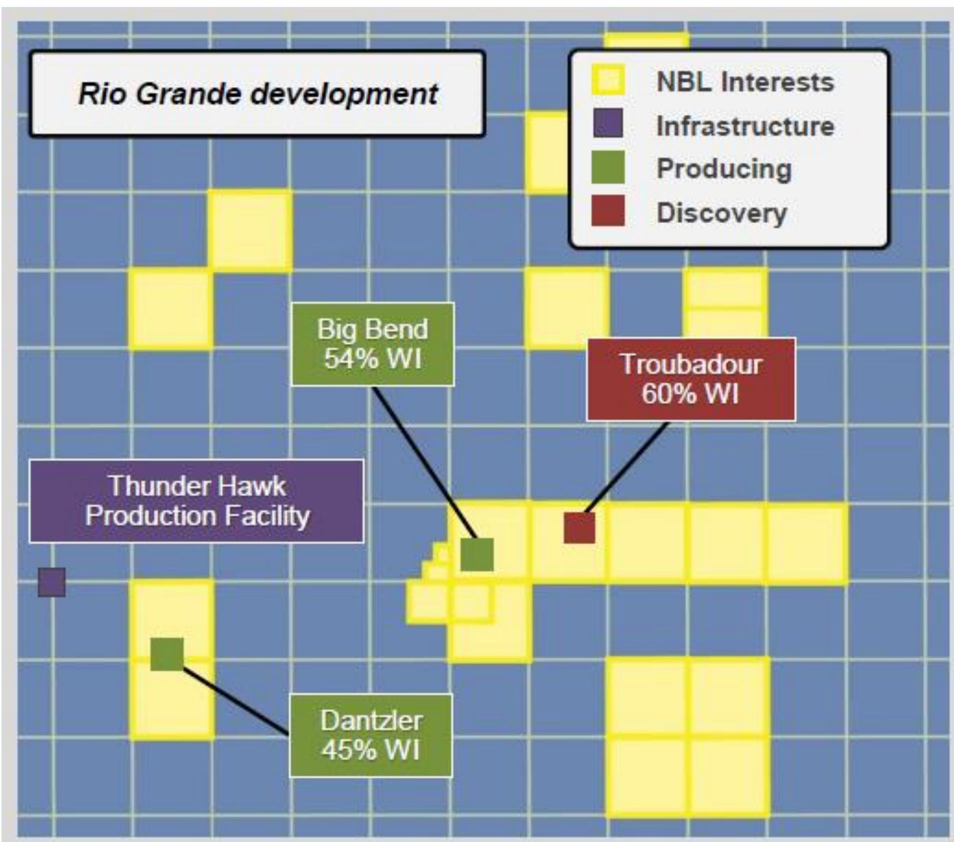


Figure P.16. Rio Grande fields are tied back to the Thunder Hawk production facility
Source: Noble Energy 2016

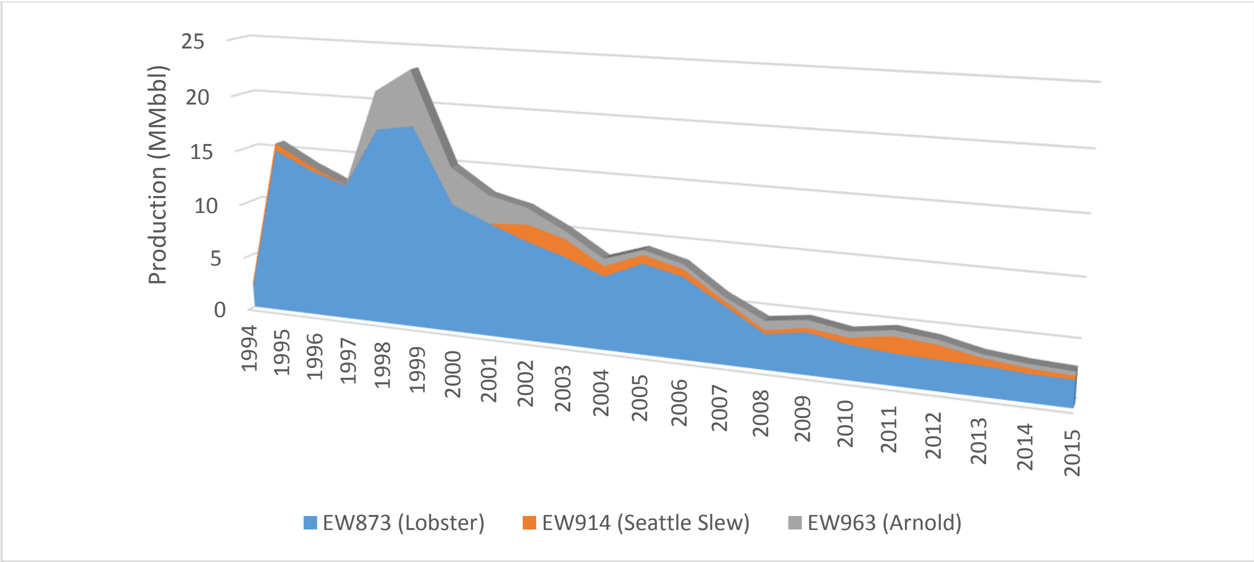


Figure P.17. Ewing Bank 873 field and subsea tiebacks oil and gas production plot, 1994-2015
Source: BOEM 2017

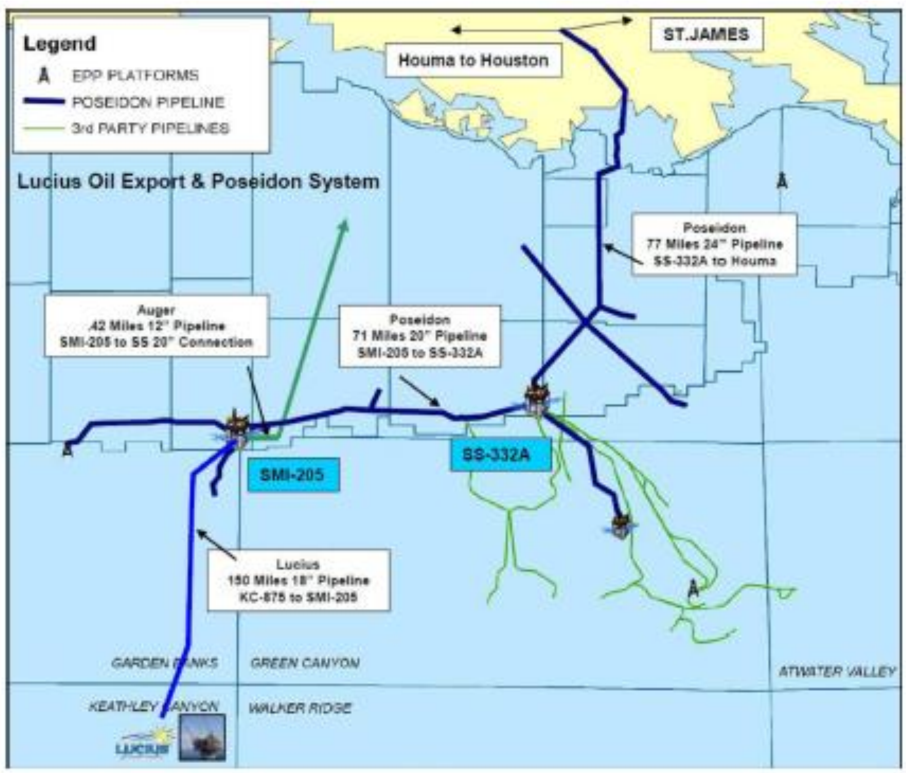


Figure P.18. Lucius oil export and Poseidon system
Source: Schronk et al. 2015

APPENDIX Q

CHAPTER 17 TABLES AND FIGURES

Table Q.1. Crude oil pipeline specifications in the OCS Gulf of Mexico

Owner	Cypress Pipeline	Marathon	ExxonMobil & Williams	Plains	ExxonMobil	Chevron	Shell
Origin	MP 69	EI 312	AC 25, EB 602, EB 643	WD 79A WD 86A SP 89B,C,D	SM Area, EI Area, SS Area	SP 78	GB 426 (Auger)
Destination	Empire Terminal, LA	Caillou Island Station, LA	Jones Creek Station, TX	West Delta Station, LA	Caillou Island Station, LA	SP 55A	SS 28
BS&W (% by volume)	1		1	1	1	1	1
Water (% by volume)		1					
S (% by weight)	0.5			0.5		0.5	
RVP (psi at 100 °F)	12	11			12	12	8.6
API°	≥20					≥20	

Note: Impurities excluded in pipeline systems include: chlorinated, oxygenated hydrocarbons, arsenic, lead.

Table Q.2. Natural gas pipeline specifications in the OCS Gulf of Mexico

Specifications	Garden Banks		Enbridge Offshore Pipelines (UTOS)		Stingray Pipeline		Nautilus Pipeline		Mississippi Canyon Gas Pipeline		Destin Pipeline Company	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Oxygen (% by volume)	0.2		1		0.005		0.2		0.2		0.2	
Hydrogen (% by volume)											0.1	
Water (lb/MMcf)	7		7		7		7		7		7	
Condensate (bbl/MMcf)									40			
H2S (Grain/CcF)	0.25		1		1		0.25		0.25		0.25	
Temperature (°F)	120	40	120	65	120		120	40	120	40	120	
Heating value (Btu/scf)					-		1400	980			1075	1000
S (Grain/Ccf)	20		20		20		5		20		10	
N2 (% by volume)			3									
CO2+N2 (% by volume)	3						4		3		3	
CO2 (% by volume)	2		3		2		2		2		2	
Dew point											0º F at 800 psia	

Note: Impurities excluded in pipeline systems include: PCBs, dust, gums, sand, oil, free water, SRB, APB, and any other microbiological agents could bring adverse import on pipeline system, iron oxides, salts, arsenic, mercury, lead, and oxides of nitrogen.

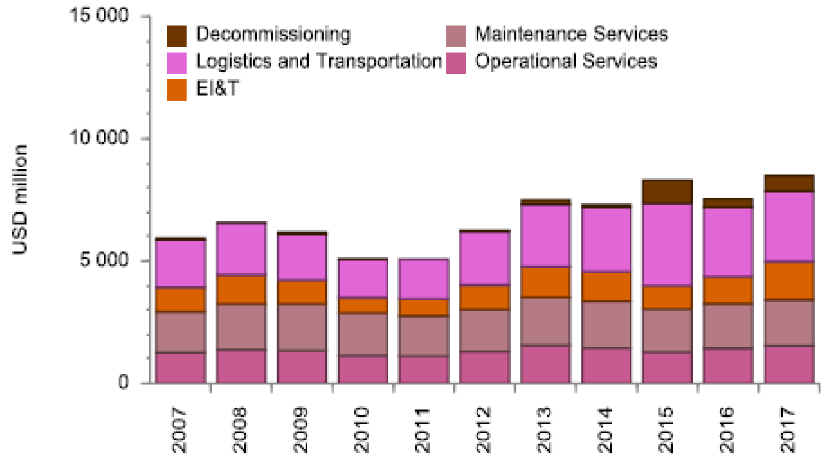


Figure Q.1. Oil and gas operational spending in the Gulf of Mexico, 2007-2017
Source: Rystad

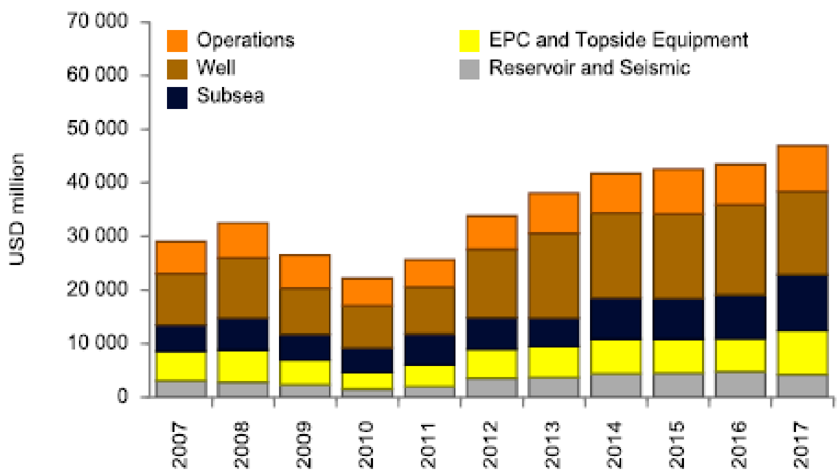


Figure Q.2. Oil and gas total spending in the Gulf of Mexico, 2007-2017
Source: Rystad

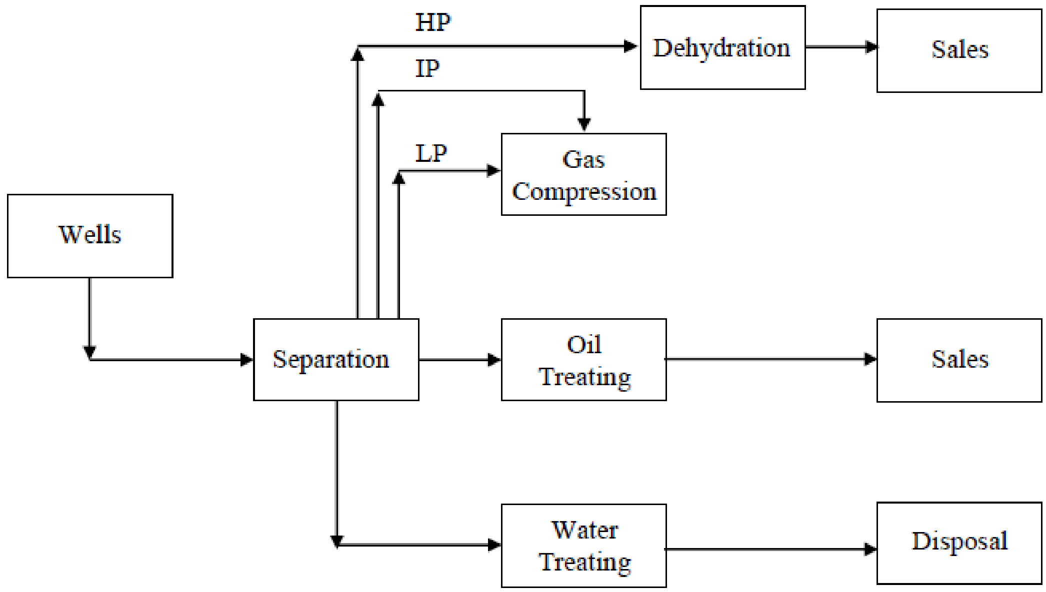


Figure Q.3. Schematic representation of a typical oil facility in the Gulf of Mexico
Source: Adapted from Thro, 2007

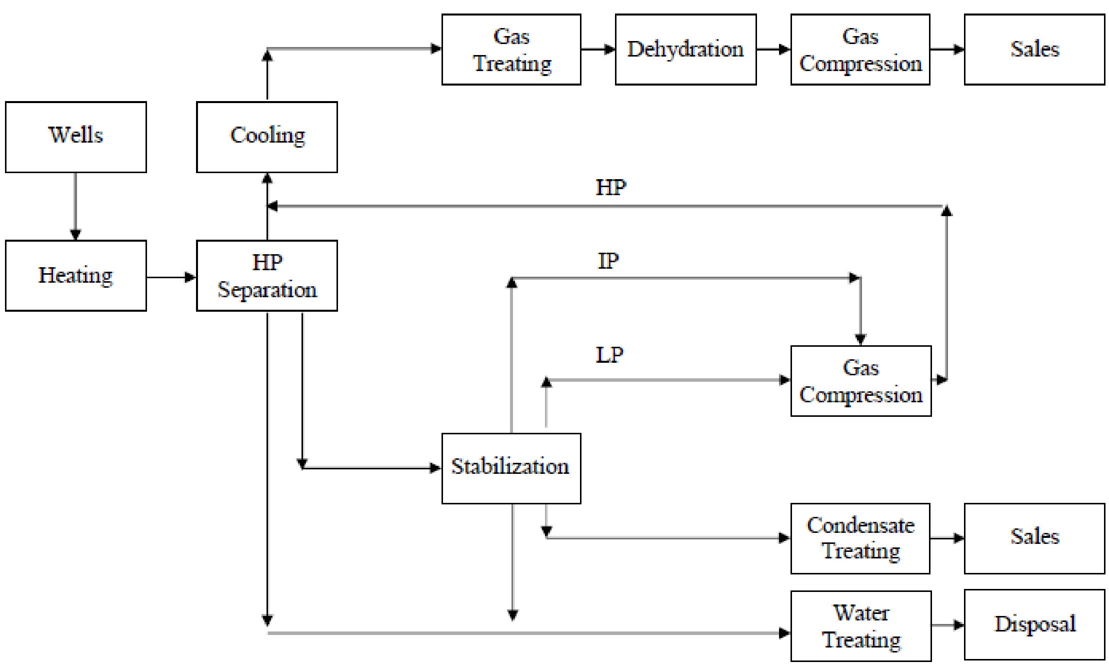


Figure Q.4. Schematic representation of a typical gas facility in the Gulf of Mexico
Source: Adapted from Thro, 2007

APPENDIX R

CHAPTER 18 TABLES AND FIGURES

Table R.1. Production and cost profile for a Gulf of Mexico shallow water oil field

Year	Oil Price ($/bbl)	Production (MMbbl)	Capital Expenditures ($ million)	Operating Cost ($ million)
1960	2.88	0.0	2.5	4.0
1961	2.88	0.0	0.0	0.1
1962	2.88	0.0	0.0	0.2
1963	2.88	0.0	0.5	0.1
1964	2.88	0.0	13.0	0.6
1965	2.86	0.9	15.5	0.5
1966	2.86	3.3	16.0	1.8
1967	2.86	5.0	3.0	2.8
1968	2.86	5.6	0.8	3.2
1969	2.86	6.7	1.0	3.6
1970	3.18	5.6	0.0	3.5
1971	3.39	5.0	0.0	3.2
1972	3.39	5.5	0.4	3.6
1973	3.96	4.8	0.2	3.8
1974	6.88	6.0	0.0	3.9
1975	7.67	4.1	0.0	6.2
1976	8.19	3.9	0.0	5.8
1977	8.57	3.2	0.0	5.4
1978	9.00	3.1	0.0	2.8
1979	13.99	2.4	0.0	3.6
1980	22.49	1.8	2.0	8.0
1981	31.13	1.0	2.1	6.0
1982	28.52	0.2	0.0	3.0
1983	26.19	0.3	0.0	1.5
1984	25.88	0.1	0.0	0.4
1985	23.95	0.1	0.0	0.3
1986	11.36	0.0	0.0	0.3
1987	15.40	0.0	0.0	5.2

Source: Dickens and Lohrenz 1996

Table R.2. Time dependence of operating cost components

	Time Dependent	Price Change	Discretionary/ Nondiscretionary	Percentage Range
Labor	−	↑	ND	15-30%
Materials & Supplies	+	↑↓	ND	5-20%
Services	+	↑↓	ND	10-20%
Logistics & Transportation	+	↑↓	ND	10-30%
Repairs & Maintenance	+	↑↓	D	20-40%
Insurance	+	↑↓	D	< 10%
Gathering & Transportation	−	↑	ND	< 5%
Third-Party Processing	−	↑	ND	20-50%

Table R.3. Record wter depths and tieback distances circa 2017

Project	Field	Water Depth (ft)	Tieback Distance (mi)
Shell - Tobago	Oil	9627	6
Anadarko - Cheyenne	Gas	9014	44.7
Shell - Penguin	Oil	574	43.4
Noble - Tamar	Gas	5446	93

Source: Offshore 2017

Table R.4. Operating strategies in Nigerian offshore field development

	Operating strategy	Direct OPEX ($/day)	Lifting cost ($/bbl)
A –	Full Operational Control	32,000	1.64
B –	Control Through Min Cost	22,000	1.13
C –	Minimize Cost	18,000	0.96
D –	Control Through Sharing	26,000	1.34

