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Modeling Structure Removal Processes in the Gulf of Mexico

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ABSTRACT

At the end of 2003, there were nearly 4,000 structures in the federal waters of the Gulf of Mexico (GOM) associated with hydrocarbon production: 2,175 active (producing) structures, 1,227 idle (non-producing) structures, and 505 auxiliary (never-producing) structures. Since 1947, when production in the GOM first began, over 2,200 structures have been removed from federal waters, and over the past decade, 125 structures on average have been removed annually. The purpose of this report is to describe the operational aspects of removal processes in the GOM and to develop a production-based model to forecast the removal of offshore structures.

In Chapter 1, a statistical description of the explosive removal process is presented. The influence of factors such as water depth, planning area, configuration type, and structure age upon the application of explosive

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CHAPTER 1: EXPLOSIVE REMOVALS OF OFFSHORE STRUCTURES

1.1. Introduction

The Outer Continental Shelf (OCS) of the U.S. Gulf of Mexico (GOM) is one of the most highly developed and mature basins in the world. Over the last 50 years, the oil and gas industry has installed over 6,000 structures and 33,000 miles of interconnecting pipelines in the gulf waters. Today, there are about 4,000 active structures installed in federal[1] water ranging from less than 10 feet to over 7,000 feet. There are also a few thousand structures in state waters off the coast of Louisiana and Texas, almost all of which are small and installed in less than 35 feet of water.

Structures need to be constructed, delivered, installed, and equipped prior to production, operated and serviced during production, and then eventually decommissioned and removed after production. Each of these activities has both a direct and indirect impact on the communities in which the service facilities and manufacturing operations are located, and hence induce a "spill-over" effect on the economic growth of regions which serve the development. An entire industry has been built in the GOM around installing production equipment and structures, servicing those structures (maintenance, repairs, supply), and then removing the structures when production ceases.

During the life of a lease, the leaseholders apply for permits to place structures on the seafloor to aid in drilling, development, and production operations. Near the end of the economic life of the lease, when the structures have been fully depreciated and reserves depleted, the structures represents a financial and operational liability, and at this point in time a decision is made to abandon. Within one year of lease termination, the Minerals Management Service (MMS) requires that the lessees remove all structures to a depth of 15 feet below the mudline and that the site be returned to prelease conditions. Although multiple techniques may be used to sever the structural components, they are generally categorized as either explosive or nonexplosive methods.

Operators wishing to remove an OCS platform or facility are required to submit a structure removal permit application to MMS for technical review and the preparation of an environmental assessment (EA) under National Environmental Policy Act (NEPA) guidelines. Prior to mobilization, additional permits are required for well abandonment (temporary or permanent) and/or pipeline decommissioning to ensure that all of the infrastructure components to and from the structure are secured. Removal operations proposing explosive severance are currently subject to the terms and conditions of a programmatic Biological Opinion (BO)/ Incidental Take Statement (ITS) issued by the National Oceanographic and Atmospheric Administration's Fisheries Service (NOAA Fisheries) under an Endangered Species Act (ESA) Consultation with MMS. If an operator proposes any activities that fall outside of the BO/ITS severance criteria (e.g., 50-lb maximum charge weight, cut depth, 900 msec detonation staggering, etc.), a site-specific ESA Consultation and new BO/ITS will be required.

[1] Federal jurisdiction in the OCS varies with the Gulf state: Florida and Texas have an extended nine nautical mile state jurisdiction, while Alabama, Louisiana, and Mississippi have the standard three nautical mile state jurisdiction.

The NOAA Fisheries Service currently assigns observers to every OCS structure removal

The GOM planning areas are denoted by

$$P = \{P_1, P_2, P_3\} = \{\text{WGOM, CGOM, EGOM}\},$$

and since the Eastern GOM has seen only a very small level of activity, this planning area will not be considered further. Since the water depth and planning area schemes are disjoint, the two categories can be combined using a Cartesian product as follows:

$$W \times P = \{\Gamma_{i,j} = (W_i, P_j) \mid i = 1, \ldots, 14;\ j = 1,2\},$$

where $\Gamma_{i,j}$ denotes the water depth and planning area category indexed by *i* and *j*; e.g., $\Gamma_{4,2}$ denotes the 31-40 feet water depth range in the Central GOM.

Structures can be classified through their attributes such as configuration type and age upon removal. Configuration type is described using four categories as follows:

$$\{T_1, T_2, T_3, T_4\} = \{\text{caissons, well protectors, fixed, floating}\}.$$

The minimum structure for offshore development of a well is a caisson, a cylindrical or tapered tube enclosing the well conductor. A small deck is sometimes provided above the wellhead, but no facilities are provided except possibly navigational aides and a small crane (Figure A.2). Structures that provide support to one or more wells drilled with a mobile drilling rig are normally referred to as well protectors. Well protectors are sized to fit within the drilling slot of a mobile drilling rig, and are usually 3- or 4-piled structures with minimum decks and production facilities (Figure A.3). Production from caissons and well protectors is usually sent to a production platform for treating. Well protectors and other fixed platforms are designed with a jacket, a three-dimensional welded frame of tubular members, used as a guide for driving piles through its legs. Fixed platforms include drilling, production, drilling/production, and auxiliary platforms (Figure A.4). Depending on the design and construction requirements and constraints, the number of piles of a fixed platform can vary from three to eight or more and can be as small as 24 inches or as large as 96 inches. Four-pile and 8-pile fixed platforms are the most common structures in the GOM.

The age of the structure upon removal is grouped according to

$$\{A_1, A_2, A_3, A_4\} = \{\text{0-10, 11-20, 21-30, } 30^{+} \text{ years}\}.$$

The number of structures removed from the water depth and planning area region $\Gamma_{i,j}$ over the time interval $(t-1, t)$ is specified in terms of configuration type and age as follows:

$R(\Gamma_{i,j}, T_k, t)$ = Number of structures removed from region $\Gamma_{i,j}$ of type T_k in year t,

$R(\Gamma_{i,j}, A_l, t)$ = Number of structures removed from region $\Gamma_{i,j}$ that fall within age group type A_l in year t,

$R(\Gamma_{i,j}, T_k, A_l, t)$ = Number of structures removed from region $\Gamma_{i,j}$ of type T_k that fall within age group A_l in year t.

The number of structures removed using explosive methods is denoted by the subscript E; e.g.,

$R_E(\Gamma_{i,j}, T_k, t)$ = Number of structures removed from region $\Gamma_{i,j}$ of configuration type T_k using explosive techniques in year t.

The percentage of structures of a given classification that are removed through explosive technology is computed as the ratio of $R_E(\cdot)$ to $R(\cdot)$; e.g., the percentage of structures of configuration type T_k removed through explosive technology in year t is computed as

$$p_E(\Gamma_{i,j}, T_k, t) = \frac{R_E(\Gamma_{i,j}, T_k, t)}{R(\Gamma_{i,j}, T_k, t)},$$

and in most cases time will be "integrated out" of the data set:

$$p(\Gamma_{i,j}, T_k) = \frac{\sum_t R_E(\Gamma_{i,j}, T_k, t)}{\sum_t R(\Gamma_{i,j}, T_k, t)}.$$

Percentage applications must be employed cautiously, however, since if the number of elements in the set $R(\cdot)$ or $R_E(\cdot)$ is "small," then (3)

Nearly 6,000 structures have been installed in the GOM through the year 2001 and one-third of these structures have now been removed. The vast majority of installations and removals have been in shallow water: 90% of all structures installed in the GOM and 96% of all the removals have been in less than 200 feet (60 meters) of water. Within the 0-200 feet category, 36% of all the structures that have been installed through the year 2001 have been removed, while only 14% of structures beyond 200 feet have been removed. Activity levels vary widely as a function of water depth.

The average annual number of structures installed and removed per water depth and planning area category over a 5-year (1996-2001) and 10-year (1991-2001) time horizon is depicted in Table A.2 and Table A.3, respectively. The value of the average annual number of installations and removals is surprisingly robust over the 5- and 10-year horizon in the sense that the mean structures removed $R = R(\Gamma_{i,j})$ and the number removed by explosive techniques ($R_E = R_E(\Gamma_{i,j})$) are shown as a function of water depth and planning area beginning from 1986. Although multiple techniques may be used to sever conductors and piling, severing is usually categorized as either explosive or nonexplosive. If explosives are used in any amount and at any stage of the decommissioning project, then the method is considered explosive. Beginning in 1986 companies planning to remove offshore structures with explosives were required to obtain a permit from the MMS, and hence only data from this period of time onward is available. The data set represents about 80% of the total structure removals to date.

The percentage of structures removed using explosive techniques is calculated as

$$p_E = \frac{R_E(\Gamma_{i,j})}{R(\Gamma_{i,j})}.$$

The percentage values depicted need to be interpreted carefully, however, since the values depend upon the selection of the water depth categories employed. An additional problem in interpreting the value of p_E is that the percentage calculation may be based on only a handful of data, and in such circumstances, one cannot assign much confidence to the values as being "representative" of conditions in the region. This is particularly a problem throughout the shallow water (0-40 feet) and deepwater (657-2,624 feet) categories of the WGOM where only a few structures have been removed. With these exceptions noted, however, there does not appear to be a significant difference between the application of explosive techniques over the WGOM and CGOM planning area, which is quite reasonable considering there is no rational reason why explosive techniques would be different across planning area unless the structure types, age[2], or year of removal are dramatically different. The data in Table A.6 supports the assertion that planning area dependence on p_E is weak, and so we can aggregate over planning area and consider the application of explosive removals throughout the GOM as representative of either the WGOM or CGOM planning area.

The description of explosive removals across the GOM as a function of configuration type is depicted in Table A.7. It is apparent from Table A.7 that the choice of removal method depends to some extent on the configuration type of the structure, but there are *no* observable trends *within* the 0-200 feet category for any of the configuration types. It is also difficult to explain the variability that does exist, and most probably, the variation of p_E

Using the categorization shown at the bottom of Table A.7, observe that caissons are the most commonly removed structure using nonexplosive methods, and well protectors and fixed platforms, if removed using nonexplosive techniques, are more commonly performed in shallow waters. Caissons have an equal chance of being removed with either explosive or nonexplosive methods, and well protectors and fixed structures realize a greater chance of an explosive removal. As the water depth increases the chance of using explosives also increase across all configuration types. The percentage values depicted for explosive removals for well protectors in the 61-200 meters water depth range is slightly suspect, however, since it is based on only six data points. Thus far, no caissons, well protectors, or fixed structures have been removed in water depth greater than 200 meters, and the two semisubmersibles that have been removed in this water depth range are included for completeness.

1.2.5. Structure Removals by Year and Configuration Type: The number of structures removed by configuration type by year is shown in Table A.8 across all water depths in the Gulf of Mexico. There are no noticeable trends in the removal rates across time except caissons and fixed structures typically compete for the greatest number of removals in any given year. The percentage values p_E can be considered a stochastic process, but it is preferable to "average out" the time variability by aggregating the $R_E(\cdot)$ and $R(\cdot)$ values and calculating

$$p_E(T_k) = \frac{\sum_t R_E(T_k, t)}{\sum_t R(T_k, t)} ,$$

as shown in the last row of Table A.8. The variability of p_E across time for a given configuration class can be explained to some extent through the age of the structure and the water depth.

1.2.6. Structure Removals by Age, Water Depth, and Configuration Type: Structures that have been removed from the GOM according to planning area and age upon removal are depicted in Table A.9. All structure types are aggregated within the same category and it is clear that a significant variation exists across planni the data is aggregated according to age upon removal, WGOM structures have a greater likelihood of an explosive removal relative to CGOM structures.

To examine the features of water depth and structure age upon removal method, structure data was aggregated and then classified as shown in Table A.11 and Table A.12. Table A.11 depicts the number of structures removed as a function of water depth and age upon removal, and it is clear that the majority of structures removed from both water depth categories are within 20 years of their installation date. The data in Table A.12 are more interesting, however, since the general trends observed earlier hold here with the same caveats: the percentage of structures removed using explosive methods increase as a function of age upon removal for the 0-60 meters category and is dominated by the application of explosive removals in the 61-200 meters water depth category. The number of structures in the 61-200 meters group, however, especially for the 21-30 and 30+ age categories, is too small to draw meaningful conclusions.

The general trends observed in Table A.7 for the application of explosive techniques also apply to individual configuration type and water depth categories as shown in Table A.13 and Table A.14. In Table A.13, observe that across all configuration types, the use of nonexplosive methods is most common in the 0-10 year category, and as the age of the structure increases, so does the likelihood that explosive methods will be applied. In Table A.14, the percentage of structures removed using explosives as a function of water depth, age upon removal, and configuration type is presented. Blank entries indicate that no structures within the given categorization were removed.

1.3. A Life Expectancy Model of Platform Removal Processes

1.3.1. A Structure Has at Least Five Lives: An offshore structure is an economic investment that has at least five distinct "lives": (1) the physical life, (2) the service life, (3) the depreciation life, (4) the design life, and (5) the economic life.

The physical life of a structure is the period of time over which the investment is actually used, specified according to design loads for specific oceanographic criteria, including wave directionality, current velocity, wave period, and wind speed. Structures in the GOM are designed to withstand a 100-year return period for hurricane wind, wave, and current environment.

The economic life of a structure is defined as the time at which the production cost of the structure is equal to the production revenue. At the time a structure reaches its economic limit, production will cease and operations will be abandoned. A lease may reach its economic limit prematurely when hydrocarbon prices are in a depressed price-demand state, but if the operator believes stronger prices will prevail in the future, then an abandonment decision is likely to be postponed until the operator can no longer sustain operating losses.

1.3.2. Sources of Uncertainty: Decommissioning represents a liability as opposed to an investment, and the pressure for an operator to decommission a structure is not nearly as strong as installation activities. There are usually no commercial incentives for early removal and operators have no incentive to "fast track" decommissioning unless pushed by regulatory time limitations.

Several sources of uncertainty impact decommissioning decision making:

- Geologic uncertainty,
- Production uncertainty,
- Price uncertainty,
- Investment uncertainty,
- Technological uncertainty, and
- Strategic uncertainty.

Production engineers estimate the reserve potential of a field based on geologic and geophysical data and then use this information to design the capacity of the structure and optimize the production schedule. Production profiles are used as a guideline to expected removal times since investment activity can dramatically alter the form of the production curve as well as the recoverable reserves. Hydrocarbon price, technological improvements, and demand-supply relations impact the revenue of the lease which also impact investment planning. When the time arrives that the cost to operate a lease (maintenance, operating personnel, transportation, fuel, insurance etc.) outstrips the income from production, the structures on the lease exist as liabilities instead of assets, and a decision is made to divest the property or abandon the structure subject to the strategic objectives of the operator. Strategic objectives are generally unobservable, nonquantifiable, and vary over time, region, and operator, further exacerbating the capability of forecast models.

1.3.3. Removal and Severance Models:

Life Expectancy Removal Model

The removal date of a structure is estimated through the relation

$$r(s) = i(s) + a(\Gamma) + k\sigma(\Gamma),$$

where,

$r(s)$ = Year of removal of structure s,
$i(s)$ = Year of initial production of structure s,
Γ = Classification category,
$a(\Gamma)$ = Average age upon removal for structure $s \in \Gamma$,
$\sigma(\Gamma)$ = Standard deviation of the age statistic.

The value for $a(\Gamma)$ and $\sigma(\Gamma)$ is defined according to configuration type, water depth and planning area, as shown in Table A.3. The value of k is user-defined.

The primary assumption of the model is that the historical characteristics of structures can be used to reasonably predict the removal trends of "similar" active structures, where "similarity" is defined for structures that fall within the same general classification category. The assumption is restrictive but is considered an acceptable first-order approximation.

The removal model adopts the approach taken by the National Research Council (NRC) 1985 report, where values for $a(\Gamma)$ were estimated as follows: "Smaller structures in shallow waters, such as caissons and well protectors, tend to be removed after 20-25 years; larger structures with more wells, such as 4- and 8-pile platforms, have a useful life of 25-30 years, and larger structures in deepwater should have a useful life of at least 30 years." The NRC heuristic approach is re-calibrated by computing the values of $a(\Gamma)$ and $\sigma(\Gamma)$ based on historic data, and then selecting k as a user-defined variable.

In Model I, set k = 1 and compute $r(s)$. If $r(s) \geq 2002$, then "accept" the removal time of structure s; otherwise, set k = 3. In Model II, the smallest integer value of k is determined such that $r(s) \geq 2002$, and for this value "accept" the removal time of the structure. Model I and Model II ensure that all installed structures will be removed based on their installation date and average age of removal plus a perturbation term. Model I presents a slow removal scenario; Model II presents an accelerated removal schedule.

Explosive Severance Model

The decision to employ explosive techniques in cutting operations depends upon a number of factors, and to the extent that these variables can be proxied by configuration type, water depth, and age upon removal, the probability that a structure will be removed using explosive techniques is written as $p_E(s)$. Structure s belongs to category Γ and is estimated to be removed at the time $r(s)$. Since the age of the structure being removed is known when $r(s)$ is "accepted," the value of $p_E(s)$ is extracted from Table A.14 to determine the probability the structure will be removed with explosives.

1.3.4. Model Results: The forecast output predicts the number of structures expected to be removed using explosive technology categorized by configuration type, water depth, and planning area across 5-year time blocks, where the block 200*X*− 200(*X*+4) is interpreted as January 1, 200*X* − December 31, 2000(*X*+4). A summary of the number of active structures expected to be removed with explosives is depicted in Table A.15 and Table A.16. A reasonable planning level suggests that between 94 and 159 structures per year will be removed with explosives in the short-term future. Structure composition indicates that major structures will play an increasingly important role both in terms of the absolute number of structures that will need to be removed as well as the expected cost of removal.

