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Coastal Marine Institute

Offshore Drilling Industry and Rig Construction Market in the Gulf of Mexico

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ABSTRACT

Mobile offshore drilling units (MODUs) are a critical element of the offshore oil and gas industry. Drilling rig markets have a large geographic expanse and are economically important with large labor impacts. The purpose of this report is to describe the MODU industry and the economic impacts of rig construction in the U.S. We emphasize dayrates in the service market and capital expenditures in the newbuild market because these are primary metrics and basic indicators of the industry. The industrial organization and major players in the contract drilling market are described and business strategies among contractors illustrated. Dayrates in the contract drilling market are analyzed and hypotheses regarding dayrate factors are tested. The major shipyards in the newbuild market are described along with the geographic distribution of construction and the status of the market circa 2011. A brief description of the processes of jackup rig construction is provided, including design tradeoffs and the drilling equipment installed. The construction costs of jackup rigs in the U.S. are analyzed and the labor, equipment, and material cost components are estimated. Factors that influence capital costs are discussed and the newbuild and replacement costs of jackups, semisubmersibles, and drillships are analyzed.

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EXECUTIVE SUMMARY

Mobile offshore drilling units (MODUs) are marine vessels that drill holes in the earth to find and produce hydrocarbons. Offshore drilling occurs throughout the world wherever hydrocarbon potential exists. Since 1950, over 120,000 wells have been drilled offshore, with about half in the U.S. Gulf of Mexico. Over the past decade, about 3,500 offshore wells were drilled each year. In 2010, revenues to drilling contractors were approximately $45 billion. MODUs consist of an ocean-going vessel with all of the systems required to support drilling, and are composed of jackups, semisubmersibles, and drillships. Currently, offshore oil represents approximately one-third of global production, and as offshore production increases in importance, MODUs will continue to play a critical role in bringing supply to market. The technological capabilities of MODUs define the boundaries of offshore exploration and production.

In this report, we survey the MODU industry and contract drilling market, and focus on newbuilding in the Gulf of Mexico. The report is organized in four sections. Chapters 1 and 2 provide background information. Chapters 3 through 6 characterize the industry sector and the contract drilling service market. Chapters 7 through 11 discuss the newbuild market with an emphasis on jackup construction, and Chapters 12 through 14 analyze the economic impacts of the newbuild market in the U.S. and construction cost functions.

Chapter 1 describes the primary types of rigs employed in the industry and defines the activity states over a rig's life. In Chapter 2, the five markets that make up the MODU industry are described. These markets include the newbuild market where rigs are built, the contract drilling market where rigs are leased, the secondhand market where rigs are sold, the upgrade and maintenance market in which rigs are upgraded and maintained for service, and the scrap market where rigs are dismantled and sold for scrap steel. The newbuild and contract drilling markets are the largest and most transparent sectors and are the focus of this report.

Chapters 3 and 4 introduce the contract drilling market. In Chapter 3, the geographic distribution, utilization and dayrate trends of rigs are presented on a regional and global basis, and the different types of contracts employed are outlined. In Chapter 4, the industrial organization and market structure of the contract drilling industry is described. Firms diversify by region, rig class, and rig quality, and specialization has impacts on dayrates and utilization. Consolidation has been a major characteristic of the industry, and in 2012, the contract drilling market is dominated by five publicly traded firms: Transocean, Noble Drilling, ENSCO, Diamond Offshore and Seadrill. The contract drilling industry provides similar services (drilling wells) using commodity-like units (rigs), and despite many years of consolidation, the industry is still highly competitive. Demand for drilling services is dynamic, and over the past decade, growth has occurred most notably in the Persian Gulf and Brazil.

In Chapter 5, we analyze the factors that impact MODU dayrates. Oil price explains large proportions of the variation in the number of active rigs and average dayrates between 2000 and 2010. Utilization is a weaker predictor of dayrates with effects varying by region and time period. Rig specifications are also shown to impact dayrates. State-owned oil companies pay higher dayrates than private oil companies which suggests that state-owned and private oil companies have different motivations for investing in drilling or have different negotiation strategies. Appraisal drilling is associated with higher dayrates than exploratory or developmental drilling.

In Chapter 6, we develop conceptual models of firm stacking and newbuild decision-making. A net present value model of newbuilding indicates that relatively high combinations of dayrates and utilization are required to justify investment in jackups. We build a model of stacking costs and show why operating a rig may be preferred over stacking even if operating expenses exceed the dayrate. We describe and illustrate the methods used by investment firms for calculating the net asset value of a rig.

Chapter 7 describes the newbuild market with emphasis on the U.S. From the early 1980s through the late 1990s, few rigs were delivered worldwide. By 2004, drilling contractors began to order new jackup rigs to replace the aging fleet which began the first major newbuilding cycle since the early 1980s. New orders stopped in 2008 following the global economic recession and decline in oil prices, and resumed in late 2010. The newbuild industry is concentrated in Asia, and the U.S. represents only a small fraction of the global market focused exclusively on jackups. The U.S. newbuild industry consists of two shipyards: the LeTourneau shipyard in Vicksburg, Mississippi and the Keppel AmFELS shipyard in Brownsville, Texas. Keppel AmFELS has work scheduled through 2013. The LeTourneau shipyard was sold twice in 2011, and, barring a major change in the market, is unlikely to deliver additional rigs in the future. U.S. yards are unlikely to win contracts for jackups employed outside the region due to competition and transport costs.

In Chapters 8 through 11, technical aspects of rig design and construction are presented. Chapter 8 defines the structural components of jackup rigs and describes the process of construction and the designs most frequently built in the U.S. Chapter 9 provides a non-technical introduction to the tradeoffs that occur in jackup design, and in Chapter 10, we present a pictorial summary of the most common drilling equipment and systems. Jackup rig displacement is generally considered proprietary but is an important determinant of construction cost since it influences material and labor requirements. In Chapter 11, a regression model of jackup rig weights using water depth capability and length and breadth of the hull as explanatory variables is constructed.

Chapter 12 analyzes the construction costs of jackup rigs built in the U.S using twenty-five jackup rigs ordered from U.S. yards between 1997 and 2007. The total value of U.S. rig deliveries peaked in 2008 at $1 billion and maintained an average of $700 million per year during the period. Since the 2008 peak, the U.S. newbuild industry has declined, and barring a major change in market conditions, future activity is expected to remain low. Labor and drilling equipment are the largest cost components of rig construction and account for over half of the total cost of a rig. Labor costs have been relatively stable over the past decade and drilling equipment costs depend on equipment specifications. The hull and superstructure steel make up a small fraction of the total costs of a rig (<5%), but the leg steel, which is often sold as part of a "rig kit", is a significant component (≈20%).

Chapter 13 discusses the factors that influence newbuild capital expenditures and replacement costs. A number of factors impact costs including market conditions, design class, vessel weight, water depth capability, rig age, upgrade status, environmental characteristics, contract structure, construction shipyard, and rig specifications. Steel and equipment cost indices are reasonable predictors of newbuild costs.

Chapter 14 evaluates the newbuild and replacement costs of jackups, semisubmersibles, and drillships using empirical data for a representative sample of inventory. Cost models provide insight into market drivers and are used by investors, government agencies, and other stakeholders to evaluate newbuild programs. Replacement cost models are used to evaluate the value and insurance liability of an existing fleet or asset. The average jackup rig for orders placed during the 2005 to 2008 newbuild cycle cost $225 million, while drillships cost more than semis with average costs of $672 and $553 million, respectively. Water depth was the single best predictor of rig cost and replacement cost models explained larger proportions of variance than newbuild models which is likely due to the manner in which cost estimates were performed. For jackups, newbuild costs exhibited a nonlinear relationship between costs and water depth, while nation of construction did not add predictive power to the models suggesting that nations are able to compensate for high labor costs. For semis, delivery year was a significant predictor suggesting that costs increased over the newbuilding cycle.

1. MOBILE OFFSHORE DRILLING UNITS

Mobile offshore drilling units (MODUs or rigs) are ocean-going vessels used to drill, complete and workover wellbores in marine environments. The fleet has grown and evolved over time as more production comes from offshore and operators move into deeper water and more challenging environments targeting more complex and harder to find reservoirs. The fleet that exists today consists of both old and new technology and includes a variety of vessel classes built to various specifications. The purpose of this chapter is to describe MODU classifications and introduce the technical factors that characterize rigs. The chapter includes a description of the function of rigs, the manner in which rigs are categorized, the main rig classes, and the activity states through which a rig transitions over its lifecycle. We conclude with a description of the newbuild and replacement cost of rigs.

1.1. MODU FUNCTION

1.1.1. Well Type

Wells are drilled for exploration, appraisal or production. Exploration wells are used to find and confirm the presence of hydrocarbons, appraisal wells delineate and define the boundaries of the reservoir, and development wells are used for production. Development drilling differs from exploration and appraisal drilling in that data acquisition is no longer the primary function of the well. In development drilling, the objective is to drill targets as efficiently as possible. MODUs are used for all well types, but are the only economic option for exploration and appraisal drilling, before offshore infrastructure is installed. Development wells may be drilled from MODUs or fixed or floating platforms.

1.1.2. Drilling a Well

During drilling, the rig bores a hole in the earth using a drillbit which is connected to and turned by a drillpipe. Drilling fluid passes down the drillpipe through the bit where it lubricates the bit and controls hydrostatic pressure inside the well. The drilling fluid carries cuttings back up to the rig through the annulus between the drillpipe and the borehole. Wells are drilled in stages and when the bottom of a stage is reached, the open-hole is cased off using steel pipe to prevent the hole from collapsing on the drillpipe. Offshore wells usually have three to four casing strings before reaching the target formation (Figure A.1).

1.1.3. Completions and Workovers

A well will be completed immediately if it is a development well, while for exploratory wells, completion activity will await field delineation and additional planning. During completion, production casing is set across the reservoir interval and the blowout preventer is removed and replaced with a dry tree or subsea wellhead. Production tubing is suspended from the wellhead and a packer is used to isolate the annulus. Finally, the production casing is perforated to make contact with the reservoir, and if necessary, the well is stimulated and fractured.

A workover the repair or stimulation of an existing production well intended to restore, enhance, or prolong production. In many cases, a workover entails the removal and replacement of production tubing after the well has been killed. A rig is required for workovers, but a smaller specialized workover rig may be used.

1.1.4. Well Configuration

Wells may be vertical, directional or horizontal (Figure A.2), and all types are used offshore. In some cases, branches spurred off from a single well (sidetracks) may be drilled to target different areas of a reservoir. Exploration wells are almost always drilled vertically with the target directly below the rig. Most developmental wells are drilled directionally because several wells targeting different zones may be drilled from a central location, or the target lies under salt or an environmentally sensitive area. Long horizontal sections may be required to tap thin beds far from the rig or heavy oils that require greater contact with the reservoir. Figure A.3 shows the depth and geology of recent offshore wells in the Gulf of Mexico (GOM).

1.1.5. Well Depth, Pressure, and Temperature

The total (or measured) depth of a well is measured along the wellbore while true vertical depth is measured straight down to the target. Both temperature and pressure increase with depth. The temperature gradient averages 2° F/100 ft (3.6° C/100 m) and varies between 0.5 to 5 °F/100ft (1 to 9° C/100 m) worldwide. The pressure on the rock is called geostatic or lithostatic pressure and increases at an average rate of 100 psi/100 ft. The pressure on the fluids in the pores of the rock is reservoir or fluid pressure, and depends on the density of the overlying water; average fluid pressure worldwide is 45 psi/100ft (Hyne, 2001).

High pressures and temperatures (above 300° F and 0.8 psi/ft) are common in deep (>15,000 ft) and ultradeep (>25,000 ft) wells (Lyons et al., 2008). Wells are classified into high pressure-high temperature (HPHT), ultra-HPHT and HPHT-hc (hors categorie or beyond categorization) categories (Figure A.4) based on technological thresholds associated with the elastomeric seals and electronic equipment used in downhole tools (Belani and Orr, 2008). Figure A.5 shows the geographic distribution of HPHT activity in 2008. HPHT wells stress many rig components and are more difficult to control relative to normal wells. Equipment and systems must be certified to operate at elevated temperatures and pressures. Upgraded equipment includes blowout preventers rated at 10,000 to 15,000 psi, enhanced mud systems including mud cooling, glycol injection units, high pressure choke and kill lines, pressure and temperature sensors, and high pressure risers.

1.2. Rig Classification

Rigs are classified according to type (bottom supported, floating), environmental capacity (harsh, moderate), water depth, and specification (standard, premium).

1.2.1. Rig Type

MODUs are classified as bottom supported and floating rigs. In bottom-supported units, the rig is in contact with the seafloor during drilling, while a floating rig floats over the site while it drills, held in position by anchors or equipped with thrusters using dynamic positioning (Figure A.6).

Bottom-supported units include barges, submersibles and jackups and are used for protected and shallow-water drilling (Figure A.7). Drilling barges are floating vessels that rest on the bottom while drilling. They are limited to approximately 30 ft water depths and are only used for inland areas such as Lake Maracaibo or the Mississippi River delta. Submersibles consist of a deck supported by pontoons; during operation, the pontoons are flooded and the vessel rests on the bottom; they are rarely used today. A jackup is a barge with legs that can be adjusted to suit a given location. Once in position, the legs are lowered, hoisting the drilling platform above the water. Jackups are the most commonly used offshore drilling rig in the world and are capable of drilling on a wide variety of tracks in water depths up to 500 ft. Jackups can only work in water depths that are less than the length of its legs and the required air gap and surface penetration at location. When moving between drilling locations, the hull is usually towed by tugs or carried by a specialist vessel, with the legs sticking high into the air.

Floating units include semisubmersibles and drillships and are used for deepwater (> 500 ft) drilling (Figure A.8). Floaters can operate in deeper water than bottom-supported units since no physical connection between the rig and the seafloor is required. Floaters are essentially ships with drilling equipment and are usually self-propelled and have a marine crew. Motion compensation systems are an essential element of all floating rigs to ensure that drilling can be performed with the vertical heave of the rig.

The semisubmersible (semi) consists of a deck supported by submerged pontoons connected by several large columns. By varying the amount of ballast in the pontoons, the unit can be raised or lowered; the lower the pontoons lie beneath the surface, the less they are affected by wave and current action. Semisubmersibles are very stable in harsh environments and most deepwater, harsh environment rigs are semisubmersibles.

A drillship is a self-propelled ship-shaped vessel. The rig derrick is usually mounted in the middle of the vessel and drilling is conducted through a large aperture known as a “moon pool.” Drillships are the most advanced and expensive sector of the rig market and many water depth records are held by drillships. New drillships are capable of drilling in 12,000 ft of water with wells up to 40,000 ft deep.

Jackups, drillships and semisubmersibles comprise the majority of the modern offshore fleet, and while other marine drilling systems exist,[1] all other systems are of either limited mobility or are not capable of drilling in offshore locations.

1.2.2. Environmental Capacity

Rigs are classified as harsh or moderate environment units. Harsh environments are characterized by frequent and severe storms as occur during winter in the North Sea, Norwegian

[1] For example, drilling tenders are barge or semi-submersible hulls that transport drilling and support equipment. Once onsite, the drilling tender transfers drilling equipment onto the platform while all other systems remain on the tender. While tenders are capable of working offshore, they are not capable of drilling on their own and are only used for developmental drilling.

Sea, North Pacific, Eastern Canada and Arctic Ocean. Figure A.9 shows average wind speeds 10 m above the ocean surface in February and July, corresponding to winter in the Northern and Southern hemispheres, respectively. In the GOM and much of Asia, moderate environmental conditions predominate but tropical storms may cause severe weather events. In Brazil, West Africa and the Persian Gulf, severe weather is rare.

In order to work efficiently in a region, a rig must be capable of operating during average one year storm conditions and surviving 100 year storm conditions (Eikill and Oftedal, 2007). Due to tropical storms, the 100 year storm conditions in the North Sea are similar to conditions in the GOM and Asia; however, one year storm conditions are far more severe in the North Sea (Table A.1). As a result, harsh and moderate environment rigs differ in maximum operating conditions, but do not differ in maximum survival conditions.

Harsh environment units have a number of design modifications to decrease weather related downtime, including increased variable load to reduce the need for resupply, increased airgap to increase wave clearance, increased automation, changes in the geometry of the legs or columns to decrease wind and wave loads, and greater spacing between the legs or columns. Harsh environment rigs are larger, heavier and more expensive to construct than moderate units (Figure A.10).

1.2.3. Water Depth

Rigs are defined in terms of their maximum water depth capability and are classified into water depth classes. Jackups are usually delineated into water depth categories <250, 250-350 and >350 ft, but other classifications may be employed. Floaters are typically divided into midwater (3,000-4,500 ft), deep (<7,500 ft) and ultradeep (>7,500 ft) categories. Water depth capabilities are frequently related to rig specifications and age.

1.2.4. Specification

High-spec (premium) rigs typically have more powerful mud pumps, a higher hook load and a greater variable load than standard rigs, but as with all classifications, definitions vary by firm. Generally speaking, a rig is considered high-spec if it can drill in deeper water than other rigs of its class, operate in harsh environments or drill HPHT wells. Rowan, for example, defines a high-spec jackup as any rig with a hook load greater than 2 million pounds. In most cases, a jackup capable of drilling in >350 ft would be high-spec while a jackup limited to <300 ft would be considered standard; for floaters, the demarcation between high and low spec occurs at approximately 5,000 ft. Table A.2 and Figures A.11(a and b) contrast a standard and high-spec jackup. The difference in replacement cost between two units is a measure of the capital expenditures required for the improvement in performance.

1.3. JACKUPS

1.3.1. Design Elements

Jackups are composed of a triangular box hull approximately 20 to 30 ft high supported by three or more legs. The hull contains all of the equipment required to operate the rig and provides displacement in the afloat condition. Legs support the weight of the jackup and provide lateral stability when elevated. The legs are generally trussed and are composed of three or four vertical chords running its entire length and connected by a lattice-work of tubular braces. The legs are raised and lowered by electro-mechanical rack and pinion jacking systems. The pinions are contained in the jacking mechanism and interact with racks on the leg chords (Figure A.12).

1.3.2. Independent vs. Mat

Foundations for jackups are classified as independent-leg spudcans or mats. Independent-leg jackups have legs that can be jacked up independently of each other and are attached to a spudcan footing. Spudcans (Figure A.13) are designed to penetrate the seafloor and transfer vertical loads from the legs to the ground; spudcan penetration also provides resistance to lateral forces acting on the legs. Mats (Figure A.14) are a rigid plate structure which connects to the bottom of each leg. Mat supported rigs are employed where the bottom conditions would cause spud cans to over-penetrate the seabed, as with soft muddy soil near the mouths of large rivers, or under-penetrate the seabed as with hard rock substrate. Independent-leg jackup dayrates are usually priced at a premium to mat jackups because they are in greater demand and have greater operational flexibility.

1.3.3. Cantilevered vs. Slot

The drilling rig on a jackup can be cantilevered or slot. A cantilevered jackup mounts the rig on cantilevers that extend outward from the hull of the unit. A slot jackup mounts the drilling unit over a slot in the deck. Cantilever designs are more versatile than slot designs since they can be used to drill and workover wells on fixed platforms (Figure A.15) and to drill closely spaced wells without repositioning the rig. All rigs built over the past decade have been cantilevered but slot jackups are common in the legacy fleet.

1.4. SEMISUBMERSIBLES

1.4.1. Station Keeping

Semis are held in position by anchors or are dynamically positioned (Banon et al., 2007). In dynamic positioning propellers (thrusters) are mounted on the vessel's hull below the waterline. Satellite positioning, wind sensors and hydrophones send information about wind, waves, and current to an on-board computer to maintain position. Dynamic positioning significantly increases fuel costs but decreases spread costs, and has been reported under most fuel and dayrate price combinations to lead to an operational cost reduction (Klaoudatos, 2006), but we are not aware of any empirical studies that support this claim. Table A.3 summarizes the advantages and disadvantages of dynamic positioning and other station keeping systems.

1.4.2. Motion Compensation

Floating rigs require motion compensation systems to correct for vertical movement of the rig due to waves. Two separate motion compensation systems are required to control the tension on the marine riser[2] and the drill string. A drill string compensator (DSC) keeps the drillbit on the bottom of the hole and within the weight limits established by the driller while a riser

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2 The riser is the pipe that passes from the rig to the blowout preventer on the seafloor and is used as a conduit for the drillpipe, drilling fluids, casing, etc.

tensioner is used to maintain the tension on the drilling riser; both systems utilize pneumatic cylinders to push or pull the drill string or riser up or down relative to the rig.

A DSC is composed of a pneumatic cylinder placed between the travelling block and the hook and connected to an air pressure system placed on the deck (Figure A.16). As the rig heaves upward, a working fluid flows out of the compensator cylinder; this allows the rod inside the cylinder to fall, moving the hook downward relative to the drill floor, but keeping it at a constant level relative to the earth. As the rig heaves downward, air flows from the pressure vessels to the cylinder, forcing the rod inside the cylinder and the attached hook upward relative to the drill floor. A riser tensioner is composed of several hydraulic cylinders with wire line sheaves at both ends and operates in the same basic fashion.

1.4.3. Displacement

A vessel's displacement is a measure of its weight, and for most vessels, an empty (lightship) and loaded (loadline) displacement is used to estimate the weight and capacity of a vessel. By contrast, semisubmersibles are designed to have variable displacements and a significant portion of their operating displacement is composed of ballast water. As a result, semi displacements are not as closely related to the weight of the vessel. Semis are specified by their transit operating and survival displacements; the transit displacement is approximately 75% of the operating displacement and survival displacement is intermediate (Halkyard, 2005).

The operating displacement and size-related measures of modern semisubmersibles are shown in Table A.4. There is significant variation in size with the smallest rig (the Gusto DSS 20) approximately half the displacement of the largest (the Aker H-6e). The Gusto MSC DSS 20 is designed for the Caspian Sea while the Aker H-6e and GVA 7500 are designed for the North Sea environment.

1.4.4. Generations

Semisubmersibles are classified into generations based on the year of construction and the technology of equipment, environmental specification, variable deck load and water depth capability (Tables A.5 and A.6; Figure A.17). As with all rig classifications, the delineation is approximate and is meant to serve as a general guideline for categorization and reporting. Variable deck load comprises all the weight beyond the lightship and ballast to be carried by the vessel.

First and Second Generation

The first generation of semis was built between 1962 and 1969 and was generally limited to water depths less than 800 feet. During this period, there were significant differences in the structural designs of vessels as the technology matured. Notable designs include the SEDCO 135 (Figure A.18) and ODECO designs. Second generation semis were built between 1970-1981 for water depth up to 1,000-1,500 feet. During the second generation two pontoon systems became standard. Notable designs include the Aker H-3.0, SEDCO 700 and the Friede and Goldman Pacesetter class (Figure A.19). Most of the first and second generation semis have now been retired, upgraded or converted to other uses such as floating production systems and accommodation vessels.

Third Generation

Third generation rigs were built from 1982 to 1986 and increased the size, payload and standards of redundancy in earlier designs (Halkyard, 2005). Third generation rigs were designed to operate in water depths up to 2,500 ft. In total, 44 third generation rigs were built, and many were upgraded in the late 1990’s and early 2000’s to increase their water depth capability and are still in service (Gavankar and Rammohan, 1998). These vessels make up the majority of the existing midwater fleet (Figure A.20).

Fourth Generation

Fourth generation rigs are large units (30,000-53,000 ton displacement) capable of handling high variable deck loads (4,000-6,200 ton) and mud volumes (3 x 1,600 hp). Pipe handling on fourth generation semis is automated and enhanced blow out preventer (BOP) controls are standard. Dynamic positioning was incorporated in some second generation rigs, but become more common in fourth generation units. Due to the low oil prices and reduced demand for drilling in the late 1980’s and 1990’s, only 13 fourth generation units were built (Keener et al., 2003). The GVA 4500 is a typical design.

Fifth Generation

The fifth generation of semisubmersible construction occurred in the late 1990’s and early 2000’s. During this period, oil prices were still low, but technology had matured so that deepwater and ultradeepwater drilling was possible and fifth generation rigs began to explore these regions. In fifth generation rigs, drill floor systems, power management, vessel management, dynamic positioning, and BOP controls are integrated and computer controlled. Most fifth generation rigs are approximately the same displacement as fourth generation rigs, but have improvements in water and drilling depth capability, due in part to dynamic positioning. Fifth generation units often have triply redundant dynamic positioning, powerful mud systems, and automated pipe handling. Most have a dual activity derrick or significant off-line activity and can operate in 7,500 to 10,000 ft water depths.

Sixth Generation

Rigs built after 2005 are considered sixth generation units (Figure A.21). Sixth generation units were typically ordered in response to the increasing oil prices and dayrates in the late 2000’s and the requirements to drill deeper more complex wells. Sixth generation rigs have water depth capability of 10,000 ft and use a modular top drive system. All sixth generation semis are dynamically positioned and are more mobile than their predecessors and capable of self-propelled speeds up to 8 knots. New designs frequently have two fully functional derricks and may incorporate a multi-purpose drilling tower instead of a conventional derrick.

1.4.5. Upgrading

A semisubmersible that is upgraded to drill in deeper water would be classified either as an upgraded or as an "equivalent" higher generation unit. For example, if a second generation rig was upgraded to drill in 3,500 ft water depth, with mud pump capacity 3 x 1,600 hp, variable displacement load of 4,300 tons, top drive and automatic pipe handling, the rig would be classified as a fourth generation unit.

1.5. DRILLSHIPS

1.5.1. Early Drillships

The first drillships were built in the late 1950's and 1960's and were structurally and functionally diverse (Figure A.22). Some first generation vessels used early dynamic positioning systems, but most were moored. By the late 1960's the basic layout of drillships was standardized. A typical design from this period is the Glomar III class (Figure A.23).

In the early 1970's, the first modern dynamically positioned drillships were built. These included the Gusto Pelican Class and SEDCO 445 class. These vessels were generally capable of operating in 2,000 to 3,500 ft water depths, approximately twice the depth of contemporary semisubmersibles. These vessels generally had 15,000 ton displacements and were capable of drilling 20,000 ft wells. Moored drillships continued to be built and some moored vessels had capabilities that matched or exceeded dynamically positioned drillships. By the late 1970's the capabilities and size of drillships had increased. For example, *Discoverer Seven Seas* delivered in 1976 was capable of drilling in 7,000 ft water depths and displaced 22,000 tons. *Discoverer Seven Seas* and several other drillships from this period are still active.

1.5.2. Modern Drillships

Between the mid 1980's and late 1990's, no new drillships were ordered. Before the late 1990's, generations were not used to describe drillship construction, and the first four generations of drillships are not well defined in the literature. When the *Discoverer Enterprise* was delivered in 1999 it was described as a fifth generation vessel, analogous to the fifth generation semis that were being built at the time (Figure A.24). Fifth generation drillships were significantly larger than previous designs (45,000 to 100,000 ton displacements) and capable of drilling in 7,500 to 10,000 ft water depths; nearly all are dynamically positioned.

In the mid 2000's contractors began to refer to newbuilds as sixth generation vessels (Table A.7). Sixth generation designs increased the maximum water depth to 12,000 ft and dual activity derricks became standard (Figure A.25). In some cases, surface BOP capabilities were included in addition to the standard subsurface BOP. In 2011, contractors reported ordering seventh generation units, but the improved capabilities of these units are not yet clear.

1.5.3. Displacement

Table A.7 describes the displacement of common sixth generation rigs. There is wide variation in drillship size with displacements ranging between 50,000 and 100,000 tons.[3] Smaller drillships (e.g. the Gusto PRD 10,000) sacrificed functionality to reduce costs, but large designs such as the Samsung 12,000 are the most popular. In Figure A.26, *Discoverer Enterprise*, a 100,000 ton drillship is compared to the 22,000 ton *Discoverer 534* drillship built in 1975 and *Transocean Richardson*, a 4th generation semi.

1.5.4. Competition with Semis

Drillships and semis compete for many of the same drilling programs, and which is better for a specific job is usually determined by availability and technical factors. Drillships can operate for up to three months without resupply, which reduces the spread requirements and allows for efficient work in frontier regions or far from shorebases. Drillships are also able to mobilize more rapidly than semis, and in some cases, have more advanced drilling equipment, but the ship-shape layout also limits space for operations relative to the semisubmersible's square shaped deck. Drillships are usually valued for exploratory and appraisal drilling in deepwater frontier regions. However, semis have more favorable motion characteristics than drillships and are favored for most harsh environments and if the drilling program requires closely spaced wells.

1.6. Activity States

Rigs transition through several distinct stages over their lifecycle (Figure A.27).

1.6.1. Active

Active rigs are working under contract and are the only state in which they receive income. Rigs receive income on a dayrates basis which is a rental charge for each day the rig is under contract, and includes the use of the rig and crew, but does not include most other costs associated with drilling the well. Dayrates vary depending on whether the rig is drilling, undergoing repairs, standing by, or in a mobilization/demobilization phase (Moomjian, 1999).

Contracts may be on a term or fixed-well basis. Term contracts specify contract duration; fixed well contracts specify the number of wells to be drilled. Term contracts are more common in most regions and markets, however, fixed well contracts are more common in the GOM jackup market. Fixed well contracts are typically used for short-term projects while term contracts are used for longer projects.

1.6.2. Ready-Stacked

Active rigs transition to inactive status when their drilling contract (work obligation) expires. If a rig is to be idled for a short period of time, the rig is typically maintained in a prepared or "ready-stacked" state. Ready-stacked rigs are idle but available for immediate use with minor preparation. In a ready-stacked state, normal maintenance operations similar to those performed when the rig is active are continued so that the rig remains work ready. Ready-stacked rigs are

3 For scale, a Nimitz class aircraft carrier is approximately 100,000 tons.

actively marketed and considered part of marketable supply. A hot-stacked rig is fully staffed and ready for immediate work. A warm-stacked rig requires minor preparation and the rehiring of semi-skilled workers.

1.6.3. Cold-Stacked

If operators do not expect a rig to be utilized in the near term, the rig is "cold-stacked." Cold-stacked rigs are frequently inactive for a period of several months to one or more years. Cold-stacked rigs are generally not considered part of the marketable supply and may not be counted in supply and utilization statistics. Cold-stacked units are stored in a wet dock (Figure A.28) and require capital and time to return to working condition. Cold-stacked rigs are maintained using inhibitive chemicals, and depending on the length of inactivity and value of the unit, doors may be welded shut and guards may be placed on duty to protect from vandalism. To bring back a cold-stacked rig into operational condition, a crew must be rehired and a series of inspection and testing procedures are required including power, load, and pressure testing; BOP certification; riser and tensioner inspection; and a host of other service checks (Aird, 2001).

Reactivation expenses vary widely depending on how long the rig has been out of service. For jackups, reactivation can range from \$4 to \$20 million and take up to 9 months (Rynd, 2012). For semis, reactivation can cost up to \$50 million and take 12 months. Due to these high costs, rigs are reactivated only after receiving a contract commitment, or if the contractor is confident the rig will successfully compete and win a work contract.

1.6.4. Dead-Stacked

A rig will transition between inactive states many times throughout its life, and as a rig ages, it will spend an increasing portion of its time cold-stacked. After being cold-stacked for several years, reactivation costs become prohibitive and a rig is labeled "dead-stacked." Dead-stacked rigs are used for parts before being retired and may remain dead-stacked for many years before being dismantled. Figure A.29 shows the dead-stacked rig *Zeus* being dismantled in the Freeport Ship Channel in Texas. All the rig equipment has been removed and two legs are currently undergoing cutting and removal operations.

1.6.5. Retired

A rig is removed from the fleet when it is sold for scrap, lost due to a catastrophic event (Figure A.30), or converted to another use. Conversion to a mobile offshore production unit or an accommodation unit is the most common alternative use. Rigs destroyed by hurricanes are scrapped or may be cleaned and towed to an approved reef site.

1.7. Rig Costs

Rigs and rig markets are described by newbuild and replacement costs. Newbuild costs are the costs charged by shipyards to build a rig. Replacement costs are an estimate of the costs to replace an existing rig with a new rig of like quality.

1.7.1. Newbuild Costs

Average newbuild costs by rig type are provided in Table A.8 for the 141 rigs under construction circa 2012. Jackups cost on the order of $200 million while semis and drillships cost approximately $600 million with drillships being slightly more expensive. There is wide variation in newbuild costs with some jackups exceeding the costs of some semis and some drillships costing over $1 billion.

1.7.2. Replacement Costs

Replacement costs are used for underwriting and financial valuation purposes to value the cash generating assets of drilling contractors. Replacement costs are not based on the depreciated newbuild costs of a rig or on second-hand market valuations, but are estimated by reference to the current newbuild market. Therefore, as prices in the newbuild market increase, replacement cost estimates respond similarly. Table A.9 shows replacement costs for selected Transocean rigs in early 2012. Due to robust activity in the newbuild market, replacement costs are relatively high, even for older units.

2. THE FIVE OFFSHORE RIG MARKETS

Contract drilling services are supplied by the newbuild and secondhand markets, are maintained and enhanced in the upgrade market, and complete their lifecycle in the scrap market. Each of the five markets engages in the trade of a unique service or good and differs with respect to key characteristics. The purpose of this chapter is to introduce the players, pricing, size and revenue of each market.

2.1. RIG MARKETS

2.1.1. Organization

The offshore rig industry is described by five markets: newbuild market, contract drilling market, upgrade market, secondhand market, and scrap market (Figure B.1).

2.1.2. Contract Drilling Services Market

In the contract drilling market, rigs are leased to exploration and production (E&P) firms to drill or service wells. E&P firms include international oil companies (IOCs), national oil companies (NOCs) and independents. The contract drilling market is the largest and most closely followed of the five markets and drives the activities of investors in the other markets.

2.1.3. Newbuild Market

The newbuild market is a specialized shipbuilding market in which labor and capital are used to convert steel and third party equipment into rigs. Drilling contractors enter into turnkey contracts with shipyards for the delivery of one or more rigs or yards may build on speculation.

2.1.4. Upgrade Market

Regular maintenance is required for safe and efficient operations and as a rig ages, its technology becomes obsolete and upgrades are required to sustain competitiveness and market value. The upgrade market is a ship repair market which both upgrades and maintains rigs for contractors. Shipyards in the newbuild market are often active in the upgrade market.

2.1.5. Secondhand Market

In the secondhand market, rigs are sold among drilling contractors and between contractors and other market participants. Rigs may be sold for use in the service market, may be converted to another use by the buyer, or sold for scrap.

2.1.6. Scrap Market

In the scrap market, shipbreaking firms buy rigs on the secondhand market, either directly from drilling contractors or from brokers. Equipment is reused where possible and the rig is dismantled with the steel recovered and sold for scrap to mini-steel mills. The scrap market is the smallest and least transparent of the five markets.

2.1.7. Cash Flows

Cash enters the contract drilling market when E&P firms purchase services from contractors. Drilling contractors use this cash to operate their units and acquire new rigs for their fleet and upgrade and maintain existing rigs. The newbuild and upgrade markets are the primary mechanisms by which capital expenditures leave the service market. Most transactions in the secondhand market occur between players in the contract drilling market.

2.1.8. Market Size

In 2010, the contract drilling market generated approximately $45 billion in revenue; approximately $18 billion flowed to the newbuild market which was associated with a peak in newbuild deliveries. Between $1 to $2 billion in capital expenditures was spent on rig upgrades and the secondhand market realized approximately $7 billion in market exchanges between companies. The scrap market is very small relative to the other markets and is usually valued at less than $50 million per year.

2.2. Contract Drilling Market

2.2.1. System Measures

The contract drilling market is described by dayrates, utilization and fleet size. Dayrate is the daily rental fee charged by the rig owner and includes the use of the rig and labor costs, but does not include most other costs associated with well construction (e.g. equipment rental, chemicals, casing, etc.). Dayrates behave according to demand and supply conditions and as rig demand exceeds supply, dayrates generally rise, and when there is too much supply, rates fall. Demand for contract drilling is driven by the capital spending patterns of E&P companies, which, in turn, is based on producer's expectations of future oil and natural gas prices, price volatility, and the availability and risks associated with exploring for and developing hydrocarbon resources. Dayrates are an indicator of market conditions and where company revenues are heading, and generally speaking, the same drivers that impact dayrates tend to drive the rest of the offshore service and support industry, so when rig dayrates rise, so does the cost of supply boats, helicopters, cementing, mud, wireline logging, etc.

Utilization is a system measure defined by the proportion of rigs working to the total fleet (i.e. active rigs/total fleet). Industry capacity is not a limited resource because companies can add rigs to respond to higher demand from producers and stack rigs when demand declines. While adding capacity takes years, drilling rigs have very long lives (25+ years) and when demand weakens, overcapacity in the market leads to prolonged declines in pricing. Utilization is a measure of the spare capacity in the market and can be computed at various levels of aggregation (i.e. firm, regional, submarket levels). High utilization rates cause dayrates to rise and provide a signal to operators that additional capacity can be absorbed in the market. Regionally elevated utilization rates lead drilling contractors to reposition fleets while globally high utilization rates encourage newbuilding investment.

Fleet size describes the total number of rigs of a given water depth or class. Fleet size is described by firm and when reported regionally is an indicator of the total capacity in the drilling market. The scale and quality of a drilling contractor's asset base is correlated with its revenue base. A large asset base implies a platform for sustainable earnings and cash flows and is related to a company's market position, its ability to compete in terms of cost structure and the ability to obtain financing for capital projects.

2.2.2. Players

The major players by 2011 rig counts are shown in Table B.1. Cold-stacked rigs are included in the count. In 2011, the fleet included 868 rigs. Fleet sizes change over time, but the changes are often slow and represent a small portion of a companies' asset base. The service market is dominated by a small number of publicly traded firms including Transocean, Noble Drilling, ENSCO, Diamond Offshore and Seadrill. In total, there are approximately 100 rig operators, but the top four firms – Transocean, Noble Drilling, ENSCO and Diamond Offshore – own 36% of the rigs and the top eight firms own over 50% of the rig fleet. There are many small players and the sector is highly fragmented which has led to consolidation over time.

The need for offshore drilling has evolved over time and in 2011 the service market is distributed throughout the world in the GOM, Brazil, Persian Gulf, Southeast Asia, India, China, the North Sea, Mexico and elsewhere (Table B.2). The top eight regions contain approximately 85% of the active fleet in 2011. Smaller markets include the Mediterranean, the Red Sea, Black Sea, Caspian Sea, Eastern Canada, the Caribbean and Western Australia. Frontier regions include the Arctic Ocean, East Africa, Ghana, and the Philippines and typically contain less than five rigs.

2.2.3. Prices

Dayrates are the primary contract specification during the bidding process and are highly variable over time and between regions. Dayrates are often announced by drilling contractors and are monitored by industry observers and assembled by commercial data providers (such as RigLogix, ODS-Petrodata, RigStar and RigData). Contract lengths are often less than a year in duration and so there is a steady stream of new contracts each month that provides a transparent and reliable indicator of the industry.

In Figure B.2, the six month moving average[4] of jackup and floater dayrates in selected regions are depicted. Prices were relatively stable from 2000 to 2005 before increasing sharply from 2005 to 2007 as oil prices rose; prices stabilized throughout 2007 and 2008, but following the 2008 recession; prices fell, especially in the more volatile jackup market.

In the jackup market, there are significant interregional differences. In the 2009 to 2011 period, jackup dayrates ranged from 50,000 to 100,000 $/day in the U.S. GOM compared with 100,000 to 175,000 $/day in the North Sea. Interregional dayrate differences in the jackup market are due to oversupply in the U.S. GOM, the large number of low spec rigs in the Persian Gulf and U.S. GOM, and the high cost of harsh environment jackups in the North Sea.

In the floater market, there is less variation between regions due to patterns of supply and demand, technical requirements, and the similarity of deepwater drilling rig capacity. In the

4 Moving averages were computed to smooth the month-to-month variation and improve the presentation.

2009-2011 period, floater dayrates generally ranged between 300,000 and 500,000 $/day with slightly lower dayrates in Southeast Asia than in the Atlantic basins.

2.2.4. Market Size

Since 1994, 2,500 to 3,700 wells have been drilled each year (Figure B.3). The number of deepwater (>400 m) wells has grown over the past 15 years while the number of shallow water (<400 m) wells has fluctuated. While many market participants are focused on the more lucrative deepwater segment, most drilling still occurs in shallow water. Figure B.4 shows the geographic distribution of offshore drilling in 2011. Asia accounted for nearly half of drilling activity while the Atlantic basins of North and South America, West Africa and the North Sea accounted for remaining activity. North America activity is dominated by drilling in the U.S. GOM, but due to the Macondo blowout on April 20, 2010, and subsequent drilling moratorium, activity levels are depressed relative to historic levels

2.2.5. Market Value

The market value of the offshore drilling market in 2010 is shown in Table B.3. We counted the number of rigs of each class active in each month and region, and multiplied by the average regional dayrate. We estimate that E&P firms paid approximately $43 billion to drilling contractors in 2010. Despite the fact that deepwater drilling makes up a relatively small proportion of the number of offshore wells drilled, the deepwater market accounts for approximately two-thirds of market revenue. Over the past decade, the contract drilling market has varied from $25 to $50 billion (Figure B.5)

Market valuation is subject to uncertainty. Large markets with a high degree of involvement by IOCs and publicly-traded drilling contractors are transparent and may be estimated with a degree of confidence. However, for small markets or those dominated by NOCs and state-owned drilling contractors, our confidence in the estimates declines and it is particularly difficult to reliably estimate the size of the Chinese market due to the large number of state-owned rigs. Additionally, the U.S. GOM data are complicated by the Macondo blowout which reduced the number of rigs operating in the GOM for much of 2010.

Table B.4 compares our estimates to those of the market intelligence firm INTSOK. Our results are lower than INTSOK's across most regions and our total market value estimate is also lower. The difference is due to the methods of analysis and the definition of the market. We only estimated payments to drilling contractors for MODU services, while INTSOK's estimates also include well management and platform rig costs.

2.3. Newbuild Market

2.3.1. System Measures

The newbuild market is specified by the number of deliveries and their prices. The market is transparent because newbuilding is a significant capital expenditure for drilling contractors and a significant source of revenue for rig-building shipyards. Prices are widely reported for investment purposes and tracked by the same firms that survey dayrates.

Drilling contractors order rigs when the expected rate of return (or net present value) from operating a new rig exceeds internal investment criteria. The benefit of investment depends on dayrates and utilization rates over the lifetime of the rig. Since these are unknowable, assumptions based on current market conditions are used. As market conditions change, the assumptions used in financial analysis respond, and investment in newbuilding may be justified. Since the newbuild market depends on dayrates and utilization rates in the contract drilling market, the cyclical nature of the contract drilling market causes similar but delayed cycles in the newbuild market.

Prices in the newbuild market are a function of demand and labor prices at shipyards, equipment costs and steel costs. As demand at shipyards increases, backlogs develop and shipyards are able to demand higher prices. In addition, demand at rig-building shipyards is generally associated with demand across the drilling supply chain. Therefore, demand and prices for drilling equipment typically increase along with demand at shipyards and this leads to further price increases.

2.3.2. Players

The largest shipyards in each segment of the market in the first quarter of 2011 are presented in Table B.5. The jackup market is dominated by Keppel and its subsidiaries, while the drillship market is dominated by Daewoo and Samsung. Keppel has shipyards located throughout the world, while the Daewoo and Samsung yards are located in Korea. The semi market is currently distributed among five Asian shipyards. Table B.6 shows the number of rigs under construction by nation circa 2011 and estimated capital expenditures. Measured by capital flows, the rig building industry in South Korea is approximately twice as large as the Singaporean industry, however, this is due to the current boom in drillship construction and may not continue after the current round of drillships are delivered.

2.3.3. Prices

Figure B.6 shows the average construction costs of jackups and floaters during the most recent newbuild cycle. The costs of jackup rigs increased from approximately $100 million for rigs delivered in 2004-2005 to approximately $200 million for rigs delivered in 2012-2013. The price difference between high-spec (>350 ft) and standard (<350 ft) jackups varied only slightly over most of the cycle. When price differences were significant (as in 2010-2011) it was because several expensive harsh environment high-spec jackups were delivered, rather than any real differentiation in cost. Both ends of the jackup newbuild market respond to the same market stimuli due to similarities in the rigs and the firms engaged in construction.

Drillships are usually more expensive than semisubmersibles with premiums ranging from a minimum of $69 million in 2011 to $275 million in 2012. Newbuild prices for semis peaked in 2011 while prices for drillships peaked in 2012 and average prices for 2013 deliveries are lower than 2012 levels for both rig classes.

2.3.4. Market Size

Figure B.7 illustrates the long-term history of the newbuild market. The market is cyclical and has exhibited several cycles over the past four decades. From the beginning of the industry in the U.S. in the late 1950's through mid-1970's the industry spread to Europe and Asia as activity levels increased. Before 1974, a total of 22 jackups and 18 floating units had been delivered. In the late 1970's and early 1980's, oil prices rose and the market grew rapidly, peaking in 1982 when 70 jackups and 11 floaters were delivered.

Oil prices declined in the early 1980's and demand collapsed; between 1986 and 1997, a total of 37 rigs were delivered. By the late 1990's, drilling technology had advanced to allow exploration in ultra-deepwaters, but few rigs were capable of ultra-deepwater drilling. Drilling contractors responded by upgrading existing rigs and ordering a limited number of floaters, the first of which were delivered in 1998. Jackup orders also began in this period, due to concerns about the age of the fleet and interest in more challenging reservoirs.

During the 2000 to 2005 period, approximately five jackups and five floaters were delivered each year. In 2005, the number of jackup orders increased dramatically followed by an increase in floater orders, due in large part to increasing oil and gas prices. Jackup deliveries peaked in 2009 when 38 rigs were delivered, while floater deliveries peaked in 2011 with the delivery of 52 rigs. In every year since 2000, high-spec jackup deliveries have outnumbered standard jackups and in 2011, only 3 standard jackups were delivered compared to 33 high-spec rigs.

2.3.5. Market Value

The value of the newbuild market is estimated[5] by summing the prices of rigs delivered in a given year. Figure B.8 depicts the value of rig deliveries by year. The value of the newbuild market peaked in 2010 at approximately $18 billion. In most years, floaters have made up the majority of the market value while jackups make up the majority of deliveries. 2009-2011 witnessed a peak in market revenue due to the high demand in the 2007-2009 period. Orders declined in 2009 and 2010 due to the recession, and as a result, market revenue in 2012 is expected to be low.

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5 The values computed underestimate the market size because cost information is not available for all rigs. Data for some rigs, such as those built by a state-owned shipyard for a state-owned drilling contractor, are not publicly released.

2.4. UPGRADE MARKET

2.4.1. System Measures

Rigs periodically undergo maintenance and upgrades, and the scale of these modifications can vary considerably. Periodic maintenance occurs over a three to ten year period and typically consists of painting, replacing corroded or worn components, upgrading living quarters, and changing out machinery and equipment. Maintenance is performed to repair defects, accommodate customer demands, or maintain the useful life and value of the rig. Maintenance does not increase the value of a rig and is typically billed to operating accounts and require between several days and several months to perform.

In addition to periodic maintenance, rigs are generally upgraded at least once over the course of their lifetime to improve technology and maintain competitiveness. Rig upgrades involve significant capital expenditures and often involve structural changes to the rig including adding dynamic positioning, increasing leg length, adding cantilever capability and increasing variable load (Dupuis and Hancock, 2008; Snyder and Childers, 1989). Installation of new drilling equipment is also common. Upgrades increase the value of the rig and its replacement cost and are considered a capital expenditure. Upgrades require at least several months to perform.

There are three categories of upgrade and refurbishment costs (Seeking Alpha, 2011). In some cases, E&P companies require modifications to a rig before commencement of a contract. These typically do not significantly alter rig specifications and are charged to the E&P company, either as a lump sum payment or amortized over the duration of the contract. Contractors spend money to maintain the rig in an acceptable state; these costs are considered operating expenditures. Finally, there are costs incurred to upgrade the specifications of the rig or extend its life; these costs are considered capital costs.

2.4.2. Players

There are minor infrastructural requirements for most maintenance activity, and in many cases, repairs and maintenance can be performed at local ports without shipbuilding or drydocking facilities (Wahlberg and Williams, 2010). More intensive upgrades are conducted at specialized facilities. The shipyards conducting major upgrades in 2009 and 2010 are given in Table B.7. Lamprell and Keppel are the dominant players and no other shipyard upgraded more than one rig. Other firms active in the upgrade market include Signal International in the U.S., Gulf Cooper in the U.S., Drydocks World in the U.A.E., Larsen and Toubro in Oman, Malaysia Marine and Heavy Engineering in Malaysia, Maua Shipyard in Brazil, PD&MS in the U.K., Rijeka Shipyard in Croatia, and Remontowa in Poland.

2.4.3. Prices

Tables B.8 to B.10 provide a sample of jackup, semi and drillship upgrade contracts. The scale of upgrades varies widely, and the scope of work allows the variation in cost to be better understood.

In Table B.8, recent jackup upgrades have cost between $10 and $30 million. These upgrades may include painting, upgrades to drilling equipment, upgrades to accommodations, the replacement of piping or electrical systems, and inspection and repair of legs and spudcans. Upgrade costs can exceed $50 million but at higher prices many firms choose to newbuild rather than upgrade (Maksoud, 2002).

Floater upgrades vary significantly in price from $15 to $340 million (Tables B.9 and B.10). At the high end of this range are complete rebuilds in which the firm uses an existing hull and replaces nearly all other components. At the low end are modifications to a small number of systems or components. The $152 million upgrades of Noble's drillships *Roger Eason* and *Leo Segerius* are representative. These upgrades added a new stern block including 85% of the ships' marine operating systems, refurbished the derrick, replaced the top drive, replaced cranes, and increased the power of the dynamic positioning system.

2.4.4. Market Size

The number of major upgraded rigs delivered between 2000 and 2010 is shown in Table B.11. Major upgrades require several months and would be considered capital expenditures. On average, 17 jackups, and 13 floaters were upgraded each year, and there were notable peaks in 2004 and 2007 approximately coinciding with the timing of newbuilding orders. This suggests that firms invest in upgrading under roughly the same conditions in which they invest in newbuilding. In total, 287 rigs were upgraded between 2000 and 2010, representing approximately half of the active fleet.

2.4.5. Market Value

Estimating market revenue is complicated by the range of costs associated with upgrades and the definition of what constitutes an upgrade. Therefore, we provide a range of market values by assuming a minimum and maximum expected upgrade cost per rig. We estimate that jackup upgrades cost at least $10 million and each floater upgrade costs at least $75 million; at a maximum, we estimate the upgrade costs as $25 and $250 million for jackups and floaters, respectively. Upgrade costs for individual rigs may fall outside of this range, but we expect the average cost in the 2010-2012 period to fall within these values. Given these assumptions, the upgrade market is estimated to have an average value of between $1 and $3.4 billion per year.

2.5. SECONDHAND MARKET

2.5.1. System Measures

The secondhand market includes a broad range of transactions. Rigs sold on the secondhand market may be old or may be newbuilds; units may be sold through mergers, liquidations, or private transactions; rigs may be sold with or without an existing contract backlog, and buyers may continue to use the vessel as a rig or may convert it to another use.

Transactions are conducted for a wide variety of reasons, reflecting the diversity of transaction types. In some cases, firms sell rigs due to bankruptcy; Hercules' purchase of Seahawk's rigs and Seadrill's purchase of PetroProd's rig are examples. In other cases, firms sell rigs to eliminate non-core assets. Frequently, this involves a large drilling contractor selling older rigs to a low-spec specialist; for example, Diamond and Transocean have both divested older jackups in recent years. Finally, rigs may be purchased through the takeover of one firm by a larger firm; examples include Seadrill's purchase of Scorpion and Transocean's purchase of Aker Drilling.

2.5.2. Players

The number of transactions by major market players between 2005 and 2010 is shown in Table B.12. Hercules and Seadrill have been the biggest buyers in the secondhand market while Transocean has been the biggest seller. Seadrill has targeted newbuild and high-spec rigs while Hercules has focused on less-expensive, low spec units. Transocean has been active in divesting older rigs, particularly jackups. Songa has been active on both sides of the market.

2.5.3. Prices

Prices on the secondhand market are determined in part by the net asset value (NAV) of the rig. NAV is an estimate of the net revenue generation potential by a rig over its remaining life. In the absence of market constraints the secondhand price should approximate the NAV, however, imperfect information, supply-demand imbalances, and financial pressure (e.g. bankruptcy) may cause NAV and secondhand market prices to differ.

Table B.13 shows the range in costs of rigs purchased on the secondhand market in 2005-2010. The range in secondhand prices is large and this is due to the variance in rig age and factors related to the buyer and seller and market conditions. The minimum value of a rig on the secondhand market is $5 million for both jackups and floaters and this is approximately equal to the scrap value of a rig. Low-priced transactions are frequently associated with conversion to another use.

The maximum price for a secondhand rig can, in theory, exceed the price of a newbuild rig. Secondhand rigs may be sold with an existing contract backlog, and this is particularly common when one firm buys all of the rigs from another firm; recent examples include Seadrill's purchase of Scorpion, Hercules' purchase of Seahawk Drilling, and Transocean's purchase of Aker. Sale with a contract backlog will increase the NAV. Secondhand rigs may also be more valuable than newbuild rigs because they are available immediately while newbuild rigs may only be delivered after a multi-year delay. This allows secondhand rigs to begin generating revenue immediately, increasing NAV. In recent years, secondhand prices for recently built rigs have been approximately equal to the newbuild price.

2.5.4. Market Size

Table B.14 shows the number of rigs sold through the secondhand market from 2005 to 2010. On average, about 20 rigs were sold each year with the majority being jackups. From 2005 to 2010, jackups transacted the most (82), followed by semis (31) and drillships (13).

2.5.5. Market Value

The total annual size of the secondhand market is estimated to be on the order of $2 to $4 billion (Table B.14). When cost data for a particular transaction were not available, the value of the transactions was estimated based on the age of the rig, its water depth capability, and the average cost of similar transactions in that year; a conservative approach was used for these estimates and as a result the values in Table B.14 are likely to underestimate the value of the secondhand market. High market value in 2010 was due to three transactions: the purchase of Skeie Drilling by Rowan, the purchase of Scorpion by Seadrill, and the purchase of Frontier by Noble. Each of these transactions exceeded $1 billion.

2.6. SCRAP MARKET

2.6.1. System Measures

In the scrap market, cold-stacked rigs are sold to specialized shipbreaking firms for dismantling and recycling (Kaiser, 2008). Owners place a premium on resale and reuse options and a low priority on scrapping because of the significant residual value in units, and as a result, rigs are rarely scrapped unless they have sustained damage from storms, blowouts or other accidents. Between 2005 and 2011, just seven rigs were sold for scrap (RigLogix, 2011).

Rig scrapping is a small part of the larger ship breaking industry concentrated in India, Pakistan, China, Turkey and Bangladesh (Saraf et al., 2010). Shipbreaking that occurs in the U.S. is primarily driven by disposal of U.S. Navy ships and other federal vessels and very little rig hull deconstruction occurs domestically. Between 2005 and 2010, only one rig (the jackup *Zeus*) was dismantled in the U.S. without first receiving storm damage (Arnold and Itkin, 2008).

2.6.2. Players

Very few drilling contractors scrap rigs. Hercules is the only major drilling contractor to sell a MODU to a scrapyard in the 2005 to 2011 period, and has sold six jackups and one submersible during this period. In addition, Seadrill sold one tender for scrap.

Rigs are occasionally scrapped after being damaged in hurricanes if repairs are uneconomic. For example, *Ocean Warwick* was badly damaged during hurricane Katrina and drifted 60 miles before being grounded. The rig was sold to Nabors, repaired, and is currently operating as *Nabors 660*. When rigs are scrapped following damage, a marine salvage firm (i.e. Smit) is contracted to remove the rig from its offshore location, and the rig is typically transported to the nearest shipyard and scrapped.

2.6.3. Prices

Most of the value in an obsolete rig lies in the drilling equipment which is removed and sold before the rig is scrapped. Vessels are sold to ship breaking firms directly or via brokers on a per ton basis and the value of a vessel will principally depend on its weight and the labor required to dismantle the unit. The scrap metal price at the time of the sale is a principal factor in the value. In 2010 and 2011, Hercules sold five jackups for scrap ranging between $1 and $5 million and with an average price of $2.5 million. This is consistent with prices in the range of $300 to $550 per ton, and is similar to scrap prices for other vessel classes.

2.6.4. Market Value

Given the small number of rigs scrapped per year and the low value of scrapped rigs, the size of the scrap market is negligible relative to the other rig markets. In many years, no rigs are scrapped, and when rigs are scraped the value of individual transactions are based on the rig weight and scrap metal price at the time of sale, rarely exceeding $5 million per unit. We estimate the average size of the market to be less than $50 million annually. As the legacy fleet continues to age, scrapping activity could increase and the market may grow; since many aging rigs are in the GOM, some of these rigs are likely to be processed by U.S. ship recyclers. The firms most likely to process scrapped rigs in the U.S. are ESCO Marine, International Shipbreaking, Marine Metals and All-Star Metals, all of which are located along the Brownsville, Texas ship channel.

3. THE OFFSHORE CONTRACT DRILLING MARKET-SUPPLY, UTILIZATION, AND DAYRATES

In the contract drilling market, E&P firms lease rigs from drilling contractors to drill wells. Approximately 120,000 wells have been drilled offshore since 1955, and about half of these are in the U.S. GOM (ExxonMobil, 1995). From 2000 to 2010, approximately 3,500 offshore wells were drilled each year with a growing percentage in deepwater (Douglas-Westwood, 2009). The purpose of the next two chapters is to characterize the offshore contract drilling market statistics and regional trends, contractors, business strategies, and market structure. In this chapter, we begin with a description of the global supply of rigs and their geographic distribution over the past decade. We characterize regional dayrates and utilization and the contracts that are used in the industry. Summary conclusions end the chapter.

3.1. DATA SOURCES

3.1.1. Utilization and Supply

Regional utilization rates and fleet sizes were obtained from the commercial service provider RigLogix and supplemented with data from Baker Hughes. RigLogix provided data on the number of contracted rigs and utilization rates from 1999-2011, while Baker Hughes provided information on the number of active rigs from 1987-2011. Contracted rigs may be drilling, performing a workover, waiting on location, mobilizing or under modification. Active rigs are defined by Baker Hughes more narrowly as rigs that are engaged in drilling and are therefore a subset of contracted rigs. Rigs engaged in workovers, production testing, or drilling for less than 15 days in a month are not considered active. In the international data, a rig must be drilling 15 days a month to be counted as active; in North America, a rig is active from the time a well is spudded until it reaches its target depth. Baker Hughes data does not differentiate between floaters and jackups.

3.1.2. Dayrates

Dayrate data were obtained from RigLogix. The dataset included information on 7,123 individual contract records for jackups, drillships and semisubmersibles between January 1, 2000 and January 1, 2011. Each contract data point included information on contract duration, location, water depth, and contract type. Contracts in the Persian Gulf, U.S. GOM, North Sea, Southeast Asia and West Africa were considered. Monthly average dayrates were computed as the average of the dayrates of all contracts for which drilling began in that month (Figure C.1). Dayrates were inflation adjusted using the U.S. BLS annual producer price index for all finished goods and the start year of the contract.

3.2. SUPPLY

The world fleet of offshore drilling rigs in January 2012 is categorized by type in Figure C.2. Of the 868 existing rigs, 539 are jackups and 329 are floaters; 644 (87%) of the total inventory were active in January 2012, and of these working rigs, 404 are jackups (83% utilization) and 259 are floaters (93% utilization).

The jackup inventory is composed of 201 low spec (<300 ft, non-harsh environment) units and 336 high spec units (>300 ft or harsh environment); 45 of the high spec units are capable of drilling in harsh environments, such as the North Sea, Eastern Canada, and the Arctic. The floater fleet is dominated by semis (223 semis versus 106 drillships).

Figure C.3 shows the distribution of high and low specification rigs according to contracted, ordered and stacked status in January 2012. The jackup and drillship fleets are dominated by high-specification, deepwater newbuilds (> 300 ft for jackups; > 7,500 ft for drillships) while the semi fleet is dominated by mid-water (< 7,500 ft) units. Semis comprise the majority of the floater fleet, but after the delivery of drillships under construction, drillships will comprise the majority of the high spec floater fleet. Most supply addition is occurring in the drillship and jackup markets and relatively few semis are under construction.

3.3. Geographic Distribution

Wells are drilled wherever hydrocarbon potential exists and mineral rights (concessions) are granted, but for geologic, economic, technological, political and historical reasons, offshore drilling remains concentrated in a relatively small part of the world's oceans.

3.3.1. Regional Characteristics

The Persian Gulf, U.S. Gulf of Mexico (GOM), Brazil, North Sea, Southeast Asia, India and China are the largest markets and account for approximately 80% of the 2011 rig market (Table C.1 and Figure C.4). Smaller markets with less than 25 active rigs in 2011 include the Mediterranean Sea, Black Sea, Caspian Sea, Eastern Canada, the Caribbean and Western Australia. Frontier regions include the Arctic Ocean and East Africa, as well as previously unexplored countries in developed regions such as Ghana in West Africa and the Philippines in Southeast Asia (Ball, 2010). Frontier regions are defined as having less than 5 active rigs.

Table C.2 summarizes characteristics of the major markets and Table C.3 describes the average water depth of jackup and floater contracts by region from 2000-2010. The average working water depth is a general indicator of the specification level of the rigs required in the region, and the standard deviation and range describe the extent of the variation required in drilling units. China, the U.S. GOM and Persian Gulf are the shallowest jackup markets and the maximum water depths in the Persian Gulf and China are approximately 300 ft. India, Southeast Asia and the North Sea are the deepest jackup markets and are the most likely to require high spec jackups. In some cases, floaters are used for shallow water drilling and this decreases the average water depth of floater contracts; in general, floaters used for shallow water drilling are older semis. The North Sea is a particularly shallow floater market because of the harsh environmental conditions while the U.S. GOM, Brazil and West Africa are the deepest markets.

Table C.4 provides a snapshot of the number of contracted and ready-stacked rigs by region, water depth and environmental operating conditions in 2011. A number of regions have some harsh environment units, but the North Sea is the only region in which harsh environment units make up the majority of the fleet. In all other major regions, harsh environment rigs are not required. Table C.4 also illustrates the distribution of the fleet by water depth. The Persian Gulf, China and U.S. GOM have a large number of <300 ft jackups, while Southeast Asia and India are dominated by >300 ft water depth units. In the floater market, the North Sea has a large number of <7,500 ft units, consistent with the average water depth of wells in the region.

3.3.2. Active Rigs

The geographic distribution of rigs follows the capital budget allocations of firms, hydrocarbon prospectivity, economic and political conditions, and other factors. Figure C.5 shows the six month moving average of the number of active offshore rigs globally and by region between 1987 and 2012. Active rigs include both floaters and jackups.

The number of active rigs in the North Sea and U.S. GOM has declined over the past decade. In the U.S. GOM, the number of active rigs peaked at approximately 160 in the early 2000's while in the North Sea, approximately 70 to 80 rigs were active throughout much of the mid to late 1980's; as of 2012, only 30-40 rigs are active in each region. After the Macondo oil spill in the U.S. GOM in 2010, a moratorium on deepwater drilling was enacted, but with the expiration of the moratorium, activity has rebounded. Both Southeast Asia and Persian Gulf markets have seen a doubling in rig count over the past 25 years from approximately 20 in the late 1980s to approximately 40 in the 2007-2012 period. West Africa peaked in the late 1990's with 35 rigs and declined to about half that level in the mid 2000's before returning to the 1990's levels in 2012.

The distribution of rigs by country within selected regions is shown in Figure C.6. In the North Sea, rig activity has declined due to a decline in the U.K. sector which has been partially offset by growth in Norway. In the Persian Gulf, growth has been uneven over the past two decades and the UAE, Qatar and Saudi Arabia have all been the dominant player at different times. Since 2005, most growth has occurred in Saudi Arabia which has been offset by a reduction in Iranian offshore activity. Nigeria has been the dominant player in the West African market since the early 1990's, but since 2009 there has been significant growth in Congo, Gabon, Ghana, Liberia, Sierra Leone and Cameroon, in part due to the end of several civil wars in the region. In Southeast Asia, activity levels in Indonesia and Malaysia have been relatively stable over the past two decades with significant growth in other nations including Vietnam and Thailand.

3.3.3. Contracted Rigs

The number of contracted jackups is closely correlated with the number of active rigs in the U.S. GOM (Figure C.7), but elsewhere, correlations are not as strong due in part to rigs that are under contract but not actively drilling (Table C.5) reflecting the way Baker Hughes counts active rigs in the U.S. GOM and internationally.

The number of contracted and active rigs follows broadly similar patterns over the 1999-2012 period (Figures C.8 and C.9). In the jackup market, the Southeast Asian and Persian Gulf markets have experienced consistent growth, while the North Sea market has remained relatively stable. West Africa has varied between 10 and 25 contracted jackups between 1999 and 2012 and experienced a dramatic decline following the 2008 recession. The U.S. GOM jackup market experienced declines in 2001 and 2009 associated with economic recessions in the U.S. and has seen a general decline in contracted jackups due to the maturity of the GOM shelf.

In the floater market, West Africa realized consistent growth between 1999 and 2012. Southeast Asia has had a relatively stable number of contracted floaters over the period, with a slight increase between 2008 and 2012. The GOM and North Sea had a peak in activity in mid to late 2001, followed by a sharp decline. Since 2002, both markets have had a relatively constant activity level.

3.4. UTILIZATION

Utilization is defined as the ratio of the number of working rigs to the number of rigs available to work at a specific point in time. The number of available rigs can include cold-stacked rigs or these units can be excluded. If cold-stacked rigs are included in the count (as is most often the case), then dead-stacked rigs that are counted as cold-stacked will bias the utilization measure downward, and regions with large numbers of dead-stacked rigs will have lower utilization rates. If cold-stacked rigs are not included, utilization rates would appear inflated and may not accurately reflect the number of rigs available to bid on a given contract. We report utilization rates including cold-stacked rigs.

3.4.1. World Trends

Worldwide rig utilization from 2000 through 2011 is shown in Figure C.10. A six-month moving average was applied to reduce short-term variation. At the beginning of the decade, jackup utilization rates exceeded floater rates, but since 2006 floaters have been more heavily utilized. In the jackup market, utilization declined throughout 2009 due to the economic recession and low oil prices; in the floater market, utilization rates declined only modestly between 2009 and 2011. Jackup and floater market utilization respond to different market stimuli and reflect differences in technology development and regional prospectivity, the timing of newbuilding orders and deliveries, and the impact of oil prices. There is no significant correlation between global jackup and floater utilization rates suggesting that regional markets are required to differentiate the trends.

3.4.2. Regional Trends

Figures C.11 and C.12 show utilization rates of jackups and floaters in selected regions. In the jackup market, utilization trends in Southeast Asia, the North Sea and the Persian Gulf have tracked each other closely over the past decade, exhibiting similar market dynamics and high utilization levels, while the U.S. Gulf of Mexico and West Africa have exhibited more variable trends over the period. In recent years, the U.S. GOM has had consistently lower utilization rates than other regions due to the decline in the shallow water market (Table C.6).

In the floater market, Southeast Asia historically had lower utilization rates than other regional markets, except for a brief interval in 2002-2003. Brazil has especially high utilization rates with sustained periods of 100% utilization due to Petrobras' role as the E&P monopolist which allows drilling contractors to better match demand and supply from a central decision making firm. In the U.S. GOM, the post-2009 decline in utilization rates has been negatively impacted by the Macondo oil spill.

3.4.3. Interregional Correlations

To the extent that global factors impact supply and demand conditions, utilization rates are expected to be correlated across regions. Conversely, if regional factors predominate, increases in utilization in one region may not be associated with increased utilization in another region and interregional correlations are expected to be poor. Oil prices, for example, form in the world market and provide similar signals to E&P firms worldwide, and if oil prices are a major driver of utilization rates, high correlations are expected; by contrast, if gas production and prices are a major driver of utilization in one or more regions, or regulatory factors dominate, low correlations are expected.

In the jackup market (Table C.7), the U.S. GOM has the lowest correlation with all other regions indicating that region-specific factors in the U.S. GOM are impacting utilization. The Persian Gulf is poorly correlated with the U.S. GOM and North Sea due to the growth in the Persian Gulf market and the decline in the more mature U.S. GOM and North Sea markets. Utilization rates in most other regions are moderately correlated ($R \geq 0.7$) indicating that global factors (e.g. oil prices) affect the regions similarly.

In the floater market (Table C.8), Southeast Asia is poorly correlated with all other regions, suggesting that regional factors dominate the market dynamics. The small negative correlations between Southeast Asia and other regions indicate no relationship, rather than a meaningful negative relationship. In general, correlations are slightly lower than in the jackup market, and the U.S. GOM and North Sea, and North Sea and Brazil, are the only regions in which the correlation coefficient exceeded 0.7. The lower correlations among the floater fleet are believed to be partially due to the high utilization rates for floaters; variation in utilization in one region may be unable to resolve small changes in variation in another region.

3.4.4. Market Conditions May Act to Reduce High Utilization

When a regional fleet is highly utilized, drilling contractors respond by marketing inactive rigs from other regions or newbuild in the high utilization market. As these rigs win contracts, they are moved into the high utilization region, increasing regional fleet size and capturing market share; over time, if the market cannot sustain the larger fleet size, utilization rates will decline. Drillers with deepwater fleets often use their backlogs to maintain earnings while stacking surplus mid-water and shallow water rigs to support prices in the markets.

Figure C.13 illustrates the concept of market capacity increasing in response to high utilization rates while Figure C.14 depicts specific examples in the Persian Gulf and Southeast Asian jackup markets. In both markets, utilization rates were high for a period of several years, and during this time contractors responded by newbuilding and moving rigs into the region doubling (Persian Gulf) and tripling (Southeast Asia) capacity. Eventually utilization rates declined. Similar patterns may not exist elsewhere or at different times. For example, in the North Sea jackup market utilization rates were high for an extended period without an increase in rig count (Figure C.15) likely reflecting the low number of harsh environment jackups capable of moving into the region.

3.5. Dayrates

Dayrates are the primary contract specification during the bidding process and a primary descriptor of the industry. Dayrates are determined by the supply and demand balance of rigs proxied by the utilization rate. For a given supply of rigs available to work in a given region, as utilization rates in the region increase, the number of rigs capable of bidding on a given contract declines and pricing power shifts to the drilling contractor, leading to higher dayrates. High dayrates provide signals to the market that the region is capable of absorbing additional rigs, and contractors either move units into the region or begin newbuilding. As dayrates decline and competition increases for contracts, drilling companies stack units or move rigs out of the market which acts to support prices.

3.5.1. Trends

In Figure C.16, the six month moving average of jackup and floater dayrates in major markets are depicted. From 2000 to 2005 stable dayrates generally prevailed followed by a sharp increase from 2005 to 2007, price stabilization in 2007 to 2009, and a decline in 2009 and 2010.

Table C.9 reports mean dayrates by region in the 2000-2006 and 2006-2010 periods. In the jackup market, Southeast Asia and West Africa have very similar average dayrates, while the Persian Gulf and U.S. GOM are significantly lower and the North Sea is significantly higher, reflecting the regional supply and demand conditions and different environmental characteristics. The Persian Gulf and U.S. GOM are relatively benign operating environments while the North Sea is a harsh environment region. In the floater market, the differences in dayrates between the two periods are more uniform reflecting the homogenous nature of the floater fleet and capacity to drill wells.

3.5.2. Interregional Correlations

Regions differ in their geologic prospectivity, fiscal regimes, development costs, political risk, and strategic value (Stroebel and Van Benthem, 2010). If regions are market oriented they will generally respond to the same market stimuli; if regions are dominated by one or more NOCs, market stimuli are expected to play a less significant role in determining dayrates. As oil prices rise, E&P firms demand drilling leading to increases in utilization and dayrates. The rate of increase in each metric is not constant across regions, but the direction of the relationship is consistent and this creates interregional correlations.

In Table C.10, the correlation of average monthly jackup dayrates between regions is depicted. For most regions, there is a modest correspondence between regions with correlation coefficients ranging between 0.49 and 0.90. While all correlations are statistically significant, dayrates in one region usually explain 25 to 60% of the variation in another region, and while regional dayrates do move together, significant interregional variation remains. The moderate correlation between regions supports the regional categorization of the market. If correlations between markets were close to one, it would be more reasonable to consider the regional markets a single global market rather than a set of interacting regional markets.

The U.S. GOM jackup market is the least correlated with other regional markets which suggests that regional supply and demand conditions, a large number of players, onshore gas production, and other regional factors play a significant role in the pricing environment. West Africa and Southeast Asia are highly correlated suggesting similar market dynamics between regions. Both West Africa and Southeast Asia are relatively mature moderate water locations with similar environmental characteristics. This is in contrast to the North Sea, a harsh weather region, the U.S. GOM, which has experienced a sustained decline in rig count with shelf maturity, and the Persian Gulf, which has experienced a sustained increase over the time period assessed.

Table C.11 shows the regional floater dayrate correlation matrix over the past decade. The regional correlations are higher in the floater market than in the jackup market, and this is at least partially due to the more global nature of the floater market. Correlations between the three Atlantic basin regions are higher than the correlations between any of these regions and the Southeast Asian market, suggesting that these three markets interact with each other more than they do with Southeast Asia because of their geographic proximity.

3.5.3. Dayrate Volatility

Volatility is a measure of the magnitude of dayrate changes over time and is calculated analogous to volatility metrics used in financial markets (Besley and Bringham, 2009). Volatility was calculated as the standard deviation of the percentage change in dayrates between quarters. A quarterly basis was used to reflect the minimum time to drill a well (three months) and to increase the sample size in each period.

In small regions with a small number of contracts negotiated in a given quarter, the effect of outliers will be magnified and high volatility is expected because of the sample size. Regions that have a large variation in the specifications of rigs required (for example, harsh and non-harsh environments or broad variation in water depths) may also experience higher volatility. Figure C.17 illustrates the quarterly change in dayrates for the highest and lowest volatility regions in the jackup and floater markets. Table C.12 describes the volatility by region. The Southeast Asian floater market is particularly volatile, likely due to the smaller size of the market. The Persian Gulf jackup market is the most volatile shallow water market. Floater markets are more volatile than jackup markets reflecting the smaller number of contracts in the floater dataset.

3.6. CONTRACTS

3.6.1. Dayrate vs. Turnkey

Drilling contracts may be on either a “dayrate” or “turnkey” basis. Under dayrate contracts, the contractor receives a fixed amount per day for drilling the well with higher rates while the unit is operating and lower rates or a lump sum payment for periods of mobilization or when operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other factors (Osmundsen et al., 2006; Moomjian, 1999; Moomjian, 1992). The E&P company bears all of the ancillary costs of constructing the well and supporting drilling operations and carries the risk for the overall success of the operation.

In a turnkey drilled well, the E&P company defines the well specifications (e.g., total depth and target, minimum hole size at total depth, formation evaluation requirements) and retains a turnkey company to plan and supervise the well on a lump-sum basis (Jablonowski and Kleit, 2006). The turnkey company subsequently retains a contractor under a dayrate contract. The turnkey company, not the drilling contractor, holds all of the risk of cost overruns. Turnkey contracts are relatively rare and are used primarily for exploration drilling by jackups when the E&P company is a small firm with limited financial and technical expertise (Moomjian, 1999; Corts, 2008). The U.S. GOM is the largest turnkey market in the world, but less than 5% of all contracts are estimated to be turnkey.

3.6.2. Term vs. Well

Contracts for drilling services may be on either a term or fixed well basis. Term contracts specify contract duration; fixed well contracts specify the number of wells to be drilled. Term contracts are more common in most regions and markets (Table C.13), except in the U.S. GOM jackup market and Southeast Asia floater market. Fixed well contracts are typically used for short-term projects while term contracts are used for longer projects; worldwide, the average duration of fixed well contracts for all regions over the period 2000-2010 was 106 days, while the average for term contracts was 456 days.

In the shallow water U.S. GOM, jackups frequently work on a one-well basis and contractors have to find a new job at the completion of every well they drill. In most other markets, long-term contracts are prevalent. Table C.14 shows the average contract duration by region for contracts between 2000 and 2010. The average duration of jackup contracts in the U.S. GOM is significantly shorter than in other regions, but elsewhere deepwater and shallow water rigs operate under similar contracts.

Markets that are dominated by short-term or fixed contracts may exhibit more volatility in dayrates than term dominated regions since negotiations occur at a higher frequency more closely reflecting market conditions. This would imply that the U.S. GOM jackup market would be more volatile than jackup markets in other regions; however, this is not the case. Instead, the Persian Gulf jackup market which is dominated by long-term contracts is the most volatile shallow water region.

3.7. CUSTOMERS

The customers of drilling contractors vary over time by region and rig class. Table C.15 shows the market share by E&P customers over the 2000-2010 period. Each contracted day is counted as one unit of market share. In general, the largest E&P customers are IOCs, but NOCs are the largest customers in the Southeast Asian and Persian Gulf jackup markets, and North Sea floater market.

The U.S. GOM jackup market is relatively unconcentrated and the top four firms only control 21% of the market. In every other market, the top four firms control at least 37% of the contracted days. The West African jackup market is the most concentrated; Chevron utilized 29% of the contracted days between 2000 and 2010 and the top four firms controlled 65% of the market. Generally speaking, markets with low levels of concentration represent more competitive markets and would normally be associated with lower dayrates for all other things equal, and similarly, markets with a low level of customer diversity would contribute to higher dayrates.

3.8. CONCLUSIONS

Over the past decade, the shallow water market has witnessed a geographic shift from the U.S. GOM to the Persian Gulf and Southeast Asia due to regional prospectivity and higher dayrates. In contrast, the major floater markets have been more stable.

Jackup utilization rates are moderately correlated between regions except in the U.S. GOM because of regional factors and declining productivity. Inter-regional utilization correlations are higher in the jackup than floater markets, due in part to the lower variance in utilization rates in the floater markets. Dayrates are moderately correlated between regions. Correlations are higher in the floater market than the jackup market because of the regional nature of the shallow water market.

There is significant volatility in dayrates and volatility is higher in the floater markets, due in part to the smaller number of contracts in the floater market and the larger influence of individual rig specifications on dayrates. The Persian Gulf jackup market and Southeast Asian floater markets have been the most volatile markets over the past decade.

Markets have generally similar contract structures with most regions maintaining a mix of term and fixed well contracts. Most regions have roughly similar average contract durations between 200 to 300 days for jackups and floaters. The Persian Gulf and U.S. GOM are significant outliers with particularly long and short contract durations, respectively.

4. THE OFFSHORE CONTRACT DRILLING MARKET–OWNERSHIP, VALUATION, AND MARKET STRUCTURE

Drilling contractors hold a portfolio of rigs of different classes, qualities and specifications that compete in regional markets to drill wells for E&P firms. Fleet value is the sum of each rig's net earnings potential over its estimated remaining lifetime based on assumed future utilization and dayrates. The purpose of this chapter is to describe the drilling contractors, strategies, and structure of the drilling market. We begin with company ownership and describe how publicly owned firms are valued by the market. The primary factors that impact valuation are debt and cash, fleet values, current and projected revenues, and net earnings. We describe how drilling contractors specialize and the newbuild strategies utilized by contractors. Market competition is characterized with an emphasis on market concentration. Summary conclusions end the chapter.

4.1. DATA SOURCES

Three sources of data are used in this analysis. RigLogix (2011) is an industry intelligence service and was used for fleet sizes, rig specifications and contract data. Jefferies (Jefferies and Company, Inc., 2012) is an investment analysis service and provided information on fleet valuation, enterprise value, revenues and capital expenditures for publicly traded firms. Annual reports were used to supplement and check commercial data. All financial data are as of Dec 31, 2011.

4.2. OWNERSHIP

Drilling contractors are corporate entities that may be owned by investors or a government. Investor-owned drilling contractors may be publicly traded or privately held. Publicly traded corporations have a large number of shareholders whereas private firms are owned by a small number of shareholders. State-owned drilling contractors may be entirely owned by a state, or a fraction of the shares may be traded on a financial exchange. The ownership structure of the firm impacts business strategies, governance, access to debt and transparency.

4.2.1. Public Firms

Table D.1 shows the fleet size and value, revenues, and enterprise values of the largest publicly traded drilling contractors in the world in 2011. Enterprise value is a firm's market capitalization plus its debt, minority interest and preferred equity, minus cash. Market capitalization is the total value of tradable shares of a company at a given point in time, determined by the product of stock price and the number of outstanding shares.

The 14 firms depicted realized $26.4 billion in revenues in 2011 from 501 drilling rigs (289 jackups, 148 semis, and 64 drillships) which we estimate is 50 to 60% of the total revenue generated by the industry worldwide. The fleet value is estimated at $98 billion, and collectively, the companies had an enterprise value of $137 billion.

Transocean was the largest contractor in terms of fleet size and revenue, but after the 2010 Macondo oil spill, Transocean's share price declined because of uncertainty associated with its future liability (Anderson et al., 2011). As a result, Seadrill was the largest firm by enterprise value with only half the revenue and one-third the fleet size. Transocean own 141 rigs, or 16% of the total fleet, including 22% of the total floater fleet. Seadrill, Diamond, ENSCO and Noble together own 209 rigs, including 88 floaters, and account for 24% of the total fleet and 27% of the floater fleet.

Transocean, Seadrill, Diamond, ENSCO and Noble are significantly larger than their nearest competitors and each had revenues of over $2 billion in 2011 with enterprise values of approximately $10 billion or more. We classify these five firms as “large-cap” and the nine smaller firms as “mid-market”. Large-cap firms operate large diverse fleets in a number of geographic regions, while mid-market firms operate smaller fleets and are more likely to specialize in a rig class and geographic region.

With the exception of Seadrill, all large-cap firms are headquartered in the U.S., as are mid-market firms Hercules, Rowan, Atwood and Vantage. Seadrill and several mid-market firms are headquartered in Norway. Most firms are incorporated in offshore financial centers for tax purposes; common centers of incorporation include Switzerland, Cypress, and the Cayman Islands.

4.2.2. State-Owned Firms

State-owned drilling contractors and their 2011 fleet sizes and primary markets are summarized in Table D.2. State-owned drilling contractors work almost exclusively in their home countries and may be a subsidiary of a National Oil Company (e.g. COSL is owned by CNOOC) or the NOC may directly own and operate the drilling fleet. The largest state-owned drilling contractors are publicly traded firms in which the government is the majority shareholder (Petrobras, CNOOC, ONGC); most other state-owned contractors are not publicly traded.