Source: Steube 2000

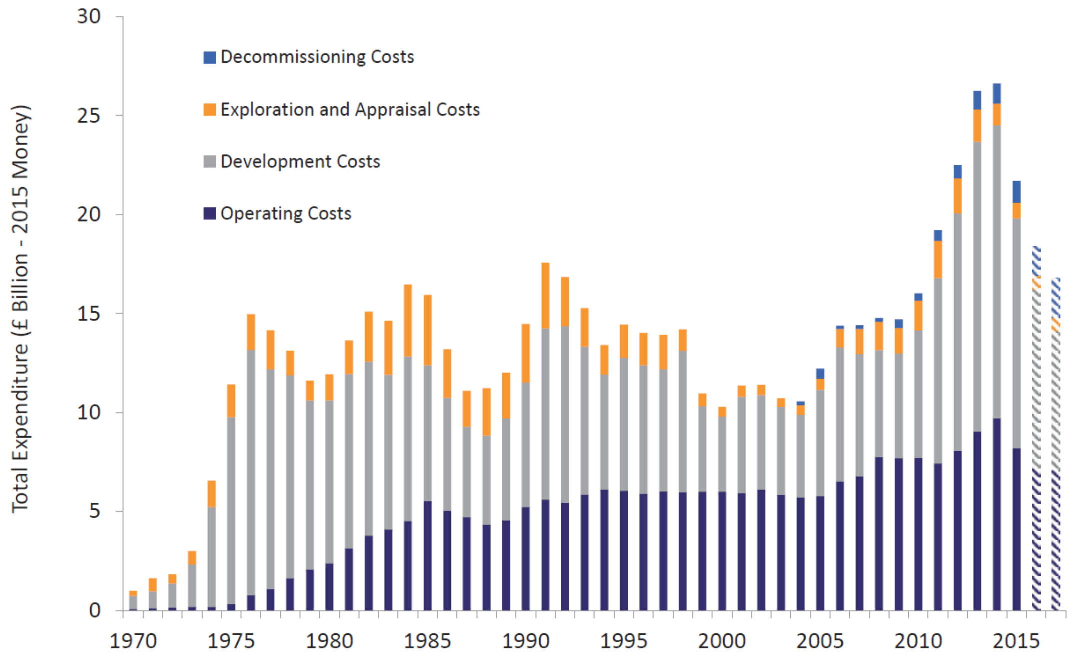


Figure R.1. Total expenditure in the UK North Sea by sector
Source: Oil and Gas Authority 2017

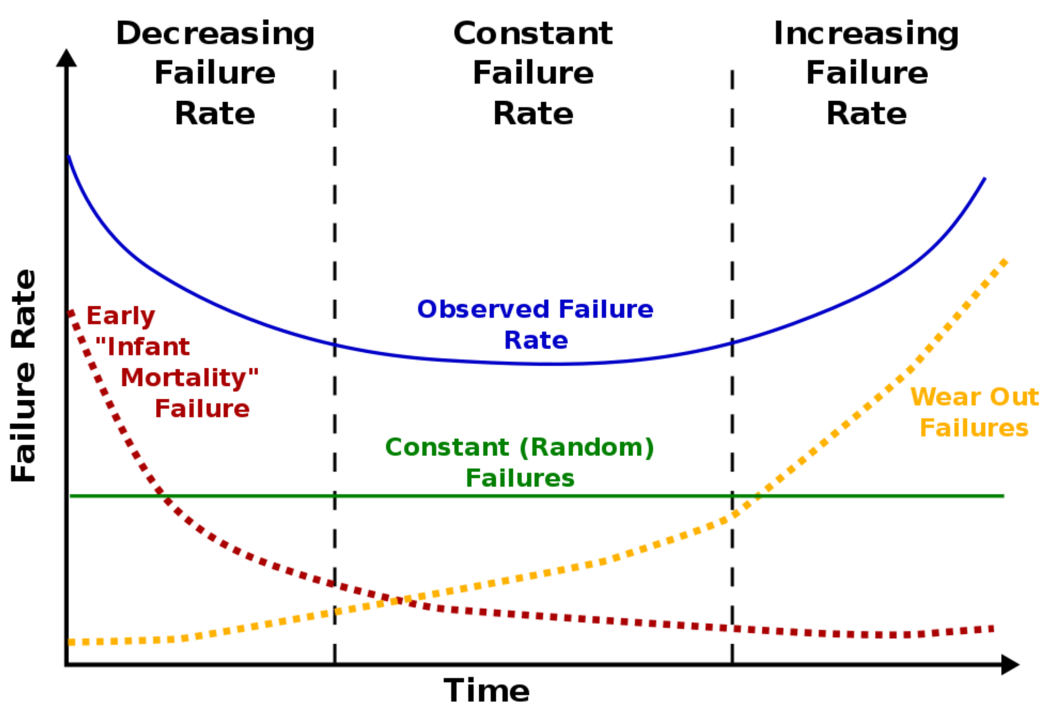


Figure R.2. The bathtub curve hazard function
Source: Wikipedia

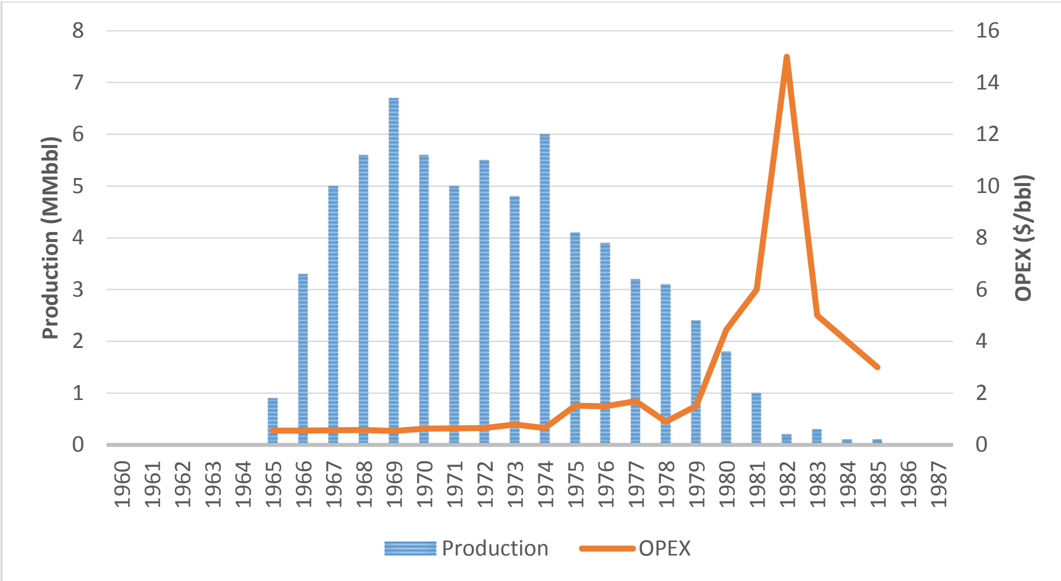


Figure R.3. Production and unit operating cost for a shallow water Gulf of Mexico oil development
Source: Dickens and Lohrenz 1996

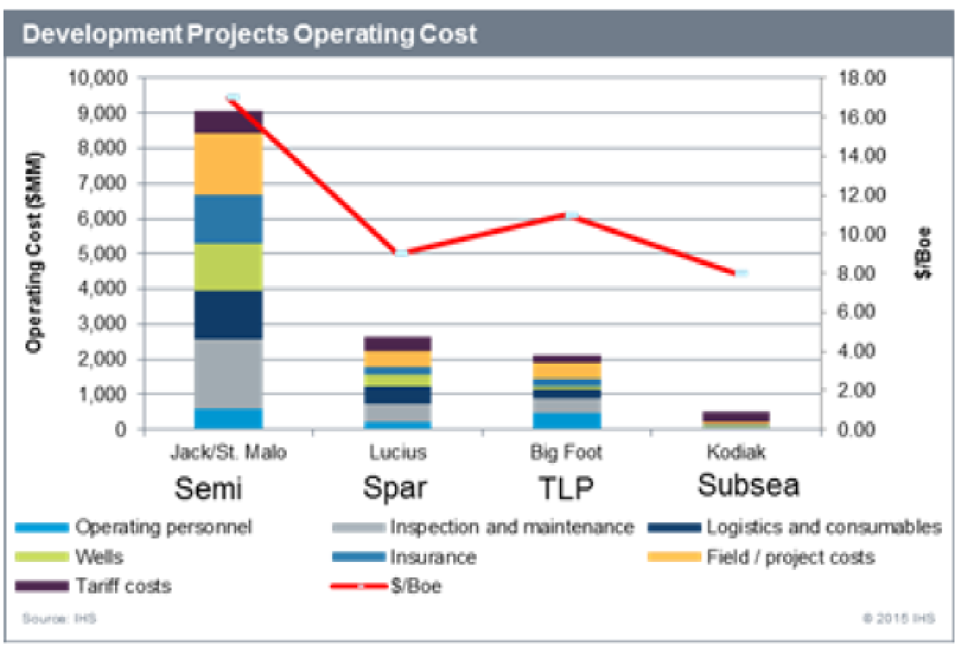


Figure R.4. Deepwater Gulf of Mexico life-cycle operating cost estimates using Questor software
Source: IHS 2015

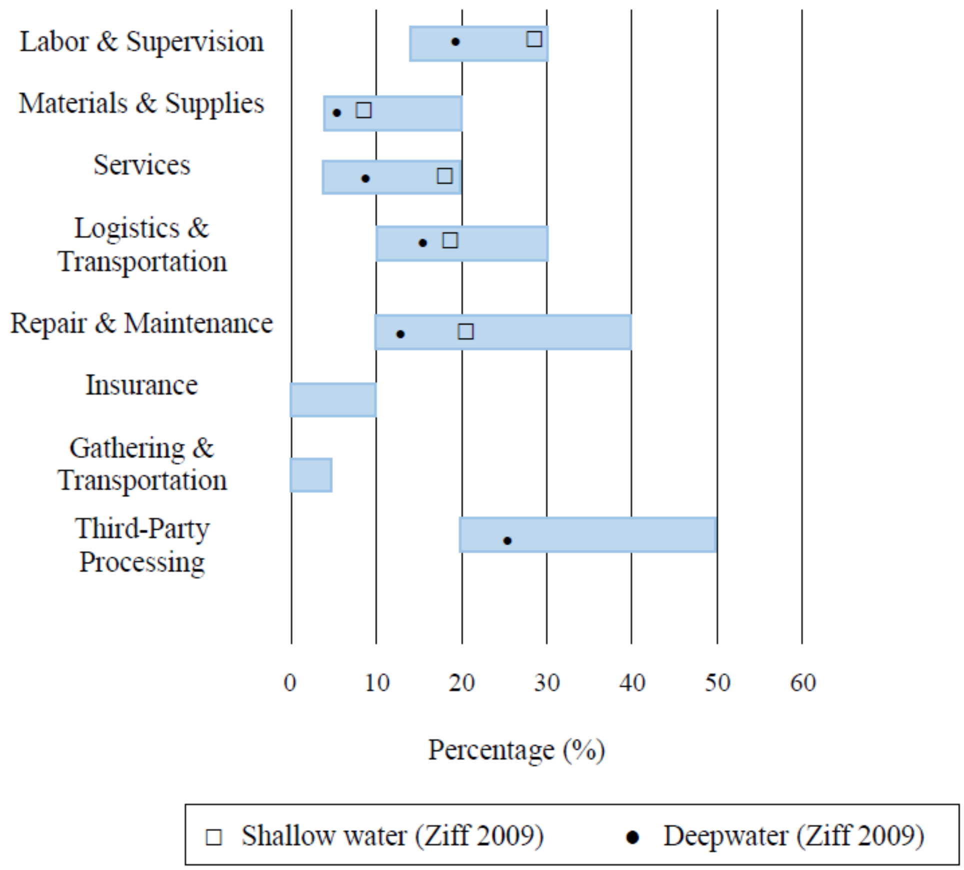


Figure R.5. Typical operating cost range in the Gulf of Mexico

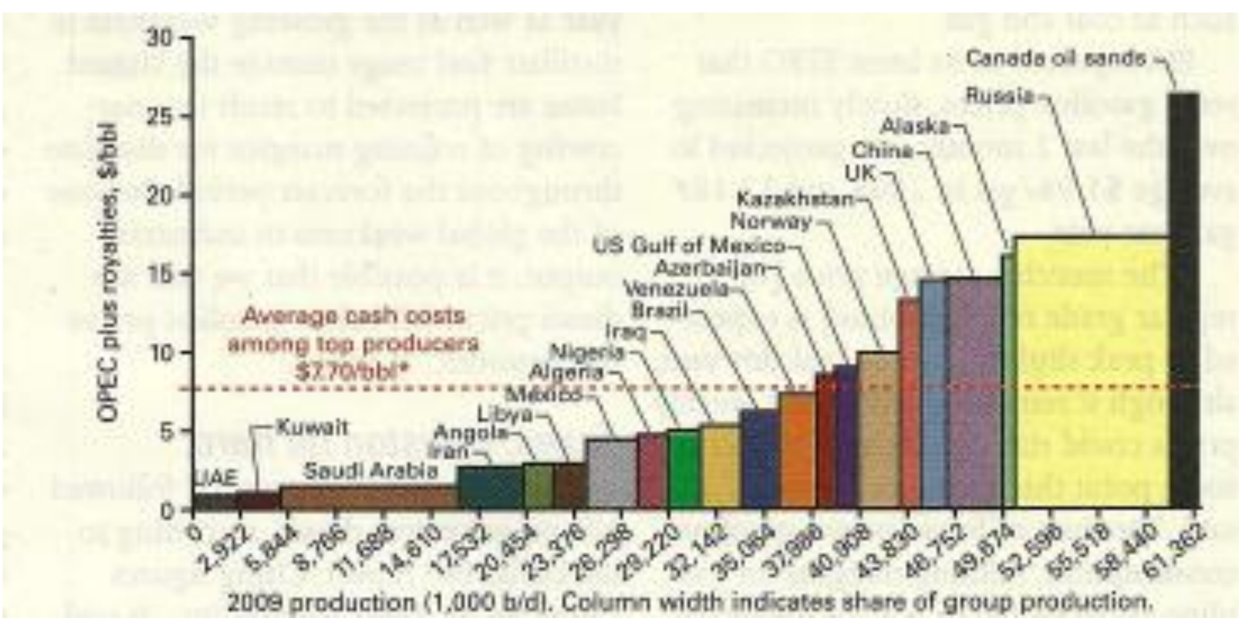


Figure R.6. Production cost in major oil producing countries – 2009

Source: Deutsche Bank 2009

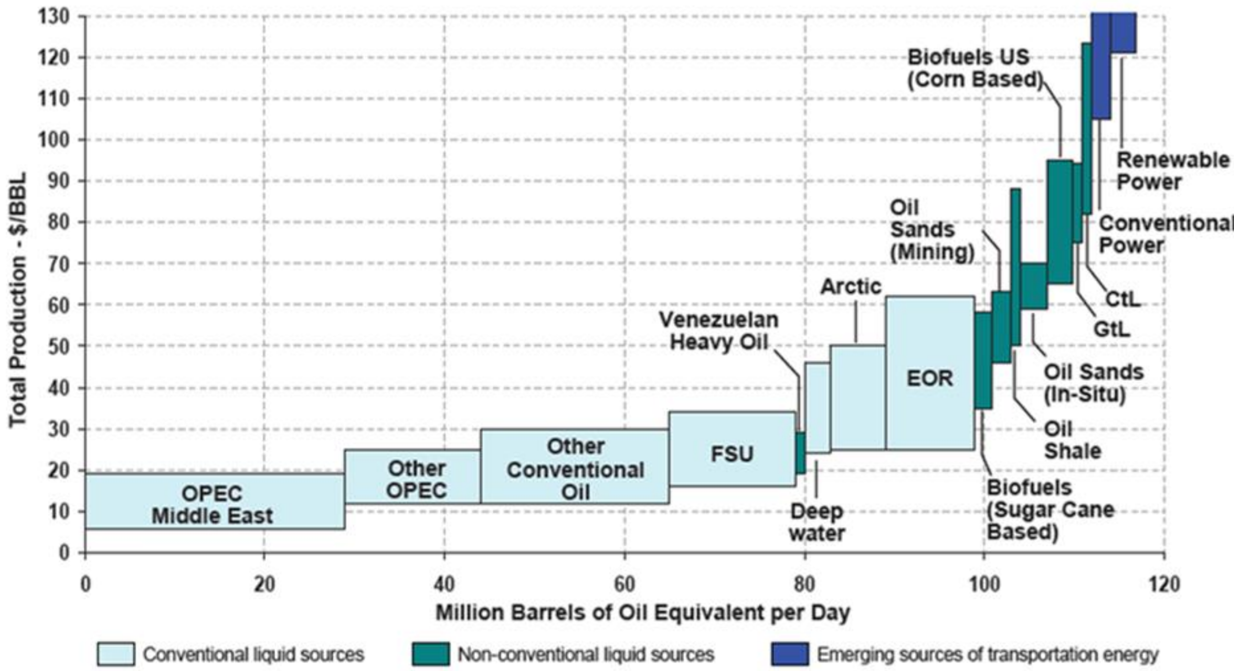


Figure R.7. Production cost range in major oil producing regions and emerging sources – 2012
Source: Booz Allen Hamilton 2012

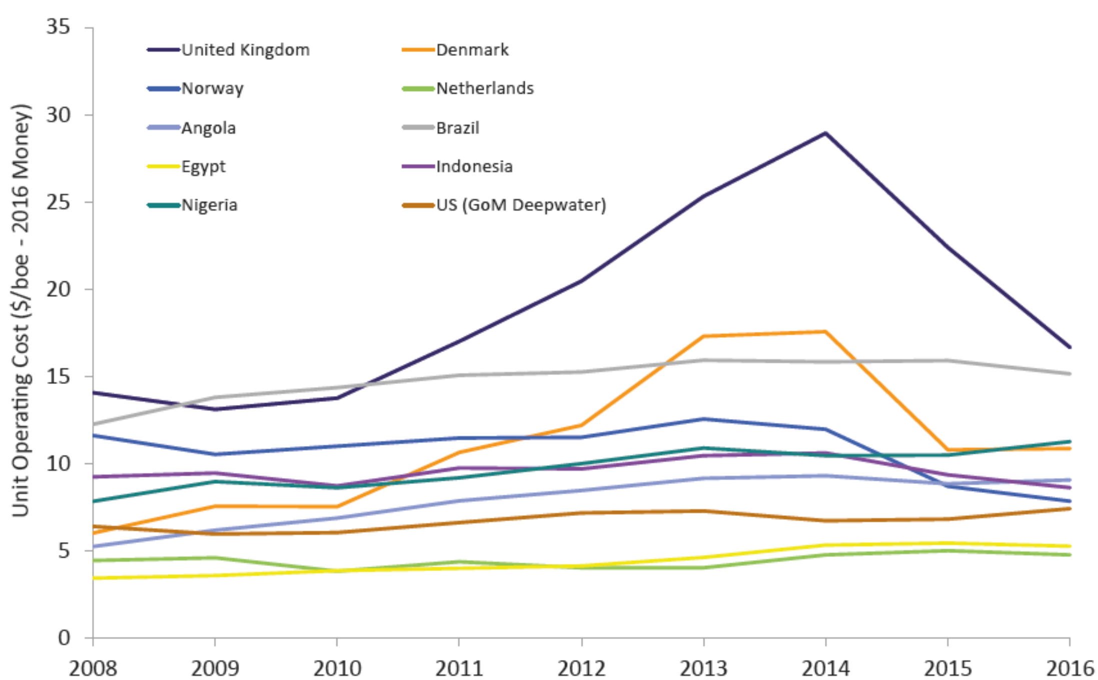


Figure R.8. Production cost trends by offshore region, 2008 – 2016
Source: Wood MacKenzie

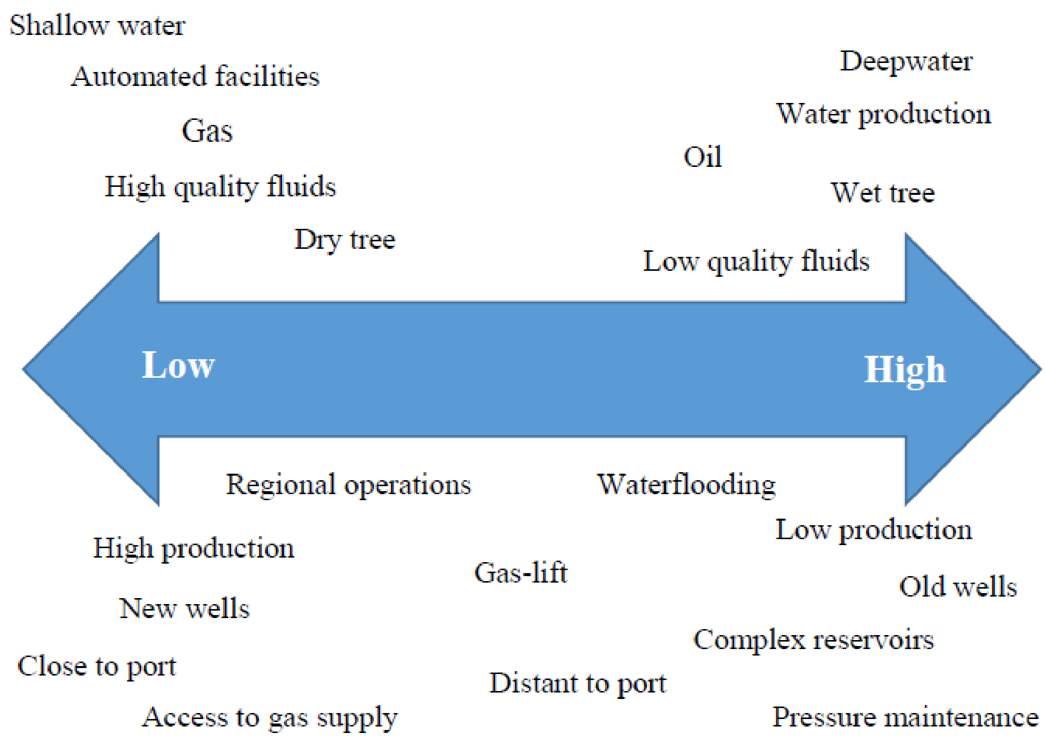


Figure R.9. Operating cost spectrum

Figure R.10. Mad Dog (top left), Thunderhorse (top right), Boomvang (bottom left) and Lucius (bottom right)
Source: BP, Anadarko