1.3.5. Model Assumptions: All removal forecasts need to be viewed relative to their structural framework. The assumptions that provide the framework to perform a forecast also, to varying extent, limit the interpretation of model results. Since operator behavior is too complex to model on an aggregate basis without the use of production profiles or private information (e.g., nomination schedules, leasehold operational cost, field development plans, strategic objectives, etc.), all non-production based forecasts are considered to have comparable levels of uncertainty. Within the class of non-production based models, the magnitude of the uncertainty cannot be mitigated through the selection of more advanced methodologies. In fact, more "advanced" approaches merely disguise and shift the uncertainty rather than actually reduce or mitigate it. Heuristic methods have some advantage over sophisticated procedures in such an environment relative to ease of implementation and focus on the model drivers. On the other hand, heuristic procedures are also rather arbitrary, and it is often desirable to investigate more advanced techniques to refine and improve the model structure.

A life expectancy and probabilistic removal model is considered an appropriate *first-order* approximation to predict removal times. Better models exist, but these models are considerably more difficult to construct and 55 Tiubject

Explosive technology was employed in 954 of the 1,626 structures decomm

CHAPTER 2: A BINARY CHOICE SEVERANCE SELECTION MODEL FOR OFFSHORE STRUCTURE REMOVAL

2.1. Introduction

Decommissioning offshore structures is often a severing intensive operation. Cutting is required throughout the structure, above and below the waterline and mudline on braces, pipelines, risers, umbilicals, templates, guideposts, chains, deck equipment and modules. More significant cutting operations are required on elements that are driven into the seafloor, such as multi-string conductors, piling, skirt piling, and stubs which need to be cut 15 feet below the mudline, pulled, and removed from the seabed. Cutting piles and conductors is probably the most critical and important part of a decommissioning project since if the piles and conductors are not cut properly, costly time delays and a potentially dangerous condition can arise during the operation.

A variety of technologies exist to perform severance operations, and the most common cutting methods include abrasive water jet, diamond wire, diver torch, explosive charges, mechanical methods and sand cutters. For severing operations that occur above the waterline, the cutting technique selected is usually dictated by the potential for an explosion. Cold cut methods are used when the potential for an explosion exists; otherwise hot cuts are employed. Cutting in the air zone is conventional, but not hazard-free, since it involves methods which are regularly used for dismantling onshore industrial facilities. Below the waterline, cutting is more specialized. In water depths that do not exceed 150 feet or so, divers perform cuts on simple elements such as braces and pipeline, and for shallow water structures such as caissons, diver torch is sometimes the preferred severance method. In water depths exceeding 150 feet, remotely operated vehicles (ROV's) deployed with abrasive, diamond wire and explosive charges are used for severance operations.

The decision of what cutting method to use will depend on the outcome of a risk-based comparative assessment involving cost, safety, technical, environmental, operational and managerial considerations. To perform a risk-based cost assessment for decommissioning projects *after* the operation has occurred is clearly an

natural disaster may take out a few structures unexpectedly, but for the most part, these factors do not play a significant role in aggregate removal patterns. Structures are designed to last the life of the field.

Abandonment options that are available to the operator include

- Relocation for reuse,
- Removal and scrap, or
- Relocation to an artificial reef site.

The topsides removal and disposal options available in decommissioning projects are shown in Figure B.2 as a decision tree. Oil and gas processing equipment and piping is sent to shore, refurbished and reused, sold for scrap, and/or sent as waste to the landfill. Deck and jacket structures have more options for disposal. The deck and jacket may be scrapped onshore, moved to a new location and reinstalled, or converted to an artificial reef site (Hakam and Thornton, 2000; Thornton, 1989). The complete removal of the jacket is the most frequently used technique in the GOM, occurring in roughly 90% of the total decommissions to date. The remaining 10% of structures that have been decommissioned have been toppled-in-place within an artificial reef or towed to an approved reef site. The Texas and Louisiana artificial reef programs currently maintain over 200 offshore structures throughout the GOM.

The economics of decommissioning are usually considered in terms of “least cost liability” as opposed to “return on investment.” Decision criteria associated with abandonment options thus generally favor minimum cost alternatives as the preferred means of most disposals. The factors

Well Plugging and Abandonment

A well abandonment program is carried out by injecting cement plugs downhole to seal the wellbore to secure it from future leakage while preserving the remaining natural resources. Techniques used to accomplish this process are based on industry experience, research, and conformance with regulatory standards and requirements (Manago and Williamson, 1998).

A traditional approach begins by “killing” the well with drilling fluids heavy enough to contain any open formation pressures. The Christmas tree is then removed and replaced by a blowout preventer through which the production tubing is removed. Cement is placed across the open perforations and squeezed into the formation to seal off all production intervals and protect aquifers. The production casing is then cut and removed above the top of the cement and a cement plug positioned over the casing stub. The remaining casing strings are then cut and removed close to the surface and a cement plug set across the casing stubs.

Mechanical methods of cutting and sand cutters are primarily associated with well plugging and abandonment (P&A) activities. After wells are plugged and casing tubing cut and pulled, a sand cutter or mechanical cutting tool may be run downhole to cut the conductors, or depending on the preference of the operator/contractor and configuration of the platform, abrasive or explosive severance methods may be applied. In a typical mechanical operation, the tubing and production casing is first cut using a jet cutter – a small explosive blast that utilizes less than five pounds explosive – and then the strings are cut out from $7\frac{5}{8}$ or $13\frac{5}{8}$ inches using a mechanical cutter.

All wellheads and casings are required to be removed to a depth of at least 15 feet below the mudline, or to a depth approved by the District Supervisor. The requirement for removing subsea wellheads or other obstructions may be reduced or eliminated when, in the opinion of the District Supervisor, the wellheads would not constitute a hazard to other users of the seafloor.

Topside Equipment and Deck Preparation

Topside preparation and deck removal is severing intensive. Cold cuts are generally made with pneumatic saws or drills, including diamond wire methods and abrasive techniques. Hot cuts – torch cutting and arc gouging – are used to cut steel when there is no risk of explosion. Arc gouging is used to remove seal welds between steel connections. Burning torches work on the same principle as the arc-gouge, where a burning rod, usually magnesium, is arced with the member to be cut. Diamond wire methods have also been occasionally employed in the GOM to cut the deck from the jacket.

Jacket Preparation

Several severance techniques are used below the waterline. Small cuts made to the jacket bracing and trimming, flowlines, umbilicals, and manifolds are typically performed with divers using burning torches, or if the water depth exceeds the diver capability, ROV’s with diver torch or abrasive technology are employed. Intermediate cuts may be required to separate the jacket into vertical sections if the piling extends up through the jacket structure.

Pipeline Abandonment

Federal regulations allow decommissioned OCS pipelines to be left in place when they do not constitute a hazard to navigation, commercial fishing, or other uses of the OCS. Pipelines will generally be removed offshore through the surf zone and capped. Onshore pipeline may be removed completely, or some sections may be abandoned in place if they transition through a sensitive environment. The pipeline end seaward of the surf zone is capped with a steel cap and jetted three feet below the mudline. Most pipelines in the GOM are abandoned in place after cleaning and cutting its structural connections.

The methodology for cutting a pipeline depends on the manner the pipeline is to be recovered. The protective coatings typical of most pipeline sections must first be removed in order to cut the pipe with an arc torch. If a pipeline crosses or is adjacent to an "active" pipeline, chances are it will not be disturbed due to the potential damage that would result if complications arise in the removal. Diamond wire methods, abrasive water jet, and pneumatic saws deployed with diver or ROV are all used to cut pipeline.

Pile and Conductor Severing

Pile and conductor severing is the most critical and typically the most expensive of all the severance operations. Piles are steel tubes welded together and driven through the legs of the jacket and into the seabed to provide stability to the structure, while conductors conduct the oil and gas from the reservoir to the surface. Piles and conductors must be cut and removed a minimum of 15 feet below the mudline. The physical characteristics that describe piles and conductors are important since they determine the technical feasibility of severance options.

Conductors are cut and pulled, if possible, early in the decommissioning process to avoid delay when the barge is on-site. Conductors are configured in various diameters and wall thickness and are characterized by the number of inner casing strings, the location of the strings relative to the conductor (eccentric vs. concentric), and the application of grout within the annuli. Conductors are usually cut with mechanical methods or explosive charges. Grouted annuli are usually easier to cut than annuli with voids since voids dissipate the energy/focus of the abrasive and explosive cutting mechanisms. Eccentricity may also pose a problem for mechanical cutters (Pulsipher, 1996). Mechanical methods are commonly applied to cut conductors during P&A activity, while if conductors are cut when the barge is on-site, then explosive charges will probably be employed.

To sever jacket legs and piles, abrasive cutters and explosive techniques are effective. In principle, mechanical cutting could be used to cut piling, but in practice it is rarely used because piles are only open when a barge is on-site (after removing the deck from the jacket), and with a barge on-site, mechanical cutting is not a cost-effective or efficient way to sever[4]. With a barge on-site, explosives are deployed down the piling and below the mudline, while abrasive cutters can be deployed internally or mounted externally using divers and a track. Obstructions within the pile (such as hangers) will necessitate additional operation or deployment of an external cut. Internal cutting is usually the preferred approach with water jet technology since it does not

[4] Redeployment of the barge is usually not an option.

require the use of divers to set up the system or jetting operations to access the required mudline depth.

2.2.4. Environmental Consequences of Severance Technology: The use of explosives to cut conductors, well casings, and piles was used for many years without regulation, but in 1986 with the strandings of numerous sea turtles in Texas, concern[5] was raised on the use and application of explosive severance methods. Before 1986, there were no rules or regulations to follow on the use of explosives, and the basic rule of thumb was, "if five pounds does a good job, then ten pounds does a hell of a good job" (DeMarsh, 2000). Since 1986, several regulations have been enacted to help minimize the number of incidental takings[6] and to quantify the impact of using explosives on sea turtles and marine mammals. Observers are currently required for all OCS removal activities using explosive charges >5 lb, and since introduction of the PROP in 1986, only two sea turtles have been killed and three turtles have been injured as a result of explosive structure is assumed to be an order-of-magnitude greater than the NOAA Fisheries study at 50,000 fish/removal, then the total number of fish kill associated with structure removals is 10 million per year – or less than 1% of the expected shrimper by-catch take.

Nonexplosive cutting methods are considered an ecological and environmentally sensitive severance method since the cutting does not create the impulse and shockwave-induced effects which accompany explosive detonation (Brandon et al., 2000). In mechanical, abrasive water jet, and diamond wire severance technology, a diesel-fueled mechanical motor is employed in the operation which results in vibrations, the emissions of CO_2 and other gases to the atmosphere, and low frequency sound waves into the ocean environment. Abrasive water jet cutting also involves using a fluid and garnet/slag for the cutting mechanism, and so there is the question of the impact of the fluid and garnet on the marine environment. Since the fluid involved in abrasive cutting is water and the garnet is inert, the environmental impact is generally considered inconsequential. Further, the noise level of the supersonic cutting jet is safe for divers and is not considered harmful to marine life. The direct products of nonexplosive cutting processes are water, metal cuttings, and abrasive particles.

There is also an environmental impact associated with the re-suspension of bottom sediments. If the foundation piles are cut below the seabed from the outside, the surrounding sediments will have to be dredged away by suction-dredging or jetted. The use of explosives to cut piling will likely disturb the sediments in the immediate vicinity of the structure. Both operations will cause re-suspension of sediments and contaminants in the cuttings. If the legs/pilings are severed from the inside using abrasive techniques, no significant re-suspension of sediments would ensue. Impacts resulting from re-suspension of bottom sediments include increased water turbidity and mobilization of sediments containing hydrocarbon extraction waste (drill mud, cutting, etc.) in the water column. The magnitude and extent of any turbidity increases would depend on the hydrographic parameters of the area, nature and duration of the activity, and size and composition of the bottom material. The overall impacts to water quality are expected to be temporary in nature and limited in scope to the site (*Federal Register*, 2002a).

ROV operator must inform either the NOAA Fisheries observer or the agent of the holder of the Letter of Authorization immediately.

- In water depth of 328 feet (100 meters) or greater, passive acoustic detection must be employed prior to detonation. If marine mammals are detected by the acoustic device, the operator must inform either the NOAA Fisheries observer or the agent of the holder of the Letter of Authorization.

when compared to a derrick barge spread of $100,000-$300,000/day, it is clear that cutting techniques will not drive decommissioning activities. The cost to sever piles and conductors is generally less than 1-3% of the total cost to decommission the structure.

2.3.2. Cost of Failure: If the cutting operation is not successful on the first attempt, then the operator will assume the cost of failure and the additional time required to re-shoot or re-cut the tubular element(s). In Figure B.5 the abrasive cutting process is charted. Contractors typically charge at work rates that depend upon the critical[8] path crane vessel time. Normally, if "extra work" is required that alters the critical path, the contractor charges the operator rates for equipment and personnel affected. If extra work is required that does not alter the critical path crane vessel time, the operator is charged a different (substantially smaller) hourly composite rate. The cost of a failed cut thus depends on the timing of the cut relative to the operational activity of the barge. There is a

These circumstances do not occur frequently – probably in about 10-15% of the structures removed from the GOM – but they do occur (e.g., see Ness et al., 1996; O'Connor, 1998) .

If the jacket is to be re-used or the structure is located in a known turtle habitat, then nonexplosive methods will likely be used if technically feasible. Clean cuts are desirable to avoid the diver cost/risk associated with flared piles and the possible damage that can occur to the re-used jacket with explosive cutting. If a structure is located in an artificial reef planning area and it can be toppled-in-place, then the piles and conductors are severed and the jacket is pushed over to form the reef (Dauterive, 2001; Reggio, 1989). If the structure does not satisfy the minimum 85 feet waterline clearance, then the structure will need to be cut in the water column and partially removed, that is, the top of the re-used jacket will be cut and placed on its side near the bottom of the jacket which will be left in place. In a partial removal, the piles do not need to be severed from the bottom structure, and since the use of explosives is prohibited in the water column, abrasive water jet, diver torch, or diamond wire methods are used to make the mid-water cuts.

2.3.5. Operator Experience and Preference: The project management team overseeing the decommissioning activities, in consultation with not been cut prior to the arrival of the derrick barge, then explosive charges will likely be used to cut all the elements at once. Mechanical and/or sand cutters are rarely deployed with a derrick barge on-site due to the time-consuming and inefficient nature of the operation.

2.3.7. Contractor Experience and Preference: If the contractor has several removals to make, then the preference is to cut as quickly and as safely as possible subject to the technological and operational requirements of the job. If explosives are required on one structural element, then a preference may arise to blow all the elements at once rather than "mix" explosive and nonexplosive severance methods, and as mentioned earlier, if pre-cuts are not performed on the conductors, then explosives are more likely to be employed to sever all the elements when the barge is on-site. On a few decommissioning projects, abrasive water jet and explosive cutting crews have served in a contingency role, but since back-up crews add significantly to the cost of the service, cutting redundancy is not standard practice.

2.3.8. Structure Characteristics: Pile and conductor severing is the most critical and typically the most expensive of all the severance operations required on the structure. The physical characteristics that describe piles and conductors are important since they allow engineers to determine the technical feasibility and potential problems of removal options.

Conductors are configured in various diameters and wall thicknesses and are characterized by the number of inner casing strings, the location of the strings relative to the conductor (eccentric vs. concentric), and whether or not the annuli are grouted. Conductors typically contain multiple strings of casing, eccentric wit

2.3.11. Configuration Type: Nonexplosive methods usually carry less financial and operational risk with shallow water, simple structures than for complex, deep water structures (National Research Council, 1986). Mechanical and sand cutters have been used effectively on shallow water caissons and small well protector jackets, and large caissons have been effectively cut by divers. As the complexity, size, and water depth of a structure increases, however, the reliability of nonexplosive methods decreases while the cost and risk/uncertainty of operations tend to increase. On large platforms, especially platforms with wells, the preferred severance method is with explosives. There is not a "smooth" transition that occurs as a function of water depth or structure complexity, but generally speaking, we would suspect that as the complexity and water depth of a structure increases, explosive methods should be applied more frequently, and this is borne out by statistical analysis of the removal data. Explosives cut quickly and reliably and crew exposure time is minimal. For special structures such as skirt-piled[9] platforms, mechanical, abrasive, and diver cuts are usually not feasible and the tubular elements are generally stabbed with explosives using an ROV.

2.4. The Probability of an Explosive Removal

The choice of which severance technique is used to cut the piles and conductors of a structure

Caissons are the most likely to be removed using nonexplosive methods, and well protectors and fixed platforms, if removed with nonexplosive technology, is more commonly performed in shallow water (Table B.2). As water depth increases, the chance of using explosives increases slightly across all configuration types. Refined partitions of the water depth data (e.g., using 3 meter, 10 meter, and 25 meter increments) indicated no observable “trends,” and so the consideration of water depth as a relevant factor is questionable. The percentage of structures removed using explosive techniques is depicted in Table B.3 according to age upon removal, configuration type, and water depth. The use of nonexplosive methods is most common across all configuration types within the 0-10 year category when the structure has the greatest chance for re-use, and as the age and water depth of structures increase, roughly speaking, the probability of an explosive removal also increases.