COSL (China) is the largest state-owned drilling contractor and owns as many rigs as National Drilling (UAE), ONGC (India) and Petrobras (Brazil). State-owned drilling contractors are smaller than public firms and the largest state-owned firms have fleet sizes approximately similar to mid-market public firms. In total, state-owned firms own 127 drilling rigs, or about 15% of the world market. Most state-owned firms are jackup oriented, but COSL, Petrobras and Socar own semisubmersibles and ONGC owns two drillships. The top four state-owned drilling contractors are important players in their home markets.

4.2.3. Private Firms

Table D.3 summarizes the largest privately owned firms and firms that are subsidiaries of larger companies. Maersk Drilling is a subsidiary of A.P Moller-Maersk and Dolphin is a subsidiary of Fred Olsen Energy. Both companies are not traded as separate stock, and their activities are not as transparent or widely tracked by market intelligence firms. Most of the firms in Table D.3 are regional specialists with Brazil and the North Sea being the most common regions.

In total, private firms own about a third of the world’s fleet and deepwater rigs. Private firms including Stena, Dolphin, Schahin, Odfjeld, Queiroz Galvao, and Odebrecht are important players in the Brazilian and North Sea floater markets and these six firms own nearly half of the privately-held deepwater fleet. Outside of the North Sea and Brazil, private firms are less likely to be major players. The only privately held firm frequently operating in the U.S. GOM is Spartan Offshore. Spartan is owned by a private equity firm and operates four low-spec jackups in the GOM. Approximately 50 other firms that own rigs are not shown in the table. In general, these firms are small, own less than three rigs and are either privately held or traded on the over the counter market.

4.2.4. Market Share

The number of days spent drilling is a measure of market share, and in Figure D.1, the total contracted days across all regional markets is depicted. Publicly traded firms dominate the market because of their larger fleet sizes, however, since 2000, state-owned drilling contractors have received an increasing share of the jackup market and now constitute approximately 25% of days on contract. In the floater market, state-owned firms account for a negligible portion of the deepwater fleet but private firms have increased their share over the decade and account for about 15% of the market in 2010.

4.3. Valuation

Publicly traded drilling contractors are continuously valued by the market. The primary factors that impact valuation are debt and cash, fleet values, current and projected revenues, and net earnings. Factors that are more difficult to observe and quantify that also impact market valuation include insurance liabilities, revenues in the distant future and customer relationships (Demers, 1970; Rankin, 1981; Speer et al., 2009; Slorer et al., 2011).

4.3.1. Revenue

Enterprise value is closely correlated with firm revenue and earnings (Figure D.2). Company revenue and earnings is determined by fleet composition (rig type, quality, and age) and geographic distribution, utilization rates, dayrates and operating cost. Firms below the regression lines have a lower enterprise value than would be expected based on their revenue or earnings, and firms above the line have a greater enterprise value than the industry average. Transocean and Diamond are the only two large-cap contractors that fall below the industry average.

Transocean’s $5 billion market discount suggests its potential liabilities associated with the Macondo oil spill (Anderson et al., 2011). Diamond falls below the industry line due in part to its older fleet despite relatively strong revenues (Anderson and Hoh, 2011). Seadrill, ENSCO and Noble have higher enterprise values than the industry average, with the premium for Seadrill being particularly large due to its focus on high-specification units which have received high utilization and dayrates in recent years (Jefferies and Company, Inc., 2012; West et al., 2011). ENSCO and Noble also have higher-spec and globally diversified fleets which contributes to their higher valuation.

4.3.2. Fleet Value

Fleet value is correlated with fleet size (Figure D.3) and is a significant predictor of enterprise value (Figure D.4). Fleet value is calculated as the sum of the net asset values of all the rigs in a firm’s fleet at the time of evaluation, where net asset value is an estimate of a rig’s net earnings potential over its estimated lifetime based on assumed future utilization and dayrates. Firms below the regression line are undervalued; firms above the regression line are overvalued and with the exception of Seadrill and Transocean, the enterprise value fits the relationship closely. The size of a firm's asset base is correlated with its revenue base and thus enterprise value. A large asset base implies a platform for sustainable revenues and correlates to the diversity of the product line (Speer et al., 2009).

Table D.4 shows firm enterprise value as a percentage of fleet net asset value for selected publicly traded contractors between 2010 and 2012. For most firms, enterprise value varied between 80 and 120% of net asset value. Valuations are market dependent and vary with market conditions, rig specifications, customers, and other factors. For example, Rowan exhibits a valuation between 60 and 90% of its net asset value because it is a jackup specialist with a large proportion of its operations in the low-dayrate Persian Gulf and U.S. GOM. By contrast, Seadrill's enterprise value is over 200% of net asset value due to the high-spec nature of its fleet and its focus on Southeast Asia and the North Sea where utilization rates are high and dayrates command a price premium.

4.3.3. Debt

The cost to construct an offshore drilling rig is substantial and the capital requirements for maintain a fleet can also be high. As a result, contract drillers often show negative free cash flow during periods of construction or major fleet enhancement. Figure D.5 shows the quarterly debt to market capitalization ratio over time for two firms (Seadrill and Songa) that have been active in newbuilding and in the secondhand market over the 2008-2011 period.

In 2008, Songa's debt to market capitalization was relatively high because it had used debt to finance the purchase of rigs and had a limited cash flow; its 2008 earnings were approximately \$200 million compared to a total debt of approximately \$1 billion. Songa's debt load declined as the company used earnings to pay off debt, such that by late 2010, Songa's debt had declined to approximately \$500 million. In 2011, Songa entered into a new credit facility to finance the construction of new rigs, increasing its debt to market capitalization ratio.

By contrast, Seadrill's debt as a proportion of market capitalization remained relatively stable from 2008-2011, even as the firm's debt load grew from \$6 billion in 2008 to \$10 billion in 2011. Instead of using cash to pay off debt, Seadrill has spent cash on acquisitions and newbuilds; strong current and projected future earnings have allowed the firm to maintain a high market capitalization and an acceptable debt ratio.

4.4. PRODUCT DIFFERENTIATION

Drilling contractors maintain a portfolio of assets specific to their business strategy and capacity to access capital markets. Generalists maintain a geographically and technically diverse fleet, while specialists are smaller firms that cannot simultaneously compete in all regions and markets and specialize to build customer relationships and capitalize on economies of scale.

There tends to be variation in demand trends across geographic regions and water depth and a diverse fleet allows contractors to respond to changing industry conditions. A fleet diversified by rig type and specification is able to adjust to market upswings and weather industry downturns. High quality and new rigs generally continue to operate (albeit at a lower dayrate) during industry downturns. Companies that provide commoditized services (e.g. shallow water jackups) are exposed to greater competitive pressures and lower barriers to entry.

Transocean, Noble, Diamond and ENSCO are generalists active in a large number of markets and regions, while most other firms specialize to a greater degree (Tables D.5 and D.6). Seadrill is the only large-cap specialist and focuses on the high spec markets in the North Sea, Southeast Asia and Brazil. All large cap drilling contractors received a majority of their 2011 revenues from the floater markets, and despite significant jackup fleets, the floater segment accounted for 85 and 93% of revenues for Transocean and Diamond, respectively. For Noble, ENSCO and Seadrill, floaters accounted for approximately 60 to 65% of revenues.

Smaller firms such as Hercules, Rowan, Atwood, and Songa are more specialized. Hercules, Rowan and Songa each specialize in a single water depth market; Atwood is less specialized and maintains a diverse fleet, however, most of its revenues are generated by its Asian floater fleet.

4.4.1. Regional Concentration

Drilling contractors concentrate assets in regions to capitalize on economies of scale through the reduction of administrative costs, build customer and governmental relationships, and match fleet and regional characteristics. There are advantages to this approach, but political risk increases with concentration, and to manage this risk, geographic diversity may be a business strategy.

Table D.7 shows the revenues by region for large publicly traded drilling contractors in 2011. Brazil is a major source of revenue for all five large-cap firms, and the U.S. GOM market is a significant source of revenue for all firms. With the exception of Hercules, the North Sea is also an important source of revenue for all firms. Diamond is particularly dependent on the Brazilian market while Hercules is dependent on the U.S. GOM market; for each firm a single market accounts for approximately half of total revenues. Since the U.S. GOM shallow water market is in decline and Petrobras has ordered a large number of floaters, this strategy may negatively impact these firms' valuations. All other firms are more geographically diverse and no region accounts for more than 30% of revenues.

4.4.2. Customer Concentration

Due to contractor's regional concentration, a small number of E&P firms frequently make up a large proportion of a contractor's revenue. This can create risk for the firm because the loss of a single client can eliminate a major source of revenue. Table D.8 shows the major customers of selected contractors in 2011. Consistent with the importance of the Brazilian market to firm revenues, Petrobras is a significant customer for several firms including Diamond.

NOCs and IOCs are the largest customers for nearly all firms consistent with their size. Transocean is particularly diverse and its largest customer (BP) only accounts for 10% of revenues. The importance of NOC customers including Petrobras, Pemex and Saudi Aramco is notable. Given the increasing role state-owned drilling contractors play in the market, these NOCs may shift towards in-house drilling contract services.

4.4.3. Age

Drilling contractors are differentiated by the age of their fleets. Figure D.6 shows the fleet age of selected contractors along with the proportion of their fleet that was inactive in December 2010. There is a positive relation between fleet age and the proportion of active rigs, indicating that firms with old fleets are more likely to stack rigs while firms with young fleets are more likely to experience high utilization. Both Hercules and Diamond have old fleets, but Diamond's rigs experienced higher utilization than Hercules due to the upgraded nature of many of Diamond's rigs and different customer and geographic base. Hercules depends heavily on U.S. jackup revenues and the decline in the GOM shallow market has led to a high degree of unutilized rigs; Diamond is more diverse and operates jackups and floaters internationally.

Figure D.7 shows the average dayrates of jackups and floaters by rig delivery year. All jackups or floaters delivered in a given year were grouped together and their dayrates averaged over the 2000-2010 period. There is a significant correlation between rig age and average dayrates implying that firms that operate newer rigs are likely to receive higher dayrates than firms that specialize in older rigs.

4.4.4. Specification and Water Depth

Figure D.8 categorizes the fleets of leading public firms into high and low spec jackups and floaters. Active and stacked rigs are included in the count, but rigs under construction are not. High-specification jackups are defined as those capable of drilling in 350 ft or greater water depths or capable of operating in harsh environments. High-specification floaters are capable of operating in at least 7,500 ft of water or in harsh environments. Transocean, Noble, Ensco, and Diamond are the only drilling contractors to own units in every rig classification. In contrast, all of Seadrill's units are high-spec, and nearly all of Hercules' units are standard jackups.

4.4.5. Net Revenue by Rig Class

Table D.9 shows average daily operating expenses, dayrates and net revenue by rig class for Transocean and Diamond in 2011. Operating expenses include all of the costs associated with operating and maintaining a rig over the course of a year, including active costs, stacked costs, and maintenance costs. Net revenue is computed as the difference between dayrate and operating cost per rig class and reflects the average daily revenue from operation. Expected net revenue is determined on an annual basis as the product of dayrate and utilization rate, minus the operating costs.

For Transocean, ultra-deepwater and harsh environment floaters are particularly profitable due to high utilization and a large difference between the dayrate and the daily operating expense. High-specification jackups were the only market segment with a negative expected net revenue in 2011. Diamond's deepwater fleet experienced higher dayrates than its ultra-deepwater fleet in 2011, and was Diamond's most lucrative market. Rigs in the mid-water market generated approximately $40 million per rig for both firms, and the jackup segment was only marginally profitable.

4.5. NEWBUILDING STRATEGIES

4.5.1. Speculative Newbuilding

Firms invest in newbuilding when the estimated net cash flows exceed internal investment criteria and capital budgets and credit markets allow investment. Newbuilding represents a significant capital expenditure while future dayrates and utilization rates are uncertain. Therefore, newbuilding is a high risk investment and firms may undertake strategies to reduce this risk. Three strategies have been employed by industry: initial contract, price discount, and speculation. Additionally, in some cases, an E&P firm will enter into a joint ownership arrangement for a newbuild rig. In the private sector this is relatively rare and is limited to extremely high-risk projects such as Shell's construction of an Arctic drillship with Frontier Drilling. Among state-owned drilling contractors and NOCs, such arrangements are more common.

Initial Contract

Under an initial contract strategy, contractors require an initial long-term contract from an E&P firm before investment in order to secure cash flows during the early life of the rig. Bob Rose, former CEO of Global Marine, summarizes the strategy: "No newbuilds without a user contract in hand (DeLuca, 2001)." Since future cash flows are discounted in decision-making, cash flows in the near term are more valuable than cash flows in the future. Without an initial contract, a drilling contractor may experience a negative net cash flow in the first years after a rig is delivered and this can have a significant negative impact on the profitability of the investment.

Proponents of an initial contract approach argue that building speculatively provides a signal to E&P firms that rig availability will increase in the future which reduces the motivation of E&P firms to commit to long-term contracts. Additionally, building without an initial contract adds supply that is not demanded, which may lead to industry-wide reductions in dayrates (DeLuca, 2001). Transocean is the largest firm in the industry and the most likely to be impacted by fleet-wide reduction in utilization or dayrates, and as a result, is the primary advocate of the initial contract approach (DeLuca, 2001; Anderson et al., 2011).

E&P firms are only likely to build against a contract when market conditions are so tight that they are unsure they will be able to contract capacity (DeLuca, 2001). As long as one or more firms are willing to build without an initial contract, E&P firms will not need to enter into construction contracts and initial contracts will be rare. In recent years, independents and IOCs have rarely entered into initial contracts for newbuilds, but initial contracts are more common for NOCs.

Price Discount

Under a price discount strategy, firms invest counter-cyclically during periods of low newbuild prices to reduce the magnitude of the risk. Stedman Garber, former CEO of Sante Fe, summarizes the position "Counter-cyclical is the best time to build, contract or not (DeLuca, 2001)." The goal of a price discount strategy is to minimize cost rather than attempt to match supply and demand, and proponents of a price discount strategy argue that the benefits of an initial contract do not justify higher capital costs. Lower capital costs allow companies to be more competitive in the long run because the capital cost is locked in for the life of the rig. While there is a risk that the rig will be under-utilized after delivery, it is likely that the newbuild rig will be utilized since they are preferred in the market, but at the cost of utilization and dayrates elsewhere in the fleet.

Speculation

During periods of high utilization and dayrates, firms enter into newbuild contracts without an initial contract with the expectation that the rig will win work during the construction period. This is a high risk strategy because there is a risk that the rig will be unutilized or utilized at a low dayrate after delivery. During newbuild cycles, speculation is the dominant strategy, and since newbuild cycles are the primary source of fleet expansion, speculative newbuilding is an important source of new rigs. A price discount strategy is differentiated from a speculative strategy in that proponents of a price discount strategy would not build speculatively during the peak of a newbuild cycle. Thus, price discounting is a popular strategy only at the beginning of a newbuild cycle (DeLuca, 2001). As of Jan 2012, 78% of jackups, 65% of semis and 62% of drillships under construction had been ordered without an initial contract.

4.5.2. Firm Size

Firms differ in newbuilding strategies and smaller firms spend a larger proportion of their value on newbuilding than larger firms. Enterprise value was used to proxy company value, and the fraction of enterprise value invested in newbuilding was determined by dividing annual newbuild expenditures by total enterprise value over the 2005 to 2011 period. This value was then plotted against the average enterprise value for each firm over the time period (Figure D.8). The natural logarithm was used because of wide differences in values.

The data suggest that as the size of the firm increased, the proportion of firm value invested in newbuilding expenditures over 2005-2011 decreased. Over the recent newbuilding cycle, large firms such as Transocean and Diamond have invested relatively little in newbuilding, while small and midsized firms such as Scorpion, Vantage, Seadrill and Aker have invested heavily. Instead, Transocean has used cash to finance acquisitions which is an alternative strategy to grow and diversify their fleet, while Diamond typically pays large dividends to shareholders.

4.6. Market Structure

Market structure characterizes the level and type of competition among rig companies and determines their power to influence prices for their service. If the industry is perfectly competitive, drilling contractors cannot raise prices above the marginal cost of operation without losing market share to their competition. According to basic microeconomic theory, perfectly competitive industries are characterized by unrestricted entry and exit of firms, large numbers of firms, and undifferentiated (homogenous) services being offered (Perloff, 2008). Here we consider whether the offshore drilling market is competitive based on a qualitative examination of these factors.

4.6.1. Mergers and Acquisitions

A number of mergers and acquisitions have occurred over the past two decades which have consolidated the industry (Figure D.10). Recent mergers and acquisitions include ENSCO and Pride in 2011, Global Santé Fe and Transocean in 2007, Transocean and Aker in 2011, Noble and Frontier in 2010, and Seadrill and Scorpion in 2010.

Much of the impetus behind industry consolidation is the competitive advantage associated with a larger capital base and greater asset diversification. Size implicitly incorporates a degree of diversification by geography, rig class, rig quality, contract duration and customer base. Large companies benefit from greater asset diversification, financial resources and liquidity, and economics of scale, and can withstand shocks or market downturns better than smaller firms and tend to be correlated with other characteristics such as market power and diversification (Cabral, 2000). Mergers are a critical growth strategy for all large-cap drilling contractors and are a means to renew and upgrade their fleets without entering into newbuild construction (Lee and Jablonowski, 2010).

4.6.2. Barriers to Entry

Significant barriers to entry exist in the offshore drilling market. Over the past decade, newbuilt jackups cost between $150 and $300 million while newbuilt floaters cost between $500 million and $1 billion. Firms entering the industry typically build three or more rigs to take advantage of economies in the construction process and in administrative costs. It is difficult to raise this amount of capital to enter a mature and competitive industry. New market entrants that are not financed by a government initially raise capital from a variety of private sources and institutional investors (e.g. hedge funds or private equity firms) and may issue an initial public offering. Following public placement, firms may gain access to loans through debt markets. For established firms, the issuance of bonds is a major source of low-cost capital (Norton Rose, 2011).

Successful entry also requires significant human capital. A high degree of specialized knowledge is necessary in management and operations positions which are only available to those already in the industry or recently retired. Drilling is an intangible service and contractors are difficult to evaluate without prior experience, which creates customer loyalty and may make operators unwilling to hire new contractors.

4.6.3. Consolidation

Figure D.11 depicts consolidation in the offshore drilling industry between 1984 and 2010. In the 1980's, there were approximately 160 drilling contractors and the top 10 firms owned about 35 to 40% of the total rig fleet. Between 1989 and 2004, the industry experienced a prolonged downturn and consolidation eliminated nearly half of the contractors. Since 2004, the number of firms has increased and new entrants have emerged to take advantage of high dayrates and greater access in regional markets. The top 10 drilling contractors in 2010 own slightly more than half of the world fleet.

4.6.4. Measures of Industry Concentration

Economists use a variety of measures to assess the concentration of a given industry. Common measures include four firm concentration ratios (CR4), eight firm concentration ratios (CR8), and Herfindahl-Hirschman indices (HHI). CR4 and CR8 measure the percentage of sales accounted by the top four and eight firms in the industry. The HHI is the sum of the squared market shares of firms in the industry.

These measures of industry concentration are reported in Table D.10 for the offshore drilling market in 2010 using contracts (not sales) as the evaluation unit. Each contract was considered one unit of market share. The floater markets are more concentrated than the jackup markets and the top four firms account for over 50% of the jackup market and nearly 70% of the semi and drillship market. The eight largest firms account for approximately 80 to 90% of the industry in all three markets. The market is far more concentrated when measured by contracted rigs because large drilling contractors are frequently more successful in maintaining high utilization than smaller firms with a few rigs. Market concentration declines when floaters are considered as a single market.

Figure D.12 shows the six-month moving average of the monthly market concentration in the jackup and floater markets from 2001 to 2010. HHI was calculated in each month assuming that any rig under contract in that month was one unit of market share. Over the period, global market concentration remained relatively stable for both rig types. In the jackup market, market concentration increased in the U.S. GOM as several firms left the region, but concentration declined in South East Asia and the Persian Gulf as new firms entered in response to growing demand. Market concentration was higher in the floater market than the jackup market. Market concentration declined in the West African and Southeast Asian floater markets, but remained relatively stable in the North Sea, GOM and global markets.

Accepted criteria have been established for determining market structure based on the HHIs for use in horizontal merger analysis (USDOJ and FTC, 2010). According to these criteria, industries with HHI below 1,000 are considered unconcentrated (i.e. more competitive); industries with HHIs between 1,000 and 1,800 are considered moderately concentrated (i.e. moderately competitive); and industries with higher HHIs are considered heavily concentrated. Based on these criteria, the offshore drilling jackup market continues to be globally unconcentrated even after an increase in merger activity, while the floater market is moderately concentrated. On a regional basis a higher degree of concentration is apparent.

4.6.5. Firm Competition

Firms can influence prices for their services through differentiation. By differentiation through technology, safety record, and crew experience, and using marketing to establish company loyalty, drilling contractors can raise their prices above marginal cost without losing market share to competitors. However, by the nature of their operations drilling rigs are quite homogenous, and there is little substantive difference between rigs of the same generation and across generations when upgraded. While there may be some instances where service differentiation is important, these are expected to be isolated. Overall, the market is commodity-like in nature which impedes the ability of firms to differentiate their products.

The offshore drilling rig industry is characterized by the production of largely similar products (wells). Barriers to entry, market size and other factors impact competition among firms, but it is difficult to quantify the magnitude of this effect and it seems unlikely that individual companies are able to significantly influence market prices. Overall, the market is considered competitive with potentially transitory non-competitive periods in certain concentrated regions or specialized markets.

4.7. Conclusions

The contract drilling market is dominated by a small number of publicly traded firms with Transocean, Seadrill, Noble, ENSCO, and Diamond being the major players and controlling about 40% of the total fleet and 50% of the floater fleet. Fleet value and revenue are good predictors of the enterprise value of publicly traded firms.

Firms specialize by rig class, region and customer, but all five of the largest contractors in 2011 generated most of their revenues from the floater market, and for Diamond and Transocean, floaters generate much greater net earnings per day than jackups. Nonetheless, these firms continue to operate in the shallow water market to foster fleet diversity.

Three newbuilding strategies were identified and speculation is the most popular method for fleet expansion despite the higher risk. Over the 2005 to 2011 newbuild cycle, smaller firms invested a larger portion of their enterprise value in newbuilding than larger firms, while larger firms were more likely to grow through mergers and acquisitions.

Merger and acquisition activity is common among the largest players in the industry and generates concerns about market concentration and competition. Despite the size of the largest players, the jackup market is not concentrated globally while the floater market is moderately concentrated.

5. EMPIRICAL ANALYSIS OF FACTORS IMPACTING DAYRATES

The offshore drilling market is segmented by geographic region and rig class and varies with both regional and global market conditions over different periods of time. In this chapter we evaluate the factors that impact rig dayrates. Our approach is to consider single factor effects over select categorizations and time periods. We motivate the analysis through hypothesis and test the validity of each hypothesis using empirical data. We examine the impacts of oil prices on demand and evaluate the relationship between dayrates and oil prices, utilization rate, rig specifications, contract length, E&P ownership, contractor size and well type. We find dayrates are positively correlated with oil prices, utilization rates, rig specifications, and contract length. NOCs pay higher dayrates than IOCs, and appraisal drilling is more expensive than developmental or exploratory drilling. There is no evidence that large firms such as Transocean can utilize market power to command premium dayrates.

5.1. HYPOTHESES

A large number of factors have the potential to influence dayrates, and in the popular press and among industry experts, a body of "common knowledge" has developed over the years. This common knowledge has not been empirically verified in publicly available or peer-review publications (but see Rankin, 1981), and as a result, the veracity of the claims and their analytic basis remain subject to scrutiny. The purpose of this analysis is to critically review basic expectations of selected claims and to quantify observed differences and trends. We evaluate trends and correlations over a multiyear period and offer reasons for the hypothesis stated. Some of these reasons can be tested, but many cannot, so our observations are tempered by the availability of data and factor analysis.

We evaluate the following hypotheses:

- H1. Demand for drilling services is positively associated with oil prices.
- H2. Dayrates increase with increasing oil prices.
- H3. Dayrates and utilization rates are positively correlated.
- H4. High specification rigs charge higher dayrates than low specification rigs.
- H5. Long-term contracts provide a price premium over short-term contracts.
- H6. National oil companies pay higher dayrates than other companies.
- H7. Large drilling contractors command higher dayrates than smaller contractors.
- H8. Appraisal drilling programs pay higher dayrates than exploratory or developmental drilling.

Hypotheses H1 to H4 evaluate basic assumptions widely reported in the industry. In hypothesis H1, rig demand is the dependent variable; in all other hypotheses, the dayrate is the dependent variable. Hypotheses H5 to H8 identify factors that may contribute to the variation in dayrates between and within regions and when time is included as a variable. These hypotheses are less obvious and require greater scrutiny. Drilling contractors frequently seek a mix of long and short-term contracts to balance risk, and hypothesis H5 evaluates the costs of this strategy. For political reasons, NOCs are expected to overinvest in drilling relative to IOCs, and this is evaluated in hypothesis H6. Hypothesis H7 examines the ability of firms to use market power to influence prices. Appraisal drilling is more technically challenging than exploratory or developmental drilling and may be associated with a dayrate premium which is tested in hypothesis H8.

5.2. METHODOLOGY

5.2.1. Data Source

Data from 7,123 rig contracts between January 1, 2000 and December 31, 2010 were obtained from RigLogix. RigLogix uses surveys and contact with industry personnel to assemble dayrate data. Data is reported on a contract basis and includes both contract variables (dayrate, contract start date, contract duration, region) and rig variables (rig type, rig delivery date, rig maximum water depth, rig maximum drilling depth). Data on the number of active rigs and regional utilization rates were employed from a separate RigLogix dataset. Data on Brent oil prices was obtained from the Energy Information Administration. Brent crude is the global benchmark of oil prices and is closely related to offshore production.

5.2.2. Categorization

Individual contract records were treated as independent data points. Activity was considered in five regions: the U.S. Gulf of Mexico (GOM), North Sea, Persian Gulf, West Africa and Southeast Asia. Each region was subdivided into jackup and floater classes. The floater class includes semisubmersibles and drillships. Jackup and floater classes were delineated by water depth, ownership, customer, and time period. The number of contracts in the dataset by region and rig class is shown in Table E.1. The U.S. GOM has the largest number of contracts in the jackup market during this time period, and along with the North Sea, is the largest floater market. In total, the U.S. GOM is responsible for over half of the number of contracts from 2000-2010, reflective of the dominant position of the U.S. GOM’s contribution to total wells drilled during the period.

Offshore drilling contracts correspond to the number of wells drilled, but the correspondence is not perfect because of differences in contract duration, work requirements, well complexity, and other factors. Wells drilled is a directly observable quantity, whereas drilling contracts may be written for multiwell programs, workovers, completions, sidetracking, etc. and are a better representation of revenue generation. The number of contracts provides a direct indicator of the demand for drilling rigs by class type, region, water depth, time period, and customer, and provides useful and direct information on the status of the rig market.

The five regions selected are the largest regions with competitive markets. Brazil is an important floater market but is monopolized by a single E&P firm (Petrobras) and was therefore excluded. Within and across regions, water depth, drilling depth, and rig class are employed to further delineate activity trends; rig classes partially correspond to water depth categories. Demand trends for shallow water, midwater, and deepwater fixtures tend to vary by region, and in some regions, one or more water depth categories are not present (e.g. the Persian Gulf has no deepwater segment) which explains the absence of rig classes. All the other regions have a full range of water depth intervals.

The time period of analysis is an important categorization since results depend on the period selected. For example, from 2004 through 2006, oil prices and dayrates rose significantly, and as a result of these changes, market conditions in the 2000 to 2005 and 2006 to 2010 periods differ in significant ways. Table E.2 depicts the average dayrate by region in the pre- and post-2006 periods. In the jackup market, the increase in dayrates pre- and post-2006 varied between regions with increases being modest in the U.S. GOM (68%) and higher in Southeast Asia (135%). In the floater market, the change in dayrates in pre- and post-2006 periods was more pronounced, and three of the four floater markets increased by approximately 200%.

While dayrates changed over the 2000 to 2010 period, the relative positioning of the regional markets remained stable. The U.S. GOM was the least expensive jackup market in both the 2000 to 2006 and 2006 to 2010 periods, followed by the Persian Gulf. West Africa and Southeast Asia experienced similar dayrates in both periods, while the North Sea was consistently the most expensive jackup market. In the floater market, Southeast Asia was the least expensive in both time periods, while West Africa was the most expensive market.

Models of market behavior and empirical analysis are unlikely to capture sudden and dramatic changes in dayrates. Whenever possible, we used data from the entire time period to maximize sample size and limit assumptions. However, in the case of utilization rates, there was a notable difference in the pre and post-2006 data, and only the post-2006 data was examined.

5.2.3. Approach

Dayrates were inflation adjusted to 2010 using the U.S. BLS annual producer price index for all finished goods and the start year of the contract. The inflation adjustment allows for comparison across the decade but may introduce bias since the U.S. producer price index cannot capture all inflationary pressures in the industry. Monthly average dayrates were applied in the analysis. In these cases, the dayrate in a given month was the average of the dayrates of all contracts for which drilling began in that month, and not the average of all active contracts in the month (Figure E.1). Data on Brent oil prices were inflated to 2010 values.

Linear regression and analysis of variance were used to test hypotheses. When multiple comparisons were performed, the Tukey-Kramer method was used (Off and Longnecker, 2001). All variables were tested for serial correlation, and when present, the AUTOREG procedure in SAS 9.2 was used. The order of the autocorrelation varied depending on the results of a stepwise autocorrelation.[6] In cases in which data were not serially correlated, ordinary least squares (OLS) regression was employed. When linear regression was performed, models were evaluated with and without logarithmic transformation. Transformed models generally performed better than non-transformed models and were adopted, consistent with standard econometric techniques (Ramanathan, 1998).

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6 The order of an autocorrelation is the number of previous periods used for the prediction of the error term. For example, in a first order autocorrelation, the error term μ_t in the standard linear regression model ($Y_t = \beta_0 + \beta_1 X_t + \mu_t$) is dependent on the error in the previous period (μ_{t-1}). In a second order autocorrelation, the error term is dependent on the error in the two previous periods.

Moving average oil prices and utilization rates are used in several models and correlated against rig supply and dayrates. Moving averages smooth out data set and are integrative in the sense that they are computed over a period of time, and thus include information on the entire period. Offshore drilling is capital intensive and development projects tend to be long, multiyear projects, relative to the short-term cycles of exploration. The data set contains exploration and development well types.

5.3. DEMAND FOR DRILLING RIGS IS POSITIVELY ASSOCIATED WITH OIL PRICES

As oil prices increase, the net income and capital budgets of E&P firms increase and drilling activity will respond. Studies have found a positive relationship between measures of drilling effort and oil prices with elasticities often greater than one (reviewed in Dahl and Duggan, 1998; Ringlund et al., 2008; Cole, 1995).

To estimate the elasticity of demand with respect to oil prices, we built a regression model using average monthly oil prices and the 3, 6, 9, 12, 18, and 24 month moving average of oil prices as predictors of the total number of rigs under contract in a given month. We consider all active rigs in all offshore basins and evaluate jackups and floaters separately. Figure E.2 shows the relationship from 2001 to 2011. Models were evaluated with and without logarithmic transformations. The natural logarithm of the dependent and predictor variables provided the best fit.

For jackups, the best model was given by:

$$\ln(N_t) = 4.2 + 0.23 * \ln(Oil_{12}),\ R^2 = 0.92.$$

For floaters the best model was given by:

$$\ln(N_t) = 2.0 + 0.64 * \ln(Oil_{24}),\ R^2 = 0.97,$$

where N_t is the number of active rigs in month t and Oil_k is the moving average of the oil price over the previous k months. Both models are first order autoregressive and the R^2 values are high and the coefficients statistically significant ($p < 0.05$) and positive for both classes. For jackups, the 12 month moving average provides the best fit, and for floaters, the 24 month moving average is a better predictor than any shorter duration moving average. These results suggests that rig activity responds slowly to changes in oil prices, consistent with the long lead times required for offshore drilling programs.

The elasticity of rig activity with respect to the moving average of oil prices was 0.23 for jackups and 0.64 for floaters. This is lower than the elasticity found for the global onshore and offshore rig fleet cited in previous studies and suggests that for every 1% increase in the moving average of oil prices, the number of working rigs increases by less than 1%. The lower elasticity in offshore rig activity is expected because offshore development is more expensive and risky than onshore development and occurs over longer development cycles encouraging E&P firms to act more conservatively and respond more slowly to changes in oil prices. This same rationale partially explains why the number of active floaters is correlated with a larger period of oil prices than jackups, since deepwater is associated with longer and more expensive development than shallow water regions.

When regions were considered separately, the trends remained the same but the strength of the relationships declined for both jackups and floaters, and in most cases, was no longer significant. This suggests that at the global level, oil prices are adequate predictors of demand, but at the regional level, local factors such as geologic prospectivity and development cycles play a more important role. Oil prices are a global metric and when oil prices rise, global demand is stimulated, but the regional distribution of that demand is determined by local factors such as licensing, regulation, customer base, and prospectivity.

5.4. Dayrates Increase with Increasing Oil Prices

Oil prices are a widely recognized driver of activity in the upstream sector since drilling is the only means to increase supply and capture the economic benefit of high prices. Increases in oil prices increase demand for drilling services and are expected to lead to increases in dayrates for all other things equal.

Figure E.3 shows the relationship between global average monthly jackup and floater dayrates and Brent oil prices between 2000 and 2010. For both rig classes, there is a cluster of data between \$40 to \$80 oil prices which corresponds to the period following the oil price declines of mid to late 2008. During this period, dayrates did not move as rapidly as the commodity price fluctuations and suggests that rapid shifts in the commodity markets are not immediately reflected in dayrates.

An autoregressive model was used to estimate price elasticity in jackup and floater dayrates over the time period 2000-2010. For both rig classes, the oil price and 3, 6, 9, 12, 18, and 24 month moving averages were used as predictor variables. Models with and without logarithmic transformations were evaluated, and models with logarithmic transformations provided a better fit than non-transformed data.

For jackups, the best model was a second order autoregressive model:

$$\ln(DR_t) = 7.8 + 0.87 * \ln(Oil_{12}),\ R^2 = 0.91,$$

and for floaters, the best model was a first order autoregressive model:

$$\ln(DR_t) = 6.8 + 1.4 * \ln(Oil_{24}),\ R^2 = 0.93,$$

where DR_t is the average dayrate in month t and Oil_k is the moving average of the oil price over the previous k months. As expected, dayrates are positively related to oil prices, and the coefficients of the oil price term are positive regardless of the length of the moving average employed. The 12 month moving average oil price was the best predictor for jackup dayrates, while the 24 month moving average was the best predictor of floater dayrates. These periods are the same as the demand model in the previous section and show that jackup dayrates respond more rapidly to changes in oil price than floater dayrates due in part to the shorter duration of the development cycles and the integrative effects of the moving average. Jackup contracts also tend to be of shorter duration than floater contracts which partially explains the differences in time periods.

The elasticity of dayrates with respect to oil prices was 0.87 for jackups and 1.4 for floaters indicating that floater dayrates are more sensitive to changes in oil prices; however, this difference reflects the duration of the moving averages and cannot be used for such an inference. Since oil prices in the floater model are averaged over a longer period, they tend to be more stable, and a 1% increase in the 24 month moving average signifies a greater shift in market conditions than a 1% increase in the 12 month moving average. Thus, the difference in elasticity between rig classes should be interpreted with caution.

Model coefficients were similar when regions were compared separately. For jackups, elasticities varied from 0.7 in the Persian Gulf to 0.95 in the U.S. GOM, and model fit declined slightly in all regions except the U.S. GOM, likely due to the reduction in sample size. For floaters, regional elasticities varied from 1.0 (West Africa) to 1.2 (Southeast Asia). Therefore, while oil prices are not a good predictor of regional demand, they are an adequate predictor of dayrates at the regional level because dayrates are more strongly correlated between regions than the number of active rigs.

5.5. Dayrates and Utilization Rates Are Positively Correlated

When regional utilization is low, the supply of stacked units is large relative to demand and contractors bid aggressively to win work, increasing competition and lowering dayrates. When utilization rates are high, there is more competition among E&P firms for access to contract drilling, and contractors can negotiate more favorable terms, increasing dayrates and providing signals to the market that additional capacity can be absorbed.

The monthly utilization rate and dayrate in the U.S. GOM jackup market from 2000-2011 is depicted in Figure E.4. Other markets exhibited similar dynamics and are not depicted. There were no statistically significant relationships between utilization rate and dayrate across the entire time period in any market or region, but in the post-2006 period, utilization and dayrates were correlated across all regions. Over longer time periods, other factors (e.g. newbuild deliveries) influence markets and may predominate.

We regressed the dayrate and the 3, 6, 9, 12, 18, and 24 month moving average of utilization rate in each of the five jackup markets and the four floater markets in the post-2006 period using the functional specification:

$$\ln(DR_t) = \beta_0 + \beta_1 \ln(U_x),$$

where DR_t is the average dayrate in month t and U_x is the x-month moving average of the utilization rate. Models with and without logarithmic transformations were evaluated, and models with logarithmic transformations provided a better fit than non-transformed data.

The best models for floaters and jackups are shown in Table E.3. In most cases, statistically significant models were developed, however, the North Sea and Persian Gulf jackup models only explained a small proportion of the variation in dayrates, and no statistically meaningful relationship in the Southeast Asian floater market existed. All successful models contained a 12, 18 or 24 month moving average predictor, and the moving averages in the jackup models were of shorter duration than those in the floater models. The floater models were autoregressive while the jackup models were not.

The relationships between utilization and dayrates varied across regions. In the Persian Gulf and North Sea jackup markets, lower variation in utilization is the likely reason robust models could not be developed. The Persian Gulf and North Sea had the lowest variance in utilization rates which the models were unable to explain. One factor utilization-based models were adequate for explaining large changes in dayrates, but were unable to resolve more subtle differences.

No significant relationship between utilization rates and dayrates was detected in the Southeast Asian floater market. The Southeast Asian floater market is significantly smaller and utilization rates are consistently lower than the other floater markets, and over the 2006-2010 period, utilization rates in the region did not follow the other markets. The Southeast Asian market is in close proximity to several other floater markets (India, China, and Australia), and due to the highly mobile nature of semisubmersibles and drillships, it may be more meaningful to classify all four Asian markets into a single regional market.

Figure E.5 illustrates the results of three predictive jackup models. As utilization rates increase, dayrates increase, and the rate of increase is higher in West Africa and Southeast Asia than in the U.S. GOM. In Southeast Asia, the relationship between utilization and dayrates is non-linear, while in the U.S. GOM and West Africa, the relationship is approximately linear (e.g. $\beta_1 \approx 1$). The results of the three statistically significant floater models are depicted in Figure E.6. The U.S. GOM and North Sea models are based on the 18 month moving average, while the West Africa model uses the 24 month moving average. All three models are non-linear, and the U.S. GOM model has the largest slope.

5.6. High Specification Rigs Charge Higher Dayrates than Low Specification Drilling Rigs

Differences in rig specification lead to product differentiation in the market (Mascarenhas, 1996). A number of rig specifications exist, but water depth and drilling depth are most critical in determining the ability of a rig to drill a given well (Harris, 1989; Robertson, 2003). As the water depth or target depth increases, the number of rigs capable of drilling declines, decreasing competition and increasing prices. For shallow water wells or shallow geologic formations, more advanced capabilities are usually not necessary. The time period is 2000-2010 and all geographic regions were consolidated into a single category. Statistically significant differences between categories are denoted by letters (e.g. categories marked “A” do not differ from other A’s, but do differ significantly from B’s, C’s, etc.).

5.6.1. Drilling Depth

The average dayrates of jackups and floaters by drilling depth category is shown in Table E.4. For both rig classes, dayrates increase with increasing drilling depth capability. For jackups, rigs with drilling depth capabilities less than 15,000 ft did not have significantly different dayrates from rigs with maximum drilling depths of 15,000 to 20,000 ft, but all other drilling depth categories were significantly different. The lack of a significant difference is likely due to the small sample size in the less than 15,000 ft category.

For floaters, rigs with capabilities less than 20,000 ft charged dayrates that were indistinguishable from those with capabilities of 20,000 to 25,000 ft, and rigs with capabilities of 25,000 to 30,000 ft were indistinguishable from rigs with 30,000 to 35,000 ft drilling capacities. Rigs with drilling capabilities less than 25,000 ft, 25,000 to 35,000 ft and greater than 35,000 ft were significantly different and the direction of the differences matched expectations.

5.6.2. Water Depth

The average dayrates of jackups and floaters by water depth capability is shown in Table E.5. In both rig classes, deeper water depth capabilities are associated with dayrate premiums. For jackups, the premium is largest ($30,000 per day) between the 300 - 350 ft and 350 - 400 ft water depth categories. There is no significant difference between the 350 - 400 and greater than 400 foot jackup categories which may reflect the small sample sizes.

For floaters, all four water depth categories are significantly different, but the biggest difference between categories is between the 5,000 - 7,500 ft and greater than 7,500 ft categories. In this case the premium is $80,000 per day while the premium among the other water depth categories is $23,000 to $34,000 per day.

5.6.3. Station Keeping

The average dayrates of independent leg cantilever versus slot or mat jackups and dynamically positioned versus moored floaters is shown in Table E.6. Dynamically positioned floaters are more expensive than moored floaters and independent leg cantilever jackups are more expensive than mat or slot units, and both differences are statistically significant. Contractors charge a premium of $113,000 per day for DP floaters and $35,000 per day for independent leg-cantilever units. The value of this premium over a 20 year operational life assuming 75% utilization rate and a 10% discount rate is $260 million for floaters and $80 million for jackups.

5.6.4. Regional Control

Dayrates are higher for rigs with greater drilling depth capabilities, water depth capabilities and more advanced station keeping abilities, however, these results could be associated with the regions in which these rigs work. Table E.7 controls for regional variation and compares dayrates by drilling depth, water depth, and station keeping ability. To conserve sample size, rigs were divided into two water depth and drilling depth categories.

Station Keeping

In the U.S. GOM, independent leg cantilever units exhibited an average price premium of 15,000 $/day relative to mat or slot units. In West Africa, the differences were also significant (43,000 $/day), but sample sizes were small. Dynamically positioned floater premiums ranged from $70,000 (West Africa) to $139,000 (Southeast Asia).

Water Depth

Except for Southeast Asia, all regions experienced higher dayrates for deeper water jackups, and the premium was relatively consistent across the period of analysis. The significant price difference between jackups with water depth capabilities less than and greater than 300 ft in the Persian Gulf is unexpected because the vast majority of the Persian Gulf is less than 300 ft deep and E&P firms cannot use the increased water depth capacity of these rigs. For floaters capable of operating in greater than 5,000 ft water depth, premiums ranged from $54,000 (West Africa) to $140,000 (U.S. GOM).

Drilling Depth

Drilling depth was associated with increased dayrates in all regions, but the size of the premium varied significantly among jackup markets, from approximately 20,000 $/day in the U.S. GOM to nearly 70,000 $/day in the Persian Gulf. The low premium in the GOM may be due to the generally low dayrates, while the high price premium in the Persian Gulf may be associated with high and low-specification rig utilization in the market. For the drilling depth threshold of 25,000 ft, floaters that can drill greater than the threshold are associated with premiums ranging from $74,000 (West Africa) to $119,000 (U.S. GOM).

High Spec Premium

The daily value of the enhanced capability by category is depicted in Table E.8. Every $10,000 in increased daily revenue represents a $23 million increase in the total revenue generated by the rig over a 20 year period, assuming a 10% discount rate and 75% utilization rate. However, since high-spec rigs typically experience higher utilization than low-spec rigs, this is likely to be an underestimate of the actual revenue premium associated with high-spec rigs.

5.7. Long-Term Contracts Are More Expensive than Short-Term Contracts

Contractors generally seek a mix of long and short-term contracts to balance risk (Rowan, 2009; OGFJ, 2007). Long-term contracts provide stable cash flows and guaranteed utilization, while short-term contracts increase the risk of stacking, but allow the contractor to take advantage of increasing markets and potential dayrate upswings (Moomjian, 2000). When dayrates are low, there is little incentive for a contractor to accept a long-term contract and short-term contracts are preferred; as a result, we expect short-term contracts to exhibit lower average dayrates than long-term contracts.

The mean duration of contracts was computed in each region over the period 2000-2010, and contracts were divided into those greater than and less than the regional mean duration and compared using a two tailed t-test. Table E.9 summarizes the results. In every region, short-term contracts had lower dayrates than long-term contracts, and in each case the difference was statistically significant. This suggests that E&P firms pay a premium for long-term contracts. For jackups, the difference between contract types ranged from 13% in Southeast Asia to 45% in the

Persian Gulf. For floaters, the premium was higher and ranged from 25% in West Africa to 85% in the U.S. GOM.

It is possible that the statistics vary temporally. If drilling contractors expect future price and utilization to decline, they may be willing to accept lower dayrates for long-term contracts. To control for the effects of time we separated the data into three periods: 2000-2004, 2005-2008 and 2009-2010 to correspond with stable, improving, and declining market conditions. We assume that observed price changes reflect market participant expectations. If the dayrate premium for long-term contracts is dependent on market conditions, we expect there to be no premium for long-term contracts in the 2009-2010 period.

Separating the data into three time periods, two rig classes and five regions provided 27 comparisons. In 26 of 27 comparisons, longer than average contracts had higher dayrates than shorter than average contracts. This trend was only significant in 14 comparisons. There is no evidence that higher dayrates for longer term contracts are affected by the changing market conditions.

5.8. NOCs Pay Higher Dayrates than IOCs or Independents

International Oil Companies (IOCs) and National Oil Companies (NOCs) may have different motivations for investing in drilling and may differ in their willingness to pay for drilling services. IOCs are motivated to maximize the present value of investments, whereas NOCs are motivated by both economic and political factors and may have a motive to subsidize domestic consumers, increase employment, or increase short-term revenue at the expense of long-term revenue (Hartley and Medlock, 2008). Each of these factors is expected to increase NOC exploration investment in the short-term and NOC willingness to pay for drilling services, increasing dayrates relative to IOCs or independents.

We considered any firm in which the government is the controlling entity to be an NOC and included firms such as Statoil, Eni, DONG, Petronas, and Petrobras, as well as the NOCs of OPEC (Saudi Aramco, ADNOC, etc.). IOCs included ExxonMobil, Chevron, BP, Total, Shell, Marathon, and ConocoPhillips, and are usually integrated across the supply chain and have international development (Jaffe and Soligo, 2007; Eller et al., 2011; Inkpen and Moffett, 2011). All other firms were classified as independents.[7]

For jackups, NOCs paid on average approximately $25,000 more than IOCs and $40,000 more than independents on a global basis between 2000-2010 (Table E.10). For floaters, NOCs paid on average $50,000 more than IOCs and $85,000 more than independents worldwide. All differences were statistically significant for both rig classes but the majority of contracts are for independents which could bias the data.

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7 Alternative classifications of NOCs, IOCs, and independents are possible. Eni is often classified as an IOC, but was considered an NOC because the Italian government owns a controlling share. Marathon was considered an IOC. Large E&P firms such as Anadarko and Apache were considered independents because they classify themselves as such.

The trend observed in Table E.10 could be caused by regional or temporal factors. If NOCs are more active in expensive markets such as the North Sea, the same trends would be expected. From 2000 to 2010, NOCs became more active worldwide, particularly the jackup segment, and this coincided with an increase in dayrates. To control for the effect of time and regions, we built a linear regression model with the contract start year as a predictor variable and E&P firm type and region as indicator variables:

$$DR = \beta_0 + \beta_1 IND + \beta_2 IOC + \beta_3 YEAR + \beta_4 GOM + \beta_5 NSEA + \beta_6 AFRICA + \beta_7 PGULF,$$

where DR is the dayrate, IND is one if the E&P firm is an independent and zero otherwise, IOC is one if the E&P firm is an IOC and zero otherwise, YEAR is the contract start year, and GOM, NSEA, AFRICA, and PGULF are indicator variables that take the value one if the region is selected and zero otherwise. When the region was Southeast Asia, all regional indicator variables are zero. The Persian Gulf variable was not included in the floater model.

The models for jackups and floaters are shown in Table E.11. After controlling for year and region, NOCs paid higher dayrates than independents and IOCs in the jackup market. NOCs paid higher dayrates than independents in the floater market, but the difference between NOC and IOC dayrates in the floater market was not significant. After controlling for temporal and regional factors, jackups employed by NOCs paid a dayrate premium of 17,000 $/day relative to independents and 11,000 $/day relative to IOCs. For floaters, NOCs paid a premium of $30,000 relative to independents. While significant, these premiums are much lower than observed in the global sample, suggesting that time or regional differences account for a portion of the global premium.

5.9. Large Drilling Contractors Are Awarded Higher Dayrates than Smaller Contractors

Large drilling contractors may be able to use market power to achieve higher dayrates than their competitors and anecdotal evidence support these claims (Sheridan, 2008; Wethe, 2012; Lee and Jablonowski, 2010). Transocean is the largest drilling contractor and was a market leader throughout the decade. We compared the dayrates paid to Transocean to the dayrates paid to its competitors in each region and rig class from 2000 to 2010. Transocean received higher than average dayrates in the North Sea and U.S. GOM floater markets, however, when we controlled for the effects of rig water depth, the dayrate difference became non-significant. Similar results were achieved when the five largest drilling contractors (e.g. Transocean, Diamond, Noble, ENSCO, and Seadrill) were evaluated as a group. Thus, while large drilling contractors receive higher dayrates than their competitors in some regions, the effect appears to be due to the higher specifications of their fleets rather than the use of market power.

5.10. Deepwater Appraisal Drilling Receives Higher Dayrates than Exploratory or Developmental Drilling

In exploratory drilling, the primary goal is to find commercial quantities of hydrocarbons, while in development drilling, the goal is to produce hydrocarbons. During appraisal drilling, the goal is to define the characteristics of the reservoir, and as a result, appraisal drilling is considered more technically demanding than exploratory or developmental drilling (Knoring et al., 1999; Sah, 2010; Haskett, 2003). Information is a primary objective of delineation and because appraisal wells may later serve as production or injection wells, they are drilled carefully with special attention to their future utility. E&P firms may prefer to use higher-specification rigs for appraisal and a dayrate premium is expected.

In the jackup markets, we found no significant differences in dayrates by well type on a regional or global basis. In the global floater market, appraisal drilling received a dayrate premium of approximately $80,000 compared to developmental and exploratory drilling, and there were no significant differences between exploratory and developmental drilling.

It is possible that appraisal wells are drilled by more advanced rigs than developmental or exploratory wells, and this could explain the observed differences. We used floater maximum water depth category as a proxy for rig specification and separated floaters into mid-water (less than 3,000 ft), deepwater (3,000 to 7,500 ft) and ultradeep (greater than 7,500 ft) categories. The increased cost for appraisal drilling in floaters is robust across rig water depth capability (Table E.12). Appraisal drilling is always significantly more expensive than development or exploratory drilling, or both. As in the total sample, there is no clear pattern between costs for exploratory and developmental drilling. It is also possible that appraisal drilling has been more common in high cost regions such as the North Sea. When regions were compared separately, appraisal drilling was always more expensive than developmental or exploratory drilling, but the difference was only significant in the U.S. GOM and North Sea where the sample sizes were the largest (Table E.12).

The observation of higher dayrates for appraisal drilling may suggest that drilling contractors require a risk premium for appraisal wells. If a drilling contractor damages a wellbore or otherwise provides inadequate well construction services, they are often contractually obligated to drill a replacement well at no additional cost to the E&P firm (Osmundsen et al., 2008). If appraisal wells are associated with a higher risk of failure, drilling contractors may require higher dayrates to undertake these programs.

5.11. Limitations

We analyzed the effects of individual factors on dayrates by holding all other variables constant. In the real world, many factors interact simultaneously to impact dayrates, and it is reasonable to assume some interaction effects are present. When we aggregate rigs and analyze single factor trends over time, we do not consider the impact of interacting factors. For example, the analysis of contract duration did not account for rig specifications. High spec rigs may be more likely to get long-term contracts than low-spec rigs and this, rather than contract length, may account for the observation of higher dayrates for long-term contracts. In practice it is the impact of multiple observable and unobservable factors that determine dayrates.

Sample size considerations limit the ability to make robust generalizations in factor analyses, especially in the floater markets. While the overall sample was large, the regional distribution of contracts was uneven, and only the U.S. GOM and North Sea had a sufficiently large number of contracts in both the jackup and floater markets. As a consequence, many comparisons within regions became insignificant. For example, when comparing dayrates for appraisal, exploratory, and development drilling within regions, the pattern of higher dayrates for appraisal drilling was consistent across regions, but significant differences were only observed in the U.S. GOM and North Sea.

The regions were treated as independent, but in reality, the regions interact and exhibit a degree of correlation. If interactions are significant, it may be inappropriate to treat the regions separately. The U.S. GOM, North Sea and West African floater markets, particularly the drillship segment, are closely correlated in terms of dayrates, but exhibit differences in supply, utilization, and customer base, and the dominance of specific factors will influence the impact of segmentation.

The data used in the analysis are subject to error due to the unique nature of drilling contracts (Moomjian, 2012 and 1999). Contracts differ in important ways outside of dayrates which may make direct comparisons less meaningful. Depending on contract terms, dayrates may be adjusted periodically, and these adjustments may or may not be specified in the dataset. In some cases, the costs of mobilization may be paid in a lump-sum while in other cases dayrates may be prorated to account for these costs; these terms are not specified in the data.

5.12. CONCLUSIONS AND IMPLICATIONS

Dayrates are the leading indicator of the offshore contract drilling market and are tracked and widely reported by a number of commercial service providers. A body of common knowledge has developed over the years, but has not been subject to empirical verification. The analyses provided in this chapter generally confirm widely-held industry assumptions.

Demand for drilling services is positively associated with oil prices for both jackups and floaters. The best predictors of demand were long-term moving averages suggesting that short-term price fluctuations associated with seasonal or temporary geopolitical events do not significantly impact activity in the market.

Dayrates increase with increasing oil prices for both jackups and floaters. Long-term moving averages of oil prices were the best predictors of dayrates, consistent with the hypothesis that high oil prices increases global demand and leads to increasing dayrates. Effects were consistent across regions indicating that regions respond similarly to increases in prices.

Dayrates and utilization rates are positively correlated, but the strength of the relationship varies over time and across regions. While utilization is a significant predictor of dayrates, a large portion of the variation in dayrates is not explained by utilization rates, suggesting that other factors such as regional prospectivity are also important.

Rigs capable of drilling deeper wells, working in greater water depths, or with more advanced station keeping capabilities have higher dayrates than rigs with lower specifications, and these results were typically consistent across regions, but the value of the premium varied and the premium was consistently lower in the West African floater market than in other regions.

Long-term contracts exhibit higher dayrates than short-term contracts and the relationship is robust throughout the decade suggesting that E&P firms have been willing to pay more to secure drilling capacity.

After controlling for regional and temporal variation, NOCs pay higher dayrates than IOCs or independents in the jackup market, and pay higher dayrates than independents, but not IOCs, in the floater market. NOCs may thus overinvest in drilling relative to private firms.

Transocean and other large contractors receive higher dayrates than their competitors, but the difference is not significant after controlling for rig specifications. There is no evidence that large firms are able to use their market power to increase dayrates, consistent with the view that the industry is highly competitive.

Appraisal drilling receives higher dayrates than exploratory or developmental drilling in the floater market, but not in the jackup market. The higher dayrates for appraisal drilling in the floater market may be due to increased risk associated with appraisal drilling.

6. CONCEPTUAL MODELS OF FIRM DECISION-MAKING

Companies that own drilling rigs conduct transactions and decide on newbuild programs and the best time to stack a rig. In this chapter, we develop models of acquisition and stacking to illustrate the primary factors in strategic decision making. Newbuilding and acquiring an existing rig are based on similar decision making processes, and here we focus on newbuilding. The models employed by industry are confidential but the economics of decision-making and future uncertainties governing the market are universal, so we suspect these models will broadly reflect industry results based on similar parameterizations. We begin by developing a net-present value model of the newbuilding decision and develop and parameterize a stacking decision model. We conclude with a review of net asset value estimation as a special case of the net present value model.

6.1. NEWBUILDING

Drilling contractors invest in newbuilding when the expected net present value (NPV) of adding a rig to the fleet is positive and justifies the risk (Cole, 1995). To achieve competitive returns, drilling contractors have to maintain a lean cost structure and control both its cash operating and capital costs, while optimizing the capital invested. Rig construction is highly capital intensive. In 2012, newbuild jackups cost on average $217 million, while newbuild semis cost $595 million and drillships $634 million, so strong returns are critical to attracting the low-cost debt and equity capital to finance newbuilding and acquisitions.

Diversity in fleet composition and the maintenance of high quality, new rigs are important to the success of a firm because they enable operators to mitigate exposure to industry downturns (Speer et al., 2009). High quality drilling rigs generally continue operating during downturns whereas older lower quality units might be taken out of service.

The decision to invest carries substantial risk because capital costs are significant and future market conditions are unknown. Factors that are known prior to undertaking a newbuild project are the capital cost of the vessel, finance terms, and the dayrate and duration of an initial contract, if applicable. Operating expenses can be estimated with a reasonable degree of certainty based on the company's historical performance, and depreciation schedules are based on current regulations. The primary unknown variables are the dayrate and utilization rate after the initial contract period and are referred to as the outyear dayrate and outyear utilization rate.

6.1.1. Model

To illustrate the economics of newbuilding investment, a NPV model was developed for a hypothetical jackup rig with an economic life of 25 years. The rig is built speculatively, and no initial contract period is assumed; therefore, the outyear utilization rate is equal to the utilization rate. This assumption is relaxed later in the section. Table F.1 summarizes the variables used.

Net Present Value

The NPV represents the discounted sum of cash flows over a 25 year period:

$$NPV = \sum_{t=0}^{t=25} \frac{Net\,cash\;flow_t}{(1+D)^t},$$

where t is the year and D is the company discount rate. Cash flows in each year consist of income generated by leasing the rig minus capital and operating costs and taxes:

$$\text{Net cash flow}_t = \text{Income}_t - \text{CAPEX}_t - \text{OPEX}_t - \text{Taxes}_t.$$

The rig is assumed to have no residual value at the end of its 25 year life.

Capital Costs

Capital costs consist of the purchase price C of the rig and an upgrade in year 10, assumed to be 25% of the purchase price: $\text{CAPEX}_{10} = C * 0.25$. The initial capital expenditure is financed through the issuance of bonds with an interest rate, I, and a date to maturity T. Therefore, when t < T, debt repayment is: $\text{CAPEX}_t = C * I$, and at t = T: $\text{CAPEX}_t = C + C * I$.

Reactivation and Finance Cost

In addition, a fixed $5 million capital expenditure is required in any year a rig is reactivated from a cold-stacked condition. To account for finance costs during construction, interest costs are accrued in year zero and income begins to be generated in year one.

Operating Expense

Operating costs include labor, maintenance, insurance, administration, and all other costs parameterized on a daily basis. Separate operating costs are accrued when the rig is active (O_a) and cold stacked (O_s), and the rig may be in only one state in any given year (i.e. the rig cannot transition between active and cold-stacked states more than once per year). It is clear that $O_a > O_s$. Annual operating costs are thus given by either:

$$\text{OPEX}_t = O_a * 365 \text{ or } \text{OPEX}_t = O_s * 365,$$

when the rig is active or stacked, respectively.

Income

Income is a function of the dayrate (DR_t) times the utilization rate (U_t) in year t:

$$\text{Income}_t = DR_t * U_t * 365.$$

Taxes

Net income is taxed at rate X and discounted for depreciation of the rig. A straight line depreciation is assumed:

$$Taxes_t = \left(Income_t - OPEX_t - \frac{C}{25} \right) * X.$$

6.1.2. Outyear Utilization Rate

The offshore drilling market is cyclical, and during periods of low utilization, rigs are stacked to reduce operating costs. We develop two models of stacking referred to as "fixed utilization" and "variable utilization".

Fixed Utilization

In the fixed utilization model, the utilization rate is equal to a fixed average rate U_e throughout the life of the rig, and stacking does not occur:

$$U_t = U_e.$$

Variable Utilization

In the variable utilization model, the utilization rate is determined by a sine function varying around the mean:

$$U_t = U_e + 0.5(\sin t),$$

where U_t is constrained between zero and one. In the variable utilization model, the rig is cold stacked in any year in which the utilization rate falls below 30%. When stacked, utilization is set to zero and operating costs are reduced (Figure F.1).

Illustration

Figure F.2 illustrates the variable utilization rate given an expected utilization rate of 70%. The period of the utilization function is approximately six years, and over the course of its 25 year life a rig cycles through four periods of high utilization and four periods of low utilization. Initially, the rig enters a period of high utilization, consistent with market conditions during a newbuild cycle, and after the fourth year utilization falls below 30% and is stacked. During the sixth year, the rig is active again and the cycle repeats. The rig is stacked when utilization falls below the line labeled "stacked." When a rig is reactivated, we assume a fixed payment of $5 million is required to bring a cold-stacked unit into an active state.

6.1.3. Parameterization

The model was parameterized under an expected and optimistic scenario. Under the expected scenario, capital cost is $200 million; active and stacked operating cost is 60,000 and 10,000 $/day, respectively; bond interest rate is 4.5%, bond maturity is 7 years, and the tax and discount rates are 15%. Under the optimistic scenario, capital cost is $175 million; active and stacked operating cost is 50,000 and 6,000 $/day, respectively; bond interest rate is 3%, bond maturity is 15 years, and the tax and discount rates are 10%. Additional assumptions are shown in Table F.2. The dayrate and average utilization rate were allowed to vary to explore the effect of changing assumptions on the break-even dayrate. Parameters were chosen based on financial information contained in the annual reports of large firms.

The purchase price of rigs are widely reported and well known. Daily operating expenditures are not available for all contractors and regions, but Table F.3 shows values for jackups reported by select firms. In the 2010-2011 time period, operating costs for stacked jackups for the two companies varied between $6,700 and $12,000 per day, while operating expenses for active jackups varied from $32,000 to $58,000 per day for standard units, and $55,000 to $87,000 per day for high-spec jackups. Table F.3 also shows stacked and active operating costs of floaters for comparison. Stacked cost for floaters is comparable to jackup units, while operating cost is significantly higher and ranges from $104,000 (midwater) to $150,000 (ultradeepwater).

6.1.4. Model Results

Break-even Dayrates and Utilization

Figure F.3 shows the break-even combination of dayrates and utilization rates in the fixed utilization rate model under the expected and optimistic scenario. As the utilization rate increases, the dayrate required to break-even on the investment decreases since higher utilization rates translate into greater cash flows.

Combinations of utilization and dayrates above the lines indicate a positive NPV, while combinations below the lines indicate a negative NPV. The break-even relationship is nonlinear and the difference between the expected and optimistic scenarios decreases as utilization rates increase. However, even at high utilization rates the difference between the scenarios is significant. At 90% utilization, the difference in dayrates between the optimistic and expected scenarios is $44,000. The model suggests that high utilization and dayrates are required to justify investment and at utilization rates of 90%, dayrates of at least $150,000 are required to make the NPV positive.

Impact of Fixed and Variable Utilization

The results of the expected scenario using the fixed and variable utilization rate models are shown in Figure F.4. At low utilization rates, the difference between the fixed and variable models is significant, and the fixed rate model requires much higher dayrates to justify investment. As the average utilization rate increases, the difference between the models decreases, and at average utilization rates U_e above 70%, the fixed utilization model gives slightly more favorable results than the variable utilization model. The crossover observed in Figure F.4 occurs because the maximum utilization rate is limited to 100% in the variable utilization model, and at high utilization rates, the sine function cannot further increase utilization and will result in lower average utilization rates. The optimistic parameterization yields similar results to the expected scenario, but break-even dayrates are approximately $50,000 to $100,000 $/day lower.

Drilling contractors are unlikely to consider building if they believe that future utilization rates will be low, and so the left extreme of Figure F.4 is of less relevance to the investment decision. At average utilization rates above 60%, the fixed and variable utilization models yield similar results, and the fixed rate mode is a good approximation to the variable rate model.

Effects of an Initial Contract

To examine the effects of an initial contract on NPV, we added an initial contract with a two year period to the model. During the two year period, the rig had a utilization rate of 100%, followed by a fixed utilization rate for the remainder of the rig's lifecycle. Figure F.5 compares the results of the expected parameterization with an initial contract to the expected parameterization with fixed and variable utilization rates without an initial contract. At low utilization rates, an initial contract reduces the break-even dayrates relative to the variable utilization model, but the differences were mostly minor. At higher utilization rates, the break-even dayrates of all three models converge. The presence of an initial contract reduces risks, but the difference is small. At 70% utilization, the difference in break-even dayrates is about $15,000/day.

6.1.5. Sensitivity

The percent change in the break-even dayrate given a 1% change in selected parameters is shown in Table F.4 for both the fixed and variable utilization models.

In the fixed utilization rate model, the rate of change in break-even dayrates is constant across utilization rates, and a single rate of change is shown under the expected scenario. In the variable utilization model, the sensitivity is dependent on the initial utilization rate. For example, in the variable utilization model, a 1% increase in active operating costs increases break-even dayrates by 0.26% when utilization rates are low (U_e = 5%), but increases break-even dayrates by 0.5% when utilization rates are high (U_e = 100%). The sensitivity of the model is shown at very high and very low utilization rates. Intermediate utilization rates have intermediate sensitivities.

For both the fixed and variable utilization models, changes in the purchase price and operating costs have a significant impact on break-even dayrates, but the impact of the interest and tax rates are minimal. For all parameters, a 1% change in the selected parameter results in a change in break-even dayrates of less than 1%. The relatively low sensitivity of the model to changes in operating costs is not intuitive. We might expect that a 1% increase in operating costs would require at least a 1% increase in dayrates, but operating costs are a fraction of dayrates, and while a $1 increase in operating costs does incur a $1 increase in dayrates, a 1% increase in operating costs causes a more modest increase in break-even dayrates.

Figure F.6 shows the change in break-even dayrates under variable discount rates. For the fixed utilization model we apply expected assumptions and a 70% utilization rate. The break-even dayrate increases as the discount rate increases, but at discount rates above 15%, the break-even dayrate flattens out and starts to decline. The negative relationship at high dayrates is atypical of NPV models, but occurs because of the finance structure. In the model, the vessel is purchased through the sale of bonds with a maturity date several years into the future. As the discount rate increases, the value of the principal payoff declines, making the NPV more positive.

6.1.6. Limitations

The model is a simplification of the newbuilding decision. Factors that were not considered include a variable dayrate, the effects of adding a rig to the fleet on the dayrates of the other rigs in the fleet, and the remaining value of the rig after the 25 year model duration. The impact of excluding these factors is briefly described.

A mean dayrate was employed in the model, but in reality, dayrates will vary around a mean, and the temporal distribution of the variance is important. Future cash flows are discounted, so if dayrates fall below the average early in the rig's lifetime but later exceed the mean, the NPV of the investment will decline. If the near term future is more predictable than the distant future, and if realized dayrates accurately reflect the mean during the first 5 to 10 years of service, the results of the model are likely to be similar to the actual NPV.

The decision to newbuild typically results in the net addition of a rig to the fleet, increasing supply, and potentially decreasing dayrates for the other rigs in an operator's fleet. This should make drilling contractors more conservative when evaluating newbuilding decisions. The effects of a small increase in fleet size on dayrates and utilization rates are difficult to detect, but the cumulative impact of several drilling contractors making investment decisions simultaneously is more significant.

Rigs are designed to have operational lives of around 25 years, but rigs often work for 30 years or more and the oldest operating rig in the current fleet is 54 years old. Therefore, significant value remains in the rig beyond the 25 year design life suggested in the model. Since it is difficult to predict market conditions 25 years in the future, it is difficult to estimate this value in a reliable way.

The financing structure of the model may be inappropriate for smaller firms and firms with high debt loads. We assumed that firms would raise capital through the issuance of bonds which is a major source of capital for large firms. In many cases, firms use more traditional loans to finance construction. Loans have higher interest rates and require repayment of capital earlier than bonds, and both of these factors would increase the dayrates and utilization required to justify construction. Many bank loans used in the industry utilize balloon payments at the end of the term and would have a financing structure similar to bonds.

6.2. STACKING

6.2.1. Decision Model

Stacking Criteria

Firms cold-stack rigs when the expected income received from the asset is less than the rig operating costs, or when the costs of stacking are less than the net costs of operating:

$$\text{Costs of stacking} < \text{Net costs of operating.}$$

The costs of stacking include the costs to prepare the rig for storage (deactivation costs), the operating costs during storage ($OPEX_s$) and the costs to reactivate the rig (reactivation costs):

$$\text{Costs of stacking} = \text{Deactivation costs} + \text{Reactivation costs} + OPEX_{s.}$$

The net costs of operating consist of the income received minus the active operating costs ($OPEX_a$).

$$\text{Net costs of operating} = \text{Expected income} - OPEX_a.$$

Thus, a rig should be stacked if:

$$\text{Deactivation costs} + \text{Reactivation costs} + OPEX_s < \text{Expected income} - OPEX_a.$$

Deactivation Costs

Deactivation costs are a fixed cost and all other costs are a function of time. Reactivation costs are assumed to include a fixed and variable component:

$$\text{Reactivation costs} = F + R * y,$$

where F is a fixed cost associated with rehiring and training workers, R is the reactivation costs needed to bring back a cold-stacked unit to an active state, and y is the number of days the rig is idle.

Operating Costs

The operating costs while cold-stacked are given by the daily operating cost times the number of days the rig is idle:

$$OPEX_s = O_s * y,$$

$$OPEX_a = O_a * y,$$

where O_s and O_a are the daily operating costs in the stacked and active states, respectively, and y is the number of days the rig is idle.

Lost Income

The potential lost income is the expected dayrate multiplied by the expected utilization rate and the number of days the rig is idle:

$$\text{Expected income} = \text{DR} * U_e * y,$$

where DR is the dayrate and U_e the utilization rate. Table F.5 summarizes the model variables.

Sign Convention

Since the stacking decision model is an inequality, the sign of the variables is important. We assume that all of the variables defined above are positive, for example, deactivation costs are \$1,000,000 rather than -\$1,000,000. As a result, the costs of stacking, as defined, will always be positive, but the net costs of operating may be positive or negative. Therefore, we force the costs of stacking to be negative, and change the direction of the inequality:

$$-\,(\text{Deactivation costs} + \text{Reactivation costs} + \text{OPEX}_s) > \text{Expected income} - \text{OPEX}_a.$$

Therefore, a rig will be stacked if the costs of stacking are less negative (greater) than the costs of operating. If the expected income minus the OPEX_a is positive, the rig will not be stacked. For example, if: Deactivation costs + Reactivation costs + OPEX_s = \$1,000,000, Expected income = \$1,000,000, and OPEX_a = \$3,000,000, then the inequality becomes:

$$-\,[1{,}000{,}000] > 1{,}000{,}000 - 3{,}000{,}000,$$

and the rig should be stacked. If the expected income increased to \$3,000,000, the rig would not be stacked because:

$$-\,[1{,}000{,}000] < 3{,}000{,}000 - 3{,}000{,}000.$$

6.2.2. Parameterization

We parameterize the model for a low-spec jackup. Low-spec jackups are the most common cold-stacked rigs and reliable cost information is available from several contractors. Here we apply the quarterly reports of Hercules Offshore from 2010-2011. The costs to deactivate and operate the rig in a cold and ready-stacked condition are well known, but the time the rig will be out of service, and the potential lost income can only be estimated. We fix the deactivation costs, the fixed component of reactivation costs (F), and the operating costs (O_a and O_s), and allow the dayrate and utilization rate to vary.

The costs to deactivate a rig include costs to move the rig to a storage location and secure the rig for storage. A reduction in the workforce will be associated with reduced direct and indirect costs, but short-term administrative cost may be incurred. Deactivation costs are not typically reported in financial documents, and we assume a fixed cost of \$1,000,000. Reactivation costs for jackups typically range from \$5 to \$10 million depending on the condition of the rig. We assume a fixed cost of reactivation of \$3 million and variable costs of \$4,000 per day. Operating expenses for an active rig depend on the size, age and replacement value. For an older jackup operating expenses are assumed to be $35,000 per day. For a cold stacked jackup, operating expenses are assumed to be $8,000 per day.

6.2.3. Model Results

The relationship between utilization rate and the benefit of stacking a rig for one year under the assumptions described and at dayrates above and below the operating expense of the rig is shown in Figure F.7. Negative values indicate that stacking the rig is the preferred strategy and positive values indicate that the rig should be operated. When the expected dayrate is $30,000 ($5,000 below operating costs), the contractor must expect a utilization rate of approximately 45% to justify operating the rig. When the expected dayrate is $40,000 ($5,000 above daily operating expenses), the contractor requires a utilization of at least 35% to justify operation. Thus, depending on the utilization rate, cold-stacking can be preferred even if the dayrate is greater than operating costs; conversely, operating the rig may be preferred even if the dayrate is less than the daily operating costs.

The effect of the duration of cold stacking on the stacking decision is shown by Figure F.8. Utilization is held constant at 50% for both dayrates. At dayrates of $40,000 per day, the rig makes money and stacking is never the preferred option. However, at dayrates of $30,000 per day, operating costs are higher than revenues and the owner loses money operating the rig for longer than 500 days. If the rig is to be stacked for 500 days or less, operating the rig is still the preferred strategy because of the high fixed costs associated with stacking.

6.2.4. Limitations

Stacking decisions are complex because firms typically operate several rigs in the same region, and the preferred strategy is the one that maximizes revenue for a firm’s fleet, which in part depends on the market position of the firm and its ability to capture the largest portion of available contracts at rates above operating expense. Large market shares typically indicate technological leadership and commands premium pricing.

By stacking rigs, a firm may be able to improve utilization rates and keep dayrates higher for the rest of its fleet. Corts (2008) studied the stacking decisions of large and small firms for two years from 1998 to 2000 and found that large firms stack and reactivate rigs more rapidly than smaller firms. He attributed this to lower reactivation costs for large firms due to their greater ability to retain labor. As the costs of reactivation decline, firms are expected to stack and reactivate their rigs more rapidly in response to changing market conditions and business strategy.

6.3. NET ASSET VALUE

6.3.1. Definition

The net asset value (NAV) of a rig is the discounted value of the rig's expected future net earnings. Several market research firms estimate the NAV of a drilling contractor's fleet for investment purposes. Jefferies, Standard and Poor's and ODS-Petrodata each develop NAV estimates and their data is widely referenced in the industry (Slorer et al., 2011; Glickman, 2006). Jefferies and Standard and Poor's calculate NAV for a particular rig, while ODS-Petrodata calculates NAV for a rig class (e.g. second generation semisubmersibles).

NAV is the summation of future expected cash flows and is estimated by calculating operating income for a rig based on current and future projected dayrates, estimated operating expenses, and estimated rig utilizations. Income is projected over a defined period (in the case of Standard and Poor's it is 10 years) and a residual value is added which is an estimate of the value of the rig after the duration of the income projection.

ODS-Petrodata valuations by rig class in the 4Q 2011 are shown in Table F.6 and Figure F.9 shows Jefferies NAV calculations for selected rigs. NAVs are a function of time and depend upon the rig's current and expected future contracts and related factors. As contracts expire and market conditions change, new contracts are negotiated which impact NAV calculations.

In Figure F.10, Jefferies' NAV estimates for the Galaxy II and Galaxy III jackups from 2009 to 2012 illustrate the time dependent nature of NAV assessment. The durability of NAV depends upon the length of a contract, and when contracts expire, NAV estimates change. In a down market with declining dayrates, NAV will generally decline, and conversely, when dayrates are increasing, NAV will increase. The rig valuations for Galaxy II and Galaxy III follow the same pattern but are not identical and depend on the specific contract each rig is working under at the time of valuation and the assumptions of the analyst.

6.3.2. Model

Conceptually, NAV models are similar to the NPV model described previously, where the NAV is the purchase price C that makes the NPV zero; that is, it is the fair market value of a rig. By modifying the NPV model, we estimate NAV.

The NAV model is a simplified version of the NPV model described in Section 6.1.1. NPV is given by:

$$NPV = \sum_{t=0}^{t=25-A} \frac{Net\,cash\,flow_t}{(1+D)^t}.$$

The model is iterated over the remaining lifetime of the rig, assuming an initial age, A, and a total lifetime of 25 years. Net cash flow is composed of income, operating expenses, and taxes, as before:

$$\text{Net cash flow}_t = \text{Income}_t - \text{CAPEX}_t - \text{OPEX}_t - \text{Taxes}_t.$$

Income, operating expense, and taxes are estimated as in the NPV model. A constant utilization rate is assumed ($U_e = U_t$). No finance structure for the capital expenditure is assumed so that the NAV is equal to the purchase price that makes the NPV equal to zero: $CAPEX_1 = C$, and when NPV = 0, NAV = C. We parameterize the model for jackups by modifying the expected parameterization used previously (Table F.7).

6.3.3. Model Results

The net asset value of rigs of different ages and under different assumptions of future dayrate and utilization rate is shown in Figure F.11. In the top panel, utilization is held constant at 90% and dayrates vary. In the bottom panel, dayrate is held constant at $120,000 and utilization rates vary. At low dayrates and utilization, the difference in NAVs for old versus newer rigs is minor, but as the dayrate or utilization rate increases, the NAV difference also increases. In reality, the age of the rig is expected to interact with dayrates and utilization, and old rigs are expected to have lower dayrates and utilization while newer rigs are expected to be more active and to capture higher dayrates.

6.3.4. NAV Comparison

In Table F.8, our NAV estimate is compared with Jefferies NAV estimates for two Transocean rigs. The default model parameters were used in the estimation, and the dayrates reflect January 2012 values for each rig. The NAV estimates match relatively closely; however, our estimates are slightly lower than Jefferies reflecting different assumptions on future dayrates, discount rates and the lifespan of the rigs.

6.3.5. Alternative Formulations

Industry models will differ from our development, but in most respects, the results are expected to be broadly similar under similar parameterizations. We assumed a total rig lifetime rather than attempting to estimate a residual rig value at some future point which both simplifies the calculations and leads to a conservative estimation. The model could be parameterized with contract data for a specific rig (as performed by Jefferies and Standard and Poor's), or with average dayrates and utilization for a rig class (as performed by ODS-Petrodata). In either case, older rigs would be parameterized with lower dayrates, utilization and operating costs than newer rigs.

7. JACKUP CONSTRUCTION MARKETS

Rig construction combines steel forms and machinery using capital and labor. Worldwide, the offshore oil and gas industry is a major consumer of shipbuilding services, and rig construction is a major fraction of shipbuilding in support of oil and gas activities. In the Southeastern U.S., shipbuilding in support of the offshore oil and gas industry is culturally and economically important, and while rig construction has declined in the past decades, it remains locally important in a small number of communities. The purpose of this chapter is to introduce the jackup construction market with an emphasis on the U.S. We describe the demand factors, players, and contract structures that impact jackup construction markets.

7.1. HISTORICAL OVERVIEW

The number of jackup rigs delivered by region over the past six decades is shown in Figure G.1. From 1950 to 2012, a total of 641 jackup rigs have been constructed. The U.S. constructed 37% of the total number of jackup rigs during this period, with Asia contributing 45%, and Western Europe 8%. Since 2000, Asia has constructed 70% of the rigs delivered, followed by 14% in the U.S. and 16% in all other countries.

Jackup construction began in the U.S. in the mid to late 1950's and was dominated by U.S. shipyards in the 1960's. Major players in the period included Marathon LeTourneau, Bethlehem Steel and Levingston. In the early to mid-1970's U.S. firms invested in Singaporean shipyards to reduce transport costs for offshore exploration in the region (Khiam, 2007; ASMI, 2011; Leong, 2006). Simultaneously, Western European, Canadian and Japanese firms developed the capability to compete and the construction market grew significantly.

The 1970's and early 1980's saw significant increases in the price of oil and improvements in jackup technology which lead to strong demand growth. The growth in demand encouraged new market participants, and by the mid 1980's, shipyards in 23 countries had delivered rigs including France, Singapore, Russia, Brazil, and Romania. At its height in the late 1970s and early 1980's, 11 U.S. shipyards were engaged in rig construction, including six in Texas, three in Mississippi and one each in Maryland and South Carolina (Colton, 2011).

Oil prices began to fall in the early 1980's, and by 1985, new jackup orders had declined precipitously. Between 1980 and 1985, 244 jackups were delivered, but between 1986 and 2000, only 30 rigs were delivered. In early 2000, the aging jackup fleet began to encourage new orders, most of which were placed in Singaporean yards (Figure G.2) due to the movement of shallow water exploration activity in other parts of the world and the general decline in the competitiveness of U.S. shipbuilding (Koenig et al., 2003). The pace of deliveries accelerated in 2006 due to increases in the price of oil, receded in late 2008 following the economic recession, and began again in late 2010.

7.2. DEMAND FACTORS

The demand for drilling rigs is impacted by oil prices, utilization and dayrates, technology, the number of countries open to exploration, field discoveries, fleet age, and construction cost. Jackups have water depth limitations and can only operate in 500 ft of water.

7.2.1. Oil Prices

The number of jackups and floaters delivered worldwide from 1974 to 2012 is depicted in Figure G.3 and correlated with the two-year lagged average annual oil prices in Figure G.4. The lag is roughly equal to the time to build a jackup and suggests that drilling contractors respond rapidly to changing oil prices by ordering rigs. Deliveries in floating rig construction follow a trend similar to the jackup market but the statistical relationship is not significant.

7.2.2. Utilization and Dayrates

When utilization rates are high, there is little spare capacity in the contract drilling market, leading to increases in dayrates. This signals to drilling contractors that additional capacity may be absorbed by the market and increases the dayrate and utilization rate assumptions used in the financial analysis of a newbuilding decision. Figure G.5 shows the relationship between the number of rigs delivered and the lagged global average jackup dayrates between 2000 and 2012. Dayrates explain over 80% of the variation in deliveries, suggesting that dayrates are an important signal to investors. New companies are encouraged to enter the market by high dayrates and utilization rates which add to demand during market upswings.

7.2.3. Technology

Improved technology and an interest among E&P firms in developing more technically challenging resources can also stimulate newbuilding demand. In the floating rig market there was a brief period of high activity from 1998 to 2002 which was driven not by oil price increases, as oil prices remained low during this time, but by the maturation of deepwater drilling technology which allowed drilling in water depth beyond 5,000 ft (Cantwell, 2000). Likewise, interest in HPHT shallow water drilling led Rowan to order several high-specification jackups in the early 2000’s (Maksoud, 2002).

7.2.4. New Discoveries

In some cases, E&P firms order rigs to fulfill a specific exploratory or developmental role. For example, in 2009, Petrobras announced plans to build up to 28 drillships for the Brazilian market as part of a major investment in its pre-salt fields. While oil prices and technological development are also important factors in the Petrobras order, the order is a direct result of Petrobras’ 2006 pre-salt discoveries. As more countries open their offshore waters to exploration, demand for rigs will increase.

