Coastal Marine Institute

A Review and Update of Supplemental Bonding Requirements in the Gulf of Mexico

Authors

Mark J. Kaiser

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ABSTRACT

In the mid-1980s, large oil and gas companies began to divest their portfolio of properties in the Gulf of Mexico (GOM). As smaller companies built up their production assets, concern was raised that the U.S. government was exposed to financial risk if abandonment responsibilities were not met. To ensure that the government is adequately protected from incurring costs associated with offshore lease abandonment, the Minerals Management Service (MMS) required operators to post a supplemental bond if at least one working interest owner on a lease does not satisfy a minimum threshold financial capacity. A supplemental bonding formula was developed in the early 1990s based upon the estimated cost to decommission offshore infrastructure. The purpose of this study is to update the supplemental bonding formula to account for changes in the cost environment and technology over the past two decades, and to present risk-adjusted alternatives to represent the uncertainty inherent in the implementation of any formula mechanism. We review the objectives of the MMS supplemental bond program and provide a set of guidelines in formula development. MMS policy on supplemental bond requirements is reviewed along with background information on decommissioning operations. The objectives of a bonding formula are described along with the tradeoffs that occur in all formula mechanisms. The philosophy of making rational tradeoffs between cost and risks is common throughout the offshore industry, and our recommendation is to select bonding levels in a risk-adjusted basis to balance the need of the government to minimize its decommissioning exposure at an acceptable level of risk. The factors that impact government decommissioning exposure is highlighted, along with detailed cost estimates of plugging and abandonment, structure removal, and site clearance and verification operations.

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removal operations and describe the factors that impact cost. Structure preparation, pipeline abandonment, and removal cost across several levels of categorization are developed as well as first-order regression models for removal cost.

Wells are drilled to explore for, delineate,

1. BACKGROUND AND REMOVAL STATISTICS

1.1. Introduction

The U.S. government sells the right to explore for hydrocarbons and develop tracks on the Outer Continental Shelf[1] (OCS) at periodic sealed-bid auctions. The bidding variable at these auctions is a cash payment, or “bonus,” which must be paid to the government before the lease becomes effective. Once the lease becomes effective, a rental and royalty payment is required.[2] Operators buy the right to extract natural resources on federal lands subject to royalty and rental payments, a commitment to operate in an environmentally sound manner, and to remove facilities at the end of the useful life of the lease. When bidding on properties, operators incorporate many factors in their evaluation, such as the probability of a commercial discovery, expected reserves and development cost, expected level of competition, and an estimate of the cost to remove the facility. The government accepts less money up-front in the bonus payment in exchange for the commitment on the part of the operator to remove facilities if the lease results in production.

The MMS is required to ensure that current and future development of offshore oil and gas resources are performed in a way that is operationally safe and safeguards the environment. Once production facilities reach the end of their service life, MMS is obligated to ensure that decommissioning operations protect the safety of workers and environmental integrity, while also ensuring that the decommissioning operations conform to the regulations and do not create future residual liability.

From the operator’s point of view, decommissioning represent a cost to be incurred in the future, while from the government’s perspective, decommissioning represents a risk of noncompliance and potential financial liability. A general bond is required on all leases to ensure compliance with rent, royalties, environmental damage and clean-up activities not related to oil spills, abandonment and site-clearance, and other lease obligations. The level of activity on the lease determines the amount of the general bond. When the cost to meet lease obligations exceeds the amount of a general bond, and the lessee cannot demonstrate the financial capability to meet these obligations, a supplemental bond is also required. Current MMS policy requires a lessee to submit a supplemental bond when the MMS estimate of cumulative potential end-of-lease liability is greater than 25% of the lessee’s net worth.

On each lease, the MMS considers all lessees, operators,[3] and operating rights[4] interest owners to be jointly and severally liable for all lease obligations. In other words, a company that sells its property remains liable for decommissioning if the current owner(s) do not comply with the

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[1] The OCS is the part of the continental shelf beyond the line that marks State ownership; i.e., offshore lands under Federal jurisdiction.

[2] The rental fee is on a per-acre basis and royalty is equal to a specified fraction of the value of hydrocarbons produced if the drilling program is successful.

[3] The operator is the individual, partnership, corporation, or other business entity having control or management of operations on a leased area or portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an MMS-approved operating rights assignment.

[4] Operating right is a leasehold interest that entitles the holder to conduct drilling and related operations, as well as responsibilities for the cost of development and operation of the property, and all lease liabilities created or established during ownership.

terms of the lease. If a property has current or previous working interest owners who are not financially capable, or if a property does not have any previous owners, then the property will be put up for sale. If a property is marginal or decommissioning liability is greater than the value of the lease, then it is unlikely that a buyer will be found for the property. Decommissioning commitments, nonetheless, have to be fulfilled. If the cost of decommissioning turns out to be greater than the supplemental bonds on the lease, then there is a problem, since the U.S. government is the party of last resort and would incur financial liability. Supplemental bonding is meant to protect the U.S. government against incurring financial liability, but as we observe above, it is one link in a long chain of events that have to occur before triggering liability.

Each producing lease in the OCS represents a different level of decommissioning risk to the government. Risk events may be triggered by occurrences specific to a few participants, such as a bankruptcy or blowout, or by events that impact several operators simultaneously, such as a hurricane event. Fortunately, the default rate of operators in the Gulf of Mexico (GOM) has historically been extremely low and the impact on operations to date minimal. Over the past two decades, only two operators in the GOM were unable to meet their decommissioning obligations. In both cases, because there was a previous record title holder of the lease who was financially capable, the federal government did not have to incur any expense (Kruse, 2007). In recent years, however, an increasing number of operators have approached the MMS to seek compensation when the cost of decommissioning operations exceeds their posted bond levels. Of course, the government does not compensate operators if their bonding levels are not sufficient to meet their commitments, but it is interesting to note the occurrence of such events and the implications on current supplemental bonding levels.

The MMS approach to computing end-of-lease liability is defined according to an empirically-derived formula (Table A.1) and has worked successfully in the past, but because the bonding formula is calibrated to projects performed in the early 1990s, there is an obvious need to update the formula to reflect current operating costs and technology. As part of a review of bonding requirements in the GOM, the MMS proposed that the supplemental bond formula be updated using more recent data and a risk-adjusted assessment be considered when setting levels. The authors were tasked with providing a recommendation for an updated supplemental bonding formula.

The purpose of this study is to discuss the tradeoffs and objectives in setting supplemental bonding levels in the GOM. We motivate the framework of our analysis and develop a risk-adjusted methodology. In this chapter, we summarize decommissioning activity in the GOM and review the legislative history of bonding requirements. Federal regulations associated with decommissioning are also outlined. We conclude by characterizing the general nature of offshore abandonment operations.

1.2. Development and Decommissioning Activity in the GOM

1.2.1. Exploration and Development Wells

The number of exploration and development wells drilled in the GOM on an annual basis is shown in Figure A.1. Exploratory (wildcat) wells are drilled in an area with no known hydrocarbon reserves, while delineation and development wells are used to delineate a known deposit and then produce it. A successful development well will produce hydrocarbons, while ‘success” for an exploratory well may not actually result in production. Onshore, discovery wells are usually turned into producers, while offshore, successful exploration wells may be plugged and abandoned because the location is not optimal for field development. Successful exploratory wells are usually protected with a caisson or well protector, and as delineation wells are drilled, the field will be developed with additional infrastructure. From 1947-2007, a total of 35,660 wellbores[5] have been drilled in the GOM: 13,665 exploratory wells and 21,875 development wells (Figure A.2).

Drilling activity dropped off significantly in 2007 due in large part to the intense recovery efforts associated with the 2005 hurricane season. The last time drilling activity in the GOM fell below 400 wells drilled was in 1992 (the year another hurricane - Andrew - entered the gulf). The ten-year (1995-2005) average number of wells drilled in the GOM is 501, while in 2006 and 2007, a total of 408 and 332 wells were drilled. The total number of exploratory and development wells by water depth category is shown in Table A.1. Since the mid-1990s, deepwater exploratory wells have played an increasingly important contribution to the total number of wells drilled.

1.2.2. Temporary and Permanent Abandonment

All producing wells pass through the same initial and final state, beginning with completion and ending with abandonment. After a well is drilled to target depth, it is evaluated to determine if it should be completed. Eventually, all wells become inactive because of diminished economic returns due to marginal oil and gas production or mechanical problems with the completion or downhole production equipment. When a well stops producing, it may either be shut-in (SI), temporarily abandoned (TA), or permanently abandoned (PA).

When an exploratory well is under evaluation or when a flowing well is no longer economic to produce, the well will often be temporarily abandoned. Wells destroyed by a hurricane will be TA’d if operators intend to re-enter the well at a later date. Wells that may be sidetracked for redevelopment may also be TA’d. Operators shut-in wells for minor problems and before the appearance of a hurricane. Shut-in operations are easier to perform and to re-enter at a later date, but require a stringent inspection schedule. TA operations are more expensive to perform but require less inspection and oversight. The cost to re-enter a TA well is also more expensive than a SI well. At the end of the life of a lease, when lease production ceases, all the wells on the lease must be permanently abandoned. SI and TA wells are thus considered a temporary or transitory stage, while a PA well is the terminal state of a wellbore.

The annual number of TA and PA operations in the GOM is shown in Figure A.3. The large number of TA operations in 2006 and 2007 is the result of the 2005 hurricane season. To date, about 19,167 wells have been PA’d and 2,000 wells TA’d (Figure A.4). The number of wellbores that remain to be PA’d is the difference between the total number of wells (exploration and development) drilled and the cumulative number of permanent abandonments. The inventory of wellbores circa 2007 that remain to be PA’d currently stands at about 16,500 (Figure A.5).

[5] Wellbores are defined as the original borehole. Sidetrack and bypass wells are not counted in this tally.

1.2.3. Structure Type

1.3. Outer Continental Shelf Bonding Program

The objective of the OCS bonding program is to ensure that all entities performing activities under the jurisdiction of MMS provide or demonstrate adequate financial resources to protect the U.S. government from incurring any financial loss.

1.3.1. Bond Requirements

Each lease is reviewed to ensure the lessees or co-lessees have adequate financial coverage to provide for the performance of all lease obligations when the designated operator and/or lessees cannot fulfill their requirements. Securities ensure that operators fully comply with all regulatory and lease requirements, including rents, royalties, environmental damage cleanup and restoration activities, abandonment and site clearance, and other lease obligations.

All leases and right-of-ways[7] (ROW's) are required to have a general bond regardless of the financial strength or supplemental bond waiver status of any of the lessees. The supplemental bond program was developed to provide the federal government additional protection against incurring costs involved specifically with abandonment and site clearance activities. The MMS determines the need for additional security by reviewing a lessee's financial ability, record of meeting obligations, and projected financial strength (MMS, 2001).

1.3.2. General Bonds

The designated operator of a lease is required to provide a general lease surety bond or pipeline ROW bond before the MMS will issue a new lease or approve a lease, ROW assignment, or operational activity plan.

Leases are designated as no operations, exploration, or development, and incur general bonds based upon the level of activity: (a) No Operations – a $50,000 lease-specific or $300,000 area-wide general bond with no MMS-approved operational activity plan; (b) Exploration – a $200,000 lease-specific or $1 million area-wide general bond for leases in a proposed exploration plan (EP) or a significant revision to an approved EP; (c) Development – a $500,000 lease-specific or $5 million area-wide general bond for leases in a proposed development and production plan (DPP) or a significant revision to an approved DPP. All ROW permittees must have a $300,000 ROW pipeline bond (MMS, 2001).

A review of bonding coverage is performed when operators request for a change of designated operator; an initial EP; an initial DPP; an initial Development Operations Coordination Document (DOCD); or a significant revision (i.e., a supplemental plan) to an approved EP, DPP, or DOCD; or request an assignment of a lease with an approved EP, DPP, or ROW plan.

1.3.3. Supplemental Bonds

The supplemental bond program was developed to protect against liability associated with decommissioning activities. Using historical data from the period 1989-1993, the MMS

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[7] A right-of-way usually refers to a grant by MMS for the construction and maintenance of a pipeline and associated structures on the OCS.

developed a bond level to ensure that the cost incurred in plugging and abandoning wells and removing facilities was covered.

The MMS computes end-of-lease liability by estimating the cost to plug and abandon all boreholes, scrap and remove onshore all structures, and site clear and verify a lease according to the algorithm shown in Table A.1.

A lessee’s supplemental bonds, cumulative liabilities, and financial strength may be reviewed at any time, but generally, initial reviews are conducted when a lessee submits an EP for approval. Subsequent reviews are conducted when a lessee requests MMS approval of: an assignment of the lease record title interest (lessee of record), or a portion of the record title interest in a lease; significant revision to an approved EP; DPP or a significant revision to an approved DPP; DOCD or a significant revision to an approved DOCD; application for a pipeline ROW or modification to an existing pipeline ROW; assignment of record title of an existing or approved pipeline ROW permit; and significant revision to an approved pipeline installation plan (MMS, 2001).

1.4. Federal Regulations

The operator is required to submit form MMS-124, “Sundry Notices and Reports on Wells,” and receive approval prior to plug and abandonment operations. Form MMS-124 contains information on the reason the well is being plugged, a description of the work requirements, and an assessment of the expected environmental impacts of the operation and the procedures and mitigation measures taken to minimize such imp manner in which explosives are used offshore to mitigate the environmental impact (Federal Register, 2002).

All abandoned well and platform locations in water depths less than 91 m (300 ft) must be cleared of all obstructions present as a result of oil and gas activities. For clearance purposes, locations are defined as follows:

- Exploratory or delineation wells drilled with a Mobile Offshore Drilling Unit: 300 ft (91 m) radius circle centered on the well,
- Single-well caissons: 600 ft (183 m) radius circle centered on the well,
- Platform: 1,320 ft (402 m) radius circle centered on the platform geometric center.

Platforms and single-well caissons in water depths less than 91 m (300 ft) are trawled for clearance verification. The MMS preferred verification technique is to drag a standard trawl net across 100% of the site in two directions. In some cases, alternative site verification techniques such as side scan sonar or documentation of sweep assembly results have been used. At the conclusion of the operation, a completion report is submitted to the MMS detailing the removal operation and certifying that the site has been cleared.

1.5. Characteristics of Offshore Decommissioning

1.5.1. All Offshore Fields Have End-of-Life Decommissioning Cost

The value of a lease at any point in time is determined by its production rate, hydrocarbon prices, remaining reserves, upside potential, operating cost, and decommissioning liability. When the market value of a field is zero, the discounted value of the remaining reserves is equal to the discounted cost of abandonment.

As long as the property value of a lease exceeds one year of cash flow, enough value usually remains in the lease that other buyers will have an interest in acquiring the property (Haag, 2005). When the value of a lease becomes negative or falls below one year’s cash flow, the pool reme is
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Each decommissioning project requires a case-by-case evaluation and is similar to field development in the sense that the project is unique in terms of the requirements of the operation, equipment used, site and market conditions at the time of the activity, contract terms, and operator preferences.

Decisions about when and how an offshore structure is decommissioned involve issues of environmental protection, safety, cost, and strategic opportunity. The factors that influence the timing and method of removal are complicated and depend as much on the technical requirements and cost as on the preferences established by the contractor, scale economies, and the scheduling of the operation.

1.5.3. Decommissioning Occurs In Distinct, Temporally Disjoint Stages

Decommissioning operations occur in stages over disjoint time frames. Each stage typically involves several types of activities.

1.5.3.1. Project Management and Engineering

The engineering planning phase of decommissioning consists of a review of all contractual obligations and requirements from lease, operating, production, sales, or regulatory agreements. A plan is developed for each phase of the project, and the process of surveying the market for equipment and vessels is initiated. Engineering personnel may be sent to the site to assess the work requirements, and the project management team will report on the options available, including the scope of work that needs to be performed and how best to prepare the bid. Permits are secured from the MMS to plug and abandon wells and pipelines, remove structures, and verify site clearance. Permits are also required in piping and equipment that contained hydrocarbons. All modules to be removed separately from the deck are cut loose, and the piping, electrical, and instrumentation interconnections between modules are cut. Work needed to prepare the modules for lifting is also done at this time. The fluids and agents used to purge and clean the vessel must be disposed by pumping them downhole through an injection well or to storage in tanks and onshore disposal in accord with MMS regulations. Equipment and other metallic debris are sent onshore to recycle or scrap, while non-metallic debris is sent as waste to a landfill.

1.5.3.4. Pipeline Abandonment

According to MMS regulations, pipelines with diameters > $8\frac{5}{8}$ inches that are installed in water depths < 200 ft are buried at least 3 ft below the mudline.[8] For lines $8\frac{5}{8}$ inches and smaller, a

has been an important cost reduction driver, but additional technological progress is not expected to play a significant role in reducing cost in the future.

Decommissioning operations are generally routine and involve standard equipment and procedures. There are no significant barriers to practice or entry, so new firms can form relatively quickly and easily if demand and supply imbalances create the conditions for new business ventures to enter the market.

1.5.6. Decommissioning Operations Occur Over Short Time Scales

Typically, decommissioning operations are completed over time scales that range from a few days to several weeks. SC&V activities usually take several days to perform, while plugging a well and removing a structure may take one to three weeks or longer. P&A and SC&V are usually performed on a dayrate basis, with the primary cost component due to the variable cost from the vessel dayrate and equipment rentals. Labor and fuel are secondary cost components. Removal operations are often performed under turnkey ("lump sum") contracts with weather risk held by the operator.