2.5. Operator Practice in the Gulf of Mexico

Since 1986, 1,626 structures operated by 127 companies have been removed in the GOM. A few hundred structures were removed before this time, but the use of explosives for decommissioning was not documented formally by operators or government agencies. Twelve of the 127 companies are responsible for half of all structures removed, while the “top 36” companies, each removing at least eleven structures, account for 80% of all abandonments (refer to Table B.4). Companies that have removed ten structures or less comprise the “bottom 91” category and contribute the remaining 20% of decommissioned structures. Summary statistics present a complicated picture of operator behavior.

2.6. Binomial Logit and Probit Models of Severance Selection

2.6.1. Model Development: A binary-choice severance selection model assumes that the operator is faced with a choice between two alternatives (explosive versus nonexplosive severance) and that the choice of which cutting method to select depends on characteristics that are identifiable. The requirements of the binary-choice model are quite strong, since as we have described previously, many important characteristics of the severance decision are not observable, and hence, not possible to incorporate within a model. It is nonetheless useful to explore the use of an econometric model since it quantifies the probability of an explosive cut and provides additional insight into the data interpretation.

while the probit model is associated with the cumulative normal probability function which is written as

$$F(z) = P(Z \le z) = \int_{-\infty}^{z} \frac{1}{\sqrt{2\pi}} e^{-.5u^2}\, du\ .$$

If the probability of an explosive removal is related to the variables in a linear fashion, such as

$$\mathrm{E}(D) = \beta_0 + \beta_1 ST + \beta_2 AGE + \beta_3 WD + \varepsilon,$$

then the probability that the observed value D takes the value 1 in the logit model is given by

$$P(L \le \beta_0 + \beta_1 ST + \beta_2 AGE + \beta_3 WD) = F(\beta_0 + \beta_1 ST + \beta_2 AGE + \beta_3 WD)$$

$$\frac{1}{1 \quad e^{(\ \ _0 \quad _1 ST \quad _2 AGE \quad _3 WD\ )}}$$

R_p^2 is not used universally, but it is a convenient and easily interpreted measure (Studenmund, 2001). The R_p^2 indicates that the equation correctly "pre trick. The modeling process in this case is only useful to quantify the data in a more sophisticated manner. The model does not reduce or eliminate uncertainty or provide additional information that is not already captured through probability tables. Relevant company and site specific information (e.g., equipment available at the time of the removal, the amount of pre-planning involved in the removal, the contractors preference and the operational scheduling, the terms of the contract, the quality of the structure blueprints, etc.) can play an important role in the choice of removal method, but because these factors are unobservable, they cannot be statistically analyzed. It is thus clear that a significant portion of the decision making framework cannot be incorporated within the model. The relationships established should thus be viewed as interpretative rather than as causal in nature.

The MMS tracks the number of structures removed, the manner of severance, and the structure classification, and this data provides the basis for the model construction. The characteristics of the structure, including the number and size of the tubular members, the application of grout, and the manner of removal of each tubular element do not form part of the MMS data set, and thus also cannot be incorporated within the decision model. It is unlikely that the inclusion of more refined data at a lower level of aggregation will provide useful information, however, and so in principle, the limitations of the MMS database are not effectual.

CHAPTER 3: MODELING THE DECOMMISSIONING TIME OF OFFSHORE STRUCTURES

3.1. Introduction

Business decisions accompany every stage of oil and gas exploration and production. A company acquires a lease or contract area based on geological and geophysical data and conceptual plays, and then invests in additional data and manpower to refine their knowledge of the region. If the results of the analysis are encouraging, exploratory drilling may result. If drilling is successful (and most often it is not), the company will confirm and delineate the field, and if the field is judged to be economic, the company will develop and produce the reserves in accord with its risk-reward perceptions of development in the area. Enhanced recovery projects may be added during the field's producing life if the incremental economics are positive. Frequently, operators will divest their property or form a joint venture/farmout type arrangement before the economic limit is reached. When the production revenue of the structure equals the operating costs, abandonment follows.

At any point in time during the life cycle of a field, and depending upon the prevailing and expected future economics, technologic development, strategic objectives, political trends, and contract terms, the operator has to make short-term operational and long-term strategic planning decisions. Four primary options exist:

- Produce. Hold the asset, produce, and manage the declining reserves.
- Invest. Invest in the asset to maintain or increase production.
- Divest. Sell all or a portion of the working interest ownership.
- Decommission. Stop production and remove the asset in accord with regulatory requirements.

Produce

Early in the life of a field after the development wells have been drilled, the field is produced according to equipment capacity and operating constraints. Capital expenditures decline quickly after development is complete, and after the field begins to flow, gross revenues turn positive. Once the exploration and development costs of the investment have been borne, the variable cost of production is usually fairly small, and the operator needs only to produce to achieve cash flow. The cumulative net cash flow breaks even at payout, after which the cash flow remains positive until such time that additional capital investments are required.

Invest

Investment will alter the production profile and will typically extend the life of the asset. If a field requires major new investment such as significant workovers or the introduction of secondary techniques to maintain production, then the field is likely to be considered a candidate for divestiture or abandonment. Major and large independent operators frequently divest property before the economic limit is reached if the rate of return does not meet a minimum threshold or the strategic goals of the company change; e.g., the operator may redefine their core assets or need to raise capital to pursue frontier development. This may lead to the removal of the structure, or if the field can still be operated profitably, then it may be purchased and operated by another firm.

Divest

Property divestment is a key feature of offshore operations. Operators regularly “carve up” assets and sell or subject them to various joint venture/farmout type arrangements throughout the life cycle of the field. This is sometimes referred to colorfully as an asset “moving down the food chain,” and in most instances, properties change hands three or more times before the structure is finally decommissioned. Companies buy producing properties and then implement a comprehensive program to increase production, typically involving drilling new stepout or infill wells and recompleting existing wells. Companies specializing of rTe7273 inpali-19.7273 73colving drilli meta-modeling methodology is employed to analyze the simulation results, and a detailed example is used to illustrate the approach. The limitations of the analysis are described and conclusions complete the chapter.

3.2. After-Tax Net Cash Flow Analysis

3.2.1. Units of Analysis: Four units of analysis are typically employed in hydrocarbon modeling: well, structure, lease, and field. The unit of categorization employed depends upon the requirements of the problem and data availability. Production problems are examined at the wellhead, while operators consider development planning and cost allocation on a lease or field basis. The U.S. government requires royalty, rent, and bonus bid payment to be paid on a lease basis.

Holes must be drilled into the Earth to search for and produce oil and gas. These holes, or wells, produce a mixture of oil, gas, water, and other materials which must be separated and treated prior to its transport to market.

A well produces from a reservoir – a porous, permeable rock body, sort of a sponge – lying underneath an impervious layer of rock that traps the resource. Several reservoirs located within a "common" geologic feature are called a field and can consist of a single reservoir or multiple reservoirs. The pressure on the fluid in a reservoir rock causes the fluids to flow through the pores into the well. The reservoir drive comes from fluid expansion, rock expansion, and/or gravity. There are four basic types of reservoir drives for oil reservoirs: 1) dissolved gas drive, 2) free-gas cap expansion drive, 3) water drive, and 4) gravity. Every oil reservoir has at least one, and sometimes two, of these reservoir drives. Gas reservoirs have either an expansion-gas or water drive (Hyne, 1995).

Each well is associated with a structure which is identified by its leasehold and type. Offshore structures vary significantly depending on the productivity of the reservoir and the quality of the produced hydrocarbons; logistical considerations in moving production to market; and the lead natural gas that has the same heat content of an average barrel of oil[10]. The annual hydrocarbon production associated with structure s_i is the aggregate of its collection of wells, $\{w_1,\ldots, w_{n_i}\}$:

$$Q(s_i,t) = \sum_{j=1}^{n_i} Q(w_j,t).$$

Similarly, the hydrocarbon production on lease l at time t is denoted by $Q(l, t)$, and is determined as the collection of all the structures contained on the lease, $\{s_1,\ldots, s_m\}$:

$$Q(l,t) = \sum_{i=1}^{m} Q(s_i,t).$$

3.2.2. After-Tax Net Cash Flow: The net cash flow vector of an investment is the cash received less the cash spent during a given period, usually taken as one year, over the life of the project. Using structure s as the basic unit of analysis, the after-tax net cash flow in year t is computed as

$$NCF(s,t) = GR(s,t) - ROY(s,t) - CAPEX(s,t) - OPEX(s,t) - TAX(s,t) - OTHER(s,t),$$

where,

$NCF(s,t)$ = After-tax net cash flow of structure s in year t,

$GR(s,t)$ = Gross revenues of structure s in year t,

$ROY(s,t)$ = Total royalties paid by structure s in year t,

$CAPEX(s,t)$ = Total capital expenditures of structure s in year t,

$OPEX(s,t)$ = Total operating expenditures of structure s in year t,

$TAX(s,t)$ = Total taxes paid by structure s in year t,

$OTHER(s,t)$ = Other expenditures of structure s in year t.

3.2.3. Cash Flow Components: The gross revenues in year t due to the sale of hydrocarbons is defined as

$$GR(s,t) = g^o(s,t)\, P^o(s,t)\, Q^o(s,t) + g^g$$

There are four basic types of hydrocarbon molecules, called the hydrocarbon series, in each crude oil: paraffins, naphthenes, aromatics, and asphaltics. The relative percentage of each series molecule controls the chemical and physical properties of the oil. Natural gas is composed of hydrocarbon molecules ranging from one to four carbon atoms in length: methane (CH_4), ethane (C_2H_6), propane (C_3H_8), and butane (C_4H_{10}). The conversion factor (or "quality" of the production stream) depends on the physical characteristics of the hydrocarbons and is a function[11] of the API gravity, the sulfur content and the gas-oil ratio (GOR).

API Gravity

The API gravity of crude oil is a measure of the density or weight of the oil. Average crude has a 25º to 35º range, with light oils falling between 35º to 45º and heavy oils below 25º. Light crude receives a higher price relative to heavy crudes because they tend to have more gasoline by volume.

Sulfur Content

The sulfur content for most crude oils falls between 1% and 2.5%, with 1% sulfur content considered "sweet" crude and 2.5% sulfur considered "sour." Sweet crude is priced at a premium relative to sour crude. Hydrogen sulfide can occur either mixed with natural gas or by itself. Hydrogen sulfide is poisonous, and when it is mixed with natural gas, causes corrosion in the well. Sweet gas has no detectable hydrogen sulfide, whereas sour gas has detectable amounts. Sweet gas is priced at a premium and sour gas facilities are more expensive to construct and operate to handle the corrosive elements.

Gas-Oil Ratio

The amount of natural gas dissolved in crude oil at the surface is called the producing gas-oil ratio (GOR) and is expressed in cf/bbl. If $Q^o(w, t)$ and $Q^g(w, t)$ represent the oil and gas production associated with well w, then the producing ga

The total allowance cost is denoted by $ALLOW(s,t)$ and the royalty rate

The general rule for charging costs directly to an operation is that the charges must be for work physically performed at the project site or exclusively for that operation. Costs which are incurred at a distant location for a number of different operations are considered indirect costs or overhead.

Taxable income is determined as the difference between net revenue and operating cost; depreciation, depletion, and amortization; intangible drilling costs; investment credits (if allowed), interest in financing (if allowed), and tax loss carry forward (if applicable). In the United States, state and federal taxes are determined as a percentage of taxable income, usually ranging between 35-50%, and here denoted by the value T, $0 \le T \le 1$:

$$TAX(s,t) = T(NR(s,t) - CAPEX/I(s,t) - OPEX(s,t) - DEP(s,t) - CF(s,t) - DECOM(s,t)),$$

where,

$NR(s,t) = GR(s,t) - ROY(s,t) =$ Net revenue of structure s in year t,

$CAPEX/I(s,t) =$ Intangible capital expenditures of structure s in year t,

$DEP(s,t) =$ Depreciation, depletion, and amortization of structure s in year t,

$CF(s,t) =$ Tax loss carry forward of structure s in year t,

$DECOM(s,t) =$ Decommissioning cost of structure s in year t.

The tax and depreciation schedule is normally legislated and will vary across time. In the United States, all or most of the intangible drilling and development cost may be expensed as incurred, whereas equipment cost must be capitalized and depreciated (Gallun et al., 2001). Tax losses in the U.S. may be carried forward for at least three years.

Decommissioning cost represents

where D is the corporate discount factor and the project is assumed to begin at time $t = 0$ and end at the abandonment time $t = t_a$. The present value provides an evaluation of the project's net worth in absolute terms, while the rate of return is a relative measure used to rank projects for capital budgeting. Economic values are not intended to be interpreted on a stand-alone basis and should be used in conjunction with other system measures and decision parameters.

3.2.5. Typical Cash Flow Patterns: Oil and gas ventures have a great variety of patterns of investment and payout, but most ventures can be decomposed into four basic stages:
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discovered, and later tends to level out at a smaller increment, so that near the mid-cycle of a field, the recoverable reserves are reasonably well-known.

3.3.2. Production Profile: Many factors impact the rate at which hydrocarbons are produced, but the two primary factors are the geologic conditions and development plan. The geologic conditions at the site – the type and characteristics of rock, depth, thickness, fault mechanisms, hydrocarbon properties – are essentially "fixed," while the development plan – well density, wellbore size, completion techniques, method of production, equipment capacity – represent design parameters. Production rates across fields vary widely because of the variability in these factors.

There is a trade-off in the investment required to produce oil and gas and the production rate achieved. A high production rate requires a large capital investment in the form of the number and type of wells drilled, structure facilities, and the capacity of production equipment. High investment also requires a higher rate of return to justify the increased capital risk, and so the preferences of the operator and their perceived risk-reward tradeoff will determine the design capacity of the field.

Most production profiles can be decomposed into three distinct phases:

Ramp-Up

Production normally builds up over the first few years of production. Following the installation, hookup, and certification of the platform, development drilling is carried out and production started after a few wells are completed. Subsea completions may be used to produce from appraisal wells before full field development.

Plateau

The plateau period represents the maximum rate of production the facilities were designed to handle, pipeline capacity, or contractual constraints. The duration of the plateau is based upon the productivity of the reservoir and the economics of the project.

Decline

After peak production, fields will decline due to the geology and pressure loss at a rate determined by the reservoir drive, investment, and economic conditions. The nature of the decline is characterized through the decline rate.

A reliable production forecast early in the life of a field can only be developed with knowledge of the development plan, reserve estimates and production capacity (Allen and Seba, 2003). Limitations on the availability and accuracy of data constrain the reliability of forecasting. During the mid-point in the life of a field, a different sort of uncertainty arises, since the production profile and the drive mechanisms of the field are now reasonably well understood, but the strategic decisions of the operator are unknown. Will the operator invest additional capital? Will the operator seek a joint operating agreement or divest the structure? Leases are held by a wide variety of working interest owners and are inevitably carved up over time and sold off or subject to a variety of joint venture/farmout type arrangements. Operators purge their portfolios of under-performing and non-core assets on a semi-regular basis, and as properties change hands, the capital expenditures and operating cost structures typically change.

3.3.3. Hydrocarbon Price and Quality: The domestic price of oil and gas is determined by the cost of imports and market conditions. Conversion factors for oil and gas adjust the benchmark price and depend primarily on the API gravity and sulfur content of the produced hydrocarbon. Hydrocarbon prices are a stochastic quantity while production quality is time dependent.

3.3.4. Capital Expenditures: Capital expenditures typically consist of geological and geophysical costs, drilling costs, facility costs, construction, installation, and any other costs required to develop the field (Gallun et al., 2001).

Geological and Geophysical Cost

Geological and geophysical (G&G) costs are pre-drilling exploration costs, and include topological, geological, and geophysical studies. G&G costs may occur before or after the acquisition of working interest in the lease, and for tax purposes, are usually expensed in the year incurred.

Drilling Cost

Drilling time and costs depend on many technical aspects of the well(s) to be drilled, such as the configuration and geometry of the well, type of drilling contract and rig type, well depth and formation complexity. Other factors include the preferences of the operator and performance of the connc aoecre 5are usually,eTw[(con prim)8.- . Tc0.5.4(e)40 Tc0u8cb5 8rc0523nc48.6.4(ny technifTD( )Tj0r

Installation Cost

The manufacturing and installation cost of the structure(s) required to develop and produce a field is typically the most significant capital expenditure, ranging between 50-75% of the total costs of the project. Drilling expenditures usually make up the bulk of the remaining cost. In the Gulf of Mexico, total *CAPEX* is frequently assumed to range between $3/BOE-$4/BOE (Johnston, 2000), but these are "zero-type" estimates that are subject to significant uncertainty.

3.3.5. Operating Cost: Direct operating cost can be expressed in terms of subcategories such as production, transportation, maintenance, and other.

Production Cost

Production cost usually contributes the greatest amount to operating cost, but the percentage breakdown varies with the operator, site, and the stage of the project's life cycle. Production costs include the cost to lift and treat (dehydrate and separate) hydrocarbons and to dispose of water, which in turn depends on the capacity of the equipment and the throughput.

Transportation Cost

Transportation costs are related to the transport of oil and/or gas from a field to a refinery or processing facility, an export terminal, or any other point of sale. These costs depend on the throughput, the distance to be covered, and the means of transport. Transportation cost items typically include pump and compressor fuel, tanker rentals (if applicable), pipeline tariffs, and terminal cost.

Maintenance Cost

Maintenance cost is associated with keeping the oilfield equipment and wells in good working condition and production. Maintenance covers material and manpower cost and is usually subdivided into facility and workover categories. Facility maintenance comprises inspection costs, preventative maintenance, and remedial costs. Workover costs occur less frequently and include the costs of well stimulation and repair.