7.2.5. Fleet Age

Rigs are exposed to a corrosive environment and over time steel in the hull and legs corrodes and must be replaced. Eventually, the maintenance and refurbishment costs exceed the returns generated by operation, and the rig is sold for scrap, placed in long-term storage or converted to another use. Rigs are designed for a 25 year operational life, but many rigs built in the 1977-

1985 period remain operational in 2012. Fleet age provides a signal to investors that new rigs may be required in the future (Wiseman, 2003).

7.2.6. Construction Cost

The newbuild market is historically cyclical. During periods of low demand, construction costs decline which may stimulate demand from drilling contractors. By building during market downturns, drilling contractors increase the risk that the newbuilt rig will not be immediately utilized, but pay lower capital costs and lower the overall financial risk associated with newbuilding. Historically, construction cost has not been a major driver of demand, and few firms take advantage of low prices to order rigs.

7.3. Players

Countries building rigs in 2012 are shown in Table G.1. Singapore is dominant in jackup construction, Korea is dominant in drillship construction, and semisubmersible construction is split between China, Korea and Singapore. Shipyards in the UAE and India also build jackups.

Table G.2 shows the distribution of rig construction by shipyard for deliveries between 2005 and 2012. Keppel and Sembcorp are dominant in jackup and semi construction, while Samsung is dominant in drillship construction. The market capitalization of selected shipyards on Dec 31, 2011 is also depicted. Many industry players are either not publicly traded or are subsidiaries of larger firms. The market cap of these firms is not included to facilitate comparison. Keppel is the largest player in the industry by a significant margin, and Sembcorp is the only competitor in the jackup market that is of approximately the same scale.

7.3.1. Singapore

Singapore is the largest producer of jackup rigs and is also dominant in semisubmersible construction. Keppel and Sembcorp are the major players, with Keppel being the larger of the two. Together, these two firms have the capacity to deliver approximately 25 jackups annually, and between 2008 and 2011 averaged 12 jackups and three semi deliveries per year. In 2011, Keppel had a market capitalization of $15.1 billion compared to $8.8 billion for Sembcorp, and their combined revenues accounted for approximately 2% of Singapore's GDP. The offshore industry accounts for 9% of total Singaporean manufacturing output.

A primary advantage of Singaporean shipyards is their low labor costs due to the use of foreign workers. Sembcorp and Keppel employed over 20,000 people in Singapore in 2011, and over 75% of these employees are foreign workers which allows Singaporean shipyards to pay employees less than one-third as much as their Korean competitors (Wong and Chang, 2011).

Both Keppel and Sembcorp utilize shipyards throughout in Asia to minimize production cost and achieve scale economics. Singaporean yards are physically constrained due to the lack of land, and face increasing labor costs associated with taxes levied on the employment of foreign workers. As a result, Sembcorp and Keppel outsource work to company-owned yards in Indonesia and China to assemble hulls or other modular components with final assembly occurring in Singapore.

Keppel

Between 2005 and 2012, Keppel delivered 38 jackups, 10 semis and two drillships from its Singaporean yards. Keppel owns rig building and repair shipyards in eleven countries, but most of their newbuilding is performed at the Keppel FELS shipyard in Singapore. Figure G.6 shows the layout of one of the four facilities at Keppel FELS. The Pioneer yard is designed to accommodate three jackups and one semisubmersible in drydocks, as well as several jackups, semis and drillships in quays. In the plan schematic, two drillships, four semis and one jackup are shown quayside. In the satellite view, three jackups, five semis and one liftboat are present. Keppel also owns yards in the U.S., Brazil, Norway, Azerbaijan, Kazakhstan, UAE, Qatar, China, the Philippines and Indonesia. With the exception of Keppel AmFELS in the U.S., Keppel's international yards are primarily focused on repair and/or non-rig construction.

Keppel's shipyards build a variety of rig designs, but the majority of their rigs use proprietary designs. Unlike other design firms, Keppel does not typically license its designs to other shipyards and their most important product is the KFELS B Class. The use of proprietary designs increases efficiency through learning as shipyards can improve manufacturing processes and optimize purchasing and logistics. These factors, along with the elimination of the license fee, are estimated to reduce costs by 10 to 15% (Wee, 2008).

Sembcorp

Sembcorp is the second largest firm in the jackup construction industry and between 2005 and 2012 delivered 33 jackups and 10 semisubmersibles. Sembcorp owns two major rig building shipyards: PPL and Jurong (Figure G.7). PPL owns the Pacific Class 375/400 design, and these rigs have made up most of the deliveries from the PPL yard. The Jurong yard has specialized in the F&G JU 2000/3000 class rigs but is also active in semi construction. In addition to its activities in rig construction, Sembcorp owns repair facilities in Sabine, Texas and Brazil, and operates yards in Singapore specializing in medium and large cargo vessels.

7.3.2. China

Rig construction in China has grown rapidly in recent years. In 2006, the first Chinese built jackup rig was delivered, and by 2011, China was the third largest construction market with significant market share in both the jackup and semi segments. In 2011, six shipyards were building jackups in China with Dalian and Yantai Raffles being the largest players. CIMC Raffles and COSCO are the largest Chinese players in the semi market and are currently building 10 semis. Three drillships are also under construction in China. All of the major players in the Chinese market are state-owned but build rigs for both state-owned and international contractors.

7.3.3. South Korea

South Korean shipyards do not build jackups but are the dominant firms in drillship construction. South Korean players include Hyundai, Samsung and Daewoo. These three firms delivered 86% of drillships and 20% of semisubmersibles from 2005-2012. In January 2012, they are constructing over three-quarters of drillship orders. Samsung and Daewoo primarily build their own proprietary designs while Hyundai builds mostly Gusto MSC designed drillships.

7.3.4. United States

Jackup Deliveries

In the Southeastern U.S., shipbuilding in support of the offshore oil and gas industry is culturally and economically important (Abel and Taylor, 2008). Table G.3 shows deliveries of jackup rigs from U.S. shipyards between 2000 and 2012. During this period, the LeTourneau yard in Vicksburg, Mississippi delivered 11 rigs, and the Keppel AmFELS yard in Brownsville, Texas delivered 14 rigs. In addition, one liftboat with an attached rig was delivered from a shipyard in New Iberia, Louisiana. On average, approximately two jackups have been delivered each year over the past decade.

Table G.4 shows non-jackup MODUs delivered between 2000 and 2012. Five semisubmersibles were delivered from U.S. shipyards from 2000 to 2002, however, three of the five vessels had their hulls built in Asia and were only outfitted in U.S. yards. Requirements for outfitting rigs are significantly different from the requirements for hull construction and are generally less specialized and capital intensive. The *Q4000* is not a drilling rig but a semisubmersible well intervention unit. While it is possible that an oil services firm could require a Jones Act certified vessel like the *Q4000*, barring a major change in market conditions, semisubmersible and drillship newbuilding is unlikely to occur in the U.S. in the foreseeable future.

Vicksburg, Mississippi

The LeTourneau yard in Vicksburg, Mississippi was the first shipyard to build a jackup rig in the U.S. and between 1958 and 2010 delivered 87 rigs (LeTourneau Technologies, 2010). The yard is located on 90 acres adjacent to the Mississippi River (Figure G.8) and exclusively builds LeTourneau designed rigs. In recent years, several Workhorse 240C class rigs have been built.

Due to the height of the bridges along the Mississippi River, only the lower sections of legs are attached to the rig in Vicksburg with the upper sections fabricated in Vicksburg and attached at the company's shipyard in Sabine Pass, Texas. The derrick must also be attached after leaving Vicksburg. The Vicksburg shipyard does not have the ability to modify or repair rigs due to the bridges, nor does it have the infrastructure typically associated with large shipyards (drydocks or launching systems) and must instead "walk" the rig into the water. Despite its historical success, the Vicksburg shipyard has attracted smaller numbers of new orders and has apparently become uncompetitive.

From 2000-2011, LeTourneau was owned by drilling services contractor Rowan which was the shipyard's major customer. In 2011, LeTourneau was sold to Joy Global which then sold LeTourneau's drilling equipment operations to Cameron for $375 million (Elswick, 2011). After the delivery of the *Joe Douglas* in 2011, the shipyard has no further work contracted, but it is likely that some work will continue in Vicksburg, primarily the construction of legs and elevating systems for LeTourneau designed rigs built elsewhere.

Brownsville, Texas

The Brownsville shipyard is located on approximately 170 acres along the Brownsville Ship Channel east of Brownsville, Texas (Figure G.9). The yard began building offshore drilling rigs in 1973 as the Marathon LeTourneau shipyard. In 1991 it was bought by Keppel and renamed Keppel AmFELS.

Since reopening, AmFELS has primarily built jackup rigs, but has also built a tension leg platform, accommodation platforms, the *Q4000* semisubmersible deepwater intervention vessel, drilling barges, derrick barges and other vessels. The AmFELS yard has also upgraded several jackup and semisubmersible rigs, including the jackups *Ocean Spartan* and *Ensco 67*, semisubmersible *Hakuryu-5*, and converted a semisubmersible drilling platform to a floating radar system for the U.S. military. In 2012, AmFELS was contracted by Diamond Offshore to conduct a $150 million rebuild and upgrade of the semisubmersible hull, *Ocean Voyager*. Since 2007, AmFELS has primarily built LeTourneau-designed Super 116E rigs for Rowan, Perforadora Central and Scorpion Offshore (now part of Seadrill). AmFELS has secured jackup construction work through early 2013 and stands to benefit from any reduction in activity at the Vicksburg yard.

7.4. Buyers

The number of newbuild rigs in the fleets of selected drilling contractors is shown in Table G.5. All rigs delivered after 2005 are included in the count as well as rigs under construction in 1Q 2012. Seadrill has been the major consumer of newbuilt rigs and has nearly twice as many newbuilt rigs as Transocean. COSL has also been a major consumer of newbuilt rigs, particularly relative to its smaller total fleet size. In the U.S., Scorpion and Rowan have been the major buyers and have purchased five and 14 rigs, respectively, since 2000.

7.5. Contracts

Contracts for rig construction are fixed-price turnkey contracts where the risk of cost escalation is held by the builder. Contracts are awarded in a competitive bidding process in which the buyer solicits bids from shipyards for the construction of a rig meeting certain specified criteria. The shipyard estimates the construction cost of the rig based on steel, labor and equipment prices, profit margins, and the rig design. Because the contract is fixed-price, accurate cost estimation is critical.

Contracts normally include three major categories of clauses: clauses that specify the product, clauses that specify the price, and clauses that detail responses to unforeseen events and apportion risk (Atwood Oceanics and PPL Shipyard, 2010; Santa Fe International and PPL Shipyard, 2001).

7.5.1. Product Specification

Detailed construction specifications are attached to the contract and construction practices are defined by classification society rules. Typically, the buyer is allowed to place a full-time technical representative at the yard to ensure compliance with contract specifications. A delivery time and place is specified. Acceptance of the vessel is based on satisfactory performance in sea trials and classification society acceptance.

7.5.2. Payment Schedule

Payments are made in installments at the execution of the contract, delivery, and at one or more project milestones. The methods by which the builder demonstrates completion of a given project milestone are defined. A schedule of penalties and options are defined if either the buyer fails to make a payment on time or the builder fails to deliver the rig by the specified date. The methods for accommodating changes to the vessel plans are described, which typically compensate the builder on a cost basis and allow for extensions in the delivery date.

7.5.3. Unforeseen Events and Risk

Force majeure clauses are used to differentiate between permissible and impermissible delays. Rig construction shipyards are located adjacent to waterways, typically in coastal regions, and are subject to flooding and hurricane risk. Contracts stipulate that the builder must carry a performance bond and insurance equal to the contract price and the circumstances under which bonds may be invoked are defined. A method for the mediation of contract disputes is also described.

Rig construction contracts are long-term agreements that specify delivery several years into the future. It is difficult for shipyards to accurately predict future price changes in supplies, and suppliers may be unwilling to provide firm quotes for products several years in advance (Conway and Will, 2006). This creates risk for shipyards which can be managed with material cost escalation clauses linked to inflation indices.

8. NONTECHNICAL PRIMER ON JACKUP DESIGN

The first offshore rigs were elevating barges designed for shallow water. As drilling progressed into deeper and more difficult environments, rigs evolved based upon the experience of the builder, operational performance, and the demands of the market. Designing a rig involves a number of tradeoffs between technical and economic factors. In this nontechnical primer we discuss the design factors that impact jackup construction and the most popular designs employed by industry. We discuss the major design factors and highlight the decisions made at the conceptual and preliminary stages. We conclude with a brief discussion of popular U.S. and international jackup rigs. For additional and more detailed information, the reader is referred to Gieger, 2004, Howe, 1986, Rammohan, 2005, and Vazquez et al., 2005.

8.1. Design Process

Rig designers balance a number of technical and economic factors as they move through design phases similar to ship construction (Figure H.1). The process is iterative and includes conceptual, preliminary and contract (detailed) phases (Eyers, 2007). Preliminary (or basic) designs for jackup rigs consist of the leg structure, spudcan, hull, deck diagrams, and information on electrical systems, piping systems and other systems. Detailed design work is performed after a contract is written and plans are customized to the clients' needs.

8.2. Notable Features

There are approximately a dozen popular modern designs. Functionally, the designs differ in their water depth capability and storm environment, variable deck load, quarters, crane capacity, installed power, and storage dimensions. In Figure H.2, four common design classes are shown: the BMC Pacific 375, KFELS N Class, LeTourneau 240C and LeTourneau Super 116E. The KFELS N Class is a harsh environment rig while the other three rigs are designed for moderate environments. Several features are notable.

(1) The hulls of the rigs are triangular and the legs are located at the corners of the hull for maximum stability.
(2) All four rigs depicted, and virtually all newbuilds, use trussed legs. Most rigs use triangular legs, but some designs, such as the LeTourneau Super 116E, use square legs.
(3) The hull is approximately twenty to thirty feet deep and there are typically several levels, including an inner-bottom, a machinery level, and a mezzanine deck (Figure H.3).
(4) The bottommost level of the hull is typically 3 to 6 feet deep. Above the inner-bottom is the machinery deck, where four or more large diesel engines are installed, as well as pumps and other machinery. The main deck contains topside facilities and storage tanks for water, drilling fluids, fuel, and other liquids.
(5) Topsides facilities include all the equipment for drilling, utilities, safety systems, accommodation, and life support.
(6) All offshore rigs have a heliport for the transport of personnel, several cranes to perform heavy lifting operations, and common layouts. The heliport

extends outside the hull for safety reasons and to avoid interference with drilling operations.

(7) Harsh environment rigs are larger and heavier than moderate environment rigs. The KFELS N Class harsh environment design, for example, has a hull 264 ft long by 289 ft wide. All the other rigs depicted are approximately 220 to 240 ft wide and 200 to 240 ft long.

8.3. JACKUP DESIGN FIRMS

The principal firms designing jackup rigs are Friede and Goldman, LeTourneau, Gusto MSC, Baker Marine, and Keppel. The number of jackup rigs under construction worldwide by class in 2012 and the number delivered over the past decade are summarized in Table H.1. The KFELS B class is the most commonly newbuilt rig, but the LeTourneau Super 116E and several Friede and Goldman designs are also popular. None of the designs included in the table are common in the legacy (pre 2000) fleet, but several designs have evolved from rigs built in the 1980 to 1985 newbuild cycle, for example, the LeTourneau Super 116 is based on the earlier LeTourneau 116.

8.4. DESIGN FACTORS

8.4.1. Number of Legs

Early jackup rigs had a large number of legs, in some cases ten or more (Figure H.4). All modern jackup rigs under construction in the oil and gas industry have three legs placed in a triangular arrangement at the corners of the hull. Other elevating vessels, including those used in offshore construction, offshore wind, older drilling rigs, and smaller workover rigs, may have four or more legs.

Three legged units have a number of advantages over four legged units (Geiger, 2004). Three leg units can carry more deck load while afloat than four leg units since they do not need to carry an extra leg and its associated jacking systems. Three leg units expose less area to wind, wave, and current loads, and are less sensitive to environmental conditions. Three leg units are also less expensive due to the reductions in steel weight (Mommaas and Blankestijn, 1984). The primary advantage of four legged units is greater stability and a reduction in the elevating time due to a simplified preloading procedure.

8.4.2. Leg Length

Water depth capability is one of the most important properties of a jackup and impacts its utility and cost. As water depth capability increases, leg length must increase, but many other rig parameters are also affected. Wang et al. (2009) examined the effects of water depth capability on the physical parameters of jackups and found that water depth was strongly correlated with leg length, hull breadth, hull depth, deck area and hull volume. Because of the broad influence on size-related parameters, water depth has a strong correlation with costs.

8.4.3. Environmental Conditions

Environmental conditions influence leg length, leg structure and hull size. Harsh environment rigs require longer legs to provide a greater air gap between the hull and sea level to allow for waves (Covellone and Thorson, 1985). Harsh environment rigs also require larger hulls to increase the spacing between legs and improve stability. The design of the leg chords is altered to minimize the effects of wind and current loadings, and the change in leg shape changes steel strength requirements of various leg components.

The trend in recent harsh environment jackup designs has been to build extremely large, high specification vessels such as LeTourneau's Gorilla class or Gusto MSC's CJ70 series. The CJ70 and CJ80 are harsh environment units and are approximately twice the weight of the moderate environment CJ46 and CJ50 (Table H.2). Figure H.5 compares the size of the CJ70 class rig to notable structures.

8.4.4. Leg Type

Jackup legs can be either single cylinders or trussed structures composed of three or four chords joined together by braces (Figure H.6). Trussed legs require a large number of welds and are more expensive to fabricate and take up more deck space than cylindrical legs; however, trussed legs have significant advantages over cylindrical legs. Trussed legs are usually lighter than cylindrical legs for the same bearing capacity which decreases steel costs and provides better stability while afloat. Trussed legs also expose less area to wind and water currents which reduces the likelihood of loss during storms (Macy, 1966; Vazquez et al., 2005; Mommaas and Blankestijn, 1984).

Early jackup rigs frequently used cylindrical legs, but as rigs moved to deeper water cylindrical legs became less popular. Today, all newbuilt rigs are designed with trussed legs. Cylindrical legs are still used on liftboats and other offshore construction vessels and continue to exist in the legacy fleet. Cylindrical legs are common for water depths below 200 feet (Macy, 1966) and for mat supported rigs (Geiger, 2004).

8.4.5. Chord Number and Type

There are several basic arrangements for leg chords (Figure H.7). The choice of chord shape is influenced by the required strength of the leg, but also by the way in which the racks of the chord interact with pinions in the elevating system (Mommaas and Blankenstijn, 1984), and wind and wave loading considerations as square chords are more susceptible to wind and wave loads than circular chords. Figure H.7 depicts half-round and teardrop chord designs.

Tubular chords are typical of F&G, Gusto MSC, Keppel Baker Marine and some LeTourneau designs, and generally utilize two "half rounds" welded to a rack to make up a single chord with an outer diameter of approximately 15 to 30 inches. Teardrop chords simplify construction but result in heavier legs containing more steel and are typical of some LeTourneau designs (LeTourneau Technologies, 2010). Teardrop chords have a rack and elevating pinions on only one side of each chord while tubular chords have elevating pinions on either side of each chord. Opposed pinions balance forces and allow for a shorter and lighter jacking system compared to teardrop chords.

Trussed legs may have either three or four chords. Most designs utilize three chords, but several popular models, including the LeTourneau Super 116E, use four chords. Four chorded legs are typically heavier and more susceptible to wind and wave loads than three chorded legs, however, there is more redundancy and lower loads on any single chord (Vazquez et al., 2005; Mommaas and Blankestijn, 1984).

8.4.6. Rack Chocks

After jacking, the vertical load of the rig may either continue to be supported by the pinions in the jacking system, or rack chocks may be inserted below the jacks to support the load (Figure H.8). Without chocks, the fixity between the hull and the legs is less than 100%, that is, movement between the hull and the legs will occur because the racks and pinions are not firmly connected. When chocks are inserted the fixity between the hull and the legs increases to 100% which allows for a reduction in the bracing required in the legs and a decrease in weight (Mommaas and Blankenstijn, 1984). Lighter legs are less expensive, reduce wind and wave loads, and increase variable loads by decreasing the lightship weight. However, smaller legs are more susceptible to breaking under uneven or increased loads, as in punch through. Most F&G, Keppel, Baker Marine and Gusto MSC rigs utilize chocks while most LeTourneau rigs do not.

8.4.7. Footing Structure

The legs may be connected either to a large mat-like structure attached to all the legs or to independent spudcans. In both cases, the purpose of the footing is to increase the surface area bearing the weight of the rig. Mat footings are box-like structures with approximately the same dimensions as the hull, usually with open areas so that they resemble an "A" (Figure H.9; Hirst et al., 1976). Mat foundations are typically subdivided to allow for selective ballasting to maintain neutral buoyancy throughout raising and lowering (Boswell and D'Mello, 1990).

Mat foundations distribute weight over a larger area than spudcans and are superior to spudcans in soft sea beds but cannot be used on uneven or sloping sea beds, nor can they be used near pipelines (Geiger, 2004). By contrast, spudcan footings can be used on uneven or sloping sea beds and in a wide variety of soil types. Mat foundations allow for nearly complete fixity of the legs which allows for legs to be lighter and smaller, reducing wind and wave loads. Spudcans became more popular as rigs increased in size and water depth. As the water depth capacity of a rig increases, the distance between its footings must increase, which can lead to increasing steel costs for mat foundations. All modern newbuilds use spudcan foundations.

8.4.8. Slot and Cantilevered Systems

In a slot system, the drillpipe extends through a slot in the floor of the rig. In a cantilevered system (Figure H.10), the drilling rig extends off of one side of the rig, and in most modern rigs, cantilevers can move in two dimensions. The cantilever can extend or retract the drill floor perpendicular to the hull, and the drill floor can move parallel to the hull, either by moving the position of the drill floor relative to the cantilever or by skidding the placement of the cantilever on the hull (Blankenstijn et al., 2003). The cantilever can move the drill floor approximately 70 to 90 feet perpendicularly and 15 to 30 feet parallel. Cantilevers add weight and cost to the rig, but allow jackup rigs to work over existing caissons and platforms. Cantilevers also increase the number of closely spaced wells that may be drilled, and allow more flexibility in "Swiss-cheesed" sea beds.[8] All these factors increase the utility of the rig.

8.5. Jackup Design Classes

Rig designs built in the U.S. over the past decade differ from those built elsewhere. LeTourneau designed rigs are dominant domestically (Table H.3) but are only a small portion of the international market. Table H.4 summarizes characteristics of rig designs commonly built in the U.S. and abroad. Three designs, the LeTourneau Super 116E, KFELS B Class and F&G JU 2000 series, make up over two-thirds of 2012 orders. U.S. rig-building shipyards had three major customers in the 2000-2012 period (Rowan, Scorpion, and Perforadora Central), and all three firms have preferred LeTourneau rigs. Until 2011, Rowan owned LeTourneau and the construction of LeTourneau designed rigs at the Vicksburg shipyard reduced transaction costs for Rowan. Perforadora Central and Scorpion are both focused on the <350 ft water depth, moderate environment market, and the LeTourneau Super 116 and 116E are typically the lowest cost designs for this market.

8.5.1. Common U.S. Built Designs

The most common designs built in the U.S. are illustrated in Figure H.11 and their hull dimensions are depicted in Figure H.12. The Tarzan is the smallest class while the Super 116E and 240C are approximately the same size. The Super Gorilla is the largest rig class by a significant margin.

LeTourneau Tarzan

The Tarzan is specifically designed for shallow water (less than 300 ft) deep drilling (35,000 ft) in moderate environments. The Tarzan was designed to provide HPHT drilling at a low cost, but the design has not been internationally successful. Four Tarzan class rigs exist, all built between 2004 and 2008 at the Vicksburg, Mississippi shipyard and all owned by Rowan. Unlike more traditional LeTourneau designs, the Tarzan uses three tubular chords with opposed pinions.

LeTourneau Super 116E

The LeTourneau Super 116E evolved from the LeTourneau 116C which was first built in 1978 and is considered one of the workhorses of the industry. The first Super 116E was delivered in 2007 and eight have been delivered through 2011. The Super 116E is designed for moderate locations and 350 ft water depths and is well suited to shallow, moderate environments such as the Persian Gulf. Like many classic LeTourneau designed rigs, it has square legs, each with four teardrop chords. In recent years, several Super 116Es have been assembled at the AmFELS shipyard in Texas, and worldwide, 12 Super 116E rigs are under construction. In 2012, prices are typically less than $200 million and can be as low as $160 million for rigs designed for the Persian Gulf with water depth capabilities less than 250 ft.

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8 A Swiss-cheesed seabed is an area in which jackup rigs have previously worked. In these areas, depressions in the seabed left by earlier rigs can constrain the areas in which a rig may be positioned.

LeTourneau 240C Workhorse

Compared to the Super 116E, the LeTourneau 240C can work in deeper water with a greater variable load and a larger cantilever reach. The 240C uses a unique leg design with four tubular chords. The 240C is a relatively recent rig design, and only three have been delivered, and all of these were built at the LeTourneau shipyard for Rowan. In 2011, KS Energy ordered two 240Cs from a COSCO shipyard in China for $194 million each and these represent the first foreign sales of a 240C design license.

LeTourneau Super Gorilla XL

The LeTourneau Super Gorilla XL is among the largest jackups in the world (Figure H.13) and is capable of drilling in harsh environments in water depths up to 550 ft and drilling depths up to 35,000 ft. The Super Gorilla XL is an upgraded version of the Super Gorilla and the *Bob Palmer* is the only rig of its class. The *Bob Palmer* cost $326 million to construct and has been let for nearly $300,000 a day on a long-term contract with Saudi Aramco from 2011 to 2015.

8.5.2. Common Internationally Built Designs

A selection of the most commonly built international designs is depicted in Figure H.14. The Gusto MSC CJ70 is among largest rigs in the world, while the F&G JU 2000E is significantly larger than the KFELS B Class or PPL Pacific 375.

KFELS B Class/Super B Class

The KFELS Super B class is the most popular rig design in the world, and through 2012, 33 have been delivered and 18 are under construction. Like other Keppel designs, the B Class is only built at Keppel's yards. It is a high specification unit approximately equivalent to the LeTourneau 240C in capabilities and cost, and as of 2012, prices range from $180 to $210 million. The B Class is available with a number of design variations including large spudcans to increase the allowable operating conditions and water depth capability of 300 to 425 ft.

Gusto MSC CJ70

The Gusto MSC CJ70 is the largest and most expensive jackup under construction. It is capable of drilling in 492 ft of water in harsh environments. In 2011, Maersk ordered two CJ70's for $500 million each and a third is under construction for North Atlantic Drilling (a subsidiary of Seadrill) for $530 million. All three rigs have secured initial contracts of three to five years with dayrates exceeding $350,000. The CJ70 is comparable to the LeTourneau Super Gorilla XL but has been more popular in recent years.

F&G JU 2000 Series

The Friede and Goldman JU 2000A, JU 2000E and JU 3000N are the most popular series of harsh environment jackups. The 2000A is limited to 350 ft water depths while the 2000E and 3000N can drill in up to 400 ft of water. The 3000N is the newest and most capable rig in the series with first delivery in 2012. The 3000N is slightly more expensive (approximately $235 to

$245 million in 2012) than moderate environment designs with similar drilling capabilities, but far less expensive than other harsh environment jackups like the MSC CJ70 or LeTourneau Super Gorilla XL.

PPL Pacific 375/400

The PPL Pacific Class 375 and 400 (also called the Baker Marine Pacific Class) are moderate environment proprietary designs owned by PPL shipyard which is a subsidiary of Sembcorp. The design is built at shipyards owned by Sembcorp, and is also licensed to other shipyards. The 400 class is capable of drilling in slightly deeper water than the 375 class (400 versus 375 ft) and can accommodate a larger crew (150 versus 120 people), but the rigs are otherwise similar and have the same hull dimensions, variable load and drilling depth. The 375/400 class is approximately similar to a LeTourneau Super 116E in terms of variable load and drilling depth, but generally has a slightly greater water depth capability. As of early 2012, three 400 ft units are under construction for Atwood, each at a cost of $190 million.

9. JACKUP RIG CONSTRUCTION

Shipyards use labor, materials and capital to turn steel and third party equipment into rigs. Major work activities include welding, material handling, pipe fitting, machinery installation, electrical systems, and outfit materials. The construction requirements are relatively simple and consist of a large flat area of land adjacent to a waterway, several cranes, and a large enclosed space for performing high quality welds. Some type of launching system is also required to transfer the constructed rig to the waterway for transportation to market. In this chapter, we provide a high-level narrative and pictorial description of the jackup construction process with an emphasis on methods used in U.S. shipyards.

9.1. WORKFLOW

The exact methods to assemble a jackup rig depend on the shipyard and rig specifications. Figure I.1 shows a generalized depiction of the work processes involved. Steel forms of different grades are received from one or more suppliers and are welded together to form the hull, legs, spud cans, liquid storage tanks, and quarters. Components are built separately and modularly and combined at different locations in the yard. The hull is assembled first and then the spudcans are placed through holes built into the hull. The first sections of the legs are attached and the living quarters and lower deck equipment added. The rig is then launched and the remainder of the leg sections and topside equipment is added.

9.2. SPUDCANS

Spudcans are hollow steel structures generally made of 50 to 100 ksi steel.[9] Spudcans may be fabricated away from the hull and lifted into holes (yokes) built into the hull, or the hull may be built around existing spudcans. Figure I.2 illustrates the two options. In the top image, the hull is being built around existing spudcans. In the bottom image, three spudcans (two in the foreground and one on the left of the image) are visible along with the hull; as the leg wells are completed the spudcans will be inserted.

9.3. HULL

The hull of the rig is a barge-type hull with a flat bottom and sides constructed using stiffened plates (Figure I.3), which significantly simplifies construction compared to a traditional ship-shaped hull. A horizontal steel plate (1) is stiffened with bulb flats placed 2 to 3 ft apart. These sections (2) are supported by framing girders (3) that are spaced 6 to 9 ft apart and the horizontal sections span between vertical bulkheads (4) that are placed at areas of high loads (Rammohan, 2005). The hull is generally made of 30-50 ksi steel; however, small sections of the hull, especially the area around the legs, are made from high strength steel.

Depending on the rig design and builder preference, the hull may be constructed modularly with different sections of the hull fabricated separately and assembled. Modules are designed to

9 Steel is specified in terms of its yield strength, the maximum pressure a material can withstand before deforming. One ksi is equal to 1,000 pounds per square inch.

utilize similar steel shapes to increase the repetition involved in construction. The use of modular construction is common in the shipbuilding industry and allows for parallel workflows, increasing shipyard output. Modular design is a relatively recent innovation in rig construction.

Figure I.4 illustrates the early to mid-construction stages of three rig hulls. In the top image, much of the hull has been completed and machinery (shrouded in green) has been installed on the lower decks. In the bottom image, two hulls are under construction. On the right, a hull in the very early construction stages is shown; on the left, construction is more advanced.

9.4. TOPSIDES

After the spudcans are in place and the hull is built, the jacking system and topsides containing living quarters and offices are installed (Figure I.5). The components of the jacking system are typically supplied by the design firm and included as part of the rig design package, with varying degrees of assembly at the shipyard. Outfitting work and the installation of machinery and equipment may be carried out before or after launching, but is most efficient if conducted prior to launch.

9.5. RACKS AND HALF-ROUNDS

Chord structure varies by rig design, but in most three-chorded rigs, chords consist of a rack welded to semicircular “half rounds” (Figure I.6). The initial manufacturing stages of the racks and half rounds is conducted by third parties which convert high grade steel forms from steel mills into racks and half-rounds.

Racks start as solid 5 to 7 inch plates of high grade quenched and tempered steel. This steel is then flame cut, a process in which a torch is used to ignite the steel. The plate is cut so that teeth are formed, making the rack. The rack may be up to 30 inches wide, root to root. The teeth of the rack are then pressed to exact measurements; the tolerance on rack teeth is typically 0.5 mm. Due to the high strength and width, rack steel is the most expensive steel used on the rig. Half-rounds start as flat plates of high grade steel. They are then cold pressed into half rounds by machine (Figure I.7). After the racks and half-rounds are machined, they are placed in shipping containers and delivered to the shipyard.

9.6. CHORD ASSEMBLY

The racks and half-rounds are delivered to the shipyard in 20 to 40 foot sections, with racks typically being in longer sections than chords. A section of rack is welded to two slightly shorter half-round chords so that several feet of rack extends beyond the end of the half-round. Two or three sections are fabricated simultaneously. The racks of these sections are welded together, leaving a several foot gap without a half-round. An appropriate section of half round is welded to the rack and then welded to the adjoining half-rounds. After individual chord sections are assembled, braces are welded to the chords and the chords are joined to form a 40 to 90 foot long section of leg.

As a result of the high structural demands placed on rig legs, the steel used on leg chords must be of extremely high quality which can make welding difficult.[10] The welding of the legs must be carried out in controlled shop conditions with submerged arc or gas metal arc welding techniques. Rather than use a flammable gas as in more familiar welding techniques, arc welding passes an electric current through an electrode. Welding consumables must also be tightly controlled to ensure quality.

The most notable problem in welding leg joints is hydrogen cracking (embrittlement) which can be caused by the marine environment. Therefore, every weld on a leg must be inspected for cracks either by x-ray, ultrasound or another method of non-destructive testing.

9.7. Launching

Rigs may be built in drydocks or adjacent to a quay. In the U.S. drydocks are not used. At the AmFELS shipyard in Brownsville, Texas, rigs are launched into the water via a slipway; at the LeTourneau shipyard in Vicksburg, Mississippi, rigs are “walked” into the water using a complicated and time consuming method of elevating the rig and moving dirt around the spudcans (Figure I.8).

9.8. Derrick and Cantilever

The cantilever and derrick are constructed separately and modularly, then assembled and installed onto the rig following launching. The derrick is usually assembled at the shipyard by a specialized firm. Like the jacking system, prefabricated components of the cantilever may be supplied by the design firm and included as part of the rig design package.

9.9. Leg Assembly

Early in construction and prior to launching, the first sections of leg are attached to the spudcans and the jacking systems. After launching, the remainder of the leg is added (Figure I.9). Depending on shipyard infrastructure, sections may be added directly to the top of the legs via crane, or sections may be added to the top of the legs using the lift capacity of the jackup After the legs are added, the jackup will be unable to pass under most bridges, thus, if the shipyard is located on a river (as is the case with the LeTourneau shipyard in Vicksburg, Mississippi), the rig will be floated to a yard with direct ocean access before the final leg sections are added.

9.10. Delivery and Classification

Following final outfitting, the rig is delivered to the buyer, usually at the builder’s shipyard. Acceptance of the rig is typically based on satisfactory sea trials and certification by a classification society. Classification societies are independent, third party organizations that serve as a verification system parties with a special interest in the safety and quality of marine vessels. These may include regulatory authorities, insurance underwriters, owners, building yards and subcontractors, finance institutions and charterers. Classification societies provide a set of guidelines for design and construction and inspect shipyards during vessel construction to ensure

[10] The large number of alloys in high strength steel increases the hardenability of the steel which decreases the weldability.

compliance to provide assurance that a set of requirements and standards are met during design and construction. Each classification society has its own rules for classification; however, many aspects of classification are similar and are meant to ensure the safety against hazards to the vessel, personnel and environment. The American Bureau of Shipping (ABS) is the most common classification society both in the U.S. and internationally, but Det Norsk Veritas is also used depending on customer preference.

10. MODU RIG EQUIPMENT

MODUs are equipped with marine and mission systems. Marine equipment is found on all marine vessels and is used to operate the vessel at sea (engines, pumps, electrical systems), while mission equipment is used to drill wells and consists of drilling equipment similar to that found on land rigs, as well as additional systems specialized for the offshore environment. In this chapter we provide a pictorial overview of the mission equipment used on offshore rigs to familiarize the reader with the essential components and their primary function. For a more detailed discussion of rig equipment and function see (Jahn et al., 2008) or (Azar and Samuel, 2007). Marine equipment is not specialized in nature and is not discussed.

10.1. MODU SYSTEMS

MODUs are designed to drill and workover wells in the offshore environment, and specification sheets as shown in Figure J.1 provide engineers the necessary data to select the rig capable of drilling their wells. A large number of specialized systems are required to drill a well. For bottom supported rigs, critical systems include those used to position and elevate the rig above a well or platform; to provide mechanical force on the bit; to control the pressure inside the wellbore; to detect and control blowouts; to handle and assemble tubulars; and to handle and store liquid and bulk materials. Floating rigs require additional systems including station keeping systems, systems to install subsea equipment and systems to compensate for the vertical movement of the rig.

Four systems common to all floaters and jackups are described: systems that provide force for drilling, mud systems to control the pressure inside the well, safety systems to control the flow of hydrocarbons, and support systems to handle tubulars (Figure J.2).

10.2. DRILLING

During drilling, two forces act on a drillbit; a rotational force (torque) imparted by the rig, and a downward force due to gravity. A topdrive is used to turn the drillstring which is used to turn the bit. The drillstring is composed of drillpipe and the bottomhole assembly. The drillpipe is a steel tube that transmits torque from the rig to the bit and allows for the circulation of drilling fluid into the well. The bottomhole assembly is composed of the bit, drill collar, and various measurement or mud circulation tools. The drill collar is a particularly heavy steel pipe that is used to add weight to the drillstring.

The topdrive is suspended from the top of the derrick by a hook (Figure J.3). As the bit bores deeper into the earth, the topdrive descends down the derrick. When the topdrive nears the drillfloor, drilling is suspended. The drillpipe is disconnected from the topdrive and a new section of drillpipe is connected between the topdrive and the existing drillsting. The topdrive is raised to the top of the derrick and drilling resumes. This process is referred to as “making a connection”.

Periodically, drilling is suspended so that the borehole may be cased with steel pipe. Casing is used to protect freshwater zones, isolate formations and avoid the loss of drilling fluids. During casing operations, the drillstring is removed from the well and large diameter steel pipe is inserted into the well and cemented into place.

Drilling fluids are circulated down the well and perform several functions. Reservoirs are under high pressures and if these pressures are not controlled, hydrocarbons will flow from the reservoir into the well during drilling, potentially causing a blowout. Drilling fluid regulates the pressure inside the well and keeps formation fluids from entering the well. Drilling fluids also lubricate the bit, and transport the drill cuttings up to the rig. Drilling fluids pass down the well through the drillpipe and return to the rig through the annulus between the drillpipe and the casing (or open hole if the well is not yet cased). Mud pumps are used to transport drilling fluids and solid control systems are used to remove drill cuttings from the mud.

10.3. Drilling Equipment

The drilling systems of a rig are shown in Figure J.3. The primary systems include the derrick, topdrive, drawworks, crown and travelling block. A kelly and rotary table are also incorporated on most MODUs, but are less efficient than the topdrive system and are not widely used. Drilling equipment consists of two related systems: the rotary system and the block-and-tackle system. The rotary system is comprised of the topdrive (or rotary table and kelly) and provides torque on the drillbit. The block-and-tackle system is the pulley system that is used to move equipment out of the well.

10.3.1. Derrick

A derrick is a pyramidal steel structure (Figure J.4) that is used to support the vertical loads acting on the drill bit and to provide a working space for the vertical assembly and storage of tubulars. At the top of the derrick is the crown block which is a part of the block and tackle system used to lower and lift the drillstring; the crown block is connected to the travelling block which moves up and down the derrick and is connected to the hook. Derricks are rated according to the vertical loads they can tolerate and modern MODU derricks are designed to support hook loads of 1.5 to 2 million pounds. Many modern rigs have a dual derrick or other offline capacity. Without offline capabilities, all major activities require successive access to the drill floor. Offline capacity allows for building of bottomhole assemblies and drillpipe and casing stands adjacent to the main drill floor allowing for parallel workflows, reducing the overall time to drill a well.

10.3.2. Topdrive

The topdrive is the machine that provides the rotational force required to turn the drillbit. The top drive consists of one or more electric motors connected to a short section of pipe called a quill which is connected to the drillstring (Figure J.5). The topdrive is suspended from the hook, and is free to travel up and down the derrick. Rotary tables and kellys are still used as an alternative to a topdrive on older rigs, but topdrives are more efficient because they enable drilling to be performed with three-joint stands of drill pipe and reduce the frequency of stuck pipe. Top drives are specified in terms of their horsepower and torque; typical values are 1,500 hp and 80,000 lb ft at 100 rpm for a jackup rig.

10.3.3. Drawworks

The drawworks is a winch placed near the bottom of the derrick (Figure J.6). The drawworks is the prime mover of the block and tackle system and is connected to the crown block. It consists of an electric motor, brakes and related systems. The drawworks provides the vertical force necessary to move loads out of the wellbore and to resist the weight of the drillstring. Drawworks are specified in terms of horsepower and static load capacity; typical values for a MODU are 6,000 hp and 2.5 million pounds static load capacity.

10.4. Mud Systems

Drilling fluids (mud) circulates through a system of pumps, high pressure hoses, and particulate removal systems (Figure J.7). Starting at the mud pumps, mud travels through the standpipe and rotary hose. The rotary hose is a flexible line that moves up and down with the drilling equipment and connects to the topdrive or kelly. Mud passes down the drillpipe through the bit and after picking up the cuttings, passes up through the annulus between the drillpipe and the borehole. Once at the surface, the mud passes into a flowline and arrives at the mud treatment equipment to remove gas, salt, silt and cuttings. After treatment, mud is discharged to mud tanks and re-enters the pumping system.

10.4.1. Mud Pumps

Mud pumps are the prime movers of the mud circulation system (Figure J.8). They are typically "triplex" pumps composed of three separate pistons driven by one or more electric motors. Mud pumps are specified in terms of horsepower and maximum operating pressure. The maximum operating pressure helps to determine the ability of the pumping system to control a well. Typical values are in the range of 3,000 hp and 7,500 psi and most modern MODUs will have three or more pumps.

10.4.2. Solids Control

When drilling mud circulates up the borehole it contains drill cuttings. These cutting are detrimental to the mud pump and must be removed. A series of machines are used for this process including shale shakers, degassers, desanders, desilters and mud cleaners. Mud cleaning is conceptually simple and primarily utilizes the differential weight of the gasses and particulates entrained in the fluid.

A shale shaker is the first step in mud cleaning and is composed of a vibrating screen sieve (Figure J.9); mud flows over the screen and solids in the mud with a diameter greater than the size of the screen are retained. Fluids and small diameter solids pass through the screen and continue through the mud treatment system. The screen sizes on a shale shaker are variable and the mud passes through several screens before progressing to the next treatment stage.

After the largest solids are removed, the mud passes to a degasser which applies a vacuum to the mud to remove gasses dissolved in the fluids. The mud then proceeds to the desander and desilter. The desander and desilter are hydrocyclones (Figure J.9); mud is fed tangentially into an inverted cone and the centrifugal force induced by the flow causes the heaviest solids to migrate to the bottom of the cone (where they are disposed of) and the lighter fluids to exit through the top of the cone. The mud passes through a number of desanders and desilters in series with the diameter of the cone determining the size of the particles removed.

The liquid underflow from a desilter may be further processed by the mud cleaner. The desilter allows some amount of usable mud to be passed through the bottom of the hydrocyclone.

A mud cleaner processes the underflow from the desilter using a vibrating sieve. Mud cleaners are employed to conserve weighting agents and to recover liquids from oil- or synthetic-based muds which cannot be environmentally discharged.

10.5. Blowout Preventer

A blowout preventer (BOP) is a piece of safety equipment installed between the drilling rig and the wellbore (Figure J.10). On jackups, it is located on the vessel below the drill floor, while in deepwater applications it is usually placed on the seafloor. In the case of a loss of well control, the function of the blowout preventer is to form a physical barrier to stop the flow of hydrocarbons up the wellbore. A number of methods exist for creating this physical barrier, and most rigs use a combination of several methods in a single BOP stack. Annular BOPs are elastomeric rings that can be mechanically squeezed to form a seal around a drillpipe, casing, or other tubular element or an openhole. In contrast, a ram BOP is a system which uses two large diameter, hydraulically powered cylinders, one on each side of the wellbore, to force together two ram blocks (Figure J.11). Ram blocks may be designed to seal around a drill pipe (a pipe ram), over a wellbore without a drillstring (a blind ram), or to shear through the drill pipe (a shear ram). Blowout preventer stacks are specified in terms of their type (annular or ram) and operating pressure (typically in the range of 10,000 psi).

10.6. Pipe Handling

During drilling, a variety of pipes must be moved from the pipe deck to the drill floor. Once on the drill floor, pipe must be turned from a horizontal to a vertical position and sections of pipe must be mated together to form stands. Stands are stored in fingerboards, then moved from the fingerboard to the wellbore and inserted into the well. Historically, much of this work was performed manually or with simple machines requiring a large degree of human intervention. On modern rigs, this activity has been mechanized and automated to improve efficiency and reduce the potential for accidents.

There are a variety of machines which perform pipe handling and most of the activities on the drill floor. An iron roughneck (Figure J.12) performs pipe handling in the immediate vicinity of the well and makes connections between the pipe already in the well and the next stand of pipe. A catwalk machine (Figure J.13) moves pipe from the pipe deck to the drill floor while a pipe deck machine (Figure J.14) moves pipe around the pipe deck. An integrated control system is used to operate all of these systems from the drillers' cabin (Figure J.15). There are a variety of methods for handling pipes, but in general these systems are composed of gantry cranes, articulated mechanical arms, and tracked systems.

11. JACKUP RIG WEIGHT RELATIONS

The weight of a rig is an important variable in cost estimation and determines the amount of steel required in construction. Rig weight is generally considered proprietary, however, because it indicates design benchmarks and performance metrics that are central to the competitive nature of the industry. Standard methods for predicting ship weight based on its physical attributes have been used for several decades (Molland, 2008), but given the structural differences between jackup rigs and ships, these techniques do not adequately predict rig weight. The purpose of this chapter is to estimate the lightship displacement of jackups based on an empirical analysis of rigs built over the past three decades.

11.1. Weight Management

Weight is a primary design factor and is associated with rig capabilities. Larger rigs have greater variable loads, can support more powerful drilling equipment, and operate in more severe conditions. Weight is an important factor in design and is linked to fabrication costs. As more steel is added to a rig, material costs and fabrication expenses increase. Complex tradeoffs are involved with weight management, and because so many interdependent factors are involved in the design process, it is difficult to quantify the effects of weight on cost (Halkyard, 2005; Ellis and Shirley, 2005). Weight is also critical in determining rig stability and the size and design of the spudcans (Endley et al., 1981; Vazquez et al., 2005).

11.2. Weight Factors

The weight of a jackup rig is primarily determined by the water depth, drilling and environmental capability of the rig, and rig design. Rig weight is also commonly called lightship displacement and refers to the weight of the rig with all machinery installed but without fuel or other cargo. We use these terms interchangeably.

11.2.1. Water Depth

As the water depth capability of a rig increases, the length of the legs increase, but at some point, incremental leg length cannot be added to a given hull design and the hull must be enlarged. As a result, water depth is correlated with a number of physical descriptors including leg length, hull breadth, hull depth, deck area and hull volume (Wang et al., 2009). Figure K.1 illustrates for three popular rigs the correspondence between water depth and weight.

11.2.2. Drilling Depth

In order to increase the drilling depth capability of a rig, designers must make allowances for more powerful drilling equipment, stronger cantilevers and greater variable loads. Larger and heavier rigs are required to accommodate more numerous and powerful drilling systems and heavier cantilever loads.

11.2.3. Environmental Capability

Harsh environment rigs are heavier than moderate environment units. For the same water depth capability, harsh environment rigs must have longer legs than moderate environment units to increase the air gap. The legs and spudcans of harsh environment rigs are built to a more robust standard than moderate environment rigs and use higher quality and thicker steel. Harsh environment units may also have greater variable loads than moderate units to reduce the frequency of resupply, and this requires a larger, heavier rig. Since jackups are particularly well suited to harsh environment operations, some contractors have built harsh environment jackups with 500 ft water depth capabilities to extend the use of jackups into waters typically limited to semis. Ultra-high specification jackups are much heavier than moderate environment units; for example, the Gusto MSC CJ70 weighs 28,000 tons, approximately twice the weight of a typical moderate environment unit.

11.2.4. Rig Design

The tradeoffs designers make between the grade and quantity of steel impact rig weight (Massie and Liu, 1990). Either larger quantities of lower grade steel or smaller quantities of higher grade steel may be employed. For example, a rig designer may increase the number of braces in each leg, but decrease the yield strength of the steel. Using lower grade steel will increase weight, but may result in lower costs. Table K.1 illustrates the variation in leg unit weights. Leg density typically varies from 2 to 6 tons/ft and is greater in harsh environment rigs.

Rigs may employ rack chocks to transfer the vertical load from the leg racks to the hull. Without rack chocks, the load is held by the pinions in the jacking system. The use of chocks increases the fixity between the hull and the legs and allows for a reduction in the bracing in the legs, reducing leg weight (Mommaas and Blankenstijn, 1984). Most F&G, Baker Marine, Keppel, and Gusto MSC rigs utilize chocks, while most Letourneau rigs do not.

11.3. Data Source

Information on rig weights are not widely available and are generally considered proprietary because they are an important aspect of design. We assembled data from 31 rigs representing 21 designs and identified their environmental class (harsh vs. moderate), water depth, hull length, hull width, build year and designer (Table K.2). Data were collected from the academic literature, specification sheets and industry personnel. In some cases, lightship displacements were estimated as the transit displacement minus the transit variable load to supplement the dataset. Transit displacement is the weight of the rig when prepared for wet tow. Transit variable load is the weight of material and ballast required during a wet tow. The use of transit displacement data introduces bias in the analysis, but errors are believed to be less than 10% of true lightship displacement. When more than one data point was available from a single rig design, the displacements were averaged to ensure that the data points were independent.

11.4. Summary Statistics

The distribution of lightship displacement from the sample set (Figure K.2) has an average of 11,479 tons (range 5,569-28,600 tons) with an average water depth capability of 314 ft (range 250-450 ft). For harsh and moderate environment rigs, the average displacement was 17,575 and 10,195 tons, respectively. The age distribution was bimodal with 10 of the 31 rigs built after 2008, and 19 of 31 built before 1985; the average age was 22 years.

11.5. SINGLE FACTOR MODELS

Figure K.3 shows the relationship between displacement and water depth and water depth squared. Water depth explains 57% of the variation in lightship weight, but water depth squared is a slightly better predictor of rig weight. The three harsh environment designs all fall above the regression line suggesting that they weigh more than average moderate environment rigs for the same water depth capability.

Figure K.4 shows the relationship between hull dimensions and rig weight. In this case, hull dimensions predict about half of the variation in rig weight, but unlike the water depth relationship, there is no trend of harsh environment rigs being heavier than moderate environment rigs for a given hull dimension. The three harsh environment designs fall at the right end of the graph suggesting larger hulls than the other rigs in the sample.

11.6. WEIGHT RELATION

A linear regression model was developed to estimate rig weight using hull length and breadth (width), water depth capability, designer, environmental class (harsh vs. moderate) and build year as predictor variables. Hull length times hull breadth entered the model as an interaction term to proxy the area of the hull. Designer and environmental class were modeled as indicator variables. Variables were checked for multicolinearity, and because breadth was correlated with length and environmental class, these variables were not permitted to enter the same model.

The best model included terms for water depth, water depth squared, and hull length times hull width:

$$D = 49{,}316 - 3{,}233WD + 0.563WD^2 + 0.12LB,$$

where D is lightship displacement (tons), WD is water depth capability (feet), and L and B are the length and breadth of the rig (feet), respectively. Environmental class, designer and build year were not significant predictors.

The model explained 91% of the variation in displacement and all terms were significant. The inclusion of the length and width interaction term explained slightly more variation than either the length or width terms individually, and the coefficients were insignificant when the interaction term and the length or width terms were included together.

Figure K.5 depicts the model output for fixed lengths and breadths. Water depth is positively correlated with weight, and as water depth increases, the slope of the relationship increases. In reality, width and breadth are not constant with increasing water depth.

The harsh environment indicator variable was not a significant predictor of weight which is likely due to the fact that only three of the 21 designs were harsh environment units. The lack of data reduces the ability of the model to accurately predict the weight of harsh environment rigs. Build year and designer were also not significant predictors, which could indicate physical similarity in rig designs over time and between designers.

11.7. Limitations

Small sample size reduces the confidence in the results and inflates model fit (Nelson and Kim, 1993). However, because the total number of rig designs in the world are limited and the sample does include most of the rigs commonly built in shipyards, including the F&G L780 Mod II, the LeTourneau Super 116, the Baker Marine 375 and the Gusto CJ 70 X 150 the relations are expected to reasonably reflect real-world conditions. Additional predictor variables could be examined, but since the model already predicts over 90% of the variation in weight, the weight relation is adequate for aggregate assessments and gross benchmarking studies. Additional error may be introduced because the lightship displacement of some vessels was based on estimated values and a number of different sources were utilized which may estimate lightship displacement differently. Deficiencies in the weight reporting may be partly offset by the averaging of multiple records.

12. CAPITAL, LABOR, AND MATERIAL REQUIREMENTS FOR JACKUP CONSTRUCTION IN THE U.S.

Jackup rig construction in the U.S. generates an average of $374 million in direct revenue each year and over the past decade has ranged between $129 and $986 million. About 2,500 people are directly employed by the industry annually, and although employment is small relative to other offshore industries, the jackup rig construction market is important regionally and culturally because of its long tradition in the region. A top-down approach is used to estimate labor and material requirements of rig construction. The cost to construct a rig is decomposed into five elements–drilling equipment, rig kit, labor, material, and profit–and for each element, a cost module is developed.

12.1. RIG CONSTRUCTION

12.1.1. U.S. Market

Two U.S. shipyards build rigs: the Keppel AmFELS yard in Brownsville, Texas, and the LeTourneau yard in Vicksburg, Mississippi. Between 2000 and 2012, the Vicksburg yard delivered 11 rigs and the Keppel AmFELS yard delivered 14 rigs. Approximately two jackups have been delivered each year over the past decade at a total value of $3.9 billion.

12.1.2. Cost Components

During the contracting process, shipyard personnel estimate the costs of construction to develop a bid price. Rig construction requires capital, labor and materials, and a budget for each cost component is developed. Capital is recovered through a profit margin assessed on each rig built; labor and material costs are estimated using an engineering-based approach and quotes from industry suppliers.

Capital

The capital costs of shipyard operation are minimal and consist of open land with access to a waterway, enclosed work spaces for welding and fabrication, several cranes, and a launching system. In Asia, launching is frequently conducted via drydock while in the U.S., launching is performed via slipway or “walking”.

Labor

Labor is required to fit, weld, and assemble steel components, attach drilling equipment, and certify, inspect and manage construction. Major work requirements during rig building include welding of steel components, assembly of piping systems, installation of equipment, outfitting, material handling, engineering and management.

Materials

Materials include steel, drilling equipment, the rig kit, engines and generators, and various other manufactured goods. Steel is used in rig construction because of its strength, durability, corrosion resistance, weldability and price. Drilling equipment includes the derrick, top drive, BOP, mud and pipe handling systems, and other systems, and is frequently purchased as a package from an integrated supplier (Figure L.1). The rig kit includes the jacking systems, design license, and other components sold by the design firm. In the case of LeTourneau rigs, kits typically include leg components, cranes, and capstans. Engines and generators provide the power and electricity to power a rig and are an essential component of reliable operations. Other material includes outfit material, piping, electrical system components, pumps, and safety equipment.

12.2. SUPPLY CHAIN DISTRIBUTION

Labor costs directly enter local economies, but material costs are distributed across greater geographic regions and often represent a greater percentage of the total cost in rig construction. Figure L.2 shows the major manufacturing centers for steel and equipment used on rigs built in U.S. yards.

For LeTourneau designed rigs, leg steel is fabricated in Longview, Texas. Lower strength 34 or 51 ksi steel is widely available throughout the shipbuilding industry and is typically ABS A, ABS AH36 or similar grades.[11] Globally, several hundred mills produce ABS certified products including 36 in the U.S., mostly in the Midwest, Southeast, Pennsylvania and West Virginia (ABS, 2011).

Table L.1 shows the major suppliers of equipment in U.S. built rigs over the 2000-2010 decade. Engines are typically sourced from Caterpillar. Caterpillar marine engines are assembled at the Lafayette, Indiana and Griffin, Georgia manufacturing facilities. Blow out preventers are sourced from Cameron, Hydril or National Oilwell Varco (NOV). Derricks are from Woolslayer, Loadmaster or NOV, and most other drilling equipment from either Lewco (a division of LeTourneau) or NOV.

Much of the drilling equipment used in jackup rigs is assembled in and around Houston, Texas, and other locations in Texas and South Louisiana. Cameron operates manufacturing facilities in Ville Platte, Louisiana; NOV operates manufacturing facilities in and around Houston, Texas, and Pampa, Texas; Woolslayer (now Lee C. Moore, A Woolslayer company) operates a manufacturing facility in Tulsa, Oklahoma; Loadmaster operates a manufacturing facility in Broussard, Louisiana; and LeTourneau drilling systems operates manufacturing facilities in Longview and Houston, Texas.

[11] ABS steel is steel that is fabricated to ABS specifications. ABS A steel is 34 ksi and ABS AH36 is 51 ksi, where ksi represents kilopounds per square inch and is used to indicate the pressure at which a steel will begin to deform plastically.

12.3. COST ESTIMATION AND ADJUSTMENT

A top-down approach is used to estimate the cost components of rig construction. Since most rigs built in the U.S. in recent years have been LeTourneau Super 116E's, we emphasize this design, but the methodology we develop is completely general. The cost to construct a rig is broken into five elements: drilling equipment, rig kit, labor, material and shipyard profit (Figure L.3). For each of the five elements, a cost estimation module is developed.

The drilling equipment and rig kit modules apply fixed prices and do not vary with other input. For all other modules, the output cost is a function of user input and module parameters. User input includes capital costs, lightship displacement, and installed power. If any of these are unknown, empirically derived relations may be substituted. Module parameters include wages and productivity assumptions.

All price assumptions and output costs are in 2010 dollars and reflect average market conditions in the 2005 to 2010 period. To apply the estimation procedure to a future time period, output is multiplied by a forecast adjustment factor. The adjustment factor is given by I_t/I_{2010}, where I_t is the value of the appropriate BLS producer price index at time t, and I_{2010} is the index value in 2010 (Table L.2 and Figure L.4).

12.4. CAPITAL EXPENDITURES

The total capital cost of the rig is user input for several component modules. In many cases, capital costs may be known and input directly; if unknown, they are estimated based on rig specifications.

12.4.1. Data Source

Cost data for all rigs ordered in the U.S. from 1996 through 2011 were assembled from the commercial data provider RigLogix. Contract costs are publicly reported because most drilling operators are public companies and rig construction represents a significant investment for the firm. The use of public data is subject to reporting bias because costs may not be reported similarly and may differ in the inclusion of owner-furnished equipment or finance costs. All data were inflated to 2010 dollars using the BLS shipyard producer price index (USDOL, BLS, 2011b) and the order date.

12.4.2. Rig Construction Cost

In Table L.3, the nominal and inflated construction costs of all U.S. built rigs ordered between 1996 and 2011 are depicted. A total of 26 rigs were built in the U.S. during this time and all rigs are independent-leg cantilever units, and all but three were LeTourneau designs. Inflation-adjusted prices range from $101 to $326 million with an average of $180 million.

Jackup costs by water depth and design class is shown in Table L.4. Costs generally increase with increasing water depth capacity, and within a water depth class, costs are reasonably similar because of similar build locations and the contract execution date. In some cases prices range significantly for similar rigs. For example, *Offshore Defender*, *Resolute*, *Courageous*, *Intrepid* and *Vigilant* are all LeTourneau Super 116s, built at the Brownsville, Texas shipyard and ordered in 2005 and 2006. *Defender* and *Courageous* cost $87 million each while the *Resolute* and *Intrepid* cost $143 million. The difference in cost results from contract options and timing. *Defender* and *Courageous* were built as options executed in 2005 but based on contracts written in 2004, while the other rigs were new contracts written in 2005 and 2006 at a time of higher demand.

12.4.3. Regression Model

Jackup costs are estimated using a multi-factor regression model based on descriptor variables specific to the rig class, user preferences, and data availability. Predictor variables include hull length, hull width, order date, drilling depth, maximum water depth, and environmental design. Costs are expected to be positively correlated with all variables.

Hull width was correlated with hull length, water depth, order date and harsh environment variables. Multicolinearity was also found between the harsh environment indicator and the hull length and order date variables. These variables were not allowed to enter the model together. The best model for the 26 rigs in the sample was specified by:

$$\text{Cost} = -96 + 0.42 * \text{WD} + 0.003 * \text{DD} + 103 * \text{HARSH},$$

where Cost is in million dollars, WD is water depth (ft), DD is drilling depth (ft), and HARSH is an environmental indicator variable (1 if harsh, 0 otherwise). All the coefficients are of the expected sign and statistically significant and the model explained 77% of the variance in cost. According to the generalized relation, every 100 feet of increased water depth capability increased construction cost by $42 million; each 1,000 feet of drilling depth capability increased cost by $3 million, and the premium for harsh environment rigs was $103 million.

12.5. Labor Cost Module

12.5.1. Labor Cost Relation

Labor cost is determined as the product of the number of man-hours required and the average hourly wage: Labor cost = Hours * Wage. The number of hours required is estimated from the capital costs divided by the productivity. The labor cost relation is thus:

$$Labor\cos t = \left(\frac{Capital\cos ts}{\Pr oductivity}\right) * Wage,$$

where capital costs are measured in dollars ($), productivity is measured in dollars of value produced per hour of labor ($ output/h labor), and wages are measured in dollars per hour ($/h). Capital cost is a user input. Wages and productivity are input based on empirical data.

12.5.2. Wages

Hourly wages in rig building are expected to be similar to the ship building industry because of the commonalities in the work requirements. In Table L.5, the costs of labor at U.S. shipyards including fringe benefits are depicted in inflation-adjusted terms (USDOL, BLS, 2011a). The inflated dollars per hour (the last column of Table L.5) is calculated assuming all employees work an average of 2,000 hours per year. In 2007 and 2008 data, employees worked an average of 1,940 and 2,033 hours per year, respectively. Labor costs in U.S. shipyards appear relatively stable over time and range from 35 to 38 $/h from 2002 to 2009.

12.5.3. Productivity

The number of man-hours required to construct a jackup rig depends on the rig type, nation of build, preassembly status, and shipyard. Jackup productivity in U.S. yards is confidential and to estimate the labor requirements in support of rig construction a suitable proxy must be employed. Steel weight or compensated gross tonnage[12] has been used to proxy the man-hours required to construct a ship (Rashwan, 2005; Carreyette, 1977; Lamb and Hellesoy, 2002; Bruce, 2006), however, jackup rigs are structurally different from other ship types and their compensated gross tonnage factors are not well defined (Lamb et al., 1995).

We use the average revenue generated by one unit of labor for the entire U.S. shipbuilding industry to proxy the relationship between labor and revenue for the rig building industry. This method assumes that productivity is similar between the U.S. rig and shipbuilding industries which is likely to be reasonable as long as the technology employed in shipbuilding is roughly similar to that used in rig building. This assumption is difficult to validate given the data constraints associated with rig construction, but provides a consistent means to estimate market revenue and infer employment in support of rig construction, and is amenable to the available data.

In Table L.6, the annual shipment value from all U.S. shipyards is divided by the annual number of hours worked to yield productivity in terms of shipyard revenue per hour of labor. One hour of labor generated between $92 to $109 of vessel value from 2002 to 2009, or on average $100 of vessel value, which is approximately equal to the productivity in Keppel's Singaporean yards in 2010 (Wong and Chang, 2011). The labor required to construct a vessel is estimated by multiplying vessel cost by the inverse of productivity. Thus, for a $200 million jackup rig we would expect approximately 2,000,000 man-hours of labor to be required in construction.

These estimates are consistent with anecdotal reports and conversations with rig construction engineers (Sheridan, 2009; Fogal, 2009) and appear to approximate operating practices. For example, Keppel AmFELS delivered a $190 million LeTourneau Super 116E rig in 2009. It was reported that rig building employed up to 470 people and required 1.5 million man-hours (Clark, 2010). Other industry reports suggest 1.25 to 1.5 million man-hours are required at AmFELS for Super 116E construction. LeTourneau's Vicksburg shipyard employed approximately 1,000 people (including contractors) during its peak employment in 2007 and 2008 (Hitchens and Barrett, 2009). In every year since 2003, LeTourneau has delivered one rig. Assuming each

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12 Compensated gross tonnage is a unit of measurement developed by the Organization for Economic Cooperation and Development (OECD) that allows relative comparison of shipbuilding outputs across countries and vessel types. Compensated gross tonnage is defined by $A*GT^B$, where GT is a vessel's gross tonnage, and A and B are class-specific conversion factors derived by OECD.

worker works 2,000 hr per year, a LeTourneau rig would require approximately 2 million man-hours.

12.6. MATERIAL MODULE

12.6.1. Steel Cost Sub-Module

Categorization

The two grades of steel that are typically used in rig construction include low-carbon steel for structural elements such as legs, decks, railings, walkways and deck plating, and high-strength, low-alloy steel for critical components and extreme climate conditions (Marshall, 1986). We categorize steel weight into three components: hull steel (typically 34 to 51 ksi), leg steel (typically 100 ksi), and miscellaneous steel (typically 72 to 90 ksi).

Steel Cost Relation

Steel costs are estimated separately for each component and summed. Costs are calculated as the weight of steel (in tons) multiplied by the price per ton. Each component (x = hull, legs, miscellaneous) is assumed to be a proportion of lightship displacement:

$$\text{Steel cost}_x = \text{Percent weight}_x * \text{Lightship displacement} * \text{Steel price}_x.$$

Weight Distribution

Lightship displacement is a user input. The proportion of lightship displacement attributable to the leg, hull and miscellaneous steel is estimated from known weight distributions of a sample of rigs (Table L.7). Although the sample size is small and based on both generic and actual rigs, interval ranges are not expected to vary significantly across rigs. Approximately 20 to 30% of a rig weight is made up of steel in the legs and spudcans, while 40 to 60% is made up of steel in the hull, jacking houses and cantilevers.

Table L.8 depicts the weight distribution of a 300 ft moderate environment rig. Fifty-three percent of the rig is composed of 34 to 51 ksi steel in the hull, 23% is composed of 100 ksi steel in the legs, and 7% is composed of miscellaneous 72 to 90 ksi steel throughout the rig. From Tables L.7 and L.8, we assume that for a moderate environment 300-400 ft water depth rig, 20 to 30% of steel is leg steel (100 ksi), 40 to 60% is hull steel (34 to 51 ksi), and 5 to 10% is miscellaneous steel (72 to 90 ksi).

Steel Price Assumption

Steel prices vary with changing market conditions and depend on yield strength, shape and quantity ordered. Deliveries are negotiated on a per-rig basis and are not publicly reported, however, hull steel prices are expected to be similar to North American A36 plate which varied from 267 to 1,080 $/ton between 2001 and 2011. We assume that leg steel costs between 4,000 and 7,000 $/ton, hull steel costs 700 to 1,100 $/ton, and miscellaneous steel costs 1,000 to 1,500 $/ton. Hull steel costs may be estimated with confidence because prices for shipbuilding steel are widely reported, although highly variable over time. Prices for leg steel are poorly known because they are not widely tracked. Miscellaneous steel is a minor cost component.

12.6.2. Engine Sub-Module

Engines and generators are a large component of material costs. While most rigs use a version of the Caterpillar 3516, a number of versions and options are available and prices vary with market conditions. Based on a 2012 survey of generator set prices, generator sets are assumed to cost 400 to 600 $/kW delivered. Table L.9 provides the installed power on selected rig designs. If the actual power of a rig is known, it may be input; otherwise, power is assumed to range from 8 to 11 MW.

12.6.3. Other Material Module

Other materials include piping, wiring and other electrical equipment, pumps, heating and cooling systems, kitchen equipment, lifeboats and other safety equipment, capstans, cranes, navigational equipment, furniture and other outfit materials. Consumables include paint, electricity, fuel, and welding supplies. The costs of these supplies are difficult to generalize, but in the shipbuilding industry they typically account for 20 to 25% of total vessel costs. We assume material costs for rigs represent a similar proportion of total costs as ship construction.

12.7. Rig Kit Module

Rig kit costs depend on the rig design and the scope of the kit and are purchased separately. All kits include a design license and jacking systems. In LeTourneau rigs, kits also include leg components, anchor winches, cranes and certain components for the cantilever and spudcans, but the precise components are negotiable. Between 2007 and 2009, LeTourneau reported income of $418 million for work on 15 to 18 rig kits, giving an average cost of $23 to $29 million per kit during this time. Recent contract costs for LeTourneau Super 116E rig kits are shown in Table L.10. Rig kits are assumed to cost between $25 and $45 million per rig. Rig kits are likely to scale in proportion to the size of the rig, and for rigs larger than the Super 116E, kits will be more expensive.

12.8. Drilling Equipment Module

Drilling equipment is not included in the rig kit. Drilling equipment includes derricks, mudpumps, topdrives, blow-out preventers, drawworks, automated pipe handling systems, and solids control systems. Drilling equipment costs vary with the drilling capabilities of the unit. Recent contract costs for jackup rig drilling equipment systems are shown in Table L.11 and Table L.12 shows the costs of specific drilling components adjusted to 2010 dollars. Costs for a complete drilling package range from $20 to $70 million. Note that the two highest costs reported in Table L.11 are both for Gusto MSC CJ70 jackups, a high specification, harsh environment design. For rigs such as the Super 116E, costs for a complete drilling package range between $20 and $50 million.

12.9. PROFIT MODULE

Profit margins are the proportion of revenue attributable to net income. The Gulf of Mexico jackup construction market competes with international markets with lower labor costs and high productivity, and as a result, profit margins in the region are expected to be low on a relative basis. For example, from 2006 to 2010, Rowan's drilling products division (principally composed of the LeTourneau shipyard) received an average profit margin of -2.7% and a maximum of 9.7%. In contrast, Keppel's marine division averaged a 13.6% profit margin over the same period. Low profit margins do not adequately protect a firm from the risks of cost overruns and we assume that profit margins below 5% are unsustainable. Profit margins above 10% are unlikely due to international competition. We select a range of 5 to 10% as representative of the industry and apply this range in subsequent calculations.

12.10. ILLUSTRATION

We illustrate the cost estimation procedure using a hypothetical moderate environment LeTourneau Super 116E constructed in the Gulf Coast in 2010. We assume an operational water depth of 375 feet, a drilling depth capability of 30,000 feet, and hull dimensions of 243 by 206 feet.

12.10.1. Capital Costs

Application of the capital cost model requires the user to substitute the operational water depth (375 ft) and drilling depth (30,000 ft) into the capital expenditure regression model to obtain $164 million. Capital cost is the primary input in the labor, material and profit modules.

12.10.2. Labor Costs

Labor requirements are determined by the product of the capital cost and the inverse productivity metric. For hourly compensation ranging between 34 and 38 $/hr and productivity between 90 and 100 $/hr, labor costs range from $51 to $69 million (Table L.13).

12.10.3. Material Costs

The water depth (WD, 375 ft), length (L, 243 ft) and breadth (B, 206 ft) of the rig are substituted into the weight relation from Chapter 11 to yield 12,575 tons. Table L.14 partitions this mass among rig components based on the assumed weight distribution described for leg steel (20-30%), hull steel (40-60%) and miscellaneous steel (5-10%). Steel costs range from $14 to $37 million and are dominated by the costs of leg steel because of its high unit costs, even though the hull contributes the majority of the weight.

Installed power is assumed to range from 8 to 10 MW and is multiplied by the unit cost (400 to 600 $/kW) yielding generator costs of $3 to $6 million. Other material costs are assumed to range from 20 to 25% of capital costs, or $33 to $41 million.

12.10.4. Rig Kit and Drilling Equipment Costs

The rig kit for LeTourneau rigs are assumed to be fixed cost between $25 and $45 million. Drilling equipment is assumed to cost $20 to $50 million.

12.10.5. Profit Margins

Profits are assumed to be 5 to 10% of capital costs, or $8 to $16 million.

12.10.6. Cost Distribution

Table L.15 shows the distribution of construction cost along with cost estimates provided by industry participants. The costs of leg steel are included in the rig kit. Approximately one third of costs are associated with shipyard labor and over half of costs are associated with materials, mostly in the drilling equipment package and rig kit. The total expected costs range from $145 to $237 million with an average of $191 million. This matches closely with the $195 million purchase price of a LeTourneau Super 116E ordered from the AmFELS shipyard in 2011, and with estimates provided by industry personnel.

12.11. U.S. Jackup Market Size

12.11.1. Market Revenue

The annual inflation-adjusted value of the U.S. jackup rig industry is shown in Table L.16 by shipyard. The total value of deliveries ranged from $129 million in 2005 and 2006 to $986 million in 2008. The three year average of delivery value is a better measure of annual industry revenues because payments for shipbuilding are spread throughout the construction process. On average, the rig building industry generates $374 million in revenue each year. Table L.16 and Figure L.5 show the distribution of estimated revenue at the two jackup shipyards in the U.S. In the early part of the decade, the LeTourneau Vicksburg yard dominated rig construction, but by 2005, the AmFELS Brownsville yard had surpassed LeTourneau in revenue.

In 2011, the Vicksburg shipyard was sold to Cameron, a flow equipment manufacturer, along with LeTourneau Technologies drilling equipment manufacturing division. The Vicksburg shipyard delivered the *Joe Douglas* to Rowan in late 2011, and as of early 2012, the Vicksburg shipyard has no newbuild orders and has stopped building rigs. Barring a significant change in market conditions, work in the yard is unlikely to resume.

12.11.2. Labor Market

U.S. shipyard productivity varies between 90 and 110 $/h of revenue generated for each hour of input labor. Using this productivity range and the three year average value of revenue, the total annual employment in the rig building industry is given in Table L.17. Between 2000 and 2010, we estimate between 800 and 3,900 people were directly employed by the jackup construction industry. Table L.18 shows the distribution of employment by shipyard and matches anecdotal reports of employment (Clark, 2010; Hitchens and Barrett, 2009).

12.11.3. Relative Size

The jackup construction market in the U.S. is small relative to related offshore industries. Other industries supporting the offshore oil and gas industry include the OSV construction market, the drilling equipment manufacturing market, and the drilling contractor market, and all three of these markets are significantly larger than the rig construction industry. In 2011, the five largest U.S. based drilling contractors (Transocean, Noble, ENSCO, Diamond and Rowan) received $19 billion in revenues, and the three largest U.S. based players in the drilling equipment manufacturing market (NOV, Cameron and Dril-Quip) received $22 billion in revenue. Between 2007 and 2010, the U.S. OSV construction industry is estimated to have received average annual revenues of $969 million compared to $615 million for the rig construction industry over the same period (Kaiser and Snyder, 2010).

13. CONSTRUCTION COST FACTORS

Many factors influence rig construction cost. Market conditions, design type and class, construction shipyard, and rig specifications are the primary factors. Contract type, shipyard productivity, and scale economies also influence cost, but are either unobservable or more difficult to ascertain the nature of their impact. The goal of this chapter is to describe the primary factors that impact rig construction costs.

13.1. MARKET CONDITIONS

Prices are determined by the demand for rig construction services and the number of shipyards capable of supplying these services. Drilling contractors demand newbuilt rigs when dayrates and utilization rates make investment criteria positive. But only a small number of shipyards around the world are capable of building rigs; and during periods of high demand, the supply of rig construction services saturates the market, leading to backlogs and price increases.

From 2000 to 2011, for both jackups and floaters, there was little activity early in the decade and prices were low (Figure M.1). The number of jackups ordered during this time numbered less than 10 per year. For floaters, there were three orders in 2001 and two orders in 2002. As orders increased in the middle part of the decade, prices rose. Following the 2008 recession, orders declined markedly, but prices only declined marginally, reflecting long backlogs and the expectation that a decline in orders would be short lived.

13.2. MATERIAL PRICES

13.2.1. Cost Distribution

Building a rig requires steel, labor, drilling and other equipment. The manner in which cost is distributed across these categories determines the variation in construction cost by rig class, complexity and time. Shipyard location plays a key role. In China, labor costs are low and are likely to represent a small proportion (on the order of 10%) of total costs. By contrast, U.S. labor costs are high and may account for as much as 30% of total costs. Steel costs are highly variable over time, and when prices are high, the percentage values in will tend to reside at the upper end of their ranges.

13.2.2. Steel

Steel is the main component of rigs and material prices have an impact on newbuild costs. On a proportional basis, jackup steel is usually a larger component of cost (10 to 20%) than in floaters (<10%). Steel prices are specified on a per ton basis and vary regionally with steel quality and shapes (Figure M.2). Rigs are constructed using a variety of steel strengths and are built throughout the world, and no single steel price reflects costs for all rigs. However, the vast majority of rigs are built in Asia, and the Asian steel price index[13] is a reasonable proxy for the rig construction market. Both rig prices and the steel index grew over the course of the decade at approximately the same rate, and are correlated (Figure M.3). The steel price index explains 70%

13 The Asian steel price index is created by the steel industry tracking firm MEPS and is the arithmetic average of steel plate prices in four Asian countries based on a survey of industry participants.

of the variation in average jackup rig prices. No significant relationship is observed between floater prices and steel prices.

13.2.3. Equipment Prices

Engines, cranes, generators, drilling equipment, and dynamic positioning systems are significant components in rig costs. These are all third-party materials purchased by the rig builder and assembled on site or at another location. The drilling equipment package is the largest equipment expenditure, and typically costs \$20 to \$70 million for jackups and \$100 to \$200 million for floaters (or on the order of 10 to 30% of total costs). Non-drilling related equipment range over similar cost intervals; and together, drilling and other equipment typically range from 30 to 60% for jackups and floaters (Table M.1).

Drilling and equipment costs are influenced by steel prices to the extent that the majority of the equipment is made from steel, but more importantly, are influenced by demand from the oil and gas and commercial shipping industries. Labor cost is also a large component in equipment manufacturing costs.

The oil and gas field machinery equipment index[14] can be used to proxy the costs of the drilling equipment installed on MODUs; the finished goods index proxies the overall rate of inflation experienced by manufactures (Figure M.4). While both indices are based on U.S. products, the oil equipment index is applicable to global MODU prices because much of the drilling equipment installed on MODUs is sourced from the U.S. Throughout the 1990's the oil and gas index grew gradually and in line with the finished goods index, but in the mid-2000s the oil and gas index increased rapidly, outpacing the overall rate of inflation, suggesting that the increase in rig prices is due in part to an increase in the costs of drilling equipment.

The relationship between average global jackup and floater prices and the BLS oil and gas field equipment index between 2000 and 2011 is shown in Figure M.5. The fact that the steel price index was a poor predictor of floater costs, while the equipment index explained 82% of the variation in prices suggests that equipment costs are a larger factor in overall prices than steel costs for floaters. The equipment and steel indices are themselves correlated (R^2= 0.84) and likely to be influenced by many of the same global factors, however, their influence on the costs of rigs is largely independent since each index impacts a separate shipyard budget category.

13.3. Exchange Rates

Contracts for rig construction are denominated in U.S. dollars, but costs at international shipyards may be in U.S. dollars, euros, Chinese yuan, South Korean won, or Singaporean dollars. For example, labor and steel costs at a South Korean shipyard may be in South Korean won while drilling equipment costs may be in U.S. dollars. For the rig builder, as the value of the U.S. dollar rises, the value of a contract increases. From the perspective of a rig buyer, a strong

14 The oil and gas field machinery and equipment price index is created by the BLS based on a monthly survey of industry firms. It is based on a basket of products including drawworks, blowout preventers, rotary equipment, drill bits, risers, production equipment, etc. Onshore and offshore equipment is included (USDOC, Census, 2004).

U.S. dollar lowers newbuild costs at international shipyards. Thus, when the dollar declines relative to a local currency, an increase in costs is expected.

13.4. LABOR

Labor costs and productivity are important drivers of shipyard costs (Wong and Chang, 2011). The costs of shipbuilding labor in the U.S. and Korea are roughly similar and about three times the labor costs of Singaporean yards. South Korea compensates for relatively high labor costs with advantages in productivity over Singaporean and U.S. yards.

Over the past decade, both labor costs and productivity have increased in Singaporean and South Korean yards (Figures M.6 and M.7), and the combination of these two factors will determine the contribution of labor to total costs. The revenue generated per dollar spent on labor is shown in Figure M.8. In the U.S., each dollar spent on labor generates approximately three dollars of revenue, consistent with labor costs accounting for approximately one third of total costs. In Singapore and South Korea, each dollar spent on labor generates approximately seven to ten dollars of revenue, suggesting labor costs make up on the order of 10 to 15% of total costs for rigs built internationally.

13.5. DESIGN CLASS

Newbuild jackup designs range from $159 to $530 million for water depths between 200 to 492 feet and variable deck load (VDL) capability of 3,750 to 7,000 tons (Table M.2). The KFELS B Class, Letourneau 116E and F&G JU-2000E are the most popular designs. In general, there is relatively little variation in cost between rigs of the same design, but some designs exhibit more variation in water depth capacity and price than others. The Letourneau Super 116E class is especially variable because several rigs are being built for the Persian Gulf market where water depth capability is not at a premium.

Semisubmersible newbuilds range from $460 to $771 million for water depth capacity ranging from 1,640 to 10,000 feet and VDLs between 5,000 and 22,000 tons (Table M.3). Operating displacement varies between 42,000 and 62,000 tons. There is more variation in costs between rigs of the same design than for jackups, and this may reflect increased customization. Most of the units are sixth generation ultra-deepwater rigs; however, the GM 4000 is designed for drilling in mid-water regions or well workovers in ultra-deepwater, while the GVA 4000 NCS is intended for harsh environment drilling in mid-water. Both of these rigs were designed to provide lower capital and operating costs in regions in which the capabilities of ultra-deepwater rigs were not required.

Drillship newbuilds range from $550 million to $1.2 billion for displacements ranging from 45,000 to 112,000 tons in part reflecting differences in oil storage capabilities, and VDLs between 15,000 and 24,000 tons (Table M.4). The Samsung 10000 and 12000 and the Gusto P10000 are the most popular designs ad are capable of storing small amounts of oil (approximately 140,000 bbl[15]) during early production, while the Gusto PRD12000 and Huisman designs exclude oil storage to reduce ship size and operating and capital costs (Duhen et al.,

15 One bbl of crude oil weighs approximately 0.15 tons, so 140,000 bbl storage is equivalent to 21,000 tons.

1998). Stena and Keppel have developed a drillship to drill slimmer, less expensive wells but to date, these smaller designs have not been as popular as the larger designs (Humphreys, 2011).