1.5.7. Decommissioning Operations Usually Have Low Carrying Cost

Since decommissioning represent a liability to operators with no promise of increased cash flow, operations are usually not fast tracked. Federal regulations require that all infrastructure on a lease be removed within one year after production on the lease ceases, so until lease production ceases, idle wells and structures often accumulate until sufficient scale exists to economically and efficiently perform the operations (Kaiser and Mesyanzhinov, 2004). In the 2005 hurricane season, operators learned that carrying a large inventory of inactive structures and wellbores carries the risk of potentially significantly higher decommissioning cost if destroyed or severely damaged. The risk of significantly higher cost should provide sufficient incentive for operators to decommission structures that no longer serve a useful economic purpose.

1.5.8. Many Factors Influence Decommissioning Costs

The cost to decommission offshore structures is influenced by a large number of variables and events that vary across each stage of the operation, and as in most offshore activities, tend to depend on factors that cannot be modeled accurately. Competition levels for services are usually high throughout the year, but seasonal variations often exist. High competition stabilizes cost in normal markets, and supply and demand forces are a dominant factor impacting cost volatility. General inflationary pressures are also present,

infrastructure are higher than under normal conditions, often ranging between 5-50 times more than conventional abandonment, and in some cases, can be significantly[9] more expensive.

Structures destroyed in a hurricane are found lying horizontally on the ocean floor, often in a tangled web of steel. When a structure fails, the pipes that cased the wells will bend and may collapse. Debris over and around the wells must be cleared and vertical sections of pipe accessed before the wells can be plugged and abandoned. In extreme cases, an operator may have to access the vertical portion of the wellbore or drill a relief well to access the old wellbore. Seafloor debris is cut by divers or remotely operated vehicles (ROVs). Divers do the work with limited access and poor visibility, and the tasks are often complex and require the design of new tools. ROVs can reduce the need for divers, but in most cases, they are unable to perform all the operations required and are expensive to operate. Complete removal may not be technically feasible or may pose unacceptable risks to diver personnel. If the integrity of the platform is sufficient, the platform can be lifted and transported to shore or a reef site; otherwise, the toppled structure will have to be cut and removed in pieces, or dismantled at site in a manner that satisfies site clearance requirements (Kaiser and Kasprzak, 2008).

[9] Taylor's 8-pile fixed platform at Mississippi Canyon 20, for example, was destroyed by a mud flow incident during Hurricane Ivan. The structure collapsed and was moved 800 ft from its original location and submerged nearly 75% below the mudline. Estimates for cleanup operations have ranged up to $500 million (Taylor, 2007). Taylor has sold off all of their producing assets and leases, except the MC20 platform, effectively exiting the Gulf.

2. FORMULA GUIDELINES

2.1. Introduction

Rational tradeoffs between cost and risks is common throughout the offshore industry, and in this chapter we espouse a similar set of guidelines in the development of a bonding formula. The objectives of a bonding formula are described along with their tradeoffs. We advocate the selection of bonding levels that balance the need of the government to maintain its decommissioning exposure at an acceptable level of risk. We also highlight the factors that impact the government's decommissioning exposure. We begin with a brief review of cost estimation techniques to provide the motivation for the limitations inherent in all bonding formula.

2.2. Decommissioning Cost Estimation

2.2.1. Cost Categories

Most decommissioning operations occur in distinct stages, and the manner in which contracts are written across each stage and how activities are accounted for and reported determine what categories arise and how cost is allocated across category. Cost allocation methods vary with each project and contractor, but most decommissioning projects are described through the following categories:

- Project Management and Engineering
- Plugging and Abandonment
- Structure Preparation
- Pipeline Abandonment
- Conductor Removal
- Structure Removal
- Site Clearance and Verification
- Miscellaneous

Work activities typically fall across one or more categories, and may be classified within a common (miscellaneous) category, such as diving and cutting, debris removal, cleanup, catering, etc. or allocated according to prescribed measures. Structure preparation, pipeline abandonment, mobilization/demobilization, and conductor removal are often aggregated within the structure removal category, which leads to the following three categories:

- Plugging and Abandonment (P&A)
- Structure Removal (REM)
- Site Clearance and Verification (SC&V)

Structure removal is usually the largest cost category, contributing anywhere from 50-80% of the total cost of decommissioning, followed by plugging and abandonment (25-50%) and site clearance and verification (5-10%). On an individual project basis, substantial variation exists depending on time, location, and operator characteristics (Twachtman and Byrd, 2008). Plugging and abandonment cost can be substantial, for instance, depending on the number and complexity of the wellbores and well access, while clearance and verification rarely constitutes more than 5% of the total cost of any operation. Project management and engineering for integrated service providers may add 5-15% to the total cost of a project.

2.2.2. Cost Estimation Procedures

Decommissioning cost estimates can be performed in a number of ways: using engineering models, historical data, statistical relations, stochastic models, scaling rules, activity breakdown, and expert input. In practice, a variety of techniques are applied, depending on the requirements of the estimate, the time and resources available, and the experience of personnel. Models of the (de)construction process and market environment in which physical activities occur are used in cost estimation. The success of th

10% to over 100%, depending on the time and assumptions involved in the estimation, the success of the operation, and the occurrence of events outside the control of operators. In offshore decommissioning, a large number of uncertain and unpredictable factors contribute to variability, including the downhole and weather conditions, market supply and demand, and the extent of preparation. The causes of uncertainty are numerous, and often, the manner in which individual factors impact costs are intractable.

An additional complication is that data sources that are available for analysis are usually small, from a specific sector (or company) of the industry, and often fail to identify those factors which make each operation unique. We are thus limited in our ability to understand why costs behave in a particular way. Our ability to infer cost trends is similarly limited, and hence estimates of decommissioning cost are only indicative of general trends relative to a specific model environment and sample set, and should only be interpreted with an understanding of their limitations.

2.2.4. Decommissioning Costs Are Market-Driven and Dynamic

Decommissioning costs are not static, and will vary over time with the market conditions for vessels and labor, the market rates for scrap steel, and various other time-dependent factors. While decommissioning costs are impacted by general inflationary pressures, they are not as volatile as traditional construction activities in the upstream sector (e.g., fabrication, drilling), since there is no significant material usage (e.g., steel) required; the cost of chemicals, fuel, and other consumables[13] usually play a small role in the total cost of the operation; and the activities are usually of short duration and scheduled at opportunistic times for contractors. Decommissioning activities are specialized but can be performed by a wide sector of the industry, and there are no significant barriers to entry which would be expected to create abnormal cost pressures.

2.3. U.S. Government Decommissioning Exposure

2.3.1. Each Producing Lease Represents a Different Level of Decommissioning Risk

Each producing lease in the OCS represents a different level of risk to the government. When a company declares bankruptcy or cannot meet lease abandonment obligations, all the lease properties in which the company is a record title holder or holds operating rights, as well as all leases in which the company held previous interest, trigger a risk event.

For a company default to trigger government decommissioning liability, several events would have to occur simultaneously. We demonstrate the sequence of events that need to occur to generate government liability (Figure B.1).

The government faces the most risk from leases that do not have at least one financially capable current or previous working interest owner. In the event that a working interest owner cannot meet lease abandonment obligations, the responsibility of decommissioning would be shared among other working interest participants. If there are no other working interest owners of the (aseq) property, or if the current owners, either individually or collectively, are not financially capable to meet the obligation, then any and all of the lease's previous owners would be required to assume responsibility. In the event that there are no previous record title holders able to meet the financial commitment of abandonment, the institutions that hold the company debt will try to sell the property to minimize their losses.

If the present value of lease production exceeds the expected cost of decommissioning, or has at least one year cash flow greater than abandonment liability, the lease may be sold to a third party who will produce until the economic limit and then assume decommissioning obligations. Otherwise, if the property is late in life and does not hold sufficient commercial reserves to cover the cost of abandonment, it is unlikely that a buyer will come forth. The value of the property and the level of production relative to decommissioning liability is another important element that determines risk exposure.

Finally, only in the event that the cost of decommissioning exceeds the posted bond level will the U.S. government be faced with decommissioning liability. If the cost of the operation falls below the posted bond, the government would hold no financial liability, since the costs are fully covered. If the cost of the operation exceeds the bonding level, then the government exposure would be the difference between the actual cost and posted bond.

2.3.2. Decommissioning Exposure Is a Function of Several Stochastic Variables

Each producing lease in the GOM can be considered to hold a certain amount of "decommissioning risk" to the government. The level of risk depends upon the number of current and previous record title holders and their financial capacity, the level of production relative to the cost of decommissioning, and the decommissioning expense relative to bonding requirements. Each event has a probability of occurrence which in most cases is difficult to compute.

2.3.2.1. Financial Capacity and Ownership Structure

The number of responsible parties associated with a lease and their collective financial capacity is a key determinant of the amount of decommissioning risk a lease holds. The ownership structure of oil and gas leases can be very complex. Transactions occur through farmouts, carveouts, acquisition and divestitures. Networking and overriding royalty interests create a multi-layered network of owners which serve as a protective mechanism for the government. With each additional user (i.e., owner) the probability that the government will be faced with decommissioning liability is reduced. Bankruptcy is not a common occurrence in the GOM, butJ20.325 0 ToB strength of parties is sufficient, this will also serve to mitigate nearly all the risk exposure. All current owners are jointly responsible. If there are no other current owners, then all previous owners are responsible.

2.3.2.2. Value of Reserves Relative to Decommissioning Liability

Decommissioning liability can create a large risk for the buyer when the abandonment costs exceed the value of reserves. Marginal leases that

2.4.1. Bonding Requirements Need to Balance Multiple Objectives and Tradeoffs

A bonding formula is meant to provide financial assurance to the government that the owners of a lease will be able to return the property to its pre-exploration condition upon cessation of production. Bonds are aimed at reducing – not eliminating – the risk of noncompliance, and so the appropriate level of risk that the government should hold is a matter of discourse and consensus.

The level of bonding to meet decommissioning obligations is usually intended to represent the level of commitment by the operator under the assumption of current prices, costs, and technology. Bonding formulas require special consideration, however, since they need to account for a high level of uncertainty in operations and cost estimation, while reasonably reflecting market conditions expected to hold over the near-term future. There is also the issue of whether a bonding formula should account for the cost the government would incur in performing decommissioning – as opposed to reflecting operator cost – since the government would likely incur greater cost under normal conditions, and possibly, significantly greater cost in unusual circumstances.[14]

What is the proper balance between the government's risk exposure and an operator's bonding requirements? How much decommissioning exposure should the government be expected to hold? Since supplementary bonding applies to all leases where at least one owner does not satisfy a specific financial threshold, any formula that sets bonding commitments at a high level would entail an incremental cost to operators, potentially discouraging or preventing investment among small companies, while placing additional economic burden on development and property transactions. On the other hand, bonding levels that are set at average cost do not adequately account for the possibility of cost falling above posted levels, essentially requiring that a portion of the risk be held by the government. If an operator is unable to perform their decommissioning obligations, for example, and the government was responsible to complete decommissioning activities, a host of troublesome litigation could potentially arise[15] in such a situation.

2.4.2. All Bonding Formula Have Limitations and Constraints

The adequacy of a bonding formula is based on our ability to estimate decommissioning cost today and forecasting cost for the time period in the future in which the formula is to be valid. All decommissioning cost estimates are uncertain because project uncertainties and structural variations cannot be adequately captured in a formula using a limited number of variables. Further, even if the precise cost of an operation could be established in advance, the future cost of that operation will be uncertain because of the nature of market conditions, weather, and the impact of other unpredictable events.

In developing a bonding formula, we are constrained by the sample set in which empirical relations are derived along with the number and type of factors available for assessment.

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[14] For example, if one or more small companies hold a large number of marginal properties that are destroyed in a hurricane, it is possible that the companies will default on their lease obligation, and the cost of decommissioning will be significantly higher than average cost.

[15] For example, where would the funds to successfully complete abandonment come from? If decommissioning was not performed adequately, would the government be held liable? Can the government permit a project for which it is the title holder? These questions, while intriguing, lie beyond the scope of this report.

Decommissioning operations are performed by a number of different project management and

Current cost is estimated based on projects and market rates at a specific point in time, and because there is no time averaging or normalizing process, is subject to the variability of the sample when the estimation is performed.

To estimate expected future cost a model will need to be developed. One of the simplest models to employ is to apply average historical cost as the baseline, risk-adjust, and then adjust for expected inflationary effects over the time period of interest. If historical cost data are believed to be a reliable and reasonably robust method to estimate future cost, then this method will be sufficient. Since decommissioning operations are not subject to significant technological progress, the main driver to cost volatility is market conditions at the time of the event. If historic data is sufficiently "representative" and project requirements are "normal," then historic cost is likely to serve as an adequate guide of expected cost if future market conditions and project requirements are also "normal" during this time.

2.4.7. Standard Deviation Multiples Provide a Simple Risk-Adjustment Mechanism
The actual cost of decommissioning will always deviate from bonding levels determined by formula, but a well-specified formula will ensure that the magnitude and sign of the deviation is consistent with regulatory objectives.

It is suggested that the average cost of decommissioning per category be adjusted by a multiple of its standard deviation and inflation-adjusted for a specific future horizon. In this way, we do not attempt to forecast site specific conditions, future market conditions, the occurrence of exogenous events, or other conditions that are not predictable. Rather, recognizing the need of a bonding formula to set risk at a level commensurate with consequence, we propose historic average cost data per category as the baseline bonding level adjusted with appropriate risk and inflation factors.

Under normality assumptions of the cost data, each standard deviation multiple selected will cover the cost of projects that fall outside the range of the average. By selecting one or two standard deviation multiples, we capture most of the upside uncertainty expected to occur within each categorization, which is consistent with a low-to-moderate risk aversion level and the ability of the model to encompass regulatory requirements.

2.4.8. A GOM Bonding Formula Needs to Be Algorithmic and Class Specific
Offshore structures in federal waters currently exist off the coast of Alaska, California, and the GOM. In the Alaska, Pacific Coast, and deepwater[17] GOM regions, only a few dozen structures currently exist, and so detailed engineering estimates can be performed at a structure level to assess liability and supplemental bonding requirements (Gebauer et al., 2004). For the deepwater regions, structures are owned by financially secure operators, and so the need for supplemental bonding is currently limited. In the shallow water region of the GOM, however, engineering estimates to assess decommissioning liability are not practical[18] or viable because of the large number and diversity of wellbores and structures. A general (generic) bonding formula is desired because the number of structures exceeds the ability to perform individual estimates.

Because of the variety of structures in the shallow waters of the GOM, an aggregate assessment needs to be performed, with cost normalized according to structure complexity, water depth, and other factors, as appropriate, across each stage of the operation. Cost estimates are intended as first-order approximations of abandonment expenses, based on site charactles in tei9.0954 Tw[(es, bC ta)4ede

selection, reuse opportunities, strategic alliances, etc. – but this would not be the scenario facing the U.S. government. If the MMS had to assume responsibility for decommissioning one or more offshore structures, it may need to secure the services of a project management firm specializing in decommissioning to manage the logistics and permitting process. Potential conflicts of interest may arise. Scale economies would not be realized, but it is conceivable that alternative removal methods (i.e., reefing) would be available to reduce costs. If safety or environmental concerns (e.g., leaking wells) warranted immediate action, activities would need to be performed on an emergency basis at additional cost. Insurance may be required to avoid liability issues. In the event that the U.S. government needed to assume abandonment obligations, we would expect the cost to be "more similar" to a major or large independent performing the operation than a small or mid-size independent.

2.5 ntial c3Sh expeNe rBe Exposo

2.6. Conclusions

The objective of the MMS bonding program is to en

3. SUPPLEMENTAL BONDING RISK-ADJUSTED TABLEAU

3.1. Introduction

For all leases in the GOM in which estimated lease liability exceeds a specified financial bonding review cycle, it is recommended that the duration in which the formula is to apply should be specified explicitly.

3.2.3. Inflation Factor

Cost indices are available for different segments of the oil and gas industry, but offshore decommissioning is a highly specialized sector which is not tracked by the U.S. Census Bureau or other agencies. There are also no good proxy measures for cost inflation that we believe is representative of the sector. Activities that depend on support and construction vessels may require an inflationary adjustment, due to changes in labor rates, fuel, demand requirements, etc. or may be relatively immune to inflationary pressures. Supply and demand conditions in the GOM determine market rates, and because the uncertainty and magnitude in market rates typically dominates inflation uncertainty, empirical data may not provide clear trends on the occurrence/absence of inflation effects. To complicate matters, inflationary effects are also sample-dependent, and unless a large and diverse sample is obtained, may not be representative of general GOM conditions. Inflationary adjustments need to be applied with caution.

3.2.4. Inflation Adjustment Period

A bonding formula is specialized by the user for the period p, starting from year T, and extending through the time horizon $T + p$, $[T, T + p]$. The value of p is user-defined. If the expected cost to perform decommissioning activity i in year j is denoted by $C_i(j)$, how do we set the bonding level B_i over the time interval $[T, T + p]$ if inflationary factors are to be incorporated in the formula?

If B_i is set at the level

representative, and care mu

3.2.8. Risk Adjustment

Bonding levels are adjusted upward from the baseline (average) cost by 1, 2 and 3 standard deviation multiples.[19] There is a trade-off in the selection of the risk adjustment, since any increase above average cost will impose a greater financial burden[20] on operators, while holding bonding levels at average cost will transfer a greater portion of decommissioning exposure to the government.