Other Cost

For offshore operations, other direct operating cost items typically include supply boats, helicopters, standby vessels, docking charges, shore base expense, underwater inspections (platforms and pipelines), communications and data transmission, weather services, personnel, small tools and supplies, and equipment standby (e.g., wireline, cementing pumps).

Indirect operating cost items include office expenses, lease supervision, engineering salaries, clerical support, warehouse, management salaries, public affairs, and insurance. Administrative and general overhead may vary significantly among operators, while insurance varies with the cost of replacement and the vulnerability of the insured unit. The method for allocating indirect costs is arbitrary, but prorated and percenta

2001). Ernst & Young LLP surveys operators in the U.S. on their average overhead rates per well by producing area and well depth. For offshore wells in the GOM, the monthly median overhead rate per well in 2002-2003 was $35,000 for a drilling well and $3,500 for a producing well. Full cycle operating cost of $2.5/BOE – $3/BOE is frequently assumed for the GOM, and the operating cost in the peak year of production may range from 3-8% total capital expenditures (Johnston, 2000).

3.3.6. Decommissioning Cost: Decommissioning occurs in stages and typically over disjoint time frames. Greatly simplified, following project engineering and cost assessment, federal and

3.4.1. Model I – Resource Recovery: The simplest "production-based" model of abandonment is derived from an estimate of the time when the expected reserves of the field are depleted. The expected time of abandonment will occur when the forecasted cumulative production equals the reserves expected to be recovered. The resource constraint determines the physical limitation of production since, under the assumptions specified, the reserves will be "depleted" at this time. The expected time of abandonment is designated formally as

$$t_a(\mathrm{I}) = \min\{t' \mid \sum_{t=t_o}^{t'} Q(s,t) \geq RES\},$$

where first production is assumed to start at time t_o. Production is reported on an annual basis, and it is clear that the minimization operator "min" will select the first time when cumulative production exceeds the resource base.

No economic factors influence the result, at least not directly, and both $Q(s, t)$ and *RES* are estimated quantities. Forecasting $Q(s,t)$ is based on assumptions regarding the decline rate, the time of peak production, and investment decisions. The resource estimate is based on current technology and price levels. After peak production, $Q(s, t)$ is assumed to be a decreasing function of time, and for a given value of *RES*, the time of first passage will be unique. The uncertainty associated with the analysis depends on the time relative to the production cycle the forecast is performed. If the analysis is performed at the beginning of the life cycle of the field, both $Q(s,t)$ and *RES* will be significantly more uncertain than if the analysis is performed during the mid-point or near the end of the field's life cycle.

3.4.2. Model II – Threshold Indicators: It is reasonable to assume that "similar" structures will exhibit "similar" conditions[13] near the time of abandonment. If the threshold limit of production and the adjusted gross revenue for structure s is denoted by $\overline{Q}(s)$ and $\overline{GR}(s)$, then the time of abandonment is estimated by

$$t_a(\mathrm{IIa}) = \min\{t \mid Q(s,t) \leq \overline{Q}(s)\},$$

$$t_a(\mathrm{IIb}) = \min\{t \mid GR(s,t) \leq \overline{GR}(s)\}.$$

Hybrid threshold models incorporate the reserves constraint of Model I in the determination of abandonment time; i.e.,

$$t_a(\mathrm{IIc}) = \min\{t' \mid Q(s,t) \leq \overline{Q}(s), \sum_{t=t_o}^{t'} Q(s,t) \leq RES\},$$

$$t_a(\mathrm{IId}) = \min\{t' \mid GR(s,t) \leq \overline{GR}(s), \sum_{t=t_o}^{t'} Q(s,t) \leq RES\}.$$

[13] This is explored more completely in Chapter 4.

The inclusion of the reserves constraint ensures that the structure cannot extract more than is available to produce. The reserve constraint is rarely realized in practice, however, since economic and strategic conditions usually dominate removal and divestment decisions.

A structure may reach its economic limit ("first passage") when hydrocarbon prices are in a depressed price-demand state, but if the operator believes stronger prices will prevail in the future, then an abandonment decision is likely to be postponed until the operator can no longer sustain operating losses. To reflect an operator's reluctance to remove a structure at first passage, more stringent conditions can be enforced, such as requiring gross revenues to fall below the threshold two or three (consecutive) years in a row:

More generally, an operator may abandon a property when a threshold limit on the level of cash flow is reached, say $E > 0$, for l

The operator selects the time of abandonment to maximize the net present value of the investment.

are anchored to the initial conditions employed. The restrictions associated with geometric and tabular presentations of multidimensional data are also significant; e.g., on a planar graph at most three or four variables can be examined simultaneously. A more general and concise approach to sensitivity analysis is now presented.

The abandonment time of a structure varies with the structural and parametric specification in a complicated manner, but it is possible to understand the interactions of the variables and their relative influence using a constructive modeling approach. The methodology is presented in three steps.

Step 1. For model φ, bound the range of each variable of interest $(X_1, \ldots, X_k) = (d(t)$, P, $\overline{G}\overline{R}, \ldots)$ within a design interval, *AA* be developed in terms of a meta-evaluation procedure. The field under consideration is labeled XYZ, and the project is dated from the beginning of development expenditures, although money would have also been required for geologic and geophysical cost, leasing cost, and exploration drilling and planning before the decision to proceed with the development was made.

3.6.1. Development Scenario: At the time of development planning, geologists estimated the XYZ field to have between 60-90 million barrels (MMbbl) recoverable reserves spread throughout several geologic zones and total depth ranging between 15,000-18,000 feet. After eight years of production and reservoir modeling, engineers now believe the ultimate recoverable resources to range between 90-110 MMbbl.

The field was developed at a capital cost of $3.5/bbl based on a 100 MMbbl recoverable reserve estimate. The drilling/production facility chosen for development was an 8-pile traditional platform structure designed to handle peak production of 12,000 bbl/day. The gas production of the field is used to supplement on-site power requirements with the remainder reinjected into the field. The hydrocarbons are primarily light, sour oil, with API gravity 42° and 3% sulfur content requiring expensive treatment facilities. There are currently six producing wells and one subsea tieback with production transported to shore through an existing pipeline. There are no other structures on the leasehold.

Based on historic data from similar fields in the area developed with similar technology, the life cycle operating cost are expected to be $3.4/bbl. The capital and operating cost during the first eight years of production are known

If the shape or size of the design space is changed, the simulation must be recalibrated and the structure equations re-estimated. Adding, deleting, or redefining variables will change the shape of the space, while increasing or decreasing the bounds of the parameters will change the size of the space. For instance, if the model parameter of *RES* is revised to reflect greater uncertainty on the recoverable reserves, say Ω = { $d(t) \sim$ U(0.08, 0.13), *RES* ~ N(100000, 20000)}, then Model Ib yields

$$A(\mathrm{Ib}) = -81.1 + 382.3\bar{d} + 0.00066RES,\ R^2 = 0.72.$$

In this case, if $\bar{d}$ = 10% and *RES* = 100,000 Mbbl, then $A(\mathrm{Ib}) = 23.1$ years.

3.6.3. Model II Results: In Model II, the gross revenue is used as a threshold indicator on abandonment, and so the data requirements are e

$$OPEX(s,t) = \$10{,}020 + \$1.6Q(s,t),$$

for $Q(s,t)$ described in Mbbl/year. This relation is based on historic data of the field and an assessment of similar structures in the region. To reflect changes that may occur in the value of the operating costs, a perturbation factor k ~ U(0.9, 1.3) is applied to the annual value of $OPEX(s,t)$. For k < 1, operating cost would be smaller than the historic relation, while for k > 1, the operating costs would exceed historic rates. The value of k is assumed constant throughout the cash flow cycle, but it is easy to allow k to vary annually, in which case the average measure $\bar{k}$ would be the output variable of interest. The royalty and tax rate are assumed to be Uniformly distributed with *ROY* ~ U(0.10, 0.20) and T ~ U(0.10, 0.20), and the threshold value of the net cash flow cut-off is E ~ U(4000, 8000).

The functional form of Model III is expressed as

$$A(\text{III}) = \alpha_0 + \alpha_1 \bar{d} + \alpha_2 \bar{P} + \alpha_3 ROY + \alpha_4 k + \alpha_5 T + \alpha_6 E\ .$$

The expected signs of the coefficients $\alpha_1 < 0$ and $\alpha_2 > 0$ follow from the discussion for Model II. As the royalty and tax rate increase, the net cash flow position of the operator will be negatively impacted, and so we expect $\alpha_3 < 0$ and $\alpha_5 < 0$. The coefficient α_4 reflects the influence of perturbations to the operating expenditures, so that as k increases, operating expenditures increase, again negatively impacting the net cash flow position of the operator. Similarly, as the value of the net cash flow threshold E is raised, structures will be abandoned earlier, and we expect $\alpha_4 < 0$ and $\alpha_6 < 0$.

The net cash flow projection for the field is computed according to the framework previously described. The gross revenues are determined as the product of the production and price trajectory, and the net revenue is determined after the royalty rate *ROY* is specified. The values for *CAPEX* and *OPEX* and the depreciation schedule are known for the first eight years of the field's life and are extrapolated thereafter. The tax is determined after the tax rate T is specified.

Four different scenarios are considered using the parameter values shown in Table C.3. The design space common to each model is given as

$$\Omega = \{\, d(t) \sim \text{U}(0.08, 0.13),\ P \sim \text{LN}(25, 3),\ ROY \sim \text{U}(0.10, 0.20),$$
$$k \sim \text{U}(0.9, 0.13),\ T \sim \text{U}(0.30, 0.50),\ E \sim \text{U}(4000, 8000)\}.$$

The results of the regression models are depicted in Table C.4. For Model IIIa,

$$A(\text{IIIa}) = 59.2 - 206.1\bar{d} + 0.17\bar{P} - 12.6ROY - 4.8k - 7.3T - 0.00071E\ ,\ (R$$

coefficients remain fairly stable and generally increase in significance, with the difference in the numerical result between the two models imperceptible: $A(\text{IIIb}) = 26.4$ years.

Alternative decision criteria can be adopted within the analytic framework. Delay can be incorporated in the model by adopting the decision rule

$$t_a(\text{IIIc}, \text{d}) = \min\{t + l \mid \bigcap_{t,t+1,t+2} NCF(s,t) \leq E\}.$$

In Model IIIc and Model IIId, the net cash flow elements must fall below E for two and three consecutive years before the operator decides to abandon. Obviously, additional constraints on the production profile will increase the expected age of the structure, and so the relevant question concerns the relative impact of the constraint. If the production decline dominates the hydrocarbon price volatility near the time of abandonment, then the incremental impact on the average age is expected to be about one year or so per additional constraint. On the other hand, if the volatility of the hydrocarbon price is a dominant factor, then we would expect the impact to deviate from the one year increment. For $\bar{d}$ = 10%, $\bar{P}$ = \$25/bbl, ROY = 16.67%, k = 1.1, T = 40%, and E = \$8,000, Model IIIc, d yield

$$A(\text{IIIc}) = 27.1 \text{ years}, \; A(\text{IIId}) = 28.2 \text{ years},$$

suggesting that production decline is the dominating factor.

3.7. Limitations of the Analysis

Significant sources of uncertainty underlie all models of decommissioning, and the framework described herein only hints at the complexity involved. Additional sources of uncertainty are now described.

3.7.1. Private Uncertainty: The primary sources of private uncertainty include geologic uncertainty, production uncertainty, investment uncertainty, and strategic uncertainty. Some forms of uncertainty are observable and quantifiable (e.g., price), while other forms are quantifiable but unobservable due to their proprietary nature (e.g., geologic). The most difficult forms of uncertainty to model are strategic decisions that are neither observable nor readily quantifiable.

3.7.2. Scale Economies: Operators who divest or farm out a structure induce a structural change in the operating cost of the asset. If O_1 represents the seller and O_2 the buyer, then the typical structural change would be

$OPEX(s, t,$

By bundling structures in a group $\{s_1, \ldots, s_k\}$ and servicing the needs of the group as a unit, scale economies can frequently be achieved, such that

$$OPEX(s_1, \ldots, s_k; t, O) \leq \sum_{i=1}^{k} \sum_{j=1}^{l} OPEX(s_i, t, O_j),$$

providing the asset a new lease on life. The decision to invest in structure s_{k+1} when a bundled unit $\{s_1, \ldots, s_k\}$ already exists is an economic decision determined by the incremental benefits of adding the production of s_{k+1} versus the incremental costs of operation and decommissioning. If structure s_{k+1} is in the same geographic area as other properties then the scale economies may provide residual benefit to the owner.

Similar to the structural changes that occur under divestment, operators can reduce the overall cost to decommission structures on a lease through timing and scale economies. Again, by bundling structures in a group $\{s_1, \ldots, s_k\}$ and performing the removal at one time, economies are frequently achieved through more favorable contract terms, reduced mobilization/ demobilization fees, etc. so that:

$$DECOM(s_1, \ldots, s_k, t) \leq \sum_{i=1}^{k} \sum_{j=1}^{l} DECOM(s_i, t_j).$$

Niche operators can act faster and are more operationally flexible than large independents or majors, and this flexibility has value that is expressed in various ways; e.g., niche players can wait until the market rates for construction barges are competitive to perform deconstruction activities.

3.7.3. Regulatory Uncertainty: Typically, a lease is terminated when production on the lease ceases, but if the operator intends to re-work wells or is pursuing drilling activity on the lease, or the lease contains an active pipeline, conditions may warrant the MMS to grant an extension of the lease termination. Since several structures may be contained on a lease, it is only when production from the *last* productive structure on the lease ceases that *all* the structures are required to be removed.

3.7.4. Random Events: Random acts of nature (e.g., see (Daniels, 1994)) also influence the ability to predict removal times, but because the frequency of such events is relatively small, these occurrences do not play a large role in aggregate removal patterns.

3.8. Conclusions

Four models were developed to model the decommissioning time of an offshore oil and gas structure, and the limitations, refinements, and extensions of each model were discussed. The models were then implemented on a generic field development plan to illustrate the simulation methodology and the manner in which the system variables interact. A meta-modeling methodology was used to construct functionals that describe how the age of the structure upon abandonment is related to various system parameters.

The high degree of uncertainty and the large number of factors associated with structure removal suggest that simple models can capture the essence of a removal forecast in a manner that is comparable to more sophisticated methodologies. Academics would probably favor the more

CHAPTER 4: A STATISTICAL ANALYSIS OF THE ECONOMIC LIMIT OF OFFSHORE HYDROCARBON PRODUCTION

4.1. Introduction

The economic life of a structure is defined as the time at which the production cost of the structure is equal to the production revenue. Economic life is normally difficult to determine directly, since full and accurate economic data are often not available on an individual structure basis, and factors such as hydrocarbon price, operational expenditures, investment decisions, and strategic objectives contribute to the uncertainty. Toward the end of the lifetime of most structures, the capital expenditures and depreciation are generally negligible and the operating cost is the primary expense element. When the gross revenue falls below the operating cost, the operator will usually shut down production and consider available divestment or decommissioning options.

The economic limit of structure s, $t_e = t_e(s)$, is defined as the time when the gross revenue of the structure, $GR(s, t)$, equals production cost, $C(s, t)$:

$$t_e = \{t \mid GR(s, t) = C(s, t)\}.$$

Gross revenue $GR(s, t)=P(t)Q(s, t)$ is an observable quantity, while production cost, $C(s, t)$, is generally unobservable. Operators on federal leases are required to report production data to the government on a well basis, and so the gross revenue and royalty stream of a structure can be estimated, but the revenue stream is only half of the equation and the cost data still needs to be inferred. As most casual observers of the oil/gas industry are aware, it is rare indeed when the net

4.2. Model Development

The economic limit of a structure is estimated following four steps:

Step 1. Estimate structure production;

Step 2. Define lease categorization;

Step 3. Compute production and gross revenue thresholds; and

Step 4. Define factor variables.

A description of each stage is now provided.

<u>4.2.1. Production Allocation:</u> Each structure is identified with a lease, and in theory, each well is associated with a (unique) structure. In practice, however, not every well in the MMS database is linked to a structure. Wells are grouped into two disjoint categories – assigned $\{w^a\}$ and unassigned $\{w^u\}$ sets. A well that is a member of $\{w^a\}$ maintains a structure assignment while wells in $\{w^u\}$ require assignment. Unassigned well production is allocated to the nearest lease structure. For $w^u \in l$, assign w^u to structure $s \in l$ based upon the criteria,

$$w^u \leftrightarrow \{s \,|\, \min_{s \in l} d(w^u, s)\},$$

where $d(w^u, s)$ represents the distance from well w^u

III. Two or more structure removals, no other producing structure on lease at time of removal;

IV. Two or more structure removals, at least one producing structure on lease at time of removal.

Every structure removed in the GOM is an element of one and only one lease category, and since the four categories are disjoint, it is clear that the aggregation strategy represents the universe of all removals. Category I represent structures with one and only one structure on the leasehold at the time of removal. If one structure is removed while one or more structures are active on the lease, the structure is classified in category II. Two or more structures may also be removed at the "same" time, or nearly the same time, typically within a month or so of one another. Structures on leases with two or more structures removed but no other producing structures on the lease are classified in category III. Category IV denotes two or more removals on a leasehold with at least one producing structure at the time of removal.