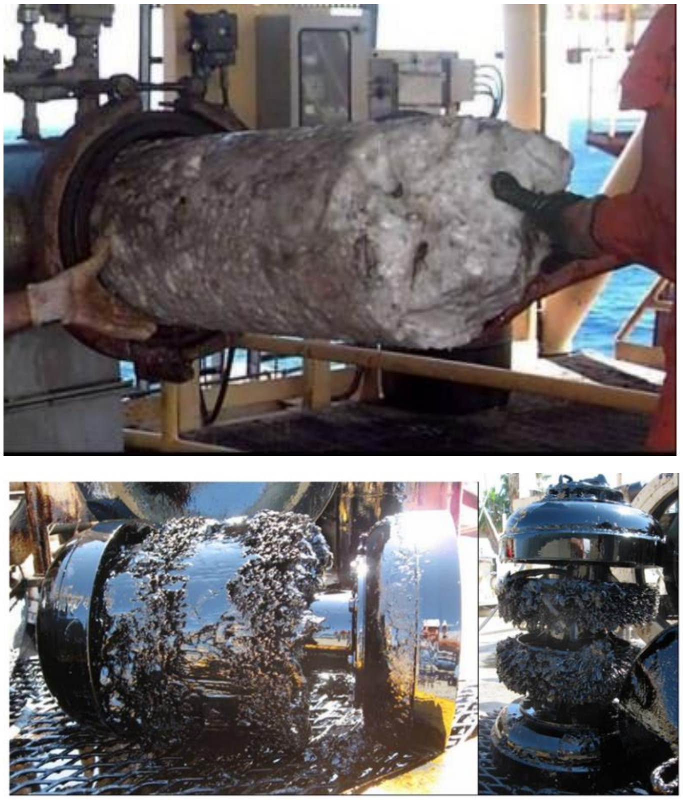


Figure R.11. Hydrates (top) and wax (bottom) removal in pipeline

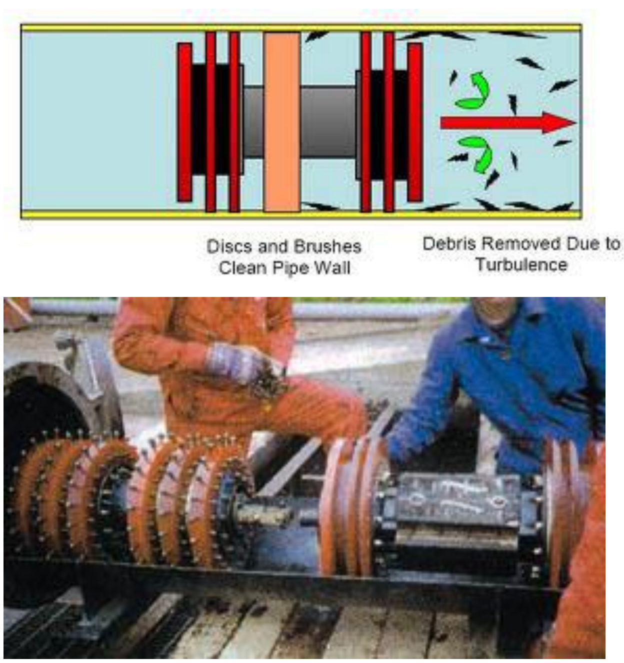


Figure R.12. Pigging operations remove buildup from pipeline and prevent corrosion
Source: omnicompressedair.com (top), Offshore Magazine (bottom)

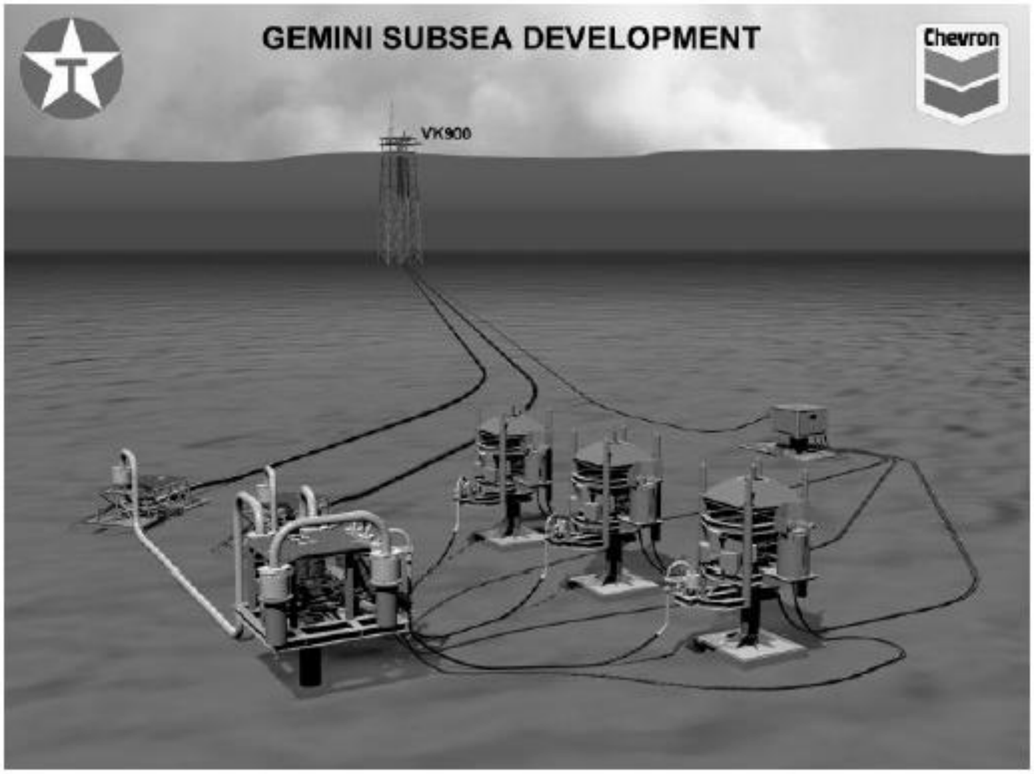


Figure R.13. Gemini subsea development
Source: Kashou et al. 2001

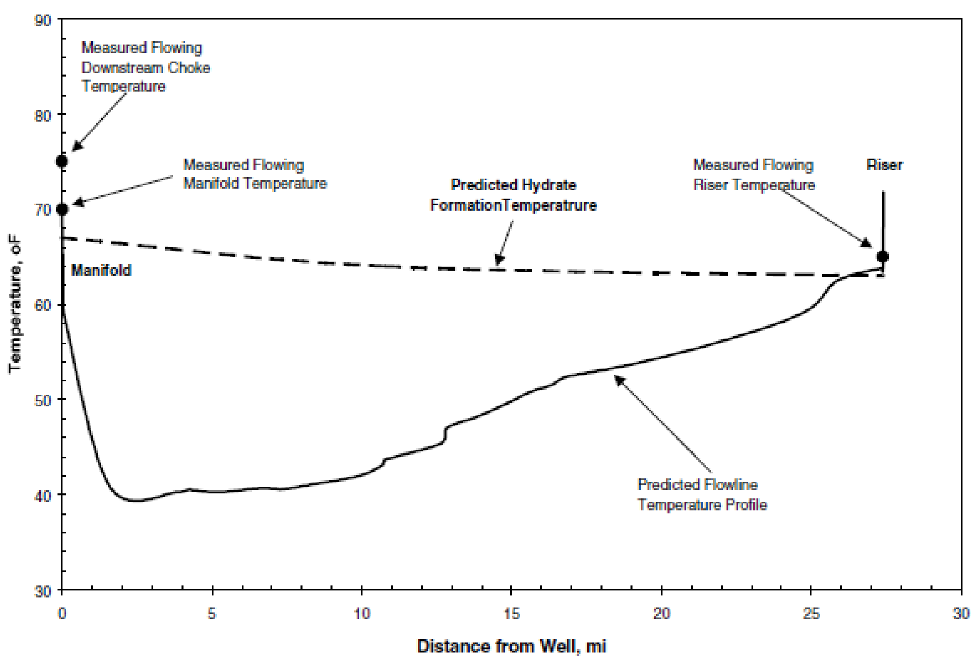


Figure R.14. Gemini flowline and hydrate formation temperature
Source: Kashou et al. 2001

Figure R.15. Eugene Island 11 complex
Source: Contango

APPENDIX S

CHAPTER 19 TABLES AND FIGURES

Table S.1. Lease operating cost data sources, strengths and limitations

Source	Limitations	Strengths
Financial Statements	Consolidated statements across multiple properties and geographies restricts comparisons, regional players diverse	Publicly disclosed according to standardized categories, regularly audited, high quality field data available in some cases
Leasing Operating Statements	Company and asset specific, confidential, not representative	High quality, detailed information
Benchmarking Studies	Small number of participants, difficult to normalize across diverse assets, confidential to participants	High quality, detailed information based on lease operating statements and normalized according to common cost categories
Survey Methods	Narrow focus, variable quality, lack of transparency unless assumptions clearly specified	Snapshot of industry conditions, direct linkage with service company cost, commonly reported
Computer Methods	Significant time and resource for development requiring experts, narrow application focus	Advanced quantitative approach, measurable benefits
Factor Models	Often hypothetical and not supported by empirical data or historical activity, does not reflect site-specific conditions	Easy-to-apply, may capture aggregate cost if based on historical data, reasonable bounds can usually be inferred
Production Handling Agreements	Contract terms are only partially disclosed and complex terms and options usually not incorporated in analysis	Factor model application defensible and reasonably easy to develop and bound with transparent assumptions
Activity-Based Costing	Quality of evaluation depends on user experience and assumptions, requires detailed evaluation and data collection, potentially time consuming	Detailed, bottom-up cost model can capture cost elements in direct, transparent fashion, includes engineering and market conditions

Table S.2. Lifting and total expense metrics

$$\text{Lifting cost per Mcfe} = \frac{\text{Total LOE} + \text{Indirect operating expense}}{\text{Mcfe production}}$$

$$\text{Lifting cost per Mcfe} = \frac{\text{Total expense} - \text{Other LOE} - \text{Total major repair}}{\text{Mcfe production}}$$

$$\text{Total Expense per Mcfe} = \frac{\text{Total expense}}{\text{Mcfe production}}$$

Table S.3. Operating expenses per boe at Energy XXI GOM, 2012-2014

	2014	2013	2012
Lease operating expense			
Insurance expense	1.90	2.08	1.77
Workover and maintenance	4.04	4.15	3.49
Direct lease operating expense	16.31	15.23	13.99
Total lease operating expense per boe	22.25	21.46	19.25
Production taxes	0.33	0.33	0.45
Gathering and transportation	1.43	1.54	1.01
Depreciation, depletion and amortization	25.75	23.95	22.76
General and administrative	5.87	4.56	5.34
Other	2.19	2.08	1.98
Total operating expenses per boe	57.82	53.92	50.79

Source: Energy XXI GOM

Table S.4. Unit production cost reported by sample Gulf of Mexico companies, 2006-2015

Company	Item	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
ATP	Direct LOE				11.57	10.34	11.54	11.31	-	-	-
($/boe)	Workover				1.87	3.26	5.76	3.15	-	-	-
	All				13.44	13.60	17.30	14.47	9.60	8.46	8.52
Callon	Direct LOE			2.33	2.43	1.60	1.60	1.42	1.53	1.30	-
($/Mcfe)	Transportation & Gathering				0.04	0.05	0.08	0.10	0.09	0.12	-
	All				2.47	1.65	1.68	1.52	1.62	1.42	1.39
Contango	Direct LOE		1.17	1.30	0.49	0.56	0.41	0.40	0.49	0.29	0.60
($/Mcfe)	Others				0.33	0.41	0.23	0.27	0.33	0.20	0.40
	All				0.83	0.97	0.63	0.67	0.81	0.49	1.00
Energy	Direct LOE		16.31	15.23	14.00	14.99	12.54	11.15	13.40	9.08	7.96
XXI	Insurance		1.90	2.08	1.77	1.99	2.77	3.39	2.26	2.16	1.98
($/boe)	Workover and Maintenance		4.04	4.15	3.49	2.72	2.67	1.59	2.84	2.24	0.31
	Transportation & Gathering		1.43	1.54	1.01	1.41	-	-	-	-	-
	All		23.68	23.00	20.27	21.11	17.98	16.13	18.50	13.48	10.26
EPL	Direct LOE				17.88	15.73	10.64	10.98	14.98	7.94	6.22
($/boe)	Transportation				0.12	0.17	0.27	0.19	0.23	0.28	0.21
	All				18.00	15.90	10.91	11.17	15.21	8.22	6.43
Energy	Direct LOE				17.75	14.73	10.70	10.74	10.38	7.50	6.30
Resource	Workover				3.17	1.90	2.94	1.32	1.38	1.08	1.44
Technology	Transportation & Gathering				1.02	0.99	0.88	1.14	0.72	0.42	0.42
($/boe)	Repairs and Maintenance				1.29	1.36	0.98	1.86	2.64	1.14	1.62
	All				13.44	13.60	17.30	14.47	9.60	8.46	8.52
McMoRan	Direct LOE				2.00	1.66	1.79	1.57	1.49	1.26	1.27
($/Mcfe)	Workover				0.42	0.79	0.39	0.25	0.44	0.35	0.19
	Hurricane Related Repairs				0.03	0.00	0.12	0.19	0.26	0.00	0.36
	Insurance				0.23	0.21	0.45	0.32	0.25	0.42	0.21
	Transportation & Gathering				0.41	0.36	0.36	0.29	0.44	0.17	0.19
	All	3.10	3.35	2.86	3.09	3.02	3.11	2.62	2.88	2.20	2.22
RAAM	Direct LOE				1.42	1.43	1.40	1.05	-	-	-
($/Mcfe)	Workover				0.11	0.32	0.46	0.34	-	-	-
	All				1.53	1.76	1.86	1.39	-	-	-
Stone	Direct LOE	1.15	1.89	1.99	2.33	2.20	1.90	-	-	-	-
Energy	Transportation & Gathering	0.68	0.69	0.42	0.24	0.11	0.09	-	-	-	-
($/Mcfe)	All	1.83	2.58	2.41	2.57	2.31	1.99	2.00	2.68	1.83	2.06
W&T	Direct LOE	1.88	2.50	2.51	2.26	2.16	1.95	2.15	2.35	1.86	1.15
Offshore	Transportation & Gathering	0.17	0.19	0.16	0.14	0.17	0.19	0.14	0.16	0.12	0.16
($/Mcfe)	All	2.05	2.69	2.67	2.40	2.33	2.14	2.29	2.51	1.98	1.31

Source: Company annual reports

Table S.5. Maritech Resources lease operating statement summary in 2005

Category	Average ($1000)	Percentage (%)
Labor and Supervision	47	8
Transportation	101	18
Contract Service & Rental	121	22
Materials & Supplies	42	8
Utility	38	7
Surface Repairs & Maintenance	26	5
Miscellaneous	141	25
Production	40	7
All	556	100

Source: Maritech Resources

Table S.6. Maritech Resources average lifting cost by annual production in 2005

Production (MMcfe)	Number	LOE ($/Mcfe)	Total Expenditures ($/Mcfe)
< 100	13	1.75	3.16
101-200	8	2.14	3.68
201-500	6	3.46	5.40
501-1000	4	2.45	3.42
1000-2000	1	1.65	2.63
> 2000	1	0.58	1.21
All	33	2.20	3.65

Source: Maritech Resources
Note: LOE includes indirect operating expense.

Table S.7. Maritech Resources average lifting cost by gas oil ratio in 2005

GOR (Mcf/bbl)	Number	LOE ($/Mcfe)	Total Expenditures ($/Mcfe)
< 5	8	3.52	5.11
5-15	4	1.61	3.28
15-100	10	2.16	3.31
100-250	4	1.66	2.87
> 250	7	1.41	3.13
All	33	2.20	3.65

Source: Maritech Resources
Note: LOE includes indirect operating expense.

Table S.8. EIA offshore Gulf of Mexico operating cost survey results (million 2009$)

Platform	100 ft	300 ft	600 ft
12-slot	8.67	8.95	
18-slot	10.1	10.4	10.9

Source: EIA 2009

Figure S.1. Delta House semisubmersible
Source: LLOG

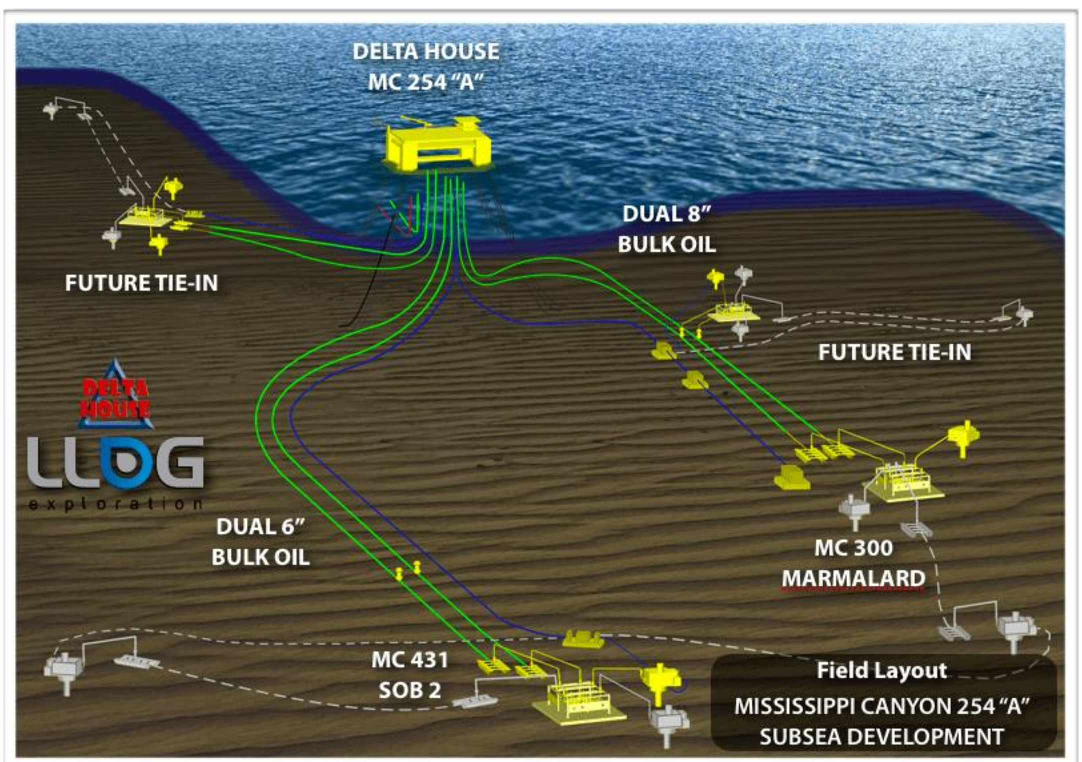


Figure S.2. Mississippi Canyon (Delta House) subsea development
Source: LLOG

Figure S.3. Hurricane Katrina damaged the Mars platform and required significant repairs
Source: Shell