For each stage of decommissioning, four bonding levels are presented:

- Average Cost: *C* (high risk)
- Risk-Adjusted Cost I: *C* + 1**SD* (moderate risk)
- Risk-Adjusted Cost II: *C* + 2**SD* (low risk)
- Risk-Adjusted Cost III: *C* + 3**SD* (very low risk)

Qualitative risk indicators "high", "moderate", "low", and "very low" are assigned to each category based on the frequency in which actual costs are likely to exceed the average costs under normal conditions. The use of the indicators is subjective and meant to be interpreted in a relative sense. It is difficult to establish in a quantitative manner the correspondence between risk and decommissioning exposure, but by incorporating one or more standard deviation terms, the government is less likely to be exposed to liability arising from inadequate bonding levels. Average cost represents the base case and is considered a high risk category. By adding one or two standard deviation multiples to the base case, the risk-adjusted cost presents a lower risk that decommissioning will exceed[21] posted bonds.

3.3. General Methodology

The methodology adopted is to recognize the uncertainty that exists in cost estimation and to incorporate a portion of this uncertainty explicitly within the bonding formula. The approach in setting bonding levels follows the same steps for each stage of decommissioning:

1) Collect, review, and analyze cost data from a sample of GOM operations over the past decade, with particular emphasis on the most recent 5 years.
2) Filter, process, and disaggregate data according to a consistent level of categorization, normalizing with respect to structure type, water depth, operator type, and related factors.
3) Compute average cost and standard deviation for each sample based on a water depth and structure type categorization.
4) Use standard deviation as a risk adjustment factor according to perceived levels of risk and the tradeoffs involved with protecting against small probability events.

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[19] Fractional multiples could also be used.
[20] The cost to the operator is not the only premium, since less capital would be available for use in E&P activities that might otherwise be used.
[21] In some circumstances, even risk-adjusted costs may not be adequate to perform decommissioning activities.

5) Balance the sample data to obtain average cost and standard deviation

- Scale economies apply in the operation; e.g., wells may be plugged individually or on a multi-well contract.
- Only "normal" operations aor.e1osider ed. P&A work for hurricane destroyed structures/wells aor.not.e1osidered.
- Only surface systems or wells with a surface tree in less than 300 ft water depth aor.e1osidered. Hybrid wells and wet.trees (subsea wells)[22]

- Removal cost for caissons and well protectors include pipeline abandonment operations. Removal cost for fixed platforms includes structure preparation activity and pipeline abandonment operations.
- Removal costs by independents and majors are computed as separate sample averages, and an equal-weighted class average is computed.
- Cost data is not inflation adjusted.

3.5.2. Removal Summary Cost

Removal cost and standard deviation data by structure type and water depth is summarized for independents in Table C.5 and majors in Table C.7. In Table C.6, a risk-adjusted removal cost tableau is computed from the average and standard deviation data presented in Table C.5. In Table C.8, a risk-adjusted removal cost tableau for majors is computed from the sample average and standard deviation data presented in Table C.7. The data for independents is analyzed in detail in Chapter 5 and in (Kaiser et al., 2008). Data for majors was provided by MMS. Due to the variation in average cost and standard deviation between independents and majors, the bonding levels escalate at different rates.

311.1. Model2leaC&V Tableau

3.5.3. Removal Bonding Tableau

The risk-adjusted removal bonding tableau is computed as the equal weight average of the independent operator sample average and major sample average elements depicted in Table C.6 and Table C.8.

3.6. Site Clearance and Verification Bonding Levels

3.6.1. Model Assumptions

- Tine period of the formula applies for 2008-2013.
- SC&V will be performed using net trawling under dayrate contracts.
- Water depth is limited to 300 ft or less.
- Structural units are grouped and counted in terms of caissons and all other jacketed structures (well protectors and fixed platforms). Due to)5 1 Tf-1.4961 -1.7206 TD0 Tc0 T

decommissioning is presented in Table C.11. Three risk-adjusted levels are presented in Tables C.12-C.14 using standard deviation as a proxy for the risk-adjustment factor. The updated formula maintains the same structure as the legacy formula, but is only directly comparable across the P&A category, where we observe that average P&A cost since the early 1990s have increased roughly seven-fold. In the structure removal category, costs have increased 2-4 times greater than the legacy formula. Site clearance and verification cost are smaller in the new formula and are structure specific. In the legacy formula, removal cost is not specified with respect to structure type, and SC&V does not refer to the number or type of structure on the lease. In the new formula, structure type is specified across the removal and SC&V categories.

3.8. Illustrative Examples

3.8.1. Example 1

On lease A in 75 ft water depth, there exists an inventory of 5 producing wells, 18 idle wells and 3 service wells; and 2 caissons, 1 well protector, and 2 fixed platforms, as defined by the MMS. The supplemental bonding required on the lease if none of the working interest owners meet the minimum financial requirements of the MMS are determined as follows. First, we enumerate the

From Table C.12,

- P&A cost = 31 * $1,383,000 = $42.87 million;
- REM cost = 3 * $2,750,000 + 2 * $3,503,000 = $15.26 million;
- SC&V cost = 3 * $26,000 + 2 * $67,000 = $212,000;

which yields a total supplemental bond requirement of $58.34 million. A summary of the bonding requirements associated with the other risk categories is presented in Table C.16.

4.2. Wellbore Classification

4.2.1. Well Life Cycle

Every well has a unique life cycle in terms of its cost, duration, recovery, and value. Although these characteristics and attributes are specific to an individual wellbore, all wells pass through the same states, beginning with completion and ending with abandonment.

After a well is drilled to target depth, it is evaluated to determine if it should be completed. Formation evaluation is a critical step in exploration since it is the stage in which information about the presence/absence of hydrocarbon bearing reservoirs is acquired. A drill stem test may be used to evaluate the flow rates of hydrocarbons, and integrating the data with logs and other tests, leads to the completion decision. If a sufficient quantity of reserves is expected to exist, with value greater than the cost to complete the well, the well will likely be completed and produced. Over its life, the wellbore may be sidetracked, deepened, plugged back, or worked over one or more times.

Eventually, all wells become inactive because of diminished economic returns or technical problems. When a well stops producing, it may either be shut-in (SI), temporarily abandoned (TA), or permanently abandoned (PA). The MMS provides specific regulations for each state depending on the status of the well.

4.2.2. Shut-in Status

A SI well is a flowing well that has its christmas tree, master valves, wing valves, and subsea safety value closed. A well is usually shut in because of technical or operational problems of a temporary nature (e.g., in the GOM, wells are shut-in if they reside within the expected path of an approaching hurricane). A well can be maintained in a SI state for any length of time as long as proper periodic maintenance procedures are followed. MMS regulations specify that "… completions shut-in for a period of six months shall be equipped with either (1) a pump through type tubing plug; (2) a surface-controlled subsea safety valve, provided the surface control has been rendered inoperative; or (3) an injection valve capable of preventing backflow" (20 CFR, Ch.II, 250.801 (f)).

4.2.3. Temporarily Abandoned Status

When an exploratory well is under evaluation or when a flowing well on an active lease is no longer economic to produce, the well will often be temporarily abandoned. After the 2005 hurricane season, a large number of wells on destroyed infrastructure were temporarily abandoned as operators assessed field redevelopment strategies. In a TA operation, the wellhead is removed, the producing formation is isolated with plugs, and casing is plugged below the mudline and a corrosion cap is inserted above the mudline (Figure D.1). For TA wells, the operator must provide within one year of the abandonment and at one-year intervals, an annual report describing plans for re-entry to complete or permanently abandon the well (30 CFR, Ch 11, 250.703). Monitoring requirements for TA wells are less than for SI wells. From an economic perspective, the operator weighs the cost of ongoing maintenance activity against the benefits of postponing well abandonment. A number of considerations are involved in the decision, including remaining recoverable reserves, strategic planning, maintenance costs, and workover costs.

4.2.4. Permanently Abandoned Status

equipment, Naturally Occurring Radioactive Material (NORM) meter, handling tools, hoses, sand cutter equipment, chicksans, casing jack, tubing pipe, and hydraulic cranes. Supplies may be expendable (e.g., bridge plug, cement, water, drilling fluid, etc.) or nonexpendable (e.g., drill pipe, special tools, etc.).

4.3.3.2. Equipment Removal

The first step in the P&A process is to remove downhole equipment such as packers, production tubing, gas lift mandrels, and downhole pumps. The operator is required to make a diligent effort to remove all downhole equipment, but because of age and wellbore conditions, this is not always possible. Equipment removal is typically accomplished using a conventional workover or drill rig with the proper rated capacity. Equipment stuck in the wellbore may be left in place if approved by the appropriate agencies.

4.3.3.3. Wellbore Cleanout

The well is cleaned with circulating fluid to remove fill, scale, and other debris covering the perforations. The circulating fluid is required to have a sufficient density to control subsurface pressure and the physical characteristics to remove unwanted material. Back pressure valves may be installed in the well. After the wellhead is removed, the blowout prevention equipment is installed.

4.3.3.4. Cement Plugging

Well plugging procedures usually require a minimum of three cement plugs, but the exact number of plugs varies with the downhole conditions of the wellbore and the number of production zones. The MMS does not require that API class cement be used, but the cement must meet the approval of the District Supervisor. Cement is pumped into the well at the desired location and after several hours (8-12 hr) hardens to form a protective plug. Cement plugs are designed to fill a certain length of casing or open hole to provide a seal against the vertical migration of fluid or gas. Most plugs are 100 to 200 feet in length.

The basic method in plugging a well is to

- Squeeze the producing zone to eliminate the influx of fluid/gas,
- Place a plug near the middle of the wellbore or near a protective pipe shoe, and
- Place a surface plug within 200-300 feet below the mudline.

There are various techniques for setting the plug and a majority of slurry systems are placed through tubing, coiled tubing, drillpipe, or tremie pipe (Smith, 1993). The method used is dependent on wellbore conditions, regulatory requirements, and contractor preference. Squeeze cementing is a common technique, and in the bullhead method, cement is pumped from the surface and forced down the wellbore by pump pressure. In the braidenhead method, pressure is placed at the surface from the casing valve.

The balance method is frequently used to place middle plugs. In the balance method, cement slurry is placed through a tremie pipe by pumping a calculated slurry volume through the pipe equal to the height of the slurry remaining in the pipe following placement. The cement falls out of the pipe filling the void as the pipe is removed. Fluid spacers may be used both ahead and behind the cement slurry to aid in placement. The use of coiled tubing to set plugs is attractive from both economic and operational standpoints because of its widespread application in workover operations.

The dump bailer is a tool that contains a measured quantity of cement that is lowered into the

crew,[23] specified materials and supplies. The operator of the well will usually retain ownership of the wellhead and all tubulars (casing, tubing), and be responsible for the disposal of all fluids circulated from the wellbore and any other waste generated on location. Under a turnkey contract, the service company is paid a fixed fee (lump sum) in return for completing the job according to the contract specification. Turnkey contracts offer contractors incentives to finish a job in a timely manner, since the contractor retains the cost savings of early completion, but unless the job requirements are well-known, also exposes the contractor to additional risk in the form of capital, environmental, and technical distance to shore. The distinction between wellbore construction, may impair the capacity to perform P&A functions. Components which feature corrosion resistant alloys can mitigate the effects of sour fluids to some extent.

4.4.10. Well Access

In normal operations, P&A activity takes place from a platform or workboat, with procedures and tools designed for vertical access. For structures destroyed in a hurricane, the wellbores are lying horizontally on the seabed in various states of damage, and often require specialized solution (Segura and Blanchard, 2008). The loss of a platform can be compensated by the use of a liftboat, and to gain vertical access to wellbores, conductors will need to be cut by divers. Diver cuts are more hazardous and expensive than mechanical cutting, and because of limited access and poor visibility, progress is often slow and personnel are exposed to more risk than under normal conditions.

4.4.11. Technology

The application and use of advanced technology varies with the contractor and job specification. Tradeoffs exist between the cost-saving potential associated with new technology versus the start-up cost of learning; e.g., multi-function fishing techniques can reduce the number of trips required to cut and recover casing and the wellhead assembly in deepwater operations, but is also more expensive and difficult to apply (Goimome-0.0.vofmo-19.iJ-2acin s1-19r and.004he

4.5. Descriptive Statistics

4.5.1. Data Source

The database for analysis was compiled from jobs performed by Tetra Applied Technologies, L.P. in the GOM from 2002 through 2007. The sample set consisted of 256 jobs and 1,156 wells

15,800-22,300 $/day for turnkey contracts, and 11,800-17,200 $/day for the composite category (Table D.1). In 2006, the average daily cost increased significantly across both contract types, to $28,000/day for dayrate contracts and $23,200/day for turnkey contracts (Table D.2). The composite category averaged $26,100/day in 2006. High dayrates have continued into the 2007 season, reflecting the continued strong demand fo

In Table D.5, total cost is correlated against the number of wells of the job and the number of days to perform the service, as follows:

Dayrate Contracts: Total_cost = 5.5 ND + 56.8 NW

Turnkey Contracts : Total_cost = 18.4 ND + 9.6 NW

All Contracts: Total_cost = 12.6 ND + 24.4 NW

The model without the fixed term is more robust in all the formulations.

4.6. Scale Economies

Jobs are typically performed at a specific site. In some cases, contracts may be let on a field or area-wide basis, with wells located at several sites. As the number of wells in a job increases, there are at least two reasons why unit cost for P&A operations may decrease. If learning effects are present for multiple well operations, then as the contractor performs the service, they may become more efficient and this should be reflect

The reported data did not allow us to differentiate between the type of operation performed under turnkey and dayrate contracts. In normal years, turnkey contracts are often used on complex wellbores or uncertain operations. During the aftermath of the 2005 hurricane season, turnkey contracts were also the preferred mechanism to help operators reduce their financial exposure and operational risk associated with clean up operations. Job requirements for TA operations are not as rigorous as PA operations, and so for all things equal, the average cost of a typical TA job would be expected to be less than a normal PA job. Unfortunately, the distinction between these operations cannot be distinguished from the data entries, and so we cannot assess the impact of this factor on the cost data.

It would be desirable to correlate P&A cost with the characteristics of the wellbore, job and contract type, and the technical aspects of the operation, but such a correspondence is difficult to realize due to the complex and uncertain nature of the operation and the lack of reliable data. Even if downhole conditions could be modeled accurately, the degree of uncertainty due to topside factors can only be reduced, not eliminated, so P&A cost estimation will always exhibit a degree of uncertain and unpredictable characteristics.

4.8. Conclusions

Plugging and abandonment operations are considered one of the more variable portions of decommissioning because it is influenced by a host of uncertain and unpredictable factors. We enumerated the primary factors that impact P&A operations and provided descriptive statistics and trend analysis for the time period 2002-2007. A significant amount of the variability and uncertainty of working offshore is not captured in the descriptive variables, and our inability to describe wellbore complexity and other attributes will impact how P&A cost can be modeled. Reliable and comary l0644 01 T A 8 po7tions and pro2distin304-4.2(lex”002-20D0 m)8(60m)91borl.

5. COST OF REMOVAL OPERATIONS IN THE GULF OF MEXICO

5.1. Introduction

Since 1973, nearly 3,000 structures have been removed from the GOM, and over the past decade, an average of 136 structures per year have been decommissioned. The purpose of this chapter is to assess the cost of removal operations in the GOM in water depth less than 400 ft. We review project data over the past five years from Tetra Applied Technologies L.L.C., one of the main decommissioning service providers in the GOM. Our data set covers 120 projects and 133 structure removals, and represents $178 million in total cost, the largest collection of decommissioned structures analyzed to date.

The outline of the chapter is as follows. We revi and requires a floating rig. The number and type of wells associated with a structure is one indicator of structure complexity.

5.2.2. Caissons and Well Protectors

The basic size and function of an offshore structure result from the requirements of the development plan (McClelland and Reifel, 1986).

transport produced oil or gas to shore. A flowline is a pipeline that transports well fluids that originate at a subsea wellhead, manifold, or remote wellhead platform to the first downstream process component (API, 1999). Sometimes, depending on product quality, composition, and location, the produced fluid can be sent to shore or injected directly into an export line without processing. An injection line directs liquids or gases into a formation, wellhead, or riser to support hydrocarbon production activity (e.g., water or gas injection, gas lift, chemical injector lines, etc.).

Most flowlines and pipelines are composed of steel, but flexible pipe fabricated from metallic wires interspersed with thermoplastic layers may also be employed. Pipelines are characterized by their grade of steel, diameter, length, wall thickness, and many other factors. Gathering lines are typically short segments of small-diameter pipelines that can be as small as 4 to 6 inches, or as large as 12 inches. Subsea pipelines generally range from 12 to 36 inches. Typically, the diameter of the lines become larger the further downstream from the wellhead as more streams commingle. Pipelines are sized to handle the expected pressure and fluid flow of field production, but as production changes in quantity and location, pipelines may be converted, upgraded, extended, or looped. OCS pipelines may join pipelines carrying production from state waters to processing facilities or distribution pipelines located near shore or farther inland.

5.3. Cost Categories

Decommissioning operations in general, and removal activities in particular, involve a number of tasks that may be reported and categorized in various ways. Operations involve the mobilization/demobilization of multiple vessels, preparation activity, diving services, explosive services, conductor removal, pipeline abandonment, and waiting on weather. The manner in which costs are allocated across activity and category depends upon the requirement of the job and company accounting system. In our assessment, we aggregate cost across three categories: (1) structure preparation, (2) pipeline abandonment, and (3) structure removal. Activities that overlap more than one category are allocated in proportion to effort.

5.4. Factor Description

The time and cost to perform decommissioning activities depends on a number of factors. Several characteristics are observable, while many others are not, and there is no way to identify and measure all of the factors that impact operations. Removal operations are complex and subject to conditions specific to the job; simple causal relations are therefore usually inadequate to capture the drivers of cost variability. We provide a list of factors that impact the cost of removal operations, and although the list is not complete, it is meant to provide an indication of the complexity and uncertainty of operations. The factors we describe include the physical characteristics of the structure and pipeline, location, structure disposition options, company type and preferences, market conditions, deconstruction practices, the occurrence and duration of exogenous events, and contract specifications.