4.2.3. Threshold Limits: The annual production and gross revenue streams of structure *s* are computed at time t_{lp} and 1, 2, …, *k* years before last production, as

$$\{Q(s, t_{lp}), Q(s, t_{lp}-1), \ldots, Q(s, t_{lp}-k)\},$$
$$\{GR(s, t_{lp}), GR(s, t_{lp}-1), \ldots, GR(s, t_{lp}-k)\}.$$

The production and gross revenue streams at time t_{lp} are referred to as a "threshold" limit, and denoted by $\overline{Q}(t_{lp}) = Q(s, t_{lp})$ and $\overline{R}(t_{lp}) = GR(s, t_{lp})$. Production and gross revenue levels at/near the year of last production represents a threshold for economic operations under conditions specific to the field, structure, operator, technology, and time of operation. The production and gross revenue levels represent a "snapshot" of the structures state in the year of last production, and presumably, conditions that approximately describe the economic limit.

Threshold indicators $\overline{Q}(\Gamma,t)$ and $\overline{R}(\Gamma,t)$ for category Γ at time *t* can be computed in several ways. An averaging process is the most common:

$$\overline{Q}(\Gamma,t) = \frac{1}{\#\Gamma(t)} \sum_{s\in\Gamma} Q(s,t), \qquad)$$

The profile $Q(s, t)$ is used to delineate three phases of production. If peak production,

$$Q^* = Q^*(s,t) = \max Q(s,t),$$

occurs in year t_p,

$$t_p = \min\{t \mid Q(s,t) = Q^*\},$$

then the peak production period is defined as the time interval when production exceeds αQ^*, where the value of α, $0 < \alpha < 1$, is user-defined and selected near the upper bound of the interval; e.g., $\alpha = 0.8$. The plateau production period is defined by the time interval $[t_c, t_d)$, where

$$t_c = \min\{t \mid Q(s,t) \geq \alpha Q^*, 0 < \alpha < 1\},$$
$$t_d = \max\{t \mid Q(s,t) \geq \alpha Q^*, 0 < \alpha < 1\}.$$

The ramp-up period is defined by $[t_i, t_c]$. The decline period is defined by $[t_d, t_{lp}]$.

The decline rate $d(s, t)$ of structure s in year t, $t_d \leq t \leq t_{lp}$, is defined as

$$d(s,t) = \frac{Q(s,t-1) - Q(s,t)}{Q(s,t)}.$$

Usually, $d(s, t) \geq 0$ but investment decisions, maintenance, production problems, weather and other events may change the sign of the decline rate for one or more years. The average decline rate of structure s over $[t_d, t_{lp}]$ is computed as

$$DEC(s) = \frac{1}{t_{lp} - t_d} \sum_{t=t_d}^{t_{lp}} d(s,t).$$

At the time of development, the peak production to expected reserves ratio, $Q^*/\mathrm{E}[RES]$, serves as a proxy for the maximum efficient production rate. To obtain a high $Q^*/\mathrm{E}[RES]$ ratio, the operator will need to have a large number of producing wells and adequate production equipment to handle the volumes of oil and gas produced. A low $Q^*/\mathrm{E}[RES]$ ratio provides an indirect indication that an operator has chosen to drill less wells and produce longer. Fewer wells require smaller production, processing, and transportation facilities; less operating personnel; reduced financing cost, and presumably, lower operating expenditures. At the time of last production, the expected value of the recoverable reserves, $\mathrm{E}[RES]$, is a deterministic and known quantity, RES, computed as

$$RES(s) = \sum_{t=t_i}^{t_{lp}} Q(s,t).$$

4.3. Descriptive Statistics

4.3.1. Data Source: The data for this analysis was obtained through the MMS Technical Information Management System database. The sample set contains over 2,000 structures removed in the GOM over the past two decades, and after eliminating structures that have never produced and structures with missing and/or ambiguous data, the final data set included 1,790 elements. Only structures that have been removed from operation are under consideration. It is clear that production and revenue thresholds can be calculated with a reasonably high level of accuracy since production and price forecasting is not required. Uncertainty arises in the calculation of

Summary statistics for Q^*/RES and RES provide a quick description of the field characteristics. The value of Q^*/RES range broadly between 20-60%, with gas fields produced with Q^*/RES as high as 40-50%. The average decline rate will often equal or exceed the Q^*/RES ratio; i.e., $DEC \geq Q^*/RES$, and this is generally supported by the empirical data. Q^*/RES is a decreasing function of structure complexity for each lease categorization, while the recoverable reserves is an increasing function of structure complexity. In symbolic form,

$$Q^*/RES(C) > Q^*/RES(WP) > Q^*/RES(FP),$$
$$RES(C) \leq RES(WP) \leq RES(FP).$$

Structure complexity serves as a proxy of the development plan, expected size and decline characteristics of the field, and this is reflected by the relational forms.

4.3.3. Average Production and Revenue Threshold Levels: Categorization of the data according to lease characteristics, structure type, and water depth is presented in Tables D.2-D.9. The number of elements within each category in the year of last production is shown in the third column of each table. Because some fields have a very short lifetime, the number of elements within each category will decrease with the time from last production (so as one moves horizontally across each row, the size of the sample set will decrease).

The value of the average production thresholds is fairly uniform across water depth and structure type in Table D.2. Well protectors in the 101-200 feet water depth category appear to be an exception due to the presence of a small number of large fields. The average production threshold ranges between 43,000 - 57,000 BOE, meaning that on average, when the annual production from an offshore structure falls within this range the structure is very near its economic limit. The gross revenue thresholds shown in Table D.3 exhibit greater variability than threshold is structure invariant is provided, however, since $\overline{Q}(C, t_{lp}) \approx \overline{Q}(WP, t_{lp}) \approx \overline{Q}(FP, t_{lp})$ and $\overline{R}(C, t_{lp}) \approx \overline{R}(WP, t_{lp}) \approx \overline{R}(FP, t_{lp})$, at least approximately, across lease categorizations. There is also a weak trend for the production and revenue thresholds to increase with water depth:

$$\overline{Q}(ST, 0-100') < \overline{Q}(ST, 101-200'),$$
$$\overline{R}(ST, 0-100') < \overline{R}(ST, 101-200') < \overline{R}(ST, 201-400').$$

4.4. Conclusions

The economic limit of an offshore structure is important from an operational perspective and provides insight into the nature of decommissioning activities. No modeling framework is perfect, however, and the best a model can do is to provide insight and ensure an interpretation supported by empirical data. The unique nature of the economic limit of structures drives the observed variability in the data set, and since the category descriptors are constrained and finite, the impact of unobservable factors on the model results may be significant. Many factors impact the economic limit of a structure and it is not possible to enumerate all the factors in modeling, but statistical analysis allows insight to be developed.

CHAPTER 5: FORECASTING THE REMOVAL OF OFFSHORE STRUCTURES IN THE OUTER CONTINENTAL SHELF

5.2. Model Framework

5.2.1. General Methodology: The methodology adopted in this paper follows a five-step process. For structure *s* and time *t*,

Step 1. Forecast production profile, $Q(s, t)$,
Step 2. Forecast revenue profile, $R(s, t)$,
Step 3. Estimate abandonment time, t_a

Step 3

<u>5.2.5. Removal Time:</u> To estimate removal time, a rule-based policy is assumed to govern and approximate operator behavior. If structures $\{s_1, \ldots, s_k\}$ exist on lease *l* and are held until production from the *last* structure ceases, then the time in which *all* the structures on the lease are removed is determined from the relation:

$$t_r(s_i) = \max_{i=1,\ldots,k}\{t_a(s_i)\} + 1,\ i = 1,\ldots, k;$$

e.g., if one structure exists on the lease, $s \in l$, then

$$t_r(s) = t_a(s) + 1,$$

while if two structures exist on the lease, $\{s_1, s_2\} \in l$, then

$$t_r(s_1) = t_r(s_2) = \max\{\, t_a(s_1), t_a(s_2)\} + 1,$$

leases form an inventory of platforms that are ex

E.4. The net present value of the total cost using a 10% discount factor is computed to range between \$2.3 – 2.5 billion.

The number of structures expected to be removed in the WGOM according to the production and revenue threshold models is depicted in Figure E.5. The total cost to decommission the WGOM from 2005-2020 is shown in Figure E.6. The net present value of the total cost using a 10% discount factor is computed to range between \$367 – 378 million.

5.4.3. Model Discussion: Modeling removal processes require a number of structural assumptions and parameterizations for decline parameters, economic limits, and removal obligations. The model results are closely linked to the model assumptions and parameterization so that changes in either of these factors will impact the forecast results.

The production threshold model dominates the revenue threshold model, and is considered less robust since hydrocarbon price is not incorporated in the analysis. It is expected that a significant number of structures removed over the next few years will remain in inventory on inactive leases, and thus the apparent removal rate will be "smoothed" out over the near-term horizon.

Decommissioning cost patterns reflect the removal forecast and the relative magnitude of abandonment. Fixed platforms in deepwater are significantly more costly to remove than shallow water caissons, for instance, and this is reflected in the higher proportional cost for fixed platform removals.

5.5. Limitations of the Analysis

Production and Revenue Model

A reliable production forecast early in the life of a field can only be developed with knowledge of the development plan, reserve estimates and production capacity, and since estimates of these parameters are either unknown or uncertain, a large degree of uncertainty exists in forecasting production profiles for structures that have yet to reach peak production. During the mid-point in the life of a field, a different sort of uncertainty arises since the production profile and the drive where $d(w^u, s)$ represents the distance from unassigned well w^u to structure $s \in l$. Model uncertainty is introduced into the forecast model since this well-structure assignment is arbitrary. Fortunately, the number of wells requiring assignment is reasonably small, and so the error associated with the assignment is believed to be reasonably small.

The quality of production is not considered a primary factor in the forecast model and was

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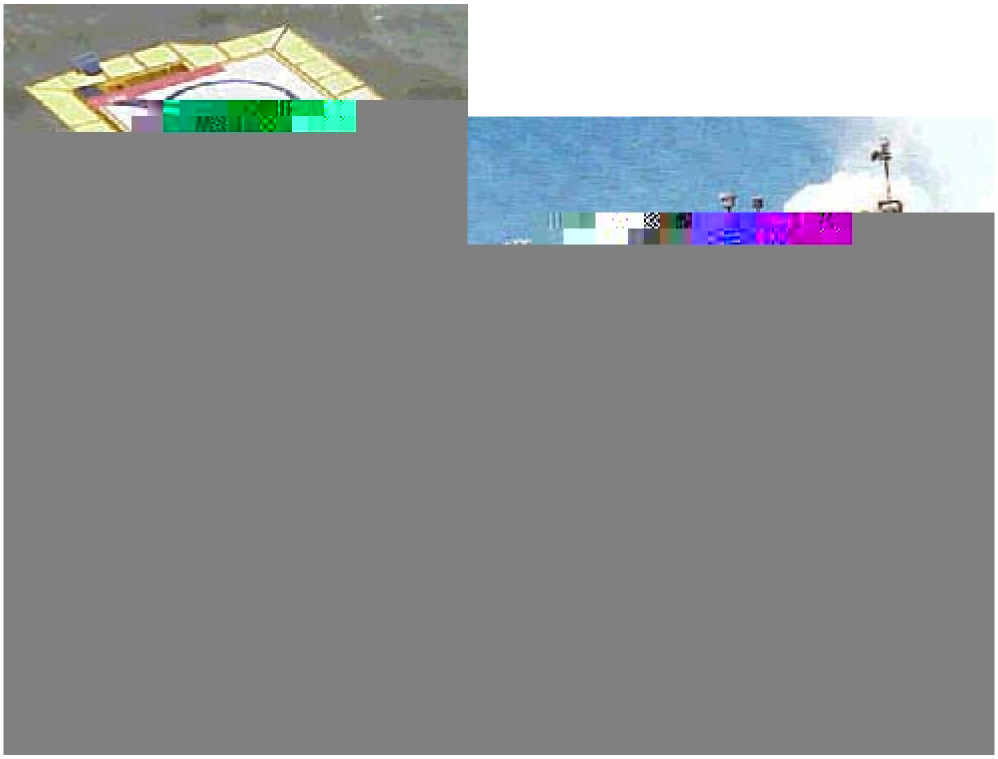
APPENDIX A
CHAPTER 1 FIGURES AND TABLES

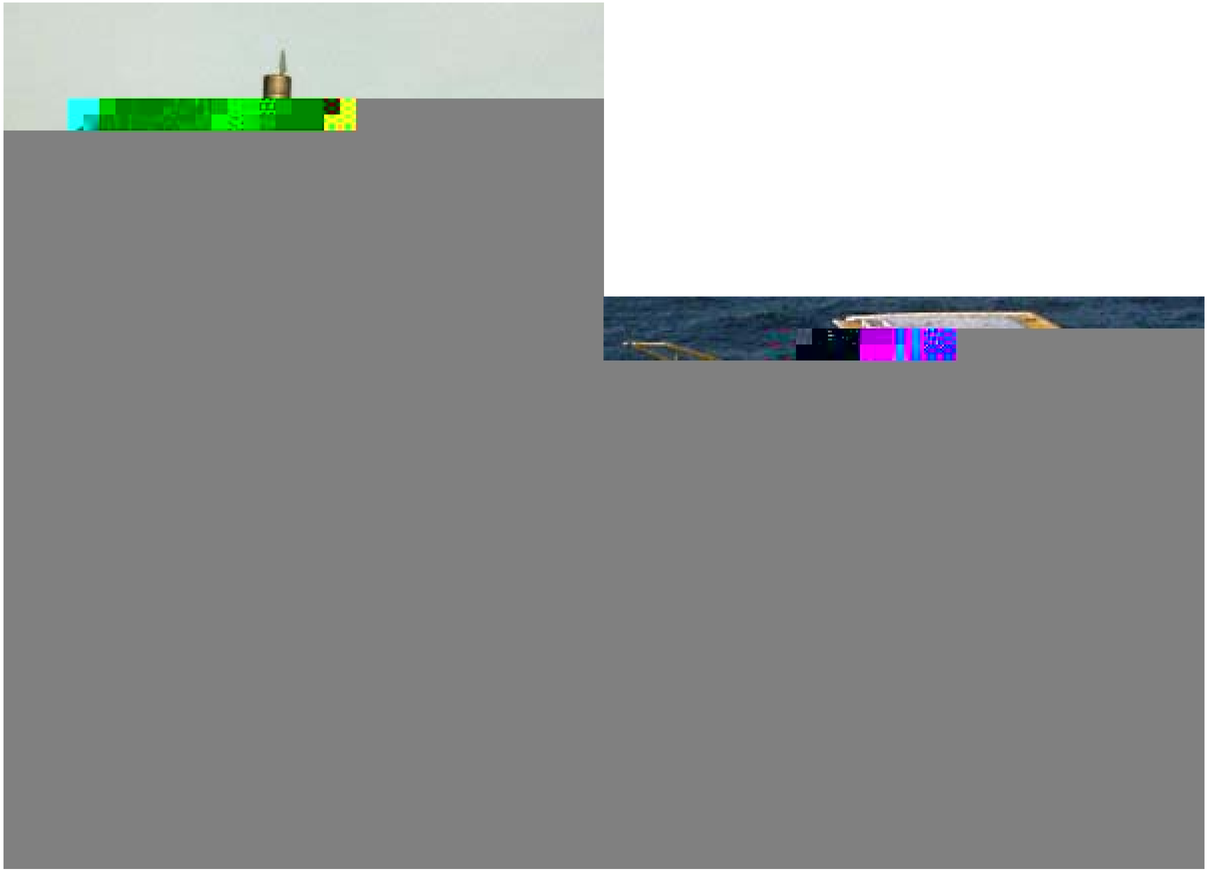
Source: Minerals Management Service, 2004 (www.mms.gov).

Figure A.1: Federal Outer Continental Shelf Leasing Program.



Source: Twachtman Synder & Byrd, Inc., 2000 (www.tsboffshore.com).

Figure A.2: Caisson Structures.



Source: Twachtman Synder & Byrd, Inc., 2000 (www.tsboffshore.com).

Figure A.3: Well Protector Structures.

Source: Twachtman Synder & Byrd, Inc., 2000 (www.tsboffshore.com).

Figure A.4: Fixed Platform Structures.

Table A.1

Total Number of Structures Installed and Removed by Water Depth and Planning Area in the Gulf of Mexico (1947-2001)

Water Depth Range (ft)	Installed			Removed		
	WGOM	CGOM	GOM	WGOM	CGOM	GOM
0-10	2	103	105	1	37	38
11-20	0	527	527	0	263	263
21-30	2	695	697	1	291	292
31-40	20	660	680	5	190	195
41-50	67	597	664	33	216	249
51-75	216	834	1,050	84	305	389
76-100	123	439	562	40	140	180
101-125	50	282	332	20	86	106
126-150	52	242	294	20	64	84
151-175	48	170	218	19	37	56
176-200	51	190	241	19	45	64
Subtotal	631	4,739	5,370	242	1,674	1,916
201-656	123	447	570	22	63	85
657-2,624	14	19	33	2	1	3
2,624+	2	6	8	0	0	0
Subtotal	139	472	611	24	64	88
Total	770	5,211	5,981	266	1,738	2,004

Footnote: Structures are defined to include all caissons, well-protectors, fixed platforms, and floating configurations located within the federal offshore waters of the Gulf of Mexico.