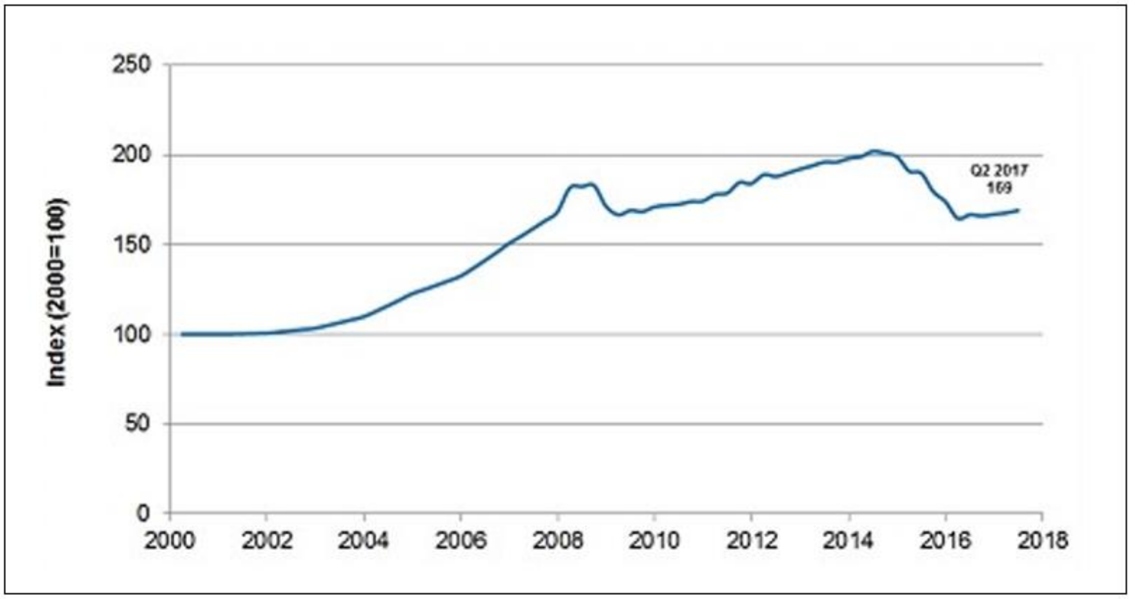


Figure S.4. Upstream world operating cost index
Source: IHS Markit

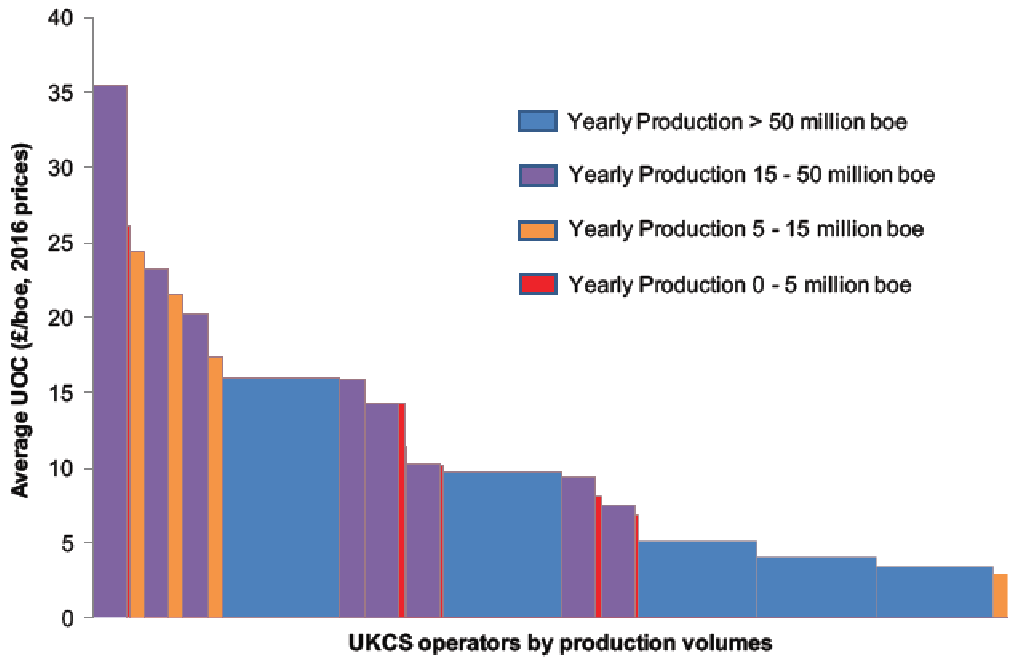


Figure S.5. Unit operating cost and hydrocarbon production by operator in 2016
Source: UK Oil & Gas Authority

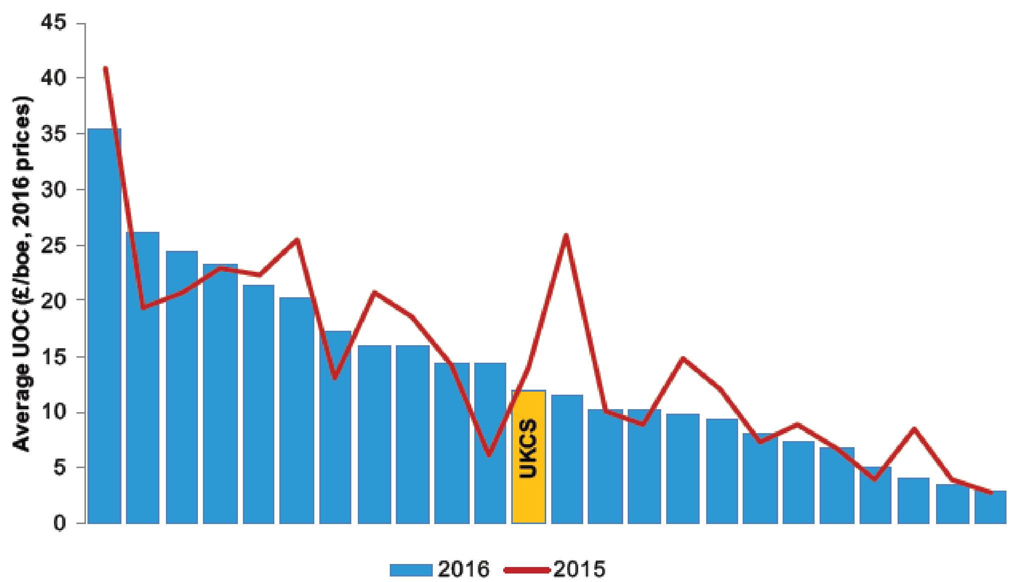


Figure S.6. Unit operating cost by operator for 2015 and 2016
Source: UK Oil & Gas Authority

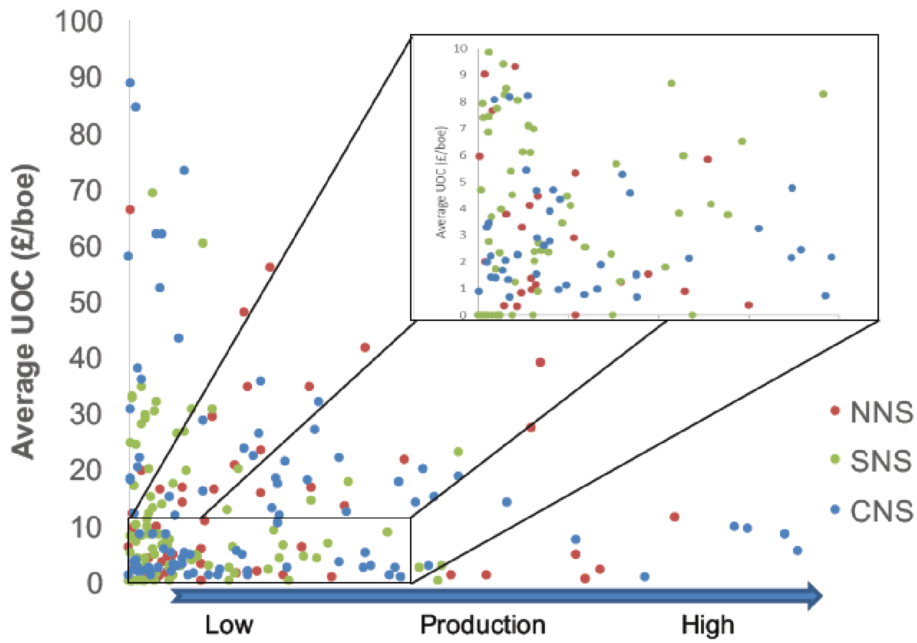


Figure S.7. Field operating cost for the South North Sea, Central North Sea and North North Sea in 2016
Source: UK Oil & Gas Authority

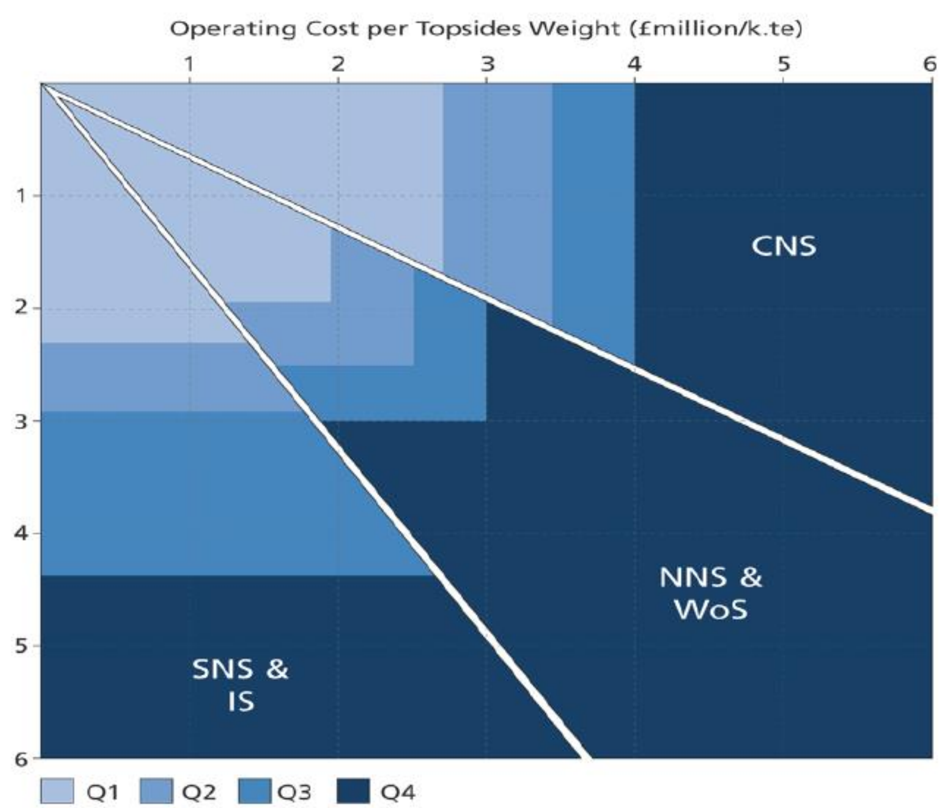


Figure S.8. Manned platform operating cost per topside weight quartile performance by location
Source: UK Oil & Gas Authority

APPENDIX T

CHAPTER 20 TABLES AND FIGURES

Table T.1. West Delta 73 production cost, 2012-2014

	2014	2013	2012
Net Sales			
Oil (Mbbls)	1496	1278	840
NGLs (Mbbls)	3.7	3.7	3.7
Natural gas (MMcf)	2737	3285	2190
Oil equivalent (Mboe)	2007	1862	1241
Average Sales Prices			
Oil per bbl	$105.06	$109.11	$111.33
NGLs per bbl	$40.74	$33.50	$61.18
Natural gas per Mcf	$4.22	$3.4	$1.67
Production Costs			
Oil equivalent ($/boe)	$19.76	$18.54	$21.30

Source: Energy XXI

Table T.2. Main Pass 61 production cost, 2010-2012

	2012	2011	2010
Net Sales per Day			
Oil (Mbopd)	6.5	7.2	5.8
Natural gas (MMcfpd)	4.1	3.0	3.5
Oil equivalent (Mboepd)	7.2	7.7	6.4
Average Sales Prices			
Oil per bbl	$105.94	$88.62	$75.37
Natural gas per Mcf	$2.91	$4.44	$4.99
Production Costs			
Oil equivalent ($/boe)	$9.77	$10.30	$11.37

Source: Energy XXI

Table T.3. South Timbalier 21 production cost, 2008-2010

	2010	2009	2008
Net Sales per Day			
Oil (Mbopd)	3.8	4.2	6.1
Natural gas (MMcfpd)	4.6	9.1	10.1
Oil equivalent (Mboepd)	4.6	5.7	7.8
Average Sales Prices			
Oil per bbl	$72.92	$65.96	$97.91
Natural gas per Mcf	$4.23	$6.14	$9.47
Production Costs			
Oil equivalent ($/boe)	$27.21	$26.22	$14.76

Source: Energy XXI

Table T.4. Ship Shoal 349 (Mahogany) production cost, 2013-2015

	2015	2014	2013
Net Sales			
Oil (Mbbls)	2313	2020	1943
NGLs (Mbbls)	97	104	90
Natural gas (MMcf)	3764	3433	3328
Oil equivalent (Mboe)	3037	2697	2589
Average Sales Prices			
Oil per bbl	$42.73	87.21	98.69
NGLs per bbl	$21.27	46.46	43.24
Natural gas per Mcf	$2.86	4.40	3.72
Oil equivalent per boe	$36.77	72.73	80.39
Production Costs			
Oil equivalent ($/boe)	$3.30	$4.12	$3.68

Source: W&T Offshore, Inc.

Table T.5. Viosca Knoll 990 (Pompano) production cost, 2013-2015

	2015	2014	2013
Net Sales			
Oil (Mbbls)	2839	1311	
Natural gas (MMcf)	3331	2894	
NGLs (Mbbls)	239	151	
Natural gas equivalent (MMcfe)	21,799	11,666	
Average Sales Prices			
Oil per bbl	$49.19	$92.53	$107.99
Natural gas per MMcf	$2.22	$ 3.10	$2.49
NGLs per bbl	$15.49	$41.27	$40.65
Natural gas equivalent per MMcfe	$6.91	$11.70	$13.50
Production Costs			
Lease operating expenses ($/Mcfe)	$0.96	$2.75	$1.98
Transportation and gathering expenses ($/Mcfe)	$0.08	$0.13	$0.14

Source: Stone Energy

Table T.6. Mississippi Canyon 109 (Amberjack) production cost, 2008-2010

	2015	2014	2013
Net Sales			
Oil (Mbbls)	10	7	5
NGLs (Mbbls)	319	415	268
Natural gas (MMcf)	8277	6899	4614
Natural gas equivalent (MMcfe)	10,250	9,428	6,373
Average Sales Prices			
Oil per bbl	$47.22	$101.94	$104.75
NGLs per bbl	$18.97	$27.41	$28.34
Natural gas per Mcf	$2.60	$4.07	$3.63
Natural gas equivalent per Mcfe	$2.73	$4.26	$3.99
Production Costs			
Natural gas equivalent ($/Mcfe)	$1.49	$1.79	$2.08

Source: W&T Offshore, Inc.

Table T.7. Fairway field production cost, 2013-2015

	2015	2014	2013
Net Sales			
Oil (Mbbls)	10	7	5
NGLs (Mbbls)	319	415	268
Natural gas (MMcf)	8277	6899	4614
Natural gas equivalent (MMcfe)	10,250	9,428	6,373
Average Sales Prices			
Oil per bbl	$47.22	$101.94	$104.75
NGLs per bbl	$18.97	$27.41	$28.34
Natural gas per Mcf	$2.60	$4.07	$3.63
Natural gas equivalent per Mcfe	$2.73	$4.26	$3.99
Production Costs			
Natural gas equivalent ($/Mcfe)	$1.49	$1.79	$2.08

Source: W&T Offshore, Inc.

Table T.8. Main Pass 299 field production cost, 2010-2012

	2012	2011	2010
Net Sales			
Oil (Mbbls)	360	348	376
Average Sales Prices			
Oil and condensate per bbl	104.03	101.75	73.41
Production Costs			
Oil equivalent ($/bbl)	$63.38	$97.83	$51.94

Source: McMoRan Oil & Gas, Inc.

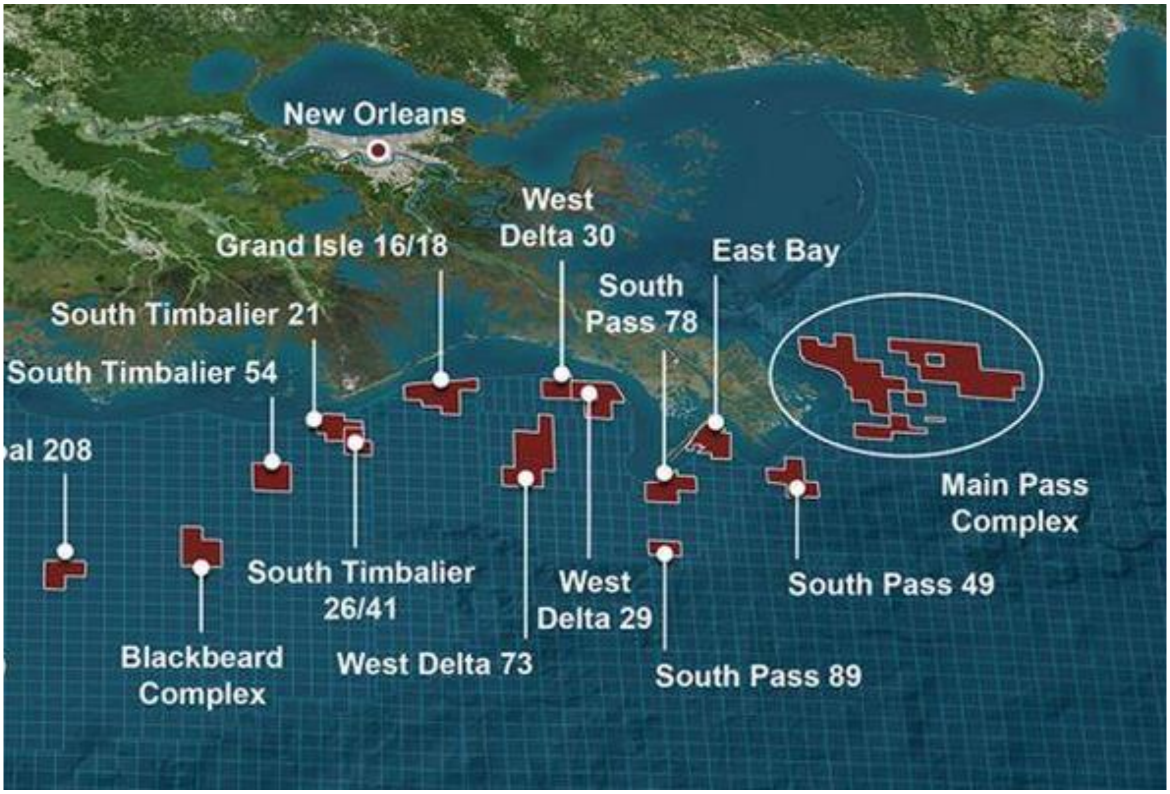


Figure T.1. West Delta 73 field location
Source: Energy XXI

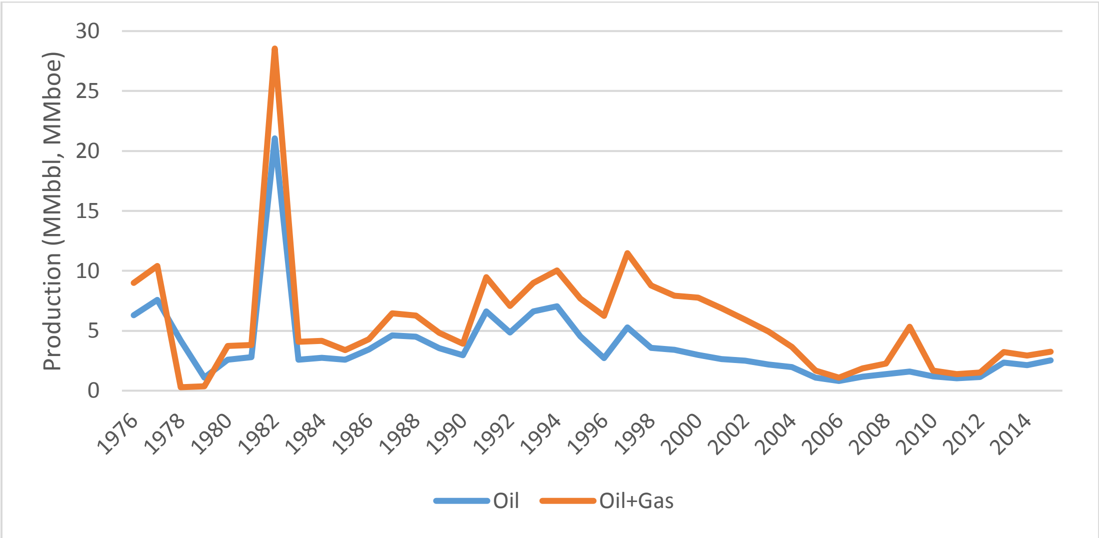


Figure T.2. West Delta 73 field oil and gas production profile, 1976-2015
Source: BOEM 2017