5.4.1. Structure and Well Type

Offshore structures and wells are classified according to their degree of complexity; structures are classified as caissons, well protectors, or fixed platforms; wells are classified as dry trees and

since it determines the time and cost for mobilization/demobilization, offloading and transport, and service cost. The location of the structure relative to shipping lanes and artificial reef sites also impact the removal options available to the operator, and subsequently, the cost of removal.

5.4.5. Water Depth

Water depth dominants process, design, and economic considerations in field development, and is a primary variable in offshore construction activities since increasing water depth generally requires the size of the rig and marine vessel to increase, reducing operational flexibility, and increasing the time and cost of the operation. Water depth correlates with the size and weight of the structure, increasing the size of the DB required in removal operations. Increasing water depth will also increase the sensitivity of the operation to environmental factors.

5.4.6. Removal Method

Removal alternatives are generally classified as total removal, partial removal, and toppling in-place. A structure "toppled-in-place" proceeds much like a complete removal operation, except that after the piles are cut and removed, the structure is pulled over and placed on its side on the seafloor (Figure E.4).

All Gulf coast states maintain artificial reef programs, and to date, more than 200 offshore structures have been converted to reefs, representing about 20% of the total number of structures decommissioned since rigs-to-reefs programs were created. Operators that transfer a platform into an artificial reef reduce the cost that they wo be re-used greatly diminishes due

The project management team overseeing the decommissioning activities, in consultation with the operator, prepares the bid package and specifies the work requirements to be performed. This information will include special requests, such as platform and jacket disposition, and preference (if any) for the severance method to be employed. The operator may also have special concerns or preferences that dictate that a specific method be employed,[32] which will impact the cost of the project.

5.4.13. Company Type

Companies approach decommissioning from different operating philosophies and business models which may lead to different cost structures. Small companies tend to be cost-minimizers, while large companies tend to focus on risk management, and these alternative perspectives will impact the cost of the operation. Large independents between offshore region. Market rates for DB spreads depend upon depth rating and crane vessel capacity.

5.4.16. Contract Specification

Removal contracts are most often written on a turnkey basis that includes weather downtime, except downtime due to named tropical storms, for work during the prime season (May 15 to October 15). In a turnkey contract, the service company bids a "lump sum" for the completed job. A lump sum optional bid may also be offered which gives the contractor the ability to quote an alternative decommissioning method not specified in the scope of work but which still meets all specifications and goals of the job. Depending upon the cost, operator preferences and perceived risk of the operation, the decommissioning mode will be selected and the contract specification written.

The team in charge of structure removal will let contract according to one or more functional activities. The project management team specifies the work requirements of the bid based upon the information available at the time. In most cases, the contractor is responsible to furnish all labor, equipment, and material, including a crane vessel with sufficient capacity, cargo barges, tugs, and necessary construction equipment to perform the operation. The base bid will normally assume that the contractor will dispose of all platform components, while the operator will accept the cost of the NMFS observers and aerial survey required for the use of explosives, and any delays associated with the severance specification.[33]

5.4.17. Negotiation

Each contract is site, time, technology and operator specific, and so it is difficult to quantify the final negotiation process that occurs. In general, however, the operator will try to write a contract as specific as possible to eliminate contingencies and minimize the cost/risk of unforeseen events. Contractors prefer operational flexibility, a wide time window, and contingencies when uncertainty exists. A wide time window allows contractors to schedule operations to efficiently use their service vessel fleet, allowing them to bid more competitively and ensure extra time for unforeseen events. Contractors also prefer the operator to accept any unexpected cost/risk associated with the operation; e.g., if explosive methods are used, the operator will frequently incur all the cost associated with marine observers, aerial surveys, diver surveys, as well as any delays associated with the presence of sea turtles, marine mammals, nighttime restrictions, pile flaring, etc. The final negotiation is a give-and-take process based upon the contract terms, precedence, market conditions, negotiation strategy, and the history of y of eo]TJ-32.9ce wind evts. ce wo4o independents, and one major.

2008 ranged between 1.2-3.3 times greater than cost reported for similar categories from the period 1998-2003 (Kaiser et al., 2003).

5.5.5. Structure Removal

The number of structures removed by water depth and structure type is shown in Table E.4. In total, 133 structures were removed in 120 projects with over half of the structures involving fixed platforms (80), followed by caissons (38) and well protectors (15).

5.5.5.1. Average Cost

Average removal cost per water depth and structure type is shown in Table E.5. The removal cost of caissons and well protectors increase with water depth. The average cost to remove a caisson in 0-100 ft is $500,000; in 101-200 ft, the average cost more than doubles to $1.2 million. Removal cost for fixed platforms range from $865,000 (0-100 ft) to $2.6 million (201-300 ft) and are about 1.5 times the cost of caisson removal. The standard deviations per category are large and frequently about half of the average – especially as the water depth increases – indicating that the water depth and structure type categorization is doing a somewhat better job of “explaining” the variation in the sample data.

We expect removal cost to increase with water depth and structure complexity because the size of the rig and the time of the operation are roughly proportional to these factors. However, recognize that our results are sample dependent and may yield significant individual variations.

In Figures E.5 and E.6, the average removal cost of caissons, well protectors, and fixed platforms are depicted in terms of water depth. We would expect fixed platforms, because of their variation in size and complexity, disposition options, and nature of the operation, to exhibit larger spreads in costs than caissons and well protectors. This is demonstrated in the plots, but we caution that this is not necessarily a generalizable result. Cost data for structures with minimal complexity are more tightly grouped and exhibit a better statistical fit than the fixed platform data.

5.5.5.2. Structure Disposition

Removal cost depends upon the removal options available to the operator. Among the 80 fixed platforms removed, more than half were reefed in place or towed to a reef site (Table E.6, Figure E.6). In 0-100 ft water depth, about a third of the structures were reefed, which increased to 84% of removals in 101-200 ft and 94% in 201-300 ft. These percentages are slightly higher than aggregate GOM reef capture statistics (Kaiser, 2006b) and represent the individual characteristics and circumstances of the sample elements. Projects performed in deep water were more expensive than on-shore removal, perhaps due million (201-300 ft), and as the number of piles per structure increased, there was an increase in cost with water depth. For 6- and 8-pile structures, removal cost ranged from $986,000 (0-100 ft) to $2.72 million (201-300 ft). The average removal cost of an 8+ pile structure is about twice that of a 3-pile platform.

5.5.5.4. Caisson Configuration

For caissons with skirt piles, removal cost ranged from $463,000 (0-100 ft) to $871,000 (201-300 ft). Caissons without skirt piles were more expensive to remove: $498,000 (0-100 ft) to $1.52 million (101-200 ft). See Table E.9. The sample size for the 0-100 ft category consisted of more than a dozen projects for each caisson type, and for these two categories, costs are quite similar. In the 101-200 ft water depth categories, the sample sets consist of less than 5 elements each, which may be partially responsible for the large differences observed.

5.5.5.5. Year of Removal

To underscore the variability inherent in the cost data, we consider the removal cost of fixed platforms over time. The number of fixed platforms removed per year is illustrated in Table E.10 and average removal cost is depicted in Table E.11. Average removal cost is generally increasing with water depth when sample sizes are sufficiently large, but across time, we observe the variation in cost that may occur. Unfortunately, it is not possible to precisely delineate why cost behave in this manner, but the usual suspects are believed to be responsible, namely, market conditions (supply and demand, which determine vessel dayrates), structure characteristics, and environmental conditions.

5.5.5.6. Total Cost

The total cost to remove a caisson and well protector is computed by adding pipeline abandonment and removal cost; and for fixed platforms preparation activity (Table E.12). We group caissons and well protectors together because they have reasonably similar functional characteristics and often do not require preparatory activity. For caissons and well protectors, the total cost of removal ranges from $686,000 (0-100 ft) to $1.5 million (101-200 ft). For fixed

Average removal cost as a function of total weight (deck, jacket, piles, and conductors) is depicted in Table E.14. Caissons are 2-4 times more expensive on a per ton basis than fixed platform removals. The average removal cost per ton of fixed platform is depicted in Figure E.7.

5.5.7. Activity Duration

Job duration is defined as the number of work days spent on a job in executing a specific set of activities or operations. Duration includes the direct time spent on the job, as well as indirect time in preparing for the activity. Mobilization/demobilization time is included in the duration estimates. Duration is an important metric in offshore operations since if the market rates for the vessels required and the duration for the project can be reliably estimated, then job cost can be approximated. Unfortunately, significant uncertainty exists in both duration and market rate estimates, making the predictive capacity of these relations limited.

The average time to perform preparation, pipeline abandonment, and removal activities is shown in Table E.15 according to water depth. Projects which involve more than one activity (e.g., preparation and removal) which did not break-out duration per category occurred in less than 10% of the sample and were excluded from analysis. Preparation and pipeline abandonment time are roughly equal, but because of the higher dayrates associated with diving and associated support vessels, the cost of pipeline abandonment will usually dominant preparation cost. The time to complete removal activities increases with water depth, which mimics (and is the reason for) the increased costs reported previously.

5.5.8. Structure Installation

Removal operations are essentially the reverse of installation activities. The cost to remove a structure of a specific type in a given water depth should therefore approximate installation cost for a similar structure in the same water depth category. Tetra Applied Technologies performed 20 structure installations (3 caissons, 5 well protectors, 12 fixed platforms) between 2003-2008. The sample is small but is sufficient to compare re

$$TC = \alpha_0 + \sum_{i=1}^{4} \alpha_i X_i \,,$$

where X_1 = WD = Water depth (ft), X_2 = WGT = Total structure weight (ton). X_3 = NP = Number of piles, X_4 = DUR = Duration (days). All the variables are numeric and the selection is based upon data availability, user preference, sample characteristics, and categorization level employed.

The total cost of structure removal is expected to increase with water depth and structure complexity, and so in a one-variable relation, the coefficient of the variable *WD* is expected to be positive and increase with complexity. In a multivariable model, we would expect cost to increase with total structure weight and duration. The nature of the sample set will dictate if specific relations hold.

Illustrative functional relations for removal costs are shown in Tables E.17 and E.18. The single variable cost models behave roughly as expected and exhibit reasonably good model fits and statistically significant coefficients. In the multivariable cost models, the results are mixed. Strong positive correlations are evident with duration and total weight. A negative correlation with number of piles reflects the characteristics of the sample data.

5.7. Limitations of Analysis

Decommissioning is governed by conditions unique to the structure, site, operator, and contractor, as well as the prevailing environmental, engineering, market, operational, and regulatory conditions at the time of the operation. The unique nature of offshore operations drives the variability observed in cost statistics, which can only be partially explained through factor analysis.

Sample select problems in statistics occur when the sampling is not random. In this study, all removal projects are performed by one service provider, and although they represent a large and diverse collection of structures and water depths, the observations cannot be construed as a random sample. Projects are performed by one company and represent mostly independent operators. We believe the data is representative of the independent sector but we cannot extrapolate our assessment to infer project cost for majors, except as a lower bound estimate.
All jobs were performed in water depth less than 350 ft. Deepwater and floating structures and subsea wells are significantly more expensive and complex to decommission, and extrapolation of the summary statistics outside the aforementioned categorization is not valid.

Decommissioning operations typically involve a number of activities which may overlap one or more categories, and if data is not properly reported and categorized, will bias summary statistics. Fortunately, because the cost data was complete and carefully recorded, we were able to minimize discrepancy and allocation bias in the study.

The data set was analyzed using standard statistical analysis. No additional processing of the data, “outlier removal,” or specialized regressions was performed. The statistical measures are believed to be reasonably representative of the removal cost of independent operators in the shallow-water Gulf of Mexico.

5.8. Conclusions

Removal operations are usually the greatest contributor to the cost of decommissioning, and for this reason, it deserves careful and regular review. Removal costs are highly variable because the operation is influenced by a host of uncertain and unpredictable factors. We enumerated and described the manner in which various factors may impact removal operations and provided descriptive statistics for the GOM covering the period 2003-2008.

A significant amount of the variability and uncertainty of working offshore is not captured in the descriptive variables, and our inability to describe the characteristics of each operation impact the manner in which cost can be accurately modeled.

Cost estimates are judgments, made by managers and engineers, of the costs expected to arise based upon a comparison of similar projects, site characteristics, market conditions, and the collective experience of the estimator. Project managers try to manage and reduce uncertainty, but cost estimates will always be uncertain because of project uncertainties, unpredictable and uncontrollable conditions, and imperfect information.

6. COST OF NET TRAWLING OPERATIONS IN THE GULF OF MEXICO

6.1. Introduction

In the United States, federal regulations require that all wells and offshore structures in the OCS be completely removed to a depth 15 ft (5 m) below the seafloor within one year after production on the lease ceases. After wells are plugged and abandoned and the structure is removed, federal regulations require that the site be verified "clear" by an independent third party.

A variety of techniques may be used to perform SC&V operations, but net trawling and diver survey are the most common in the GOM. In diver salvage, divers identify targets and attach lift lines to the debris, and a crane on a surface support vessel lifts the debris from the water bottom and places it on deck for subsequent disposal on land. Net trawling uses conventional trawling techniques with a reinforced net assembly to pick up debris on the water bottom. Diving spreads typically perform many different services throughout decommissioning, and it is usually not possible to isolate clearance services from other activities, such as structure preparation, pipeline cutting, dredging, etc. For the purpose of cost benchmarking, it is preferable to analyze net trawling operations rather than diver surveys, since net trawling is well defined, focused exclusively on clearance and verification activity, and the data is transparent and easy to interpret.

The amount of time involved to clear a site depends on a number of factors that are uncertain and unobservable, such as the amount, size, and type of debris present at the site; the equipment available to perform

6.2.1. Structure Type

The area that must be trawled for clearance and verification is determined by the structure type that previously occupied the site. Federal regulations require clearance operations centered on the well or the geometric center of the facility, with radius determined by the well or structure

6.2.6. Water Depth

Water depth is often a primary variable in offshore construction activities since increasing water depth requires the size of the vessel to increase, reducing operational flexibility and increasing the cost of the operation. For net trawling operations, however, the vessel size is fairly insensitive for water depth ranging up to 300 ft (91 m) or so. Water depth does contribute to the time to set and retrieve netting, and may be an important factor if a given depth threshold is exceeded; e.g., water depth greater than 300 ft (91 m) might necessitate using remotely operated used – standard shrimper nets and heavy-duty “Gorilla” nets – and are priced according to the cost of repair or if lost/unrepairable, as follows:

$$K_2 = \begin{cases} K_{21}, \text{Gorilla - net repairable,} \\ K_{22}, \text{Gorilla - net lost or unrepairable,} \\ K_{23}, \text{shrimper - net repairable,} \\ K_{24}, \text{shrimper - net lost or unrepairable.} \end{cases}$$

Separate contract components cover boards, dummy doors, cables, chains, and buoys that are lost or damaged[35] at the variable rate $\$K_3$/incident. The company renting the vessel must arrange for the disposal of trash collected from the operation.

Document preparation and a close-out report on the trawling operation to MMS NTL 98-26 specifications is charged at a flat rate of $\$K_4$/site.

6.3.2. Total Cost

Job specification is defined by the characteristics of the well/structure that occupied the site and the type of service requested by the operator. Job *J* is characterized by a number of factors, but only a few variables are typically recorded, such as the structure type (caisson (*C*), well protector (WP), platform (*P*)), the age *AGE* of the structure upon removal, and the water depth *WD* at the site.

The total cost of job *J*, *TC(J)*, is given by the value

$$\mathrm{TC}(J) = K_1 TD + K_{21} GR + K_{22} GU + K_{23} SR + K_{24} SU + K_3 M + K_4,$$

where *TD* = total number of days from dockside, *GR* = total number of Gorilla nets repairable, *GU* = total number of Gorilla nets lost or unrepairable, *SR* = total number of shrimper nets repairable, *SU* = total number of shrimper nets lost or unrepairable, and *M* = total number of incidental events. The value of the parameters K_1, K_2, K_3, and K_4 are specific to the terms of the contract and vary over time.

6.4. Descriptive Statistics

6.4.1. Data Source

Data for 308 jobs performed by B&J Martin, Inc. over the five-year period from 2001-2005 comprised the sample set. Jobs classified as “partially” completed or “incomplete”, and those operations sited in state waters, were excluded from analysis. To maintain the confidentiality of the data, no information regarding the operator was identified and only aggregate statistics are presented.

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[35] Repairs to rigging or towing blocks caused by hang-ups are put out to bid. The company renting or 308 joeTmamnt a-d( )Tj/TT

The use of Gorilla nets is often applied to older structures and platforms, and about 35% of platform jobs in the sample employed Gorilla nets. Only about 10% of caisson sites used Gorilla nets for trawling. It is unlikely that caissons will have debris that would necessitate the use of Gorilla nets, while for platforms - depending on the age, function, and prior clearance activities – Gorilla nets are more commonly applied.

6.4.3. Total Cost

The total cost of SC&V operations for caissons and platforms are tabulated in Table F.3 and Table F.4 according to jobs that employ only regular nets, jobs that apply Gorilla nets, and all jobs (regular and Gorilla net applications). The standard deviation of the total cost (*TC Deviation*) indicates the dispersion of the average. The variable *Percentage* reports the percentage of total cost that arises from the dayrate, which provides an indirect indication of the relative difficulty of the operation, since for difficult jobs, loss/damage will play a larger role in the total cost of the operation. *Percent Deviation* indicates the dispersion of the percentage variable.

the activity. Service time is unpredictable, and so average cost decomposed according to structure type was shown to be a useful benchmark to gauge SC&V cost commitments. Water depth did not appear to be a significant factor in determining SC&V cost.