Table A.2

Average Annual Number of Structures Installed and Removed in the Gulf of Mexico According to Water Depth and Planning Area (1996-2001)

Water Depth	Installed			Removed		
Range (ft)	WGOM	CGOM	GOM	WGOM	CGOM	GOM
0-10	(0, 0)	(2.8, 2.5)	(2.8, 2.3)	(0.2, 0.4)	(2.6, 2.7)	(2.8, 2.8)
11-20	(0, 0)	(6, 2.9)	(6, 2.9)	(0, 0)	(16.2, 8.6)	(16.2, 8.6)
21-30	(0.2, 0.4)	(11.2, 5.2)	(11.4, 5.4)	(0, 0)	(11.8, 6.6)	(11.8, 6.6)
30-40	(0.8, 0.4)	(13.4, 4.0)	(14.4, 3.6)	(0.6, 1.3)	(10, 5.2)	(10.6, 6.2)
41-50	(2.8, 1.9)	(5.8, 1.3)	(8.6, 2.2)	(2.6, 1.8)	(14.6, 7.7)	(17.2, 8.5)
51-75	(7.6, 1.9)	(18, 6.4)	(25.6, 6.0)	(7.8, 6.5)	(19.8, 6.4)	(26.7, 10.9)
76-100	(2.4, 1.7)	(11, 4.3)	(13.4, 4.8)	(4.6, 4.4)	(8, 2.2)	(12.6, 3.1)
101-125	(1, 0.7)	(8.2, 4.1)	(9.2, 4.8)	(2, 2)	(6.8, 7.4)	(8.8, 9.2)
126-150	(1.4, 1.1)	(6.6, 2.5)	(8, 2.9)	(0.8, 1.3)	(4.2, 1.5)	(5, 2.1)
151-175	(0.8, 0.8)	(5.2, 3.3)	(6, 3.1)	(1.2, 0.8)	(2.8, 0.8)	(4, 0)
176-200	(1, 1.2)	(5, 2.6)	(6, 3.8)	(0.8, 0.8)	(3.8, 1.5)	(4.6, 1.8)
Subtotal	(18, 3.8)	(93, 12.6)	(111, 13.2)	(20.6, 18.6)	(100.6, 17.8)	(121.2, 21.3)
201-656	(3.6, 1.5)	(16.2, 4.9)	(19.8, 6.3)	(1.4, 1.1)	(5.4, 2.6)	(6.8, 3.3)

Table A.3

Average Annual Number of Structures Installed and Removed in the Gulf of Mexico According to Water Depth and Planning Area (1991-2001)

Table A.4

The Age Distribution of Active Structures in Shallow Water (0-60m) by Configuration Type and Planning Area (1947-2001)

		Caisson	Well Protector	Fixed Platform

Table A.6

Number of Structures Removed (*R*), Structures Removed by Explosive Technique (R_E), and the Percentage of Explosive Removals (p_E) as a Function of Water Depth and Planning Area (1986-2001)

Water Depth Range (ft)	WGOM			CGOM			GOM		
	R	R_E	p_E	R	R_E	p_E	R	R_E	p_E
0-10	1	1	100	20	11	55	21	12	54
11-20				210	71	34	210	71	34
21-30	1	1	100	208	145	70	209	146	70
31-40	4	3	75	150	88	59	159	91	59
41-50	31	22	71	155	107	69	186	129	69
51-75	78	34	44	238	130	55	316	164	52
76-100	41	20	71	109	61	56	150	81	54
101-125	19	12	63	81	45	56	100	57	57
126-150	20	15	75	60	49	82	80	64	80
151-175	17	10	59	34	23	68	51	33	65
176-200	16	13	81	44	26	59	60	39	65
201-656	23	17	74	64	49	77	87	66	76
657-2,624	2	1	50				2	1	50
$2{,}624^+$									
Water Depth Range (m)	**WGOM**			**CGOM**			**GOM**		
	R	R_E	p_E	R	R_E	p_E	R	R_E	p_E
0-60	228	131	57	1,309	756	58	1,537	887	58
61-200	23	17	74	64	49	77	87	66	76
200^+	2	1	50				2	1	50
Total	253	149	58	1,373	805	58	1,626	954	59

Table A.7

Number of Structures Removed (*R*), Structures Removed by Explosive Technique (R_E), and the Percentage of Explosive Removals (p_E) as a Function of Water Depth and Configuration Type for the Gulf of Mexico (1986-2001)

Water Depth Range (ft)	Caisson			Well Protector			Fixed Platform			All	
	R	R_E	p_E	*R*	R_E	p_E	*R*	R_E	p_E	*R*	*R*

Table A.8

Number of Structures Removed (*R*), Structures Removed by Explosive Technique (R_E), and the Percentage of Explosive Removals (p_E) as a Function of Time and Configuration Type for the Gulf of Mexico (1986-2001)

Year	Caisson			Well Protector			Fixed Platform			Total		
	R	R_E	p_E (%)	R	R_E	p_E (%)	R	R_E	p_E (%)	R	R_E	p_E (%)
1986				1	0	0	1	0	0	2	0	0
1987	10	0	10	2	0	0	7	0	0	19	0	0
1988	46	5	11	9	2	22	36	19	53	91	26	29
1989	46	34	74	7	6	86	34	30	88	87	70	80
1990	53	26	49	9	5	56	36	29	81	98	60	61
1991	54	26	48	16	11	69	44	36	82	114	73	64
1992	44	19	43	13	9	99	40	33	83	97	61	63
1993	77	49	64	30	12	40	61	41	67	168	102	61
1994	42	22	52	16	14	88	66	51	77	124	87	70
1995	59	40	68	9	7	78	49	34	69	117	81	69
1996	48	13	27	15	8	53	56	29	52	119	50	42
1997	92	54	59	14	11	79	71	38	54	177	63	58
1998	35	14	40	11	8	73	29	13	45	75	35	47
1999	72	35	49	17	9	53	45	32	71	134	76	57
2000	49	37	76	19	13	68	66	42	64	134	92	69
2001	22	7	32	11	9	82	35	21	60	68	37	54
Total	749	381	51	199	124	62	676	448	66	1,624	953	59

Table A.11

Number of Structures Removed (R) and Percentage of Structures Removed (p) as a Function of Water Depth and Age Upon Removal (1986-2001)

Water Depth Range (m)	Age Upon Removal (yr)				
	0-11	11-20	21-30	30^+	Total
0-60	600	441	283	213	1,537
61-200	36	36	12	3	87
200^+	2	0	0	0	2
Total	638	477	295	216	1,626
Water Depth Range (m)	**Percentage p (%)**				
	0-11	11-20	21-30	30^+	Total
0-60	39	39	18	14	100
61-200	41	41	14	3	100
200^+	100	-	-	-	100
Total	638	477	295	216	100

Footnote: $p = R/R_T$, where R_T denotes the total number of structures per planning area.

Table A.12

Number of Structures Removed Using Explosives Techniques and the Percentage of Explosives Removal as a Function of Water Depth and Age Upon Removal (1986-2001)

Water Depth Range (m)	Age Upon Removal (yr)				
	0-11	11-20	21-30	30^+	Total
0-60	283	276	173	156	888
61-200	28	27	8	3	66
200^+	1	0	0	0	1
Water Depth Range (m)	**Percentage p_E (%)**				
	0-11	11-20	21-30	30^+	Total
0-60	47	63	61	73	58
61-200	78	75	67	100	76
200^+	50	-	-	-	50

Footnote: $p_E = R_E/R$, where the R values are obtained from Table A.8.

Table A.13

Number of Structures Removed (R), Number of Structures Removed by Explosive Technique (R_E), and the Percentage of Structures Removed by Explosives (p_E) Categorized According to Age and Configuration Type (1986-2001)

Age	Caisson			Well Protector			Fixed Platform		
	R	R_E	p_E (%)	R	R_E	p_E (%)	R	R_E	p_E (%)
0-10	295	116	59	75	40	53	266	154	58
11-20	204	115	56	52	35	67	221	153	69
21-30	157	83	53	36	21	58	102	77	75
30^+	93	67	72	36	28	78	87	64	74
Total	749	381	51	199	124	62	676	448	66

Table A.14

Percentage of Structures Removed by Configuration Type and Water Depth in the Gulf of Mexico (1986-2001)

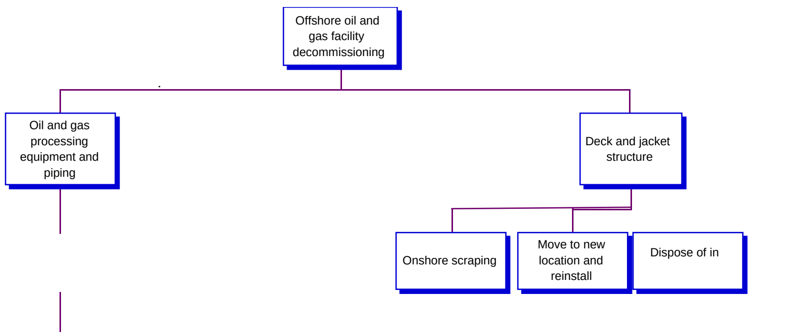
Water Depth Range (m)	Caisson				
	0-11	11-20	21-30	30^+	Total
0-60	39	56	53	72	51
61-200					
Water Depth Range (m)	**Well Protector**				
	0-11	11-20	21-30	30^+	Total
0-60	52	67	58	77	62
61-200	100	67		100	83
Water Depth Range (m)	**Fixed Platform**				
	0-11	11-20	21-30	30^+	Total
0-60	55	68	77	73	65
61-200	76	76	67	100	75

Table A.15

Medium-Term Forecast of the Number of Structures Removed in the Gulf of Mexico by Explosive Technique (Model I)

Water Depth Range (m)	Forecast Horizon	CAIS		WP		FP		Total
		W	C	W	C	W	CC5(P)5.5u(W)-43.b40.2(C)14 re	

APPENDIX B
CHAPTER 2 FIGURES AND TABLES


Offshore oil and gas facility decommissioning
Oil and gas processing equipment and piping
Deck and jacket structure
Onshore scraping
Move to new location and reinstall
Dispose of in

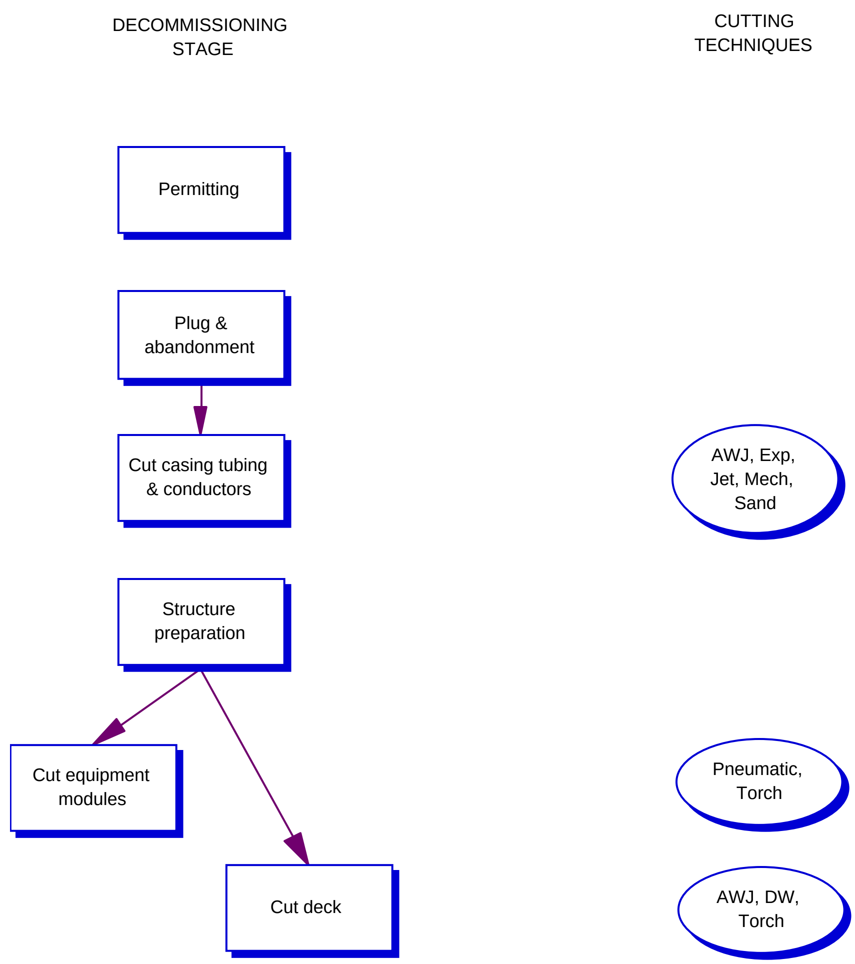
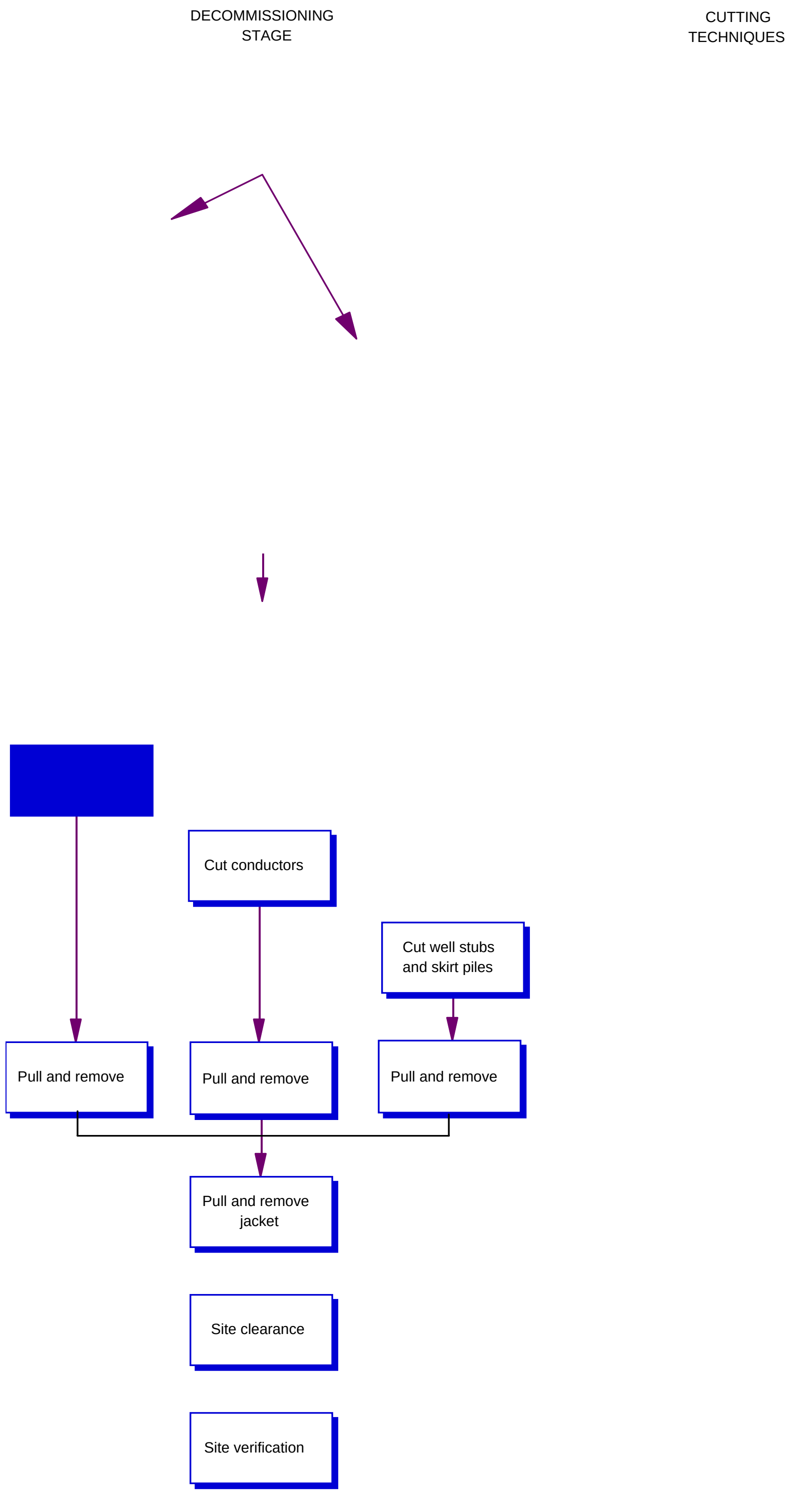
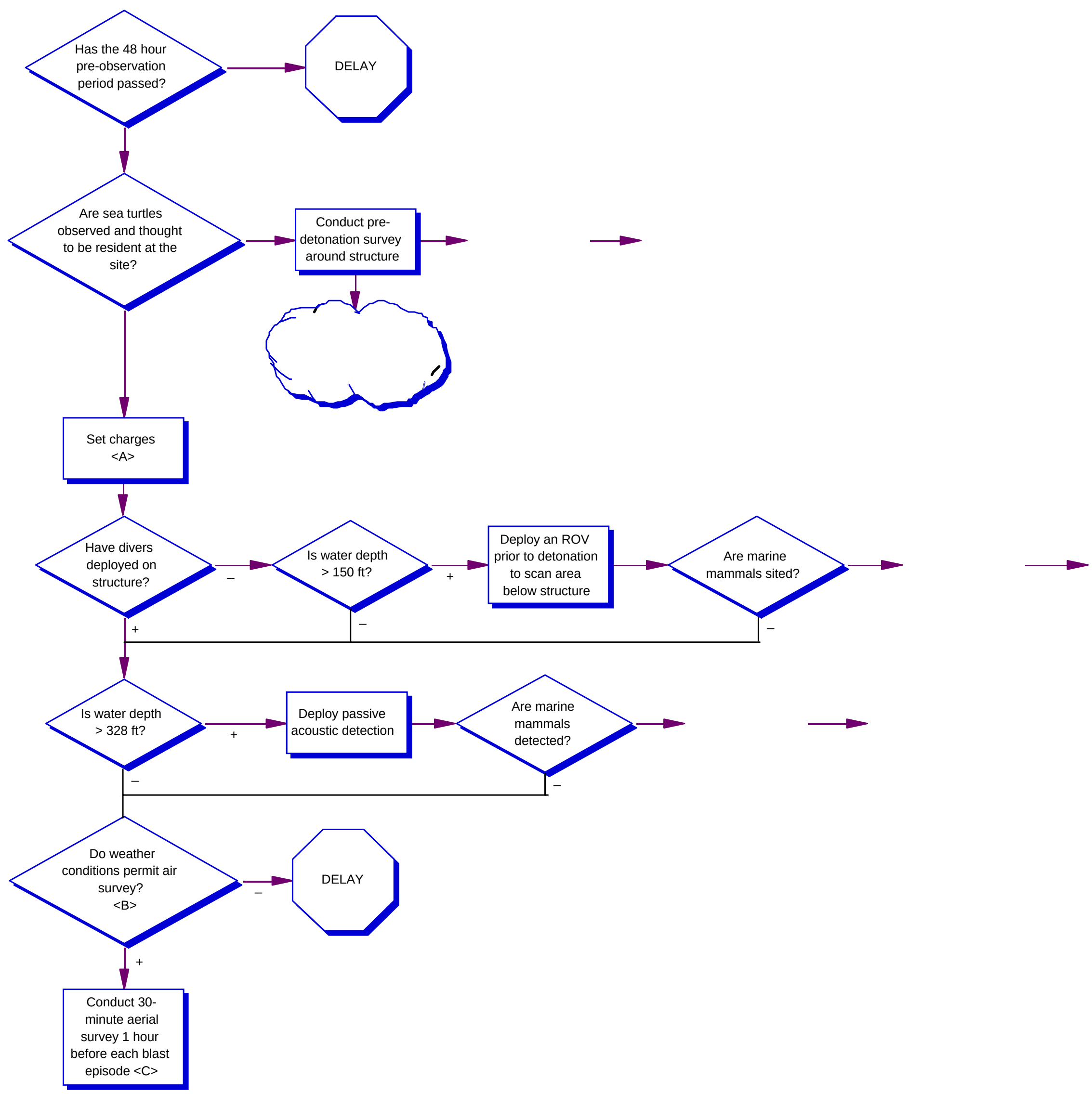
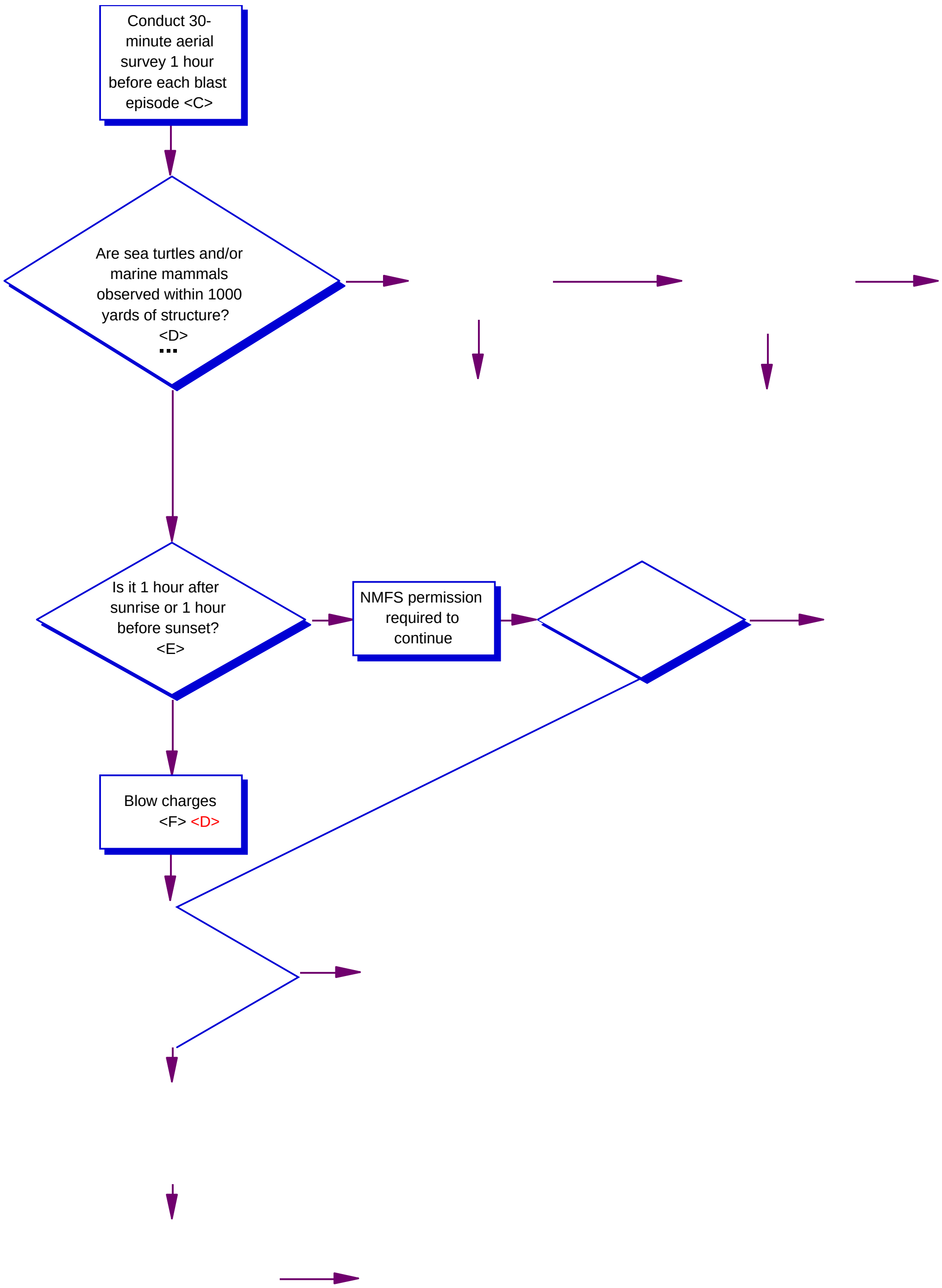
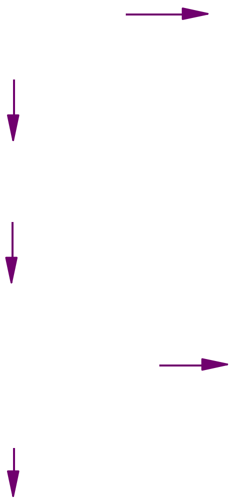