Figure T.3. West Delta 73 complex
Source: Energy XXI

Figure T.4. Main Pass 61 platform
Source: Energy XXI

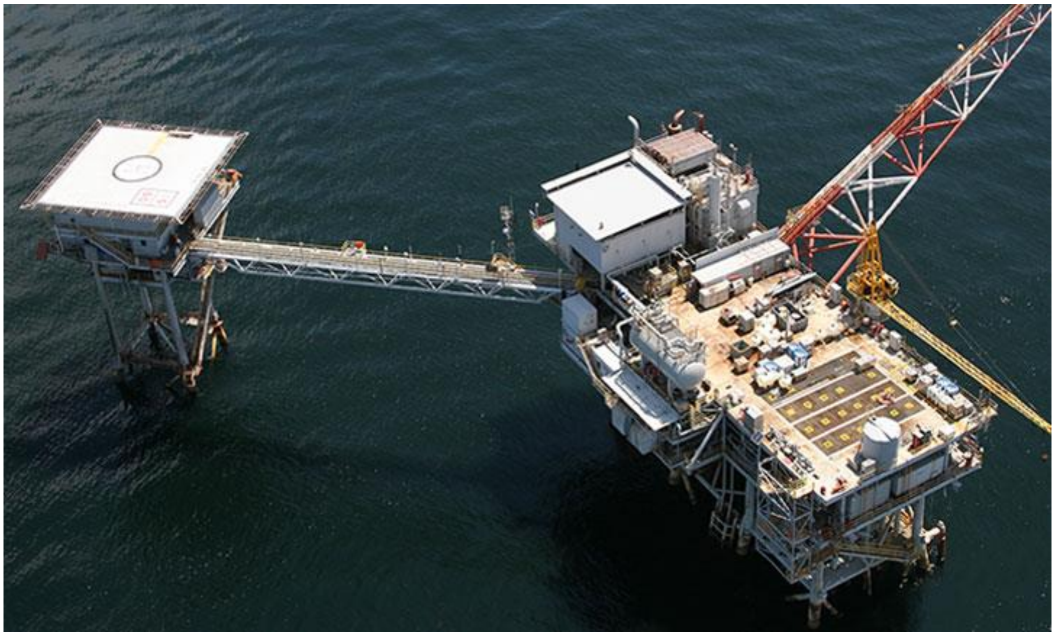


Figure T.5. South Timbalier 21 platform
Source: Energy XXI

Figure T.6. Another South Timbalier 21 platform
Source: Energy XXI

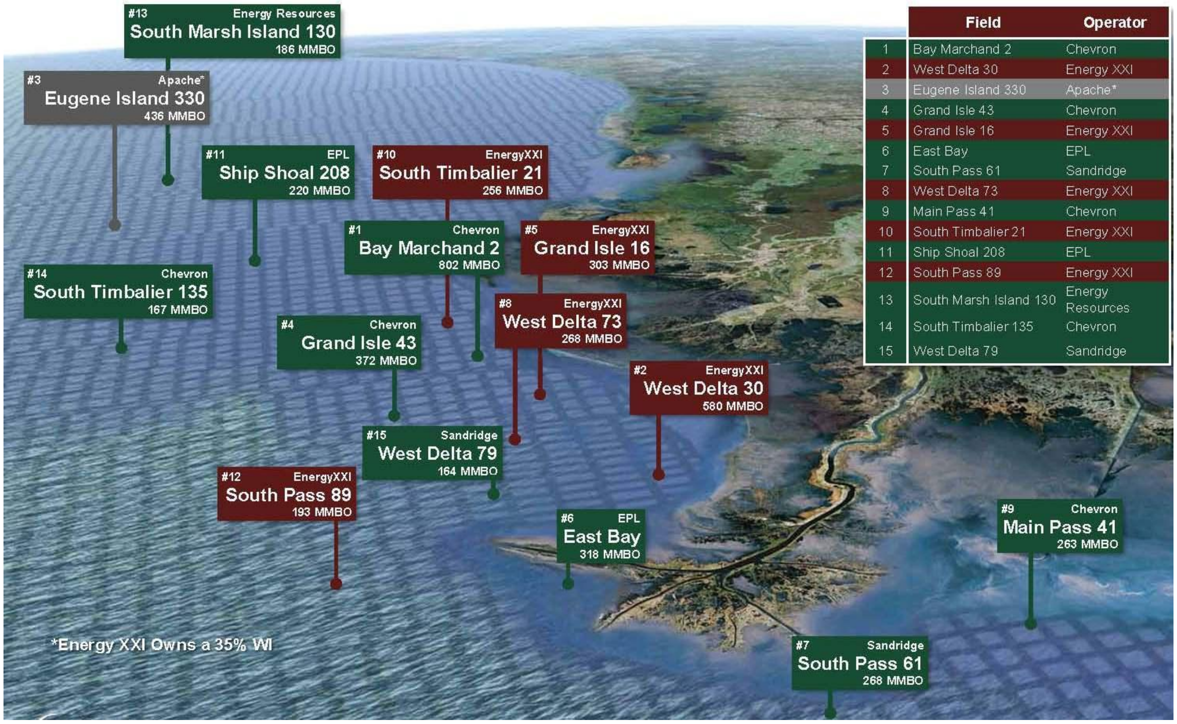


Figure T.7. Aerial perspective of South Timbalier 21 field location

Source: Energy XXI

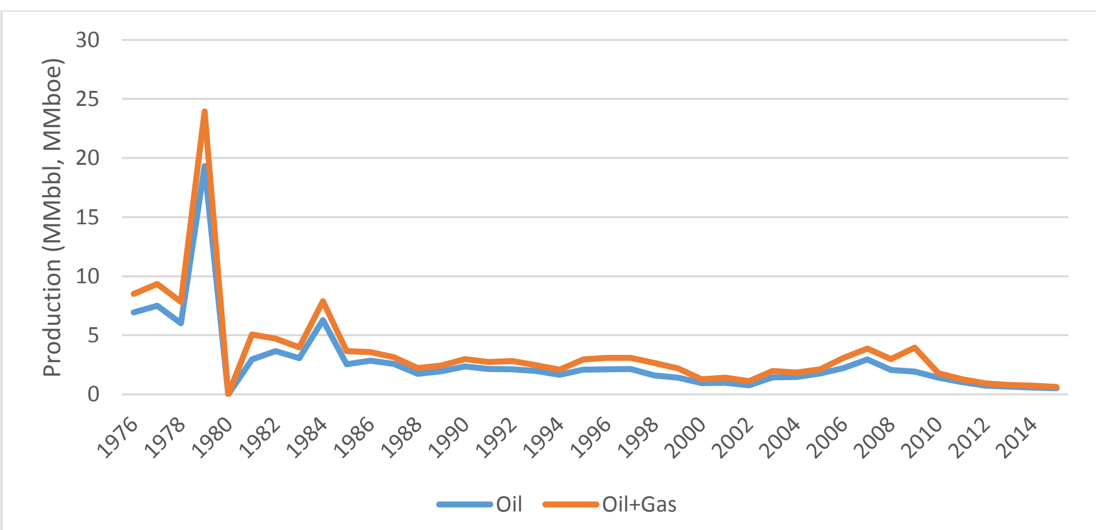


Figure T.8. South Timbalier 21 field oil and gas production profile, 1976-2015

Source: BOEM 2017

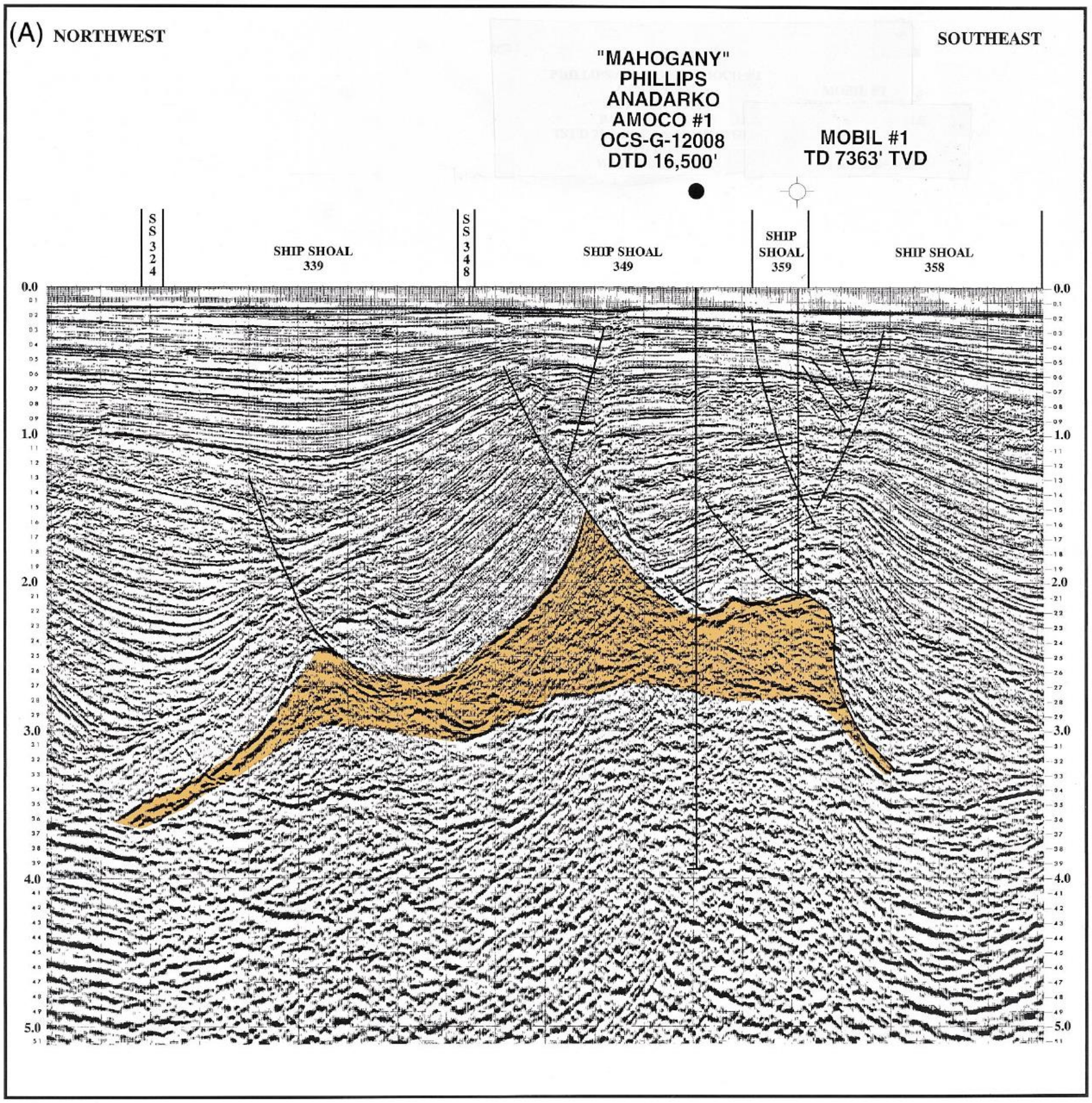


Figure T.9. Seismic profile from the Ship Shoal 349 #1 exploration well
Source: Montgomery and Moore 1997

Figure T.10. Ship Shoal 349 (Mahogany) production complex
Source: W&T Offshore, Inc.

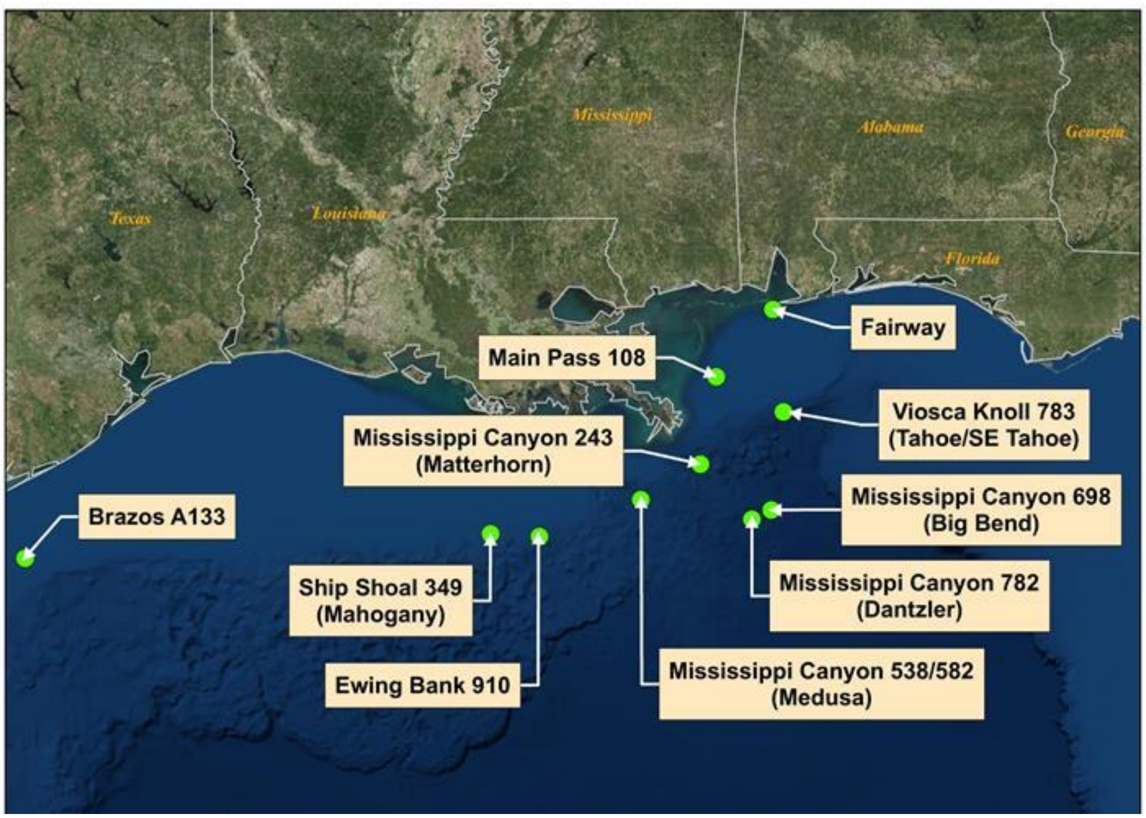


Figure T.11. Ship Shoal 349 (Mahogany) field location
Source: W&T Offshore, Inc.

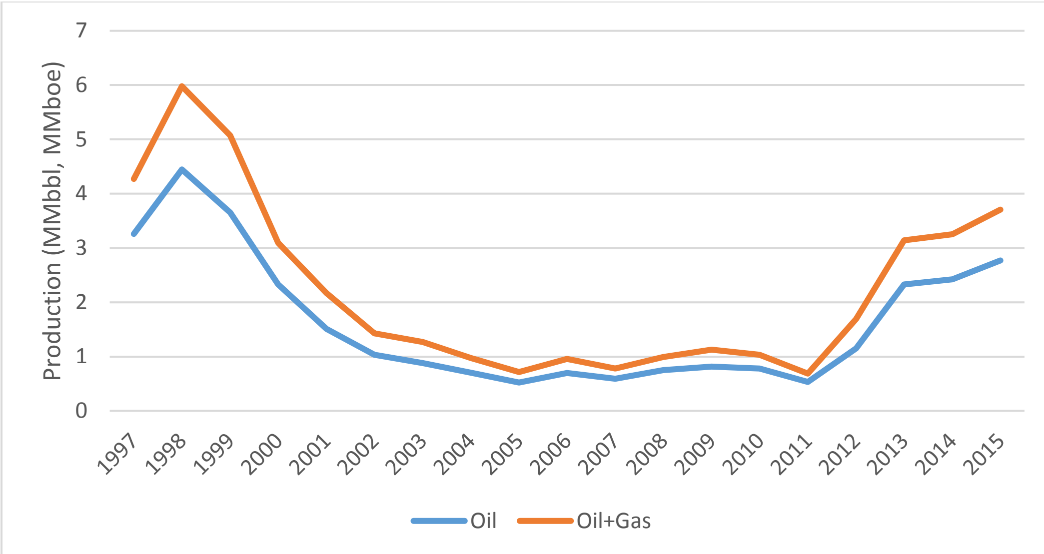


Figure T.12. Ship Shoal 349 (Mahogany) field oil and gas production profile, 1997-2015
Source: BOEM 2017

Figure T.13. Viosca Knoll 990 (Pompano) production complex
Source: Stone Energy

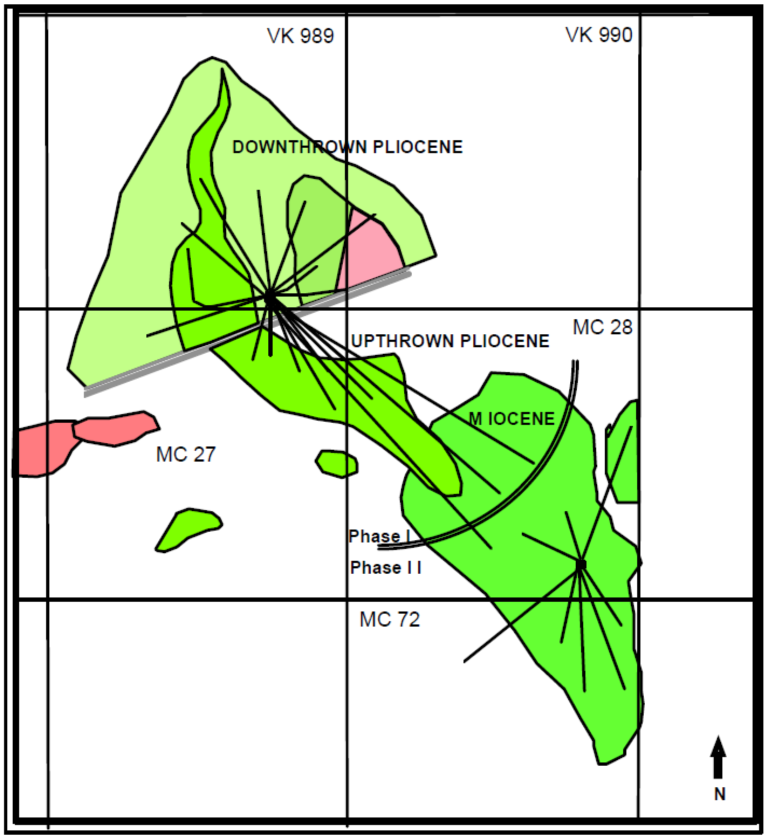


Figure T.14. Pompano initial phase I and phase II development
Source: Willson et al. 2003

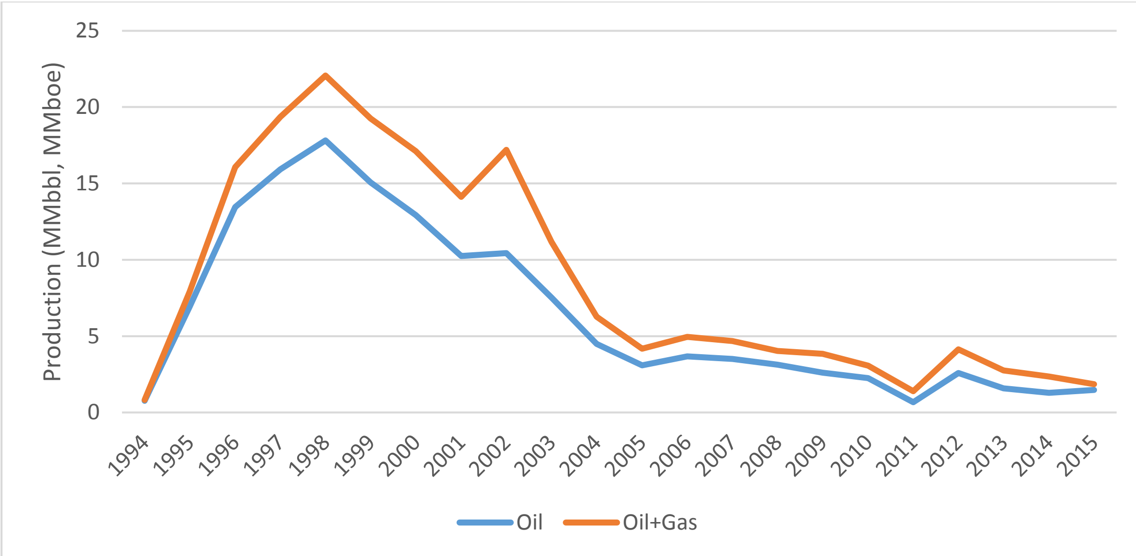


Figure T.15. Viosca Knoll 990 (Pompano) field oil and gas production profile, 1994-2015
Source: BOEM 2017