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APPENDIX A

CHAPTER 1 TABLES AND FIGURES

Table A.1.

MMS Approach[a] to Estimate the Total Decommissioning Cost per Leasehold

Decommissioning Stage	Water Depth (feet)	Estimated Cost

Table A.3.

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

	Water Depth					
Structure Type[a]	0-60 ft	61-200 ft	201-600 ft	601-1,000 ft	> 1,000 ft	Total
CAIS	1970	488	4	0	0	2,462
FP/Manned	384	501	301	18	6	1,210
/Unmanned	860	1,135	301	3	0	2,299
/Total	1,244	1,366	602	21	6	3,509
CT	0	0	0	1	2	3
MOPU	2	2	0	0	0	4
SEMI	0	0	0	0	6	6
SPAR	0	0	0	0	14	14
SSMNF	0	1	0	0	0	1
SSTMP	0	1	1	0	1	3
TLP	0	0	0	0	10	10
WP	450	310	39	0	0	799
TOTAL	3,666	2,438	646	22	39	6,811

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

Source: MMS, 2007.

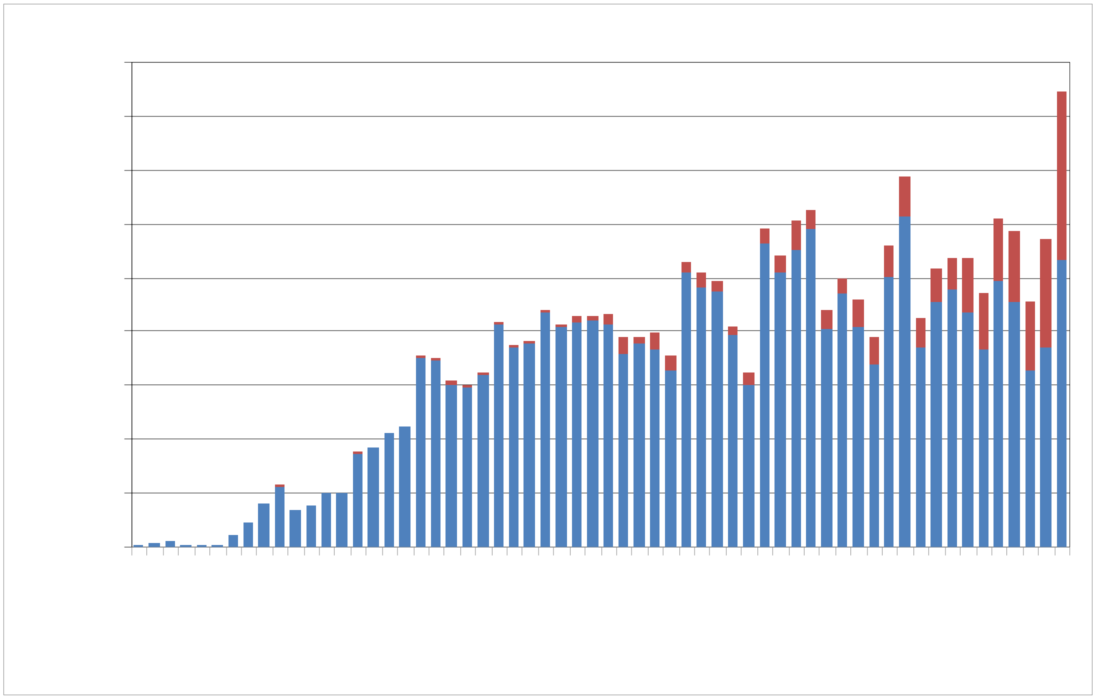
Table A.4.

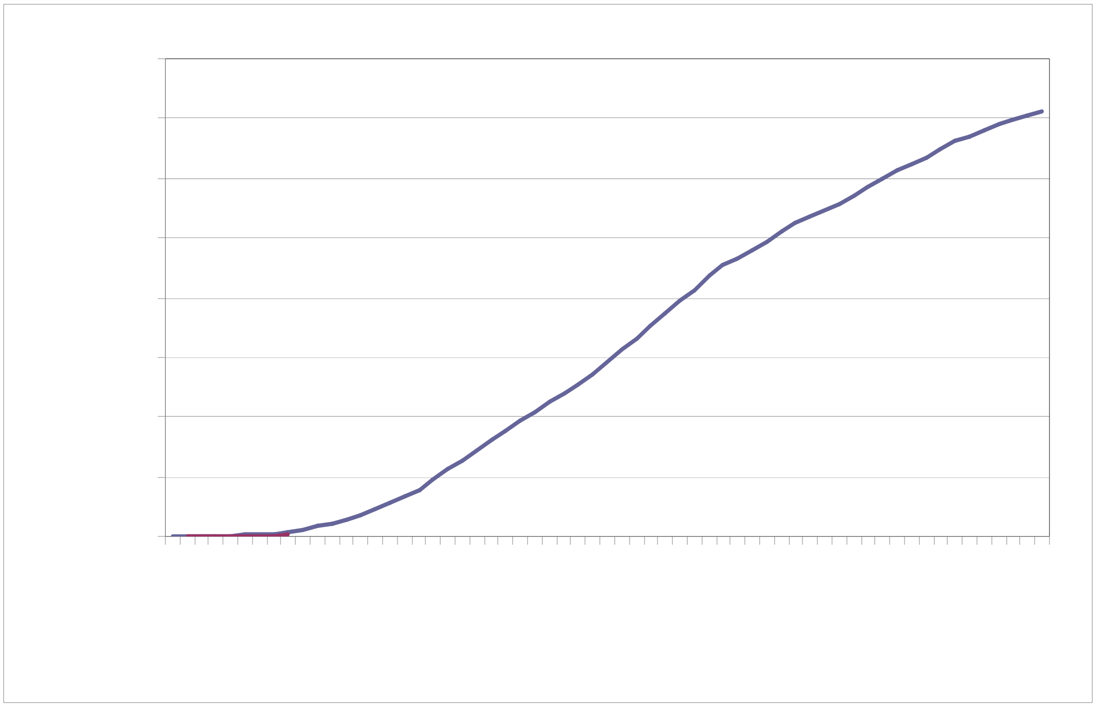
Structure Removals by Structure Type and Water Depth (1997-2007)

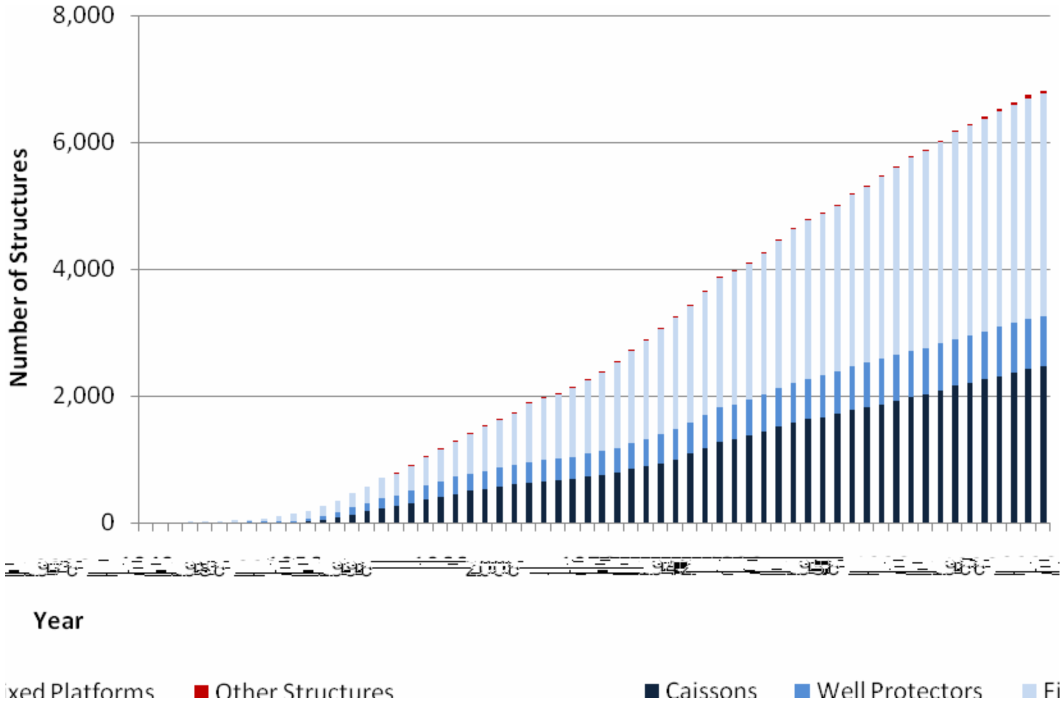
	Water Depth					
Structure Type[a]	0-60 ft	61-200 ft	201-600 ft	601-1,000 ft	> 1,000 ft	Total
CAIS	1,084	283	2	0	0	1,369
FP/Manned	39	68	30	1	0	138
/Unmanned	393	523	127	0	0	1,043
/Total	432	591	157	1	0	1,181
CT	0	0	0	0	0	0
MOPU	0	2	0	0	0	2
SEMI	0	0	0	0	1	1
SPAR	0	0	0	0	14	14
SSMNF	0	0	0	0	0	0
SSTMP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

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

Source: MMS, 2007.



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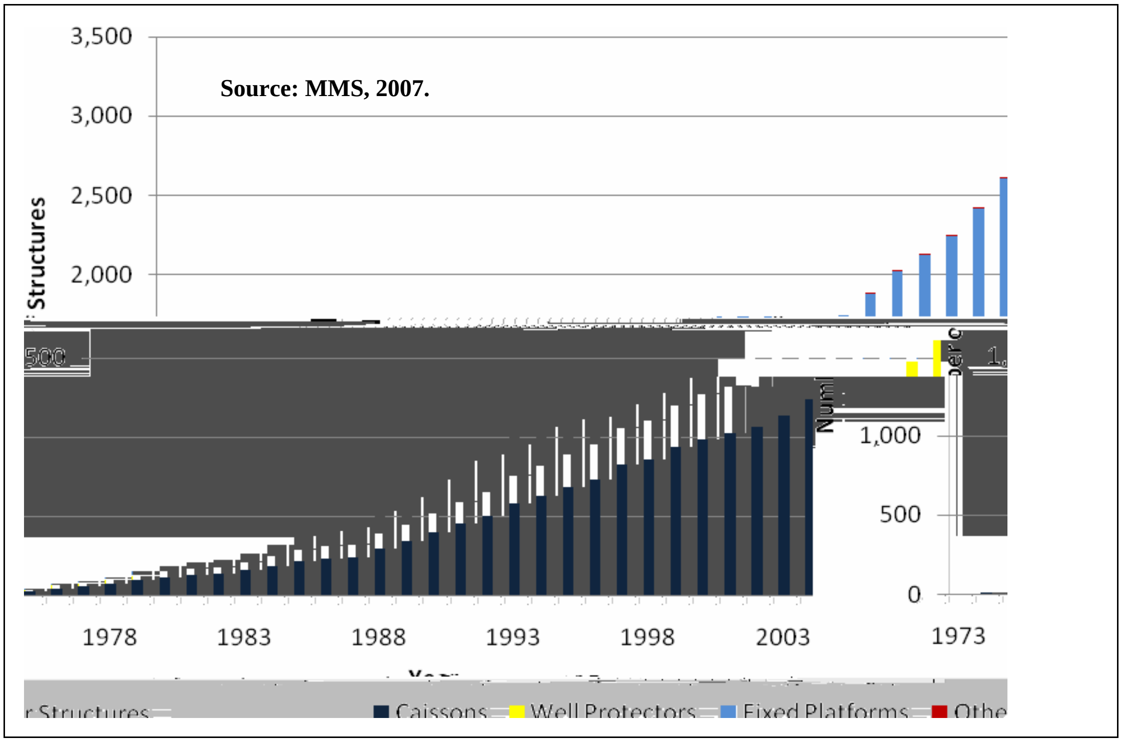

Figure A.9. Cumulative Number of Structure Removals in the Gulf of Mexico (1973-2007).

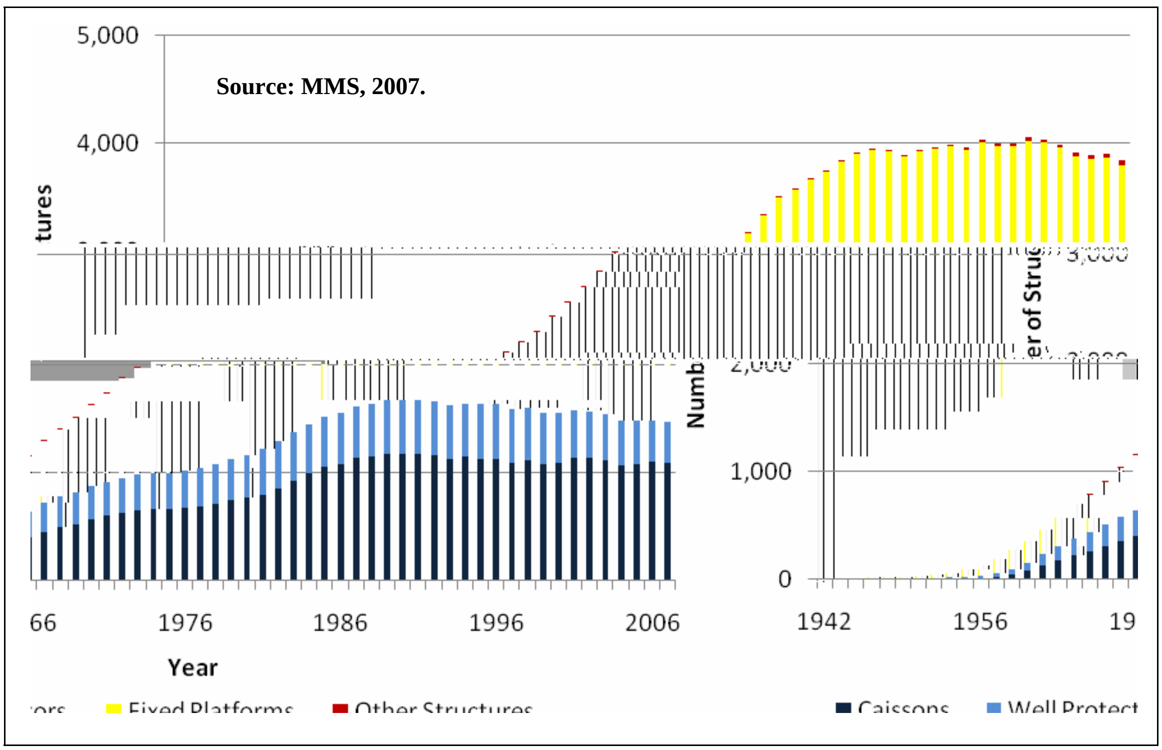

Figure A.10. Active Structures in the Gulf of Mexico (1942-2007).

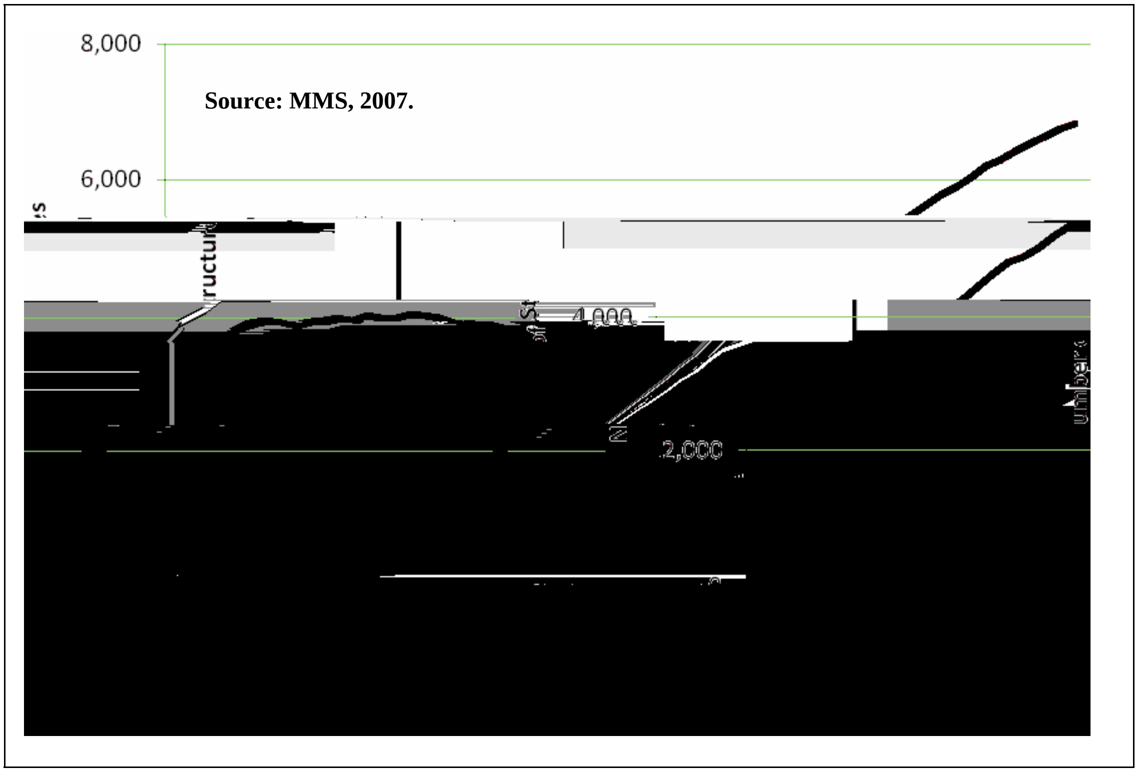

Figure A.11. Cumulative Number of Installed, Removed and Active Structures in the Gulf of Mexico (1942-2007).