13.6. Rig Specifications

Rig designs vary in drilling capabilities, VDL capacity, maximum water depths, and environmental criteria. As vessel specifications increase, costs rise, for all other factors held constant.

13.6.1. Structural Weight

Weight is associated with rig capabilities. Larger rigs have greater variable loads, can support more powerful drilling equipment and can operate in more severe conditions. Weight is an important factor in design and is linked to fabrication costs; as more steel is added, material costs and fabrication expenses increase. However, complex tradeoffs are involved with weight management, and because so many interdependent factors are involved, it is difficult to quantify the effects of weight on cost (Halkyard, 2005; Ellis and Shirley, 2005).

13.6.2. Water Depth

Water depth is a primary determinate of jackup costs. The legs of a jackup are made of expensive high grade steel, and as water depth capacity and environmental criteria increase, so will the costs of construction. For example, leg chord steel in the U.S. Gulf Coast cost $6,000/ton in 2012; for an average sized jackup, material costs for leg steel may range from $12-30 million.

Wind and wave forces act in proportion to leg length, and above a certain threshold, a rig cannot be extended to deeper water by simply extending its legs. Instead, a new and larger rig design is required (Covellone and Thorson, 1985; Marshall, 1986; Salama, 2005).

For drillships and semisubmersibles, water depth capability is not as strongly correlated with costs because the rigs are floating units; and with the exception of the drilling risers and anchor handling systems, do not have elements that pass through the water column. Increased water depth is associated with increased costs for risers, riser tensioners, mud pumps, anchor winches, drill strings and mud storage facilities (Shu and Loeb, 2006).

13.6.3. Operating Environment

Rigs capable of operating in harsh environments are heavier and more expensive than moderate environment rigs. Harsh environment jackups have longer legs to increase the airgap, and as leg length increases, the distance between the legs and the size of the hull must also increase. Similarly, semisubmersibles built for harsh environments must have longer and thicker columns than moderate environment units which in turn increases costs. Drillships are not typically designed for operation in harsh environments, but interest in Arctic exploration has led to harsh environment designs, and can cost over $1 billion to build.

13.6.4. Equipment Specifications

As the drilling depth capability of a rig increases, more robust pumping units and safety systems are required to handle the higher formation pressures and temperatures, increasing costs. The power, storage and VDL capacities determine the maximum drilling equipment that may be installed on the rig. Drilling depth may be used to proxy equipment specification, but it is the actual specifications that determine rig cost. Important specifications include the hook load, riser pressure, rated pressure and diameter of the blow-out preventer, degree of offline capability, storage capabilities, number and power of mud pumps, mud tank capacity, number and flowrate of shale shakers, desilters, desanders, cementing unit operating pressure, and capacity of the BOP handling system.

13.7. Contract Type and Options

Rigs may be built by drilling contractors with or without a firm contract commitment from an E&P company. When building a rig speculatively, contractors may approach negotiation more aggressively and be less willing to pay than when building a rig with a contract commitment. Building a rig on speculation increases risk and the firm may only be willing to accept this risk when market conditions (e.g. recession) put downward pressure on costs, making the investment more likely to be profitable over the life of the rig.

For example, in 2011, Maersk Drilling ordered two MSC CJ70 jackups on speculation for $500 million each; two months later, Seadrill ordered the same rig for $530 million after receiving an initial contract. Similarly, in June 2008, Seadrill ordered a Pacific Class 375 rig on speculation from PPL shipyard for $215 million; the next month Egyptian Drilling received a contract and ordered the same rig from the same shipyard for $220 million. These data are anecdotal and the differences small, but the general concept is clear.

Rigs ordered on option allow a contractor to purchase one or more additional rigs at a fixed price simultaneously with their initial order or at a later time. Typically, options must be exercised within a year of contract signing and the cost of optioned rigs is frequently higher to account for the risk of inflation, and because the option has inherent value for the contractor by locking in future newbuilding capacity.

13.8. Shipyard Characteristics

Shipyards vary in their rig building experience, labor costs, supply chain management, tax structure and government subsidies, construction methods, reputation and degree of integration (Gray, 2008). Many of the major rig shipyards maintain their specialization with proprietary designs. Keppel-FELS and LeTourneau each have their own line of jackup rigs and while these yards can and do build other designs, they have gained significant experience by building specific rigs and may be able to do so at lower costs than other yards (Wee, 2008). Similarly, many yards have long-term contractual relationships with rig operators; these operators often prefer a particular design class or company and they may order several identically designed rigs to be delivered from the same yard which will likely lead to cost reductions through learning.

Large rig shipyards exist in Singapore, China, India, South Korea, Russia, the United States and the United Arab Emirates. These countries differ markedly in their labor practices and costs, tax structures, the importance of rig/shipbuilding to the overall economy, and the degree of government intervention (Koenig et al., 2003) which contributes to construction cost differences across countries. Competition acts in the opposite direction however, and forces high-cost shipyards to offer similar prices and accept lower returns to win work, reducing price differences.

Shipyards differ in the methods in which they construct rigs based on their level of automation, subcontracting, and the degree of serial production line usage. The particular method of fabrication and assembly is unique for each yard and rig and depends upon space and equipment availability. Singaporean shipyards are particularly space limited. South Korean yards are less space limited and use a sophisticated "mega-block" method of ship construction in which very large ship sections are fabricated separately and then assembled in a floating dock (Wang and Chong, 2011). A high degree of specialization will likely lead to reduced costs and enhanced quality control standards, but this is only feasible for yards with a constant supply of orders.

13.9. BACKLOGS

The amount of time between when the rig is ordered and delivered is important in determining costs and risks to both parties (Moyst and Das, 2005; Duffey and Van Dorp, 1998). The time to construct a rig depends on a number of factors but is typically 18 to 36 months; however, the time between contract finalization and rig delivery can significantly exceed the construction time due to shipyard backlogs. During construction, the buyer is required to make payments on the rig but does not receive income which can create cash flow problems for buyers. Additionally, as the time between ordering and delivery increases, market conditions may change, creating risk for the buyer and seller; for the buyer, rig utilization and dayrates may decline while for the seller, steel, labor or material costs may increase. When there is a particularly long delay between contract finalization and the start of construction, a cost escalation clause may be included.

14. NEWBUILD AND REPLACEMENT COST FUNCTIONS

Rigs are the primary assets of drilling contractors and their newbuild and replacement costs are frequently required in corporate planning and financial valuation. Cost functions provide insight into the factors that influence costs and are used by investors, government agencies, and other stakeholders to evaluate newbuild programs or the value of an existing rig or fleet. The purpose of this final chapter is to develop generalized newbuild and replacement cost functions based on rig attributes. Robust multi-factor cost models for jackups and semis are derived, but for drillships suitable models could not be developed due to the homogenous nature of the units and the small variation in costs in the sample. For drillships, average cost and standard deviations adequately describe the sample statistics. Water depth was the single best predictor of rig cost and replacement cost models explained larger proportions of variance than newbuild models which is likely due to the manner in which cost estimates were performed.

14.1. DATA SOURCES

Newbuild costs are widely reported in public documents, and because most contracts are turnkey in nature, the values are accurate representations of the costs paid by owners to shipyards, excluding financing and interest expenses. The replacement value of rigs is more ambiguous and is estimated by market intelligence firms, drilling contractors and insurance companies using specialized algorithms and expert opinion. Replacement costs reflect the costs to replace a rig with a new asset of similar quality. Newbuild and replacement cost data from Jefferies (Jefferies and Company, Inc., 2009) was applied in our analysis.

We focus on the physical factors related to the capability of the rigs rather than more difficult to quantify time-dependent factors such as market conditions. The time period of analysis is fixed at October 2009 and the cost functions derived are reflective of this time period. It is relatively simple to adjust for a future period. For a near-term future period, cost can be adjusted using an appropriate index or alternatively, if the samples are updated, a new cost function can be derived and the model re-estimated.

For newbuilds, the sample set includes 39 jackups, 35 semis and 37 drillships and represented the majority of rigs under construction in 2009-2010. A number of jackups were under build by National Oil Companies or on speculation by shipyards; cost information on these rigs were not available. The replacement cost sample includes 282 jackups, 149 semis and 35 drillships and included active, ready- and cold-stacked units. The world fleet at the time of analysis was 470 jackups, 200 semis and 50 drillships, and so the sample is reasonably representative of the total inventory. Rigs not included in the sample are those owned by small private operators and National Oil Companies where information on the replacement costs is not available or reported.

Jefferies and Company, Inc. (2009) provides basic information on rig operating water depth, delivery year and design. These data were supplemented with information on drilling depth and environmental operating conditions from RigZone, contractor websites, trade press literature and design descriptions from naval architecture firms. No adjustments for inflation are made since cross-sectional analysis was performed and all costs are reported in 2009 dollars.

14.2. Summary Statistics

14.2.1. Average Cost

Summary statistics on the average cost and water depth of the rig samples are shown in Table N.1. Compared to existing rigs, the average jackup in the newbuild sample costs more ($225 versus $142 million) and was capable of drilling in deeper water depths (362 versus 293 ft). Average newbuild semis and drillships costs were $553 and $672 million, respectively, relative to fleet replacement values of $366 and $470 million.

14.2.2. Cost Variation

The large dispersion in newbuild jackup costs is primarily attributable to four harsh environment rigs capable of drilling in over 400 ft of water (Figure N.1). These rigs each cost over $450 million whereas most other rigs in the sample cost approximately $200 million. There is also wide cost variation among semis due to the presence of harsh environment designs, but less variation in drillship newbuild costs with all drillships costing between $585 and $750 million. The coefficient of variation for newbuild jackups is significantly greater (0.46) than for semis (0.18) or drillships (0.08). The lack of variation among the drillship sample indicates that regression models are unlikely to be able to distinguish the factors that make drillships unique and capture cost variation. Replacement cost is uniform across rig types which is likely due to the manner in which replacement cost is estimated and similar lifecycle and upgrade regimes (Figure N.2).

14.2.3. Rig Age

The distribution of rig ages in the world fleet circa 2009 is shown in Figure N.3. The drillship fleet is younger and has a smaller vintage range than the semisubmersible or jackup fleet and age is less likely to be a reliable predictor of drillship replacement cost. A primary difference between the replacement and newbuild data is the age range of the vessels. In the newbuild data, all rigs were built in the 2009-2012 period, while in the replacement models rigs were built over several decades. Age may impact the replacement costs because for all else equal, as technology improves, costs should decrease. For example, a 300 ft water depth jackup with a drilling depth capability of 25,000 ft would have been considered a high specification unit in the early 1980's and may have commanded a premium; by the late 2000's, such a rig would be standard and may be priced at a discount.

14.2.4. Water Depth and Environmental Capability

Water depth and operating environment are related determinants of newbuild costs for jackups (Table N.2). In harsh environments, jackups with water depth capabilities of 350 to 400 ft cost 90% more than jackups with 300-350 ft water depth capabilities; in moderate environments, the price premium is 23%. For semis, there is a significant water depth price premium in harsh environments, but a less notable premium in moderate environments; harsh environment, ultra-deep water semis (>7,500 ft) are 56% more expensive than harsh, midwater units (<2,500 ft), but in moderate environments, the price premium between ultra-deep and deepwater (2,500 to 7,500 ft) is only 4%. Small sample sizes may influence these results, but in general, large cost differences are found in harsh environment rigs because of design variability and country of build differences.

14.2.5. Country of Build

Table N.3 shows the distribution of rig costs by country of origin for newbuilds. Korea (35%), Singapore (24%), and China (20%) captured 80% of the newbuild market in 2009 and continue to reflect current newbuild share. Singapore is the primary jackup builder, China is dominant in semi construction, and Korea dominates drillship construction. In both the jackup and semi market, there is significant international competition, but in 2009, nearly all drillships were built in Korean yards. Singaporean shipyards have slightly lower costs than their competitors; in every market in which Singaporean yards have market share, the average cost at Singaporean yards is less than in any other nation. No other nation has a notable cost advantage.

14.3. Model Development

14.3.1. Function Specification

Econometric techniques are common in maritime valuation assessments because of their versatility, theoretical foundation and robust estimators. Newbuild cost functions and second hand market valuations is an active area of research for shipbuilding (Mulligan, 2008; Adland and Koekebakker, 2007; Dikos, 2004; Tsolakis et al., 2003; Dikos and Marcus, 2003) but has not been studied in the context of offshore drilling rigs. We specify newbuild and replacement cost models using a multi-factor linear functional:

$$C(U) = \alpha_0 + \sum \alpha_i X_i,$$

where C(U) represents the cost of rig class U and the number and selection of the descriptor variable X_i is specific to the rig class, user preferences, and data availability. Variables examined include designed environmental conditions, rig specifications, market conditions, age, upgrades, life extensions, and related factors. The coefficients of the model formulation are estimated through ordinary least-squares regression and α_0 can be interpreted as a fixed-term component. In general, we report the results of several models for each rig class to highlight differences and compare predictors. When multiple models are presented, the "best" model is identified on the basis of R^2.

Cost are estimated with and without the fixed-term component and the effects of forcing α_0 to be zero were examined because models without a fixed cost component allow for the determination of the relative contribution of each variable. Whenever the intercept term in a regression model is set to zero, the model fit R^2 and statistical significance improve due to the manner in which R^2 is calculated.[16] There is no meaningful way to interpret R^2 values, however, and they are not reported for regressions through the origin. The standard error (SE) of a regression going through the origin is meaningful and we report SE to allow for model comparisons (Hahn, 1977).

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16 In a regression with an intercept, the R^2 is the proportion of variance explained by the regression (R^2 = 1-SSE/SST, where SSE is the variance not explained by the regression and SST is the total variance). SST is determined by summing the squared differences between the observed values and the mean value (SST = $\sum(Y_i - \bar{Y})^2$, where Y_i is the ith observation and $\bar{Y}$ is the mean). However, when the regression is forced through the origin, the SST becomes the sum of the squared differences between the observed values and zero (SST = $\sum(Y_i - 0)^2$) while SSE does not change. This will increase the SST and therefore the R^2 (Eisenhauer, 2003).

14.3.2. Variable Description

For newbuilds, the following variables were considered: operating water depth, year of delivery, drilling depth, environmental design conditions (harsh or non-harsh environment), variable deck load, and country of build. For replacement cost, water depth, year of delivery, years since upgrade (effective age), upgrade status, and environmental design conditions were examined. Variable deck load was not considered in the replacement cost analysis due to data limitations. For jackup replacement and newbuild costs, water depth squared was examined because higher-order terms of deadweight have previously been shown to be a reliable predictor (Mulligan, 2008) and because rig weight is better correlated with water depth squared (Chapter 11).

Water depth, drilling depth and variable load are continuous variables. Delivery year is a discrete variable that enters the newbuild model as X rather than 200X, while for replacement costs, the actual year of delivery is used. Year of delivery precludes using the derived relations in a predictive manner for a future time period. When qualitative variables are used they are referred to as indicator or dummy variables and they take the value 0 or 1; e.g., rigs designed to operate in a harsh environment can be categorized using an indicator variable: HARSH = 1, NOT HARSH = 0.

14.3.3. Expectations

Water depth and drilling depth are expected to be positively correlated with costs for all rig types. Water depth should have a pronounced impact on jackup costs because of the leg length correspondence and the increased cost to build. Newbuild costs are also expected to increase over time because the period of analysis is relatively short (2009 to 2012) and contracts made for later deliveries were finalized in early 2008, before commodity prices fell, credit markets tightened, and shipyard demand was high. Harsh environment rigs are expected to cost more than non-harsh environment rigs and costs are expected to be higher in developed countries such as Korea and the U.S. and lower in China and India. We also expect that newer rigs and more recently upgraded ones will be more expensive to replace than older rigs that have not been upgraded.

14.4. NEWBUILD COST MODELS

14.4.1. Single Variable Models

Single variable linear regression models using water depth, year of delivery and drilling depth capability were examined. The relationships behaved as expected in most cases with increases in water depth, drilling depth and build year having a positive influence on cost, however, most relations were not significant. The only statistically significant relationship involved water depth and jackup costs (Figure N.4).

14.4.2. Jackups

Multivariate newbuild cost models were specified using an environmental indicator (HARSH), water depth (WD, ft), and water depth squared (WD^2, ft^2) terms. Variables for country of build, drill depth or delivery year did not add explanatory power and were excluded.

The impact of variable deck load was minor and was not included in the best model. The best model took the form:

$$\text{Newbuild Cost} = \alpha_0 + \alpha_1\text{HARSH} + \alpha_2\text{WD} + \alpha_3\text{WD}^2.$$

All costs are reported in million dollars and the results of several variable combinations are shown in Table N.4. Model A explained the largest portion of the variation in newbuild costs and contains both water depth and water depth squared terms of opposite signs. Figure N.5 illustrates the output of model A; in the figure, the upper line is the model for harsh environment rigs, while the lower line is the model for moderate environment rigs. Costs increase at an increasing rate with water depth, consistent with our a priori expectations.

Models B and C compare the effects of the water depth and water depth squared terms and suggest that water depth squared is a slightly better predictor than water depth. In models A through C, negative and large positive intercepts are inconsistent with a priori expectations. Therefore, we examined the effects of constraining the y-intercept (α_0) to zero in models D through F. The standard error of the regression models through the origin is higher than the analogous standard regression model, suggesting weaker fit. When the y-intercept is set to zero, the magnitude of the coefficients changes, but the signs of the coefficients do not change, suggesting that the direction of the relationships between water depth and operating environments and costs are robust.

All of the models in Table N.4 contain indicator variables for environmental conditions and the coefficients for these variables range from 140 to 201.6 suggesting that harsh-environment rigs are approximately $140 to $200 million more expensive than non-harsh environment rigs which is consistent with the summary statistics described previously. The absence of nation of build and drilling depth variables from the models is not surprising. The lack of a geographic difference is likely due to international competition which forces all shipyards to offer competitive pricing. Drilling depth was not a good predictor of costs because it is relatively invariant in the sample with most rigs capable of drilling either 30,000 or 35,000 ft wells.

14.4.3. Semisubmersibles

Semisubmersible newbuild cost models did not yield robust models. The best model of construction costs contained water depth and delivery year:

$$\text{Newbuild Cost} = \alpha_0 + \alpha_1\text{WD} + \alpha_2\text{YEAR}.$$

The model results are shown in Table N.5 with and without the fixed cost component. Both models had similar coefficients but poor predictive ability. The model suggests that for each 1,000 foot increase in water depth capability, cost increases by $25 million, and as the year of delivery increases, costs increase by $38 million. Thus, a semi for delivery in 2012 should cost approximately $100 million more than an identical semi delivered in 2009 because of the market conditions which influence contract negotiations.

For an average 8,333 ft water depth semi delivered in 2010, model B (α_0=0) estimates cost at $535 million. Approximately 37% of the cost is associated with the water depth term and 63% is associated with the delivery year term. The influence of the delivery year on costs is time dependent and related to commodity prices and shipyard demand when the contracts were written. Hence, these terms generally do not extrapolate outside the period of analysis and are generally not preferred in the specification. Market conditions in the 2009-2012 period led to increasing price with time, however, if a different time period were selected, conditions are likely to be different.[17] Understanding the time dimensions of cost is an important determinant of applying empirical relations outside their sample window.

14.4.4. Drillships

No combination of variables was able to capture the distinguishing features of drillship construction. The vast majority of drillships are under construction in Korea which eliminates the country of build variability inherent in the jackup and semi data sets and orders in the sample occurred over a short time period (2007 to mid-2008) reducing the temporal difference due to market conditions. Additionally, many of the vessels under build are one of three similar designs. In this case, the average cost of drillships adequately describes the characteristics of the sample.

14.4.5. Design Class

Design class was investigated as an explanatory variable for each rig class using the single-factor model:

$$\text{Newbuild Cost} = \alpha_0 + \alpha_1\text{DESIGN}.$$

For semisubmersibles and drillships, design class did not improve the model results, but for jackups, the variable was statistically significant (Table N.6). Nine design classes were employed to categorize the sample data and each design class used its own indicator variable such that the cost is equal to the intercept plus the coefficient associated with the design class. For example, to determine the newbuild cost of an F&G Super M2 from Table N.6, take the intercept and add -41.6. In cases where the p value of a parameter is not less than 0.05, the parameter cannot be said to differ from zero and the estimated cost is simply the intercept.

The model predicted over 95% of the variance in costs and suggests that there is more variation between rig classes than within rig classes; however, the model cannot be generalized beyond the rig classes depicted. The Letourneau Super 116, the F&G Super M2 and the MSC CJ46 are priced at a discount; the KFELS ModVB, Letourneau 240C and Pacific Class 375 may be considered average; and the KFELS N Class, MSC CJ70 and F&G 2000A are priced at a premium. All three premium designs are for harsh environments.

17 For example, the *Sevan Brasil*, will be delivered in 2012 at a cost of $685 million, but two identical rigs built at the same shipyard for delivery in 2014 each cost $526 million.

14.5. Replacement Cost Models

Replacement costs reflect the costs to replace a rig with a new asset of like quality and are related to newbuild cost. For a recently built rig, replacement cost may be estimated by reference to the rig's original newbuild cost adjusted for market conditions, or the newbuild cost of similar rigs under construction. Replacement cost depends on technology trends, labor and material cost, construction supply and demand conditions, and the age of the rig at the time of the assessment. If new technology and improved construction methods, high competition among shipyards, and low demand for steel prevail in the future, replacement costs will be lower. Conversely, when there is high demand for shipbuilding services and a high price environment, replacement costs increase (Figure N.6). Since many of the factors that influence newbuild prices also impact replacement costs, we expect that model results will be similar.

14.5.1. Single Variable Models

Single variable linear regression models were created to investigate factor impacts on replacement costs. Water depth was a significant factor for jackups (Figure N.7) and floaters (Figure N.8). Delivery year was a useful descriptor for drillships (Figure N.9) but not for jackups and semisubmersibles due in part to the effect of upgrading which subverts the age variation. Drill depth was not a significant factor for any rig type.

14.5.2. Jackups

Multivariate replacement cost models were specified using water depth (WD, ft), environmental indicator (HARSH), and year of delivery (YEAR, yr):

$$\text{Replacement Cost} = \alpha_0 + \alpha_1\text{WD} + \alpha_2\text{WD}^2 + \alpha_3\text{HARSH} + \alpha_4\text{YEAR}.$$

Model results are shown in Table N.7. Upgrade status was not a useful indicator of costs and was excluded. Age and water depth were significant predictors in several models, but are absent from the best model (model A). Water depth squared was a better predictor than water depth, consistent with the newbuild model relations. Costs increase with increasing water depth, harsh environments, and for younger rigs, as expected. Constraining the intercept to zero had little impact on parameter estimates.

As in jackup newbuild models, the jackup replacement cost model included an environmental indicator with a coefficient of 10.6. This suggests that in the replacement cost sample, a harsh environment rig enjoys a premium approximately $11 million more than a non-harsh rig, much less than for newbuilds and likely due to the capabilities of the harsh environment rigs currently under build. The MSC CJ70 is capable of operating in harsh environments in water depths up to 492 ft, and can drill wells up to 40,000 ft deep with a 7,000 ton VDL; the KFELS N Class has similar capabilities. These additional advanced capabilities make modern harsh environment rigs more expensive than those of the legacy fleet.

Assuming an average moderate environment jackup with a water depth capability of 293 ft delivered in 1982, the replacement cost is estimated by model C (α_0=0) to be $131 million. Approximately 60% of the costs are associated with the delivery year term and 40% is associated with the water depth term.

14.5.3. Semisubmersibles

Replacement cost models were specified using water depth (WD, ft), year of delivery (YEAR, yr), and environmental indicator (HARSH):

$$\text{Replacement Cost} = \alpha_0 + \alpha_1\text{WD} + \alpha_2\text{YEAR} + \alpha_3\text{HARSH}.$$

Model results are shown in Table N.8. All coefficients were consistent with expectations. The coefficient of the water depth term was 0.020 indicating that for every 1,000 foot increase in water depth, costs increase by $20 million. Newer rigs had higher replacement costs than older rigs, and each year increased cost by $2.2 million. Harsh environment rigs cost $23.8 million more than moderate environment rigs. For the average semi in the sample, model B (α_0=0) estimates that 30% of costs were associated with the water depth term and 70% were associated with the delivery year term.

14.5.4. Drillships

Replacement cost models were specified using an environmental indicator (HARSH) and water depth (WD, ft) variables:

$$\text{Replacement Cost} = \alpha_0 + \alpha_1\text{HARSH} + \alpha_2\text{WD}.$$

Year of delivery was correlated with water depth and excluded from the model. Results are shown in Table N.9. The coefficient of the water depth term was positive and for every 1,000 ft increase in water depth replacement costs increased by $31 million. The harsh environment coefficient suggests that a harsh environment drillship costs $196 million more than a moderate environment drillship. This is far more than the harsh environment premium in the jackup or semi cost models, and is partially the result of semis and jackups being more amenable to modification for harsh environments.

14.6. APPLICATION

Model application is straightforward. To determine the cost of a newbuild 350 foot water depth, harsh environment jack-up with a 3,000 ton variable load in 2009-2010, for example, we apply the results from Table N.3 and select model A since it has a low standard deviation and coefficients with the expected signs. To determine cost we substitute WD =350, VDL = 3000 and HARSH = 1 into:

$$\text{Newbuild Cost} = 1248 + 140{*}\text{HARSH} – 6.88{*}\text{WD} + 0.011{*}\text{WD}^2,$$

to obtain $328 million. Confidence intervals are calculated using the standard error; a 95% confidence interval is given by $265 to $391 million.

14.7. LIMITATIONS

The models developed are primarily limited by the sample size of the data from which they are constructed, and for the replacement cost, the manner in which costs are estimated. All three of the newbuild cost models and the drillship replacement cost model had sample sizes under 40 rigs. This is due to the limited drillship fleet size and the small number of rigs under construction at the time of analysis.

Some of the explanatory variables may be subject to error. The models treat the environmental design conditions as a simple variable that can only take the form harsh or non-harsh. However, for jackup rigs, the environmental conditions which a rig can withstand depend in part on the water depth at that location. For example, a rig designed to operate in 350 ft in the Gulf of Mexico may only be able to operate in 200 feet in the North Sea. Overall, water depth was the single best predictor of rig cost. Water depth is believed to serve as a proxy for structural weight, and if weight were included the model fits may improve.

The data provide a snapshot of market conditions as of October 2009. By fixing the time of assessment the effects of market fluctuations on cost data are eliminated which allows for a better analysis of the physical factors (water depth, harsh environment capacity, etc.) that influence costs. While we suspect that the factors identified as influencing costs apply to the market generally, the value of individual coefficients and model output will change with changes in shipyard supply and demand.

It is possible to build dynamic models of rig cost, but these require a different dataset and model structure, and most importantly, prognostication of market conditions. By constraining the data to a particular point in time, problems with autocorrelation were avoided. While a time-series analysis of newbuild or replacement costs would be valuable, the focus of this analysis was primarily on the physical factors that impact costs. Time-series models may be adequate predictors of newbuild costs, but their application requires the estimation of market conditions in a future period and given the volatility of the offshore oil and gas market, this may prove difficult.

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APPENDIX A

CHAPTER 1 TABLES AND FIGURES

Table A.1.

Environmental Criteria Used in Rig Design by Offshore Region

		North Atlantic	Gulf of Mexico	Asia/Pacific
100 year	Wave height (ft)	46-52	52	18-45
	Wind velocity (kn)	66-79	93	45-109
	Surface current (kn)	1.1-2.9	3.5	3.7-3.9
1 year	Wave height (ft)	42	13	16-20
	Wind velocity (kn)	57	30	33
	Surface current (kn)	1.7	0.8	3.5

Source: DNV, 2010

Table A.2.

Jackup Specification Comparison for Standard and High-Spec Units-
Rowan Juneau vs. *Rowan EXL III*

	Rowan Juneau (standard)	*Rowan EXL III* (high-spec)
Water depth (ft)	210	350
Drill depth (ft)	25,000	35,000
Year built	1977	2010
Mud pumps (number x hp)	2 x 1,600	3 x 2,200
Hook load (million lbs)	1.25	2
Variable load (million lbs)	5.5	6.5
Replacement cost (million $)	146	210

Source: Rowan, 2012; Jefferies and Company, Inc., 2012.

Table A.3.

Advantages and Disadvantages of Station Keeping Systems

	Jack-up	Anchor Spread	Dynamic Positioning
Advantages	Relatively simple Not susceptible to power/system failures Low fuel costs	Simple Not susceptible to power/system failures Capable of operating in 5,000 ft water depth	Maneuverability once in position No anchor handling tugs are required Not dependent on water depth Short mobilization and positioning times
Disadvantages	No maneuverability once positioned Limited to water depths of 500 ft Limited by seabed conditions	Limited maneuverability once anchored Anchor handling tugs are required Time to set anchors increases costs	Complex systems incur extra costs and maintenance High fuel costs

Table A.4.

Displacement and Size of Modern Semisubmersible Designs

Design	Operating displacement (tons)	VDL (tons)	Deck dimensions (ft x ft)
Gusto MSC DSS 20	33,500	4,400	208 x 211
Gusto MSC DSS 38	43,000	5,200	228 x 228
Gusto MSC DSS 51	58,000	8,800	254 x 256
F&G EXD	58,000	9,900	379 x 259
F&G Millennium	40,000	6,800	344 x 240
Aker H-6e	64,500	7,000	295 x 230
GVA 7500	61,000	8,200	389 x 317

Source: Industry press.

Table A.5.

Semisubmersible Rig Generations and Technology Development

Generation	Approximate years of construction	Water depth (ft)	Variable load (tons)	Technology implementation
I	1962 - 1969	600-800	1,000-2,000	2 x 1,250 hp mud pumps, kelly, manual derrick
II	1970 - 1981	1,000-1,500	2,300-3,300	2 x 1,600 hp mud pumps, kelly, manual derrick
III	1982 - 1986	1,500-2,500	3,800-4,500	2 x 1,600 hp mud pumps, kelly, automatic pipe handling
IV	1987 - 1998	3,500-7,000	3,800-5,000	3 x 1,600 hp mud pumps, top drive, automatic pipe handling, DP
V	1999 -2005	7,500-10,000	5,000-8,000	4 x 2,200 hp mud pumps, top drive, dual activity, DP
VI	2005-	10,000	7,000-8,500	4-5 x 2,200 hp mud pumps, modular derrick drilling machine, DP3, dual activity

Source: PETEX, 2005; Keener et al., 2003.

Table A.6.

Typical Semisubmersible Specifications by Generation

Generation	Design	Displacement (tons)	Water depth (ft)	Drilling depth (ft)	Station keeping	Example
I	SEDCO 135		600	10,000	Moored	*SEDCO 135F*
II	Aker H-3	24,000	1,000	20,000	Moored	*ENSCO 5003*
III	Aker H-3.2	31,000	1,500	20,000	Moored	*Deepsea Bergen*
IV	GVA 4500	38,000	7,000	30,000	Moored or DP2	*Transocean Rather*
V	F&G ExD	51,000	7,500	37,500	DP2	*Development Driller II*
VI	Aker H-6e	71,000	10,000	33,000	DP3	*Aker Barents*

Source: Industry press.

Table A.7.

Specifications of Modern Drillships

Design	Displacement (tons)	Variable load (tons)	Water depth (ft)	Hook load (tons primary/auxiliary)	Mud pumps (number x hp)
Gusto P10000	75,000	20,000	10,000	1,250/750	4 x 2,200
Gusto PRD10000	54,000	15,000	10,000	1,000	4 x 2,200
Samsung 12000	105,000	22,000	12,000	1,250/1,000	4-6 x 2,200

Source: Industry press.

Table A.8.

Costs of Rigs Under Construction in 2012 in Million Dollars

	Jackups	Semis	Drillships
Average	217	595	634
Minimum	159	460	550
Maximum	530	809	1,150
Standard deviation	73	96	92
Sample size	77	17	47

Source: Data from Jefferies and Company, Inc., 2012.

Table A.9.

Replacement Costs of Selected Rigs in 2012

Rig	Class	Delivery year	Upgrade year	Replacement cost (million $)
Deepwater Discovery	Drillship	2000		615
Deepwater Navigator	Drillship	1974	2000	400
Discoverer Inspiration	Drillship	2010		640
GSF Celtic Sea	Semi	1982	1998	423
Cajun Express	Semi	2000		540
Transocean Spitsbergen	Semi	2010		850
Constellation II	Jackup	2004		210
GSF High Island	Jackup	1979		150
Transocean Honor	Jackup	2011		189

Source: Data from Jefferies and Company, Inc., 2012.

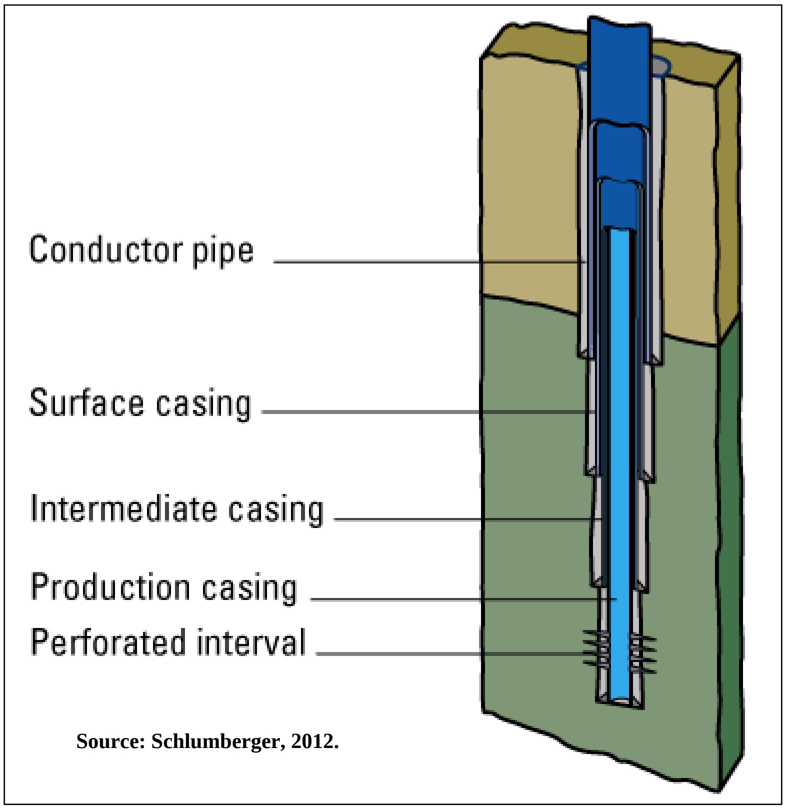


Figure A.1. Casing diagram for a typical well.

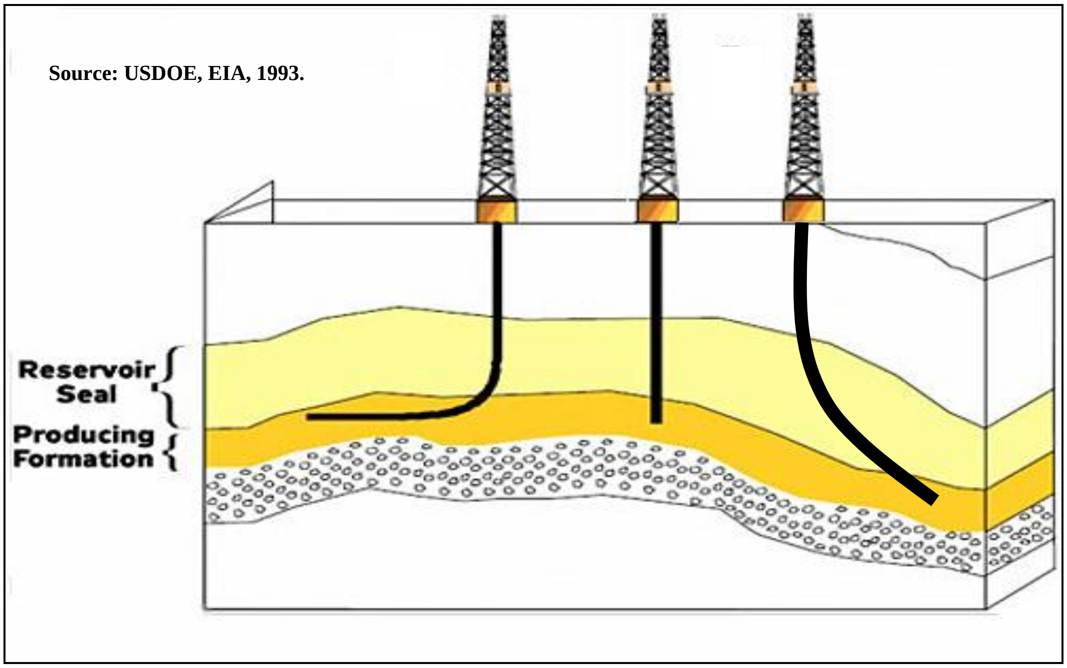


Figure A.2. Horizontal, vertical, and directional well configuration.

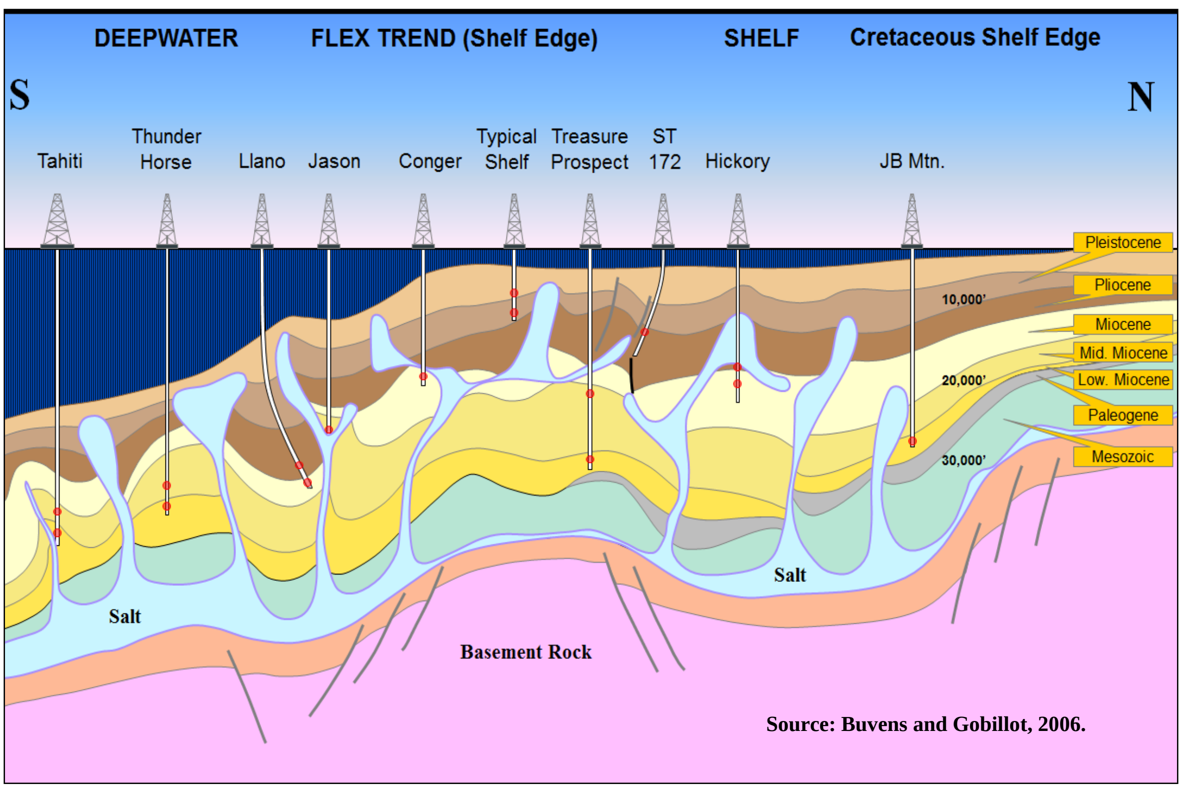


Figure A.3. Depth and well configuration of selected offshore wells in the U.S. GOM.

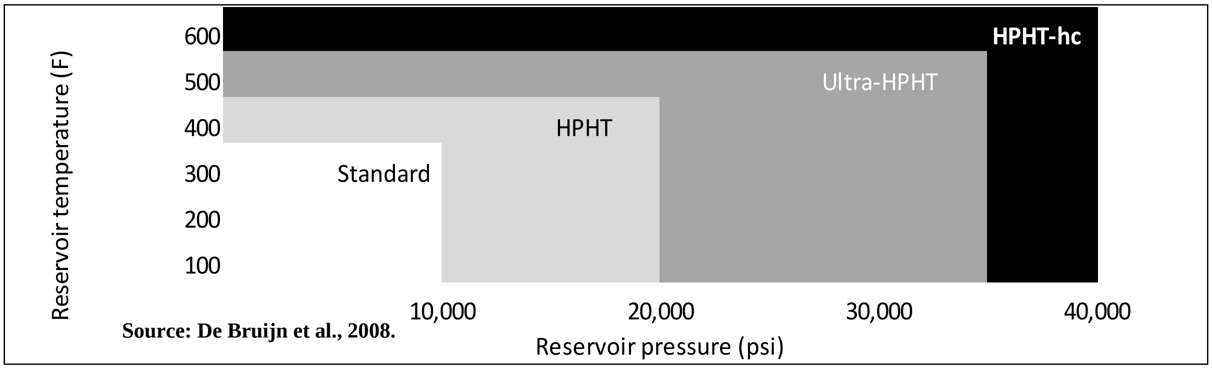
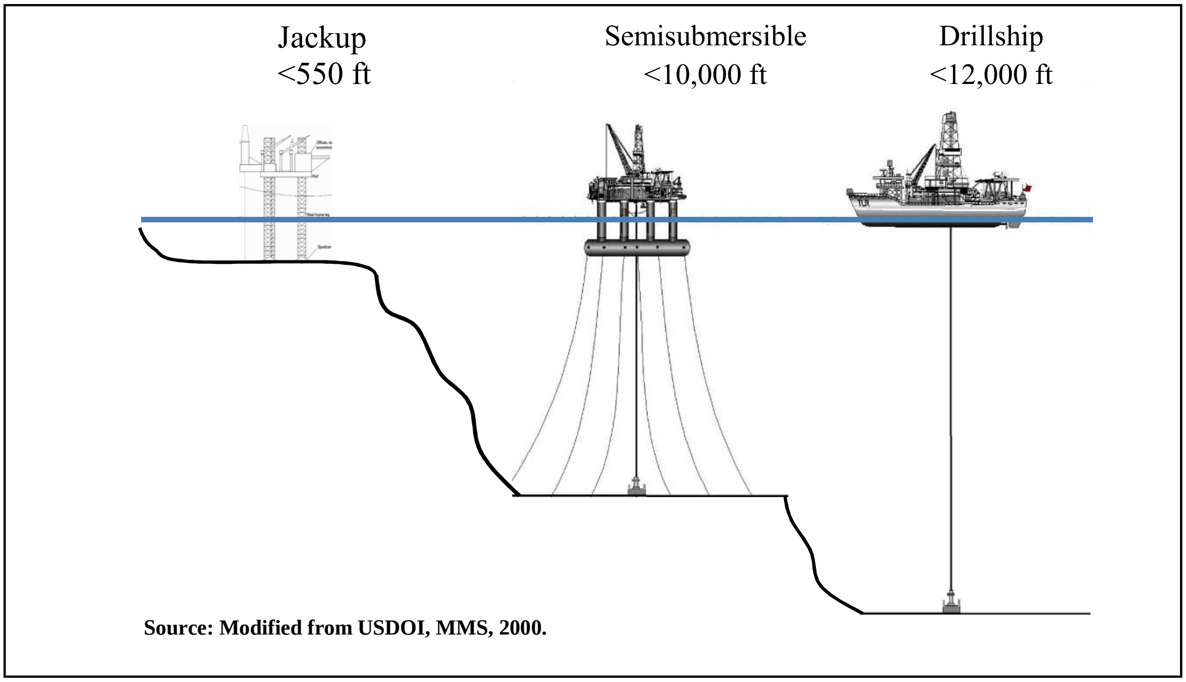


Figure A.4. High temperature high pressure reservoir classification.

Figure A.5. Global distribution of HPHT drilling in 2008.



Source: Modified from USDOI, MMS, 2000.

Figure A.6. Bottom supported versus floating rigs.

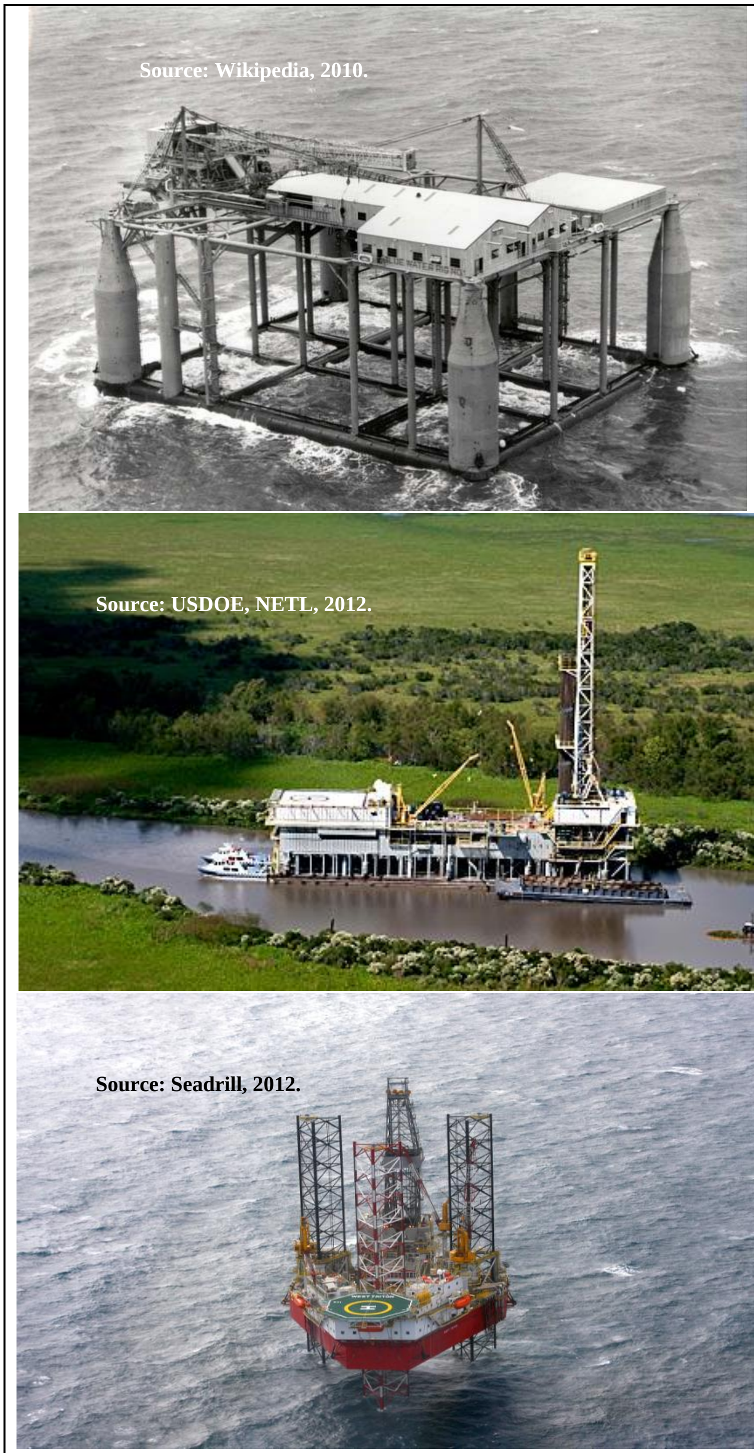
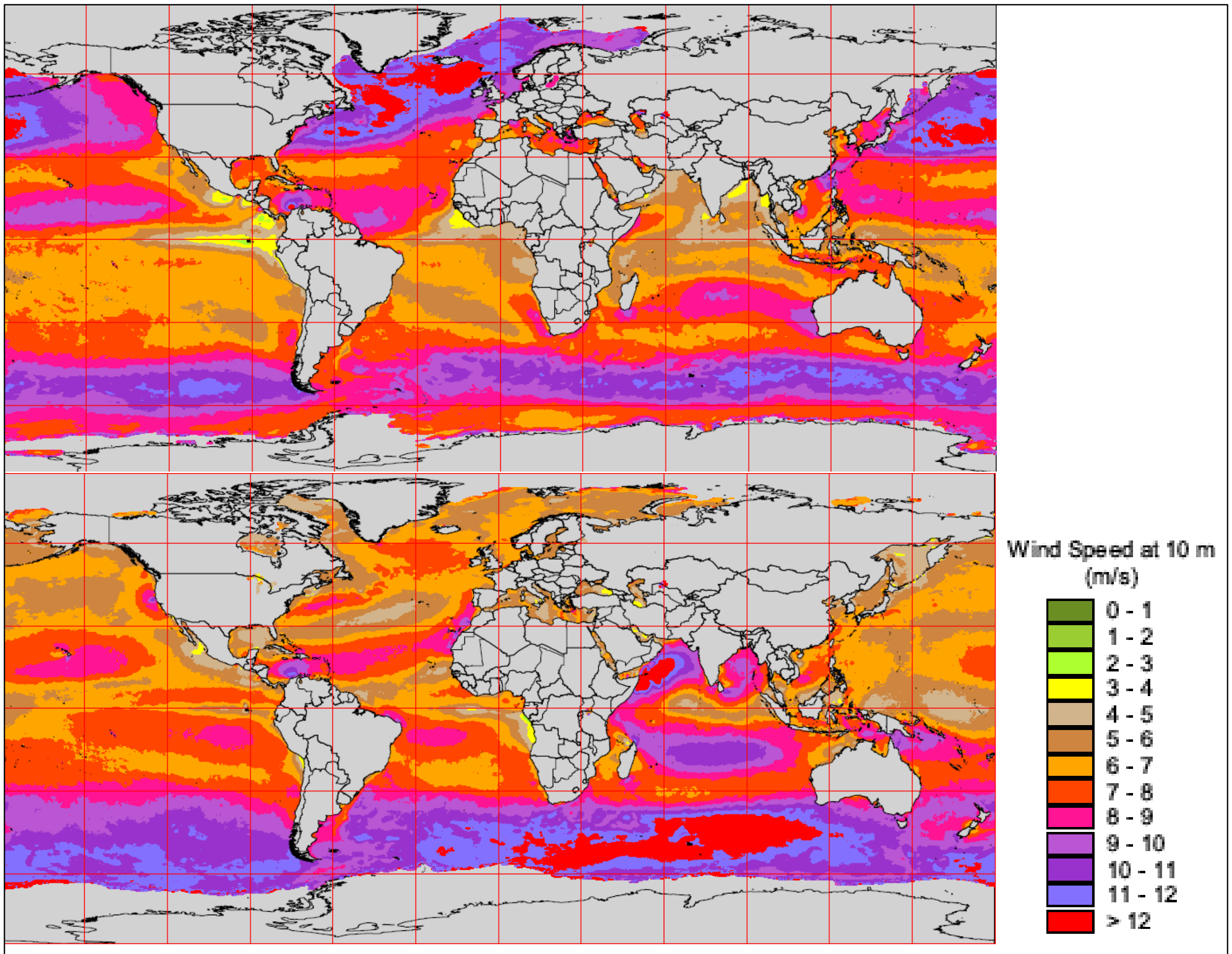


Figure A.7. An old submersible, a drilling barge, and a cantilevered jackup drilling rig.

Source: Seadrill, 2008a and 2009a.

Figure A.8. Floating rigs. Left, the *West Aquarius*, a semisubmersible; right, the *West Polaris* drillship.



Source: SWERA, 2012.

Figure A.9. Average wind speeds over the ocean in February (top) and July (bottom).

Figure A.10. The harsh environment *Bob Palmer* next to a moderate environment rig.

Rowan Companies, Inc. www.rowancompanies.com

Rowan Juneau

LeTourneau Technologies 116-S Class Jack-up

PRIMARY RIG CHARACTERISTICS

Maximum Water Depth
210 ft

Hook Load
1,250,000 lbs

Mud System Maximum Pressure
5,000 psi

Cantilever Skid Out
N/A

Substructure Travel
10 ft transverse to Port or Starboard

Quarters Accommodation
91 Persons

Heliport - can accommodate:
Sikorsky S-61 N

Year In Service
1977

Life Enhancement
2009

Leg Length
343 ft

Hull Length
248 ft

Hull Width
201 ft

Hull Depth
26 ft

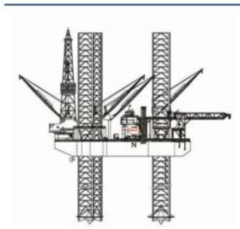
Gear Unit Height
24 ft

Maximum Drilling Depth
25,000 ft

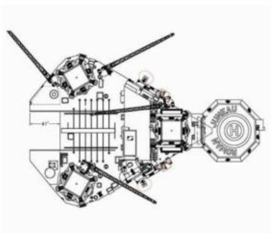
Longitudinal Leg Centers
129 ft

Transverse Leg Centers
142 ft

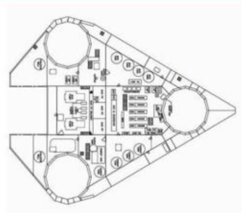
SIDE PROFILE



MAIN DECK



MACHINERY DECK



Source: Rowan, 2012.

Minor changes / modifications to the above listed equipment could occur.
Should you have specific questions, please contact the Marketing Department at: marketing@rowancompanies.com or 713-960-7647

Rowan Juneau www.rowancompanies.com

CAPACITIES

Maximum Drilling Payload	5,538,000 lbs
Hook Load	1,250,000 lbs
Rotary Load	1,000,000 lbs
Setback load	450,000 lbs
Liquid Mud	1,465 bbls
Sand Traps	165 bbls
Pipe Storage (main)	2000 sqft x 7 ft high
Pipe Storage (cantilever)	N/A
Covered Sack Storage	1,500 sq ft
Bulk Cement	5,440 cu ft
Bulk Barite	5,440 cu ft
Potable Water	1,127 bbls
Drill Water	6,676 bbls (incl. combo tanks)
Diesel Fuel	3,768 bbls
Base Oil	700

WELL CONTROL

Diverter	21-1/4" 2000psi Hydril
Annular	(1) 13-5/8" 5K Hydril
BOP	(1) 13-5/8" 10K Type U Single, (1) 13 -5/8" 10K Type U Double with Blind Shear, w/ 4-1/16" 10K outlets
Choke Manifold	(18) Cameron 2 1/16" Type F 10K psi, H2S trimmed, (6) Cameron 4 1/16" Type F 10K psi H2S trimmed
Control Unit	Stewart and Stevenson ssb2-3S11

DRILLING EQUIPMENT

Derrick	167ft Lee C. Moore 30ft x 30ft
Top Drive / Power Swivel	Varco TDS-4H
Traveling Block	National 660H500
Crown Block	National 760 FA
Drawworks	National 1625-DE
Auxiliary Brake	Baylor 7838
Drill Line	1-1/2"
Rotary	National C-375
Prime Movers	5 - Caterpillar D-399 TA @ 1325 hp
Emergency Generator	1 - Caterpillar D-398 @ 860 hp
Cementing Equipment	Halliburton HCS-25D Twin HT400
Torque Wrench / Spinner	TW61 Wrench / Varco SSW30 Spinner
Cranes	(4) LeTourneau PCM 120AS

MUD SYSTEM

Mud Pumps	(2) National 12-P-160 Triplex. 1600 hp each
Mud Pits	1467 bbls total - 3 mud pits and 1 slug pit
Mud Mixing Pumps	(2) Mission Magnum
Shale Shakers	(3) Derrick Flo Line Cleaners, 2 Brandt Dual Tandem
Desanders	DEMCO 3 CONE
Desilters	Derrick FLC-503, 20 CONE W/3 Screen Mud Cleaner
Degasser	1- Swaco Total Mud Degasser
Mud Processing Pumps	(2) Mission Magnum
Maximum Pressure	5,000 psi

Minor changes / modifications to the above listed equipment could occur.
Should you have specific questions, please contact the Marketing Department at: marketing@rowancompanies.com or 713-960-7647

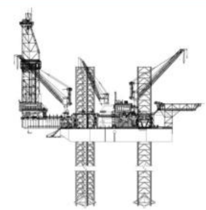
Figure A.11a. Specifications of a standard jackup (*Rowan Juneau*).

Rowan Companies, Inc. www.rowancompanies.com

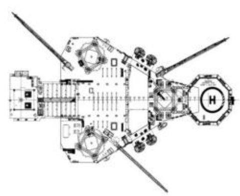
Rowan EXL III

LeTourneau Technologies EXL Class Jack-up

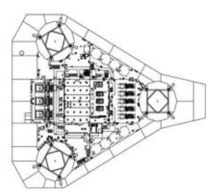
SIDE PROFILE



MAIN DECK



MACHINERY DECK



PRIMARY RIG CHARACTERISTICS

Maximum Water Depth
350 ft

Hook Load
2,000,000 lbs

Mud System Maximum Pressure
7,500 psi

Cantilever Skid Out
70 ft. aft of transom

Substructure Travel
15 ft. transverse to Port or Starboard

Quarters Accommodation
120 Persons

Heliport - can accommodate:
Sikorsky S-61N

Year In Service
2010

Life Enhancement
-

Leg Length
477 ft

Hull Length
228 ft

Hull Width
206 ft

Hull Depth
26 ft

Gear Unit Height
32 ft

Maximum Drilling Depth
35,000 ft

Longitudinal Leg Centers
129 ft

Transverse Leg Centers
142 ft

Source: Rowan, 2012.

Minor changes / modifications to the above listed equipment could occur.
Should you have specific questions, please contact the Marketing Department at: marketing@rowancompanies.com or 713-960-7647

Rowan EXL III www.rowancompanies.com

CAPACITIES

Maximum Drilling Payload	6,491,000 lbs
Hook Load	2,000,000 lbs
Rotary Load	2,000,000 lbs
Setback load	900,000 lbs
Liquid Mud	3,668 bbls
Sand Traps	350 bbls
Pipe Storage (main)	2,000 sq. ft. x 7 ft. high
Pipe Storage (cantilever)	2,000 sq. ft. x 7 ft. high
Covered Sack Storage	1,600 sq ft
Bulk Cement	6,805 cu ft
Bulk Barite	6,805 cu ft
Potable Water	1,762 bbls
Drill Water	13,882 bbls (incl. combo tanks)
Diesel Fuel	3,704 bbls
Base Oil	934

WELL CONTROL

Diverter	Vetco Gray 36-1/2" , 500 psi WP
Annular	13-5/8" Hydrill GX 10k psi
BOP	2 x 13-5/8" 15k Cameron type U, doubles, 4 x 3-1/16" 15k outlets. H2S trim
Choke Manifold	30 x Cameron 3-1/16" Type FLS Manual 15K PSI, H2S Trim 1 x Cameron 3-1/16" Type FLS Hydraulic 15K PSI, H2S Trim 4 x Cameron 4-1/16" Type FLS Manual 10K PSI, H2S Trim 2 x 3-1/16"15,000 PSI Adjustable Chokes, H2S Trim 2 x 3-1/16"15,000 PSI Hydraulic Drilling Chokes, H2S Trim 2 x 3-1/16"15,000 PSI Positive Chokes, H2S Trim
Control Unit	Cameron 3,000 PSI BOP Control Unit, 80-15 Gallon Bottles with 1,100 Gallon Reservoir Tank

DRILLING EQUIPMENT

Derrick	Loadmaster Model 2000 KIP, 32'x 35'Base, 170'High, 2,000,00 lbs. on 14 Lines
Top Drive / Power Swivel	Lewco 750 ton , OEM 1,500 HP AC Motor Output Torque 72,000 ft. lbs. continuous / 100,000 ft. lbs intermittent
Traveling Block	Lewco Model LBLK-1000, 2,000,000 lbs.
Crown Block	Loadmaster, Cap: 2,000,000 lbs.
Drawworks	Lewco Model 3000 HD Driven by 2 x 1,500 HP AC Motors
Auxiliary Brake	Baylor 15050W
Drill Line	1-3/4"
Rotary	Lewco Model D495 Driven by 1 x OEM 1,150 HP AC Motor
Prime Movers	5 x Cat 3516 CHD each Driving 1 x Kato 1525 KW Gen.
Emergency Generator	1 x Cat 3516 CHD each Driving 1 x Kato 1525 KW Gen.
Cementing Equipment	AC Drive provided (for Operator supplied unit)
Torque Wrench / Spinner	NOV IR 30120 Iron Roughneck-100,000 ft lbs make / 120,000 ft lbs break
Cranes	2 x LeTourneau PCM-220 SS Pedestal Cranes With 140' Booms, 1 x LeTourneau PCM-120 SS Pedestal Cranes With 100' Boom

MUD SYSTEM

Mud Pumps	3 x Lewco W-2215 2,200 HP, Driven by 2 x OEM 1,150 HP AC motors
Mud Pits	3668 bbls total, (6 mud pits + 2 slugging pits)
Mud Mixing Pumps	2 x Badger 8 x 6 x 14 pumps / 125 HP motor
Shale Shakers	4 Derrick DP-628 Box/Top feed shakers
Desanders	3 x 10" cones
Desilters	20 x 4" cones
Degasser	Derrick Vacu-Flow 1,200 GPM
Mud Processing Pumps	2 x Badger 8 x 6 x 14 pumps / 125 HP motor
Maximum Pressure	7,500 psi

Minor changes / modifications to the above listed equipment could occur.
Should you have specific questions, please contact the Marketing Department at: marketing@rowancompanies.com or 713-960-7647

Figure A.11b. Specifications of a high-spec jackup (*Rowan EXL III*).

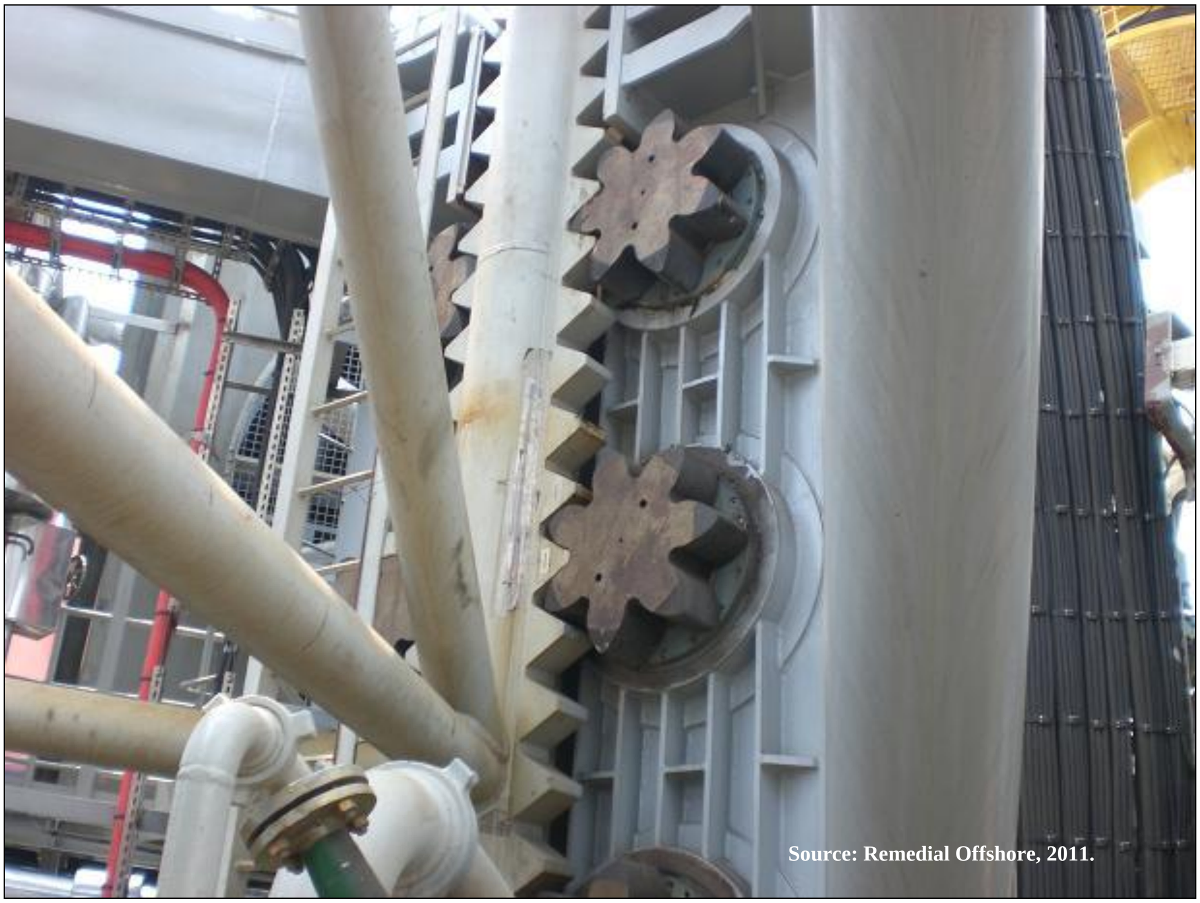


Figure A.12. Rack and pinion elevating system of a F&G Super M2 rig.

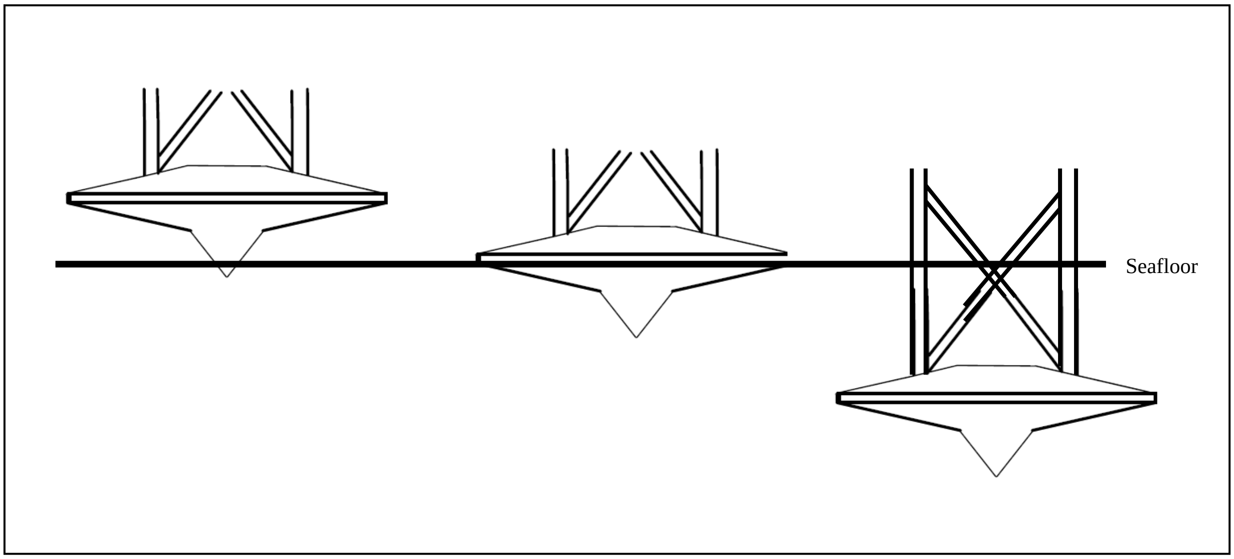


Figure A.13. Spudcan penetrating the seafloor during jackup operation.

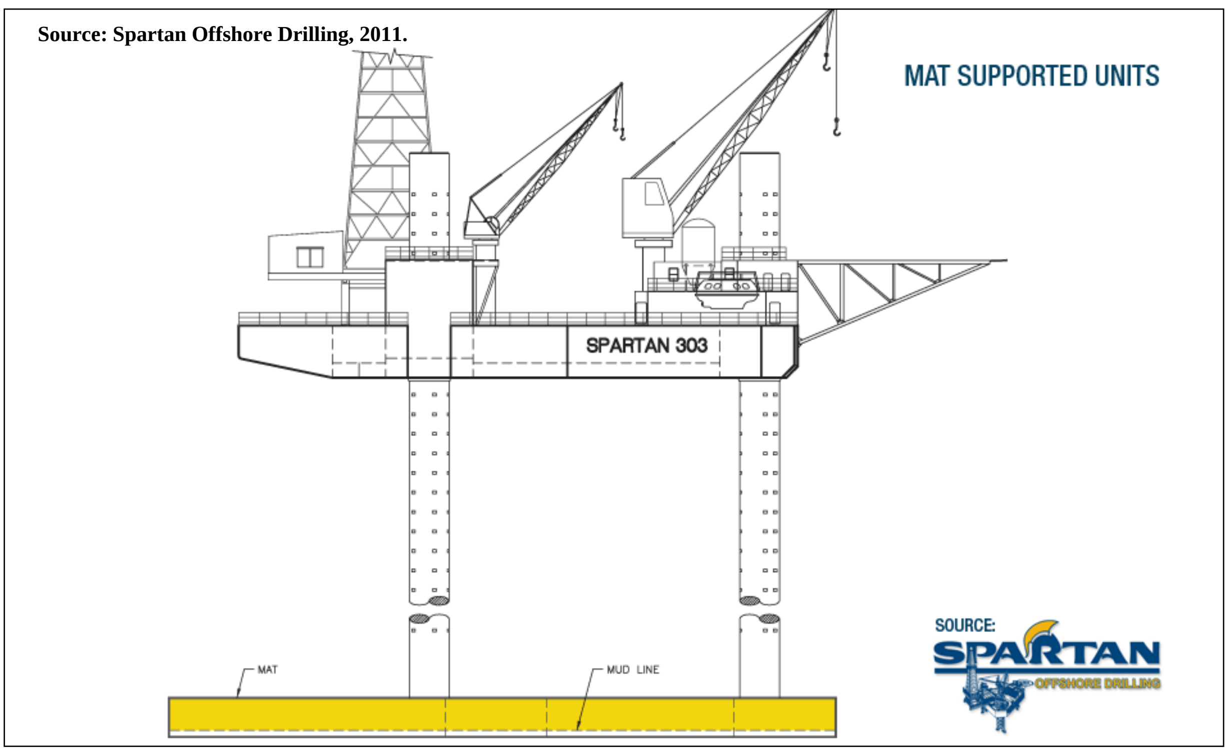
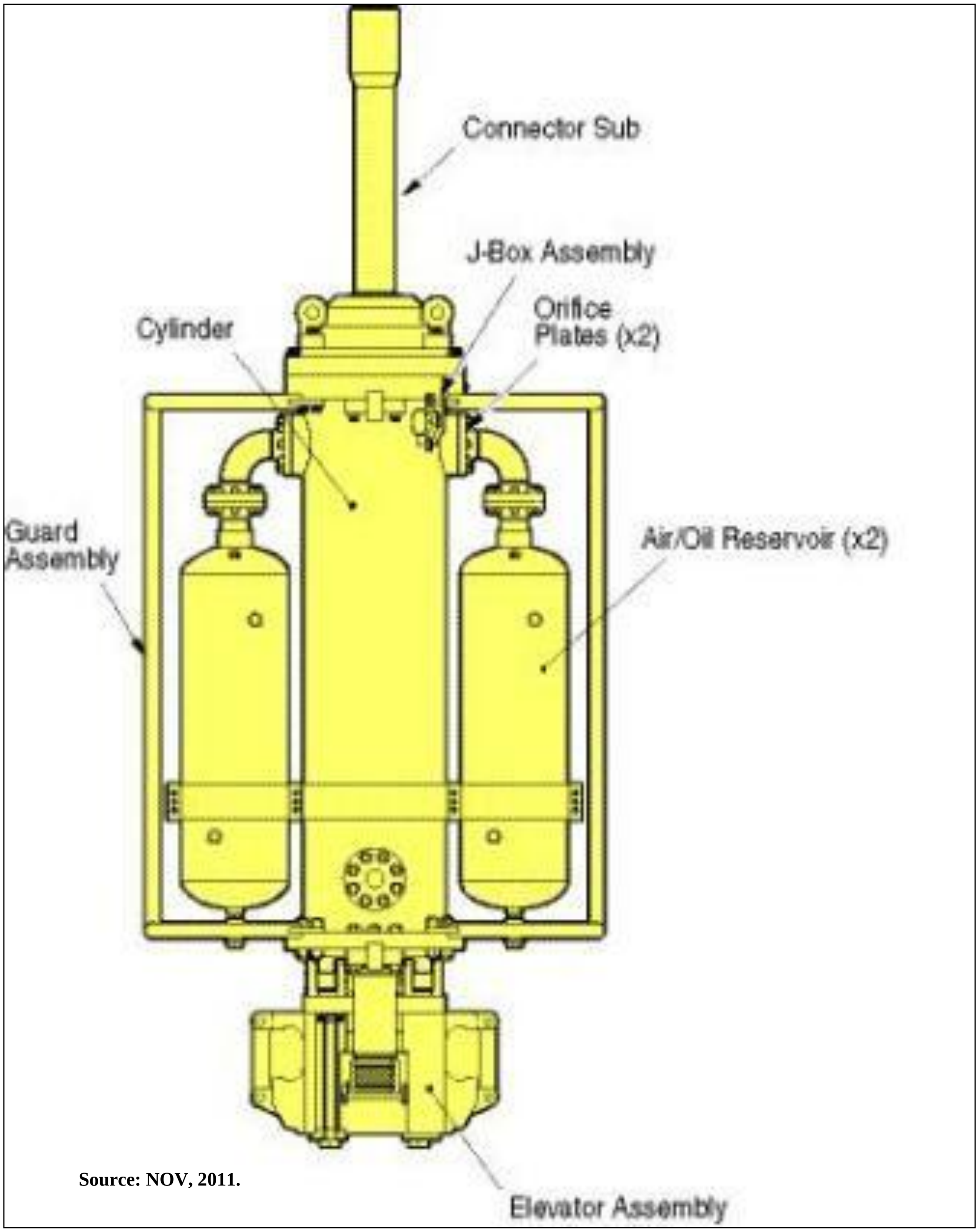


Figure A.14. Mat foundation.

Figure A.15. A cantilevered jackup rig operating at a platform.



Source: NOV, 2011.

Figure A.16. Diagram of an NOV drill string compensator.

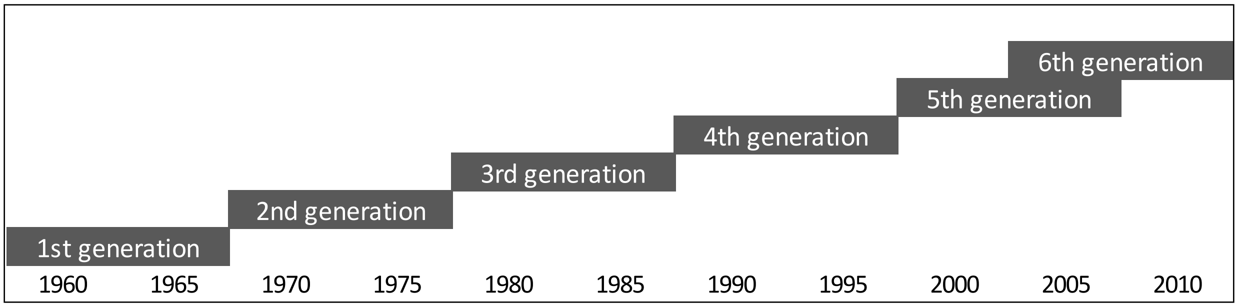


Figure A.17. Semisubmersible generations classified according to Transocean.

Figure A.18. The SEDCO 135-E, a 1st generation semisubmersible, built in 1967.

Figure A.19. *Essar Wildcat*, a 2nd generation Aker H-3 semisubmersible, built in 1977.

Figure A.20. *Ocean Patriot,* a 3rd generation Bingo 3000 semisubmersible, built in 1983.

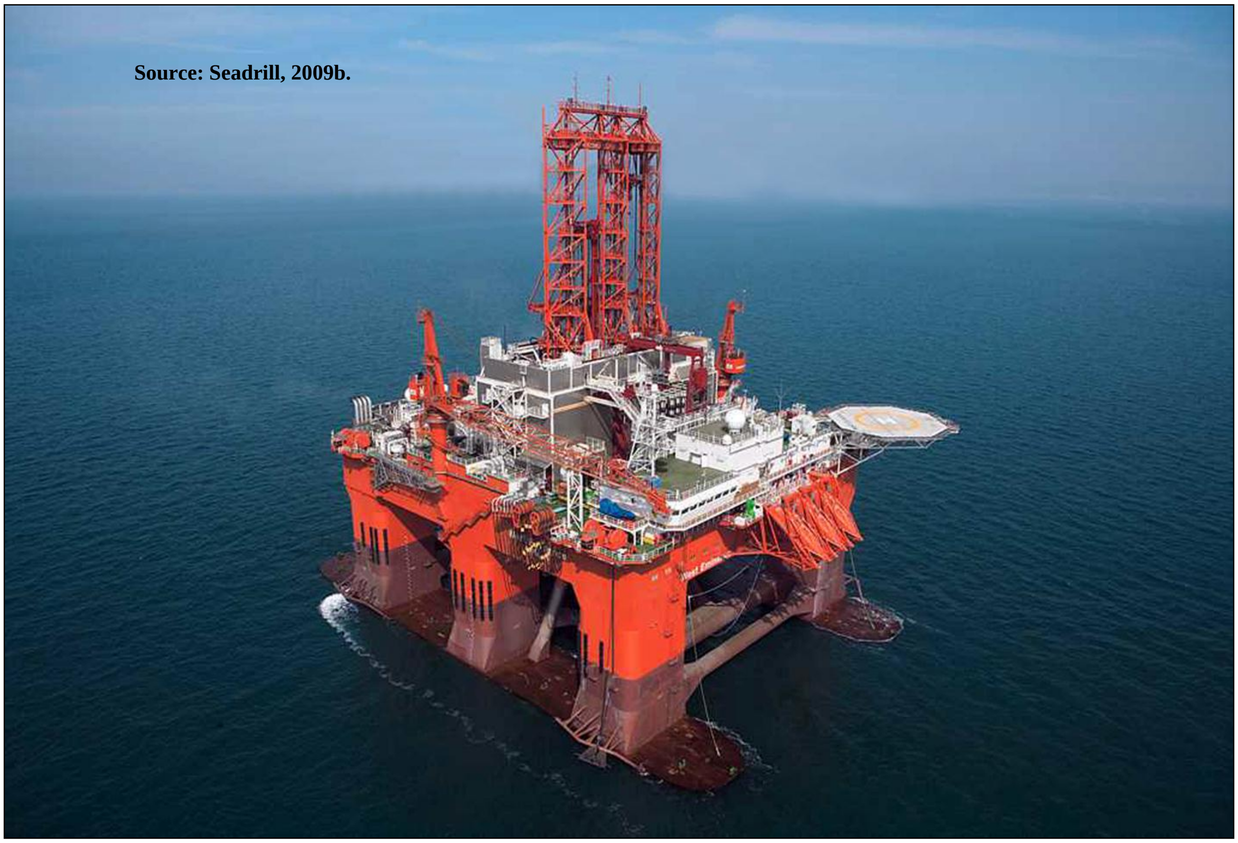
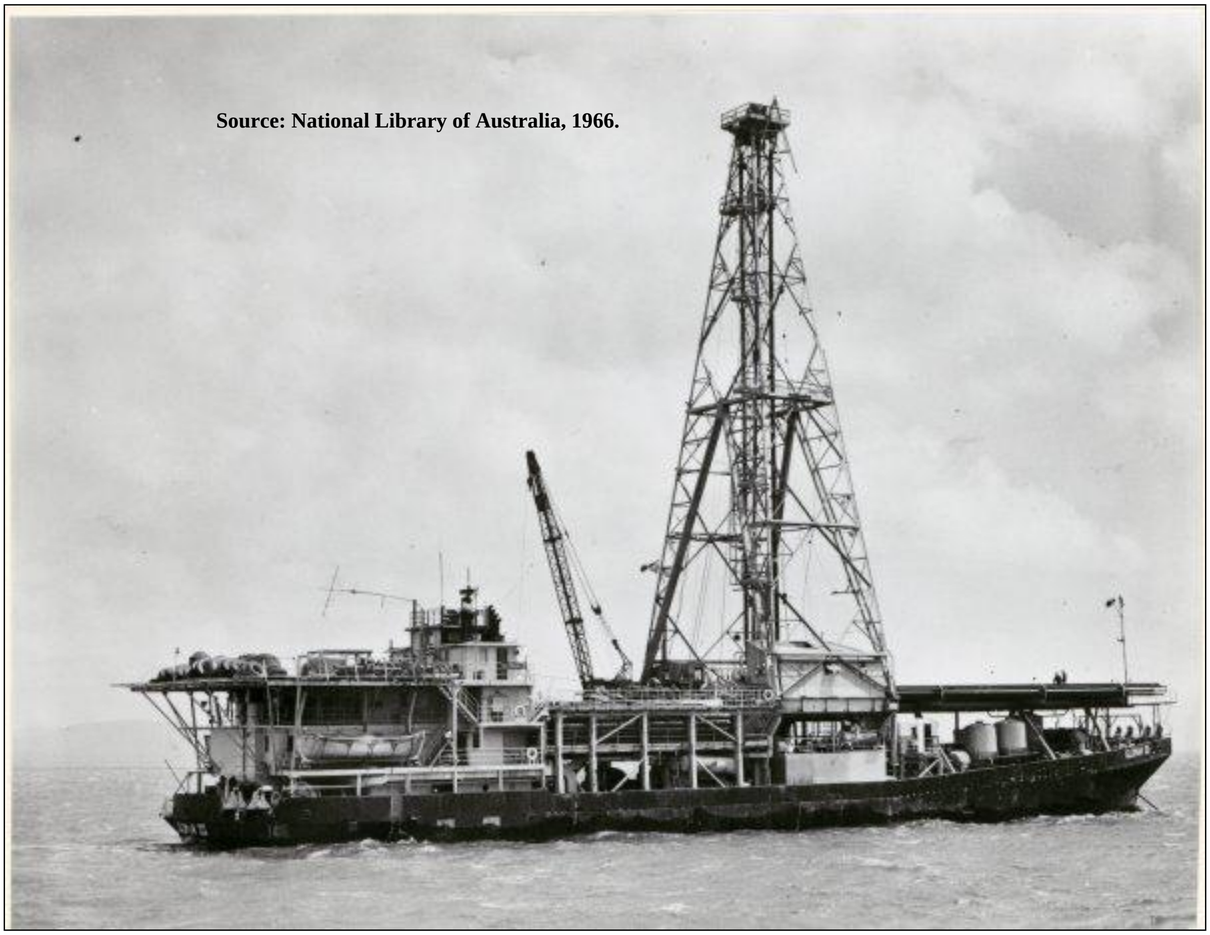


Figure A.21. *West Eminence*, a 6th generation semisubmersible, built in 2009.