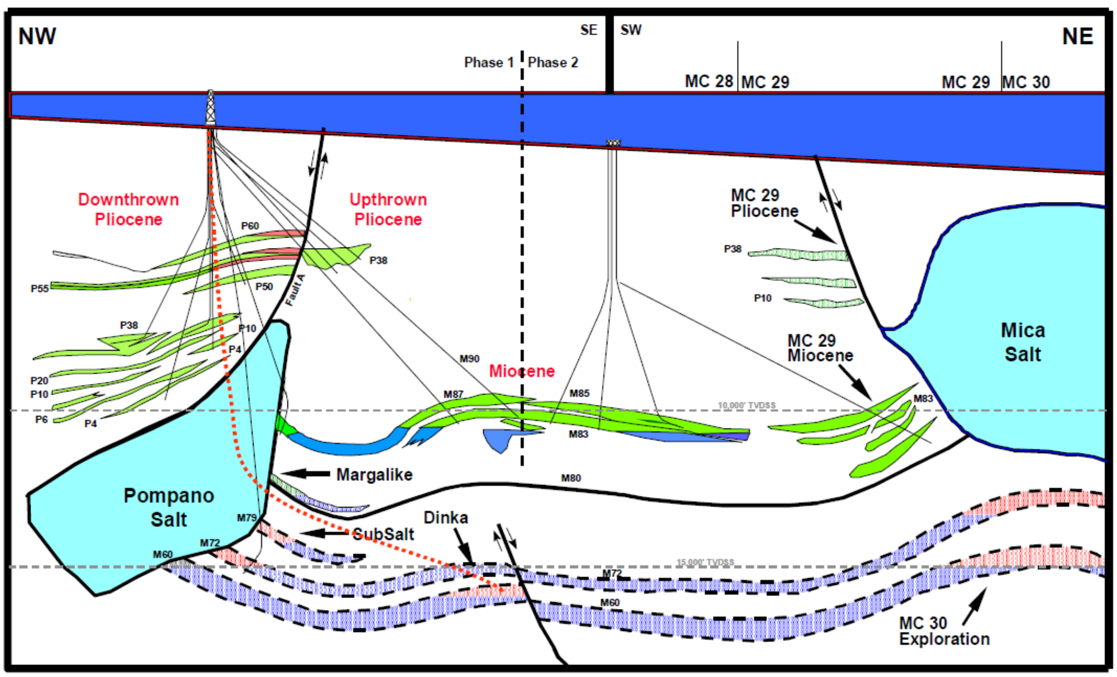


Figure T.16. Cross section through the Pompano field
Source: Willson et al. 2003

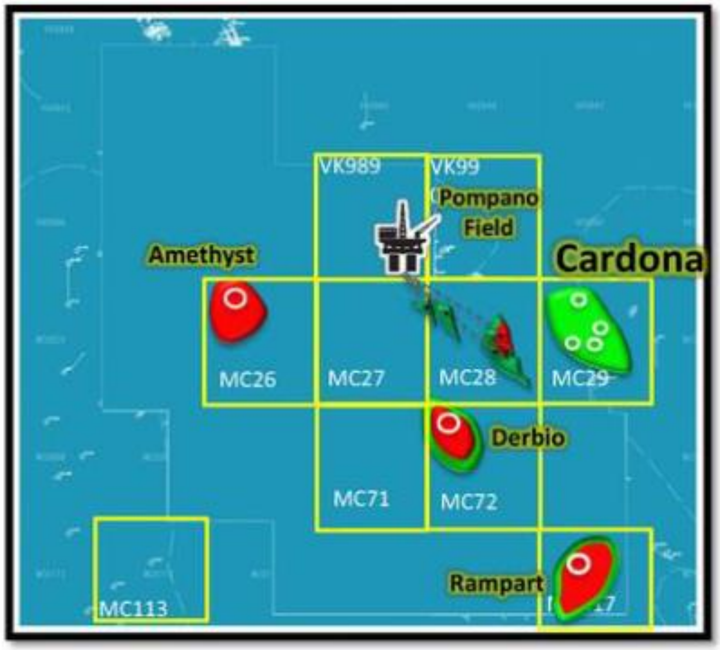


Figure T.17. Pompano field location and subsea tiebacks planned circa 2016
Source: Stone Energy

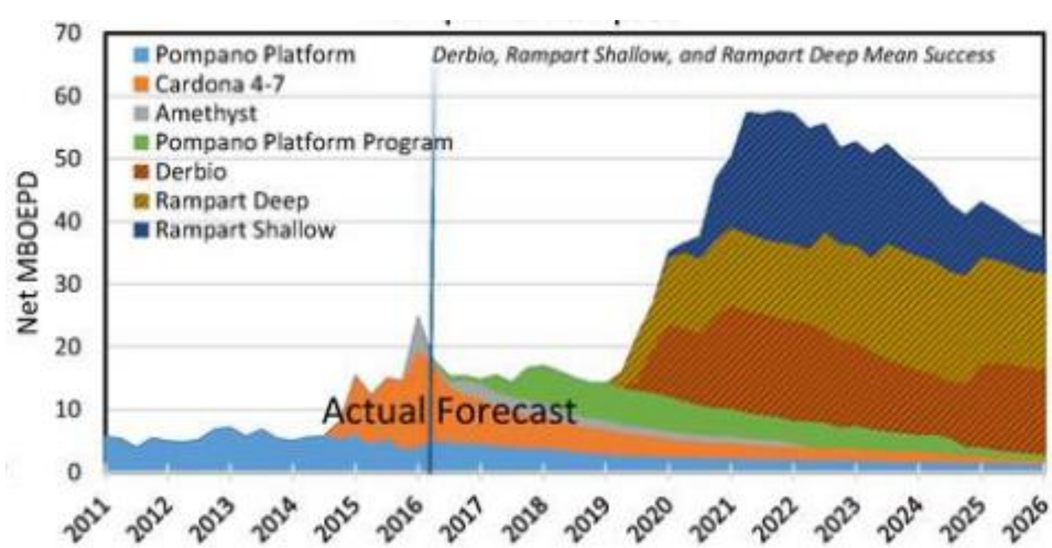


Figure T.18. Pompano current and planned future subsea tiebacks and estimated production
Source: Stone Energy

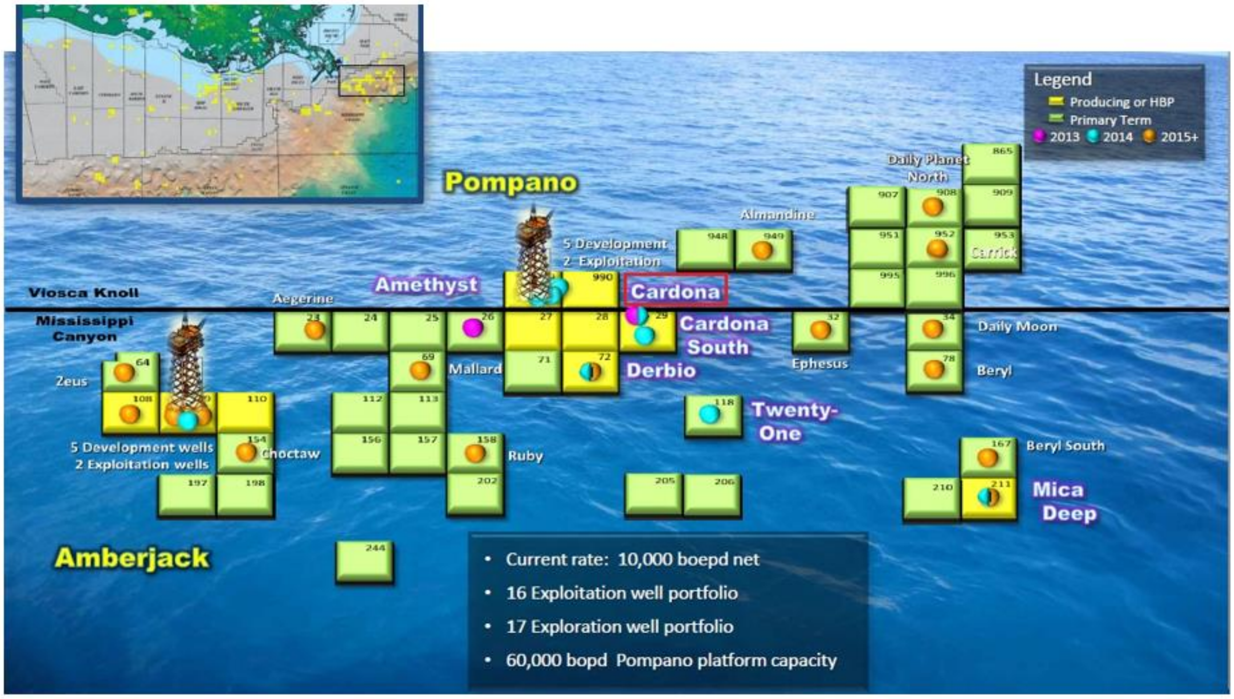


Figure T.19. Mississippi Canyon 109 (Amberjack) field location
Source: Stone Energy

Figure T.20. Mississippi Canyon 109 (Amberjack) production platform
Source: Stone Energy

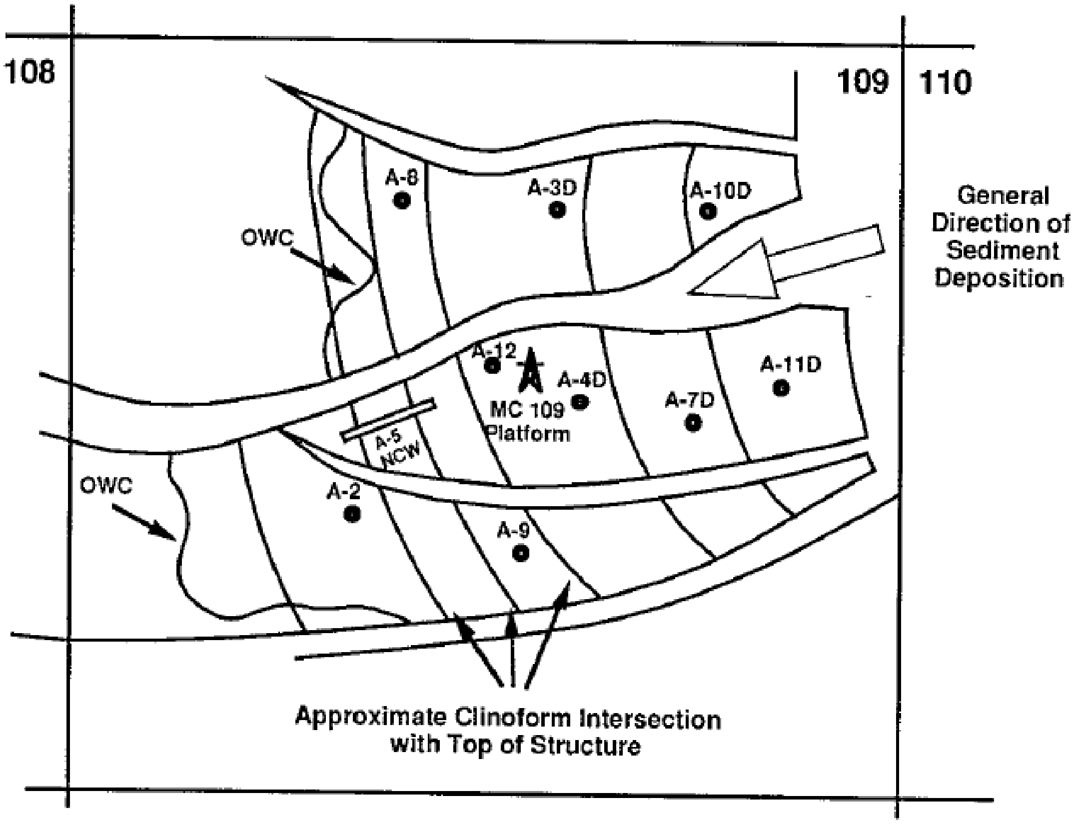


Figure T.21. Mississippi Canyon 109 clinoform intersections create reservoir compartmentalization
Source: Johnston 1993

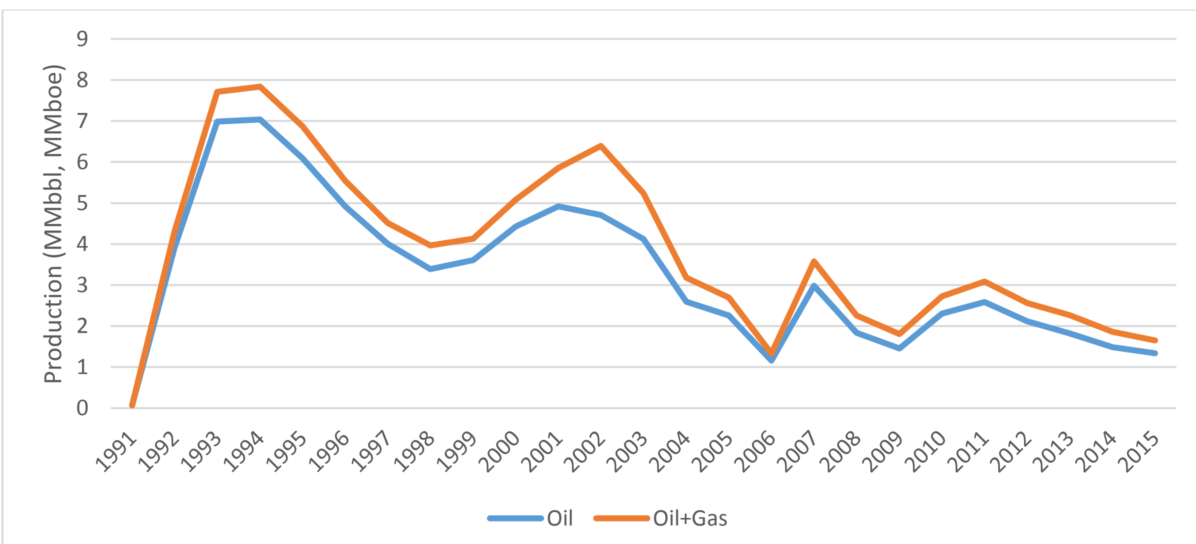


Figure T.22. Mississippi Canyon 109 (Amberjack) field oil and gas production profile, 1976-2015
Source: BOEM 2017

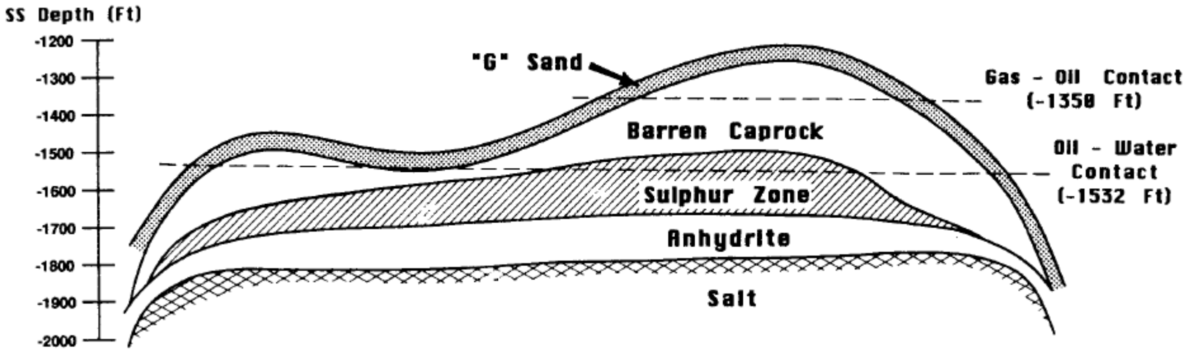


Figure T.23. Northwest to southeast cross-section across Main Pass block 299
Source: Lewis and Taylor 1992

Figure T.24. Main Pass block 299 production and mining complex
Source: Freeport-McMoRan

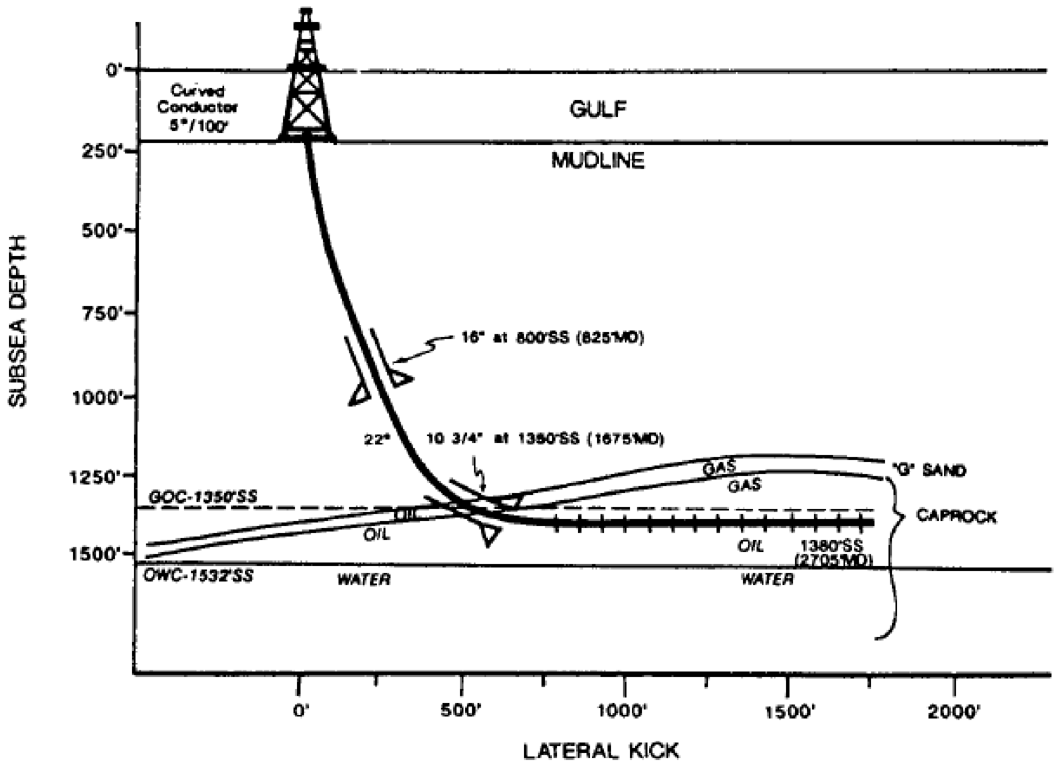


Figure T.25. Horizontal well completions at Main Pass block 299 were placed structurally high
Source: Lewis and Taylor 1992

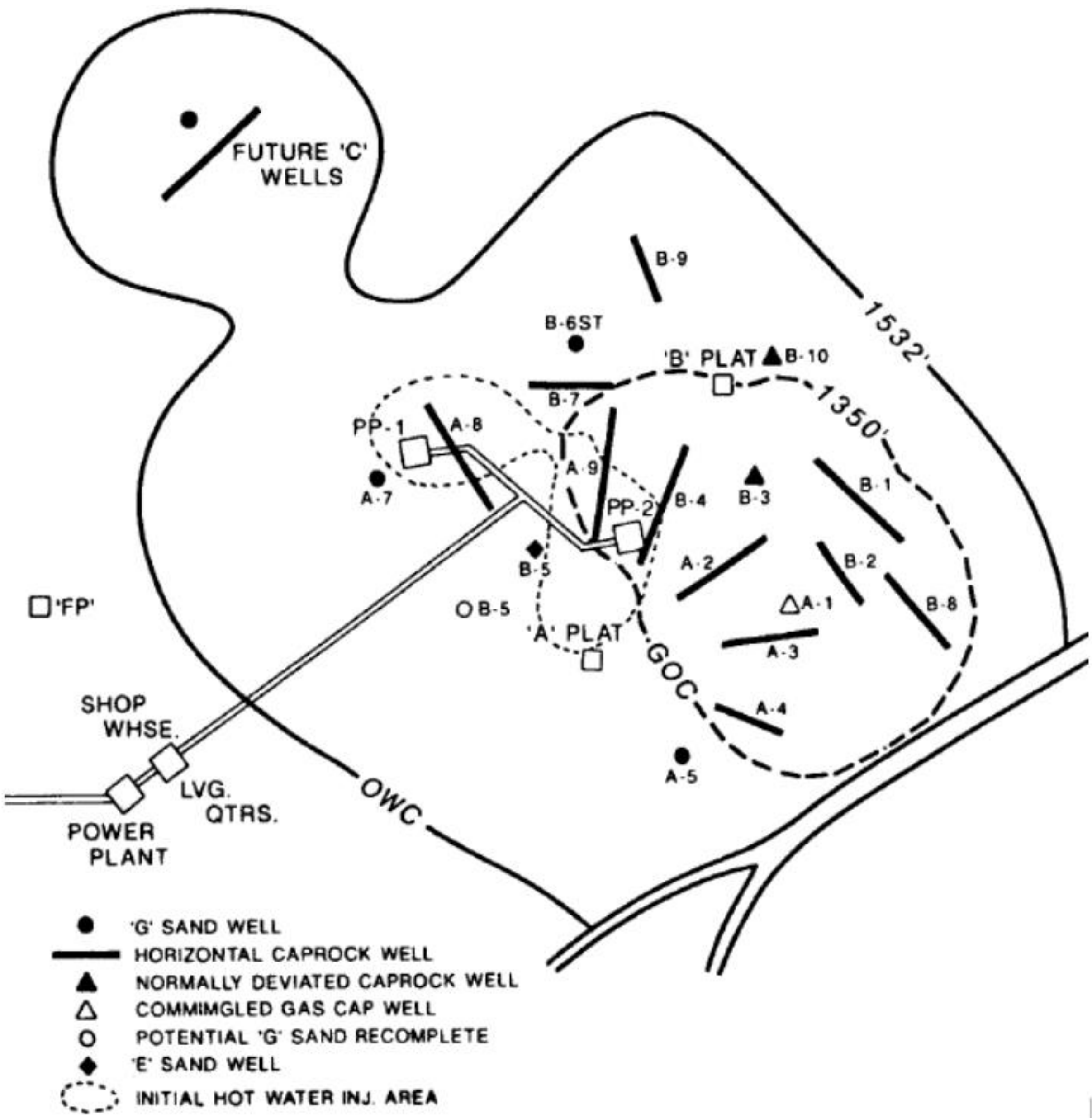


Figure T.26. Schematic of production complex and horizontal wells at Main Pass block 299
Source: Lewis and Taylor 1992