APPENDIX B

CHAPTER 2 TABLE AND FIGURE

Table B.1.

Average Dismantlement, Restoration, and Abandonment Cost per Well for Offshore Properties

Average Cost per Well ($/well)	All (%)	Successful Efforts (%)	Full Cost (%)	Independent (%)	Major (%)
≤ $1,000	5.3	0	11.1	6.3	0
$1,000 - $50,000	10.5	0	22.2	12.5	0
$50,001-$300,000	42.1	50.0	33.3	37.5	66.7
$300,001-$1,000,000	42.1	50.0	33.3	43.8	33.3
≥ $1,000,000	0	0	0	0	0
	100 (19)[a]	100 (10)	100 (9)	100 (16)	100 (3)

Source: 2001 PricewaterhouseCoopers survey (Coe et al., 2001).

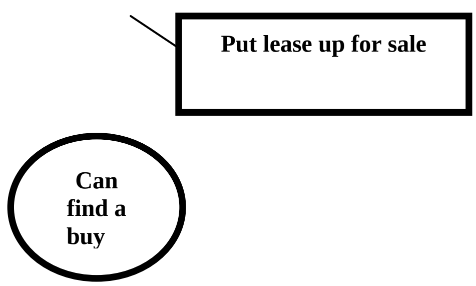

Figure B.1. Sequence of Events Required to Trigger Government Liability.

APPENDIX C

CHAPTER 3 TABLES

Table C.1.

MMS Supplemental Bonding Legacy Formula[a]

Decommissioning Stage	Water Depth (feet)	Estimated Cost[b] ($1,000)
Plug & Abandon	all	100
Structure Removal	< 150	400
	151 - 200	600
	201- 299	1,250
	> 300	2,000+
Site Clearance & Verification	< 150	300
	151- 249	400
	> 250	500

Source: MMS, 1998.

Footnote: (a) The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate.

(b) The P&A unit cost is per borehole, the structure removal cost is per structure, and the SC&V cost is per leasehold. Total lease liability is computed by summing the unit cost elements for the number of wells and structures per leasehold.

Table C.2.

Plugging and Abandonment Cost – Independent Operators

Year	Number of wells	Dayrate

Table C.3.

Plugging and Abandonment Cost – Majors (2005-2007)

Water Depth (ft)	Number of wells	Average Cost ($1,000)
0-100	75	1,172 (992)
101-200	27	967 (935)
201-300	13	956 (494)
All	115	1,099 (956)

Source: MMS, 2007.

Table C.5.

Removal Cost Statistics – Independent Operators

Water Depth (ft)	Caisson & Well Protector ($1,000)	Fixed Platform ($1,000)
0-100	686 (560)[a]	1,131 (970)
101-200	1,525 (881)	2,023 (1,276)
201-300		3,468 (2,590)

Source: Kaiser, Dodson, and Foster 2008.
Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table C.6.

Removal Cost Tableau – Independent Operators, No Cost Inflation

Water Depth (ft)	Caisson & Well Protector ($1,000)	Fixed Platform ($1,000)
IND:		
0-100	686	1,131
101-200	1,525	2,023
201-300		3,468

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Table C.7.

Removal Cost Statistics – Majors

Water Depth

Table C.9.

Removal Cost Tableau – Independents and Majors, Equal Weight Average[a], No Cost Inflation

Water Depth (ft)	Caisson & Well Protector ($1,000)	Fixed Platform ($1,000)
C:		
0-100	1,260	1,527
101-200	1,813	2,470
201-300		3,090
C+ 1**SD*:		
0-100	1,731	2,580
101-200	2,750	3,503
201-300		5,199
C + 2**SD*:		
0-100	2,202	3,633
101-200	3,687	4,836
201-300		7,307
C + 3**SD*:		
0-100	2,673	4,686
101-200	4,624	6,169
201-300		9,416

Footnote: (a) $C = (_{IND} + _{MAJ})/2$, $SD = (_{IND} + _{MAJ})/2$ obtained from Table C.6 and Table C.8.

Table C.10.

Site Clearance and Verification Cost Tableau – Independents and Majors, No Cost Inflation

Structure Type	*C* ($1,000)	*C* + 1**SD* ($1,000)	*C* + 2**SD* ($1,000)	*C* + 3**SD* ($1,000)
Caisson	16	26	36	46
Well Protector & Fixed Platform	43	67	91	115

Source: Kaiser and Martin 2008.

Table C.11.

Supplemental Bonding Tableau[a] (2008-2013) – High Risk (Average Cost)

Decommissioning Stage	Water Depth (ft)	Estimated Cost[b] ($1,000)	
Plug & Abandon	all	773	
		CAIS & WP[c]	FP
Structure Removal	0 - 100	1,260	1,527
	101 - 200	1,813	2,470
	201- 300		3,090
		CAIS	WP & FP
Site Clearance & Verification	all	16	43

Footnote: (a) The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate.
(b) Plug and abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit cost elements for the number of wells and structures per leasehold.
(c) CAIS = caisson, WP = well protector, FP = fixed platform.

Table C.12.

Supplemental Bonding Tableau[a] (2008-2013) – Moderate Risk (Average Cost + 1*Standard Deviation)

Decommissioning Stage	Water Depth (ft)	Estimated Cost[b] ($1,000)	
Plug & Abandon	all	1,383	
		CAIS & WP[c]	FP
Structure Removal	0 - 100	1,731	2,580
	101 - 200	2,750	3,503
	201- 300		5,199
		CAIS	WP & FP

Table C.13.

Supplemental Bonding Tableau[a] (2008-2013) – Low Risk
(Average Cost + 2*Standard Deviation)

Decommissioning Stage	Water Depth (ft)	Estimated Cost[b] ($1,000)	
Plug & Abandon	all	1,993	
		CAIS & WP[c]	FP
Structure Removal	0 - 100	2,200	3,633
	101 - 200	3,687	4,836
	201- 300		7,307
		CAIS	WP & FP
Site Clearance & Verification	all	36	91

Table C.15.

Supplement Bond Requirements Under Various Risk-Adjustments – Example 1

	Risk-Adjusted Cost Level ($ million)			
Stage	*C*	*C* + 1**SD*	*C* + 2**SD*	*C* + 3**SD*
P&A	20.10	35.96	51.82	67.68
REM	6.83	10.35	13.87	17.39
SC&V	0.161	0.253	0.345	0.437
Total	28.39	46.56	66.04	85.51

Table C.16.

Supplement Bond Requirements Under Various Risk-Adjustments – Example 2

	Risk-Adjusted Cost Level ($ million)			
Stage	*C*	*C* + 1**SD*	*C* + 2**SD*	*C* + 3**SD*
P&A	23.96	42.87	61.78	80.69
REM	10.38	15.26	20.73	26.21
SC&V	0.134	0.212	0.290	0.360
Total	34.47	58.34	82.80	107.26

APPENDIX D

CHAPTER 4 TABLES AND FIGURES

Table D.1.

Plug and Abandonment Statistics, 2002-2005

	2002	2003	2004	2005

Table D.3.

Composite Average Plug and Abandonment Statistics, 2002-2007

Parameter (unit)	DR	TK	ALL
Avg_cost_well ($1000/well)	122	143	134
SD_Acw	11	11	8
Avg_cost_day ($1000/day)	15	20.3	17.9
SD_Acd	1.4	1.3	1
Avg_days_well (days/well)	9.8	8	8.8
SD_Adw	0.7	0.5	0.4
Number_jobs	116	140	256
Number_wells	300	856	1156
Number_wells/Number_job	2.6	6.1	4.5

Footnote: DR= dayrate contracts, TK = turnkey contracts, ALL = dayrate and turnkey contracts.

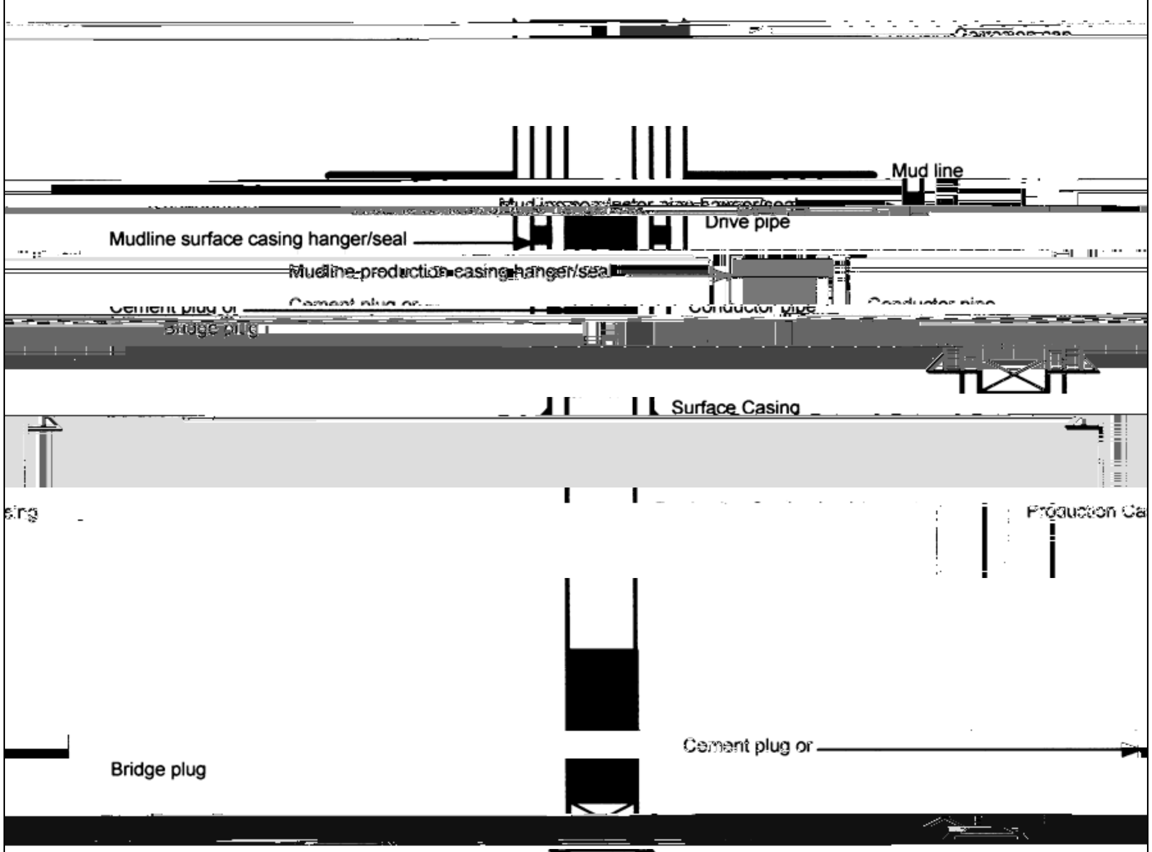
Table D.4.

Regression Model Results – I

Table D.5.

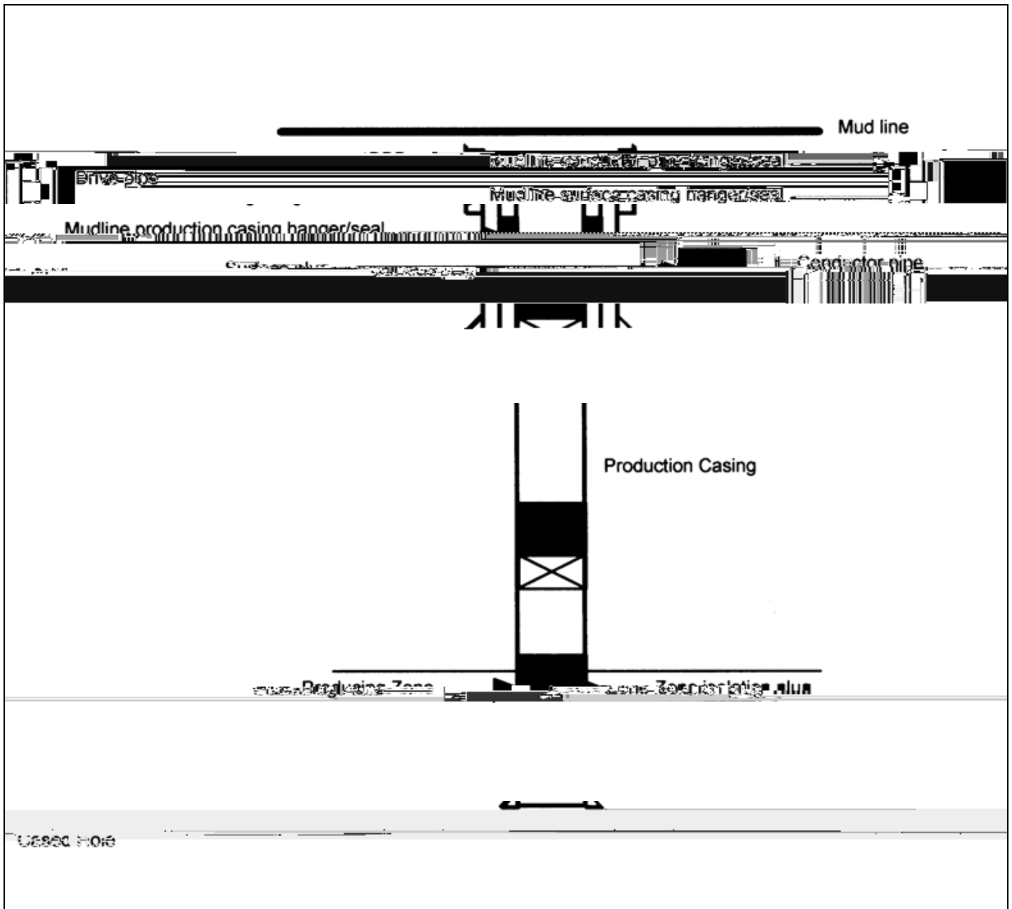
Regression Model Results – II

Parameter	$TC = {}_0 + {}_1ND + {}_2NW$[a]					
	Dayrate		Turnkey		All	
	${}_0 = 0$	${}_0 \neq 0$	${}_0 = 0$	${}_0 \neq 0$	${}_0 = 0$	${}_0 \neq 0$
${}_0$						



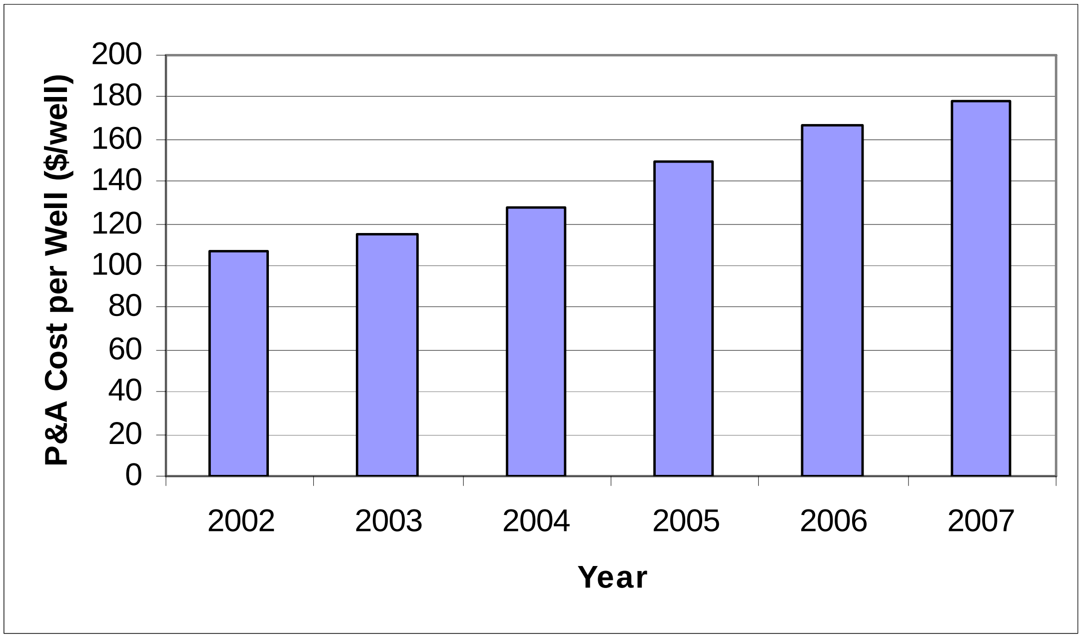
Source: MMS, 2000.

Figure D.1. Temporary Abandonment Well Schematic.