Source: Business Men's Studio, 2007.

Figure A.22. *E.W. Thornton*, a drillship built in 1965.



Source: National Library of Australia, 1966.

Figure A.23. *Glomar III*, a drillship built in 1966.

Figure A.24. A modern drillship, the 5th generation *West Navigator,* built in 2000.

Figure A.25. Dual activity derrick on the 6th generation *West Polaris* drillship built in 2008.

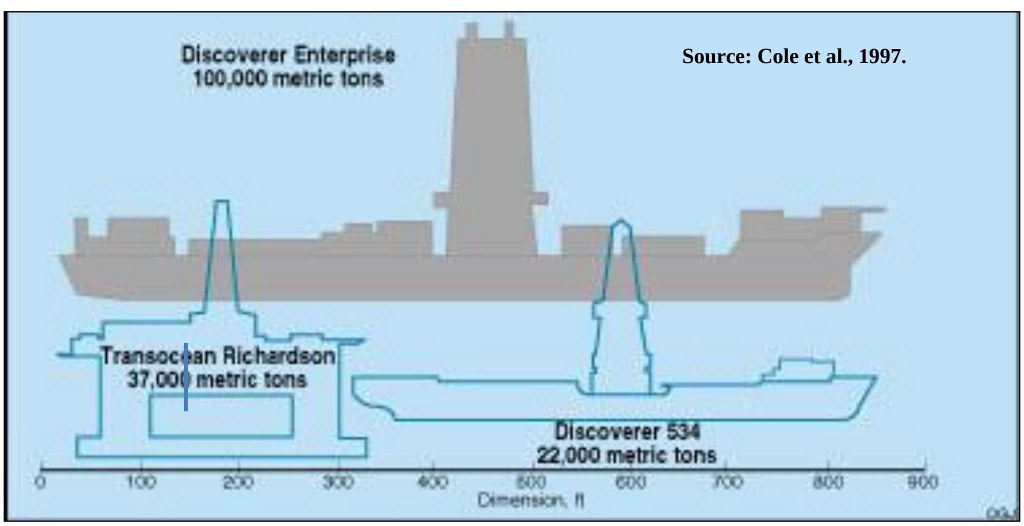


Figure A.26. Size comparison of *Discoverer Enterprise*, *Discoverer 534*, and *Transocean Richardson*, a 4th generation semi.

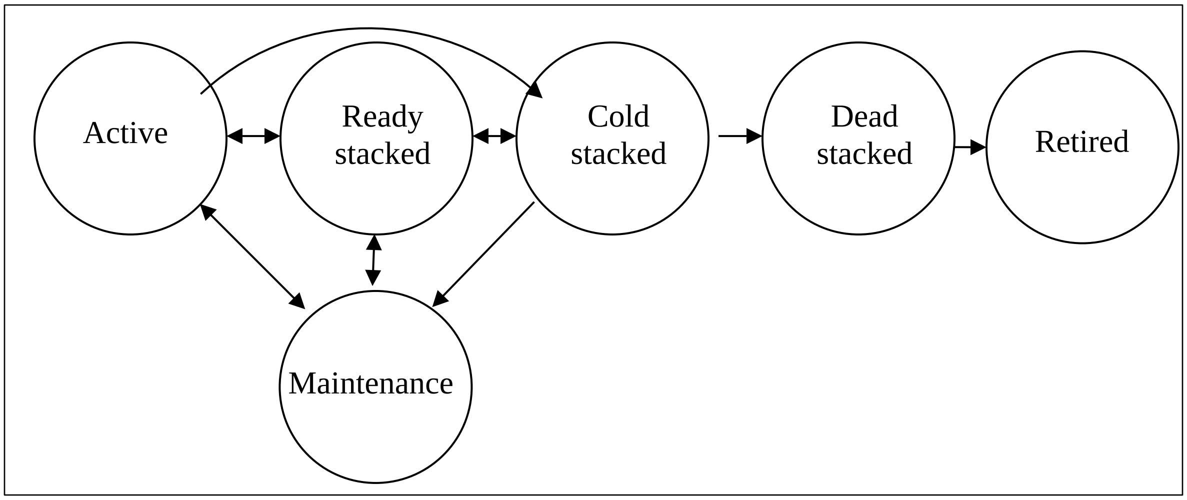


Figure A.27. Transitions among rig activity states.

Figure A.28. Four cold-stacked rigs in Sabine Pass, Louisiana.

Source: Texas General Land Office, 2008.

Figure A.29. The dead-stacked jackup rig *Zeus* being dismantled in Freeport, Texas.

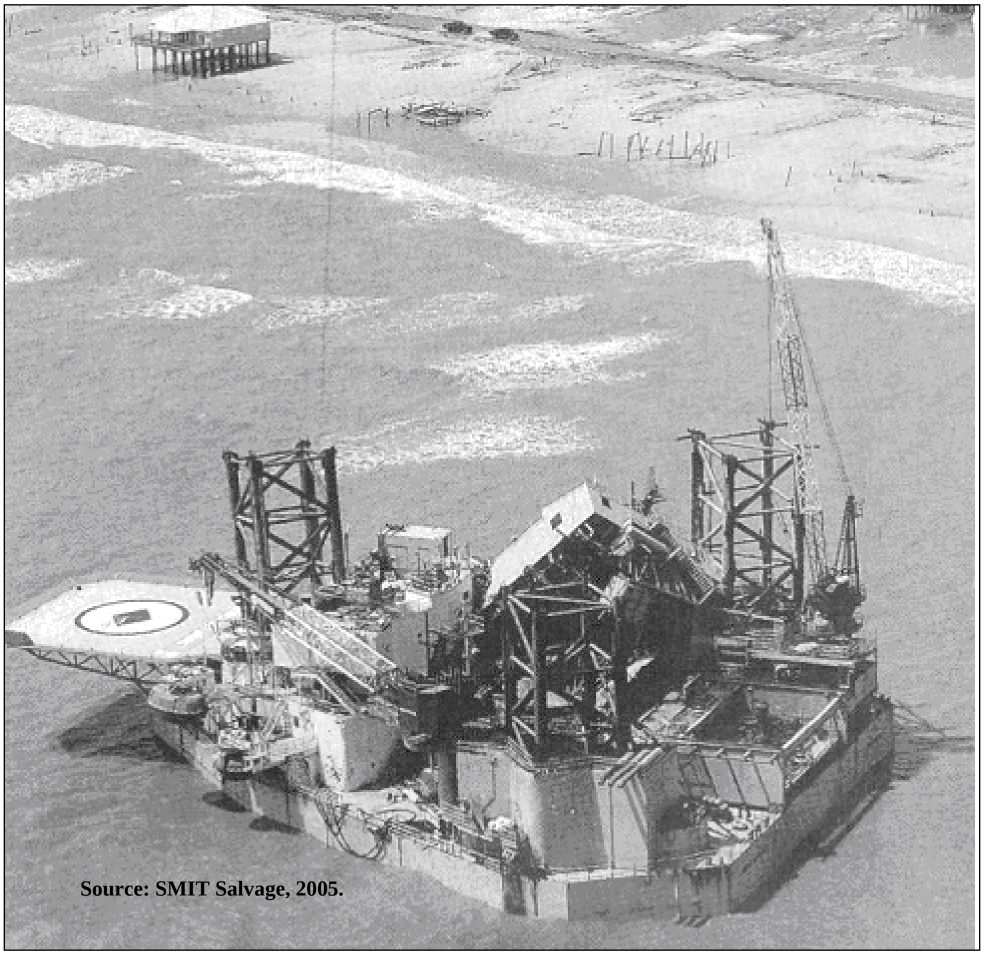


Figure A.30. *Ocean Warwick* grounded near Dauphin Island, Alabama, following Hurricane Katrina. Later rebuilt, the rig is currently operating.

APPENDIX B

CHAPTER 2 TABLES AND FIGURES

Table B.1.

Distribution of Rigs by Class and Operator, Including
Cold-Stacked Rigs and Rigs under Construction in the 1Q 2011

Company	Jackup	Drillship	Semi	Total
Transocean Ltd.	68	23	50	141
Noble Drilling	45	13	14	72
ENSCO	49	7	20	76
Diamond Offshore	13	3	32	48
Seadrill Ltd	21	6	12	39
Hercules Offshore	53	0	0	53
COSL	27	0	6	33
Rowan	31	0	0	31
Maersk Drilling	14	0	6	20
Aban Offshore	15	3	0	18
Saipem	7	2	7	16
Nabors Offshore	16	0	0	16
Atwood Oceanics	6	1	6	13
National Drilling	13	0	0	13
ONGC	8	2	0	10
Petrobras	6	0	4	10
All others (87 firms)	147	46	66	259
Top 4 firms	205	46	116	367
Top 8 firms	337	52	134	523
Total	539	106	223	868

Source: Data from RigLogix, 2011.

Table B.2.

Geographic Distribution of Active Rigs by Nation in 2011

Region	Jackups	Semis	Drillships	Total
US GOM	51	20	10	81
Persian Gulf	85	0	0	85
Brazil	3	52	15	70
North Sea	32	36	2	57
Southeast Asia	42	9	2	53
West Africa	17	13	9	39
India	34	2	9	45
China	28	4	0	32
Mexico	24	3	0	27
Egypt	20	2	2	24
Australia	1	7	1	9
Ghana	0	3	2	5
Azerbaijan	2	3	0	5
Venezuela	3	0	2	5
All others	49	20	8	77
Top 4	171	108	27	306
Top 8	292	136	47	475
Total	394	175	57	626

Source: Data from Rigzone, 2011.

Table B.3.

Contract Drilling Service Market Size in 2010

	Jackups (million $)	Floaters (million $)	Total (million $)
Persian Gulf	3,253		3,253
Southeast Asia	1,931	2,092	4,023
North Sea	1,865	6,436	8,302
India	1,263	1,369	2,632
Mexico GOM	1,075	256	1,331
West Africa	994	4,314	5,307
US GOM	983	3,781	4,765
Red Sea	511		511
Mediterranean	509	1,291	1,799
China	1,377	526	1,903
Venezuela & Caribbean	296	292	588
Brazil	72	7,615	7,688
Australia	57	1,022	1,079
Total	14,187	28,588	42,775

Source: Data from Rigzone, 2011; Authors calculations.

Table B.4.

E&P Firm Investment in Contract Drilling
Services by Region in 2010

Region	INTSOK estimate (billion $)	Author's estimate (billion $)
Brazil	9.2	7.7
Asia	8.5	8.5
North America	8.6	6.1
West Africa	8.8	5.3
North Africa and Mideast	5.2	5.5
Russia and FSU	1.8	
Australia	3.3	1.0
North Sea	3.4*	8.3
Total	48.8	42.7

Note (*): Does not include Norway
Source: Rystad Energy, 2011.

Table B.5.

Number of Newbuild Rigs on Order by Shipyard in 2011

Shipyard	Drillship	Jackup	Semisub
Daewoo	11		3
Samsung	16		2
Keppel FELS	1	17	4
*Jurong**		5	3
*PPL**		6	
Dalian		4	
ABG		4	
Hyundai	6		
Lamprell		4	
COSCO	1		3

Note: (*) Part of Sembcorp Marine.
Source: Data from RigLogix, 2011.

Table B.6.

Worldwide Distribution of MODU Construction in 2011

Country	Drillship	Semi	Jackup	Capital expenditures (million $)	Percentage (%)
South Korea	38	5	0	27,125	47.8
Singapore	2	7	33	13,402	23.6
China	3	6	9	6,979	12.3
Brazil	7	0	2	5,088	9.0
UAE	0	1	6	1,585	2.8
India	0	0	5	1,048	1.8
Vietnam	0	0	1	180	0.3
US	0	0	2	375	0.7
Russian Federation	0	0	1	100	0.2
Malaysia	0	0	1	227	0.4
Norway	0	1	0	614	1.1
Total	50	20	60	56,723	

Source: Data from RigLogix, 2011; Authors calculations.

Table B.7.

Number of Rigs Upgraded in 2009 and 2010 by Shipyard

Shipyard	Nation	2009	2010
Aker	Norway		1
Keppel	Singapore	2	2
Keppel	Netherlands	1	2
Hindustan	India		1
Keppel	Philippines		1
Lamprel	UAE	3	8
L&T	Oman		1
Keppel	Brazil	3	
Sembawang	Singapore	1	
Others		3	
TOTAL		13	16

Source: Offshore Magazine, 2009 and 2010.

Table B.8.

Examples of Jackup Rig Upgrade Contracts

Customer	Shipyard	Year	Cost (million $)	Scope
ENSCO	Lamprell	2008	14.8	Steel renewal, leg repairs, accommodation upgrade, piping renewal, painting
Aban Offshore	ABG	2011	13.2	Painting, steel renewal, replacement of equipment
Gulf Drilling	Keppel-Qatar	2011	16.2	Major upgrade
National Drilling	Drydocks World	2010	20	Life extension
Millennium Offshore	Lamprell	2011	27.5	Conversion to accommodation unit
GSP	Lamprell	2010	12	Upgrade electrical, drilling equipment, accommodation refurbishment
Japan Drilling	Lamprell	2010	11.8	Three month refurbishment

Source: Industry press.

Table B.9.

Examples of Semisubmersible Rig Upgrade Contracts

Customer	Shipyard	Year	Cost (million $)	Scope
Transocean	Semco	2011	20	Piping installation
Diamond Offshore	Keppel AmFELS	2012	300	Complete rebuild
Noble	Signal	2010	15	Addition of helideck, quarters upgrade, structural modifications
Awilco	Remontowa	2010	75	Increase variable load, new accommodations, power supply
Diamond	Keppel	2008	310	Complete rebuild
Fred Olsen		2010	160	Survey, renewal and upgrade
Awilco	Remontowa	2010	15	Survey

Source: Industry press.

Table B.10.

Examples of Drillship Upgrade Contracts

Customer	Shipyard	Year	Cost (million $)	Scope
Transocean	Signal	2010	32.4	Living quarters upgrade, equipment replacement, painting, hull and tank repair
Noble	Keppel Brazil	2010	152	Replacement of accommodations and heliport; modifications to stern
Neptune Marine	Sembawang	2009	340	Increase water depth capacity, add dynamic positioning, upgrade drilling equipment

Source: Industry press.

Table B.11.

Number of Major Upgrades by Year and Estimated Market Value, 2001-2010

	Jackups	Floaters	Total	Market value ($ billion)
2001	8	7	15	0.6-1.9
2002	32	10	42	1.0-3.3
2003	15	12	27	1.0-3.3
2004	22	15	37	1.3-4.3
2005	9		9	0.1-0.2
2006	13	20	33	1.6-5.3
2007	36	29	65	2.5-8.1
2008	18	18	36	1.5-4.9
2009	9	4	13	0.4-1.2
2010	11	5	16	0.5-1.5
Total	172	115	287	10.1-34.3

Source: Offshore Magazine, 2001-2010.

Table B.12.

Number of Transactions in the Secondhand Market by Firm, 2005-2010

Firm	Buyer	Seller
Hercules	7	4
Seadrill	8	3
Transocean		10
Songa	4	4
Noble	6	
ENSCO	1	4
Rowan	3	2
Diamond	1	4
Maersk	2	3
Aban	3	1
Saipem	4	

Source: Data from RigLogix, 2011.

Table B.13.

Average and Range of Prices in the Secondhand Market, 2005-2010

Year	Jackups ($ million)	Floaters ($ million)
2005	42 (22–60)[a]	37 (13–60)
2006	67 (17–210)	102 (14–270)
2007	148 (26–212)	321 (211–675)
2008	106 (9–200)	294 (5–676)
2009	84 (5–199)	475 (460–490)
2010	188 (26–356)	288 (102–560)

Source: RigLogix, 2011.
Note: (a) Price range shown in parentheses.

Table B.14.

Transactions and Market Valuation in the Secondhand Market, 2005-2010

Year	Jackups	Drillships	Semis	Total	Market value ($ billion)
2005	9	1	5	15	0.5
2006	20	1	10	31	2.1
2007	13	3	6	22	3.7
2008	10	1	3	14	2.2
2009	10	0	3	13	2.0
2010	20	7	4	31	6.8
Total	82	13	31	126	17.3

Source: Data from RigLogix, 2011; Authors Calculations.

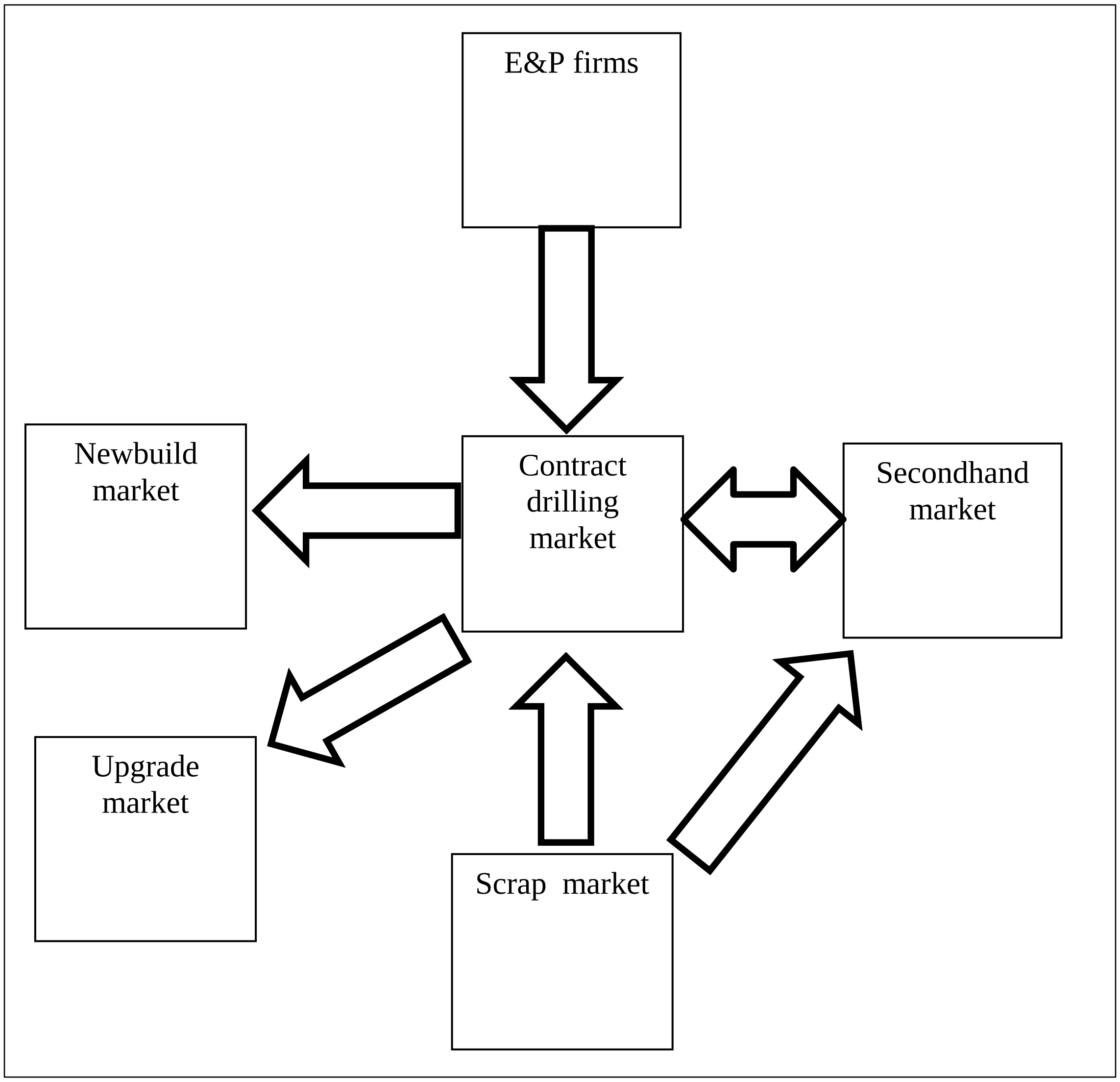
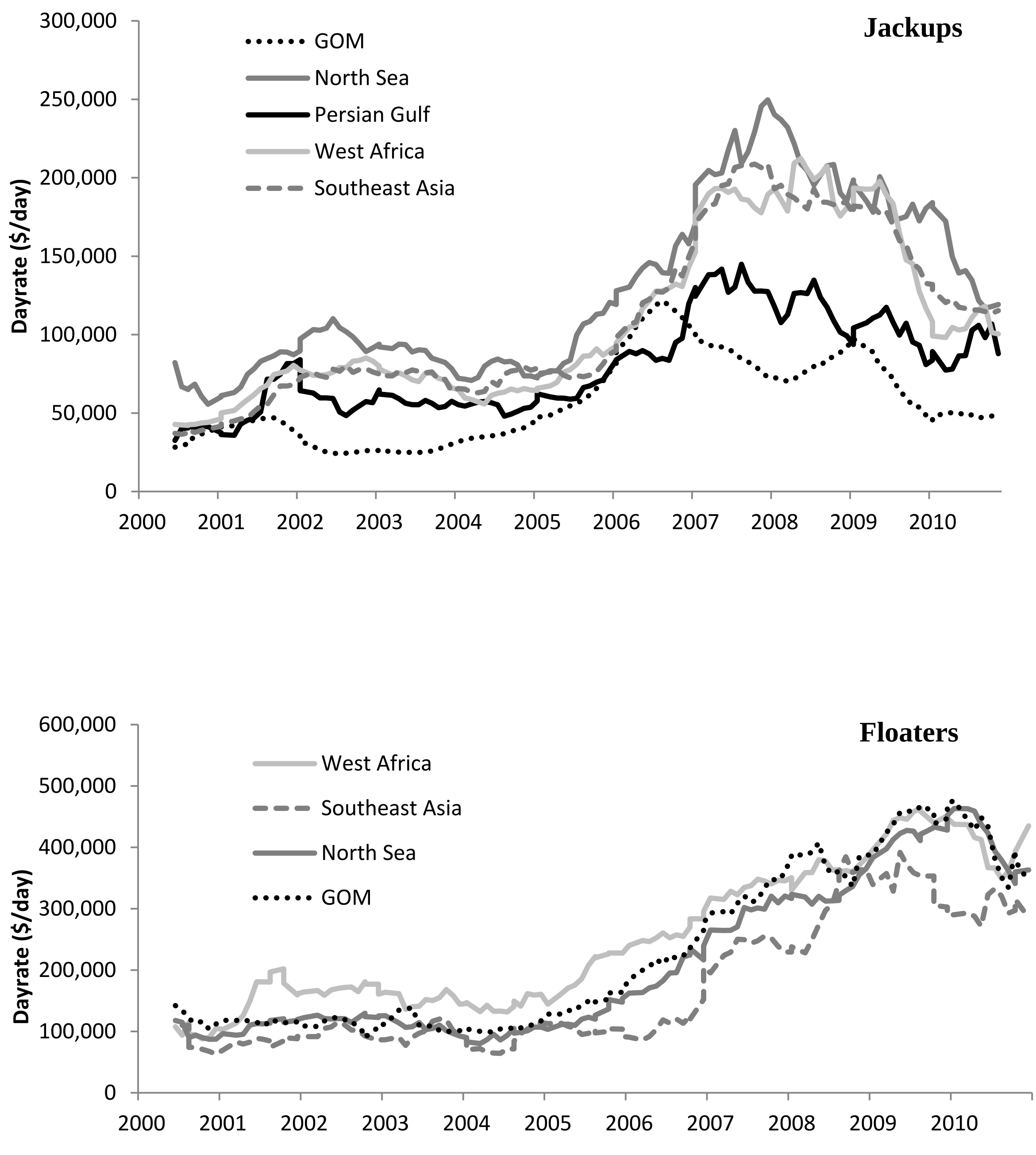
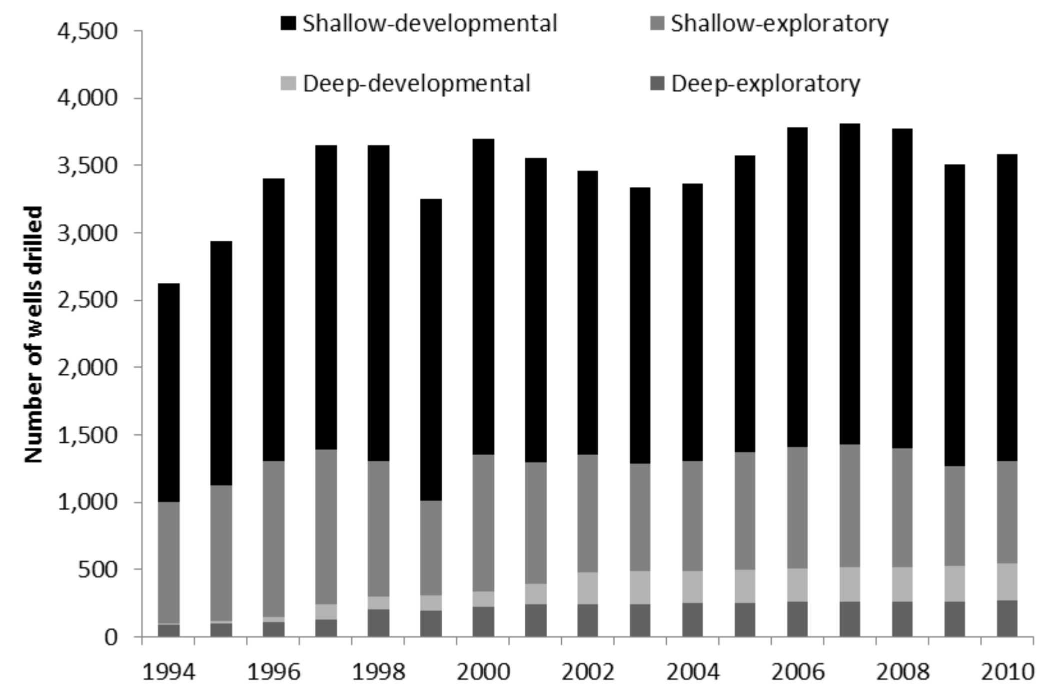


Figure B.1. Direction of cash flow through offshore rig markets.



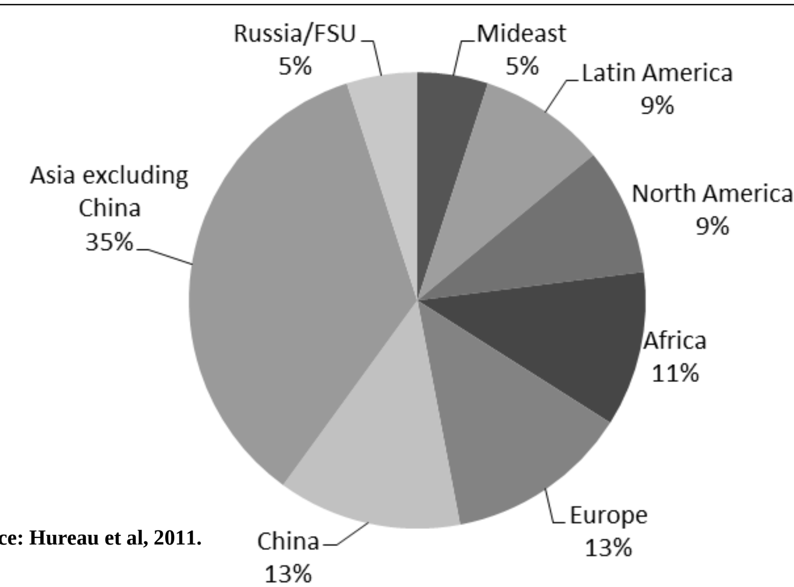
Source: Data from RigLogix, 2011.

Figure B.2. Six month moving average of regional jackup and floater dayrates, 2000-2011.



Source: Douglas-Westwood, 2009.

Figure B.3. Number of wells drilled per year, 1994-2010.



Source: Hureau et al, 2011.

Figure B.4. Geographic distribution of the number of offshore wells drilled in 2011.

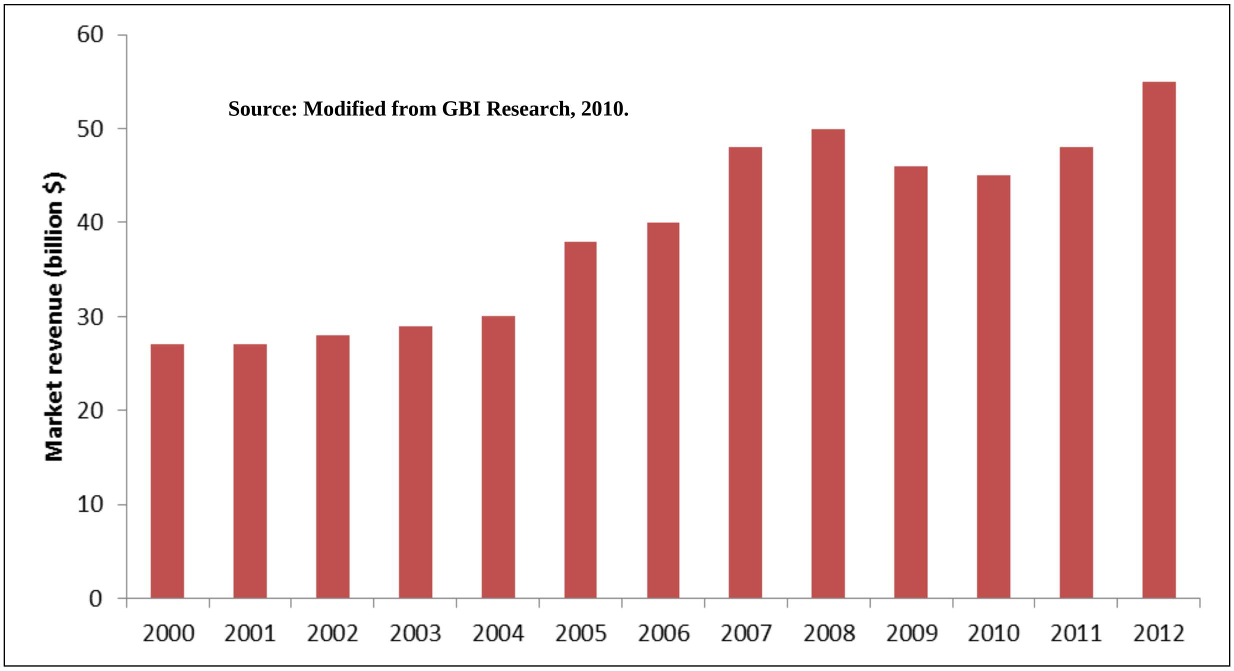
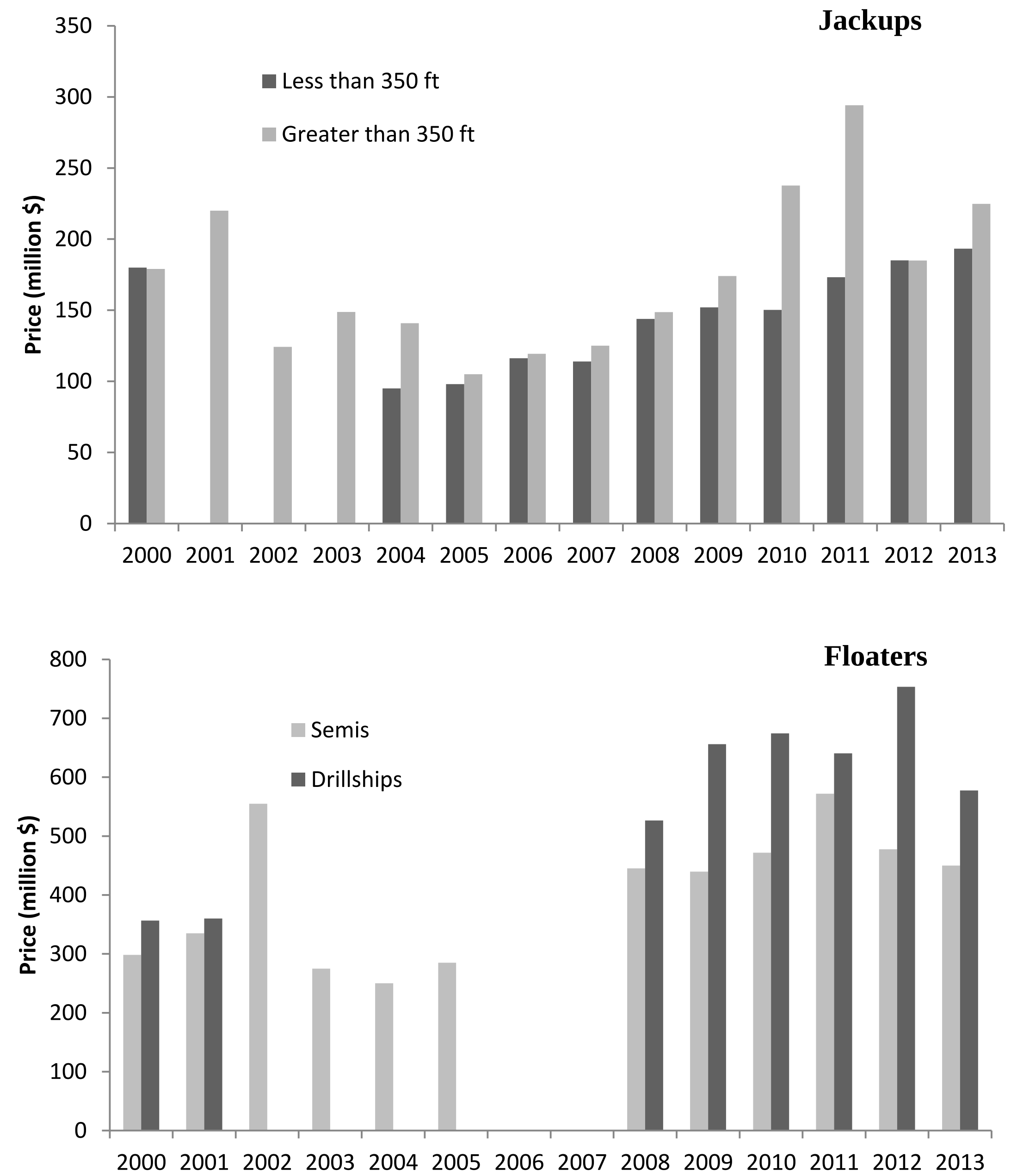


Figure B.5. Annual revenue of the offshore contract drilling market, 2000–2012.



Source: Data from RigLogix, 2011.

Figure B.6. Average cost of jackup and floater deliveries by water depth, 2000–2013.

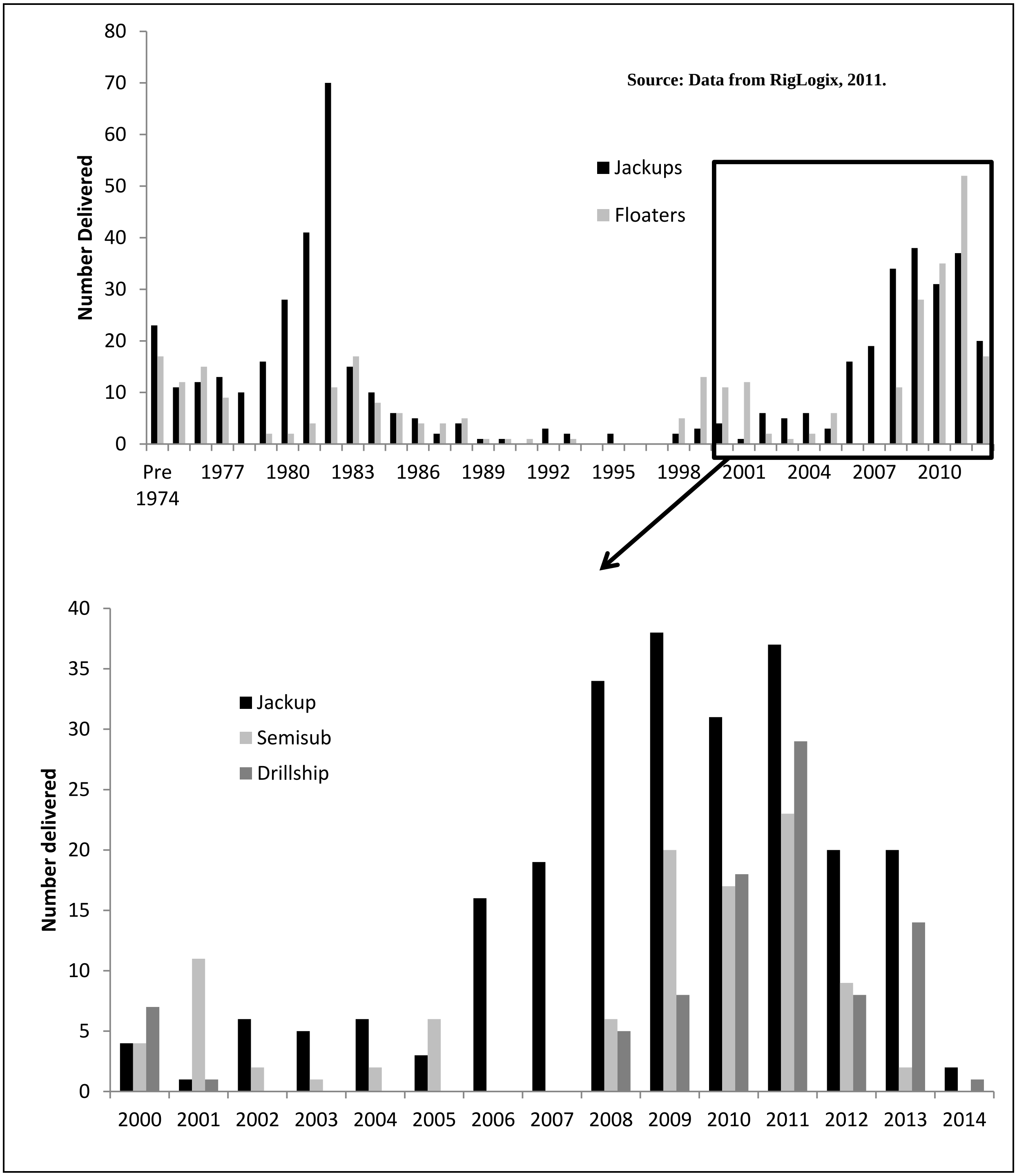


Figure B.7. Deliveries of newbuild rigs by class, 1974–2014.

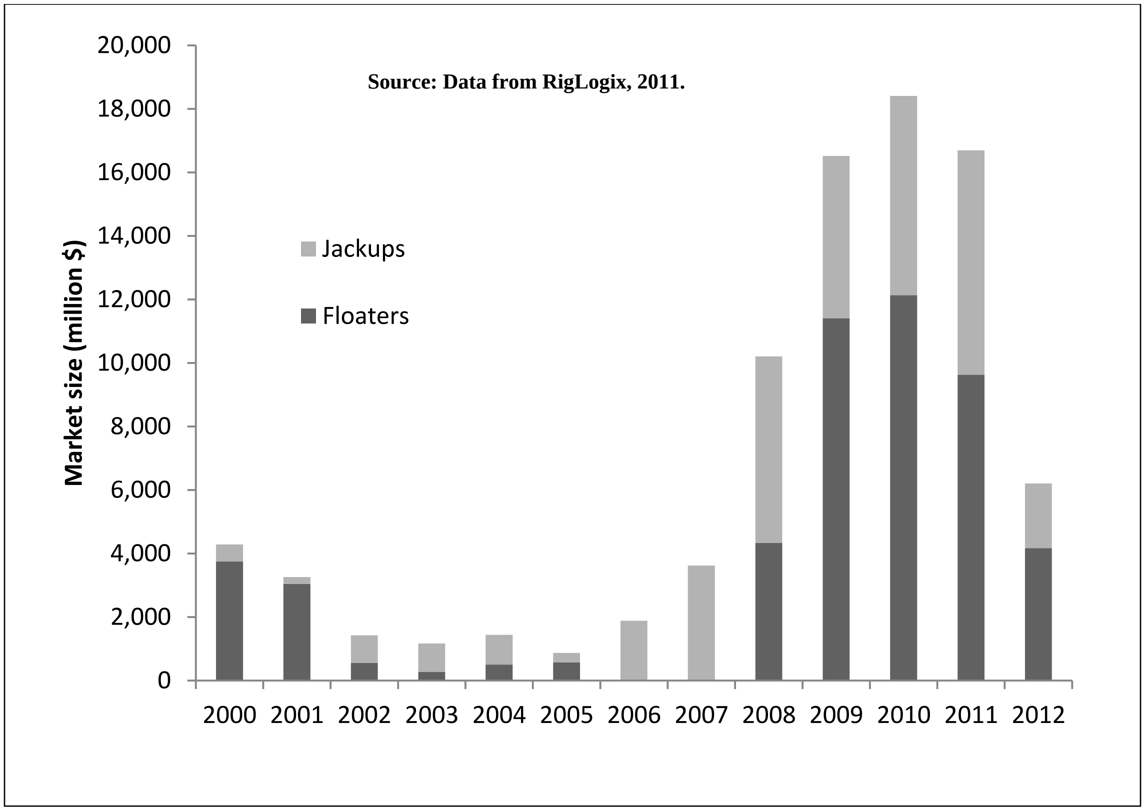


Figure B.8. Newbuild market size, 2000–2012.

APPENDIX C

CHAPTER 3 TABLES AND FIGURES

Table C.1.

Distribution of Active Rigs by Nation in 2011

Country	Jackups	Semis	Drillships	Total	Region
US	51	20	10	81	US GOM
Brazil	3	52	15	70	Brazil
India	34	2	9	45	India
China	28	4	0	32	China
Norway	7	22	1	30	North Sea
UK	12	14	1	27	North Sea
Mexico	24	3	0	27	Mexican GOM
Egypt	20	2	2	24	Red Sea/Mediterranean
UAE	24	0	0	24	Persian Gulf
Saudi Arabia	23	0	0	23	Persian Gulf
Iran	20	1	0	21	Persian Gulf
Qatar	20	0	0	20	Persian Gulf
Malaysia	12	6	1	19	Southeast Asia
Nigeria	9	4	4	17	West Africa
Angola	4	7	5	16	West Africa
Vietnam	13	2	0	15	Southeast Asia
Indonesia	11	1	1	13	Southeast Asia
Singapore	2	6	3	11	Southeast Asia
Australia	1	7	1	9	Australia
Netherlands	8	0	0	8	North Sea
Gabon	4	2	0	6	West Africa
Thailand	6	0	0	6	Southeast Asia
Ghana	0	3	2	5	West Africa
Azerbaijan	2	3	0	5	Caspian Sea
Denmark	5	0	0	5	North Sea
Venezuela	3	0	2	5	Caribbean
All others	45	14	5	64	
Total	394	175	57	626	

Source: RigLogix, 2011.

Table C.2.

Major Features of Offshore Regions

Region	2010 Production (million BOE/day)	Features
West Africa[a]	3.9	Nations vary in maturity with Nigeria well developed and Cameroon and Ghana frontier regions. Nearly all production is from Nigeria and Angola; growth is in the deepwater market, especially in Angola, but the shallow water market accounts for most production. IOCs are major E&P players.
China	1.0	CNOOC and subsidiary COSL are the major players. Major development began in the 1980's and 1990's and investment has increased from $3.4 billion in 2005 to $12.5 billion in 2011. Offshore activity accounts for 20% of national production.
India	1.1	Growing market with a strong gas sector. Offshore accounts for two-thirds of national production. The NOC ONGC and public firm Reliance are major E&P players.
Southeast Asia[b]	3.1	Strong shallow and deepwater segments. Subject to typhoons. Rig count has approximately doubled since 1990. Offshore production accounts for half of production in Indonesia and over 90% of production in Malaysia.
North Sea[c]	6.1	Mature region with harsh and moderate conditions. There has been a modest decline in rig count since 2000. Statoil and IOCs are major E&P players.
Persian Gulf[d]	6.7	NOCs are primary players. Between 1990 and 2010 rig count increased fourfold from approximately 20 to 80.
Mexico GOM	2.5	Primarily a shallow water market with little deepwater activity. Developed rapidly in the early 1990's and again in the early 2000's. Offshore production in decline. Deepwater exploration slated for 2011.
US GOM	2.7	Mature offshore region. Shallow water region in decline; deepwater market growing. Accounted for 15% of total oil production in 2011. Periodically severely impacted by hurricanes.
Brazil	2.1	Large deepwater market with little shallow water activity. Offshore accounts for 90% of national production. Growth in production due to pre-salt discoveries. Petrobras is the NOC and major E&P player.

Source: Rystad Energy, 2011.
Note: (a) Composed of Nigeria, Angola, Cameroon, Ghana, Gabon, and Equatorial Guinea.
(b) Composed primarily of Indonesia (33% of production) and Malaysia (65% of production); Vietnam and the Philippines are emerging markets.
(c) Dominated by UK and Norway with minor activity in the Netherlands, Germany and Denmark.
(d) Includes Saudi Arabia, Kuwait, Qatar, UAE, Bahrain and Iran.

Table C.3.

Average Water Depth of Rig Contracts, 2000–2010

	Jackups (ft)				Floaters (ft)			
	Average	Standard deviation	Min	Max	Average	Standard deviation	Min	Max
West Africa	125	84	17	397	3,372	1,888	118	9,325
China	85	42	20	300	1,112	1,599	75	6,709
India	187	80	9	352	3,270	2,694	135	9,678
Southeast Asia	170	71	15	531	2,006	2,041	55	7,732
North Sea	165	77	24	426	786	718	87	5,354
Persian Gulf	113	65	8	307				
Mexico GOM	138	66	32	305	1,096	1,341	145	5,741
US GOM	106	79	6	485	3,540	2,288	30	10,139
Brazil					3,437	1,930	30	9,370
World	119	82	6	531	2,674	2,195	30	10,139

Source: Data from RigLogix, 2011.

Table C.4.

Active and Ready-Stacked Rigs by Market in 2011

		Jackups (ft)		Floaters (ft)	
	Environment	<300	>300	<7,500	>7,500
North Sea	Moderate	10	6	15	2
	Harsh	0	20	17	4
Persian Gulf	Moderate	43	52	0	0
	Harsh	0	3	0	0
West Africa	Moderate	6	13	12	10
	Harsh	1	2	4	4
India	Moderate	6	28	6	5
	Harsh	0	0	0	0
US GOM	Moderate	33	17	8	22
	Harsh	0	2	0	1
Brazil	Moderate	4	3	40	13
	Harsh	0	0	6	5
China	Moderate	17	12	3	0
	Harsh	0	0	0	1
Southeast Asia	Moderate	2	48	16	6
	Harsh	0	0	2	1
Mexico	Moderate	9	14	1	1
	Harsh	0	1	0	1
All others	Moderate	20	26	14	10
	Harsh	1	5	7	3
Total	Moderate	150	219	115	69
	Harsh	2	33	36	20

Source: RigLogix 2011.

Table C.5.

Relationships between the Number of Active and Contracted Rigs, 1999–2011

Region	Correlation coefficient	Average proportion (%) of contracted rigs that are active
US GOM	0.95	82
Southeast Asia	0.65	75
Africa	-0.27	44
Persian Gulf	0.43	40
North Sea	0.49	71

Source: Data from RigLogix, 2011; Baker Hughes 2012.

Table C.6.

Average Utilization Rates by Region, 2000–2010

	Jackups (%)			Floaters (%)		
	2000–2006	2006–2010	2000–2010	2000–2006	2006–2010	2000–2010
West Africa	84	81	83	82	90	86
Southeast Asia	86	81	84	57	50	54
North Sea	89	91	90	73	91	82
Persian Gulf	85	82	84			
US GOM	74	55	65	69	82	76

Source: Data from RigLogix, 2011.

Table C.7.

Jackup Utilization Regional Correlation Matrix, 2000–2010

	US GOM	West Africa	Southeast Asia	North Sea	Persian Gulf
US GOM	1				
West Africa	0.50	1			
Southeast Asia	0.55	0.84	1		
North Sea	0.37	0.70	0.71	1	
Persian Gulf	0.33	0.73	0.83	0.56	1
Average	0.44	0.70	0.73	0.59	0.61

Source: Data from RigLogix, 2011.

Table C.8.

Floater Utilization Regional Correlation Matrix, 2000–2010

	US GOM	West Africa	Southeast Asia	North Sea	Brazil
US GOM	1				
West Africa	0.62	1			
Southeast Asia	-0.14	0.15	1		
North Sea	0.82	0.66	-0.14	1	
Brazil	0.68	0.39	-0.05	0.82	1
Average	0.50	0.46	-0.05	0.54	0.46

Source: Data from RigLogix, 2011.

Table C.9.

Average Dayrates by Region between 2000–2006 and 2006–2010

	Jackups			Floaters		
	2000–2006 ($/day)	2006–2010 ($/day)	Change	2000–2006 ($/day)	2006–2010 ($/day)	Change
West Africa	69,379	154,488	123%	163,534	374,130	129%
Southeast Asia	67,846	159,731	135%	92,229	278,060	201%
North Sea	86,927	180,657	108%	113,330	337,589	198%
Persian Gulf	58,126	106,541	83%			
US GOM	48,776	81,865	68%	122,530	361,995	195%

Source: Data from RigLogix 2011.

Table C.10.

Jackup Dayrate Regional Correlation Matrix, 2000–2010

	US GOM	North Sea	Persian Gulf	West Africa	Southeast Asia
US GOM	1				
North Sea	0.49	1			
Persian Gulf	0.51	0.64	1		
West Africa	0.54	0.73	0.72	1	
Southeast Asia	0.58	0.78	0.77	0.90	1
Average	0.53	0.66	0.66	0.72	0.76

Source: Data from RigLogix, 2011.

Table C.11.

Floater Dayrate Regional Correlation Matrix, 2000–2010

	US GOM	North Sea	West Africa	Southeast Asia
US GOM	1			
North Sea	0.88	1		
West Africa	0.84	0.87	1	
Southeast Asia	0.77	0.79	0.77	1
Average	0.83	0.85	0.83	0.78

Source: Data from RigLogix, 2011.

Table C.12.

Quarterly Volatility in the Shallow and Deepwater Markets, 2000–2010

	Shallow (%)	Deepwater (%)
West Africa	15.7	28.7
Southeast Asia	12.6	37.5
US GOM	15.0	17.2
North Sea	18.3	18.2
Persian Gulf	23.4	
Average	17.0	25.4

Source: Data from RigLogix, 2011.
Note: Volatility is defined as the standard deviation of the percent change in dayrates between quarters.

Table C.13.

Contract Type by Rig Market and Region, 2000–2010

	Shallow water		Deepwater	
	Fixed well (%)	Term (%)	Fixed well (%)	Term (%)
West Africa	39	61	38	62
Southeast Asia	40	60	64	36
US GOM	76	24	45	55
Persian Gulf	22	78		
North Sea	47	53	40	60
World	52	48	43	57

Source: Data from RigLogix, 2011.

Table C.14.

Average Contract Duration in Days, 2000–2010

	West Africa	Persian Gulf	Southeast Asia	North Sea	US GOM	All regions
Jackups	260	511	248	190	77	148
Floaters	261		213	233	173	212

Source: Data from RigLogix, 2011.

Table C.15.

Largest E&P Customers by Region, 2000–2010

	Region	First	Second	Third	Fourth	Top four
Jackups	US GOM	Chevron (8)	Apache (6)	BP (4)	ADTI (3)	21
	North Sea	Maersk (18)	Shell (9)	Conoco (9)	BP (6)	43
	Southeast Asia	Petronas (12)	Shell (11)	Total (7)	Chevron (6)	37
	Persian Gulf	Saudi Aramco (22)	ADMA (9)	Rasgas (6)	Maersk (5)	43
	West Africa	Chevron (29)	Exxon (18)	Total (11)	Addax (6)	65
Floaters	US GOM	BP (16)	Shell (10)	Anadarko (9)	Chevron (6)	40
	North Sea	Statoil (30)	Shell (11)	Norsk Hydro (10)	BP (7)	58
	Southeast Asia	Shell (18)	Petronas (12)	Exxon (8)	Murphy (8)	46
	West Africa	Total (23)	Exxon (16)	Chevron (10)	Shell (5)	55

Note: Market share as a percent of total contracted days in parenthesis.

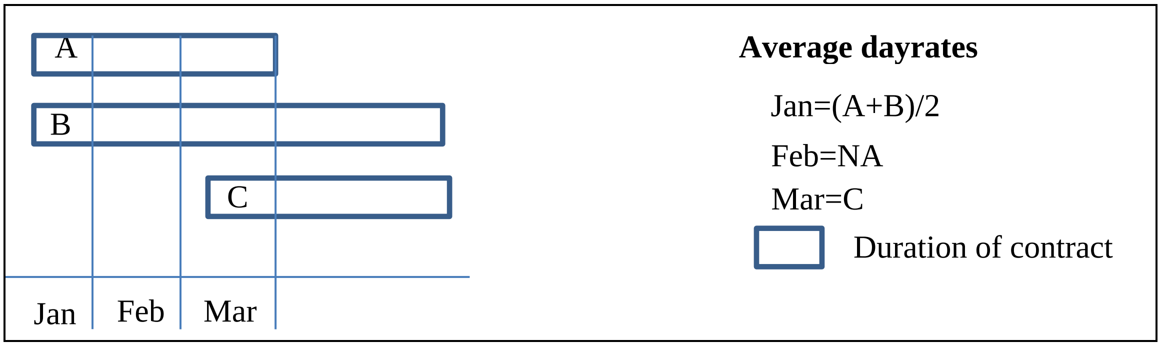
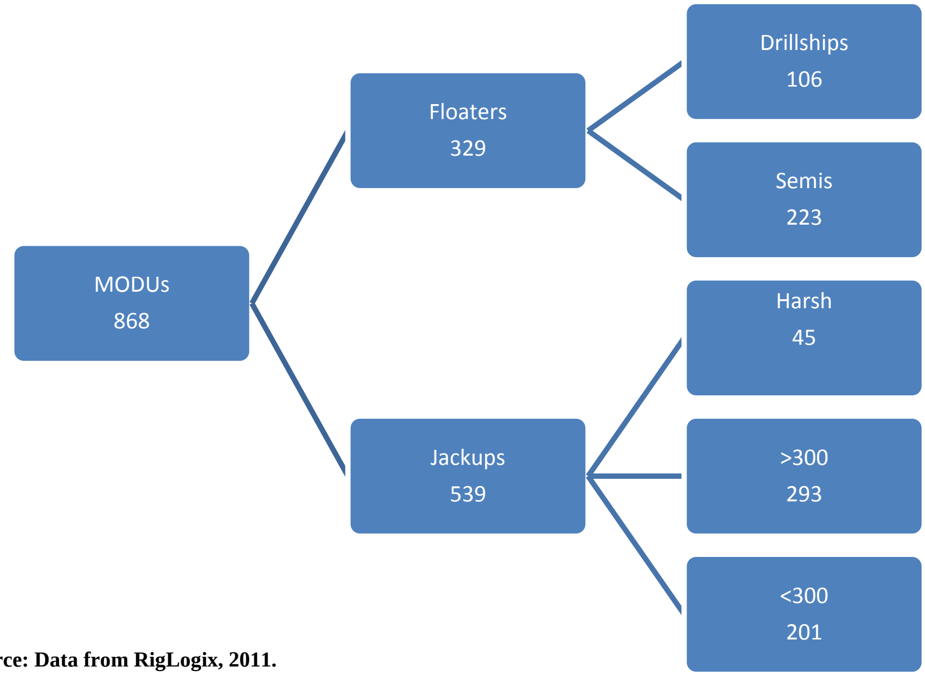


Figure C.1. Illustration of the method used for averaging dayrates.



Source: Data from RigLogix, 2011.

Figure C.2. Global supply of newbuild and existing MODUs in the 1Q 2012.

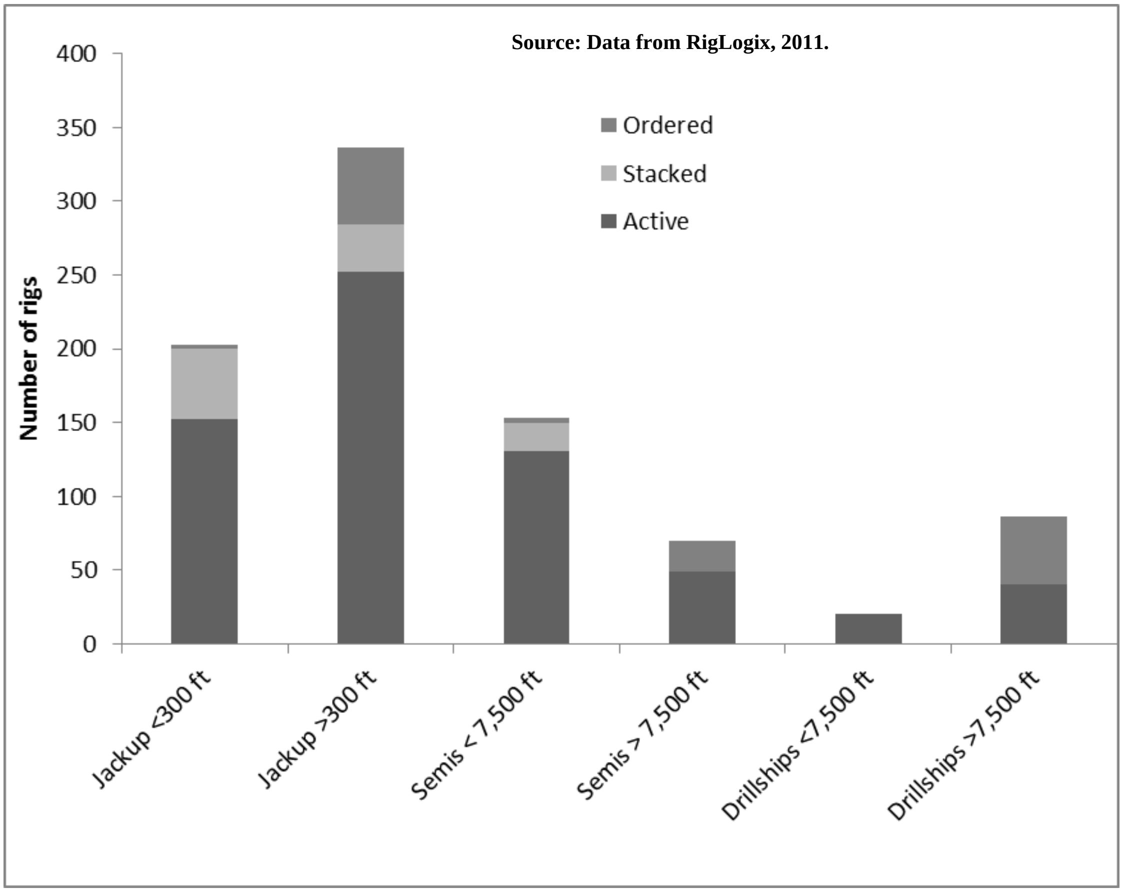


Figure C.3. Global supply of MODUs in the 1Q 2012.

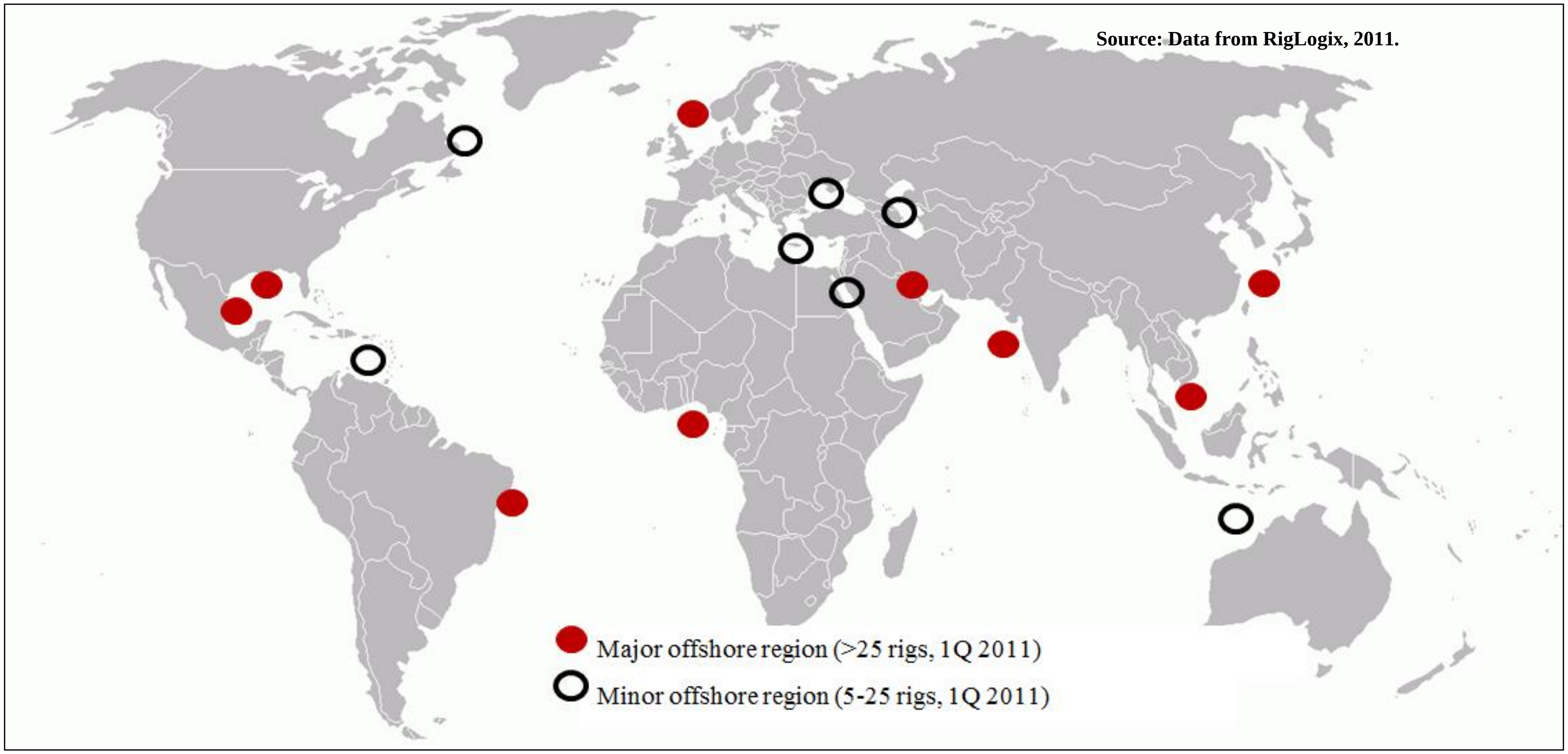


Figure C.4. Offshore drilling regions and 1Q 2011 drilling activity.

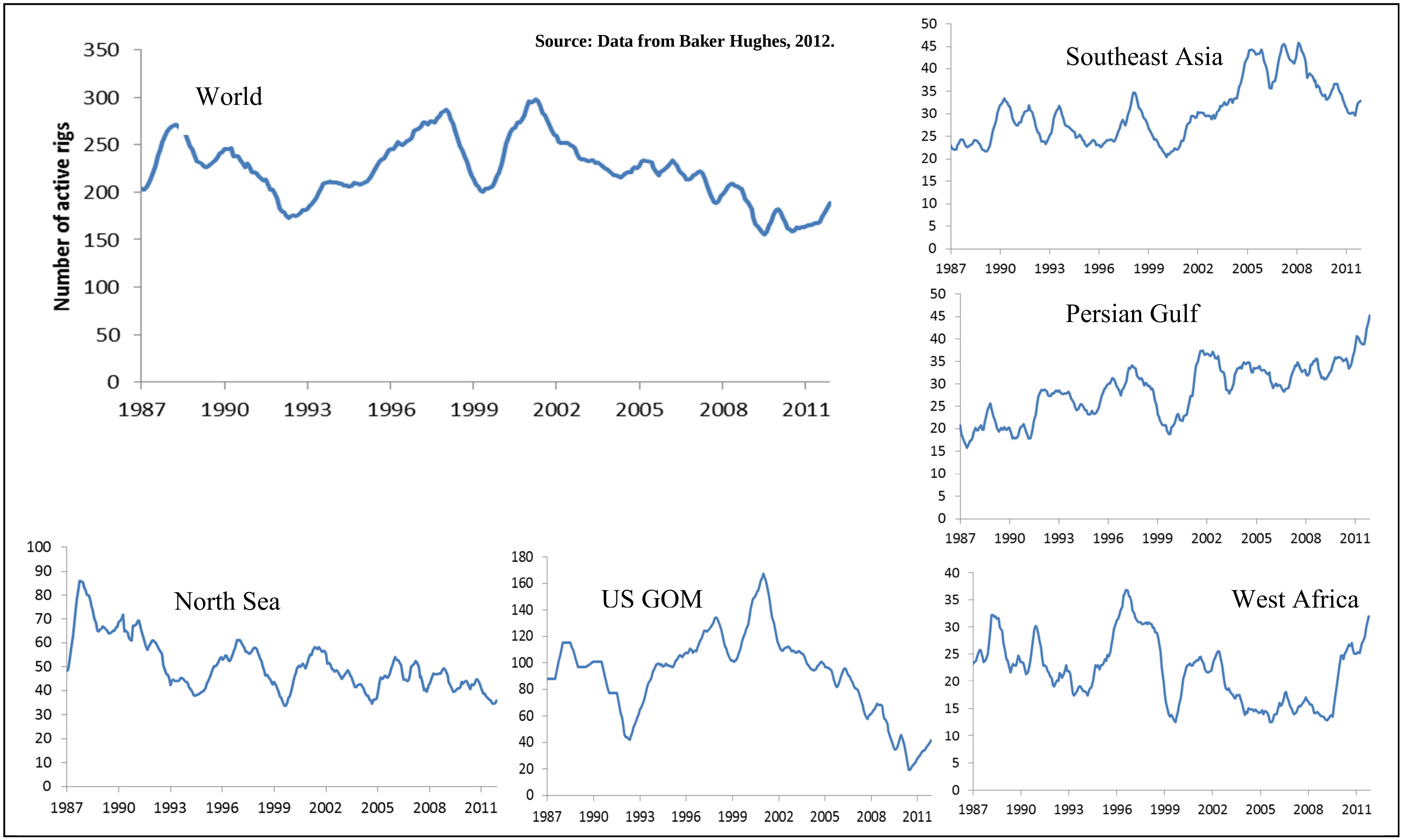


Figure C.5. Number of active rigs by region, 1987–2012.

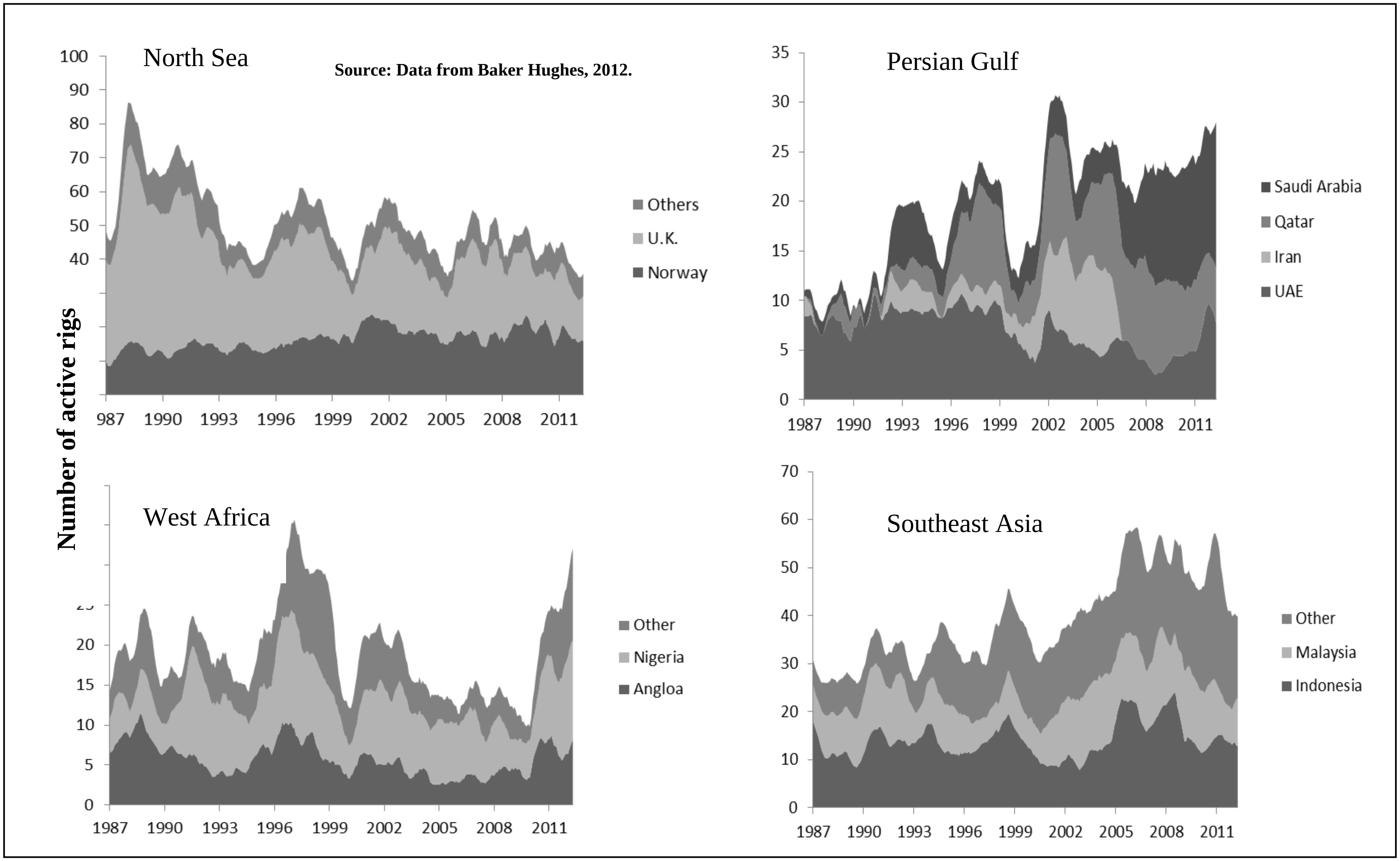


Figure C.6. National distribution of active rigs within regions, 1987–2012.

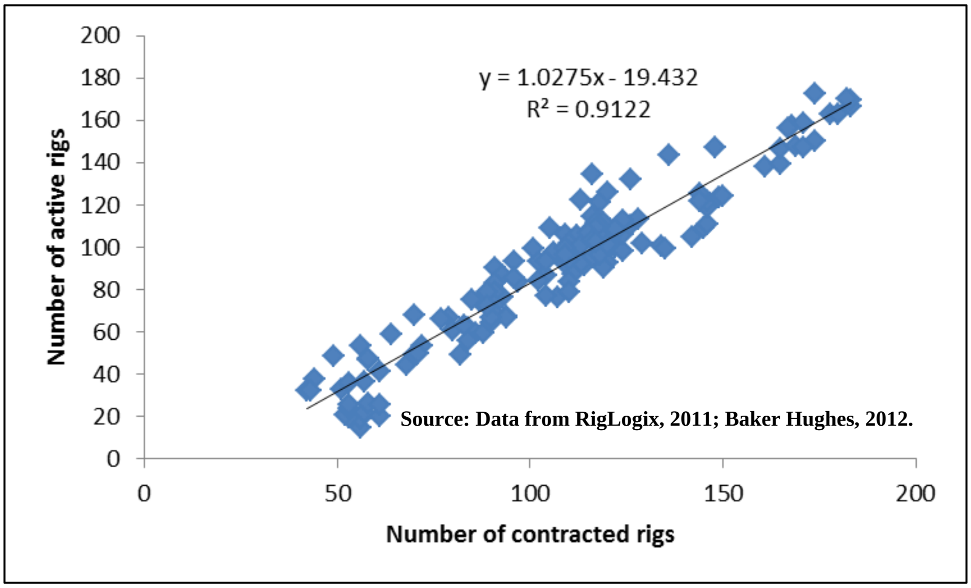


Figure C.7. Relationship between the number of contracted jackups and the number of active rigs in the U.S. GOM by month, 1999–2011.

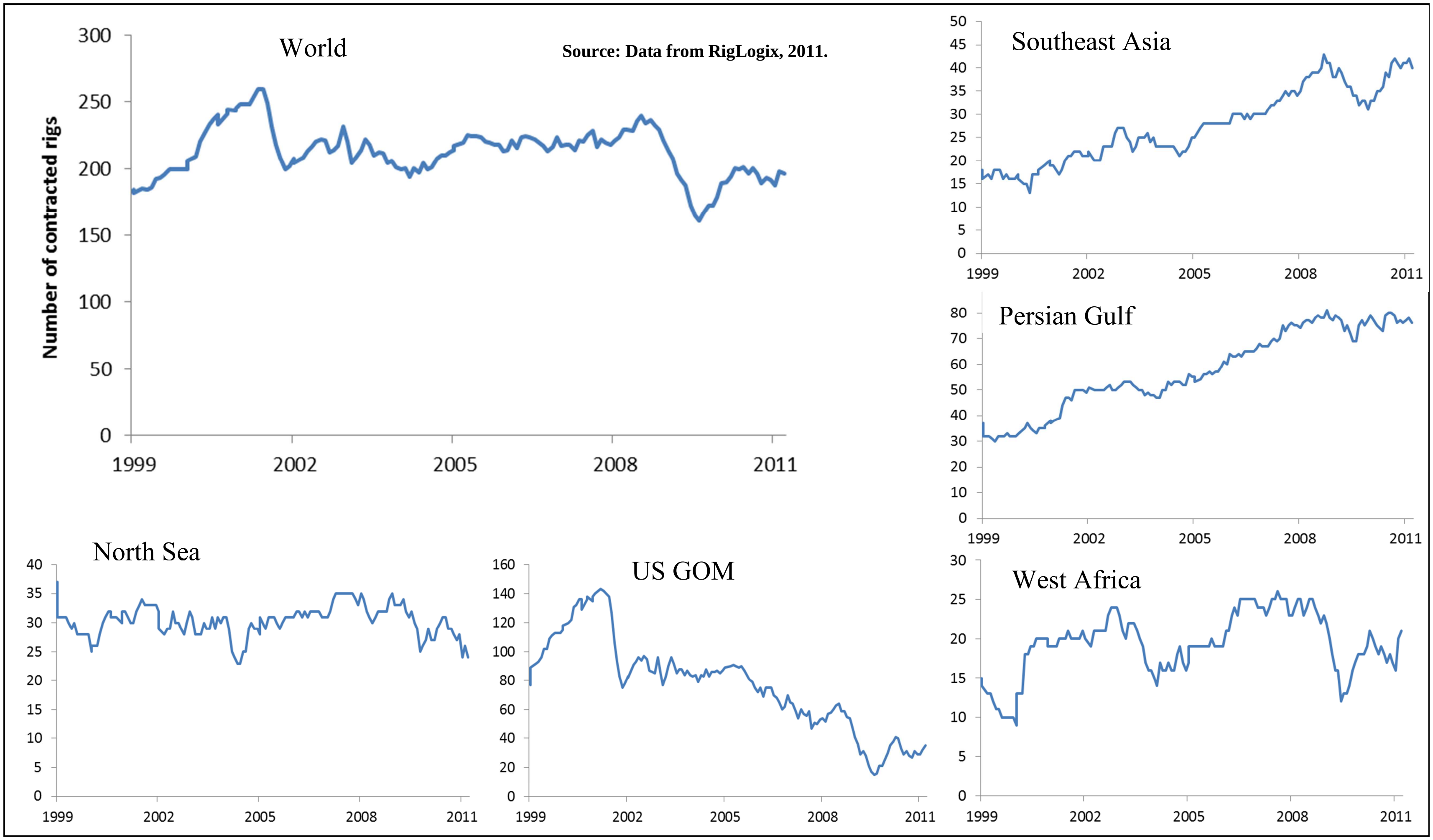


Figure C.8. Number of contracted jackups by region, 1999–2012.

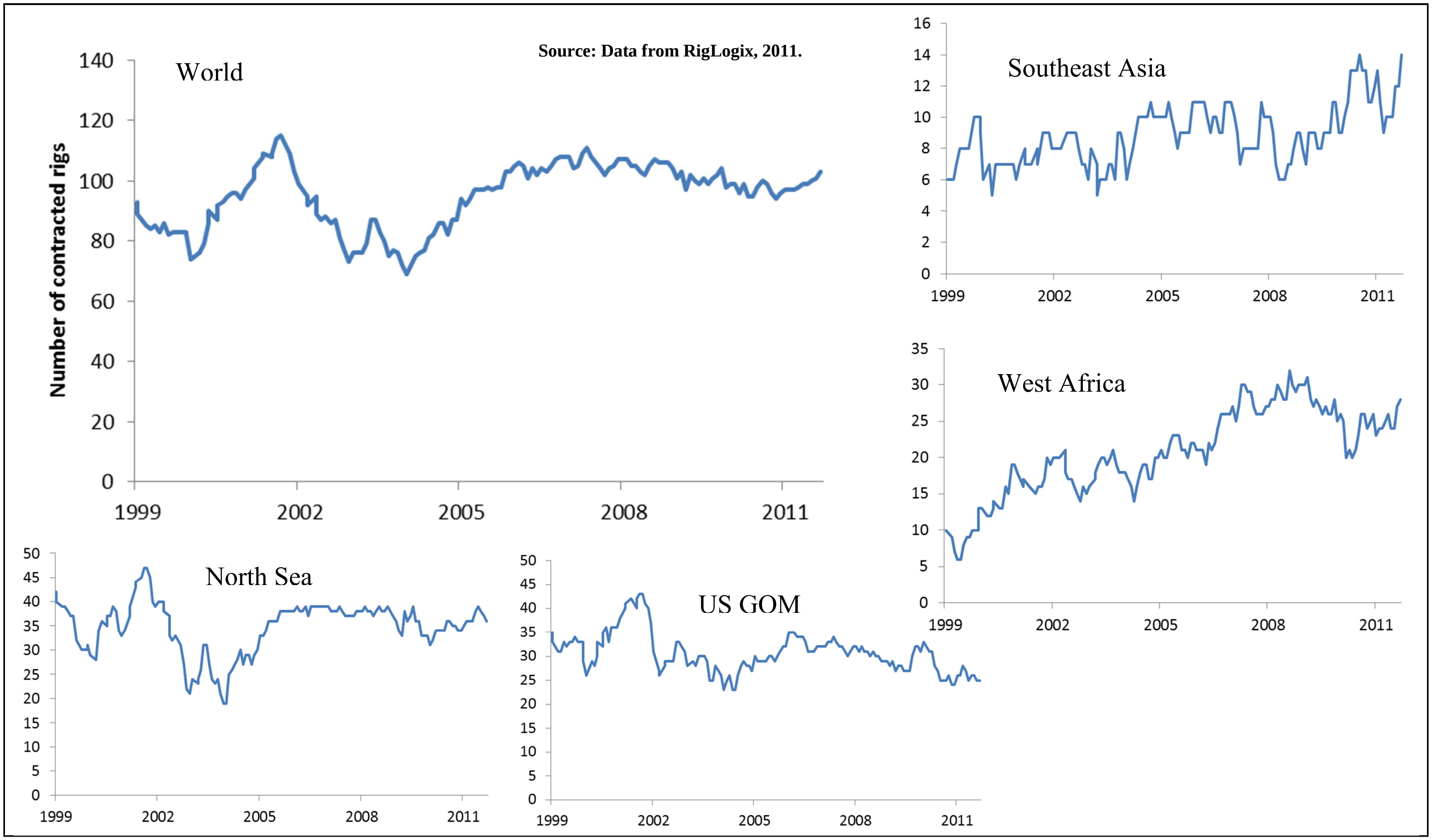


Figure C.9. Number of contracted floaters by region, 1999–2012.

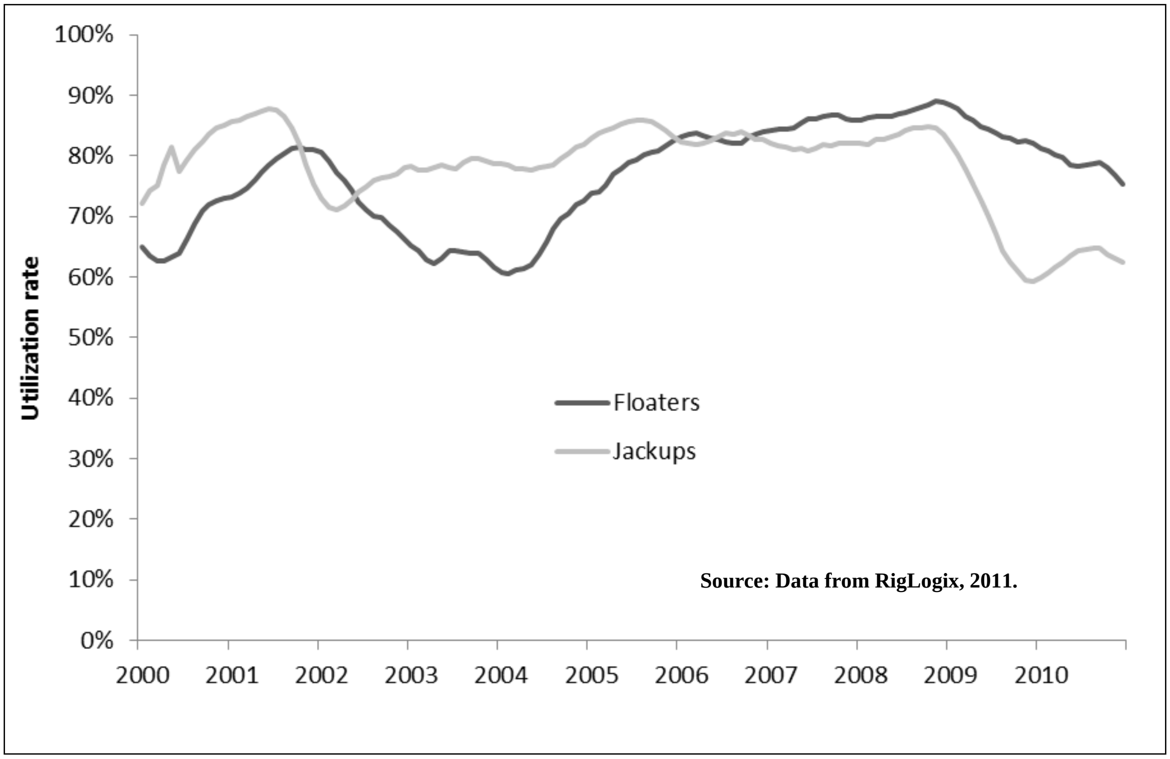
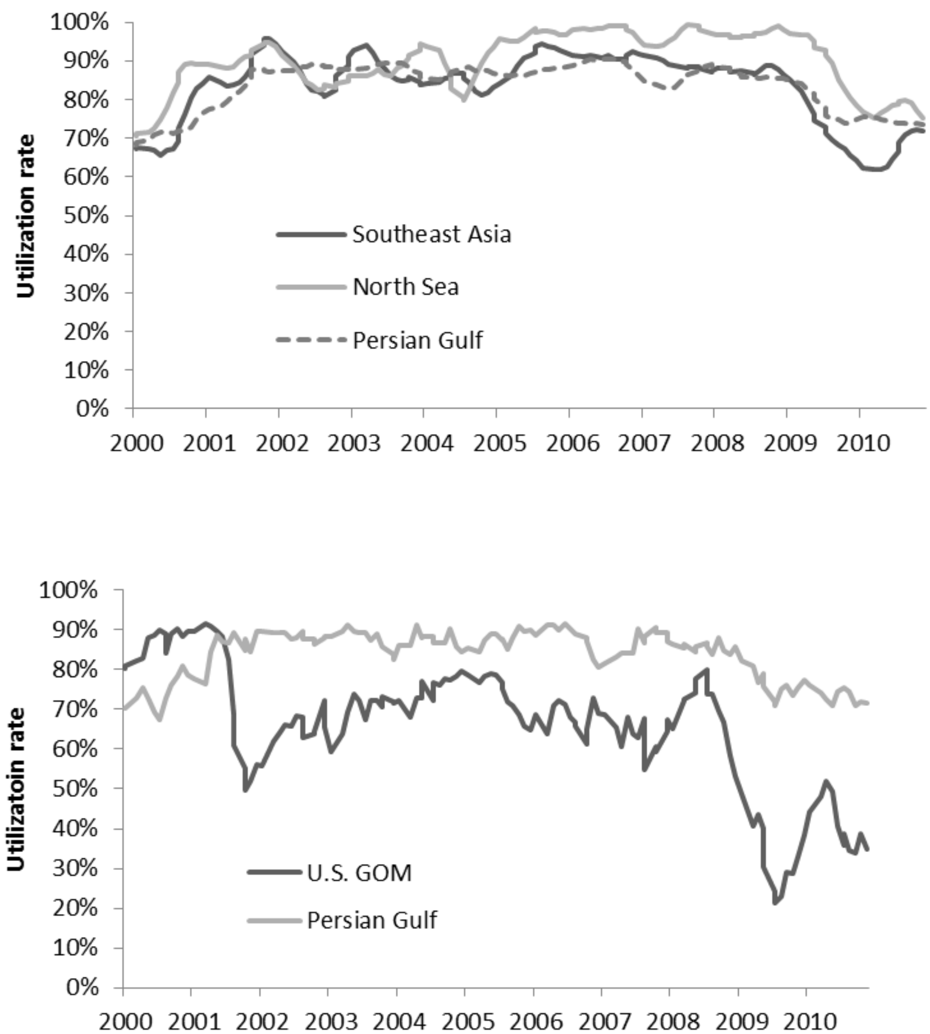


Figure C.10. Six month moving average of world utilization rates, 2000–2011.