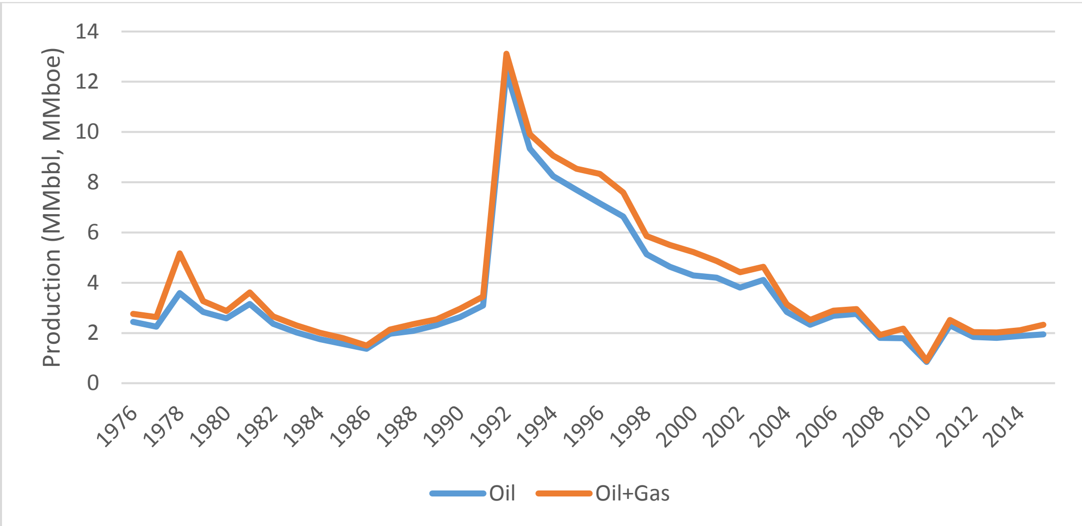


Figure T.27. Main Pass 299 field oil and gas production profile, 1976-2015

Source: BOEM 2018

APPENDIX U

CHAPTER 21 TABLES AND FIGURES

Table U.1. Energy XXI GOM LLC corporate production cost, 2012-2014

	Cost ($/boe)	Percentage (%)
Direct LOE	15.18	68%
Workover & Maintenance	3.79	17%
Insurance	2.01	9%
Transportation & Gathering	1.34	6%
Total	22.32	100%

Source: Energy XXI GOM

Table U.2. Destin pipeline rate schedule firm transportation rate

	Monthly Reservation Rate ($/Dth/mo)	Daily Reservation Rate ($/Dth)	Transportation Rate (¢/Dth)
Maximum Rate	$7.19	$0.237	0.3¢
Minimum Rate	0.00	0.00	0.3¢
Fuel Retention Percentage	0.3%		

Source: FERC

Table U.3. Mars pipeline tariff firm transportation rate

From	To	Rate
MC 807 (Mars A)	WD 143	$2.61/bbl
WD 143	Bay Marchard 4	$1.16/bbl, if <30,000 bbl $0.70/bbl, if >30,000 bbl
Bay Marchard 4	Fourchon Terminal	$0.15/bbl
Fourchon Terminal	Clovelly/Caverns	$0.43/bbl

Source: Shell Midstream Partners

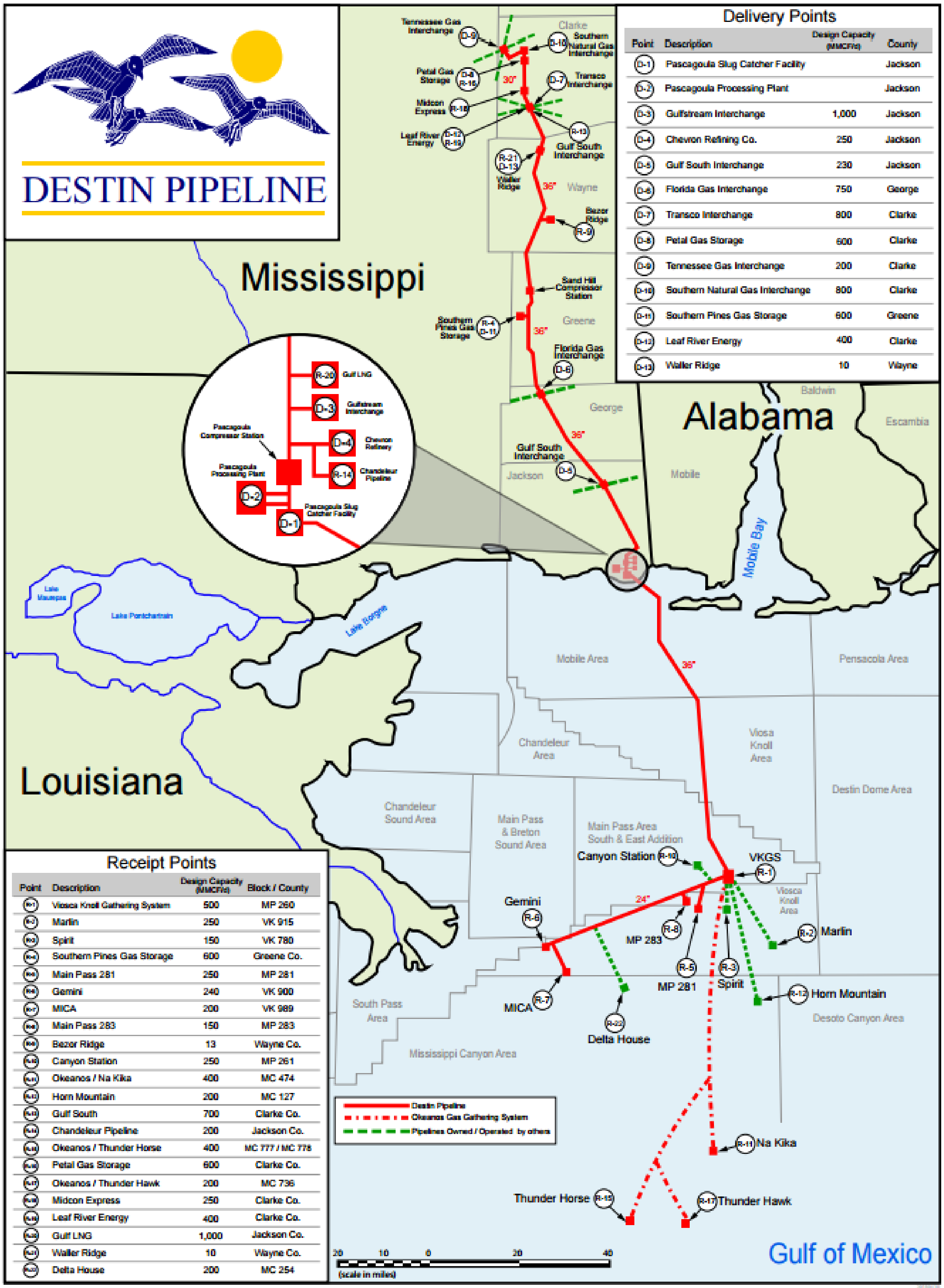
Table U.4. Typical fees and expenses in production handling agreements

Infrastructure Access Fee	Monthly $/unit - Minimum monthly - Annual adjustment
Operation and Maintenance Expenses	Reimbursement of host operating expenses for oil, gas, and produced water - Monthly $/unit - Shared expenses via throughput ratio - Sole expenses (host and satellite)
Deferred Production Compensation	Compensation for deferment of host production during hook-up of satellite production system
Platform Oil Quality Bank	Monetary adjustments based on API gravity and sulfur value differentials

Table U.5. Big Bend and Dantzler hypothetical production profile and PHA cost terms

	Production (MMboe)	Fixed ($ million)	Variable ($ million)	Total ($ million)
2016	10	20	40	60
2017	9	20	36	66
2018	8.1	20	32.4	5204
2019	5.6	20	22.4	42.4
2020	2.2	20	8.8	28.8
2021				
Subtotal		100	140	

Note: Assumes fixed cost of $20 million/yr and $4/bbl variable cost.



Delivery Points

Point	Description	Design Capacity (MMCF/d)	County
D-1	Pascagoula Slug Catcher Facility		Jackson
D-2	Pascagoula Processing Plant		Jackson
D-3	Gulfstream Interchange	1,000	Jackson
D-4	Chevron Refining Co.	250	Jackson
D-5	Gulf South Interchange	230	Jackson
D-6	Florida Gas Interchange	750	George
D-7	Transco Interchange	800	Clarke
D-8	Petal Gas Storage	600	Clarke
D-9	Tennessee Gas Interchange	200	Clarke
D-10	Southern Natural Gas Interchange	800	Clarke
D-11	Southern Pines Gas Storage	600	Greene
D-12	Leaf River Energy	400	Clarke
D-13	Waller Ridge	10	Wayne

Receipt Points

Point	Description	Design Capacity (MMCF/d)	Block / County
R-1	Viosca Knoll Gathering System	500	MP 260
R-2	Marlin	250	VK 915
R-3	Spirit	150	VK 780
R-4	Southern Pines Gas Storage	600	Greene Co.
R-5	Main Pass 281	250	MP 281
R-6	Gemini	240	VK 900
R-7	MICA	200	VK 989
R-8	Main Pass 283	150	MP 283
R-9	Bezor Ridge	13	Wayne Co.
R-10	Canyon Station	250	MP 261
R-11	Okeanos / Na Kika	400	MC 474
R-12	Horn Mountain	200	MC 127
R-13	Gulf South	700	Clarke Co.
R-14	Chandeleur Pipeline	200	Jackson Co.
R-15	Okeanos / Thunder Horse	400	MC 777 / MC 778
R-16	Petal Gas Storage	600	Clarke Co.
R-17	Okeanos / Thunder Hawk	200	MC 736
R-18	Midcon Express	250	Clarke Co.
R-19	Leaf River Energy	400	Clarke Co.
R-20	Gulf LNG	1,000	Jackson Co.
R-21	Waller Ridge	10	Wayne Co.
R-22	Delta House	200	MC 254

Figure U.1. Destin Pipeline system map

Source: FERC

Figure U.2. Mars A platform
Source: Shell Offshore

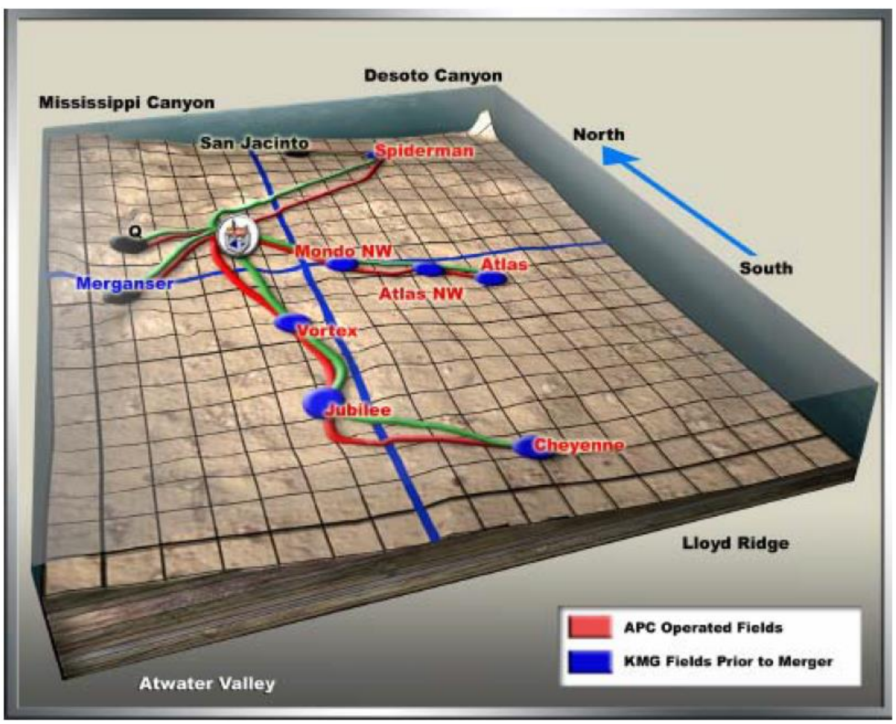


Figure U.3. Independence project layout
Source: Burman et al. 2007

APPENDIX V

CHAPTER 22 TABLES AND FIGURES

Table V.1. Offshore operating cost categories and cost basis

Element	Basis
Personnel	
Process operators	Annual
Process maintenance	Annual
Supervision	Annual
Crew Transportation	
Helicopters	Monthly fixed, hourly flight rate
OSV	Monthly fixed, dayrate
Logistics	
OSV supply boats	Dayrate
Standby vessels	Monthly
Docking charges	Monthly
Warehouse	Monthly
Chemicals	Volume
Fuel, water	Volume
Repairs and maintenance	Rate + schedule
Service company personnel	
Service company equipment	
Contractor services	
Equipment standby	Monthly
Pipeline tariffs	Volume, capacity, distance, age
Communications, data transmission	Annual
Catering	Per person per day
Insurance	Annual

Table V.2. Labor and transportation cost comparison – shallow water vs. deepwater

Component	Shallow Water Manned Platform	Cost ($ thousand/yr)
Labor	5 men · 2wk/cycle · $125,000/man-yr	1250
Material Transport	0.8 · $7800/d · 1 d/trip · 52 trips/yr	324
Crew Transport	$3230/d · 0.25 d/trip · 26 trips/yr	21
Catering	5 men · $50/man-day · 365 d/yr	91
Total		1687
Component	**Deepwater Manned Facility**	**Cost ($ million/yr)**
Labor	30 men · 2wk/cycle · $125,000/man-yr	7.5
Material Transport	$30,662/d · 2d/trip · 52 trips/yr	3.19
Crew Transport	$2500/hr · 5 hr/trip · 26 trips/yr	0.33
Catering	30 men · $50/man-day · 365 d/yr	0.55
Total		11.57

Table V.3. Direct cost calculation for a light twin helicopter

			Cost Per Year ($)		
I	Fixed Costs		500 hrs	1000 hrs	2000 hrs
	A Depreciation (5 years, 30% residual value per year)		98,000	98,000	98,000
	B Insurance				
	1. Liability and property damage	$5000			
	2. Hull insurance (10% of initial cost)	$70,000			
	Total insurance per year	$75,000	75,000	75,000	75,000
	C Pilot ($90,000 per year)		90,000	90,000	90,000
II	Hourly Costs	$			
	A Fuel (85 gal at $2/gal) per hour	170			
	B Oil and lubricants (10% of fuel) per hour	17			
	C Maintenance labor per hour	20			
	D Spare parts and spares in reserve per hour	25			
	E Engine overhaul per hour	8.50			
	Total cost per flying hour	240.50	120,500	240,500	481,000
	Total cost per year		383,250	503,500	744,000
	Total cost per hour		766.50	503.50	372.00

Note: All values are meant to be illustrative. Purchase cost assumed to be $700,000.

Table V.4. Water injection problems and solutions

Potential Problem	Possible Effect	Solution
Suspended solids	Formation plugging	Filtration or flotation
Dissolved precipitates	Scaling and plugging	Scale inhibitors
Bacteria	Loss of injectivity and reservoir souring	Biocides and selection of sour service materials
Dissolved gas	Corrosion and loss of injectivity	Degasification

Source: Jahn et al. 2008

Table V.5. FPSO water treatment costs per barrel based on seawater injection and produced water treatment

Chemical Treatment	Chemical Dosage (ppm)	Daily Treatment Chemical Vol (L)	Daily Expected Chemical Cost ($ @ $4/L)	General Cost $/bbl Water
Seawater injection: 300 Mbbl/d				
Filter aid	2	95	380	0.001
Oxygen scavenger	2	95	380	0.001
Weekly biocide (2-4 hrs)	200	125	500	0.002
Scale inhibitor	2	95	380	0.001
Daily manpower $ (16 person)			4384	0.015
Facility cost $			100,000	0.33
Total cost $			106,024	0.35
Produced water: 10 Mbbl/d				
Water clarifier	5	8	32	0.003
Weekly biocide (2-4 hrs)	200	53	212	0.021
Corrosion inhibitor	20	32	128	0.013
Scale inhibitor	2	95	380	0.001
Daily manpower $ (16 person)			4384	0.004
Facility cost $			100,000	0.614
Total cost $			105,136	

Source: Wigget 2014

Table V.6. Corrosion inhibitor cost for different gas flow rates

Gas Rate	Inhibitor @ 0.5 L/MMcf	Cost @ $10/L	Annual Cost
50 MMcfd	25 L/d	$250/d	$91,250
1 MMcfd	0.5 L/d	$5/d	$1825

Source: Cavaliaro et al. 2016

Table V.7. Production chemical applications and injection points

Chemical	Operation Mode	Injection Point(s)	Possible Combination	Rate (ppm)
Methanol	Continuous (gas) Intermittent (oil)	Tree/Downhole	CI	50-100% vol based on water
Glycol	Continuous (gas) Intermittent (oil)	Tree/Downhole	CI	50-100% vol based on water
PPD	Continuous	Tree/Downhole	CI	100-300
PI	Continuous	Tree/Downhole	CI or AI	100-300
Asphaltene Dispersant	Continuous	Downhole @ Packer	CI	100-500
Asphaltene Solvent	Intermittent	Tree	CI	50-500
CI	Continuous	Tree	MeOH, glycol, dispersants	10-50
SI	Continuous	Downhole @ Packer	CI	1-2% vol based on water
LDHI	Continuous	Tree/Downhole	MeOH, MEG	1-2% vol based on water

AA= anti-agglomerant low dosage hydrate inhibitor
AI = asphaltene inhibitor (asphaltene dispersant/solvent)
CI = corrosion inhibitor
MEG = ethylene glycol
LDHI = low dosage hydrate inhibitor
PI = paraffin inhibitor
PPD = pour point dispersant
SI = scale inhibitor

Source: Bomba et al. 2018

Table V.8. Pompano subsea well maintenance requirements

Operation	Base Case (per well/yr)	Worst Case (per well/yr)
Paraffin scraping	6.0	15.0
BHP survey	1.0	1.0
Set and recover plug	0.2	0.5
Tubing caliper survey	0.125	0.25
SCSSV repair	0.05	0.125

Source: Kleinhans and Cordner 1999

Table V.9. Completion interval and tubing wellbore constraints

Completion Interval Constraints	Production Tubing Constraints
Damage skin	Tubing string design
Sand production	Artificial lift
Scale formation	Sand production
Emulsion formation	Scale formation
Asphaltenes drop-out	Choke size
Unwanted fluid	

Source: Jahn et al. 2008

Table V.10. Primary causes of well impairment

Category	Description	Remedy*
Scale	Inorganic minerals deposited from water	Calcium carbonate removed with HCl or organic acids, barium sulfate treated chelates
Organic Deposits	Deposition of solids from the oil phase, usually a combination of asphaltenes and resins, the most polar components of the oil	Asphaltenes remediated with aromatic solvents
Fines Migration	Flow-induced movement of clay-sized particles from pore bodies to pore throats causing a reduction in permeability	Combination of HCl and/or organic acids with HF acid

* Typical industry guidelines. For example, scale treatment involve injecting treatment solution, soaking (e.g., 12-24 hr), and flowing the well back. For fines migration treatments, a 9% HC1/1% HF is commonly used.

Table V.11. In-service inspection intervals for fixed, manned, and unmanned platforms

Level	Exposure Category		
	L-1	L-2	L-3
I	1 yr	1 yr	1 yr
II	3 yr (5 yr)	5 yr (10 yr)	5 yr (10 yr)
III	6 yr (6 yr)	11 yr (11 yr)	

Source: NTL 2009-G32

Note: Unmanned platform inspection intervals denoted in parenthesis.

Table V.12. Risk considered for consequence-based criteria for the Gulf of Mexico

Exposure	Life Safety	Consequences of failure
L-1	Manned, non-evacuated	High
L-2	Manned, evacuated	Medium
L-3	Unmanned	Low

Source: Ward et al. 2000

Table V.13. Estimated service life for selective offshore maintenance coating systems

Type	Exposure	Coating System (primer/midcoat/topcoat)	Surface Preparation	Number Coats	DFT Min. (mils)	Service Life (yr)
Alkyd	Atm.	Alkyd/Alkyd/Urethane	Blast	3	6	4
Epoxy	Atm.	Surface tolerant epoxy/STE	Hand/power	2	10	9
Epoxy	Atm.	Epoxy/polyurethane	Blast	2	6	8
Epoxy zinc	Atm.	Epoxy zinc/epoxy/epoxy	Blast	3	11	14
Organic zinc	Atm.	Organic zinc/epoxy/polyurethane	Blast	3	12	15
Zinc/epoxy	Imm.	Organic zinc/epoxy/epoxy	Blast	3	10	12
Metallizing	Imm.	Metallizing/epoxy/epoxy	Blast	3	13	18

Source: Helsel and Lanterman 2016

Note: Atmospheric (Atm.) marine exposure is defined as very high corrosion in offshore areas with high salinity. Immersion (Imm.) service is salt water immersion at ambient temperature and pressure. Service life is considered to be the time until 5 to 10% coating breakdown occurs and active rusting of substrate is present.

Table V.14. Typical offshore maintenance painting schedule

Operation	Painting Occurs in Year	Cost
Touch-up @ Practical Life (PL)	PL	C_{PL}
Maintenance Repaint (MRP)	1.33 PL	C_{MRP}
Full Repaint (FRP)	MRP + 0.50 PL	C_{FRP}

Table V.15. Typical offshore paint and protective coating cost circa 2016

	DFT (mils)	Spray ($/ft^2)	Brush/Roll ($/ft^2)
Epoxy, 100% solids	20	1.89	1.47
Polyurethane, Aliphatic Acrylic	2	0.28	0.22
Siloxane, Epoxy	4	1.02	0.79
Zinc Rich, Inorganic	3	0.40	0.31

Source: Helsel and Lanterman 2016.