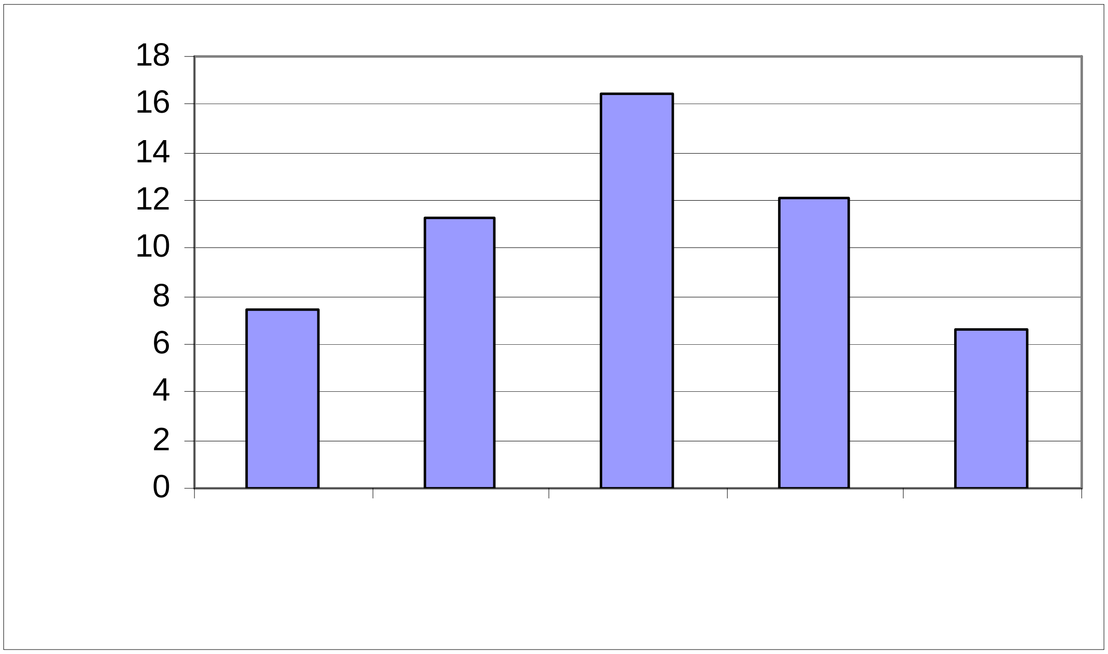


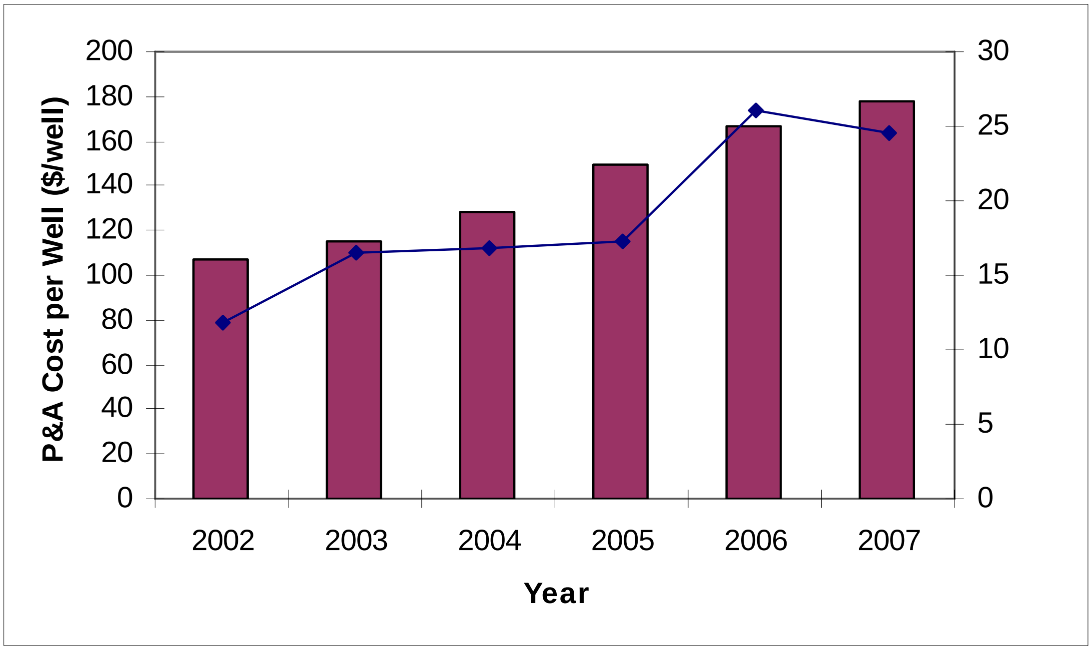
Source: MMS, 2000.

Figure D.2. Permanent Abandonment Well Schematic.



P&A Cost per Well ($/well)
200
180
160
140
120
100
80
60
40
20
0
2002
2003
2004
2005
2006
2007
Year


18
16
14
12
10
8
6
4
2
0


P&A Cost per Well ($/well)
200
180
160
140
120
100
80
60
40
20
0
30
25
20
15
10
5
0
2002
2003
2004
2005
2006
2007
Year

APPENDIX E

CHAPTER 5 TABLES AND FIGURES

Table E.1.

Total Project Cost of the Sample Set, 2003-2008 ($ million)

Water Depth (ft)	Caisson ($ million)	Well Protector ($ million)	Fixed Platform ($ million)	All ($ million)
0-100	16.0	6.2	28.8	51.0
101-200	11.4	-	60.7	72.1
201-300	-	-	54.6	54.6
All	27.4	6.2	144.1	177.7

Table E.4.

Number of Removed Structures

Water Depth (ft)	Caisson	Well Protector	Fixed Platform	All
0-100	29	15	28	72
101-200	9	-	32	41
201-300	-	-	18	18
> 300	-	-	2	2
All	38	15	80	133

Table E.5.

Average Structure Removal Cost

Water Depth (ft)	Caisson ($1,000)	Well Protector ($1,000)	Fixed Platform ($1,000)	All ($1,000)
0-100	499 (304)[a]	393 (190)	865 (623)	619 (492)
101-200	1,227 (612)	-	1,634 (948)	1,545 (884)
201-300	-	-	2,579 (1,498)	2,579 (1,498)
All	672 (501)	393 (190)	1,576 (1,200)	1,150 (1,086)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.7.

Average Cost of All Fixed Platform Removals by Disposition

Water Depth (ft)	Onshore ($1,000)	Reef ($1,000)	All ($1,000)
0-100	969	682	865
101-200	1,363	1,765	1,669

Table E.10.

Number of Fixed Platforms Removed by Year, 2003-2008

Water Depth (ft)	2003	2004	2005	2006	2007	2008
0-100	6	3	8	5	5	1
101-200	8	0	4	5	13	2
201-300	1	1	1	4	10	1
> 300	0	0	0	1	1	0
All	15	4	13	15	29	4

Table E.11.

Average Removal Cost of Fixed Platforms by Year, 2003-2008

Water Depth (ft)	2003 ($1,000)	2004 ($1,000)	2005 ($1,000)	2006 ($1,000)	2007 ($1,000)	2008 ($1,000)
0-100	578 (373)[a]	1,406 (573)	716 (373)	1,496 (809)	453 (168)	1,050 (-)
101-200	1,681 (1,001)	-	1,650 (1,001)	1,428 (726)	1,542 (1,191)	2,521 (1,300)
201-300	1,810 (-)	3,293 (-)	4,827 (-)	1,832 (821)	2,747 (1,770)	1,687 (-)
> 300	-	-	-	1,736 (-)	3,718 (-)	-

15797 6e) 18945 (16050) 19945 ;8-)

Table E.13.

Average Deck Weight to Jacket Weight Ratio

Water Depth (ft)	Caisson	Well Protector	Fixed Platform	All
0-100	0.36 (-)[a]	0.50 (0.38)	1.25 (0.98)	1.12 (0.95)
101-200	0.87 (0.46)	-	0.92 (0.52)	0.91 (0.51)
201-300	-	-	0.66 (0.39)	0.66 (0.39)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.14.

Average Removal Cost per Ton

Water Depth (ft)	Caisson ($1,000/ton)	Well Protector ($1,000/ton)	Fixed Platform ($1,000/ton)	All ($1,000/ton)
0-100	9.5 (-)	2.3 (1.5)	1.5 (0.7)	2.0 (2.0)
101-200	6.6 (3.7)	-	2.3 (2.2)	2.8 (2.7)
201-300	-	-	2.3 (1.5)	2.3 (1.5)
> 300	-	-	1.7 (0.8)	1.7 (0.8)
All	7.6 (3.1)	2.3 (1.5)	1.7	2.3 (2.1)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.15.

Average Duration of Preparation, Pipeline Abandonment, and Removal Operations – Fixed Platforms

Water Depth (ft) (ft)	Preparation (days)	Pipeline Abandonment (days)	Removal (days)
0-100	7.5 (3.0)[a]	6.3 (3.0)	6.9 (6.3)
101-200	9.1 (4.7)	5.5 (3.3)	14.1 (10.9)
201-300	9.7 (5.4)	6.3 (6.7)	24.2 (11.4)
> 300	9.3 (2.9)	-	32.0 (12.7)
All	8.6 (5.2)	5.9 (3.5)	12.1 (11.1)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.16.

Average Structure Installation Cost

Water Depth (ft)	Caisson ($1,000)	Well Protector ($1,000)	Fixed Platform ($1,000)	All ($1,000)
0-100	534 (-)[a]	986 (205)	1,009 (482)	909 (419)
101-200	833 (-)	1,825 (1,148)	1,675 (987)	1,619 (943)
201-300	-	-	2,809 (617)	2,809 (617)
All	633 (212)	1,489 (938)	1,501 (879)	1,368 (858)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.17.

Single Variable Removal Cost Regression Models

	Removal Cost[a] ($1,000) = *WD* (ft)		
Parameter	Caisson	Well Protector	Fixed Platform
	8.2 (15.1)[b]	7.1 (9.6)	9.4 (10.5)
n	35	10	57
R^2	0.84	0.80	0.64

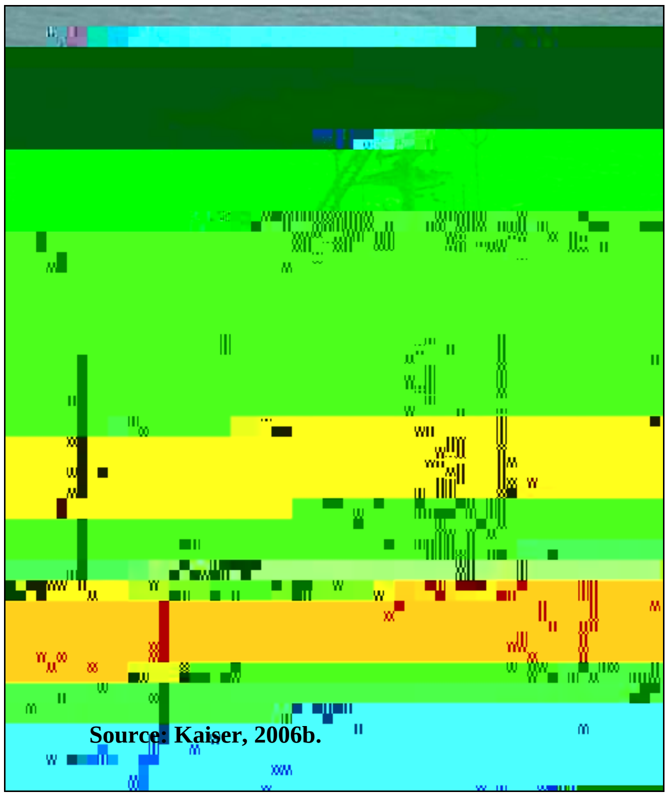
Footnote: (a) Removal cost reported in $1,000. *WD* = water depth (ft).
(b) t-statistics reported in parenthesis; (*) denotes t-statistic < 1.

Table E.18.

Multivariable Removal Cost Regression Models

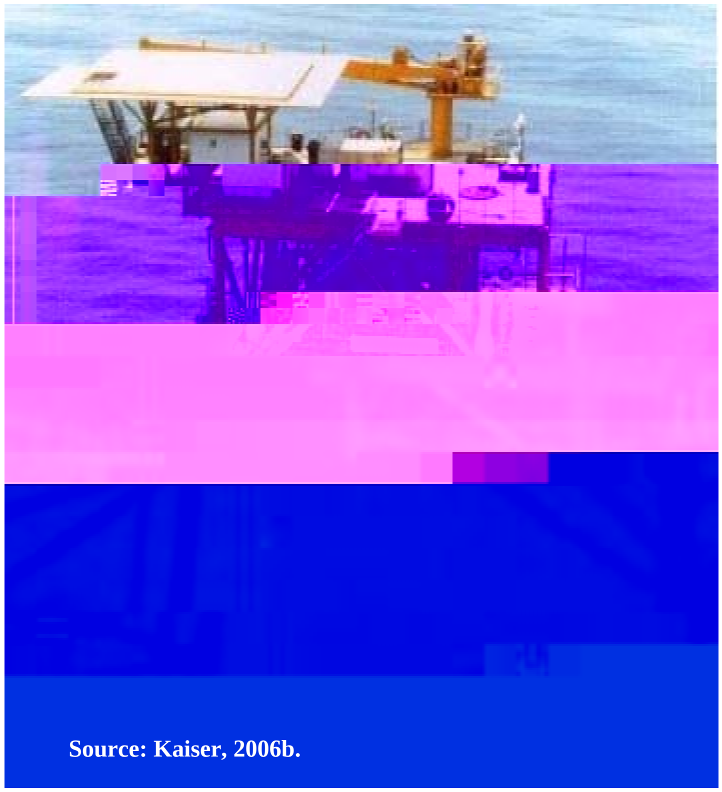
Parameter	Removal Cost[a] ($1,000) = $_1$*WD* (ft) + $_2$*WGT* (ton) + $_3$*NP* + $_4$*DUR* (days)				
	Well Protector		Fixed Platform		
	Model I	Model II	Model I	Model II	Model III
$_1$	1.7 (*)[b]	1.6 (1.3)	3.3 (3.3)	1.6 (1.6)	1.8 (2.5)
$_2$				0.5 (4.0)	0.0007 (11.4)
$_3$		-112.1 (-5.5)	-41.0 (-1.9)		
$_4$	68.3 (1.8)	140.5 (7.0)	71.5 (8.2)	41.3 (5.0)	
n	8	8	57	36	43
R^2	0.76	0.79	0.83	0.87	0.93

Footnote: (a) Removal cost reported in $1,000. *WD* = water depth (ft), *WGT* = total weight (tons), *NP* = number of piles (#), *DUR* = duration (days).
(b) t-statistics reported in parenthesis; (*) denotes t-statistic < 1.



Source: Kaiser, 2006b.

Figure E.1. Single-well Caisson Structure.



Source: Kaiser, 2006b.

Figure E.2. Well Protector Structure.

Figure E.3. Fixed Platform Structure.

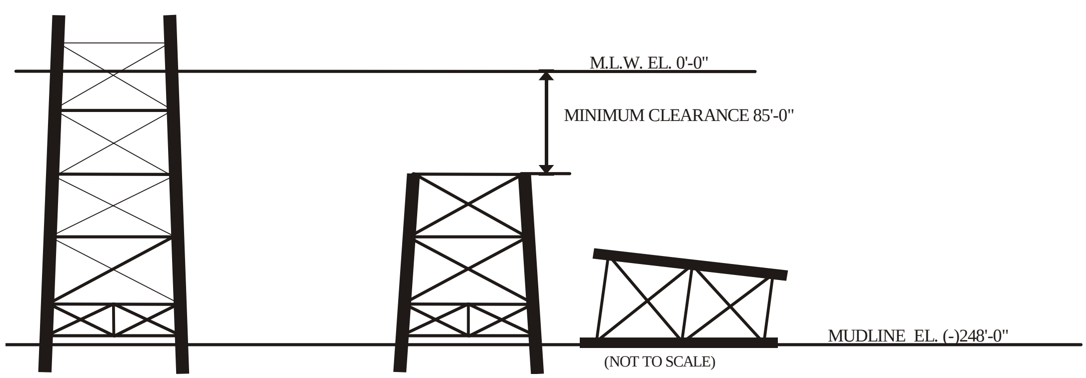


Figure E.4. Platform Removal Methods.

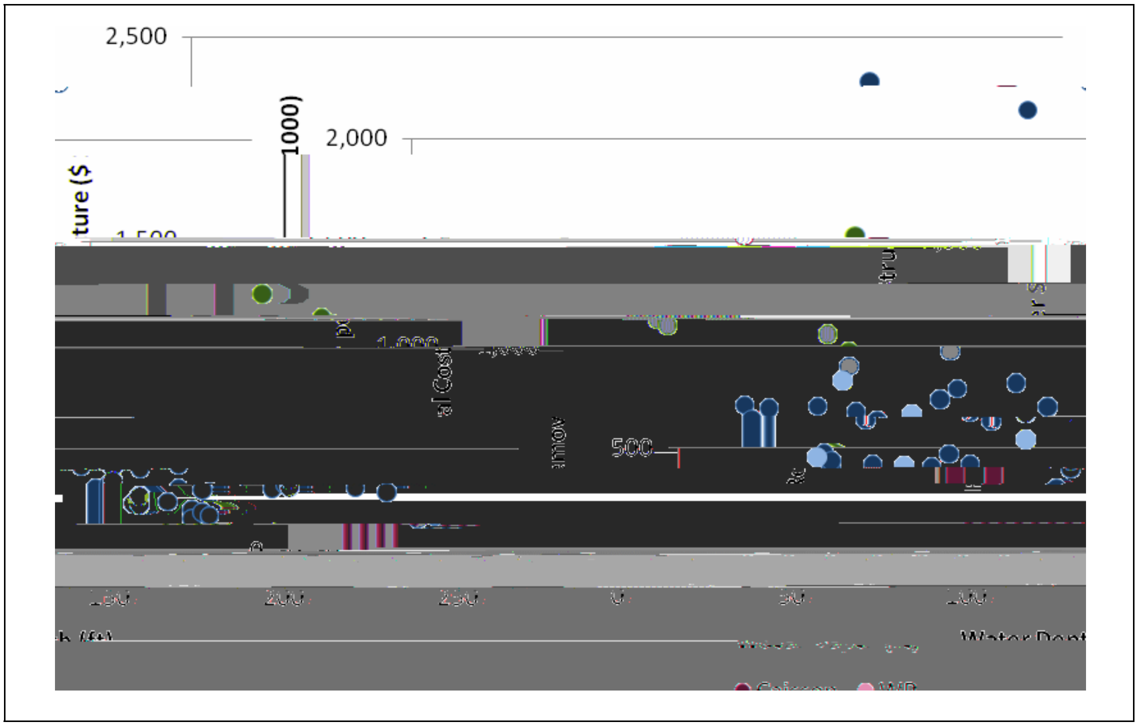


Figure E.5. Average Removal Cost of Caissons and Well Protectors.