Source: Data from RigLogix, 2011.

Figure C.11. Six month moving average of jackup utilization rates in selected regions, 2000–2011.

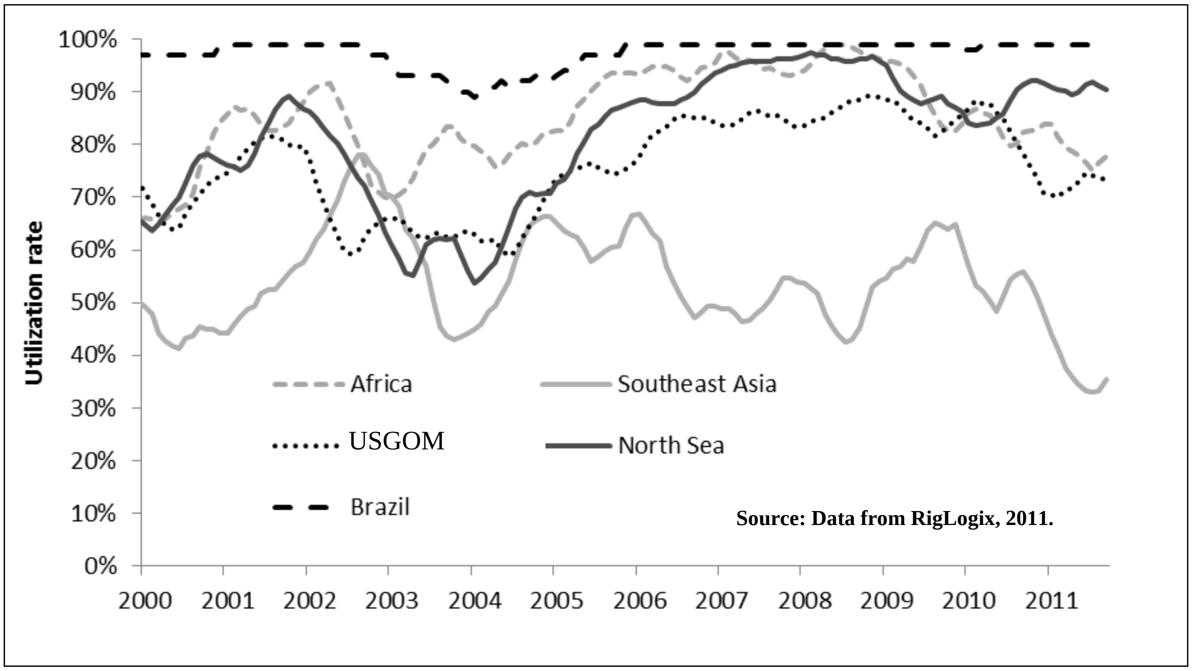


Figure C.12. Six month moving average of floater utilization rates in selected regions, 2000–2011.

	Initial conditions	Rig movement	Final conditions
Region A	Utilization: $\frac{10\text{ active rigs}}{20\text{ total rigs}} = 50\%$		Utilization: $\frac{10\text{ active rigs}}{15\text{ total rigs}} = 67\%$
		5 inactive rigs move to Region B	
Region B	Utilization: $\frac{18\text{ active rigs}}{20\text{ total rigs}} = 90\%$		Utilization: $\frac{18\text{ active rigs}}{25\text{ total rigs}} = 72\%$

Figure C.13. Illustration of the movement of rigs in response to high utilization rates.

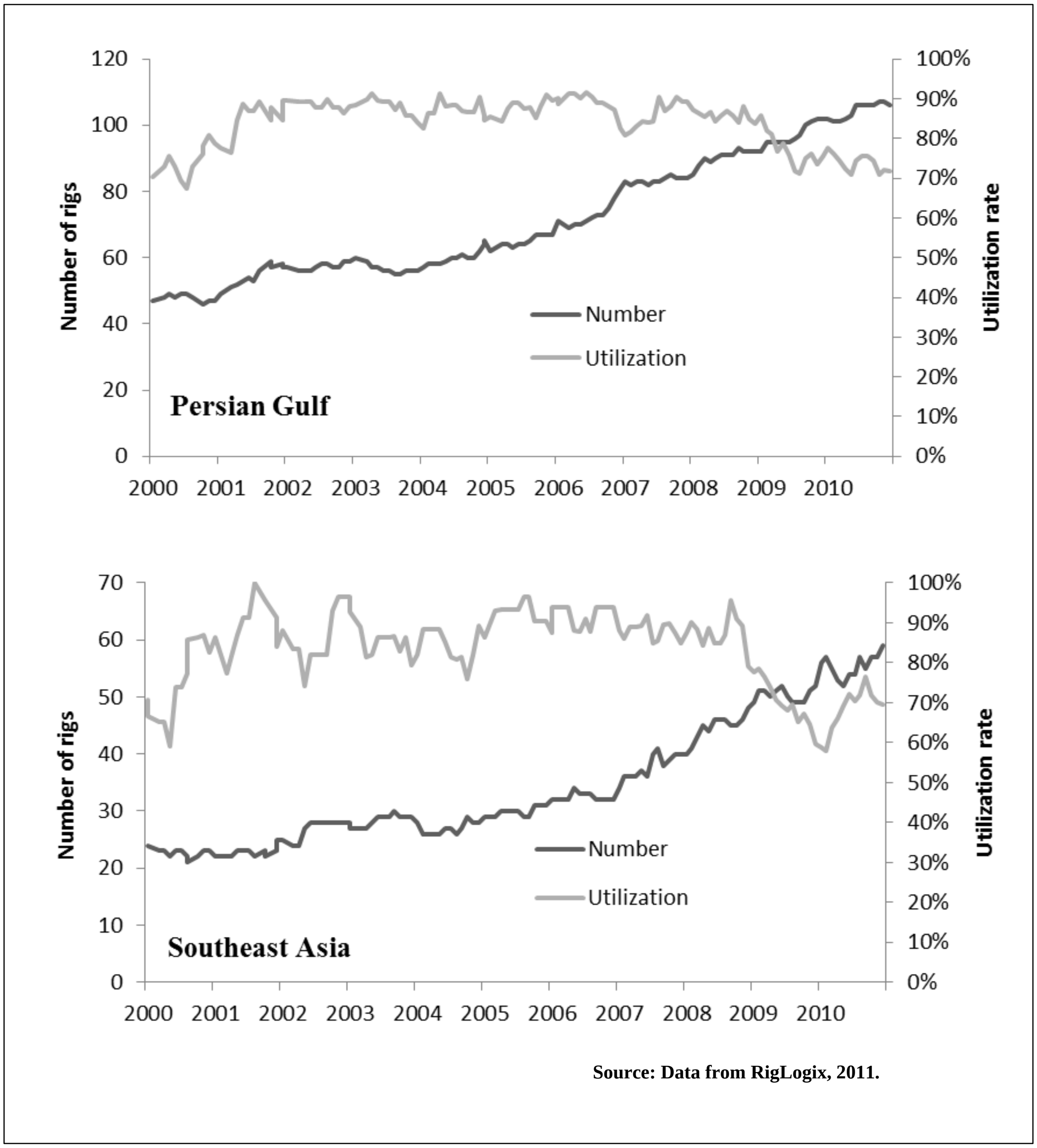


Figure C.14. Relationship between utilization rate and the increase in market capacity in the Persian Gulf and Southeast Asia, 2000–2011.

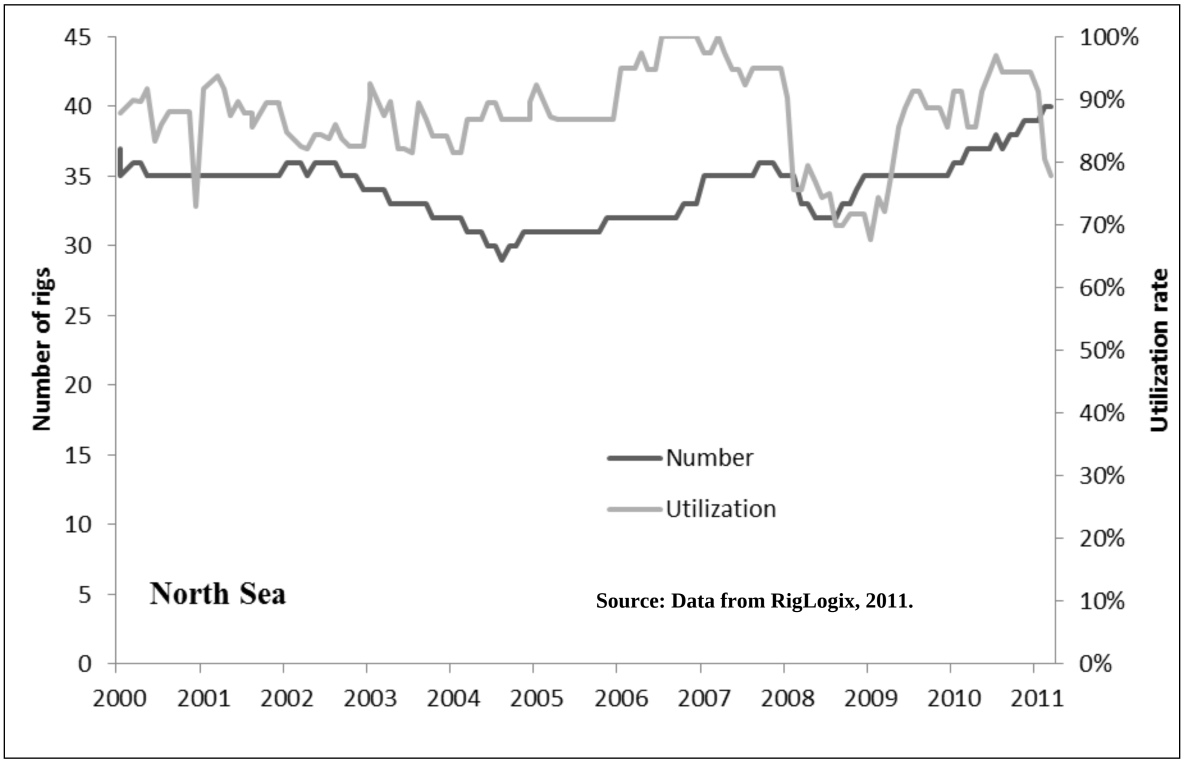


Figure C.15. Relationship between utilization rate and rig movement in the North Sea, 2000–2011.

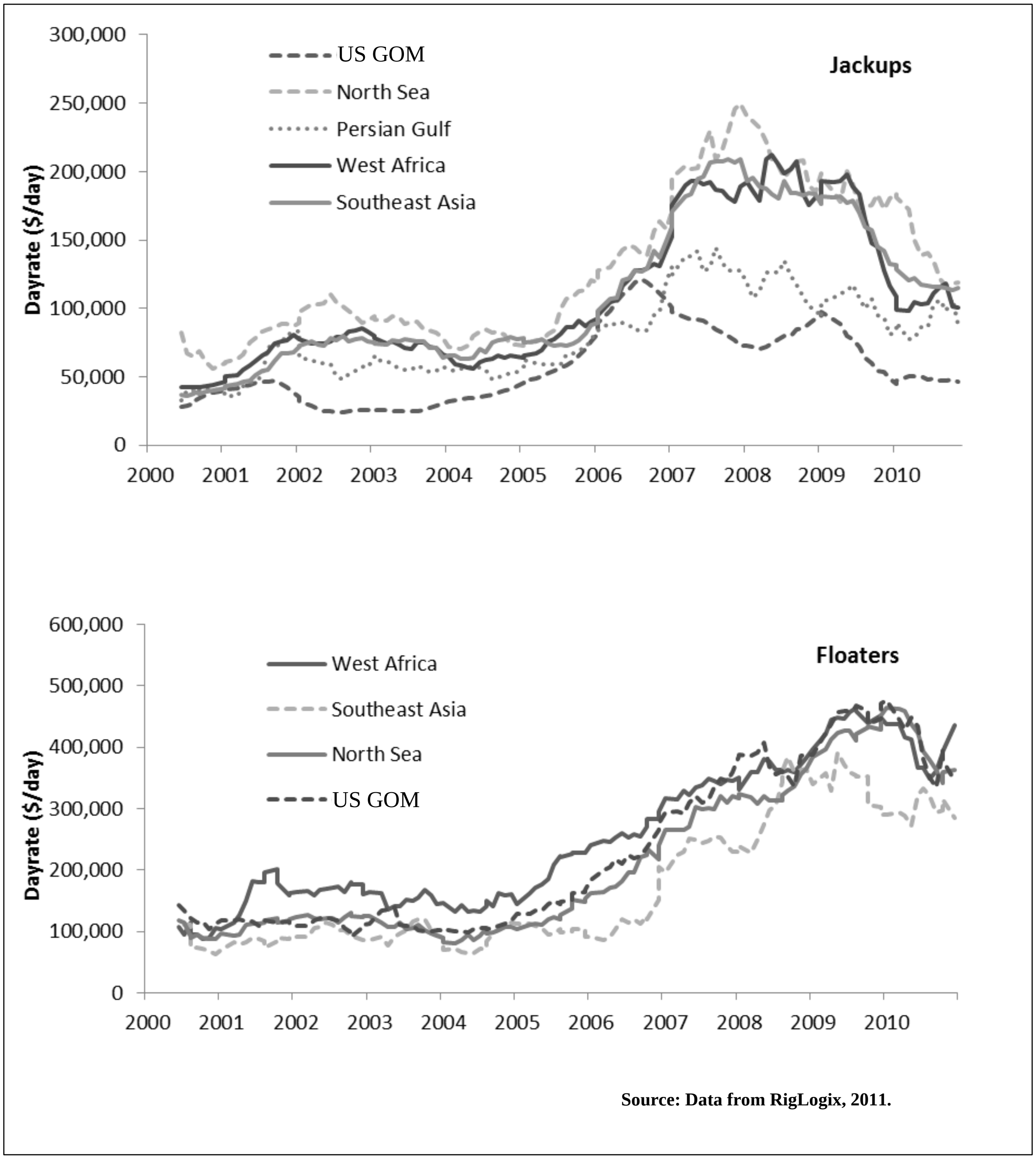


Figure C.16. Six month moving average of jackup and floater dayrates, 2000–2011.

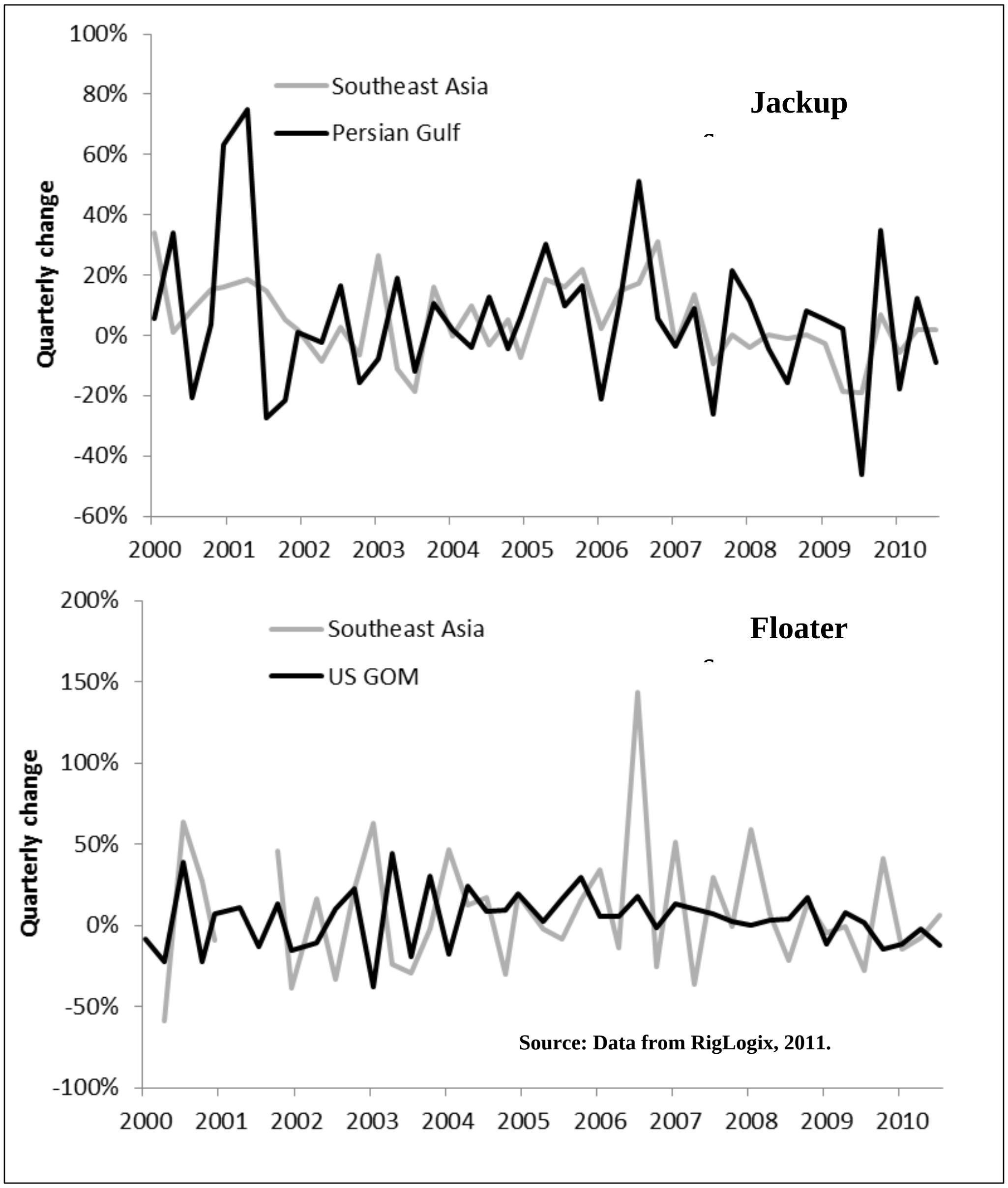


Figure C.17. Quarterly change in average dayrates in selected regions, 2000–2011.

APPENDIX D

CHAPTER 4 TABLES AND FIGURES

Table D.1.

The Largest Publicly Traded Drilling Contractors in 2011

Firm	Enterprise value[a] (billion $)	Fleet value[a] (billion $)	2011 revenue (billion $)	Jackups	Semis	Drillships	Total	Headquarters
Transocean	25.4	32.1	9.1	68	50	23	141	U.S.
Seadrill	27.1	15.6	4.0	21	12	6	39	Norway
Diamond Offshore	8.9	8.7	3.3	13	32	3	48	U.S.
ENSCO	16.7	14.5	2.8	42	18	5	65	U.S.
Noble	13.3	11.7	2.7	45	14	13	72	U.S.
Saipem	26[c]	4.5	1.0[b]	7	7	2	16	Italy
Rowan	4.5	5.7	0.9	31	0	0	31	U.S.
Songa Offshore	1.7	1.9	0.7	0	5	0	5	Norway
Ocean Rig	3.6	3.0	0.7	0	2	4	6	Norway
Atwood Oceanics	3.2	2.7	0.6	6	6	1	13	U.S.
Aban	2.9	2.4	0.6	15	0	3	18	India
Hercules Offshore	1.3	1.1	0.5[b]	33	0	0	33	U.S.
Vantage	1.5	1.7	0.3	4	0	4	8	U.S.
Japan Drilling	0.4	1.2	0.3	4	2	0	6	Japan
Total	110.5	106.8	26.4	289	148	64	501	
% of world fleet				54%	66%	60%	58%	

Note: (a) Enterprise and fleet value evaluated on December 21, 2011. (b) Only includes offshore drilling revenues. (c) Most of Saipem's enterprise value is associated with non-offshore drilling activities and is not included in the total.
Source: Jefferies and Company, Inc., 2012; financial reports; RigLogix, 2011.

Table D.2.

The Largest State-Owned Drilling Contractors in 2011

Firm	Nation/Market	Jackups	Semis	Drillships	Total	Publically traded
China Oilfield Services Ltd.	China	27	6	0	33	Yes
National Drilling	UAE	13	0	0	13	No
ONGC	India	8	0	2	10	Yes
Petrobras	Brazil	6	4	0	10	Yes
Socar	Azerbaijan	6	3	0	9	No
Egyptian Drilling	Egypt	7	0	0	7	No
Gulf Drilling International	Qatar	6	0	0	6	No
CNPC	China	4	0	0	4	Yes
Gazflot	Russia	2	2	0	4	No
NIDC	Iran	4	0	0	4	No
Arabian Drilling	Saudi Arabia	4	0	0	4	No
PV Drilling	Vietnam	4	0	0	4	No
Sheng Li	China	4	0	0	4	No
VietSovPetro	Vietnam	3	0	0	3	No
Caspian Drilling	Azerbaijan	0	2	0	2	No
Saudi Aramco	Saudia Arabia	2	0	0	2	No
ArcticMorNefteGazRazvedka	Russia	2	0	0	2	No
Petrobaltic	Poland	2	0	0	2	Yes
PDVSA	Venezuela	2	0	0	2	No
KNOC	Korea	0	1	0	1	No
Pemex	Mexico	1	0	0	1	Yes
Total		107	18	2	127	
% of world fleet		20%	8%	2%	15%	

Source: RigLogix, 2011.

Table D.3.

Selected Privately Held Drilling Contractors in 2011

Firm	Market	Jackups	Semis	Drillships	Total
Maersk Drilling[a]	North Sea	14	6	0	20
Stena Drilling	North Sea	0	4	4	8
Dolphin A/S[b]	North Sea	0	7	1	8
Schahin	Brazil	1	2	4	7
Odfjell	North Sea	0	4	2	6
Queiroz Galvao	Brazil	0	6	0	6
Odebrecht	Brazil	0	2	3	5
Perforadora Central	Mexico	5	0	0	5
GSP	Black Sea	5	0	0	5
Jagson	India	4	0	0	4
Spartan Offshore	GOM	4	0	0	4
SeaWolf	Africa	3	0	0	3
Subtotal		36	31	14	81
All others		107	36	31	174
Total		143	67	45	255
% of world fleet		27%	30%	42%	29%

Note: (a) Subsidiary of A.P. Moller-Maersk; (b) Subsidiary of Fred Olsen Energy
Source: RigLogix, 2011.

Table D.4.

Enterprise Value of Selected Drilling Contractors as a Percent of Fleet Value, 2010–2012

Firm	1Q 2012 (% of NAV)	1Q 2011 (% of NAV)	1Q 2010 (% of NAV)
Transocean	62	117	133
Seadrill	225	245	266
Diamond	93	128	131
ENSCO	116	104	83
Noble	104	126	106
Rowan	75	89	60
Atwood	111	126	112
Hercules	132	132	129
Vantage	59	92	80

Source: Jefferies and Company, Inc., 2009, 2011, and 2012.

Table D.5.

Specializations and Business Strategies of Selected Firms in 2011

Firm	Specialization	% of 2011 revenues from floater fleet	Business strategies
Diamond	Semis and jackups	93	Operates an old but upgraded fleet; frequently pays investor dividends rather than newbuilding but is entering high-spec drillship market.
ENSCO	Generalist	60	Formerly operated a jackup-focused fleet, but acquired Pride in 2011, adding floaters and diversifying fleet.
Hercules	Low spec jackups	0	Buys inexpensive secondhand rigs; does not typically participate in newbuilding; focused on U.S. GOM and Persian Gulf.
Noble	Generalist	60	Seeks to operate a diverse fleet in a number of regional markets.
Rowan	Jackups	0	Traditional jackup operator moving into deepwater market; operates primarily in high-spec shallow water markets.
Seadrill	High-spec	64	Operates only high spec rigs; active in newbuilding and maintains aggressive growth strategy; focuses on Southeast Asia, North Sea.
Songa	Semis	100	Operates small fleet of semis with emphasis on the North Sea.
Transocean	Generalist	85	Active in all major regions and water depths, but focused on deepwater.
Atwood	Semis	83	Operates a small but relatively diverse fleet; primarily focused on Southeast Asia.

Source: Financial reports.

Table D.6.

Four Largest Firms by Number of Active Rigs per Region and Water Depth Category in 2011

Water depth (ft)	West Africa		Southeast Asia		North Sea		Persian Gulf		US GOM	
<250	Noble Drilling	2	Hercules Offshore	1	ENSCO	5	National Drilling	11	Hercules Offshore	19
	Hercules Offshore	1	Schlumberger	1	Noble Drilling	4	Nabors Offshore	5	Nabors Offshore	5
	KCA Deutag	1			Swift Drilling BV	1	ENSCO	4	ENSCO	3
	SeaWolf Oil Services	1					Noble Drilling	4		
250–550	Transocean	6	Seadrill	11	Maersk Drilling	8	Rowan	10	Rowan	8
	Noble Drilling	2	Transocean	8	Rowan	5	Noble Drilling	9	ENSCO	5
	SeaWolf Oil Services	2	ENSCO	8	Transocean	4	Transocean	5	Noble Drilling	3
	Pride International	1	Vantage Energy Services	3	Noble Drilling	4	Aban Offshore	5	Hercules Offshore	1
<3,000	Transocean	3	Transocean	2	Transocean	12			Diamond Offshore	1
	Noble Drilling	1	Japan Drilling	2	Dolphin A/S	4			Larsen O&G	1
	Saipem	1	Maersk Drilling	2	Diamond Offshore	3				
			Diamond Offshore	1	Songa Offshore AS	2				
3,000–7,500	Transocean	6	Transocean	3	North Atlantic Drilling	2			Transocean	4
	Diamond Offshore	1	Diamond Offshore	1	Transocean	1			Noble Drilling	3
	Noble Drilling	1	Noble Drilling	1	Saipem	1			Diamond Offshore	1
	Saipem	1	Atwood Oceanics	1	Dolphin A/S	1				
>7,500	Transocean	2	Transocean	2	Aker Drilling A/S	2			Transocean	8
	ENSCO	2	Seadrill	1	Odfjell	1			ENSCO	6
	Seadrill	2	Saipem	1	Stena Drilling	1			Noble Drilling	3
	Ocean Rig Asa	2	ENSCO	1	North Atlantic Drilling	1				

Source: Data from RigLogix, 2011.

Table D.7.

Drilling Contractor Revenues in Million U.S. Dollars by Region in 2011

	Diamond	ENSCO	Hercules	Noble	Rowan	Seadrill	Transocean
Brazil	1,641	583		572		710	1,000
US GOM	323	753	302	524	264	185	1,900
UK	152	240		164	230	150	1,200
Norway					74	1,392	
Angola	318	250				182	
Mexico	62	148	16	402	28		
Saudi Arabia			93	96	204	69	
Nigeria			98			204	
China						230	
Qatar				132	60		
India			61	102			
Other	826	866	85	703	79	918	4,900

Note: Blank values do not indicate that the contractor received no revenue from the region; only that the revenue was not considered significant enough to list separately
Source: Financial reports.

Table D.8.

Major E&P Customers of Selected Drilling Contractors in 2011

Drilling Contractor	E&P Customers (% of revenues)			
	First	Second	Third	Fourth
Atwood	Chevron (30%)	Shell (21%)	Kosmos (21%)	
Diamond	Petrobras (35%)	OGX (14%)		
ENSCO	Petrobras (16%)			
Hercules	Chevron (25%)	Saudi Aramco (13%)	ONGC (9%)	PEMEX (3%)
Noble	Shell (24%)	Petrobras (18%)	Pemex (15%)	
Rowan	Saudi Aramco (29%)	McMorRan (21%)	Total (11%)	
Seadrill	Petrobras (17%)	Statoil (15%)	Total (10%)	Shell (9%)
Transocean	BP (10%)			

Source: Financial reports.

Table D.9.

Transocean and Diamond Performance Statistics by Market Segment in 2011

Firm	Rig class	Operating costs* (1,000 $/day)	Dayrate (1,000 $/day)	Net revenue (1,000 $/day)	Utilization (%)	Expected net revenue (1,000 $/year)
Transocean	Ultra-deepwater	199	533	334	79	81,056
	Deepwater	135	349	214	44	6,774
	Harsh floaters	171	450	279	95	93,623
	Mid-water floaters	91	280	189	69	37,303
	High-spec jackups	81	114	33	71	-22
	Jackups	29	96.5	67.5	49	6,674
Diamond	Ultra-deepwater	169	342	173	82	40,676
	Deepwater	119	416	297	94	99,295
	Mid-water floaters	86	269	183	72	39,303
	Jackups	36	82	46	47	927

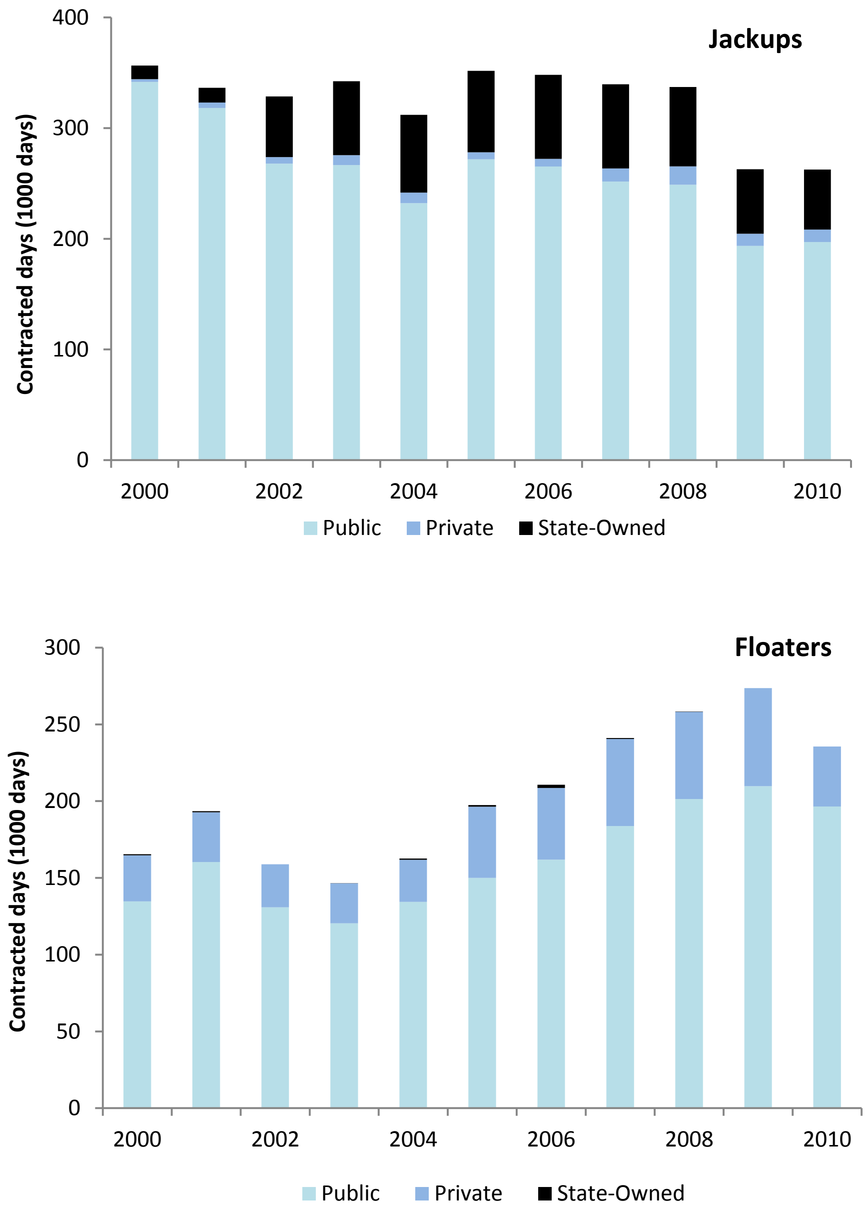
Note: (*) Includes active and inactive costs
Source: Financial reports.

Table D.10.

Market Concentration Metrics of the World MODU Fleet in 2010

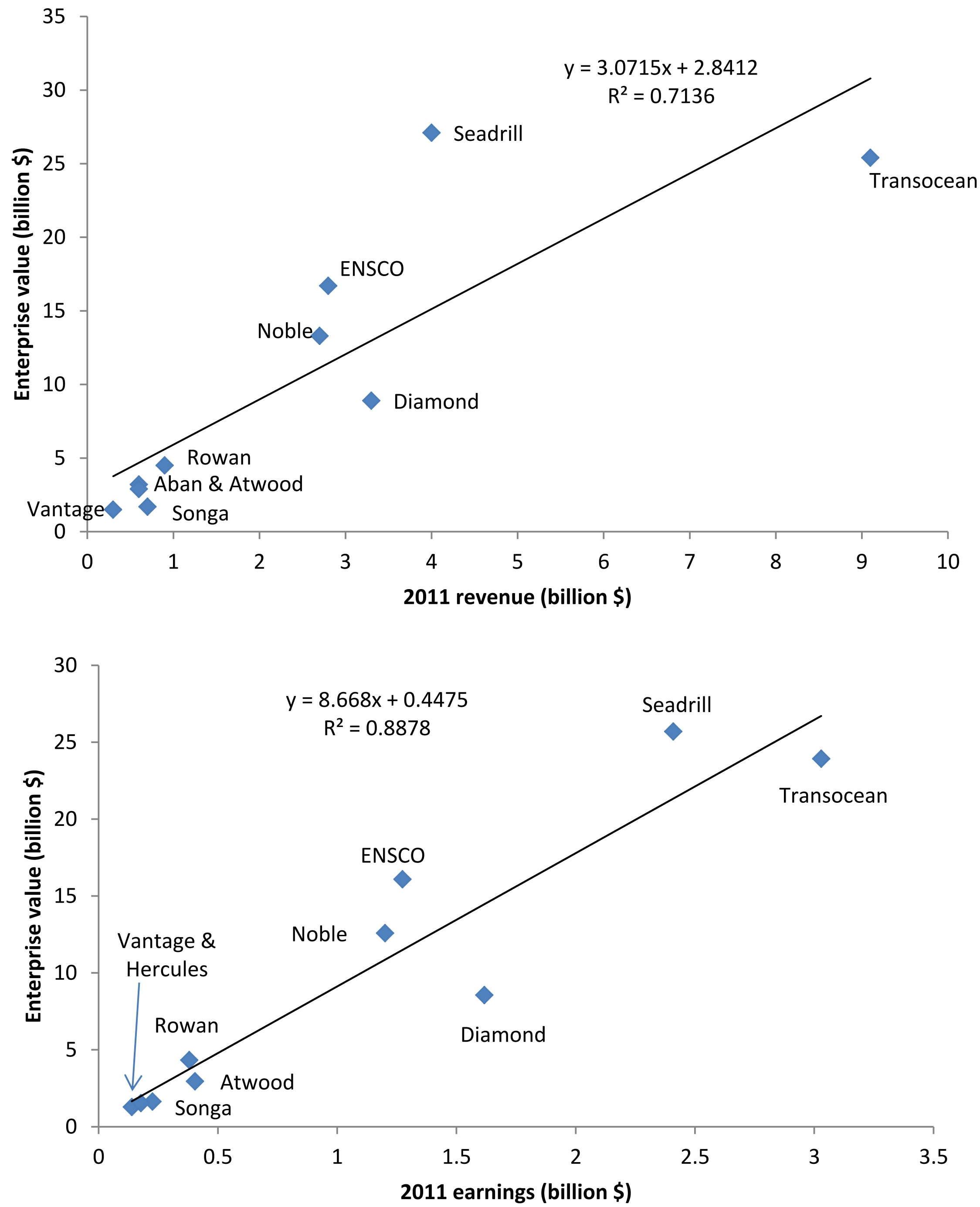
	Jackup	Semisub	Drillship	Floaters
CR4 (%)	53	68	69	54
CR8 (%)	79	85	88	67
HHI	940	1,628	2,511	1,692

Source: Data from RigLogix, 2011.



Source: Data from RigLogix, 2011.

Figure D.1. Contracted days in global offshore drilling market by company ownership, 2000–2010.



Source: Data from Jefferies and Company, Inc., 2012.

Figure D.2. Relationship between enterprise value and revenue and earnings for selected drilling contractors on December 31, 2011.

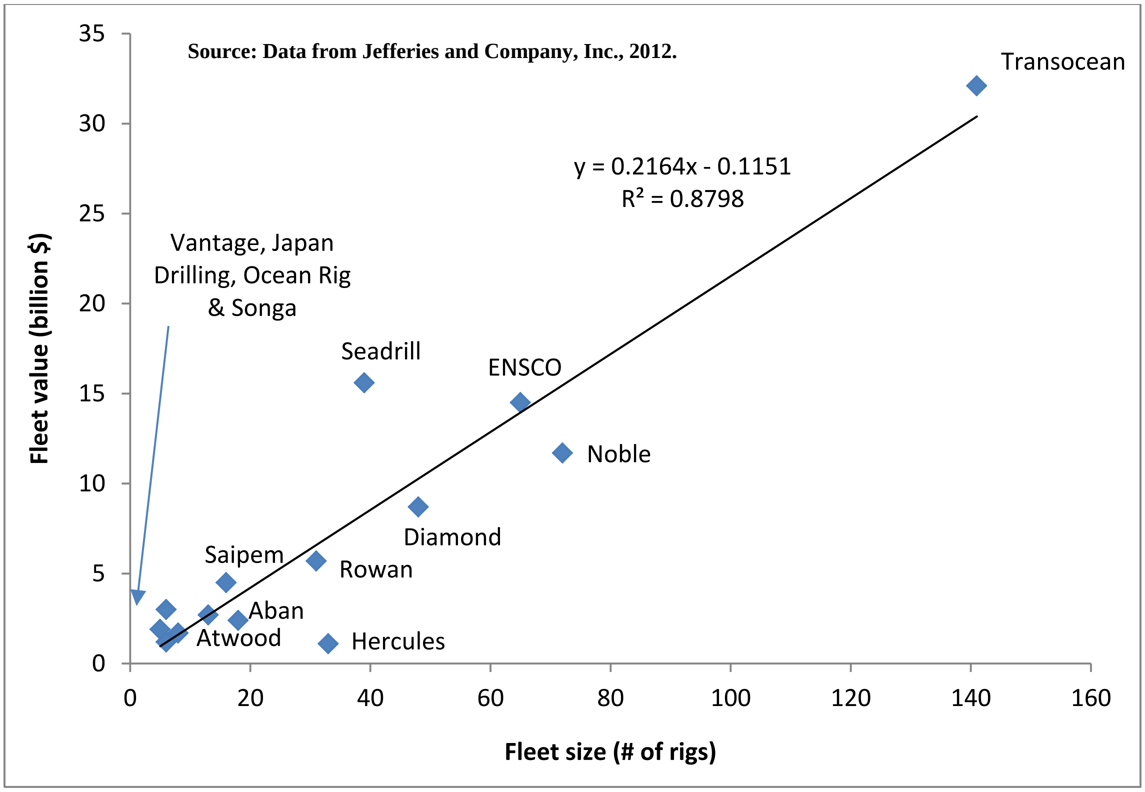


Figure D.3. Relationship between fleet size and fleet value for selected drilling contractors on December 31, 2011.

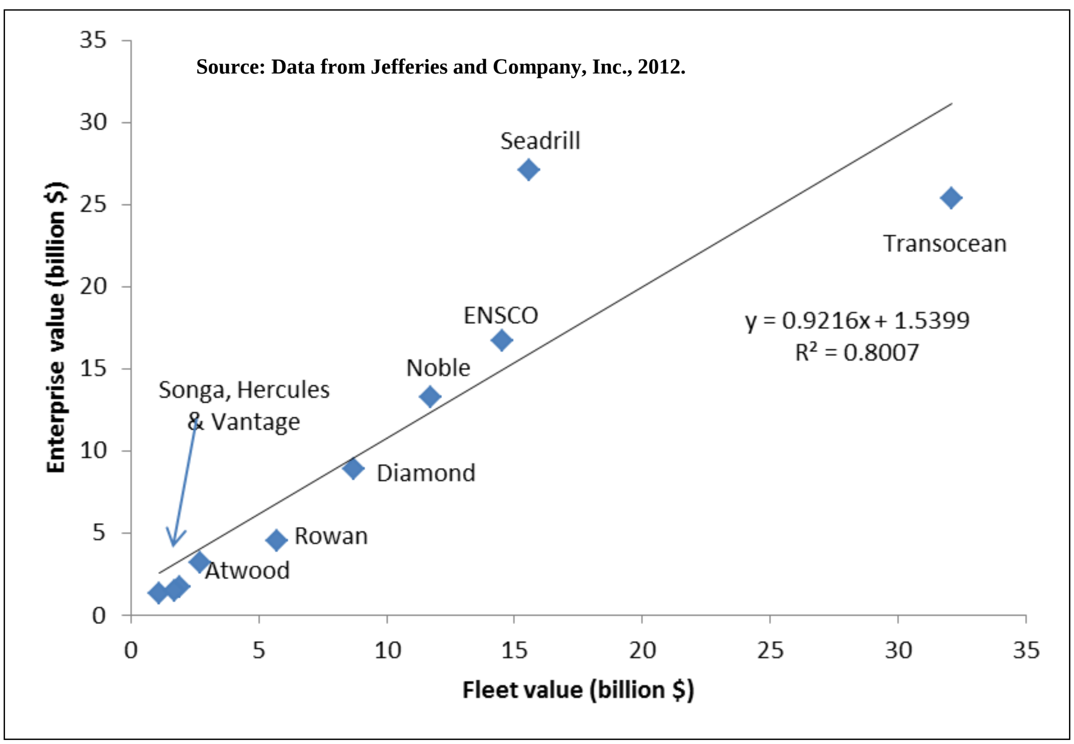


Figure D.4. Relationship between enterprise value and fleet value for selected drilling contractors on December 31, 2011.

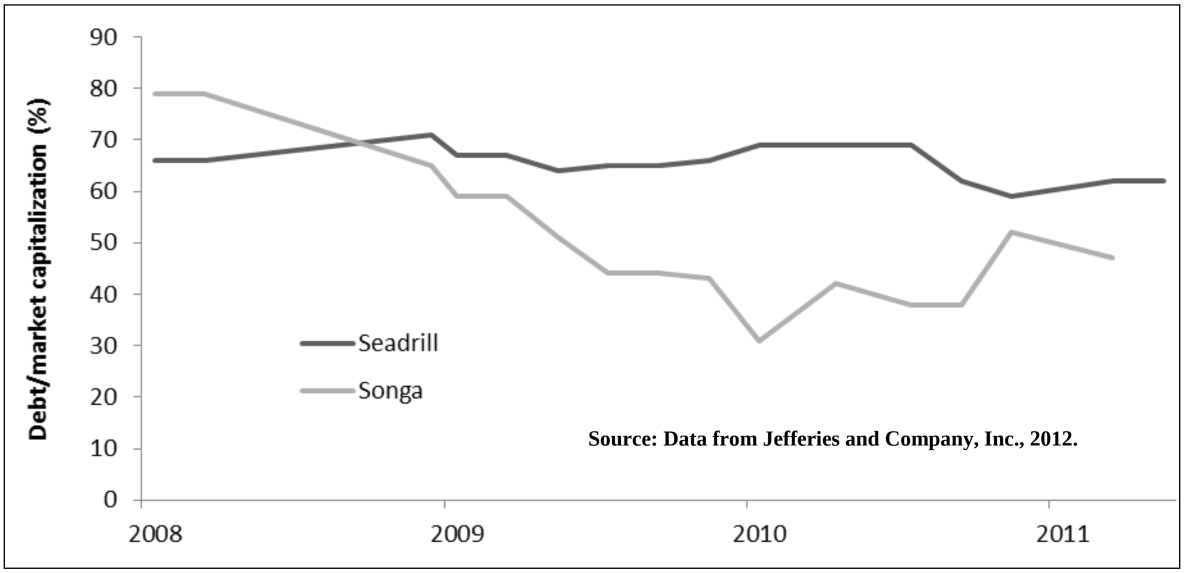


Figure D.5. Debt to market capitalization of Seadrill and Songa, 2008–2011.

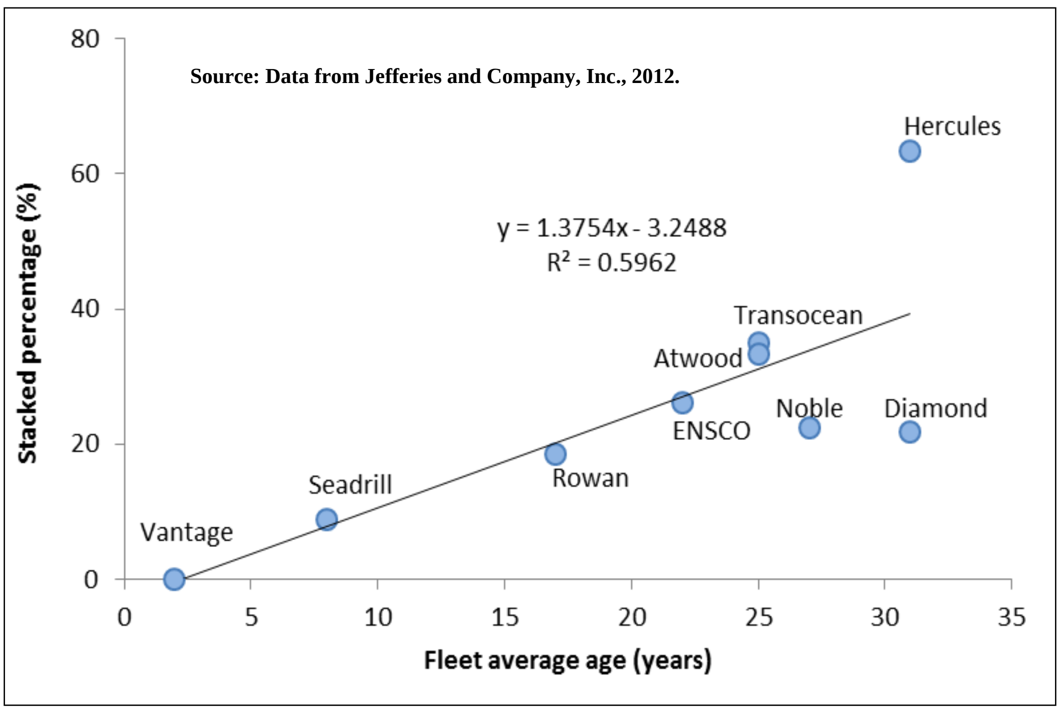


Figure D.6. Average fleet age and the proportion of the fleet stacked in December 2010.

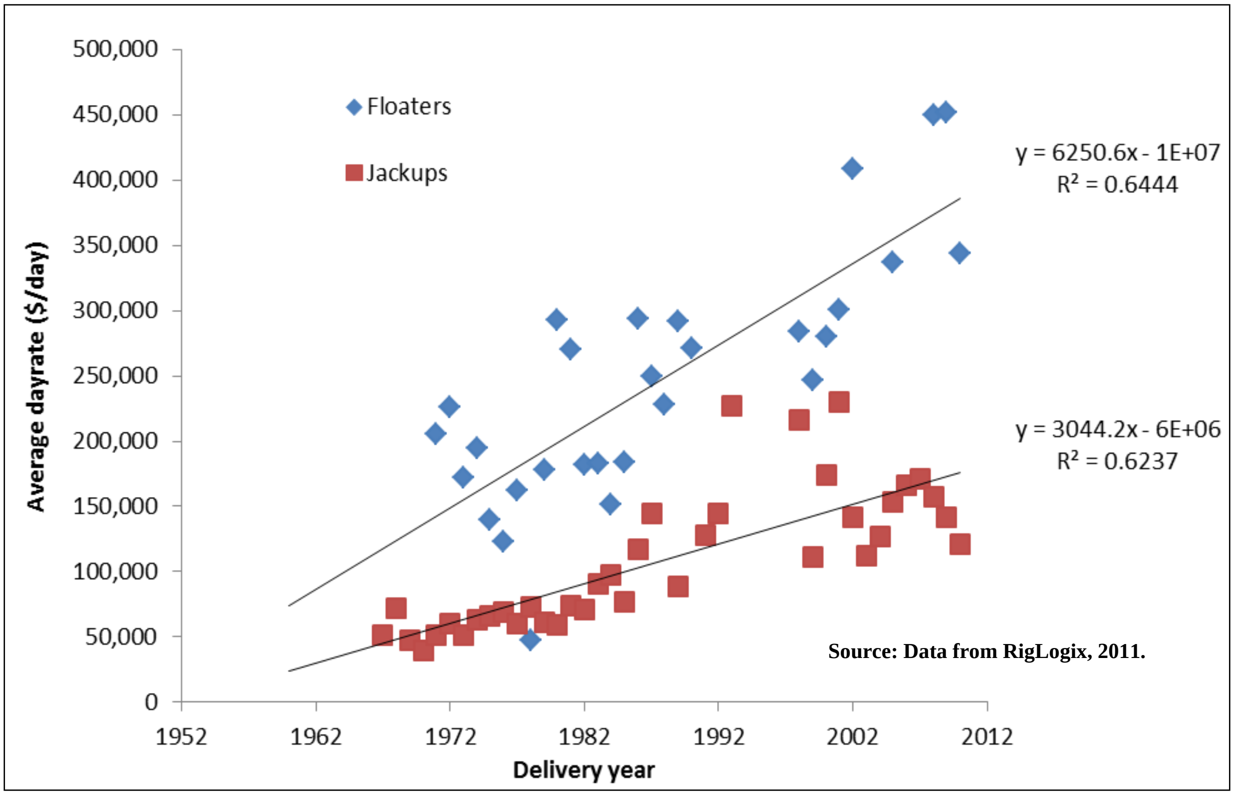
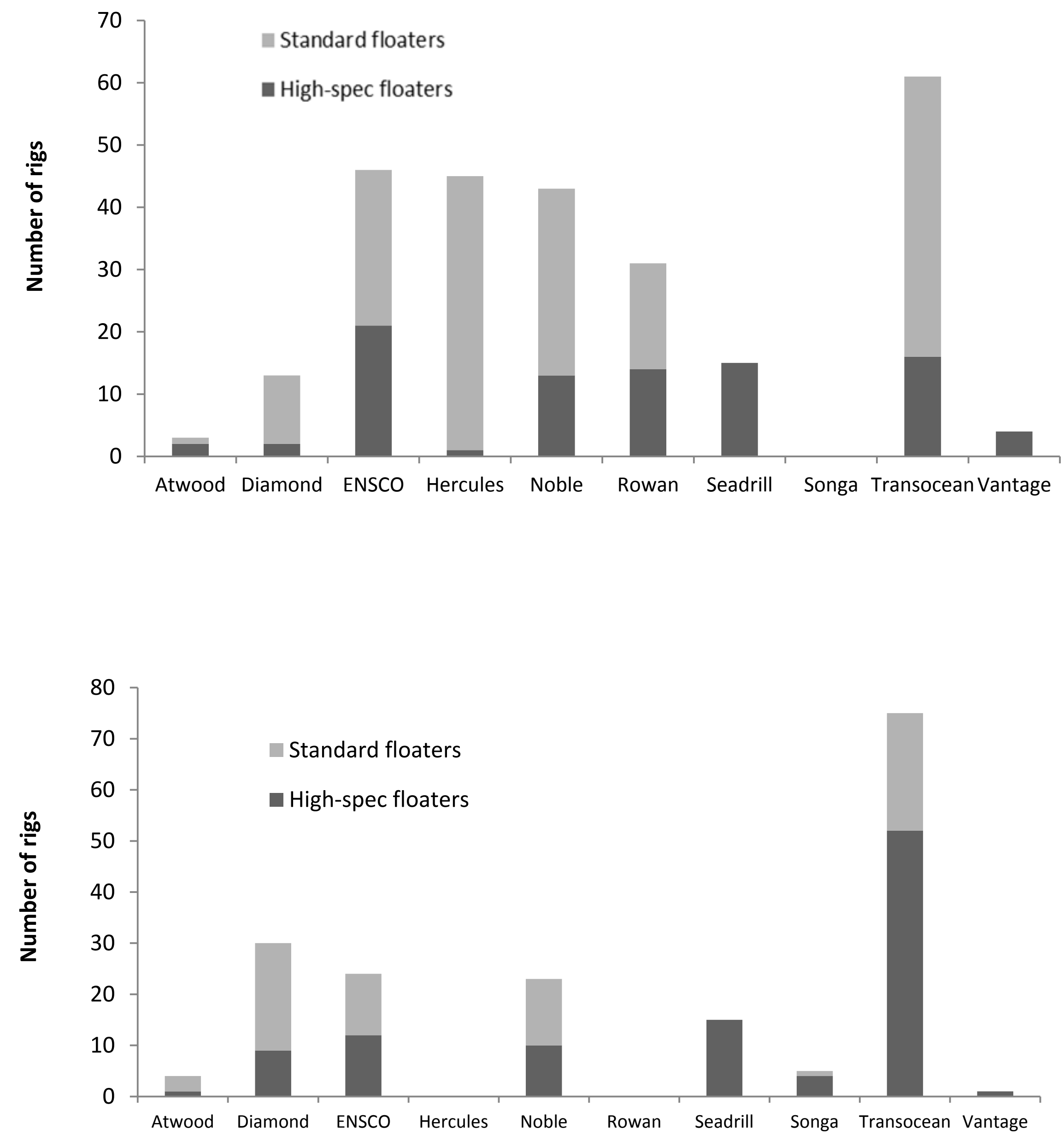


Figure D.7. Delivery year and average dayrates of jackups and floaters from 2000–2010.



Source: Financial reports.

Figure D.8. Inventories of jackup and floater fleets for selected firms in 2011.

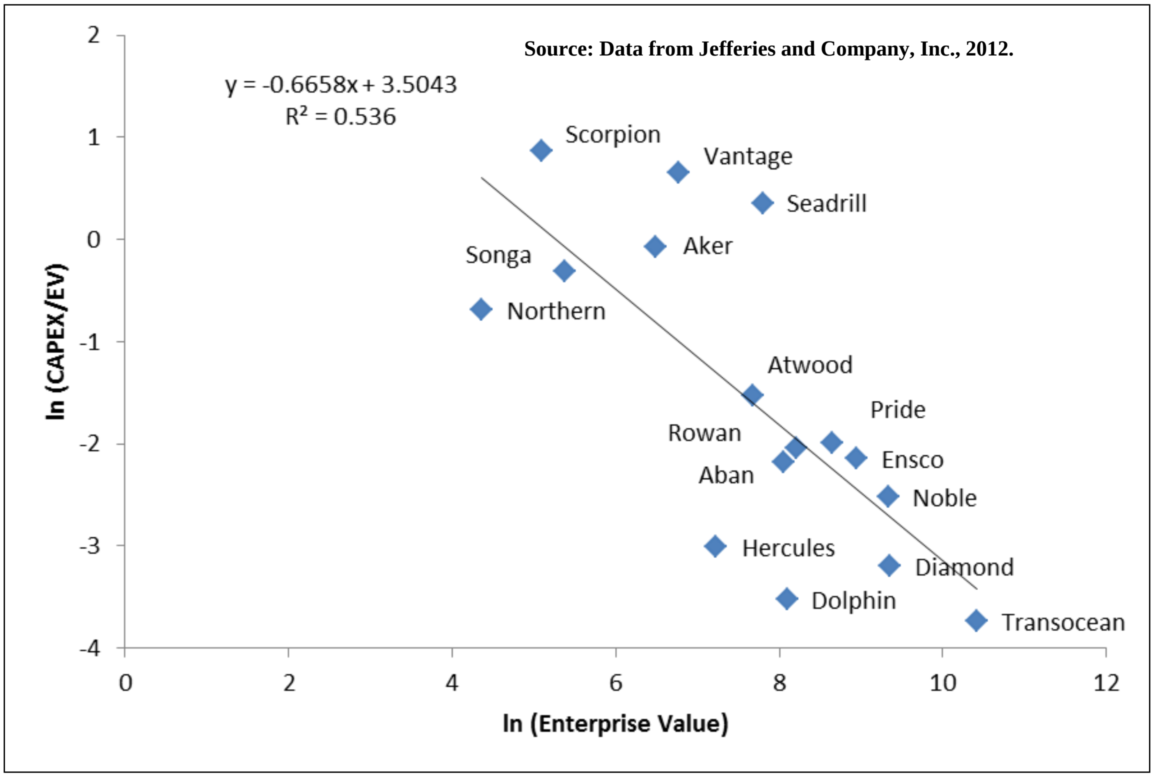


Figure D.9. Relationship between firm size and relative newbuilding expenditure, 2005–2011.

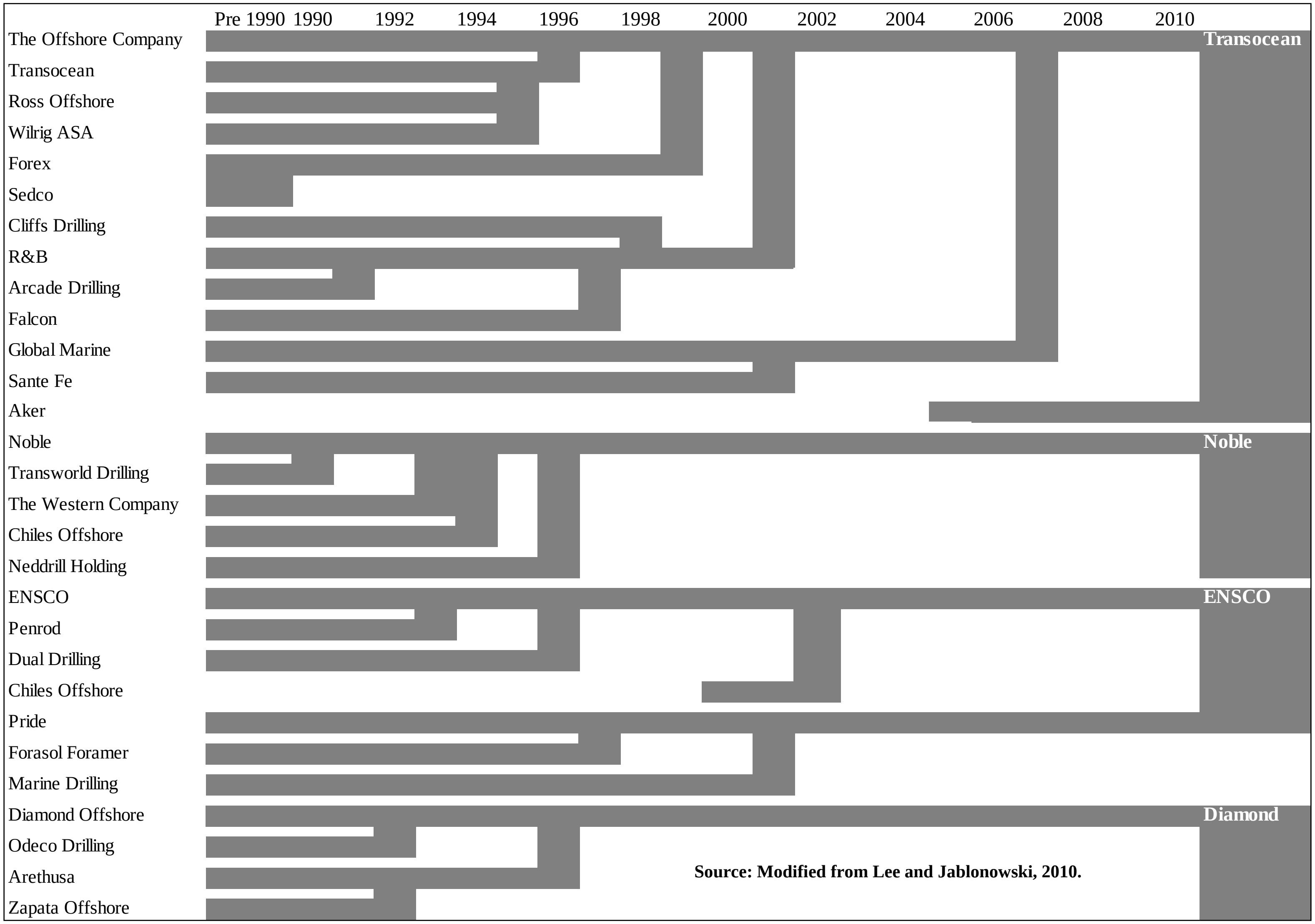


Figure D.10. Selected mergers among major players in the offshore drilling market, 1990–2010.

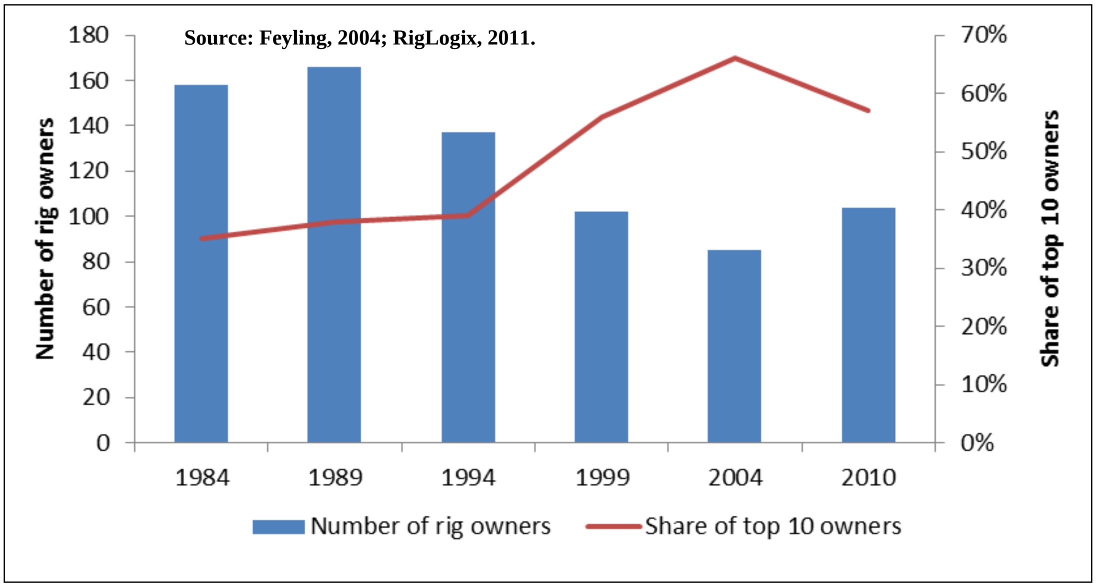


Figure D.11. Consolidation in the offshore contract drilling industry, 1984–2010.

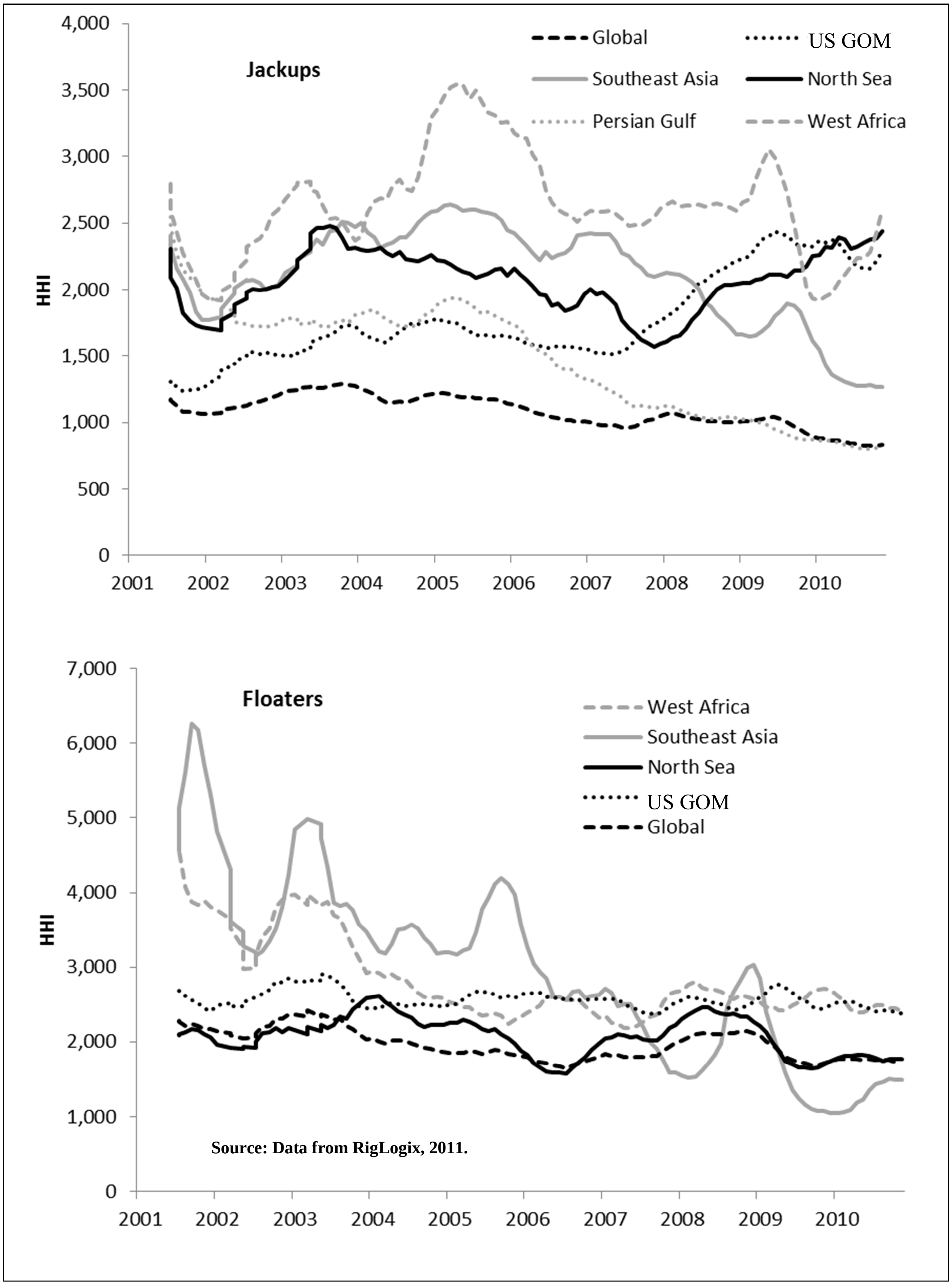


Figure D.12. Herfindahl-Hirschman Index of jackup and floater regional markets, 2001–2010.

APPENDIX E

CHAPTER 5 TABLES AND FIGURES

Table E.1.

Offshore Drilling Contracts by Region, 2000–2010

	Jackup	Drillship	Semisub	Total
West Africa	314	114	243	671
Southeast Asia	465	25	149	639
North Sea	600	14	615	1,229
Persian Gulf	341	0	2	343
US GOM	3,441	91	709	4,241
Total	5,161	244	1,718	7,123

Source: Data from RigLogix, 2011.

Table E.2.

Average Dayrates by Region between 2000-2006 and 2006–2010

	Jackups			Floaters		
	2000–2006 ($/day)	2006–2010 ($/day)	Change	2000–2006 ($/day)	2006–2010 ($/day)	Change
West Africa	69,379	154,488	123%	163,534	374,130	129%
Southeast Asia	67,846	159,731	135%	92,229	278,060	201%
North Sea	86,927	180,657	108%	113,330	337,589	198%
Persian Gulf	58,126	106,541	83%			
US Gulf of Mexico	48,776	81,865	68%	122,530	361,995	195%

Source: Data from RigLogix, 2011.

Table E.3.

Models of the Relationship between Utilization Rates and Dayrates, 2006–2010

	$\ln(DR_t) = \beta_0 + \beta_1 \ln U_x$						
		β_0	β_1				
	Region		x=12	x=18	x=24	R^2	Autoregressive order
Jackups	West Africa	12.2	1.2			0.62	none
	Southeast Asia	12.3	1.7			0.80	none
	North Sea	12.2		3.0		0.27	none
	Persian Gulf	12.2		3.9		0.35	none
	US GOM	11.7	1.0			0.77	first
	World	12.0	1.5			0.67	none
Floaters	West Africa	12.8			3.0	0.98	first
	Southeast Asia						NA
	North Sea	12.8		2.4		0.99	second
	US GOM	13.3		3.5		0.99	second
	World	13.4		3.9		0.99	second

Source: Data from RigLogix, 2011.

Table E.4.

Relationship between Maximum Drilling Depth and Dayrates, 2000–2010

	Drilling depth category (ft)	Dayrate ($/day)	Number in sample	Standard error ($/day)	Significantly different
Jackups	Less than 15,000	53,804	41	4,299	A
	15,000 to 20,000	58,421	1,866	786	A
	20,000 to 25,000	86,580	1,632	1,257	B
	25,000 to 30,000	98,508	975	1,919	C
	Greater than 30,000	170,375	100	7,707	D
Floaters	Less than 20,000	168,664	117	10,794	A
	20,000 to 25,000	176,570	1,099	3,885	A
	25,000 to 30,000	255,213	407	7,324	B
	30,000 to 35,000	264,882	212	9,020	B
	Greater than 35,000	409,058	35	23,104	C

Source: Data from RigLogix, 2011.

Table E.5.

Relationship between Maximum Water Depth and Dayrates, 2000–2010

	Water depth category (ft)	Dayrate ($/day)	Number in sample	Standard error ($/day)	Significantly different
Jackups	Less than 200	51,916	1,045	860	A
	200 to 250	69,241	1,520	1,089	B
	250 to 300	81,192	1,245	1,374	C
	300 to 350	88,616	726	2,005	D
	350 to 400	118,920	517	3,129	E
	Greater than 400	112,378	108	5,389	E
Floaters	Less than 2,500	170,227	856	4,361	A
	2,500 to 5,000	193,760	426	6,515	B
	5,000 to 7,500	227,887	320	7,333	C
	Greater than 7,500	309,754	360	7,615	D

Source: Data from RigLogix, 2011.

Table E.6.

Rig Specifications and Average Dayrates, 2000–2010

	Station keeping	Average dayrate ($/day)	Number in sample	Standard error ($/day)
Jackups	Independent leg cantilever	87,746	3,480	940
	Mat or slot	53,125	1,134	820
Floaters	DP	295,775	408	6,923
	Moored	182,891	1,458	3,443

Source: Data from RigLogix, 2011.

Table E.7.

Effects of Rig Specification on Dayrates by Region, 2000–2010

		Station keeping		Water depth		Drilling depth	
	Region	Mat or slot	IC	<300 ft	>300 ft	<25,000 ft	>25,000 ft
Jackups	US GOM	52,820	67,334*	53,035	72,342*	55,473	78,692*
	Persian Gulf	72,192	88,758	77,617	98,785*	80,155	149,148*
	West Africa	63,401	106,436*	92,554	113,135*	101,833	151,267*
	North Sea	56,227	125,691	108,099	135,411*	108,011	153,195*
	Southeast Asia	98,415	112,842	123,181	113,566	100,624	148,617*
		Moored	DP	<5,000 ft	>5,000 ft	<25,000 ft	>25,000 ft
Floaters	US GOM	164,102	295,672*	109,536	249,683*	132,681	252,088*
	West Africa	225,577	295,959*	225,852	279,454*	226,167	300,893*
	North Sea	193,719	293,500*	199,186	302,776*	196,592	309,149*
	Southeast Asia	173,393	311,534*	157,737	236,094*	159,480	267,475*

Note: (*) Indicates significant difference (p<0.05).
Source: Data from RigLogix, 2011.

Table E.8.

Premium Associated with High Specification Rigs, 2000–2010

	Region	Premium ($/day)		
		Station keeping	Water depth	Drilling depth
Jackups	US GOM	14,514	19,307	23,219
	Persian Gulf		21,168	68,993
	West Africa	43,035	20,581	49,434
	North Sea		27,312	45,184
	Southeast Asia			47,993
Floaters	US GOM	131,570	140,147	119,407
	West Africa	70,382	53,602	74,726
	North Sea	99,781	103,590	112,557
	Southeast Asia	138,141	78,357	107,995

Note: Computed as the difference in row categories in Table E.7. Blank values indicate non-significant results.

Table E.9.

Influence of Contract Duration on Dayrates in the Jackup and Floater Markets, 2000-2010

	Region	Average contract length (days)	Long-term dayrate ($/day)	Short-term dayrate ($/day)	Premium ($/day, %)
Jackups	West Africa	260	111,273	85,986	25,287 (29)
	Southeast Asia	248	111,619	98,831	12,788 (13)
	North Sea	190	126,263	100,086	26,177 (26)
	Persian Gulf	511	100,421	69,345	31,076 (45)
	US GOM	77	59,385	48,465	10,920 (23)
Floaters	West Africa	261	297,852	237,797	60,055 (25)
	Southeast Asia	213	238,702	167,538	71,164 (42)
	North Sea	233	257,595	192,843	64,752 (34)
	US GOM	173	295,625	159,880	135,745 (85)

Note: Long-term and short-term contracts are defined relative to the regional mean duration. Premium is the difference between long and short-term contracts as a percentage of long-term dayrate.
Source: Data from RigLogix, 2011.

Table E.10.

Average Dayrates by E&P Firm Classification, 2000–2010

	E&P firm	Average dayrate ($/day)	Number in sample
Jackups	NOC	114,608^{A}	261
	IOC	88,588^{B}	1,008
	Independent	71,788^{C}	3,893
Floaters	NOC	274,776^{A}	200
	IOC	226,757^{B}	610
	Independent	189,832^{C}	1,145

Note: Letters indicate significant differences at p=0.05.
Source: Data from RigLogix, 2011.

Table E.11.

Models of the Relationship between Dayrates and E&P Firm Ownership, 2000–2010

$\mathrm{DR} = \beta_0 + \beta_1\mathrm{IND} + \beta_2\mathrm{IOC} + \beta_3\mathrm{YEAR} + \beta_4\mathrm{GOM} + \beta_5\mathrm{NSEA} + \beta_6\mathrm{AFRICA} + \beta_7\mathrm{PGULF}$			
Coefficient	Variable	Jackup model	Floater model
β_0	Intercept	-14,940,018	-67,703,588
β_1	IND	-16,914	-30,484
β_2	IOC	-10,962	-4,631^{NS}
β_3	YEAR	7,512	33,859
β_4	GOM	-37,064	6,1427
β_5	N.SEA	16,058	49,386
β_6	AFRICA	-2,579^{NS}	84,499
β_7	PGULF	-29,575	

Note: NS indicates the term is not significant.
Source: Data from RigLogix, 2011.

Table E.12.

Average Floater Dayrates by Well Type, 2000–2010

		Appraisal ($/day)	Development ($/day)	Exploratory ($/day)
Water depth	Midwater (< 3,000 ft)	271,624^{A}	202,623^{B}	237,740^{AB}
	Deepwater (3,000-7,500 ft)	430,455^{A}	325,031^{B}	291,286^{C}
	Ultra-deepwater (>7,500 ft)	438,750^{A}	403,759^{AB}	357,191^{B}
Region	West Africa	433,974^{A}	366,197^{A}	338,087^{A}
	Southeast Asia	328,742^{A}	217,513^{A}	258,469^{A}
	North Sea	344,632^{A}	240,501^{B}	307,938^{A}
	U.S. GOM	378,404^{A}	331,684^{A}	258,624^{B}
	All floaters	362,727^{A}	286,758^{B}	289,567^{B}

Note: Letters indicate significant differences at p=0.05.
Source: Data from RigLogix, 2011.

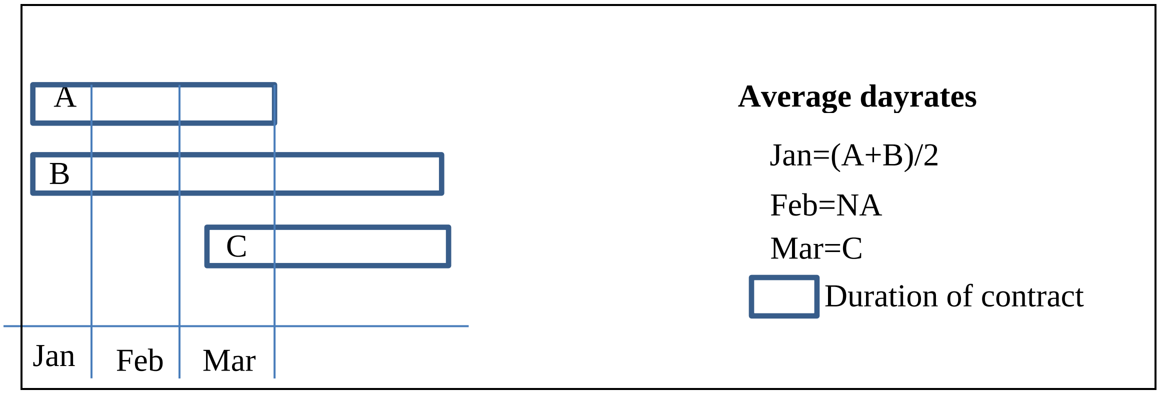
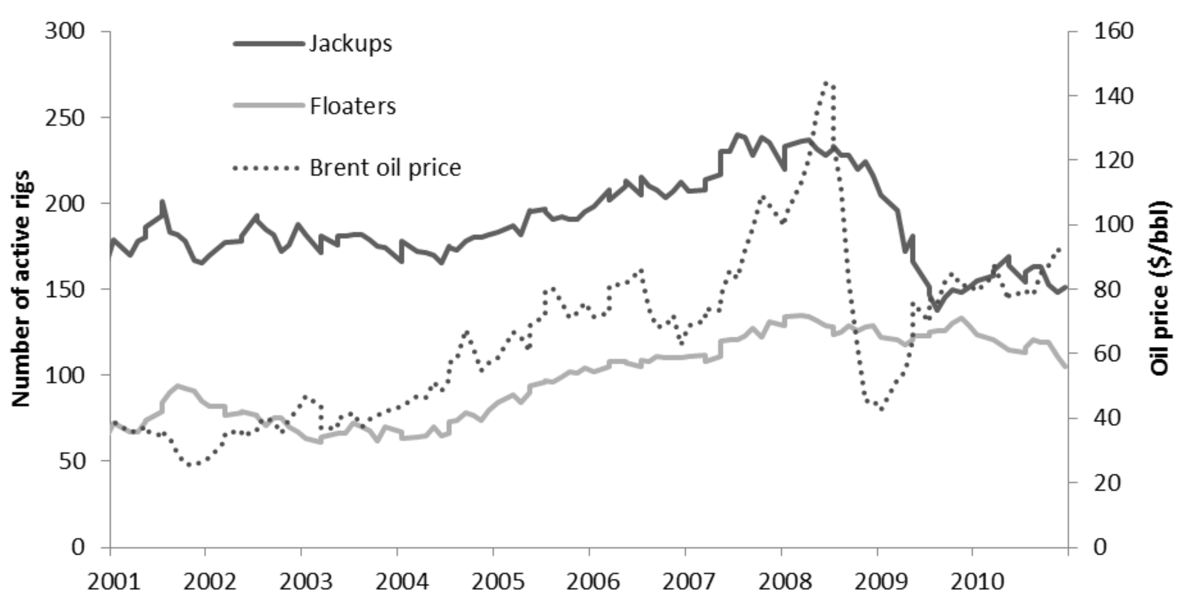
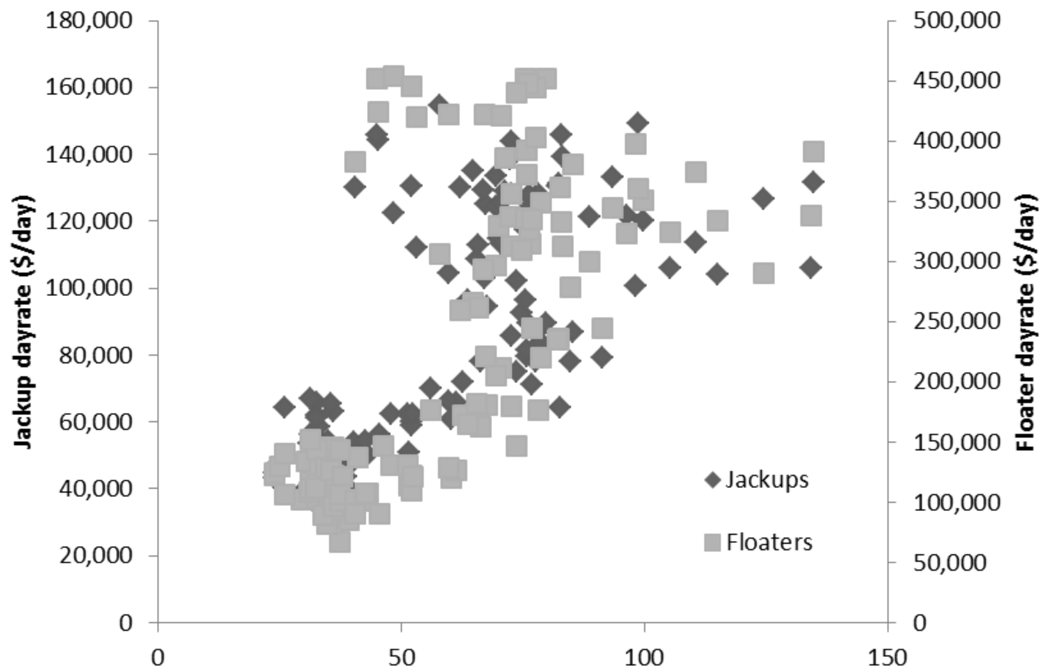


Figure E.1. Illustration of the method used for averaging dayrates.