Table V.16. Estimated annual maintenance painting cost at Auger TLP

	Annual Cost ($)	Unit Cost ($/ft^2)
Labor	1,200,000	16.00
Material		
Paint	112,500	1.50
Garnet	26,000	0.35
Disposal		
Non-hazardous	7670	0.10
Hazardous	5100	0.07
Subtotal	1,351,270	18.02
Indirect (40% subtotal)	540,508	7.21
Total	1,891,778	25.22

Note: Assumes 6-man crew with garnet reused once. Logistics, transport and catering costs assumed to be 40% of the direct cost.

Table V.17. Conversion of tons of steel to square feet

Member	Sq Ft/Ton
Typical Mix Size/Shapes	250
Large Structural	100
Medium Structural	200
Light Structural	400
Light Trusses	500

Table V.18. Deepwater Gulf of Mexico structure inventory topsides operating weight

	Medium Topsides		Large Topsides	
	Number	Mean (t)	Number	Mean (t)
Semisubmersible	4	9150	3	23,550
Spar	9	8400	7	20,460
TLP	6	9900	5	22,720

Source: D'Souza et al. 2016

Note: Medium topsides operating weight defined to range between 5000 to 12,000 tons. Large topsides operating weight defined to be greater than 12,000 tons.

Table V.19. Level II and III inspection cost at Cognac

	Inspection Type	Cost ($1000)
Diver inspection	Level III, top 200 ft	23
ROV-1 inspection	Level II, entire structure	161
ROV-2 inspection	Level III, 200-1025 ft	266
Mooring		28
Total		480

Source: Miller and Hennegan 1990

Table V.20. Deepwater ROV vs. AUV hypothetical cost comparison

	ROV & Vessel	AUV & Vessel
Typical Vessel Spec	240 ft LOA, IRM class, DP2	120 ft LOA, Utility class
Deck Footprint	~ 1000 ft^2	~ 500 ft^2
System Weight	~ 80 tons	~ 10 tons
Vessel Crew Size	20-40	6-8
Inspection Rate	X	4X faster
Vessel Day Rate	$3X	$X

Source: McLeod et at. 2012

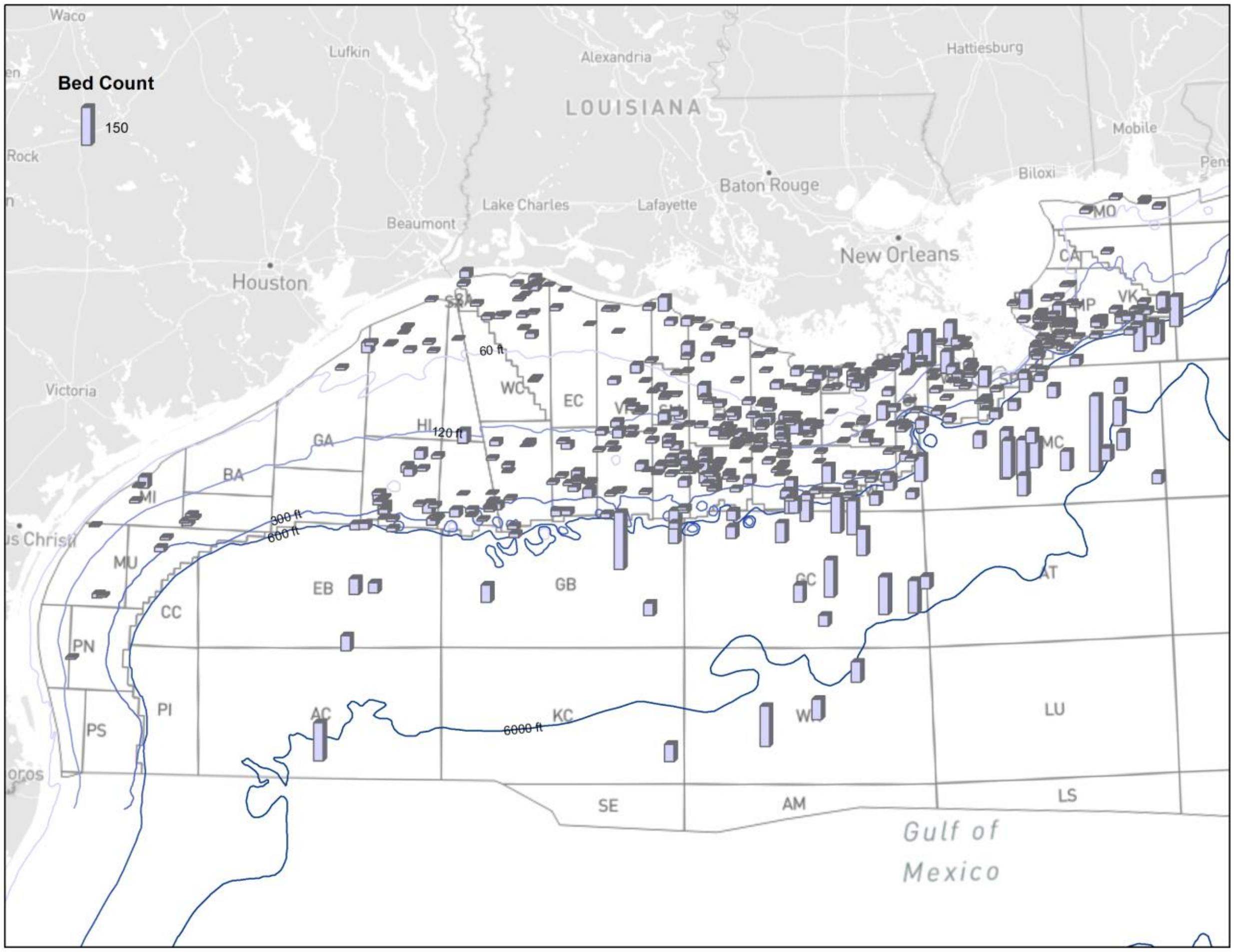


Figure V.1. Bed count on manned platforms in the Gulf of Mexico circa 2018
Source: BOEM 2018

Figure V.2. Offshore supply vessel *Gloria B. Callais* (top); fast support vessel *Cougar* (bottom)

Figure V.3. Eurocopter 135 EC
Source: Helis.com

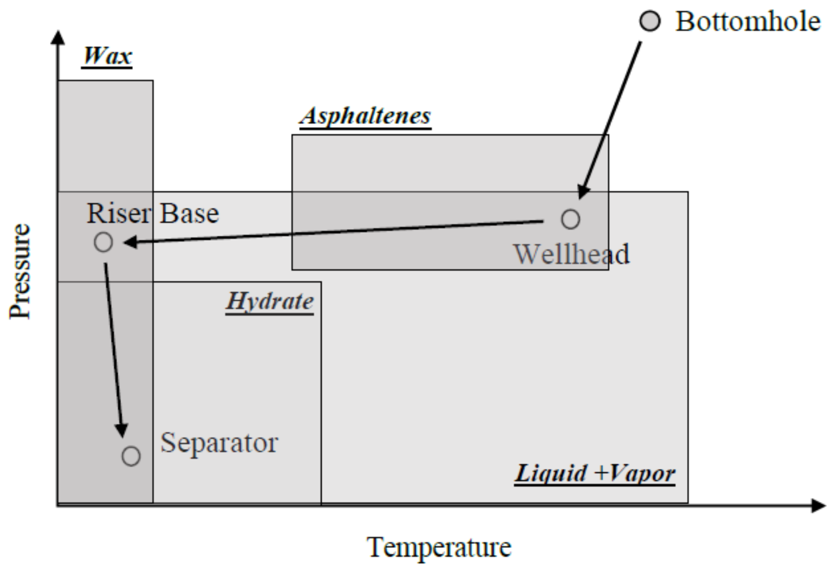


Figure V.4. Regions of pressure-temperature that will create asphaltenes, wax and hydrate production issues

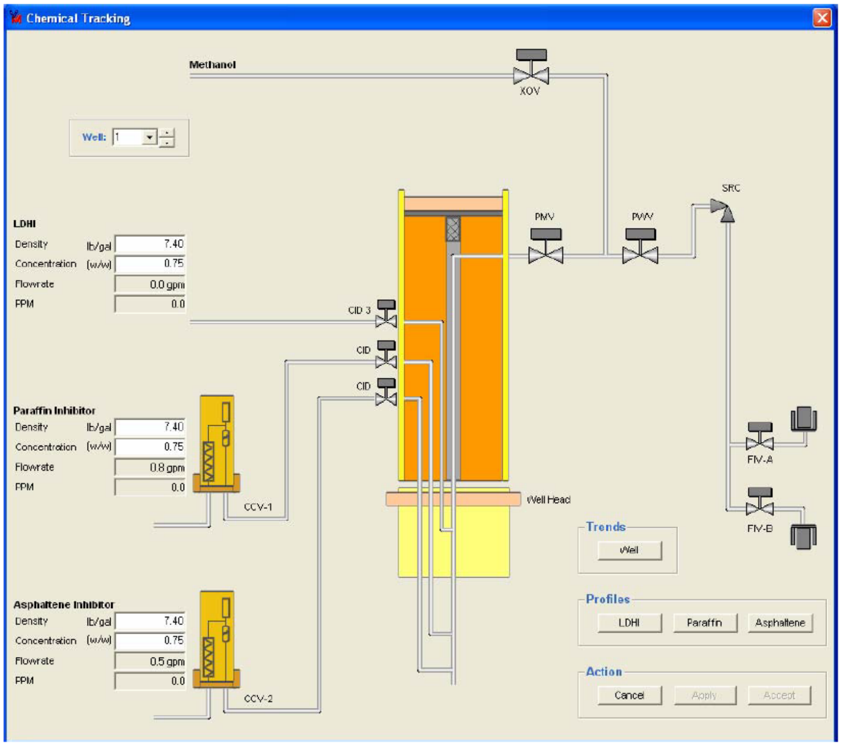
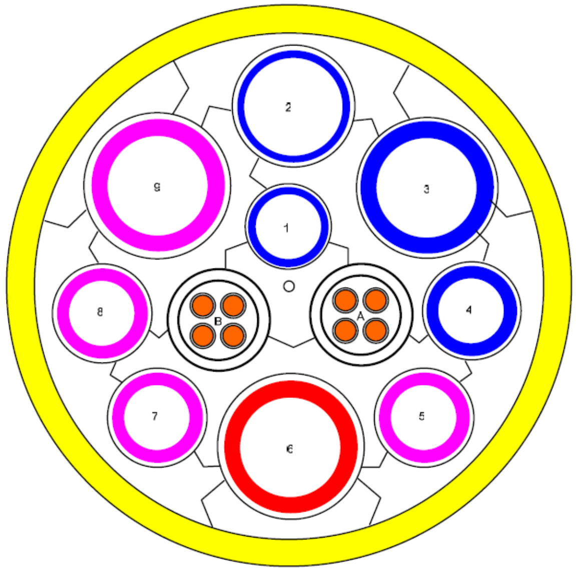


Figure V.5. Representation of tree injection system and downhole locations at K2
Source: Brimmer 2006



#	Tube Size (ID)	Max Pressure (psi)	Line Function
1	½″	10,000	HP "A"
2	¾″	5,000	LP "A"
3	¾″	15,000	LP "B"/share
4	½″	15,000	HP "B"/share
5	½	15,000	Asphaltenes inhibitor
6	¾″	15,000	Annulus access line
7	½″	15,000	LDHI
8	½″	15,000	Paraffin wax
9	¾″	15,000	Methanol line
A			Power/single cable
B			Power/single cable

Figure V.6. Umbilical cross section for K2 subsea development
Source: Brimmer 2006

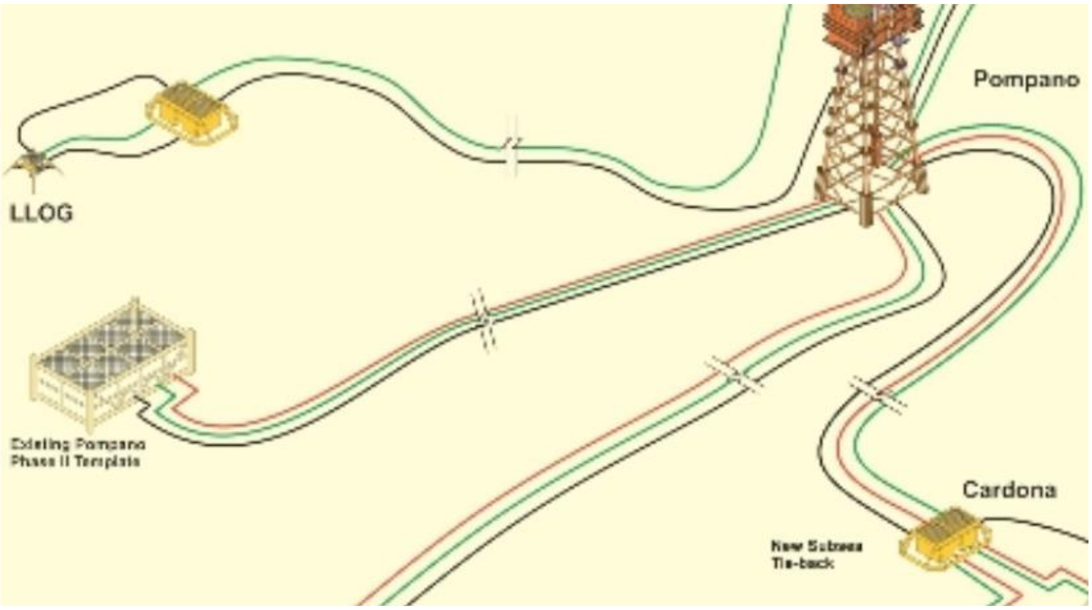


Figure V.7. Pompano subsea tieback schematic
Source: Stone Energy

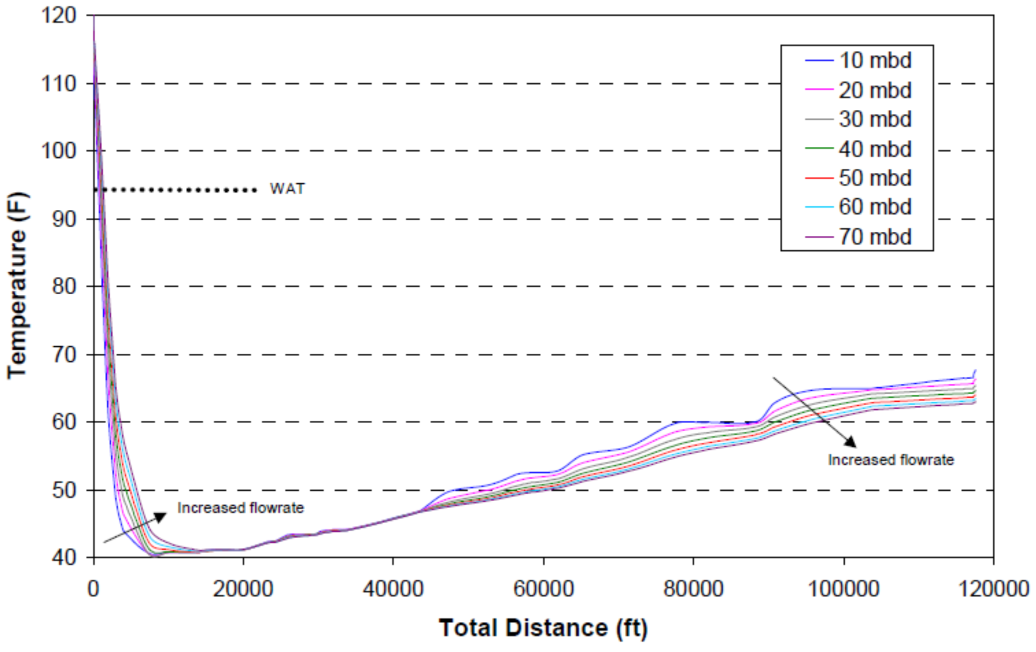


Figure V.8. Marlin oil export line temperature profile
Source: Fung et al. 2006

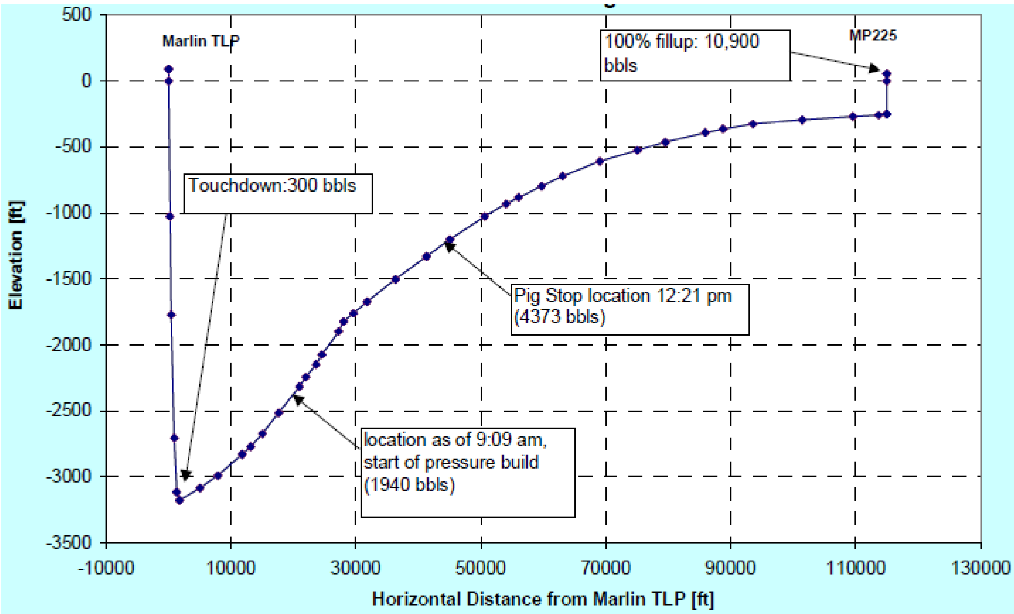


Figure V.9. Marlin oil export pipeline profile estimated stuck pig location
Source: Fung et al. 2006

Figure V.10. Offshore structures need constant maintenance to protect steel surfaces from corrosion
Source: Hempel

Figure V.11. Birds eye view of the Auger tension leg platform
Source: Shell

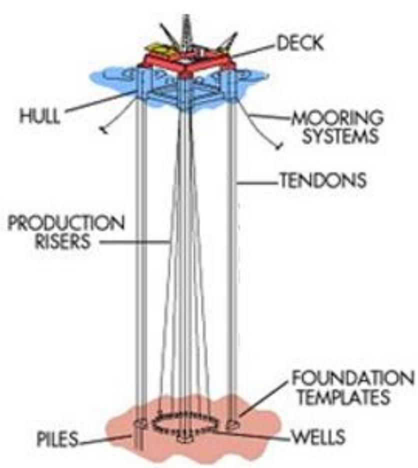


Figure V.12. Schematic of the Auger tension leg platform
Source: Shell

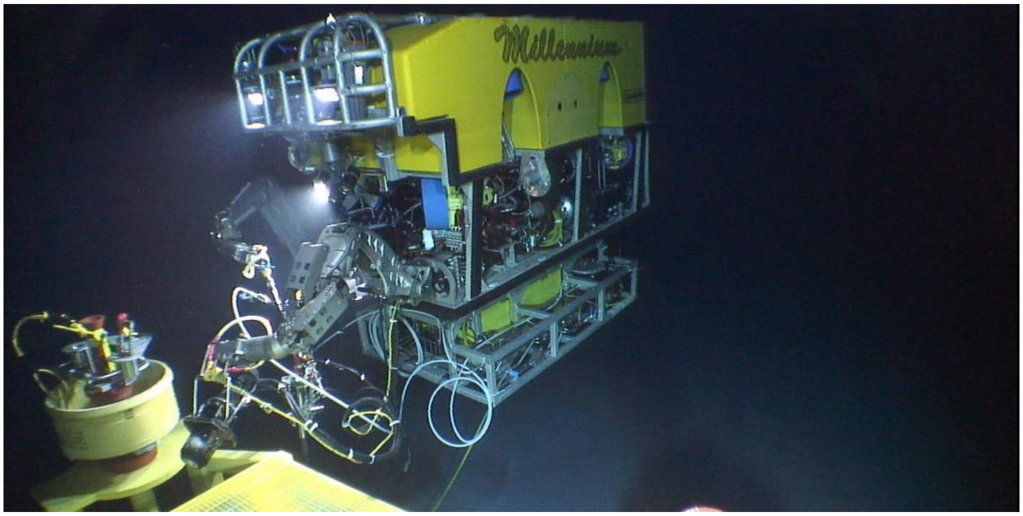


Figure V.13. Remotely operated vehicles are needed for most deepwater inspection and repair
Source: Oceaneering