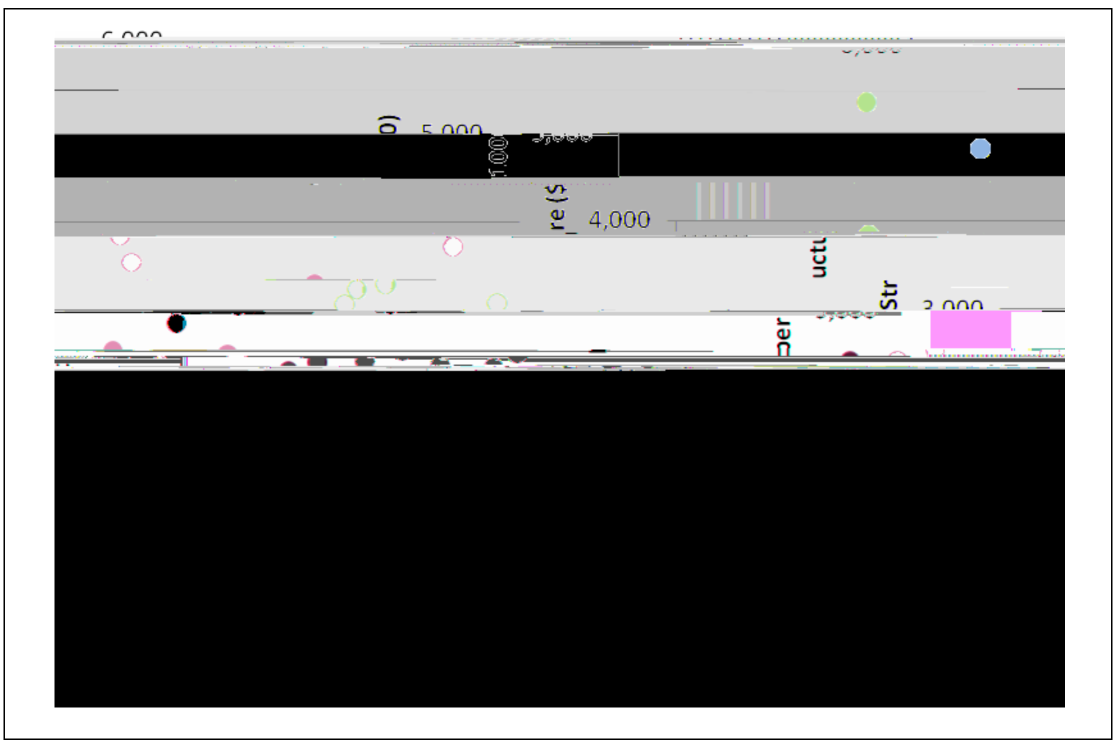


Figure E.6. Average Removal Cost of Fixed Platforms.

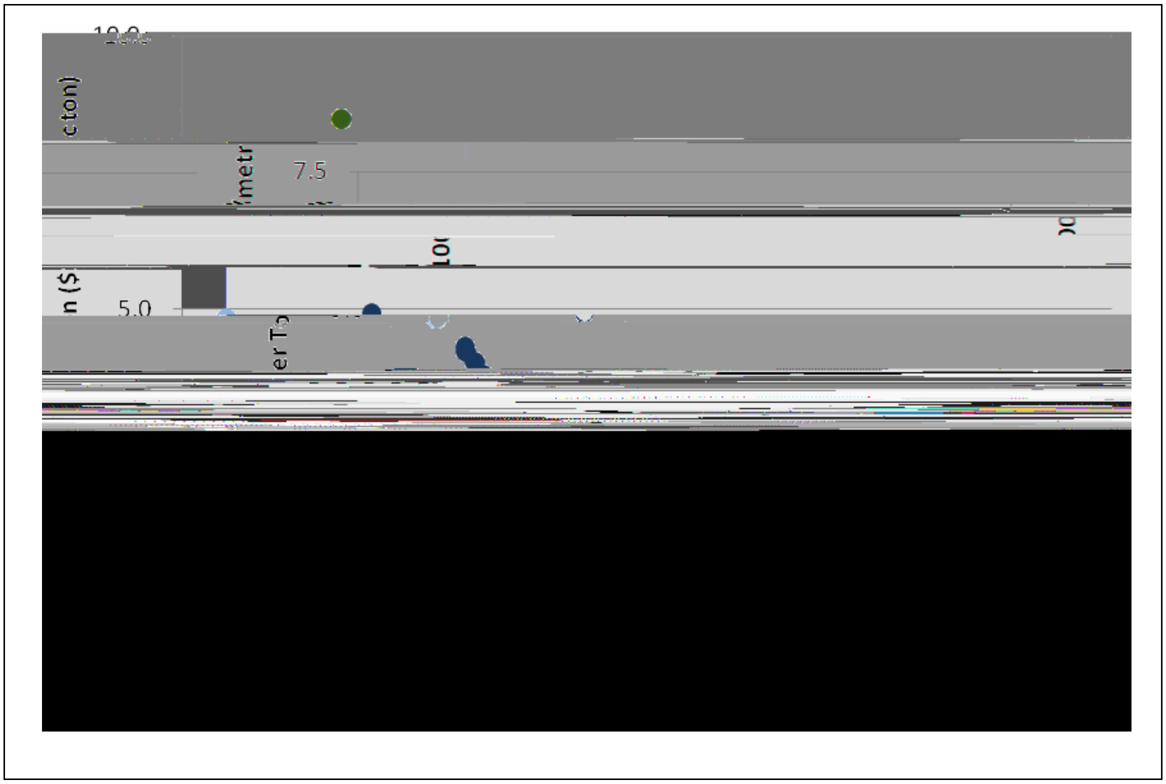


Figure E.7. Removal Cost per Ton of Fixed Platform Structures.

APPENDIX F

CHAPTER 6 TABLES AND FIGURES

Table F.1.

Net Trawling Site Clearance and Verification Contract Parameters for B&J Martin, Inc. (2007)

Contract Parameter (unit)	Parameter Value ($1000)
K_1 ($/day)	4.5
K_{21} ($/event)	2.4
K_{22} ($/event)	4.8
K_{23} ($/event)	1.2
K_{24} ($/event)	2.2
K_3 ($/incident)	At cost
K_4 ($/site)	0.8

Table F.2.

Summary Statistics of Net Trawling Site Clearance and Verification Operations in the Gulf of Mexico (2001-2005)

Parameter (unit)	Caisson – Regular Net	Caisson – Gorilla Net	Platform – Regular Net	Platform – Gorilla Net
TD (day)	3.4	5.4	6.8	8.8
LD (day)	2.2	3.2	4.4	5.8
SR (number)	1.1		2.0	
SU (number)	0.8		1.7	
GR (number)		2.5		3.5
GU (number)		2.5		4.7
N (item)	4.7	10.8	16.3	30.2
WD (feet)	69	72	124	93
AGE (year)	18.7	24	13.4	27
TC ($/job)	14,302	26,369	32,030	63,119
Number Jobs	139	20	92	49

Footnote: TD = Total number of days from dock, LD = Total number of trawl days; SR = Repairable shrimper nets; SU = Unrepairable shrimper nets; GR = Repairable Gorilla-nets; GU = Unrepairable Gorilla nets; N = Number of items collected; WD = Water depth, AGE = Age of structure upon removal; TC = Total cost of job.

Table F.3.

Site Clearance and Verification Statistics for Caisson Structures, 2001-2005

Caisson - All	2001	2002	2003	2004	2005	2001-2005
Total Cost ($)	17,516	15,677	16,271	13,938	18,061	15,964
TC Deviation	14,096	6,930	10,250	9,552	9,764	10,036
Percentage (%)	79.2	80.6	71.7	82.1	79.0	79.7
Percent Deviation	17.4	13.7	20.0	14.3	14.9	16.3
Number Jobs	21	27	22	57	40	167
Caisson - Regular						
Total Cost ($)	13,682	15,210	12,250	13,006	16,659	14,302

Table F.4.

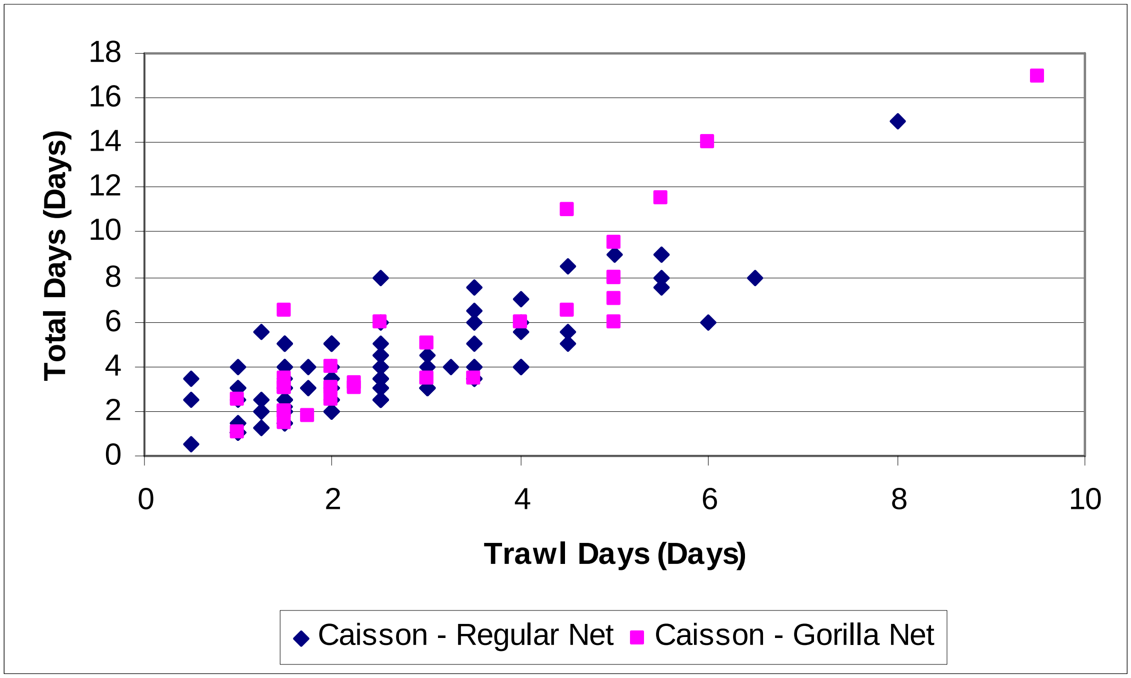
Site Clearance and Verification Statistics for Platform Structures, 2001-2005

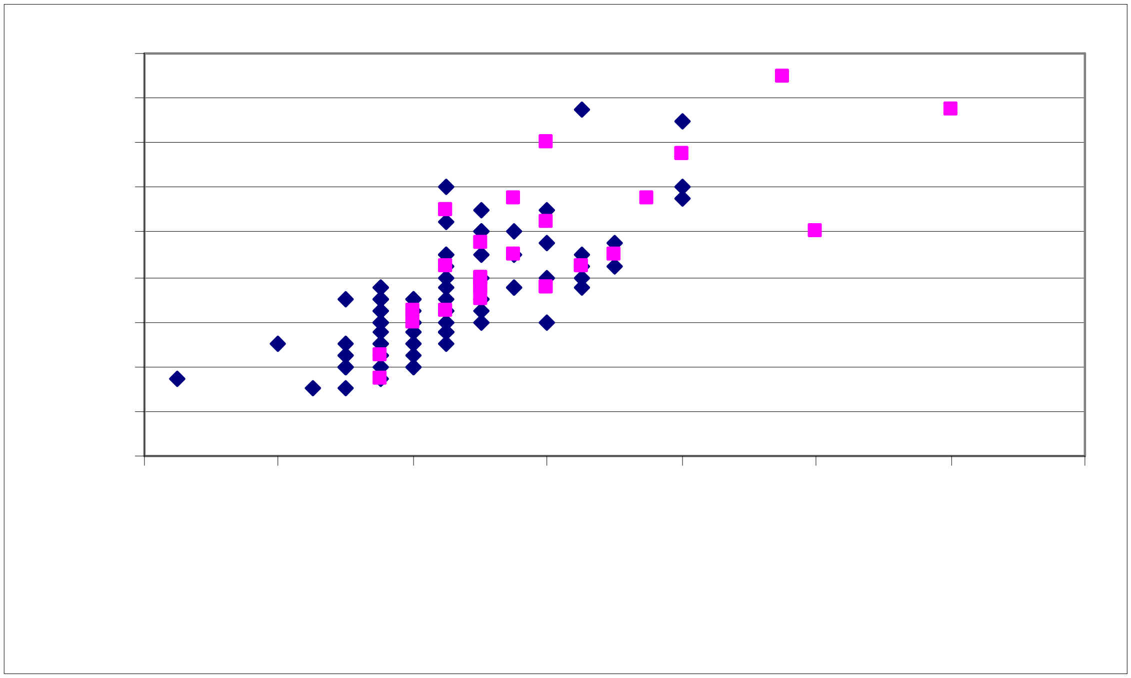
Platform - All	2001	2002	2003	2004	2005	2001-2005
Total Cost ($)	45,966	44,502	32,694	48,872	42,480	42,834
TC Deviation	25,994	34,111	13,686	23,776	20,892	24,390
Percentage (%)	71.1	75.0	75.7	72.7	75.5	72.3
Percent Deviation	19.8	20.2	17.1	16.2	16.1	17.4
Number Jobs	25	25	24	23	44	141
Platform - Regular						
Total Cost ($)	33,325	27,568	29,536	40,703	32,277	32,030
TC Deviation	18,549	9,450	10,826	23,853	11,437	14,689
Percentage (%)	80.0	85.0	81.7	82.1	85.5	82.1
Percent Deviation	14.5	8.2	11.1	11.2	8.8	10.3
Number Jobs	15	18	20	12	27	92
Platform - Gorilla						
Total Cost ($)	64,927	88,047	48,488	57,783	58,685	63,119
TC Deviation	24,511	36,450	17,165	21,222	22,490	26,119
Percentage (%)	57.6	49.5	45.8	62.5	59.4	55.7
Percent Deviation	19.7	19.7	5.3	15.0	11.5	13.2
Number Jobs	10	7	4	11	17	49

Footnote: The Percentage variable represents the portion of the total cost due to the time variation of the project, and excludes the operational cost due to loss and damage of nets. TC Deviation and Percentage Deviation represent the standard deviation of the Total Cost and Percentage variables.

Source: Kaiser and Martin, In press.

Figure F.2. Gorilla Net Application.


18
16
14
12
10
8
6
4
2
0
Total Days (Days)
0
2
4
6
8
10
Trawl Days (Days)
Caisson - Regular Net
Caisson - Gorilla Net



its financial resources to guarantee an operator's performance. On a case-by-case basis, the MMS has allowed a lessee to furnish a third-party guarantee or a lease-specific abandonment account as alternatives.

In 1998, MMS updated and revised the procedures used in assessing the financial strength of OCS leases in the requirements to submit a supplemental bond. As specified in the NTL 98-18N, Supplemental Bonding Procedures, a waiver of the supplemental bond requirement on a specific lease or ROW may be granted by the MMS if at least one record title lessee meets the criteria established. Production and financial ratios[39] are currently employed to assess lessee's financial strength and reliability (MMS, 2001).

In 2001, Secretary Norton formed a Bonding Task Force comprised of the Bureau for Land and Minerals Management, Office of Surface Mining and MMS, to examine the scope and severity of the changes in the bonding market and to develop recommendations to address identified problems (Schlief, 2002; Fulton, 2002). No significant changes were made to the bonding levels or mechanism as a result of the review.

In 2005, Hurricanes Katrina and Rita caused widespread destruction in the GOM, and unprecedented losses to the offshore industry in terms of physical damage and business interruption, estimated at $15 billion. The disruption to coastal communities and facilities, combined with an increase in demand for labor and offshore support vessels in the aftermath of the storms, led to a significant increase in dayrates across the service sector, which impacted the cost of decommissioning services for a sustained period of time.

[39] The MMS use two financial ratios to assess strength and reliability: the current ratio and the debt-to-equity ratio. The current ratio is the ratio of the current assets (CA) to current liability (CL), where CL comprise debts that come due within one year and CA represent the ability to satisfy those obligations. A measure of the amount of leverage in a company's capital structure is its debt-to-equity ratio. The higher the proportion of loans the higher the firm is leveraged.

APPENDIX I

RELATED DEPARTMENT OF THE INTERIOR BONDING REQUIREMENTS

Congress has enacted several laws and Federal agencies have developed regulations requiring companies to demonstrate that they have sufficient financial resources to perform the reclamation and clean up of sites after the completion of exploration, mining, and production activities. The Department of Interior's (DOI) bureaus may require a surety bond or proof of other financial security prior to approving a plan of operation or issuing a lease or permit. A summary of some of the bonding requirements in laws administered by the DOI include:

- The General Mining Law of 1872, 30 U.S.C.A. sec. 22-45 applies to "locatable minerals" such as precious metals and gemstones. The DOI requires 100 percent of the estimated reclamation cost to be secured by a bond.

- The Mineral Leasing Act of 1920 (30 U.S.C.A. sec. 181-287) applies to coal, oil, gas, phosphate, sodium, potassium, and other minerals and requires adequate bonds for