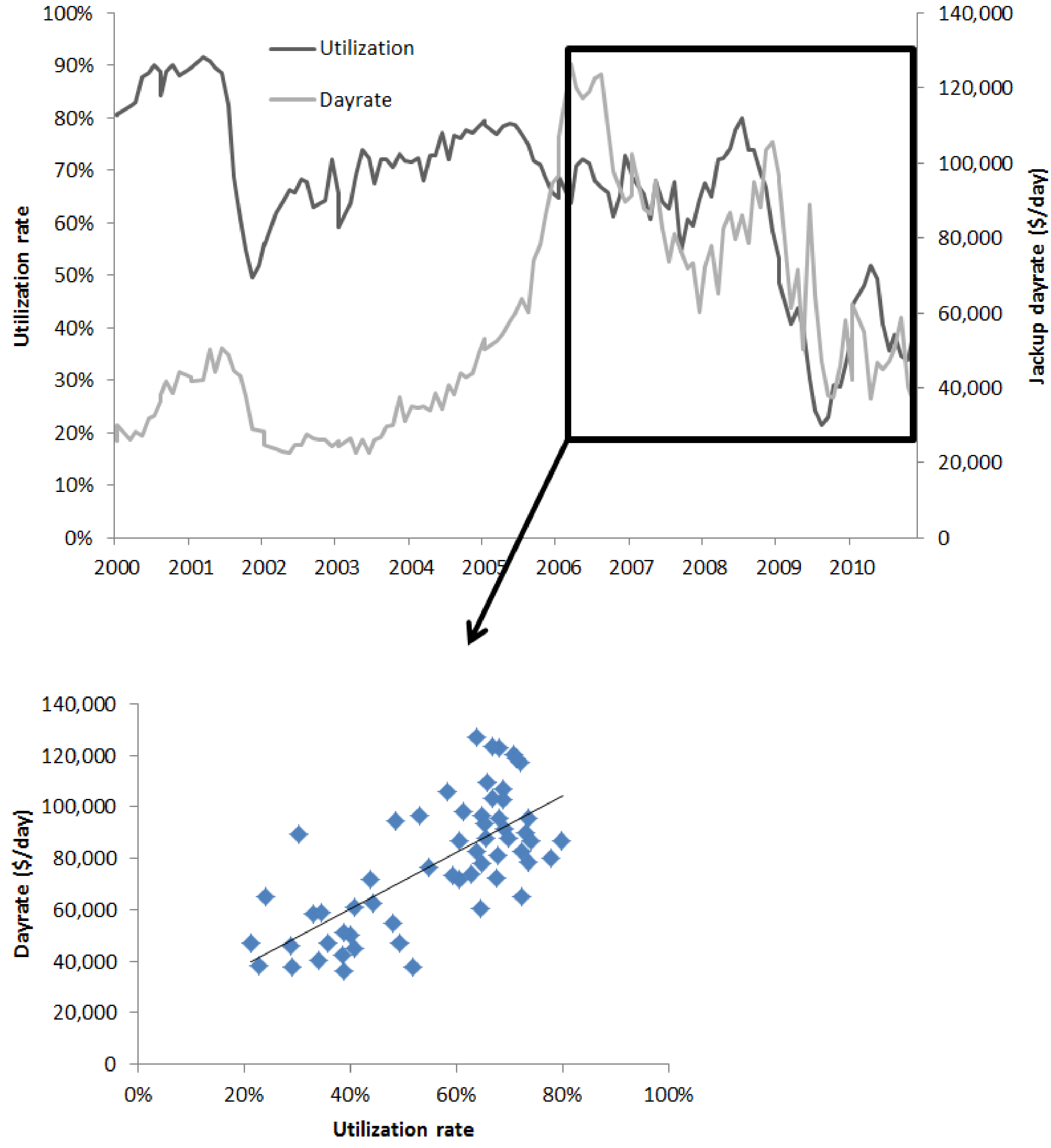
Source: Data from RigLogix, 2011.

Figure E.2. Global active rig count and oil prices, 2001–2011.



Source: Data from RigLogix, 2011.

Figure E.3. Relationship between jackup and floater dayrates and oil prices, 2000–2010.



Source: Data from RigLogix, 2011.

Figure E.4. Dayrates and utilization rate in the U.S. GOM jackup market.

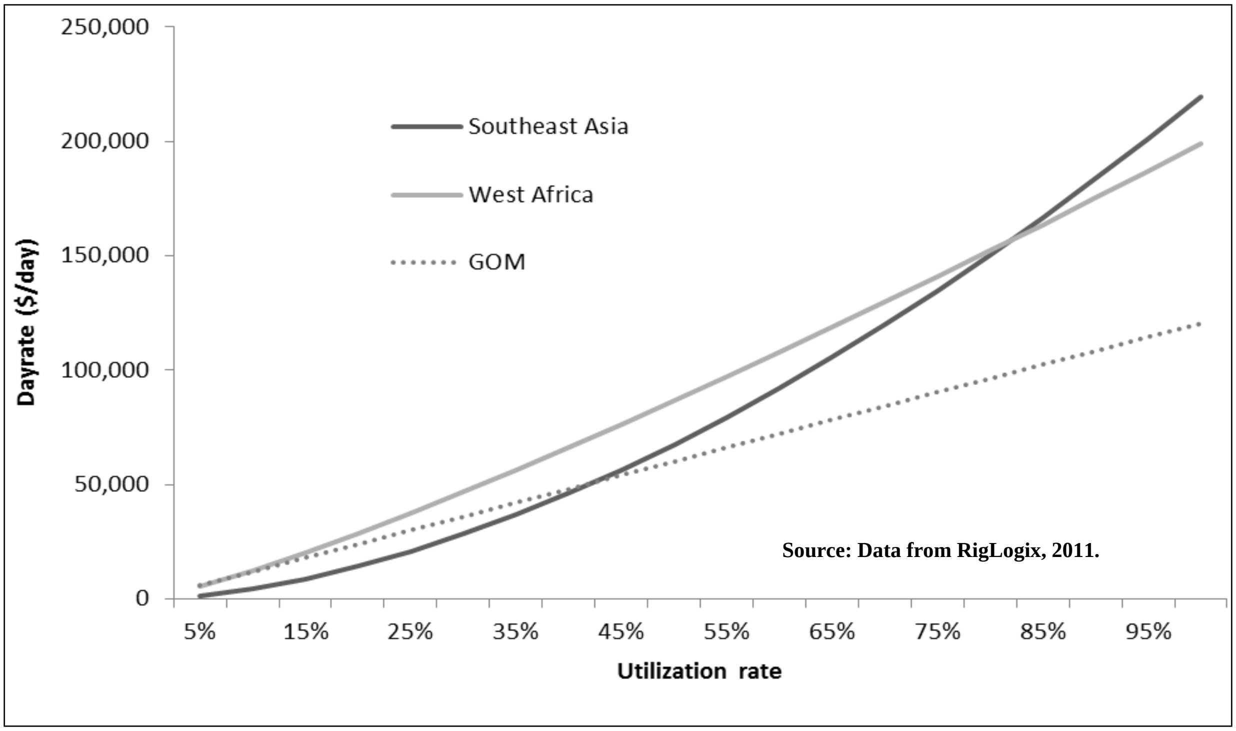


Figure E.5. Model relationship between utilization rates and dayrates in three jackup markets, 2006–2010.

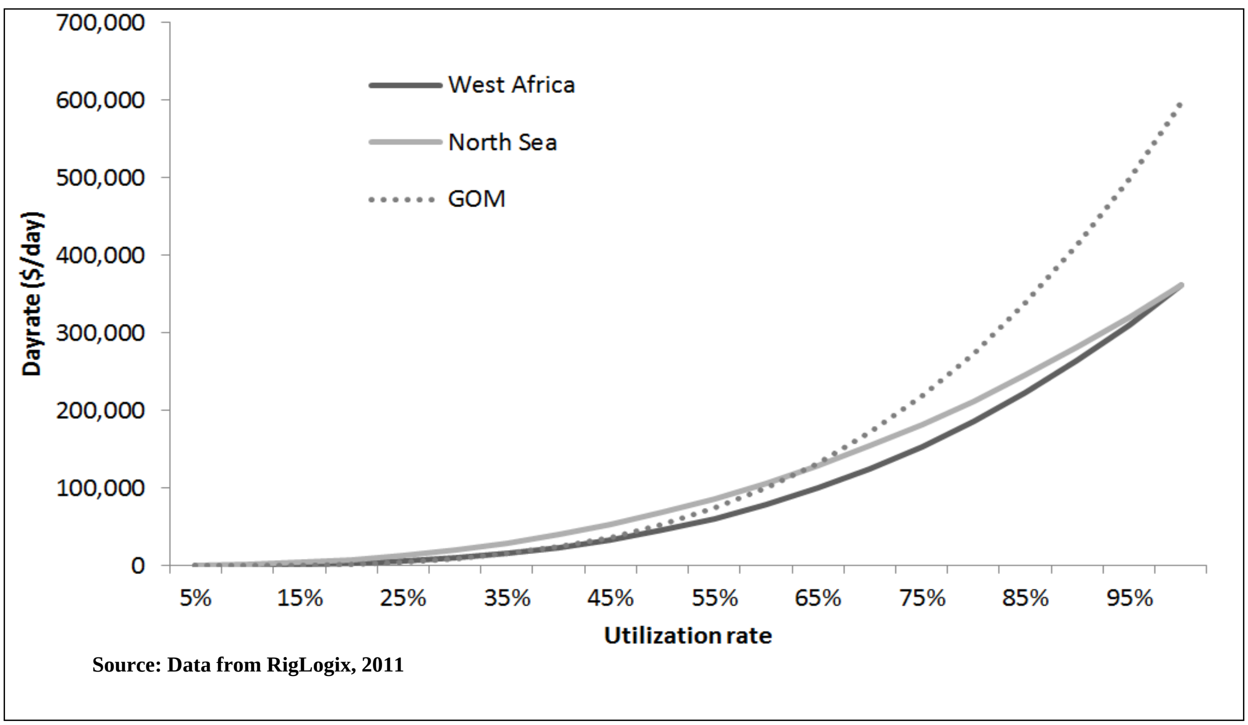


Figure E.6. Model relationship between utilization rates and dayrates in three floater markets, 2006–2010.

APPENDIX F

CHAPTER 6 TABLES AND FIGURES

Table F.1.

NPV Newbuild Model Variable Definitions

Variable	Unit	Description
C	$	Purchase price of the rig
T	yr	Maturity of debt
I	%/yr	Interest rate of debt
G	% of C	Upgrade cost
O_a	$/day	Daily operating costs when the rig is active
O_s	$/day	Daily operating costs when the rig is stacked
DR	$/day	Dayrate
t	yr	Life time of the rig
U_t	%	Utilization rate in year t
U_e	%	Average utilization rate over t
X	%/yr	Tax rate
D	%/yr	Discount rate

Table F.2.

Optimistic and Expected Parameterizations of the Newbuilding Model

Variable	Unit	Expected	Optimistic
C	$ million	200	175
T	yr	7	15
I	%/yr	4.5	3
G	% of C	25	25
O_a	$/day	60,000	50,000
O_s	$/day	10,000	6,000
DR	$/day	Variable	Variable
t	yr	25	25
U_t	%	Variable	Variable
U_e	%	Variable	Variable
X	%/yr	15	10
D	%/yr	15	10

Table F.3.

Stacked and Active Operating Expenditures for Jackups and Floaters, 2010–2011

Rig type	Firm	Rig type	Status	OPEX ($/day)
Jackups	Transocean	High-spec	Operating	87,000
			Stacked	10,600
		Standard	Operating	46,000
			Stacked	6,900
	Hercules	Domestic	Operating	32,000
			Stacked	6,700
		International	Operating	47,000
			Stacked	8,000–12,000
	Diamond	High-spec	Operating	55,000
		Standard	Operating	45,000–
Floaters	Transocean	Ultra-deepwater	Operating	150,000
		Deepwater	Operating	137,000
			Stacked	26,000
		Midwater	Operating	104,000
			Stacked	10,000

Source: Firm annual reports.

Table F.4.

Percentage Effects of a 1% Change in Selected Variables on the Break-Even Dayrate

Model	OPEX (O_a)	Interest rate (I)	Purchase price (C)	Tax rate (X)
Fixed utilization	0.50%	0.12%	0.50%	0.04%
Variable utilization				
$U_e = 0.05$	0.26%	0.15%	0.65%	0.16%
$U_e = 1$	0.50%	0.12%	0.50%	0.04%

Table F.5.

Stacking Model Variable Definitions

Variable	Units	Description
O_a	\$/day	Daily operating costs when the rig is active
O_s	\$/day	Daily operating costs when the rig is stacked
DR	\$/day	Dayrate
U_e	%	Average utilization rate
y	days	Time rig is to be stacked
F	\$	Fixed reactivation costs
R	\$/day	Variable reactivation costs

Table F.6.

Net Asset Values of Rig Classes, 4Q 2011

Class	Water depth (ft)	Environment	Built	NAV (million $)
Jackup	400	Moderate	Modern	210
Jackup	375	Moderate	Modern	203
Jackup	350	Moderate	Modern	195
Jackup	300	Moderate	Modern	180
Jackup	400	Harsh	Modern	230
Jackup	375	Harsh	Modern	223
Jackup	350	Harsh	Modern	215
Jackup	300	Harsh	Modern	200
Jackup	350	Moderate	1980’s	70
Jackup	300	Moderate	1980’s	50
Jackup	350	Harsh	1980’s	105
Jackup	300	Harsh	1980’s	80
Semi			Second generation	170
Semi			Third generation	210
Semi			Fourth generation	300
Semi			Fifth generation	530
Semi			Sixth generation	570
Drillship			1970’s	110
Drillship	4,000			205
Drillship	8,000			540
Drillship	10,000			590

Source: Morgan Stanley, 2011.

Table F.7.

Parameterization of the NAV Model

Variable	Unit	Description	Value
C	$	Net asset value	NAV
O_a	$/day	Operating costs	60,000
DR	$/day	Dayrate	Variable
t	yr	Remaining life of the rig	25-A
U_e	%	Utilization	Variable
X	%/yr	Tax rate	15
D	%/yr	Discount rate	15
A	yr	Age of the rig	5, 10 or 20

Table F.8.

Comparison of NAV Estimates for Two Standard 300 ft Jackup Rigs in January 2012

Rig	Age	Dayrate ($/day)	Utilization rate (%)	Discount rate (%)	Authors NAV (million $)	Jefferies NAV (million $)
Galaxy II	14	167,000	90	15	166	170
Galaxy III	13	144,000	90	15	131	156

Source: Jefferies and Company, Inc., 2012.

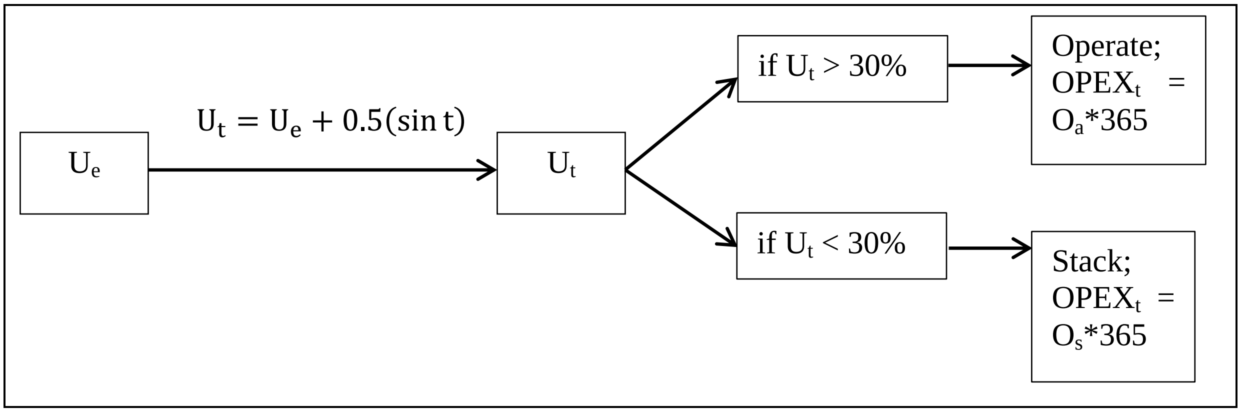


Figure F.1. Diagram of the variable utilization model and stacking decision.

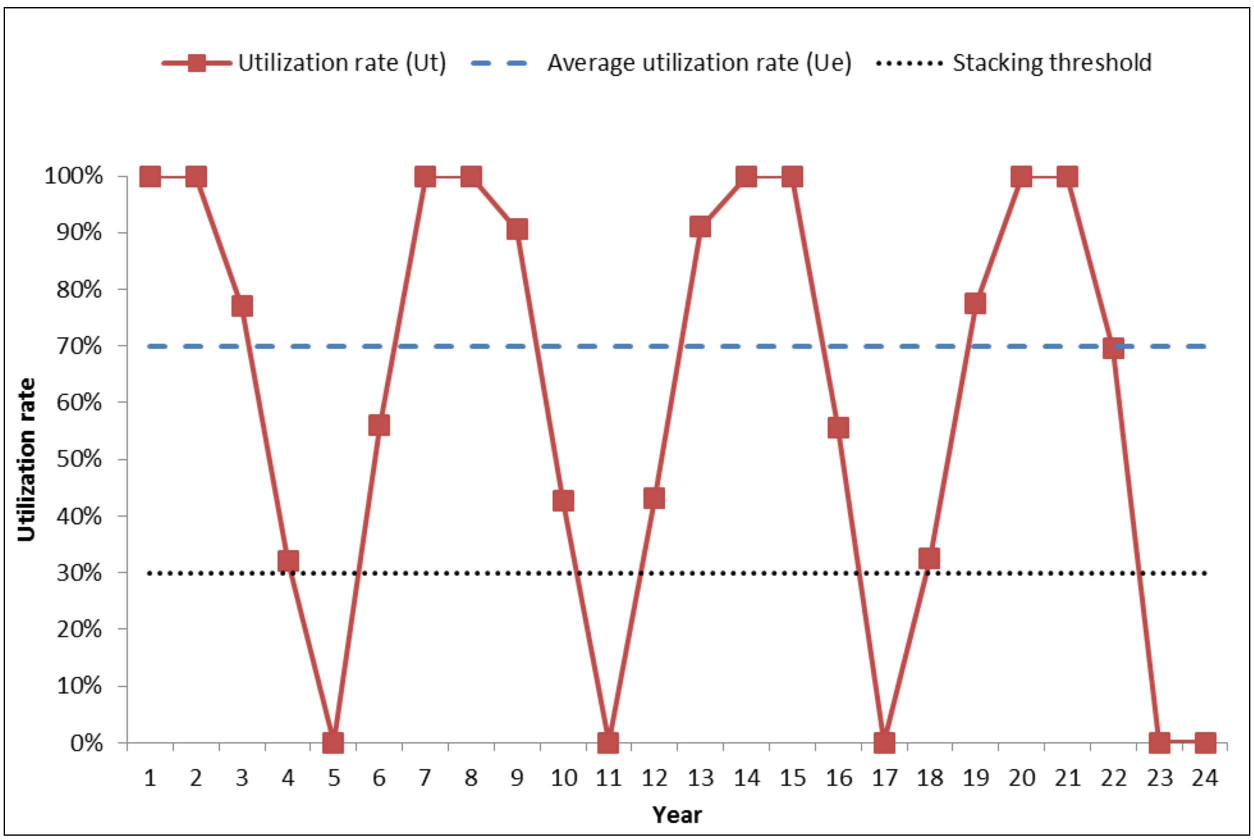


Figure F.2. Utilization rate over the rig lifecycle in the variable utilization model.

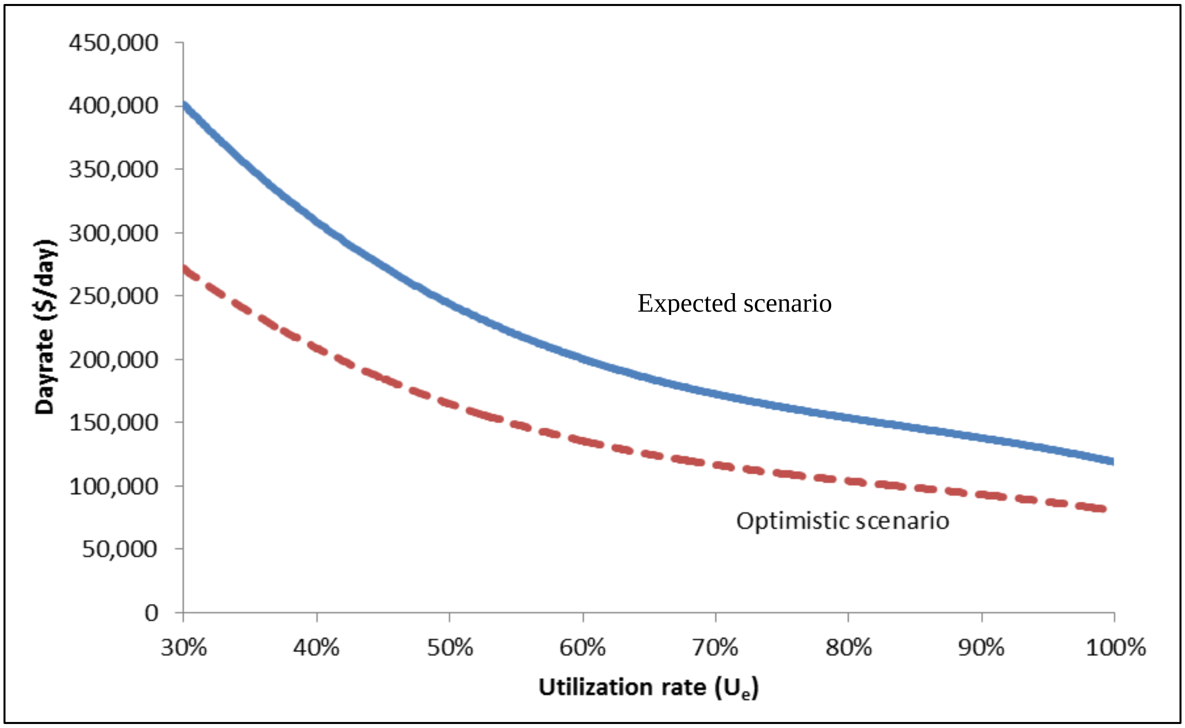


Figure F.3. NPV break-even points of utilization and dayrates under expected and optimistic assumptions for fixed utilization.

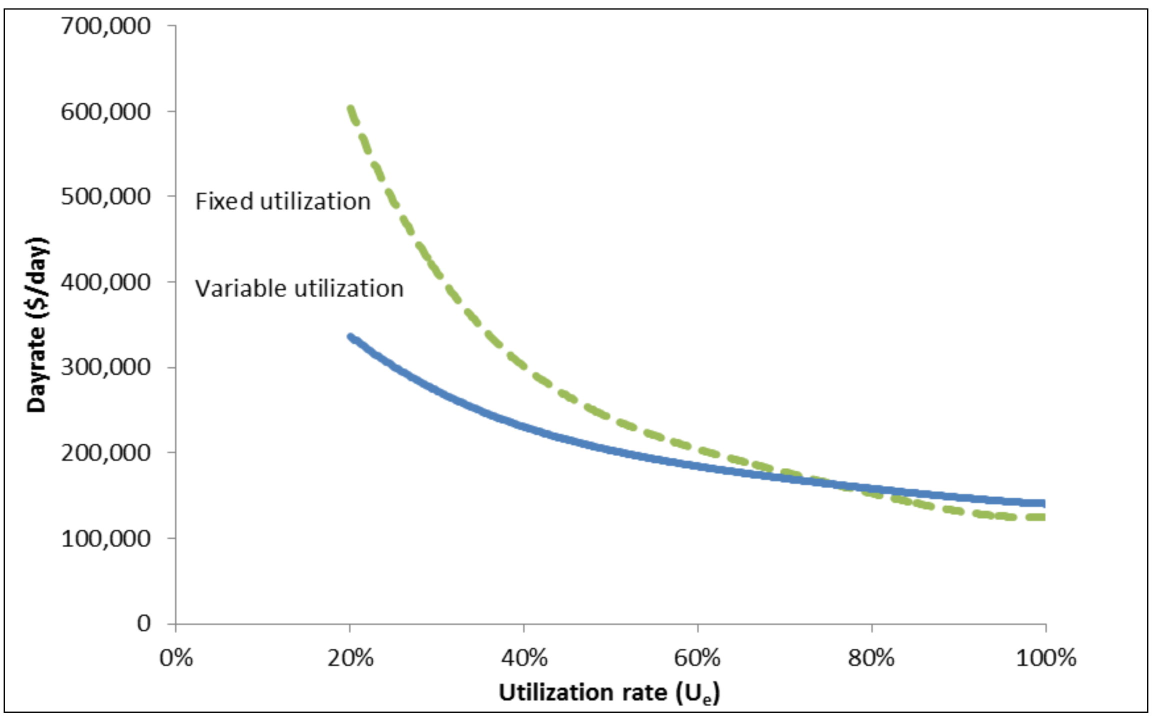


Figure F.4. NPV break-even points of utilization and dayrates with fixed and variable utilization rates under the expected scenario.

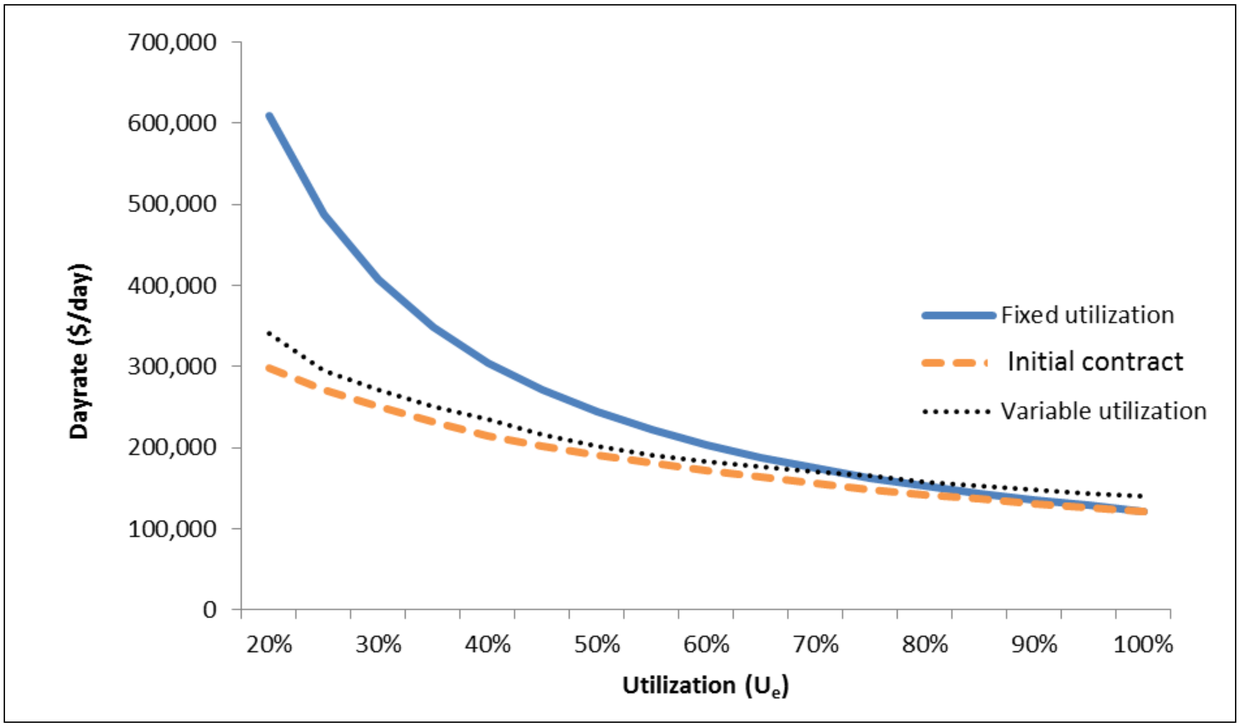


Figure F.5. The impacts of an initial two year contract on break-even dayrates and utilization rates.

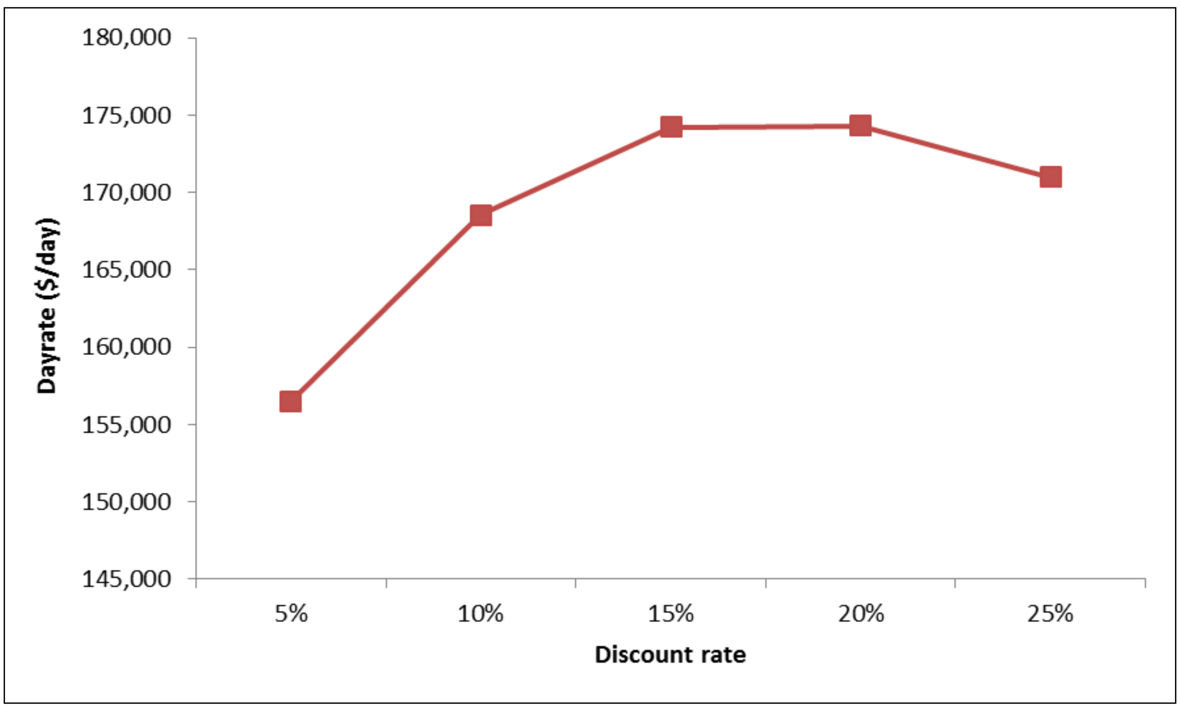


Figure F.6. Sensitivity of the break-even dayrate fixed utilization model to changes in discount rate.

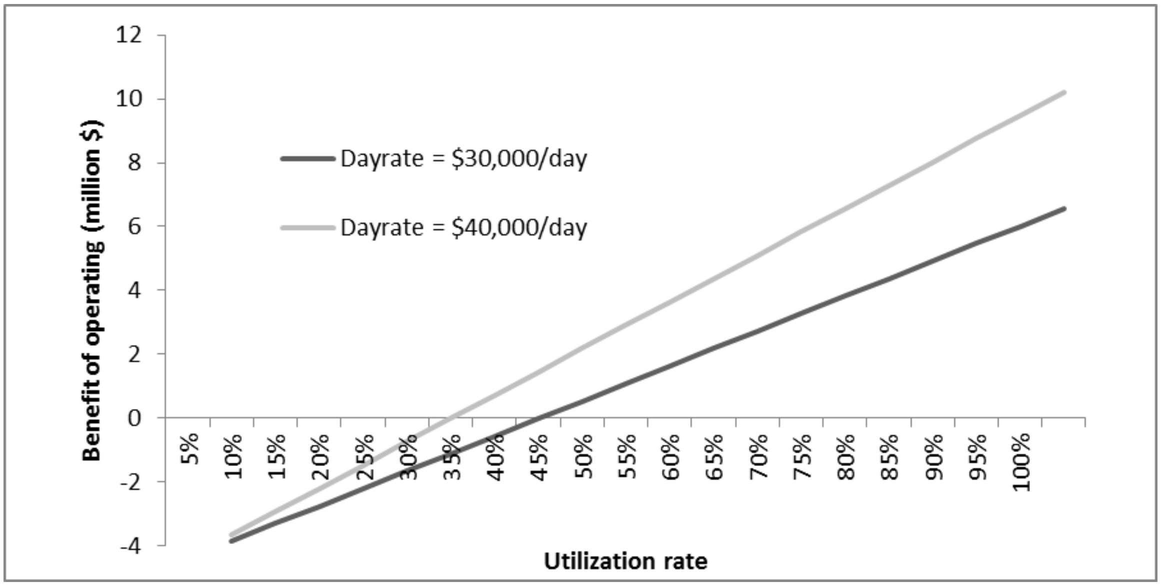


Figure F.7. Effect of utilization on the benefit of the stacking versus operating.

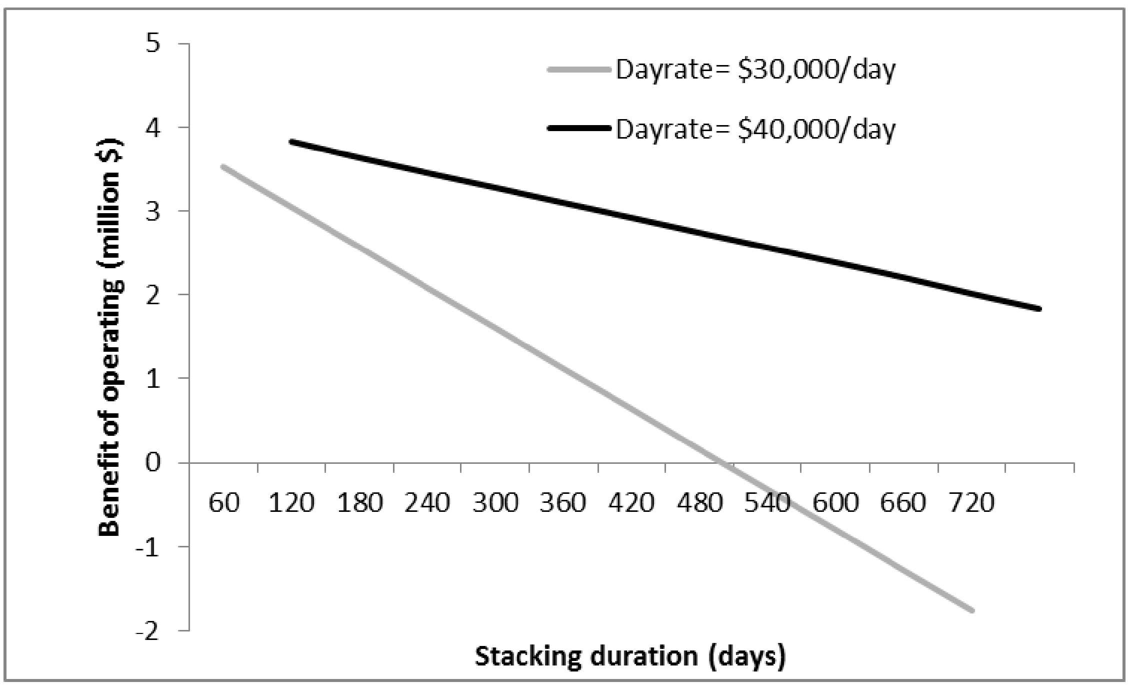


Figure F.8. Effect of stacking duration on the benefit of stacking versus operating.

Source: Jefferies and Company, Inc., 2011.

Rig Name	Rig Design	Year Delivered/ Upgraded	Max. Water Depth	Current Location	Current Status	Operator	Net Asset Value	Asset Repl. Value	Cont. Exp.	Est. Current Dayrates
Semisubmersibles - 11										
West Eminence	CS-50 MkII (N) (DP)	2009	10,000'	Brazil	Drilling	Petrobras	$810.0	$640.0	7/15	$618,500
West Orion	F&G ExD (DP)	2010	10,000'	Brazil	Drilling	Petrobras	845.0	640.0	7/16	618,500
West Taurus (2)	F&G ExD (DP)	2008	10,000'	Brazil	Drilling	Petrobras	830.0	640.0	2/15	650,000
West Pegasus	Moss Maritime CS50 Mk II (DP)	2011	10,000'	Mexico	Drilling	PEMEX	630.0	640.0	8/16	465,000
West Aquarius	GVA 7500-N (DP)	2008	10,000'	Far East	Drilling	ExxonMobil	680.0	640.0	2/13	526,000
West Hercules (1)	GVA 7500-N (DP)	2008	10,000'	Far East	Drilling	Husky	660.0	640.0	5/12	495,000
West Alpha (3)	Dyvi Ultra Yatzy	1986	2,000'	North Sea	Drilling	Consortium	355.0	425.0	7/12	509,000
West Phoenix (3)	CS-50 MkII (N) (DP)	2008	10,000'	North Sea	Drilling	Total	650.0	640.0	1/12	553,000
West Venture (3)	Smedvig ME-5000 (DP)	2000	6,000'	North Sea	Drilling	StatoilHydro	510.0	610.0	7/15	444,000
West Capricorn	F&G ExD (DP)	2011	10,000'	US Gulf	Enroute	-	478.0	478.0	-	-
West Sirius	F&G ExD (DP)	2008	10,000'	US Gulf	Drilling	BP	660.0	640.0	7/14	474,000
Drillships - 4										
West Polaris (4)	Saipem 10000 (DP)	2008	10,000'	West Africa	Drilling	ExxonMobil	720.0	640.0	10/12	611,000
West Navigator (3)	MST III-CADS (DP)	2000	7,500'	North Sea	Drilling	Shell	635.0	636.8	6/14	618,000
West Capella	Saipem 10000 (DP)	2008	10,000'	West Africa	Drilling	Total	725.0	640.0	4/14	542,000
West Gemini	Saipem 10000 (DP)	2010	10,000'	West Africa	Drilling	Total	670.0	640.0	9/12	447,000

Figure F.9. Sample net asset values of Seadrill floaters as calculated by Jefferies, 4Q 2011.

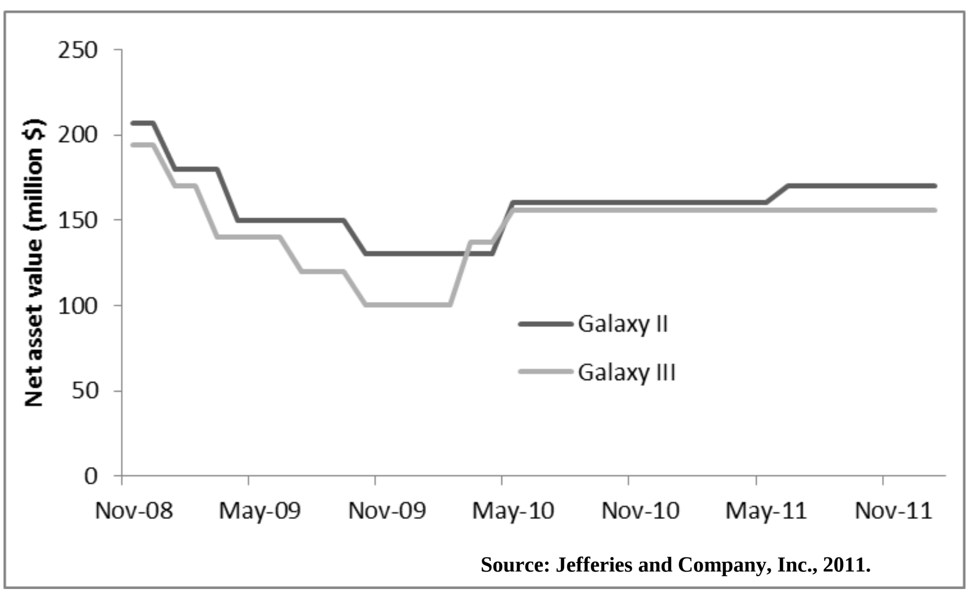


Figure F.10. Net asset value over time for two similar rigs, November 2008–November 2011.

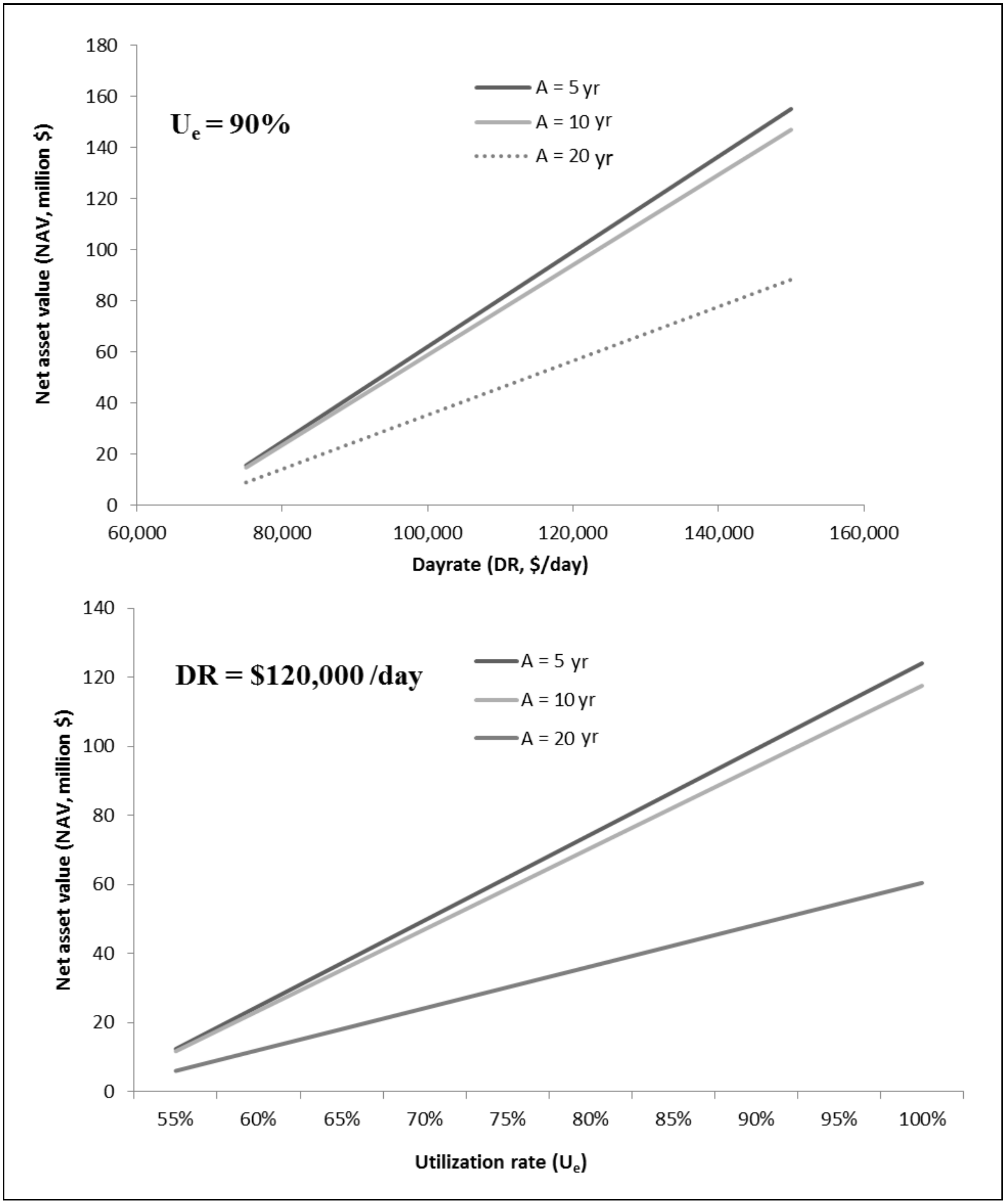


Figure F.11. Relationship between NAV and dayrates and utilization rates for rigs of different ages.

APPENDIX G

CHAPTER 7 TABLES AND FIGURES

Table G.1.

Worldwide Distribution of Rig Construction in 2012

Country	Jackups	Semis	Drillships
Singapore	40	4	
China	18	6	3
Mexico	1	4	
UAE	8		
Brazil	2	1	7
India	5		
Vietnam	2		
Korea			37
Italy		1	
Russia	1		
Total	77	16	47

Source: Data from Jefferies and Company, Inc., 2012.

Table G.2.

Shipyard Deliveries from 2005-2012 and 2011 Market Capitalization

Shipyard	Nation	Jackups	Semis	Drillship	2011 market capitalization (billion $)
Keppel	Singapore	38	10	2	15.1
Sembcorp	Singapore	33	10		8.8
Daewoo	Korea		6	12	7.6
CIMC Raffles	China	3	6		
Samsung	Korea		4	24	9.5
IMAC	UAE		4		
COSCO/Dalian	China	12	4		3.1
Aker	Norway		2		
Severodvinsk	Russia	1	1		
LeTourneau	U.S.	8			
AmFELS	U.S.	12			
Lamprell	UAE	12			0.5
ABG	India	4			0.3
CNOOC	China	4			
Others		13	3	4	

Table G.3.

Jackup Construction in U.S. Shipyards, 2000–2012

Name	Shipyard	Delivery date	Design	Drilling depth (ft)	Harsh	Water depth (ft)
Rowan Gorilla VI	Vicksburg, MS	2000	LeTourneau Super Gorilla 219-C	35,000	Yes	400
Rowan Gorilla VII	Vicksburg, MS	2001	LeTourneau Super Gorilla 219-C	35,000	Yes	400
Seawork 1	New Iberia, LA	2002	Liftboat		No	140
ENSCO 105	Brownsville, TX	2002	KFELS B Class	30,000	No	375
Bob Palmer	Vicksburg, MS	2003	LeTourneau Super Gorilla XL 224-C	35,000	Yes	550
Tonala	Brownsville, TX	2004	KFELS B Class	25,000	No	375
Scooter Yeargain	Vicksburg, MS	2004	LeTourneau Tarzan Class 225-C	35,000	No	300
Bob Keller	Vicksburg, MS	2005	LeTourneau Tarzan Class 225-C	35,000	No	300
Hank Boswell	Vicksburg, MS	2006	LeTourneau Tarzan Class 225-C	35,000	No	300
Offshore Courageous	Brownsville, TX	2007	LeTourneau Super 116	30,000	No	350
Panuco	Vicksburg, MS	2007	LeTourneau Super 116E	25,000	No	350
Offshore Defender	Brownsville, TX	2007	LeTourneau Super 116	30,000	No	350
Offshore Resolute	Brownsville, TX	2008	LeTourneau Super 116	30,000	No	350
Ocean Scepter	Brownsville, TX	2008	KFELS B Class	35,000	No	350
Offshore Vigilant	Brownsville, TX	2008	LeTourneau Super 116	30,000	No	350
Rowan Mississippi	Vicksburg, MS	2008	LeTourneau Workhorse 240C	35,000	No	375
JP Bussell	Vicksburg, MS	2008	LeTourneau Tarzan Class 225-C	35,000	No	300
Atwood Aurora	Brownsville, TX	2008	LeTourneau Super 116E	30,000	No	350
Offshore Intrepid	Brownsville, TX	2009	LeTourneau Super 116	30,000	No	350
Ralph Coffman	Vicksburg, MS	2009	LeTourneau Workhorse 240C	35,000	No	400
Tuxpan	Brownsville, TX	2010	LeTourneau Super 116E	30,000	No	375
Rowan EXL I	Brownsville, TX	2010	LeTourneau Super 116E	40,000	No	350
Rowan EXL II	Brownsville, TX	2010	LeTourneau Super 116E	35,000	No	350
Rowan EXL III	Brownsville, TX	2010	LeTourneau Super 116E	40,000	No	350
Joe Douglas	Vicksburg, MS	2011	LeTourneau Workhorse 240C	35,000	No	350
Rowan EXL IV	Brownsville, TX	2012	LeTourneau Super 116E	40,000	No	350

Source: Data from RigLogix, 2011.

Table G.4.

Deliveries of Semisubmersibles from U.S. Shipyards, 2000–2012

Name	Water depth (ft)	Nominal cost (million $)	Delivery year	Shipyard
ENSCO 7500	8,000	225	2000	TDI- Halter, Orange, TX
Ocean Confidence	10,000	510	2001	TDI- Halter, Sabine, TX
Leiv Eiriksson	8,200	440	2001	Friede Goldman Halter, Pascagoula, Mississippi
Erik Raude	10,000	555	2002	Friede Goldman Halter, Pascagoula, Mississippi
Q4000	1,000	156	2002	AmFELS

Source: Colton, 2011; Industry press.

Table G.5.

Number of Newbuild (2005-2012) Rigs in the Fleets of Selected Drilling Contractors in 2012

Firm	Jackups	Semis	Drillships	Total
Seadrill	20	10	6	36
Transocean	4	5	11	20
COSL	15	5		20
ENSCO	7	7	5	19
Noble	8		8	16
Rowan	13		3	16
Maersk	8	3	4	15
Diamond	1	4	4	9
Aban	9			9
Vantage	4		5	9
Atwood	4	2	2	8
National Drilling	5			5
Songa		4		4
Stena			4	4

Source: Data from RigLogix, 2011.

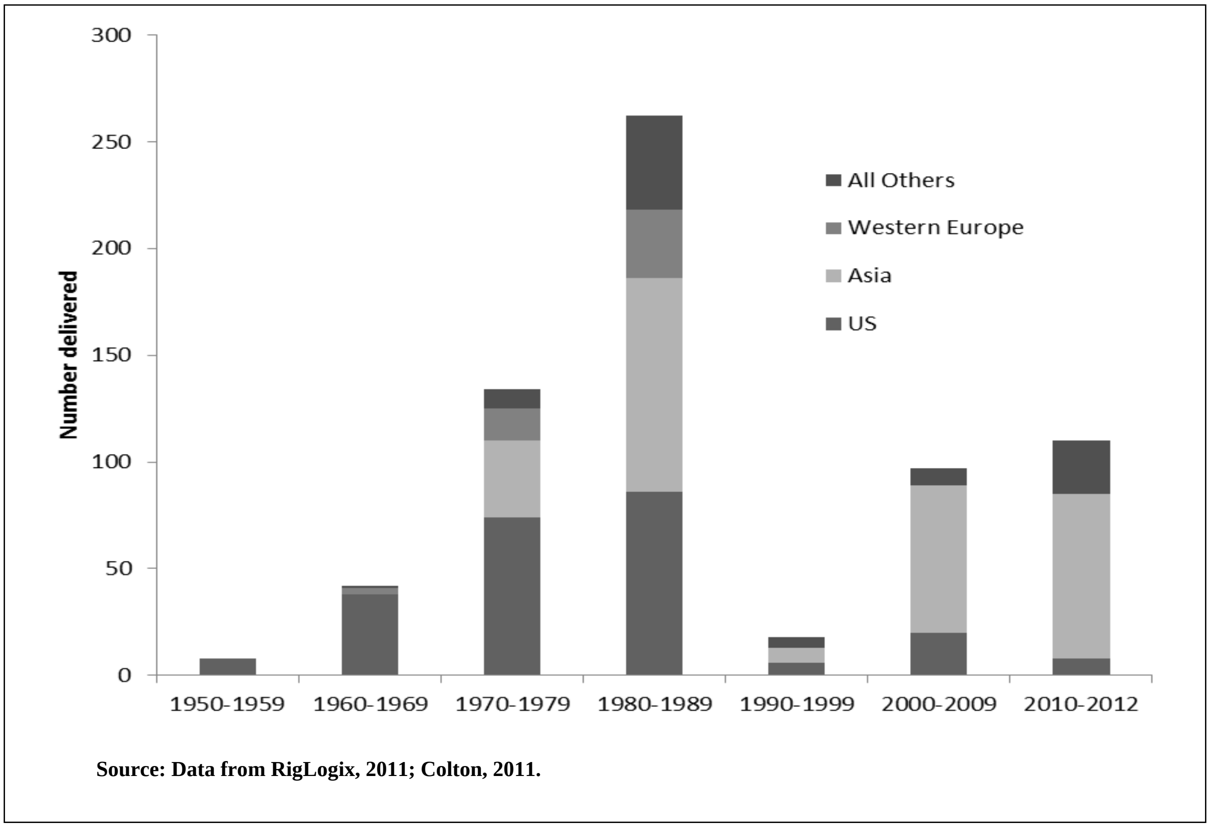


Figure G.1. Jackup rig construction by region, 1950–2012.

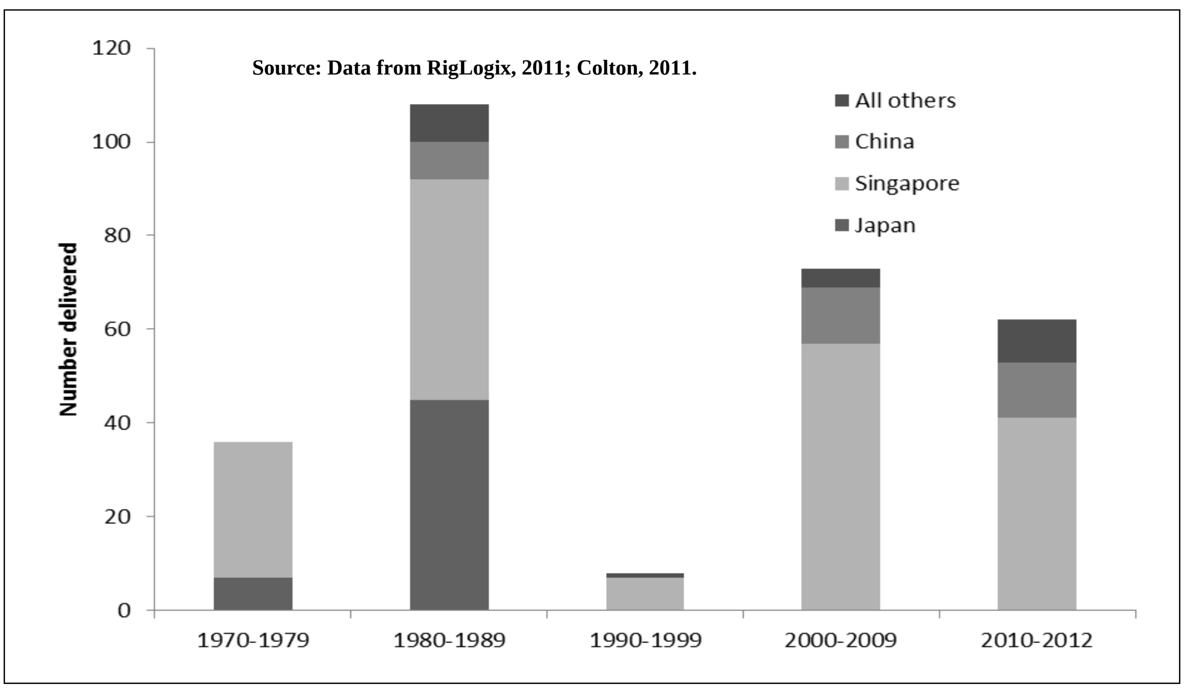
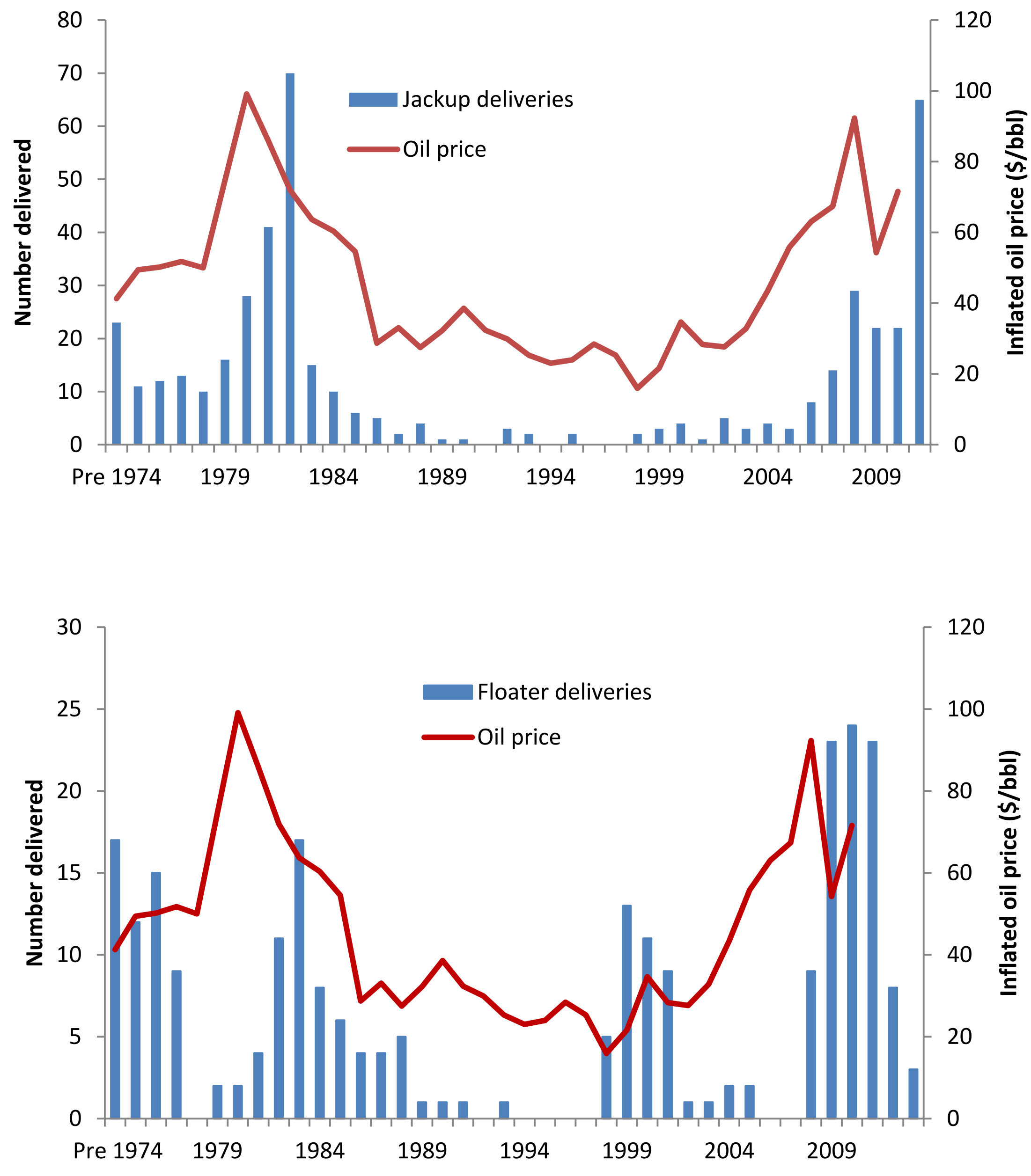


Figure G.2. Jackup rig construction in Asian countries, 1970–2012.



Source: Data from RigLogix, 2011.

Figure G.3. Oil price and worldwide delivery rates of jackup rigs and floating rigs, 1974–2012.

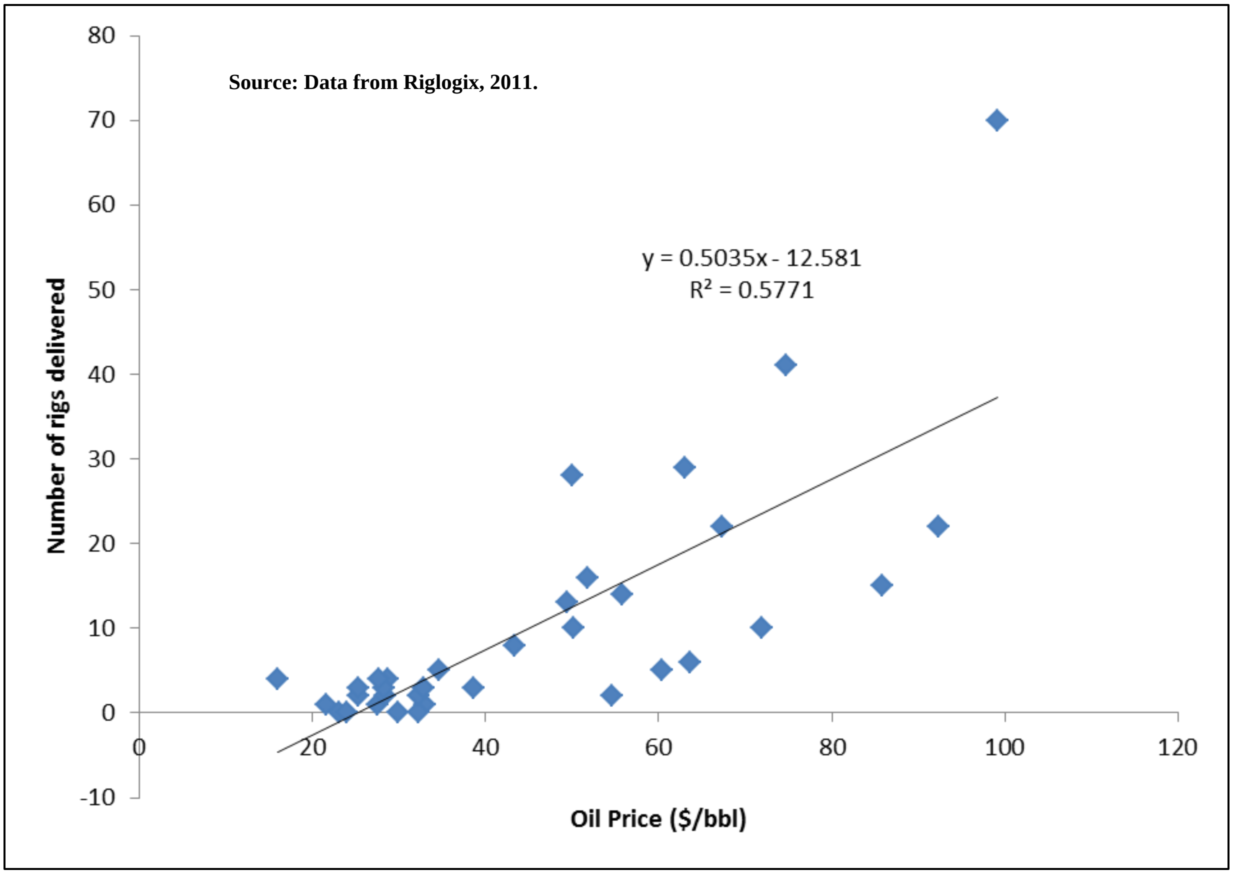


Figure G.4. Relationship between the two-year lagged oil price and number of jackups delivered, 1975–2012.

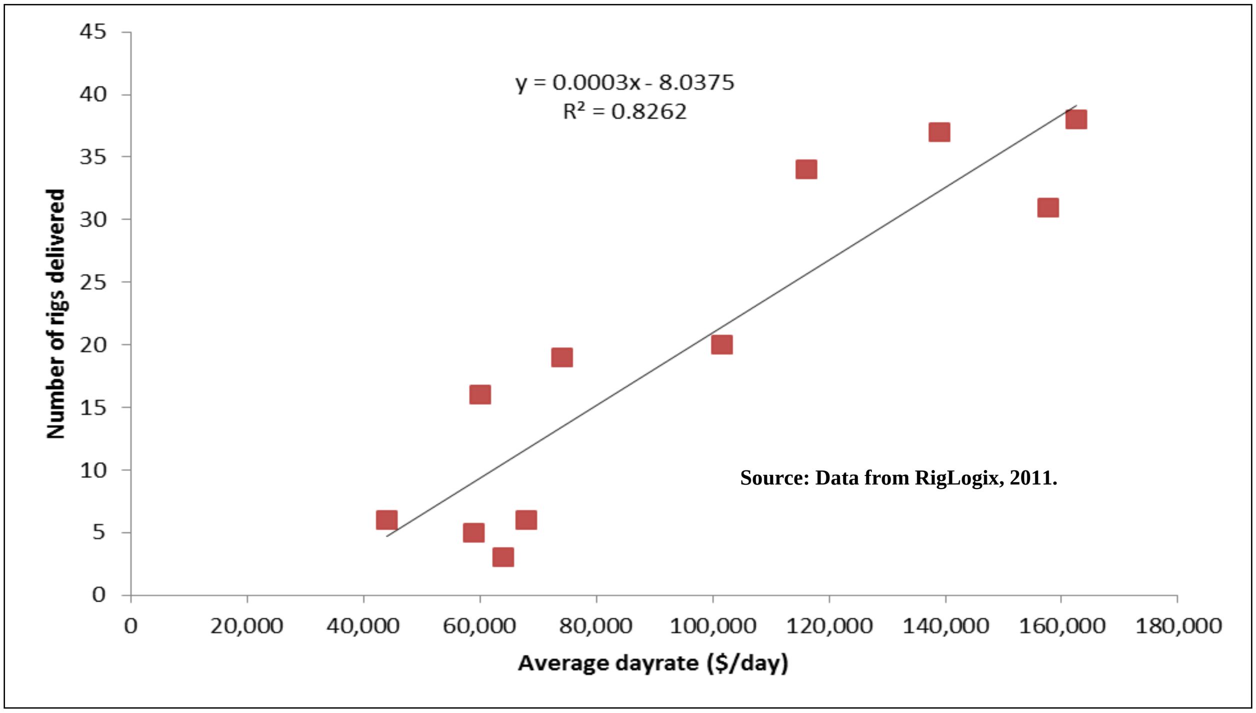
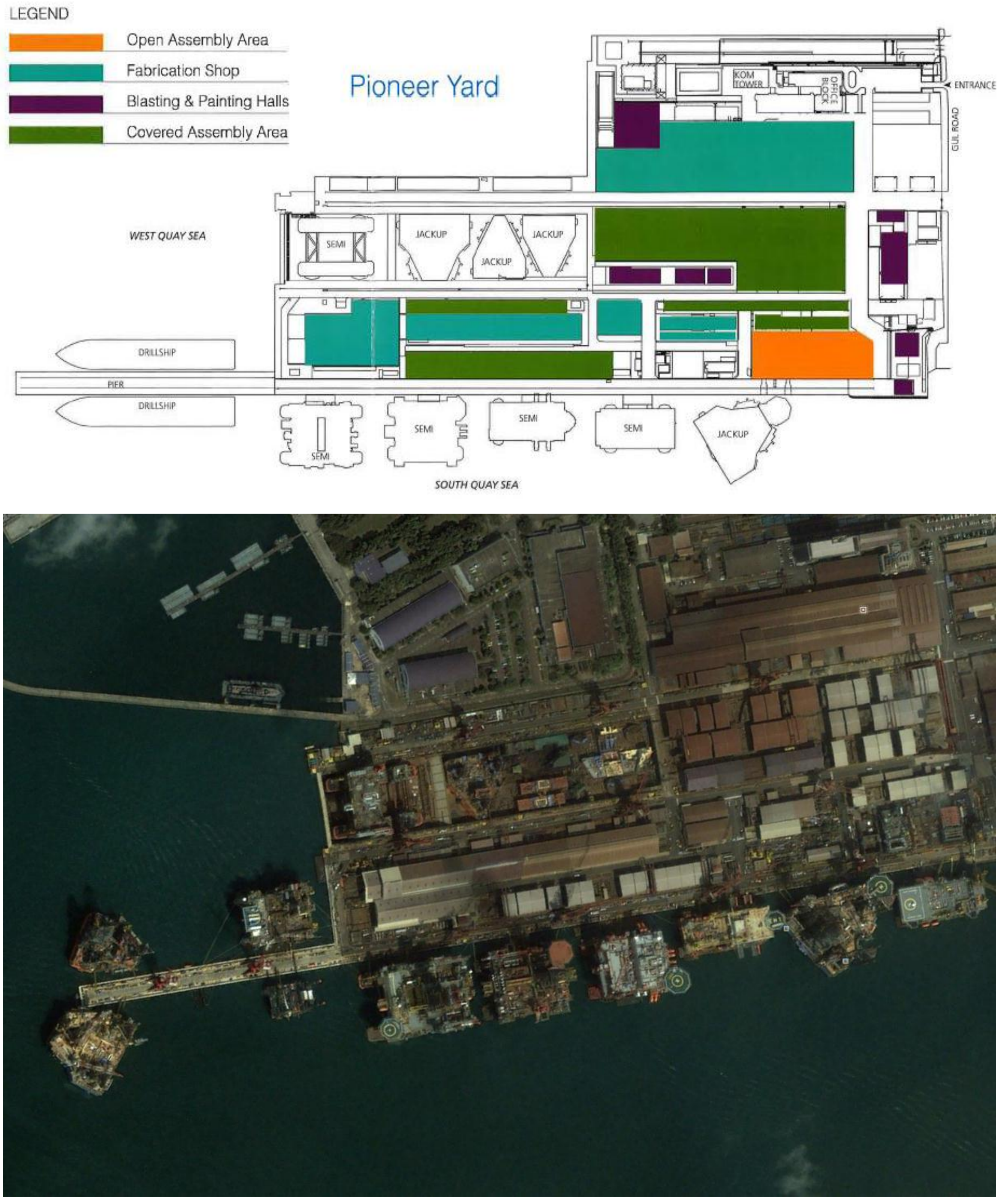
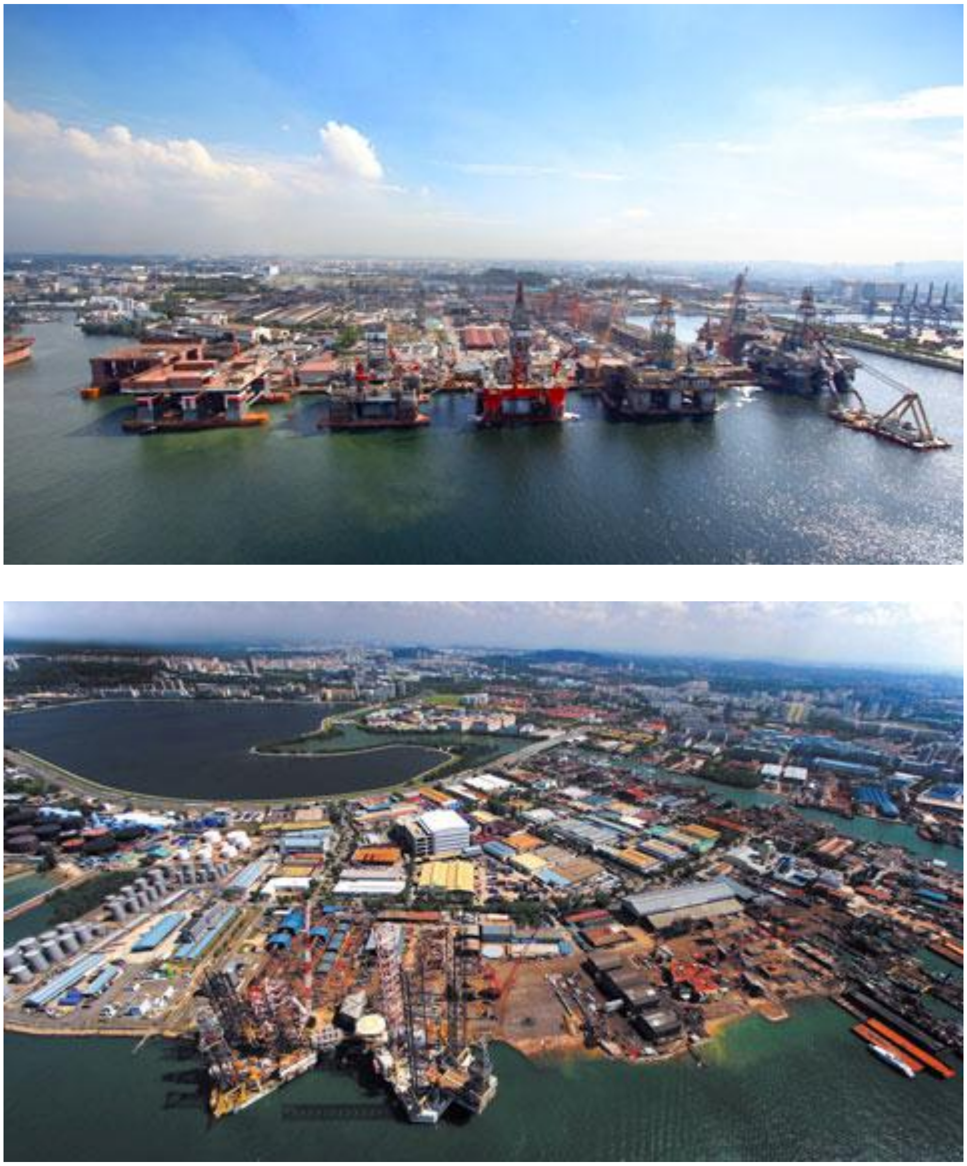


Figure G.5. Relationship between the two-year lagged average dayrate and number of jackups delivered, 2000–2012.



Source: Keppel FELS, 2011; Google Earth, 2011.

Figure G.6. Layout of the Keppel FELS shipyard in Singapore and satellite view in 2011.



Source: Sembcorp Marine, 2012a and 2012b.

Figure G.7. Sembcorp's Jurong and PPL shipyards in 2012.

Figure G.8. The LeTourneau Vicksburg, Mississippi shipyard.

Figure G.9. The AmFELS Brownsville, Texas shipyard.

APPENDIX H

CHAPTER 8 TABLES AND FIGURES

Table H.1.

Number of Rigs Delivered and Under Construction Worldwide by Design Class, 1Q 2012

Rig Class	Number under build (1Q 2012)	Number delivered (2000–2011)	Harsh design
F&G Super M2	5	11	
MSC CJ70	3	3	Y
MSC CJ46	2	8	
MSC CJ50		4	
F&G 2000E/2000A	15	11	Y
CPLEC CP 300	2		
LeTourneau Super 116E	12	20	
LeTourneau 240 C	2	3	
LeTourneau Super Gorilla		3	
LeTourneau Tarzan		4	
PPL Pacific 375/400	3	28	
KFELS B/Super B Class	19	30	
KFELS Super A Class	6	2	Y
KFELS N Class		3	Y
F&G 3000N	6		Y
F&G L780		5	
Unknown/other	2	5	
Total	77	140	

Source: Data from RigLogix, 2011.

Table H.2.

Characteristics of Selected Gusto MSC Jackups

	CJ46	CJ50	CJ70
Hull dimensions (ft)	203 x 213	223 x	292 x
Leg length (ft)	483	480	672
Water depth (ft)	350	350	492
Elevated weight (tons)	13,640	18,700	33,000

Source: Gusto MSC, 2010.

Table H.3.

Jackup Rigs Delivered from U.S. Yards between 2000–2012

Design	Number delivered
LeTourneau Super 116/Super 116E	14
LeTourneau Super Gorilla	3
LeTourneau 240 C	3
LeTourneau Tarzan	4
KFELS B Class	2

Source: Data from RigLogix, 2011.

Table H.4.

Characteristics of Commonly Built Jackup Rigs

Design	Length (ft)	Width (ft)	Leg length (ft)	Variable load (tons)	Drilling depth (ft)
LeTourneau Tarzan	215	196	445	3,850	35,000
LeTourneau Super 116E	243	206	477	3,650	30,000
LeTourneau 240C	228	220	491	4,850	35,000
LeTourneau Super Gorilla XL	306	300	713	5,950	35,000
KFELS Super B Class	246	218	486	5,600	35,000
Gusto MSC CJ70	290	319	672	8,000	40,000
F&G 2000E	231	250	547	6,500	35,000
Pacific Class 375	236	224	506	3,750	30,000

Source: Rig specification sheets.

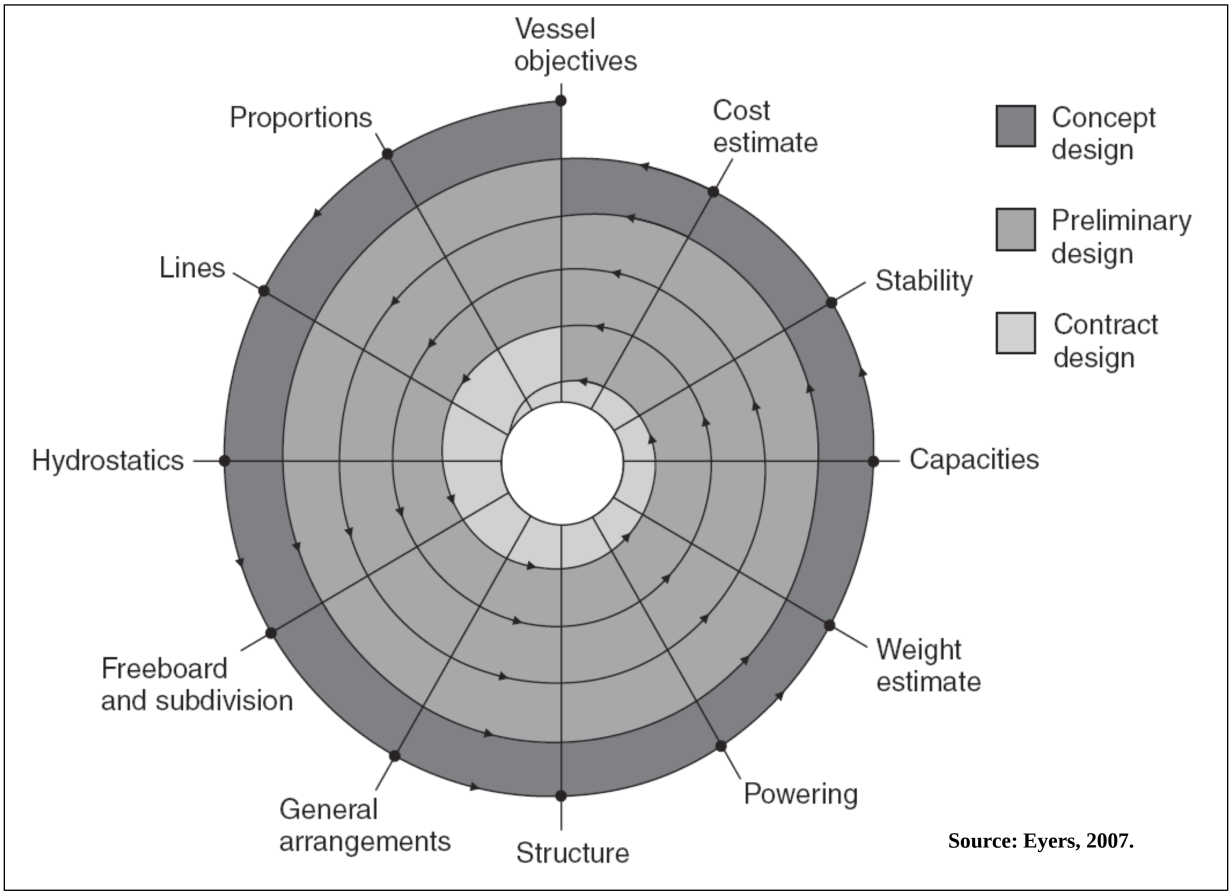


Figure H.1. Jackup rig design is analogous to ship design spiral.

Source: Seadrill, 2008a; Rowan, 2012.

Figure H.2. Four common rig designs; clockwise from upper left: BMC Pacific 375; KFELS N class; LeTourneau 240 C; LeTourneau Super 116E.

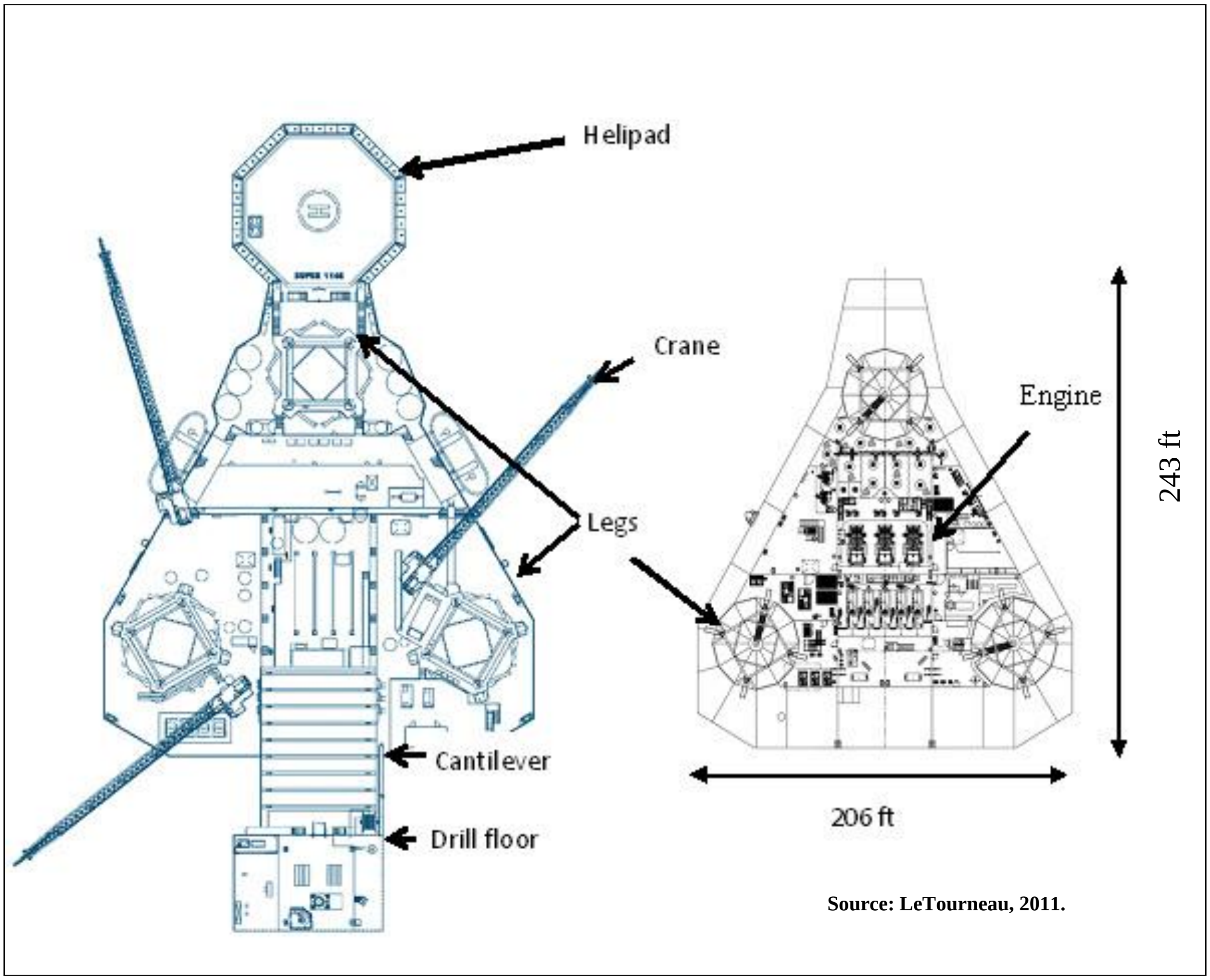


Figure H.3. Main deck (left) and machinery deck (right) layout of a LeTourneau Super 116E.