Figure B.3: Decommissioning Is Often a Severing Intensive Operation.


DECOMMISSIONING STAGE
CUTTING TECHNIQUES
Cut conductors
Cut well stubs and skirt piles
Pull and remove
Pull and remove
Pull and remove
Pull and remove jacket
Site clearance
Site verification


Has the 48 hour pre-observation period passed?
DELAY
Are sea turtles observed and thought to be resident at the site?
Conduct pre-detonation survey around structure
Set charges <A>
Have divers deployed on structure?
–
Is water depth > 150 ft?
+
Deploy an ROV prior to detonation to scan area below structure
Are marine mammals sited?
+
–
–
Is water depth > 328 ft?
+
Deploy passive acoustic detection
Are marine mammals detected?
–
–
Do weather conditions permit air survey? <B>
–
DELAY
+
Conduct 30-minute aerial survey 1 hour before each blast episode <C>


Conduct 30-minute aerial survey 1 hour before each blast episode <C>
Are sea turtles and/or marine mammals observed within 1000 yards of structure? <D>
Is it 1 hour after sunrise or 1 hour before sunset? <E>
NMFS permission required to continue
Blow charges <F> <D>



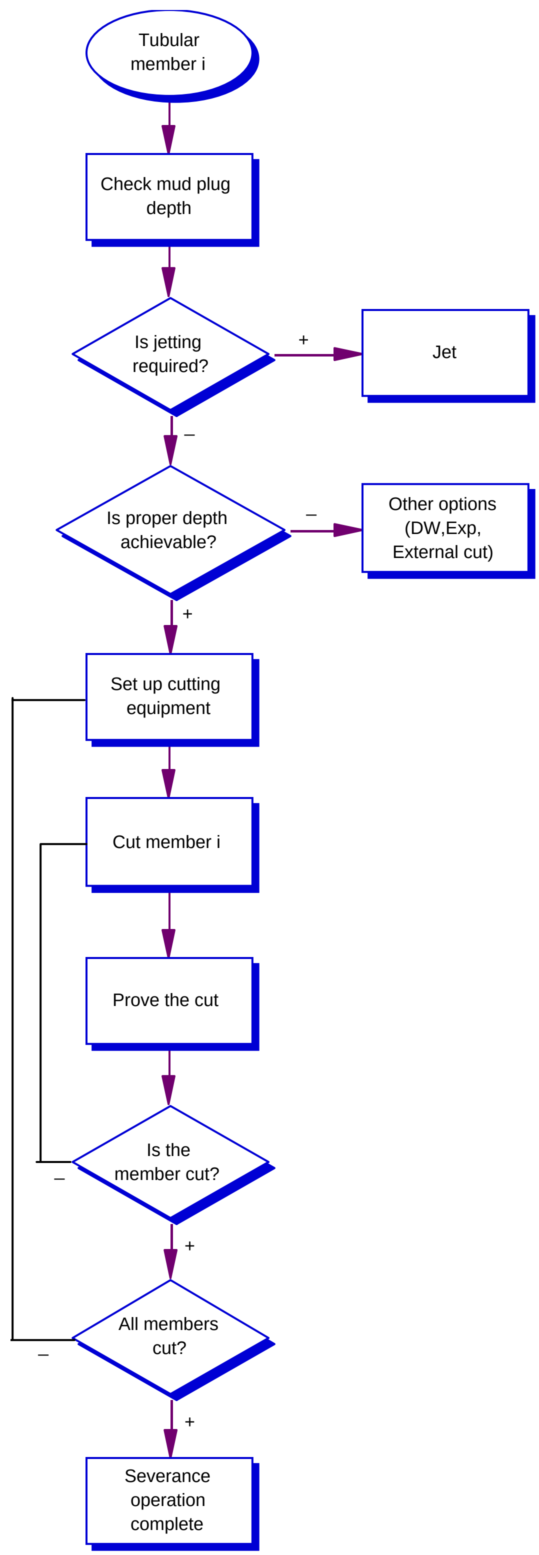
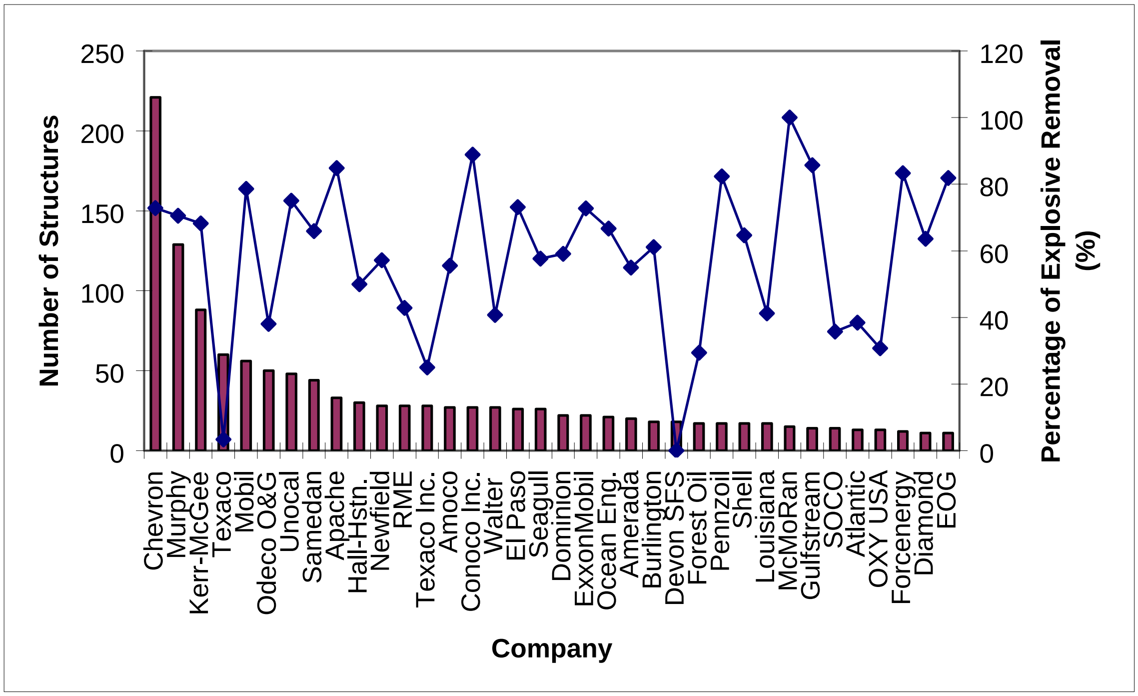


Figure B.5: The Abrasive Water Jet Cutting Process.



250
200
150
100
50
0
Number of Structures
120
100
80
60
40
20
0
Percentage of Explosive Removal (%)
Chevron
Murphy
Kerr-McGee
Texaco
Mobil
Odeco O&G
Unocal
Samedan
Apache
Hall-Hstn.
Newfield
RME
Texaco Inc.
Amoco
Conoco Inc.
Walter
El Paso
Seagull
Dominion
ExxonMobil
Ocean Eng.
Amerada
Burlington
Devon SFS
Forest Oil
Pennzoil
Shell
Louisiana
McMoRan
Gulfstream
SOCO
Atlantic
OXY USA
Forcenergy
Diamond
EOG
Company

Table B.1

Gulf of Mexico Active and Removed Structures by Configuration Type, Water Depth and Number of Slots (1947-2001)

Configuration Type	Water Depth (feet)	Number of Slots	Active	Removed
Caisson				
	0-80		1076	921
	80-200		117	112
	200+		5	1
Well Protector				
	0-80			
		0-6	271	193

Table B.2

Number of Structures Removed (R), Structures Removed by Explosive Technique (R_E), and the Percentage of Explosive Removals (p_E) as a Function of Water Depth and Configuration Type for the Gulf of Mexico (1986-2001)

Water Depth Range (m	Caisson			Well Protector			Fixed Platform			All		
	R	R_E	p_E	R	R_E	p_E	R	R_E	p_E	R	R_E	p_E
0-60	749	381	51	193	119	62	595	387	65	1,537	887	58
61-200				6	5	83	81	61	75	87	66	76
200^+										2	1	50
Total	749	381	51	199	124	62	676	448	66	1,626	954	59

Table B.3

Percentage of Explosive Removals by Configuration Type and Age Upon Removal in the Gulf of Mexico (1986-2001)

Age Upon Removal (Year)	Caisson		Well Protector		Fixed Platform	
	0-60m	61-200m	0-60m	61-200m	0-60m	61-200m

Table B.4

APPENDIX C
CHAPTER 3 TABLES

Table C.1

Design Space for Models I and II

Parameter	Model Ia	Model Ib	Model IIa	Model IIb	Model IIc
RES	N(100000, 10000)	N(100000, 20000)			
$d(t)$	U(0.08, 0.13)	U(0.08, 0.13)	U(0.08, 0.13)	U(0.08, 0.13)	U(0.08, 0.13)
P			LN(25, 3)	LN(25, 3)	
$P(t)$					LN(25, 3)
GR			U(15000, 30000)	U(15000, 50000)	U(15000, 50000)

Table C.2

Model I and II Regression Results

A(

Table C.3

APPENDIX D
CHAPTER 4 TABLES

Table D.1

Summary Statistics for Structures Removed in the Gulf of Mexico

Lease Categorization	Parameters	Caisson	Well Protector	Fixed Platform	All
I	$\overline{Q}\ (t_{lp})$ (BOE)	50,973	91,584	52,608	57,238
	$\overline{R}\ (t_{lp})$ ($)	604,667	1,147,691	698,593	733,805
	IDLE (yr)	(2.6, 3.9)[a]	(3.2, 4.6)	(1.9, 2.6)	(2.3, 3.2)
	Q/RES*	(0.43, 0.23)	(0.38, 0.18)	(0.38, 0.20)	(0.40, 0.20)
	RES (MMBOE)	1.02	2.06	4.20	3.10
	n	170	73	389	632
II	$\overline{Q}\ (t_{lp})$ (BOE)	32,000	30,700	36,174	32,798
	$\overline{R}\ (t_{lp})$ ($)	392,006	384,021	522,685	422,867
	IDLE (yr)	(6.5, 6.1)	(8.0, 7.6)	(4.6, 4.8)	(6.3, 6.2)
	Q/RES*	(0.34, 0.21)	(0.29, 0.19)	(0.26, 0.16)	(0.31, 0.20)
	RES (MMBOE)	1.71	3.00	6.83	3.21
	n	397	124	171	692
III	$\overline{Q}\ (t_{lp})$ (BOE)	36,693	25,588	39,606	35,035
	$\overline{R}\ (t_{lp})$ ($)	531,191	354,210	575,522	507,282
	IDLE (yr)	(3.9, 4.2)	(4.1, 4.0)	(3.6, 4.6)	(3.8, 4.3)
	Q/RES*	(0.41, 0.25)	(0.35, 0.19)	(0.35, 0.18)	(0.40, 0.23)
	RES (MMBOE)	1.58	3.88	6.16	3.53
	n	78	35	53	166
IV	$\overline{Q}\ (t_{lp})$ (BOE)	39,061	22,832	39,429	37,495
	$\overline{R}\ (t_{lp})$ ($)	528,159	353,362	538,132	512,209
	IDLE (yr)	(8.9, 7.3)	(6.7, 5.5)	(7.1, 7.5)	(8.4, 7.2)
	Q/RES*	(0.27, 0.17)	(0.19, 0.10)	(0.23, 0.13)	(0.26, 0.18)
	RES (MMBOE)	2.21	2.51	11.83	3.71
	n	224	30	46	300

Footnote: (a) Ordered pair (x, y) denotes mean x and standard deviation y.

Table D.2

Average Production Threshold Levels At/Near the Year of Last Production – Lease Category I

Structure Type	Water Depth (ft)	n	$\overline{Q}\ (t_{lp})$ (BOE)	$\overline{Q}\ (t_{lp} - 1)$ (BOE)	$\overline{Q}\ (t_{lp} - 2)$ (BOE)	$\overline{Q}\ (t_{lp} - 3)$ (BOE)
Caisson	0-100	140	50,106	120,809	158,112	144,080
	101-200	30	53,196	205,617	259,381	165,009
Well Protector	0-100	34	51,749	140,063	211,940	230,572
	101-200[a]	39	125,427	244,752	256,661	270,160
Fixed Platform	0-100	173	48,042	163,978	284,005	294,172
	101-200	140	56,922	224,423	281,210	322,129
	201-400	76	42,911	280,082	334,861	397,075

Footnote: (a) Includes 5 structures in the 200+ category

efBT10.02 0 0 10. 5 struc48001 re0264985.,0e0264985.,0e0264985441 S9 TwTc-gor,0etruct1522 0.4800[((48001 re0264985.,0e0264985.,0e0264985441 S9 TwTc-g735 Tw[(6985441 S9 TwT

Table D.4

Average Production Threshold Levels At/Near the Year of Last Production – Lease Category II

Structure Type	Water Depth (ft)	n	$\overline{Q}\ (t_{lp})$ (BOE)	$\overline{Q}\ (t_{lp} - 1)$ (BOE)	$\overline{Q}\ (t_{lp} - 2)$ (BOE)	$\overline{Q}\ (t_{lp} - 3)$ (BOE)
Caisson	0-100	376	30,959	96,127	142,145	179,518
	101-200	14	33,155	53,670	99,175	158,244
Well Protector	0-100	103	23,832	72,639	117,468	146,701
	101-200	20	67,355	212,480	329,858	539,504
Fixed Platform	0-100	107	25,197	82,540	104,389	154,998
	101-200	51	41,349	138,647	162,908	253,433
	201-400	15	89,712	478,356	527,775	611,107

Table D.5

Average Revenue Threshold Levels At/Near the Year of Last Production – Lease Category II

Structure Type	Water Depth (ft)	n	$\overline{R}\ (t_{lp})$ ($)	$\overline{R}\ (t_{lp} - 1)$ ($)	$\overline{R}\ (t_{lp} - 2)$ ($)	$\overline{R}\ (t_{lp} - 3)$ ($)
Caisson	0-100	376	385,188	1,183,751	1,815,805	2,244,257
	101-200	14	457,331	785,508	1,225,973	1,932,231
Well Protector	0-100	103	261,355	884,105	1,554,026	1,812,339
	101-200	20	1,034,012	2,851,025	4,331,782	5,938,351
Fixed Platform	0-100	107	350,700	1,179,240	1,698,004	2,529,227
	101-200	51	675,103	2,069,231	2,509,057	3,605,908

APPENDIX E
CHAPTER 5 FIGURES AND TABLES

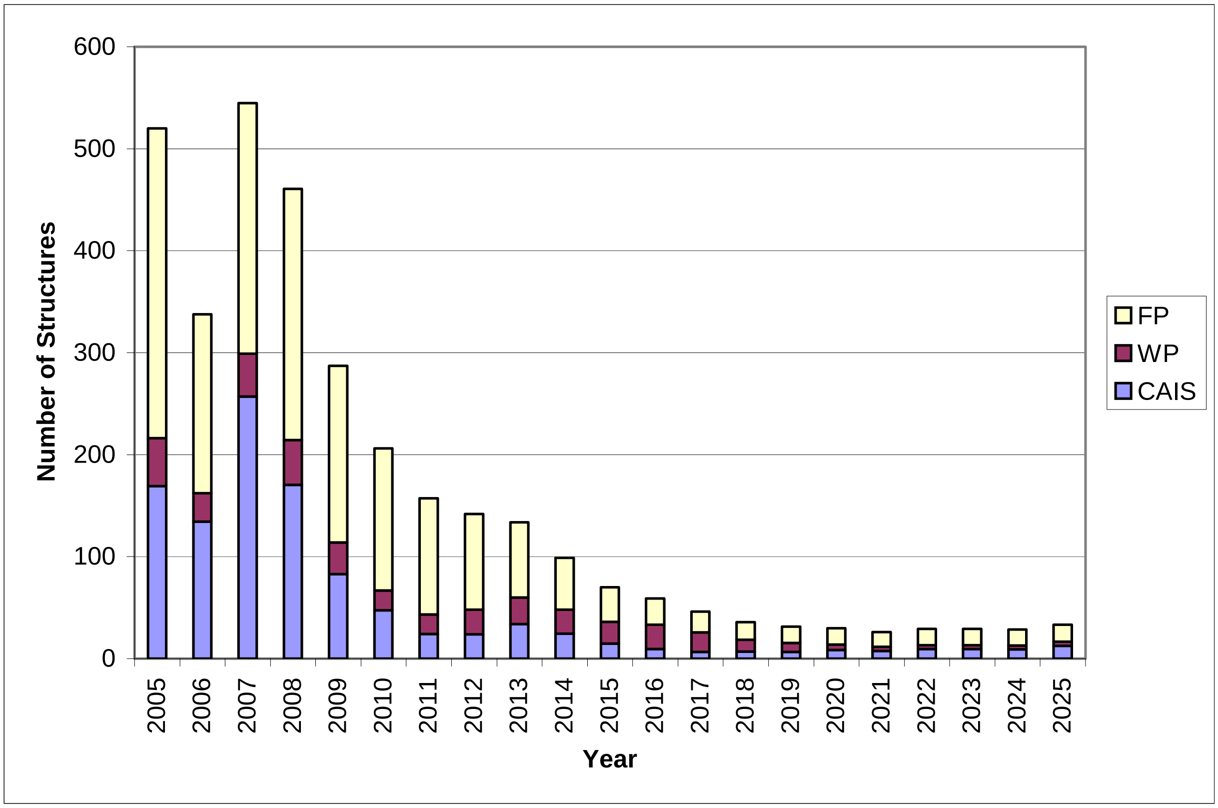
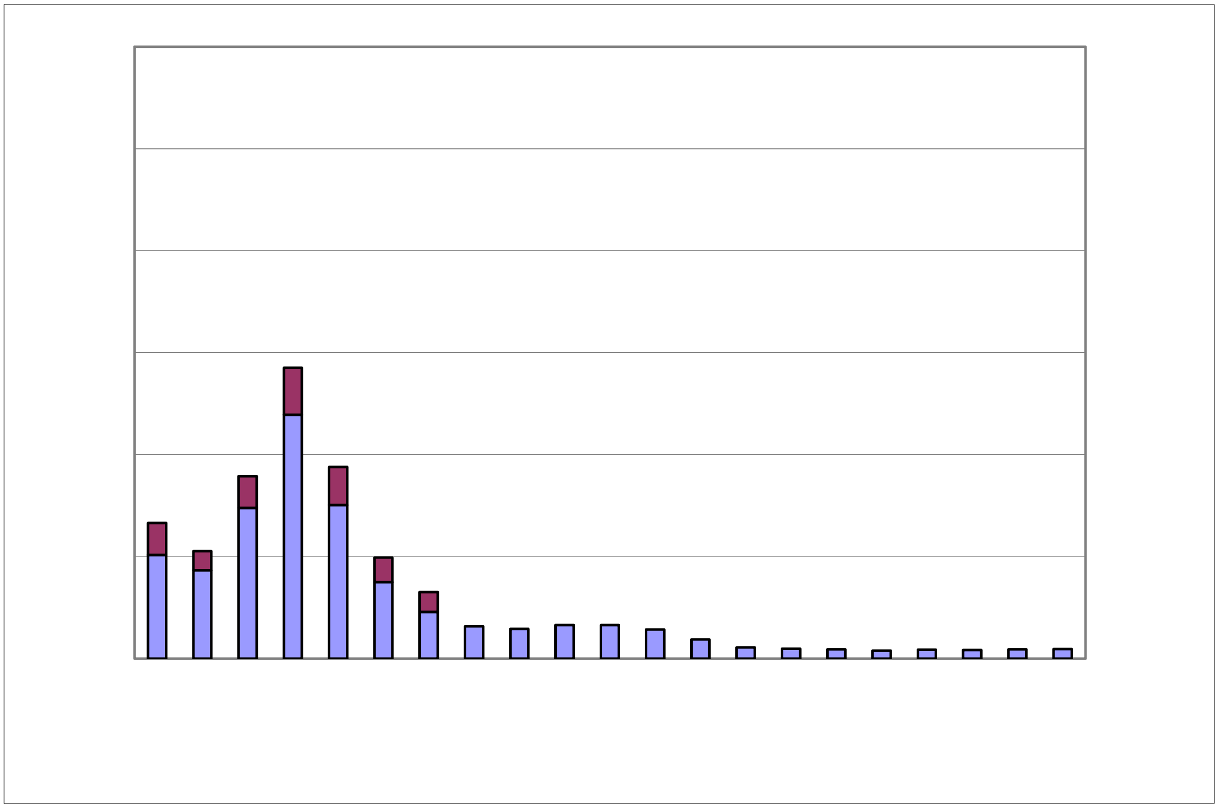


Figure E.1: Central GOM Production Threshold Structure Removal Forecast.



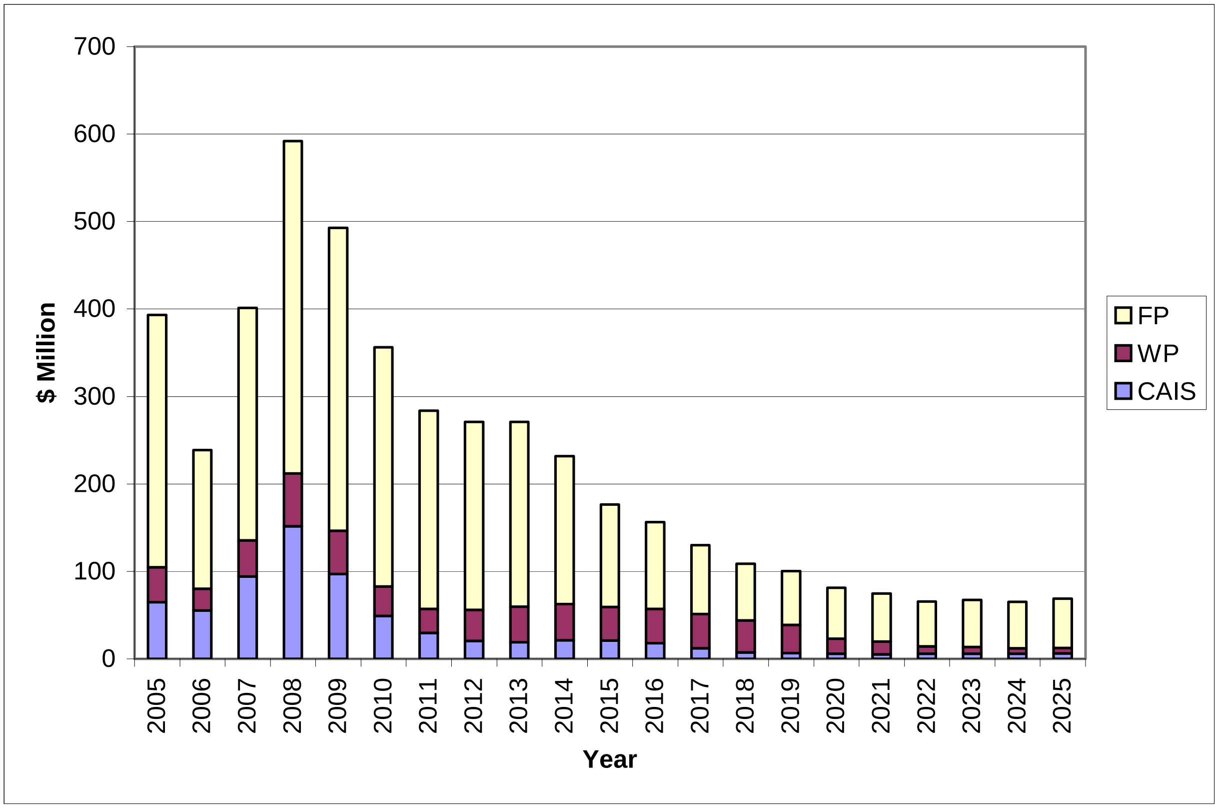


Figure E.4: Central GOM Revenue Threshold Removal Cost Forecast.

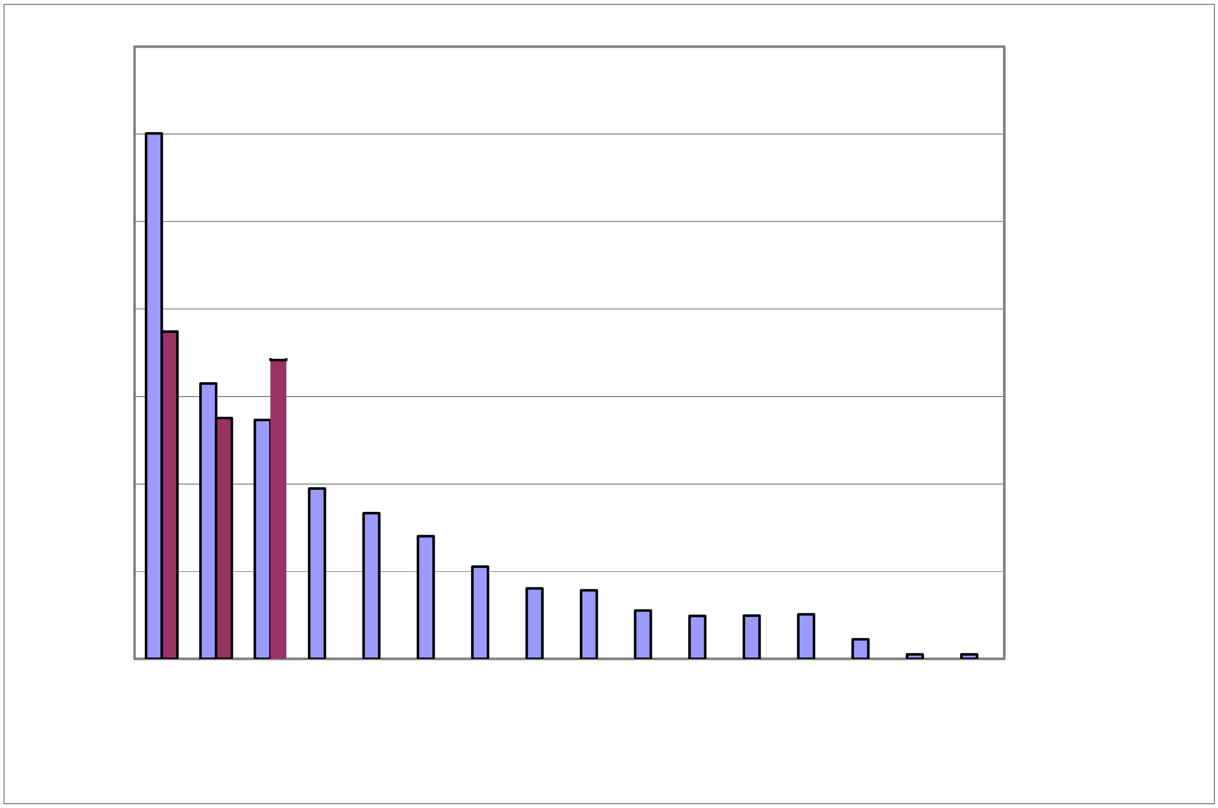


Table E.1

Number of Structures Removed in the Gulf of Mexico (1973-2002)

Year	Caisson	Well Protector	Fixed Platform	Total
1973	1	0	0	1
1974	4	1	0	5
1975	24	9	3	36
1976	20	8	2	30
1977	10	5	2	17
1978	18	3	5	26
1979	21	4	10	35
1980	19	8	9	36
1981	16	2	6	24
1982	8	2	5	15
1983	22	6	10	38
1984	25	14	14	53
1985	30	11	14	55
1986	16	8	10	34
1987	10	2	11	23
1988	55	8	36	99
1989	48	9	37	94
1990	60	11	37	108
1991	57	16	44	117
1992	48	13	45	106
1993	78	30	64	172
1994	43	16	66	125
1995	59	8	46	113
1996	49	15	55	119
1997	92	14	71	177
1998	36	11	29	76
1999	74	18	46	138
2000	52	20	69	141
2001	33	15	58	106
2002	24	17	54	95
TOTAL	1,052	304	858	2,214

Table E.2

Active, Idle, and Auxiliary Structures on Active Leases (2003)

k	Number of active leases with *k* active structures	Number of active structures	Number of idle structures	Number of auxiliary structures
1	944	944	291	129
2	245	490	141	79
3	84	252	96	66
4	35	140	84	43
≥ 5	48	348	286	123
Total	1,356	2,175	898	440

Table E.3

Table E.4

Idle and Auxiliary Structures on Inactive Leases in the Gulf of Mexico (2003)

Water Depth	WGOM	CGOM

The Department of the Interior Mission

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

The Minerals Management Service Mission

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

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

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