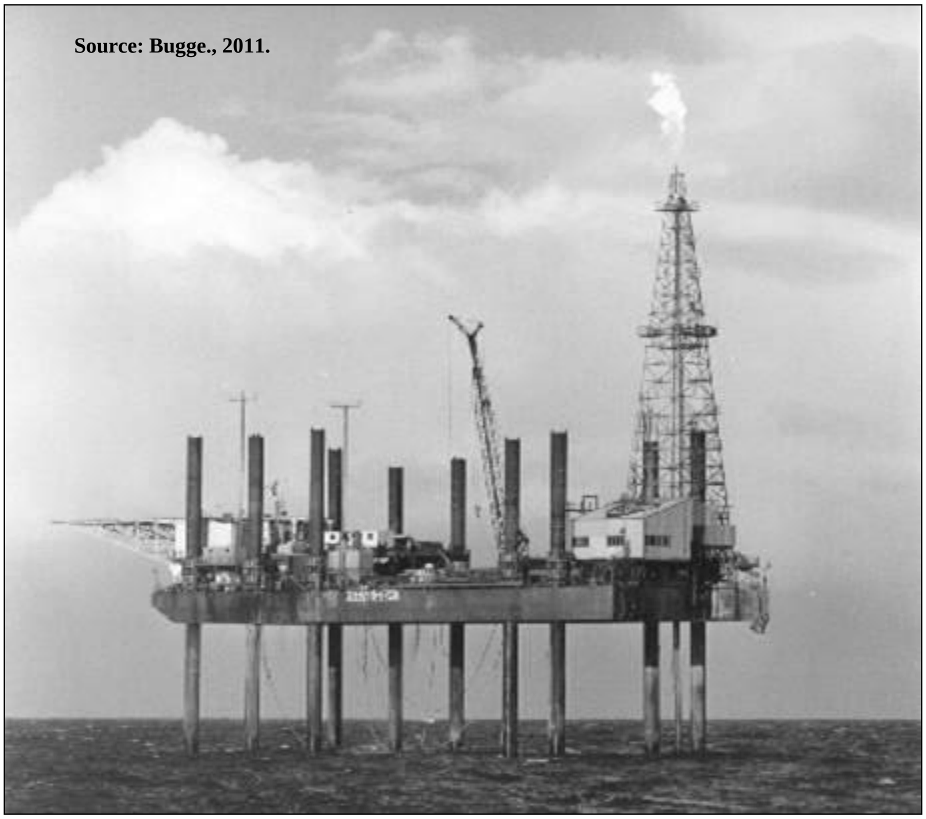


Figure H.4. Early jackup rig *Sea Gem* in 1964.

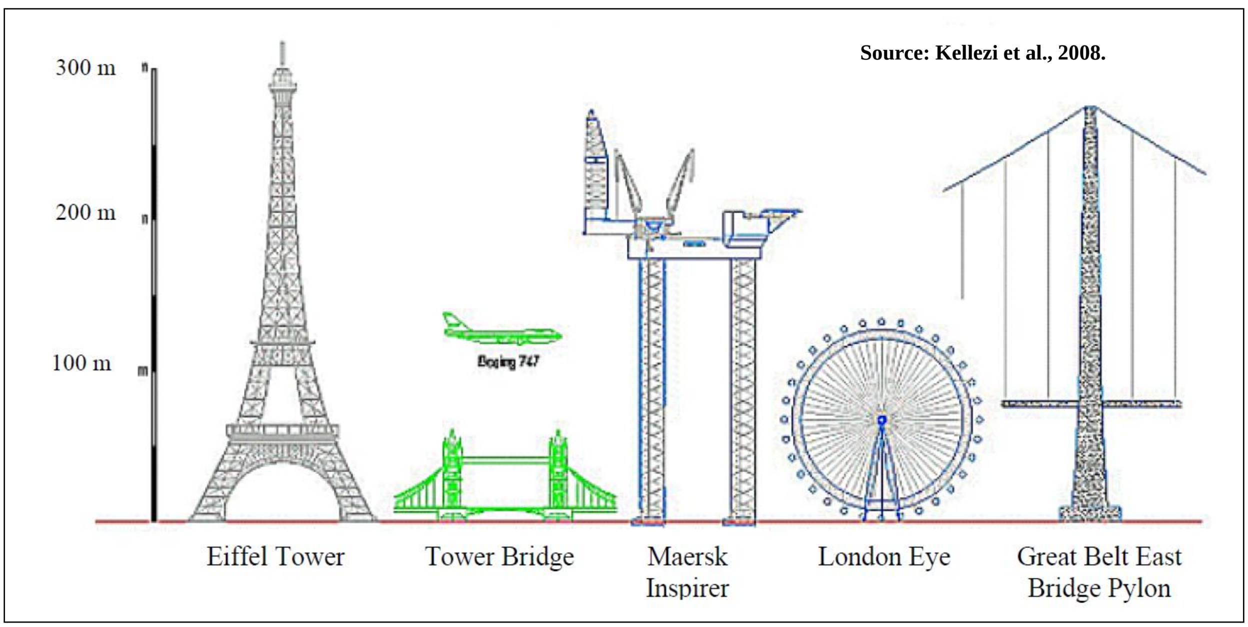


Figure H.5. Size comparison of the Gusto MSC CJ70 class rig.

Figure H.6. Cylindrical and trussed legs on the Bethlehem MS-225 *Spartan 202* and Gusto MSC CJ70 *Maersk Inspirer*.

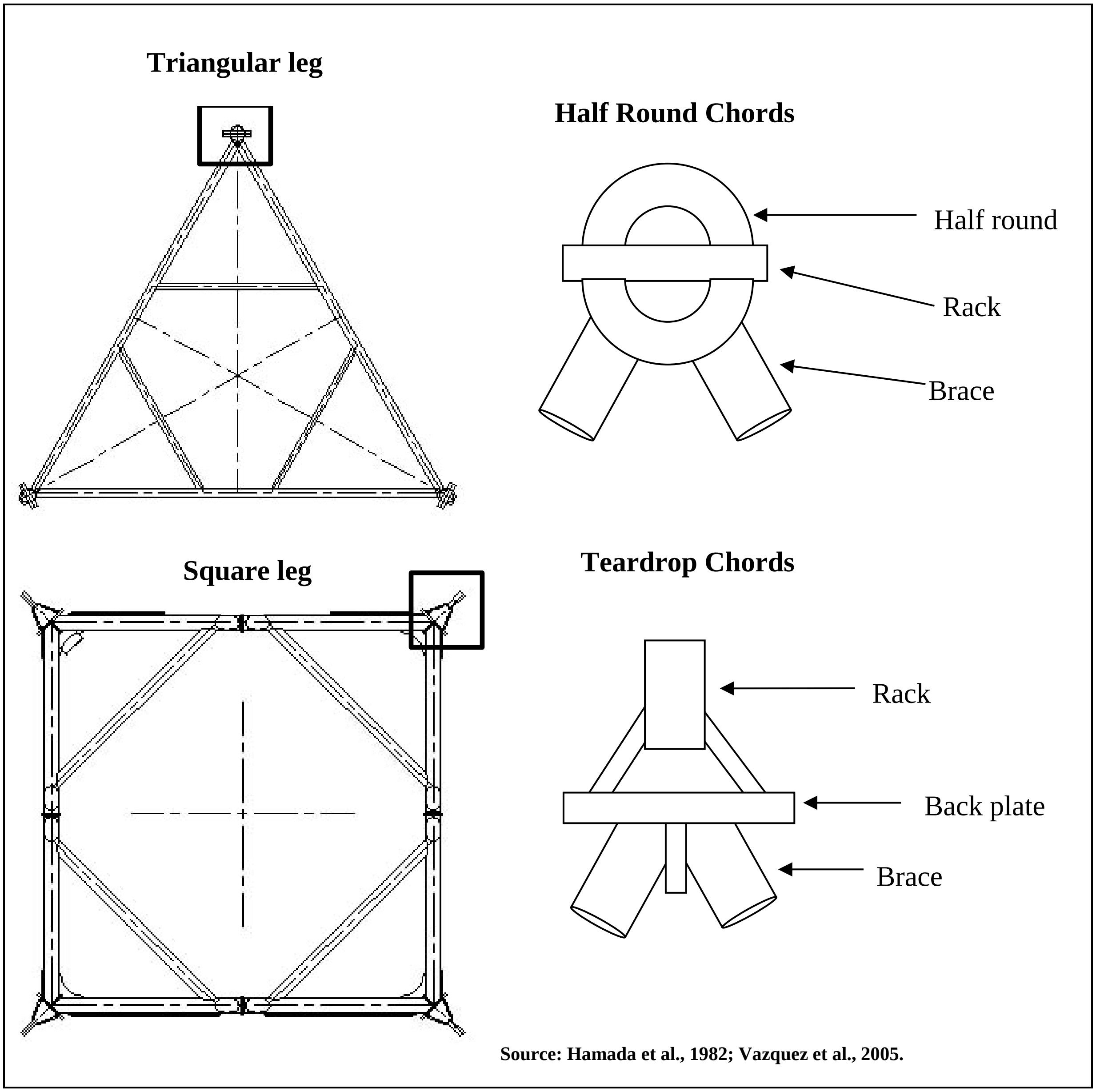


Figure H.7. Alternative leg and chord designs.

Source: Remedial Offshore, 2011.

Figure H.8. Rack chocks are inserted against the leg's racks to transfer the vertical load away from the pinions.

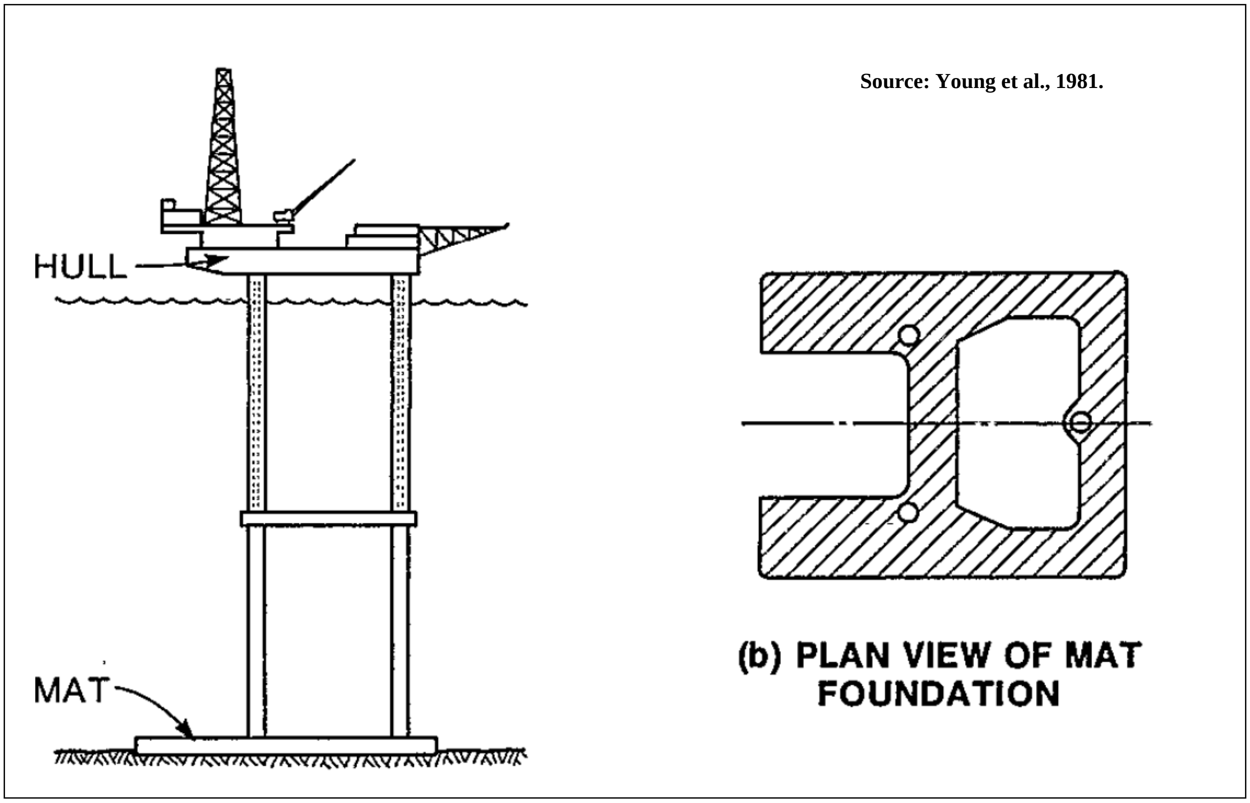


Figure H.9. Mat foundation of a jackup rig.


Source: JDC, 2008.

Figure H.10. Cantilever drilling rig operating over a fixed platform.

Figure H.11. Common U.S. built jackup designs; clockwise from top left: LeTourneau Super 116E, LeTourneau Tarzan, LeTourneau 240C, LeTourneau Super Gorilla XL.

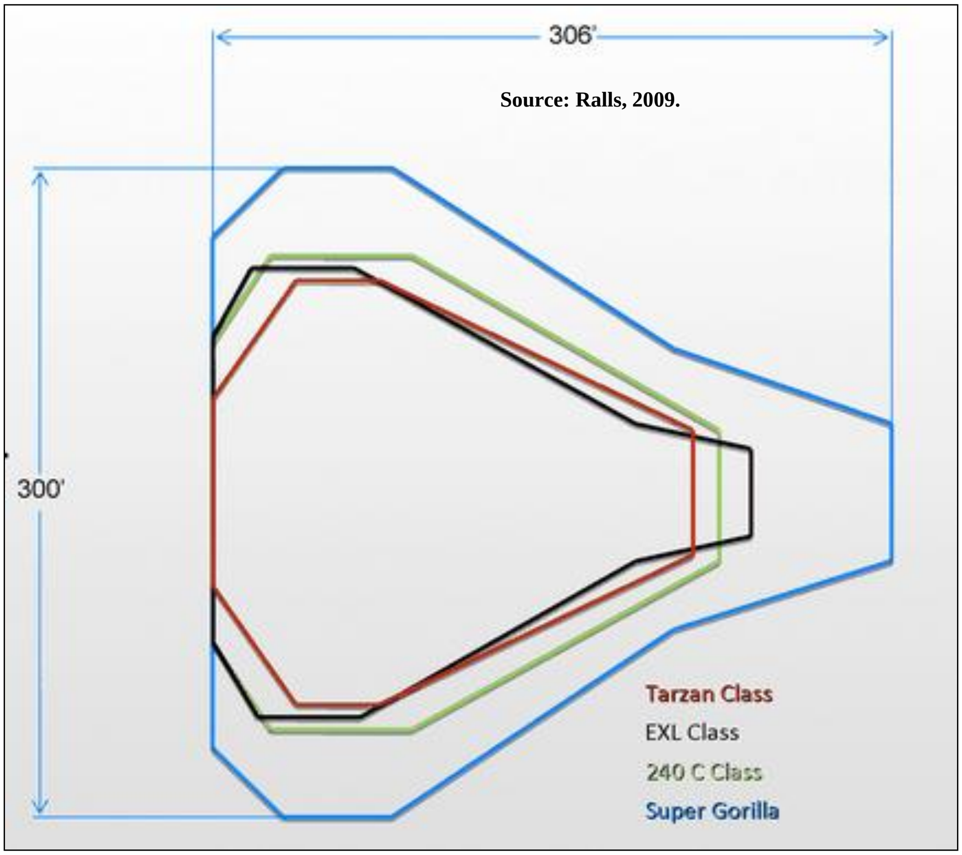


Figure H.12. Hull dimensions of common LeTourneau jackup designs.

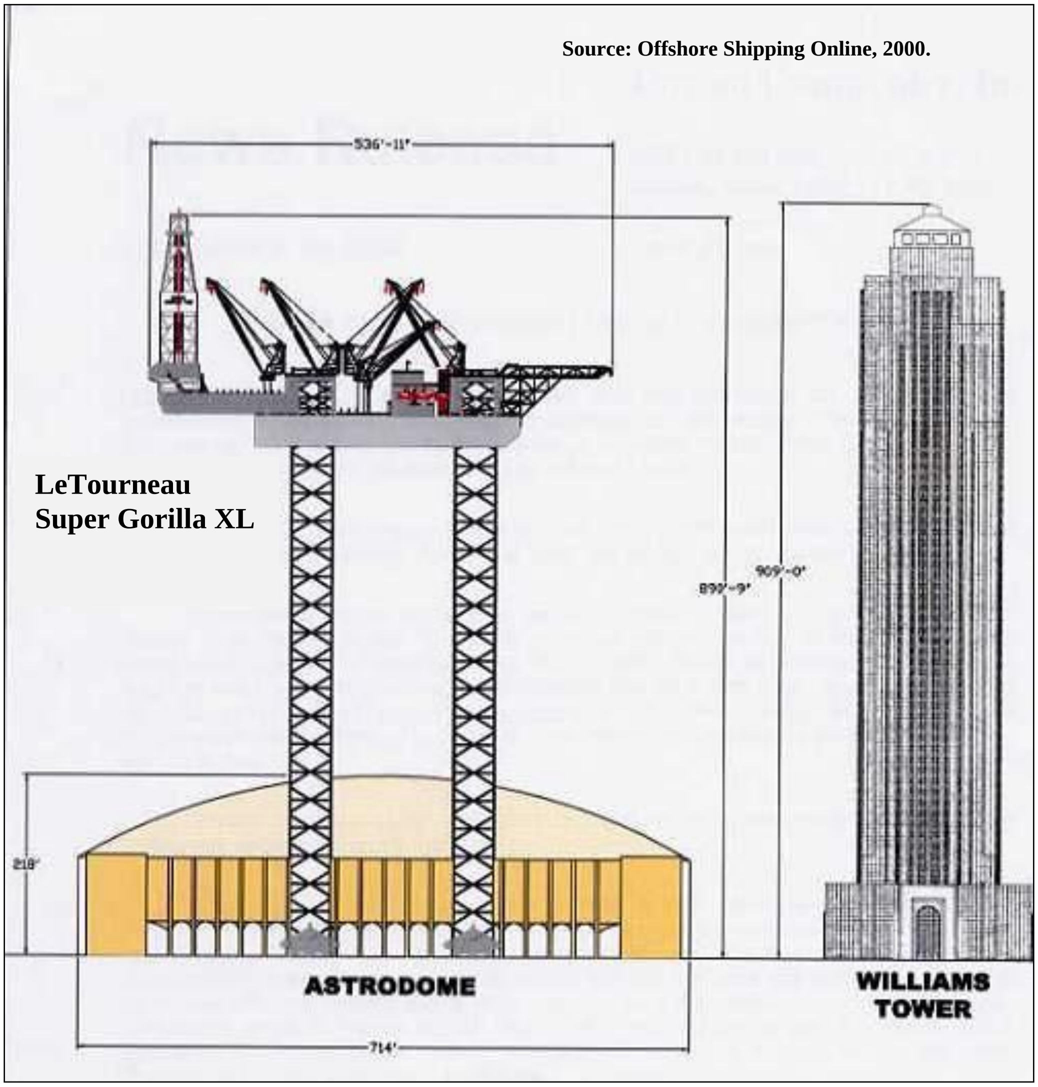


Figure H.13. LeTourneau Super Gorilla XL size comparison.

Figure H.14. Commonly built international jackups; clockwise from upper left: KFELS B Class, Gusto MSC CJ70, Pacific Class 375, F&G JU 2000E.

APPENDIX I

CHAPTER 9 FIGURES

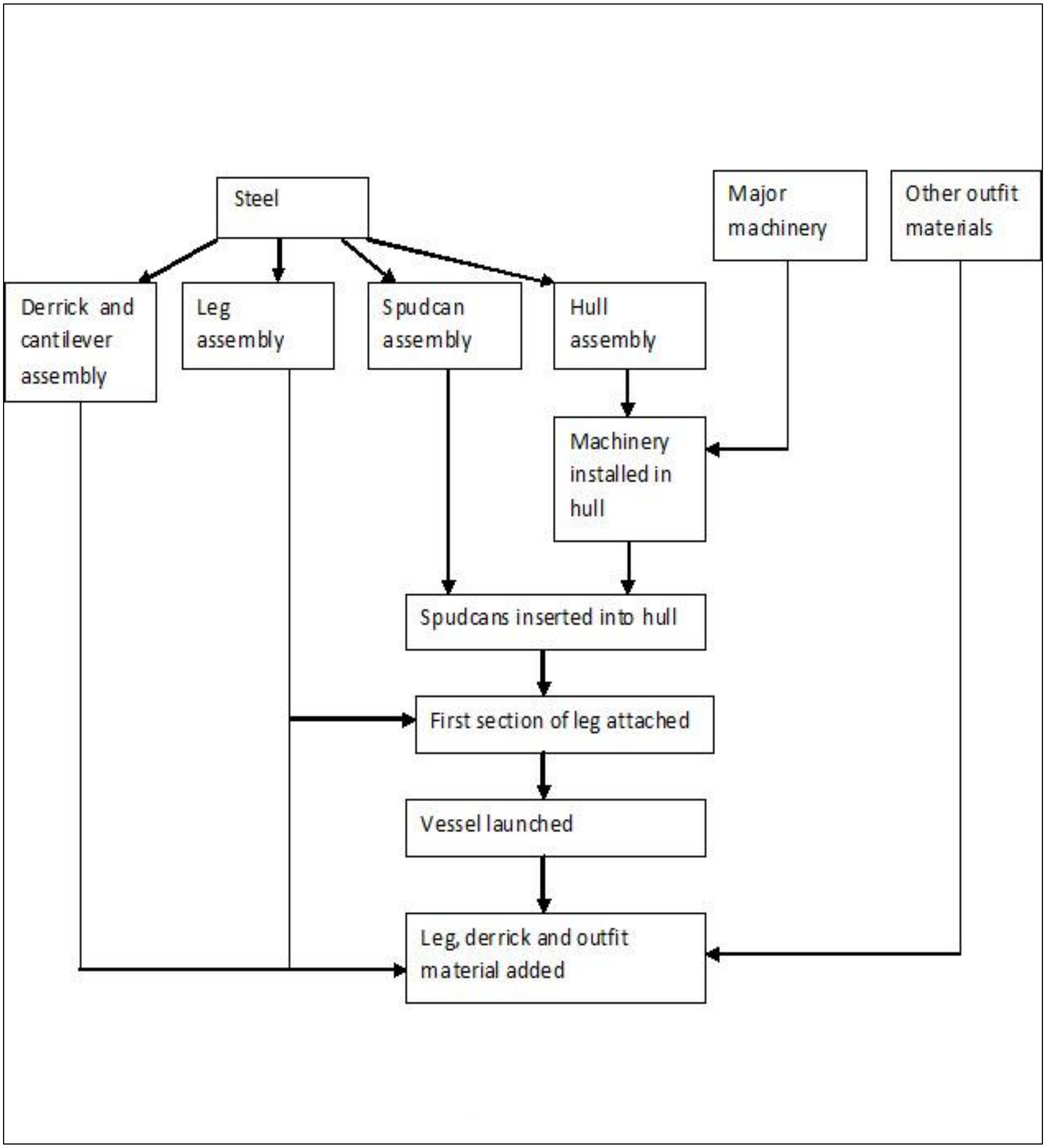


Figure I.1. Work processes in jackup assembly.

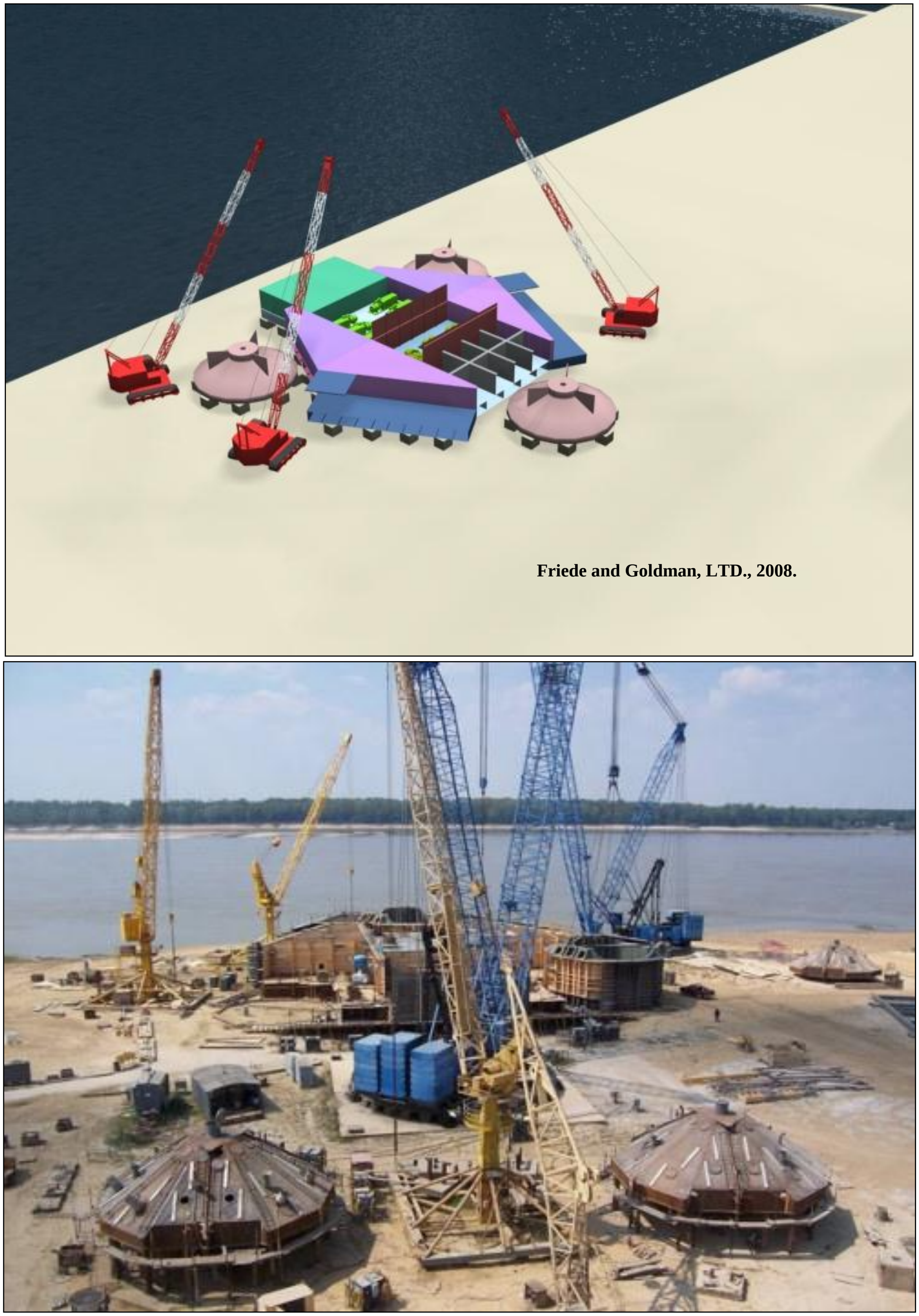


Figure I.2. Early construction stages of jackup rigs: F&G JU 2000E (top) and *Hank Boswell* (bottom) at the LeTourneau Vicksburg, Mississippi yard.

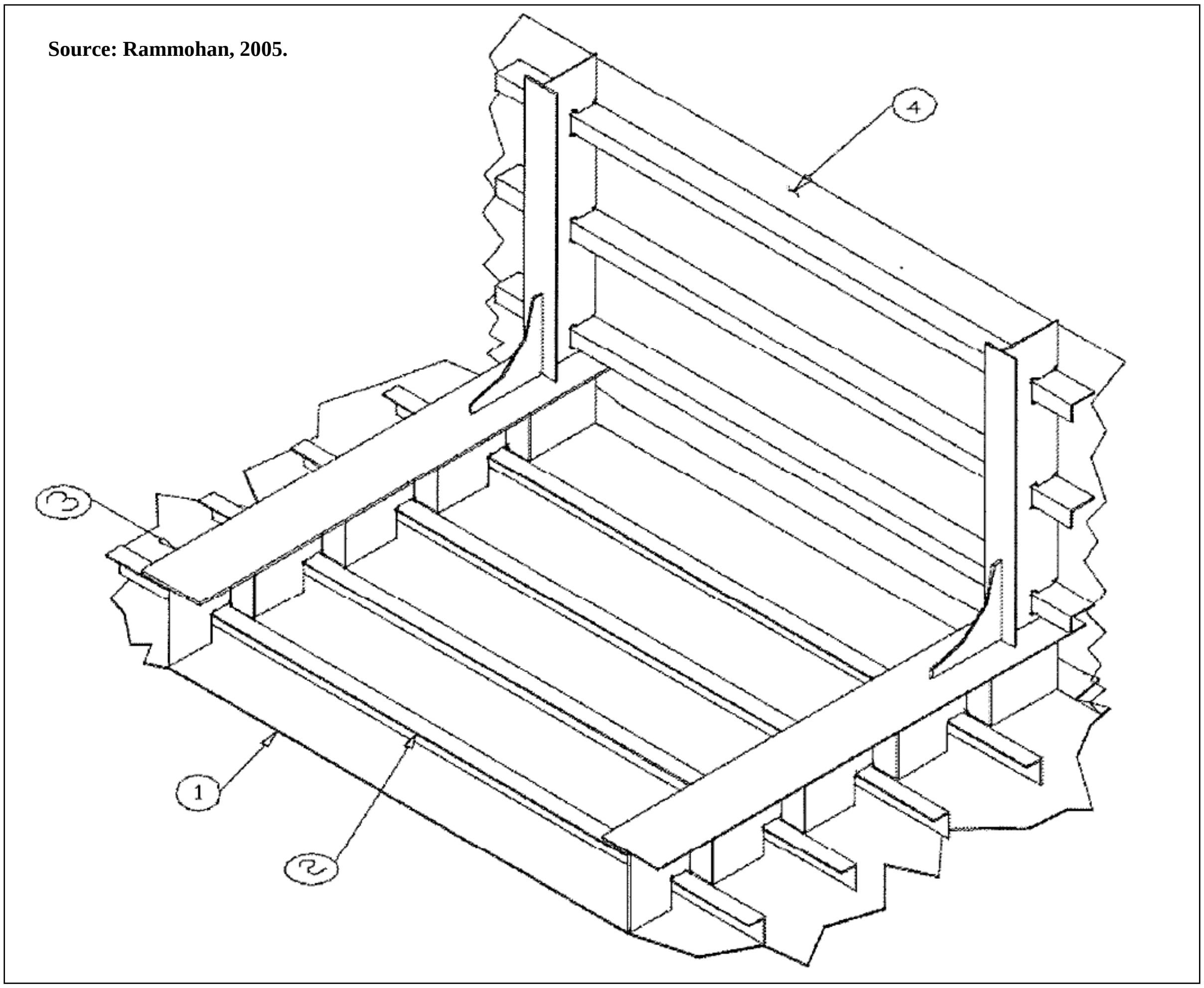


Figure I.3. Structural design of a jackup hull.

Figure I.4. Hull construction of a F&G Super M2 rig (top) and two LeTourneau Super 116s at the AmFELS Brownsville, Texas yard.

Friede and Goldman, LTD., 2008.

Figure I.5. Topside installation on F&G JU 2000E (left) and *Bob Palmer* (right) at the LeTourneau Vicksburg, Mississippi yard.

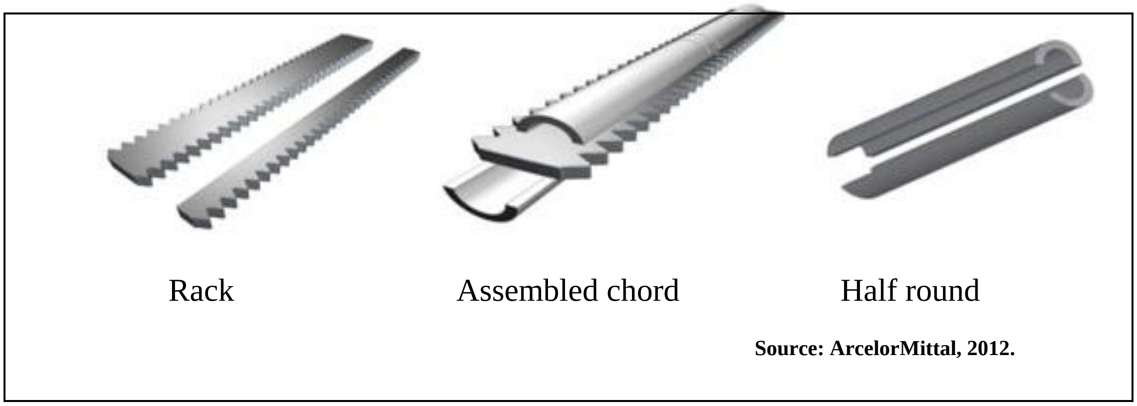


Figure I.6. Principal components of leg chords.

Figure I.7. Formed half chords pressed by Jackrabbit Steel.

Figure I.8. Launching rigs at AmFELS (top) and LeTourneau (bottom) shipyards.

Source: Remedial Offshore, 2011.

Figure I.9. Construction of F&G Super M2; top section of leg installed.

APPENDIX J

CHAPTER 10 FIGURES

Seadrill

West Ariel

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GENERAL	
Delivery	Q2, 2008
Hull ID	B-291
Major Upgrades	-
Design	KFELS 'B' Class
Previous Names	Seadrill 8
Flag	Bahamas
Classification Agency	ABS
Dimensions	234' x 208' x 25'
Transit draft	16'
Target VDL - Operating	7,500 kips
Target VDL – Survival	5,000 kips
Outfitted Max WD	400'
Min WD	55'
Leg Length	517' (incl spudcan tip)
- usable below hull	460' (incl spudcan tip)
Leg Spacing	142' transverse 129' longitudinal
Spudcan Diameter	47'
Max Drilling Depth	30,000'
Cantilever Envelope	70' aft 30' transverse
Max Combined Load	2,500 kips at 60' aft CL
Quarters	- 104 (Aust/NZ) - 112 (elsewhere)
Helideck Size	73' diameter
Helideck Capacity	S61N & S92
Helideck Compliance	CAP437
DRILLING PACKAGE	
Derrick (SWL)	1,500 kips
Racking Capacity	30,000' x 5-1/2" dp
Drawworks	Varco ADS-10T 3000 HP AC
Rotary Table	Varco RST-49,5
Top Drive	Varco TDS-8SA, 750T
- continuous torque	62,500 ft lbs @ 95 rpm
Pipehandling	Dolly retract system Varco AR-3200C Varco PS-21 powerslips Varco rotating mousehole
MUD SYSTEM	
Pressure Rating	7.5k psi
Pumps	3 x Lewco W-2215
Solids Control	1 x Dual gumbo box 5 x Brandt LCM-3D 1 x Brandt LCM-3D mud conditioner

CAPACITIES	
Diesel	2,630 bbls
Drillwater	3,825 bbls (dedicated tanks) 16,094 bbls (pre load tanks)
Potable Water	2,053 bbls
Bulk Product	11,100 ft³
Sack Storage	5,000 sx
Base Oil	662 bbls
Brine	855 bbls (dedicated tank) - 1,084 bbls (mud pits 5 & 6)
Liquid Mud	3,613 bbls
Mudpits (excl slug/mix)	6
WELL CONTROL	
Diverter	49.5" KFDJ 2,000 psi
High pressure BOP	1 x CIW 18-3/4" 10k psi annular preventer 2 x CIW 18-3/4" 15k psi double ram preventers
Choke & Kill Manifold	15k psi TechDrill
CRANES	
Pedestal Cranes	3 x Favco 7.5k / 10k
API SWL	50ST @ 40' / 11ST @ 120'
BOP Crane	2 x 75ST
POWER	
Main Engines	5 x CAT3516B-HD x 2,150 HP
Total Power	10,750 HP
Main Generators	5 x Kato 6P7-2650 x 2,306 HP
Emergency Power	1 x Cat 3508B x 915 HP
OTHER	
Mooring System	4 x 27.5ST mooring winches
Conductor Tensioner	500 kips vertical
TUBULARS	
Drillpipe	15,000' x 5-1/2"
FEATURES	Helo refuelling system Dual mud system Autodriller SBM modified

Source: Seadrill, 2008b.

Figure J.1. Example specification sheet for Seadrill's KFELS B Class jackup.

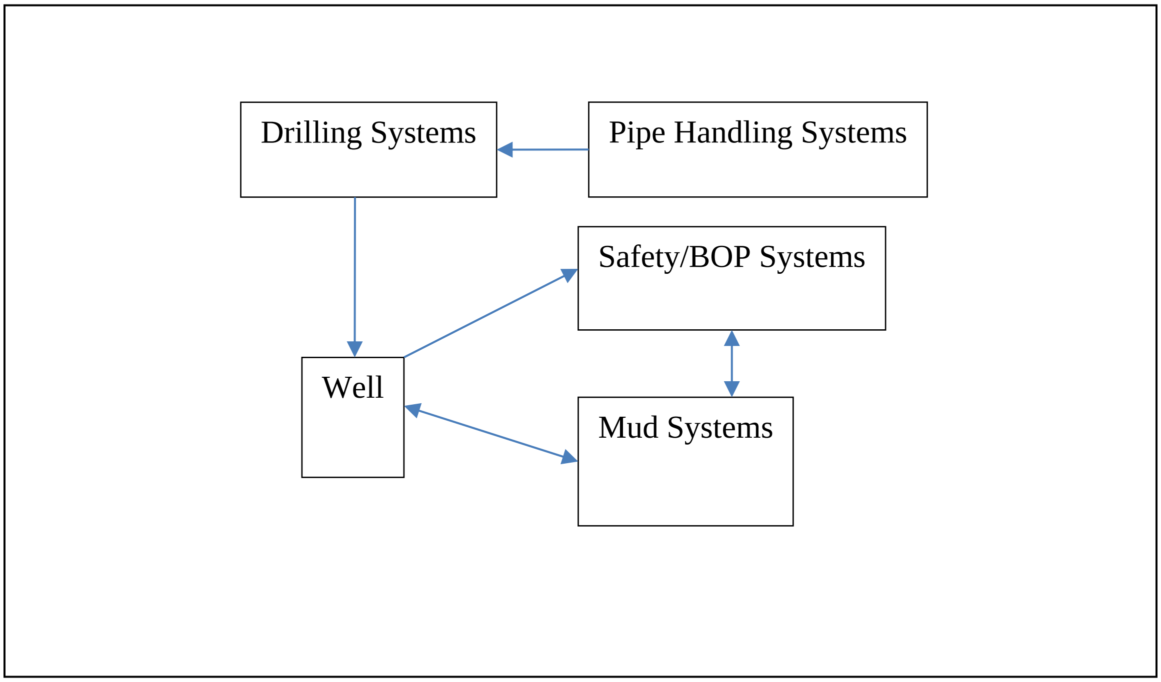


Figure J.2. Interactions between major rig systems.

1. Crown Block and Water Table
2. Catline Boom and Hoist Line
3. Drilling Line
4. Monkeyboard
5. Traveling Block
6. Top Drive
7. Mast
8. Drill Pipe
9. Doghouse
10. Blowout Preventer
11. Water Tank
12. Electric Cable Tray
13. Engine Generator Sets
14. Fuel Tanks
15. Electric Control House
16. Mud Pump
17. Bulk Mud Components Storage
18. Mud Pits
19. Reserve Pits
20. Mud Gas Separator
21. Shale Shaker
22. Choke Manifold
23. Pipe Ramp
24. Pipe Racks
25. Accumulator

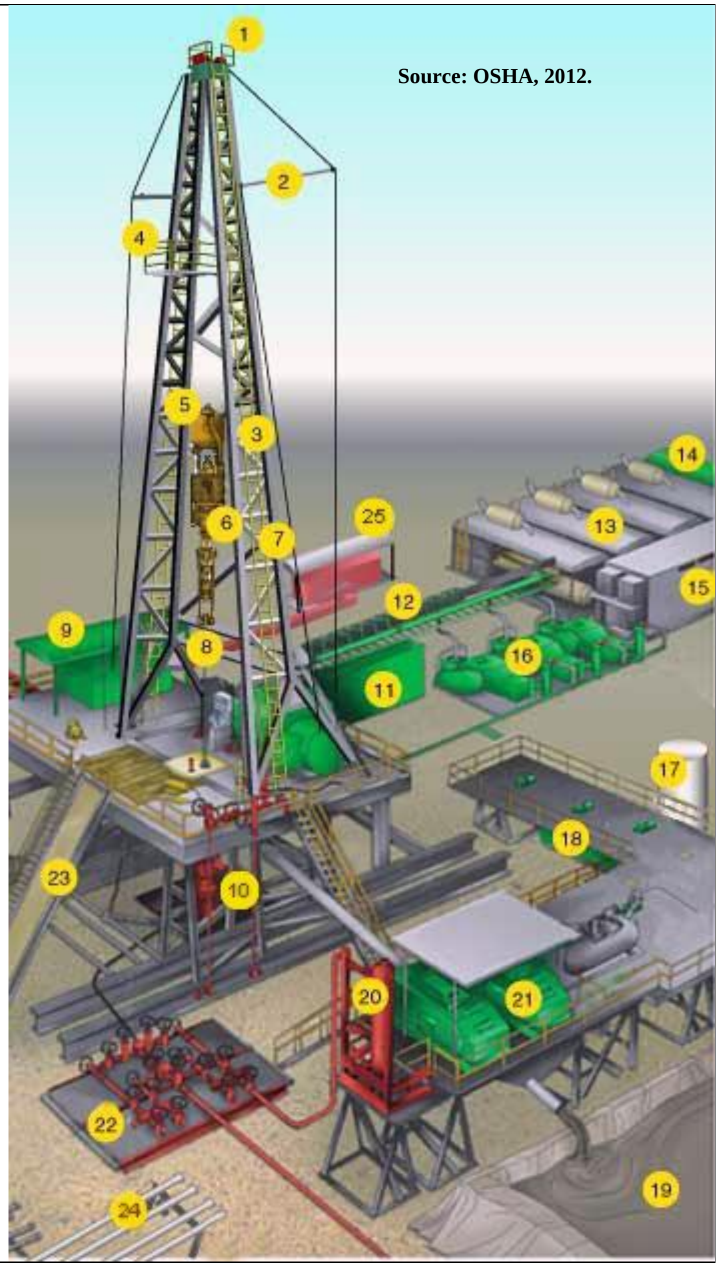


Figure J.3. Drilling rig system components.

Source: Bugge, 2011.

Figure J.4. A derrick and cantilever on a jackup rig.

Figure J.5. Top drive system.

Source: Bugge, 2011.

Figure J.6. Drawworks.

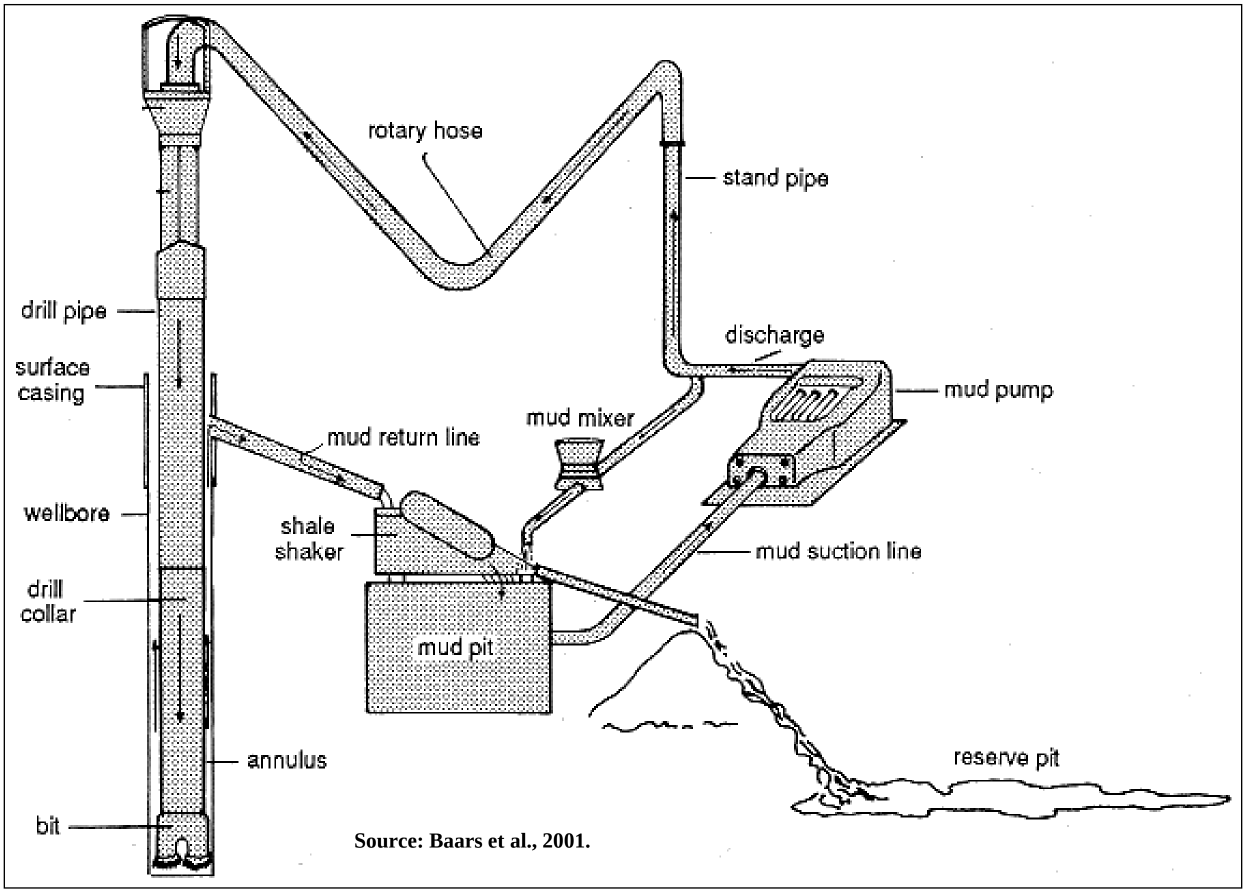
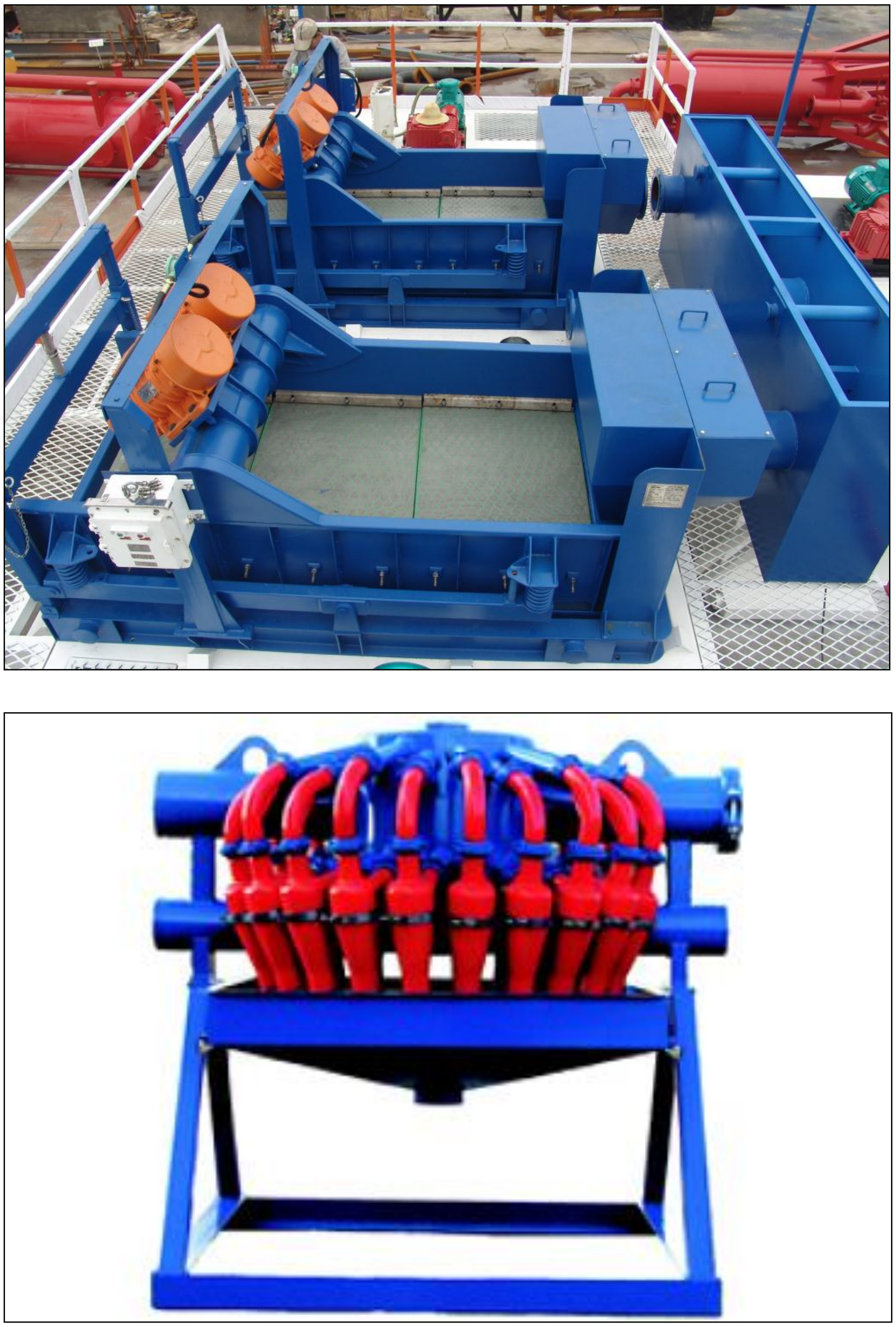


Figure J.7. Drilling fluid circulation diagram.

Figure J.8. Lewco mud pump.



Source: GN Solids Control, 2011; NOV. 2011.

Figure J.9. Shale shaker (top) and hydrocyclone (bottom).

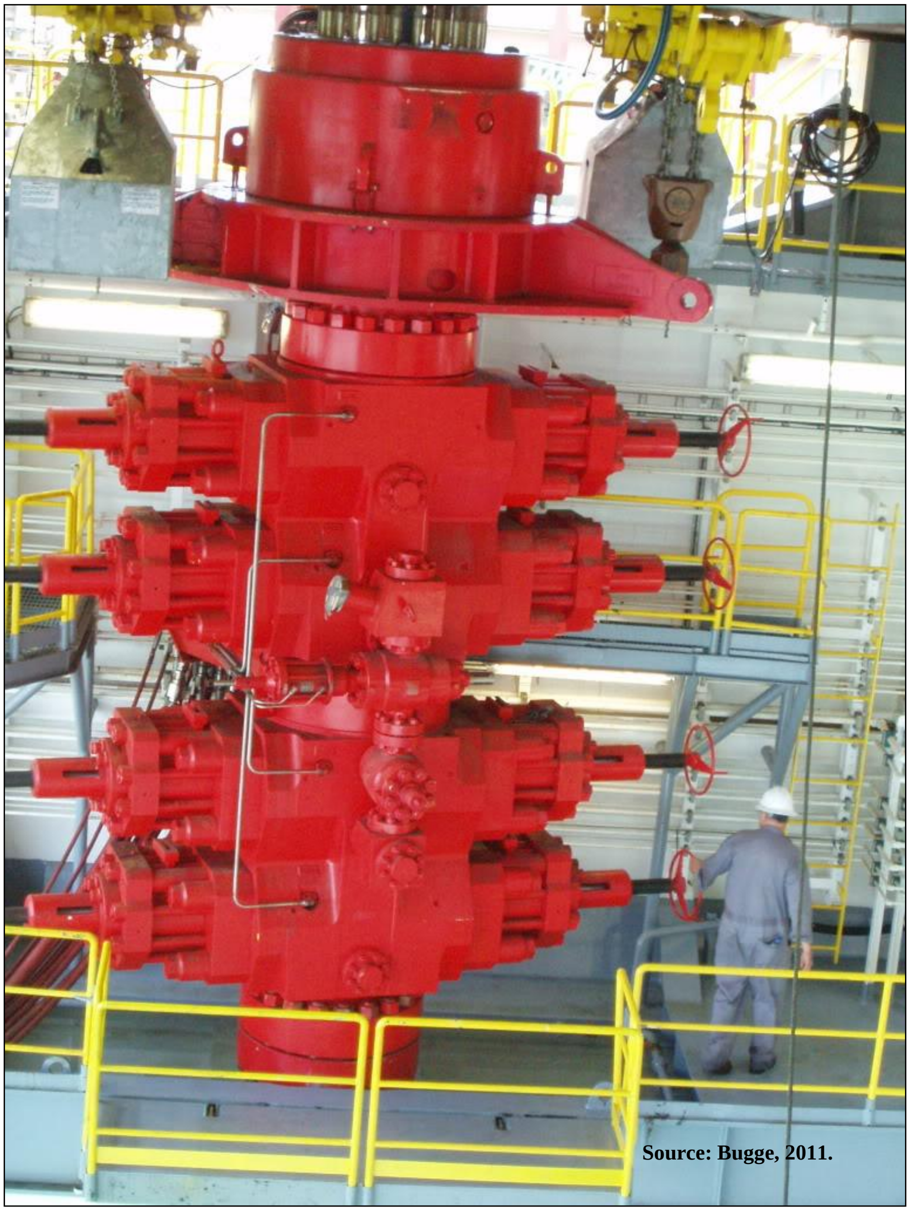


Figure J.10. BOP stack on a jackup rig including four ram BOPs and one annular BOP.

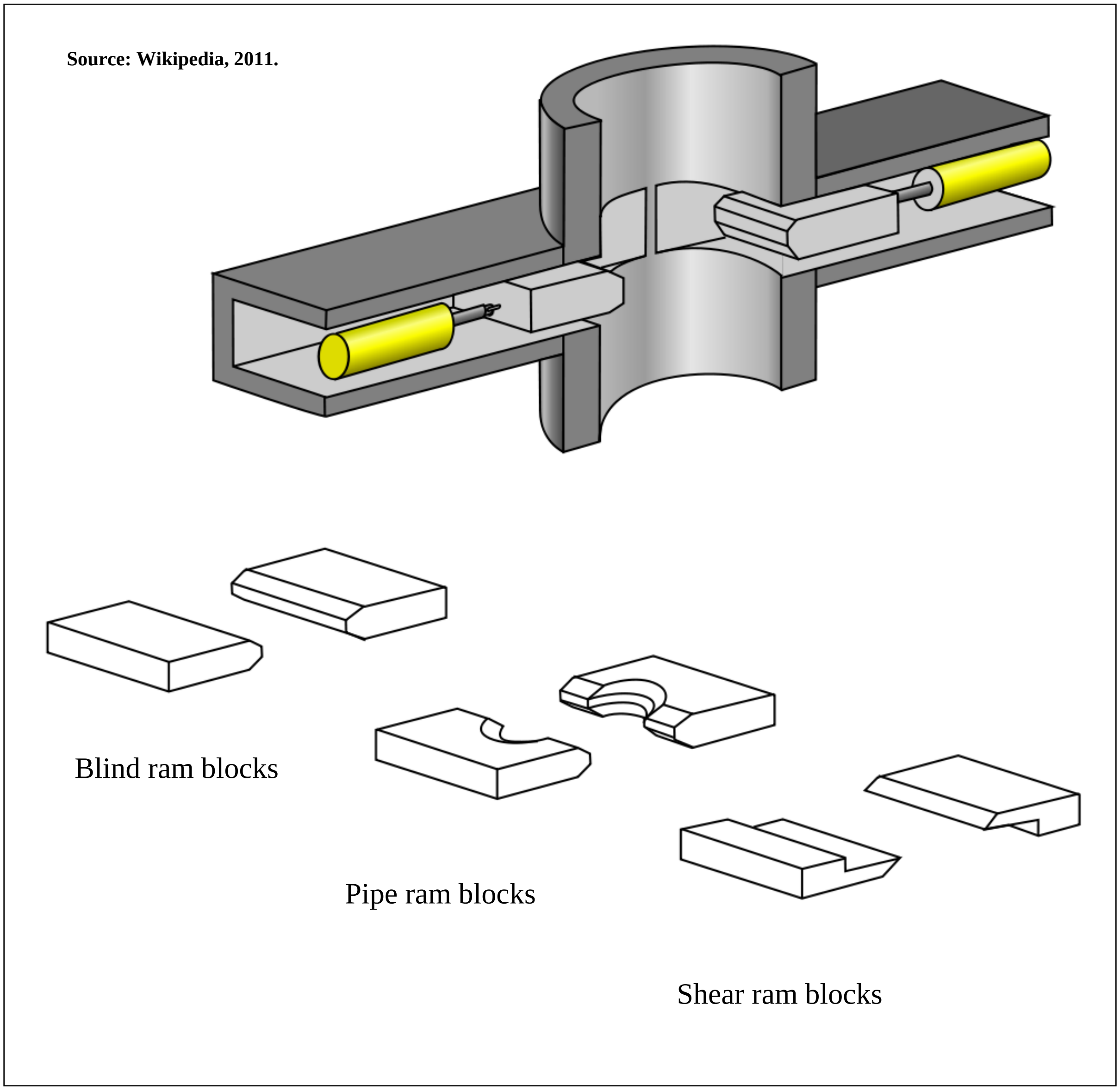


Figure J.11. Schematic of a ram BOP.

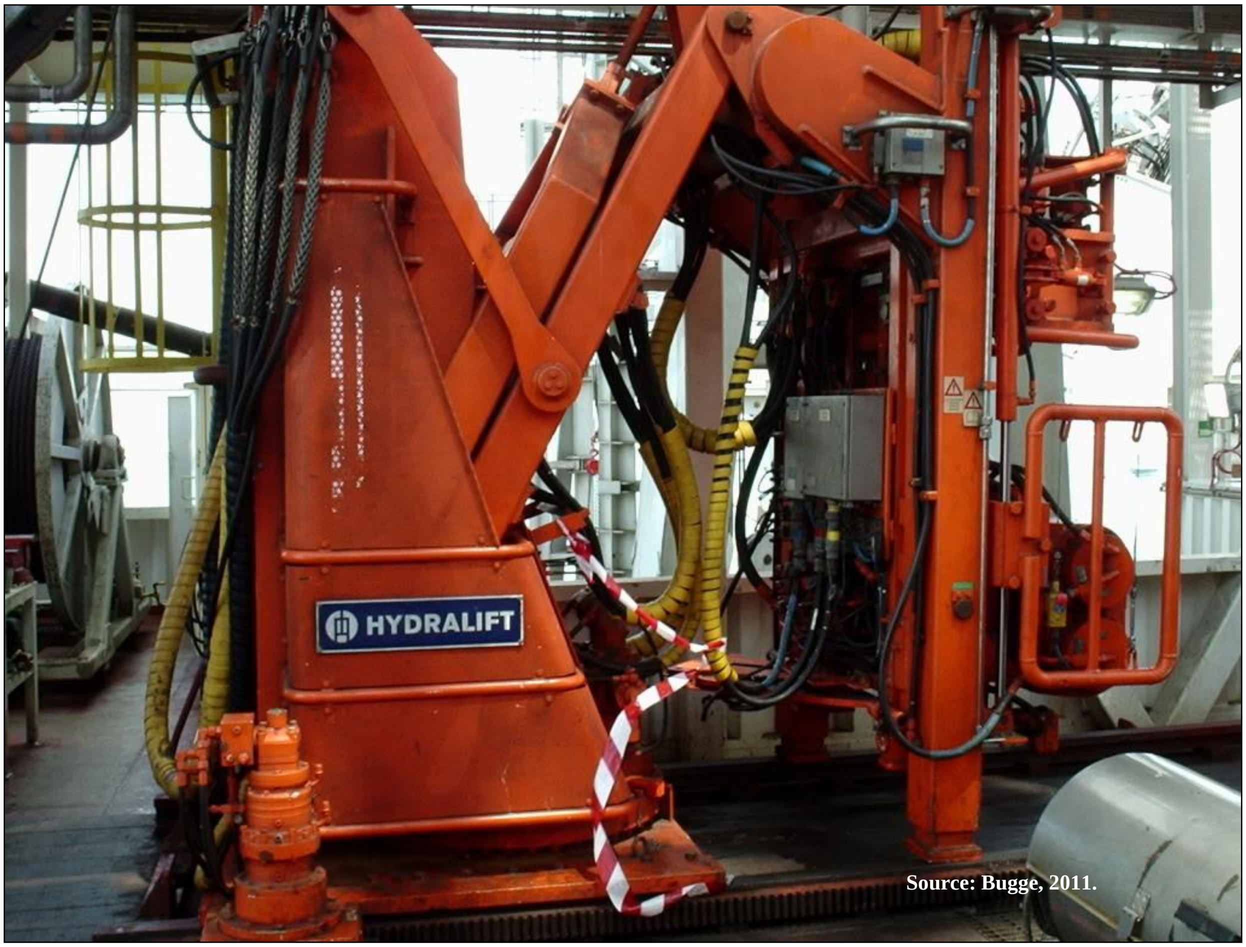


Figure J.12. Iron roughneck.

Source: Bugge, 2011.

Figure J.13. Catwalk machine.

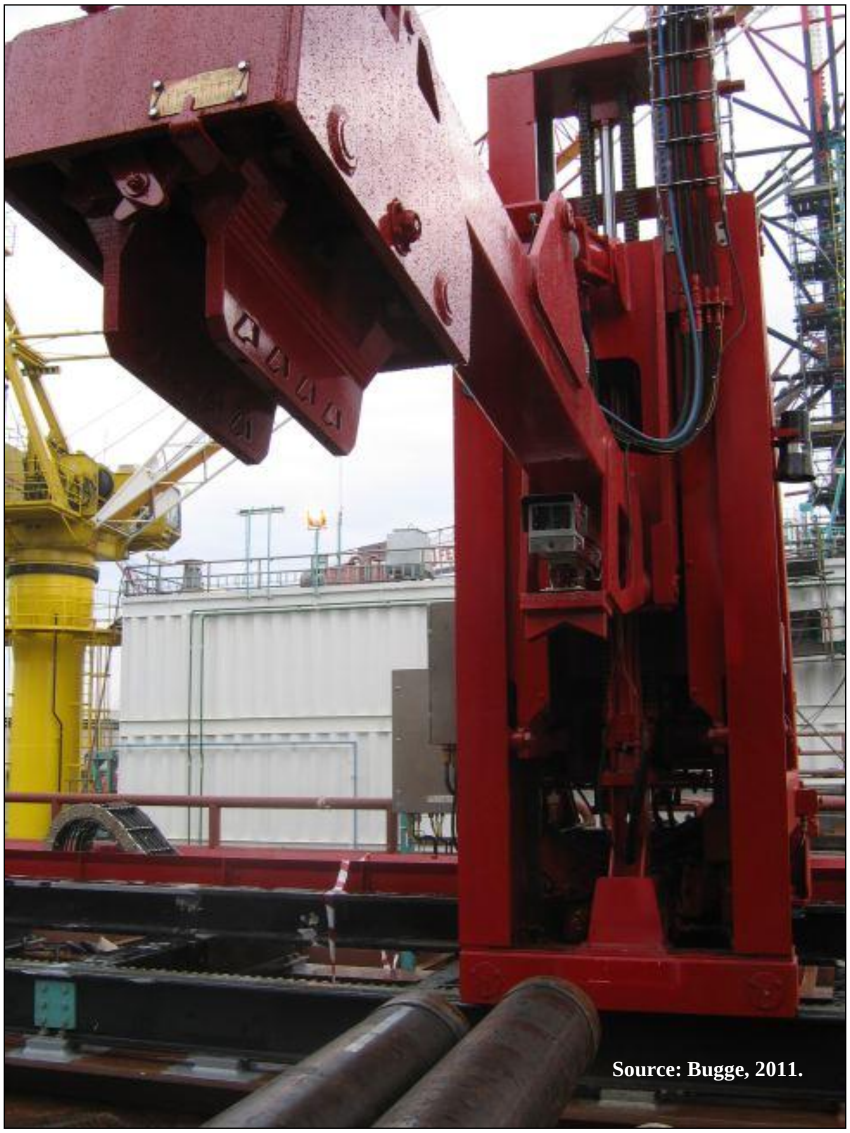
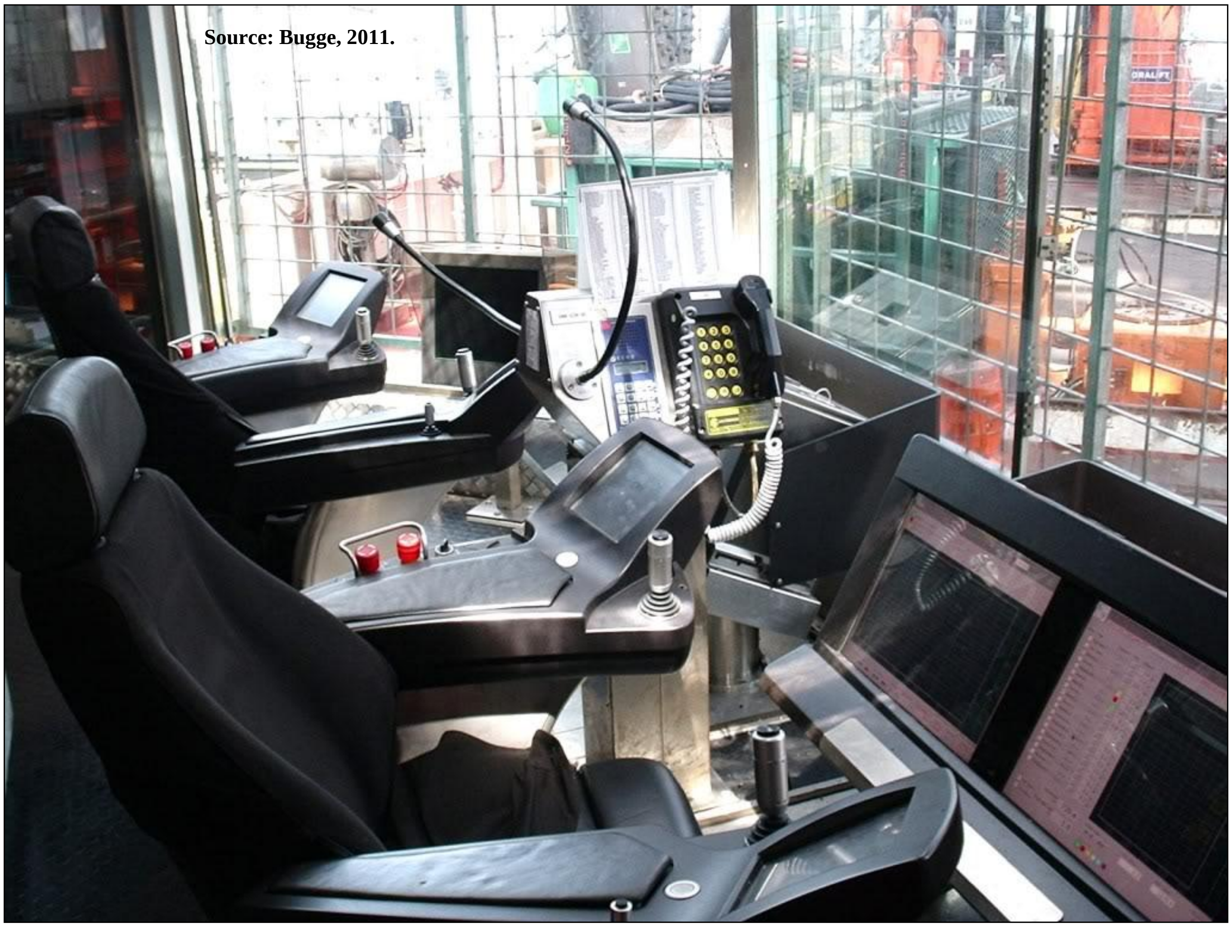


Figure J.14. Pipe deck machine.



Source: Bugge, 2011.

Figure J.15. Drilling control stations.

APPENDIX K

CHAPTER 11 TABLES AND FIGURES

Table K.1.

Leg Weights of Alternative Rig Designs

Source	Rig type	Environmental design	Leg mass (tons)	Leg length (ft)	Leg density (tons/ft)
Massie and Liu, 1990	Generic	Moderate	1,400	508	3
Cassidy et al., 2004	Generic	Harsh	3,141	558	6
Pers. Comm.	Confidential	Moderate	971	482	2
William et al., 1999	Generic	Harsh	2,123	377	6
PetroProd, 2009; Yang et al., 2002	CJ70	Harsh	2,255	672	3
Global Chimaks, 2009	F&G L780	Moderate	585	338	2

Table K.2.

Jackup Rig Lightship Displacements

Rig Name	Design	Weight (tons)	Water Depth (ft)	Severe?	Build Year	Length (ft)	Width (ft)
*Ensco 97**	LeTourneau 82 SDC	5,559	250	No	1980	207	176
*Ensco 96**	Hitachi 250 C	5,969	250	No	1982	193	174
*Ensco 94**	Hitachi 250 C	6,417	250	No	1981	193	174
*Ensco 88**	LeTourneau 82 SDC	6,745	250	No	1982	207	176
*Ensco 53**	F&G L780 Mod II	7,172	300	No	1982	180	175
Diamond M Nugget	Levingston 111	7,263	300	No	1976	208	178
*Ensco 54**	F&G L780 Mod II	7,747	300	No	1982	180	175
*Amarnath**	F&G L780 Mod II	7,749	300	No	1982	180	175
DYVI Beta	CFEM	8,030	350	No	1978	230	212
*Ensco 95**	Hitachi 250 C	8,443	250	No	1982	193	174
Generic	CJ 40	8,525	300	No	2010	193	180
Sagadrill2	Mitsubishi T76J	8,720	300	No	1981	194	184
Sagadrill1	Mitsubishi T76J	9,228	300	No	1984	194	184
Soraya		9,350	225	No	1970	177	133
*Vicksburg**	LeTourneau 84S	9,625	300	No	1976	238	213
*Ensco 92**	LeTourneau 116 C	9,711	250	No	1982	243	200
*Ensco 87**	LeTourneau 116 C	9,751	350	No	1982	243	200
Offshore Resolute	LeTourneau Super 116	10,605	350	No	2008	243	206
Offshore Courageous	LeTourneau Super 116	10,682	350	No	2008	243	206
Offshore Vigilant	LeTourneau Super 116	10,698	350	No	2008	243	206
Offshore Freedom	LeTourneau Super 116E	11,274	350	No	2009	243	206
*Energy Exerter**	CFEM 2005	11,364	300	Yes	1982	245	283
*Energy Enhancer**	CFEM 2005	11,368	300	Yes	1982	245	283
Generic	Generic	12,200	330	No	1990	255	295
Generic	CJ 46 x 100	12,210	375	No	2010	214	203
Murmanskay	CDB Corall	14,800	330	No	1991	357	252
Arcticheskaya	CDB Corall	15,200	330	Yes	2011	357	252
Glomar Moray Firth	CFEM T2600C	15,334	300	Yes	1984	324	284
Hakuryu 10	BMC 375	17,500	375	No	2008	236	224
Generic	CJ 50 x 120	17,600	400	No	2010	230	223
Generic	CJ 70 x 150	28,600	450	Yes	2010	291	318

Note: (*) Estimated as transit displacement minus transit variable load.
Source: Industry press; rig specification sheets.

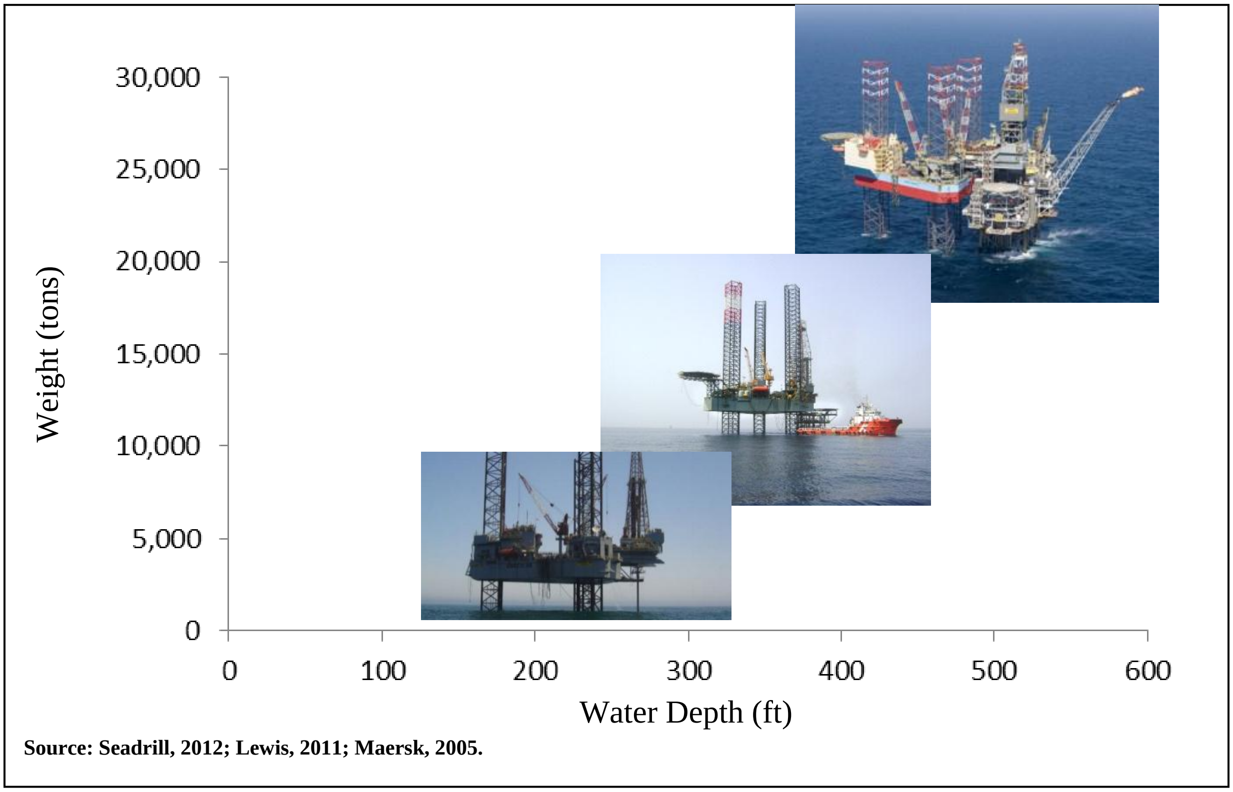


Figure K.1. The Hitachi 250, LeTourneau Super 116E, and Gusto MSC CJ70 rigs.

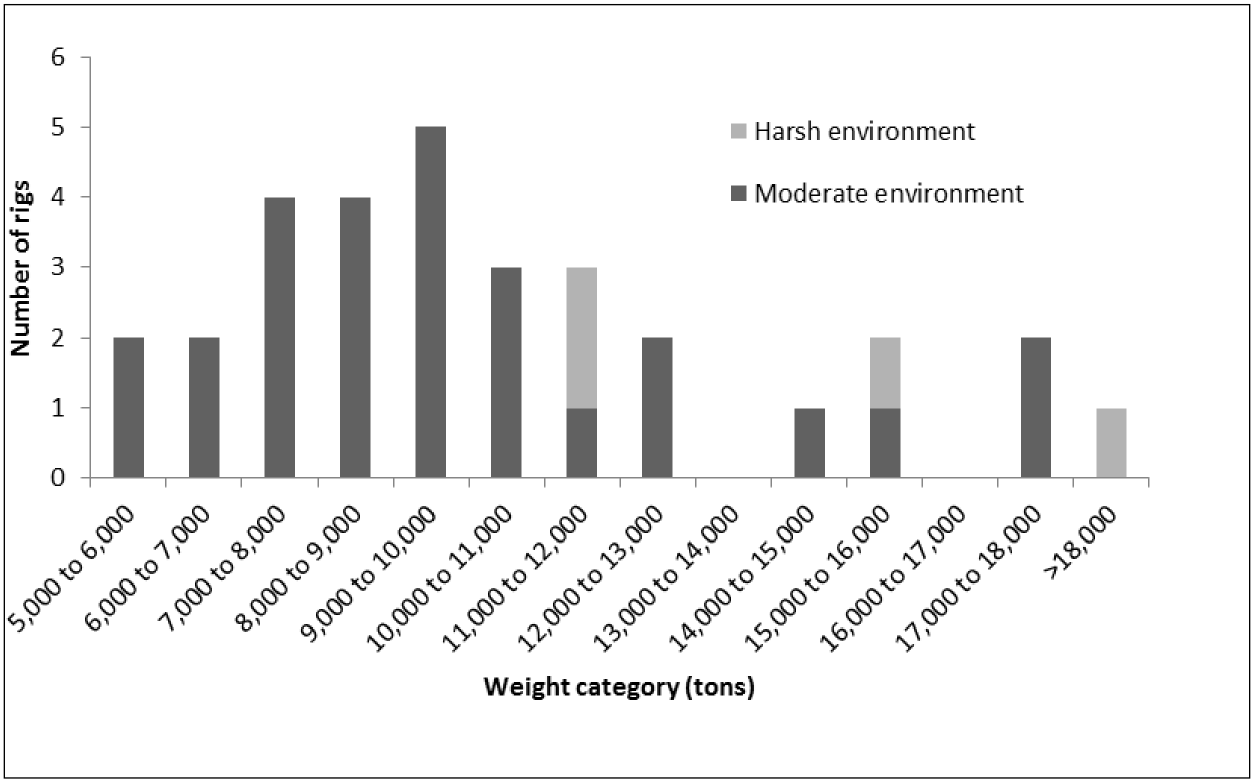


Figure K.2. Distribution of rigs in the sample.

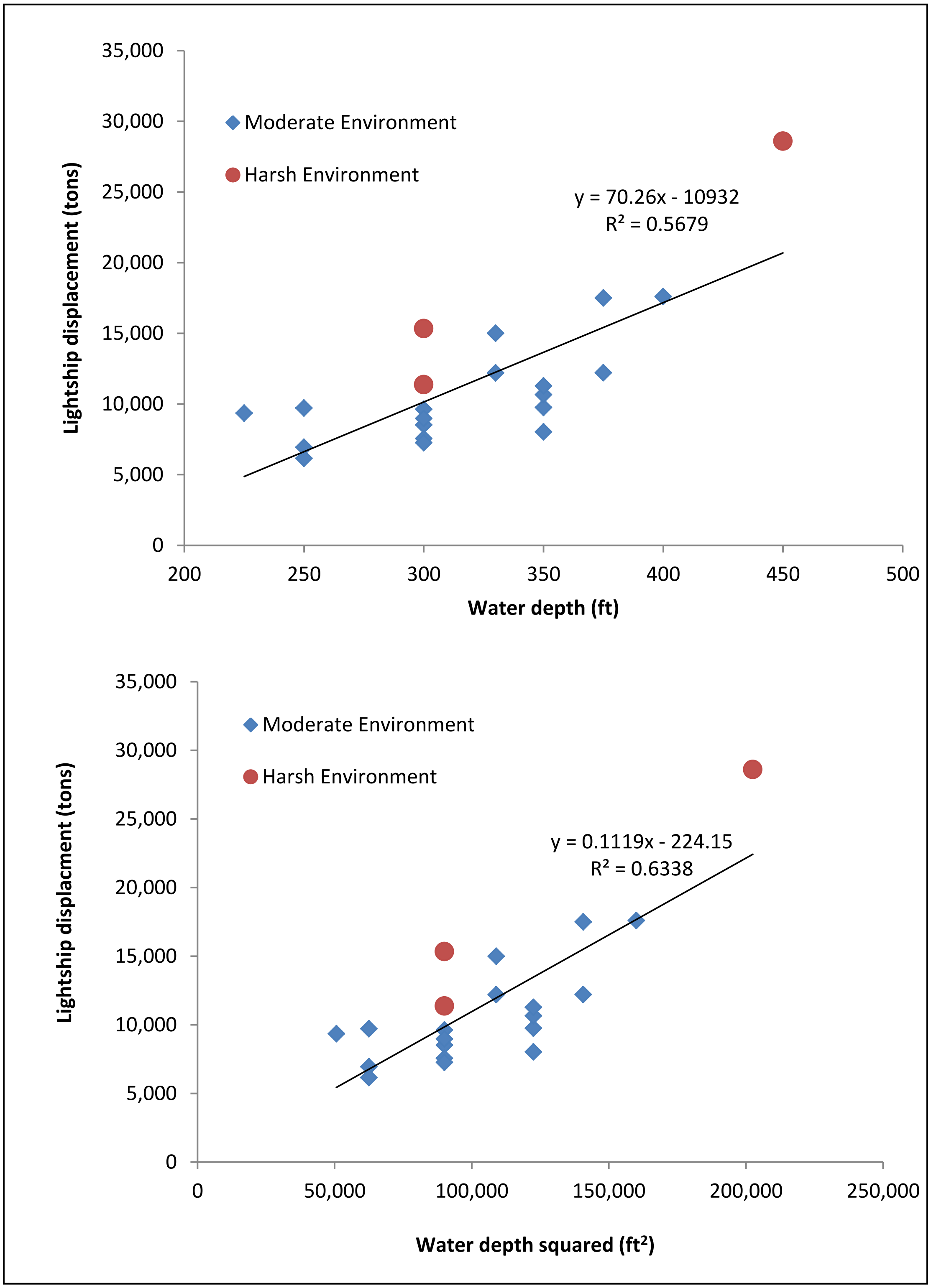


Figure K.3. Relationship between water depth and rig weight.

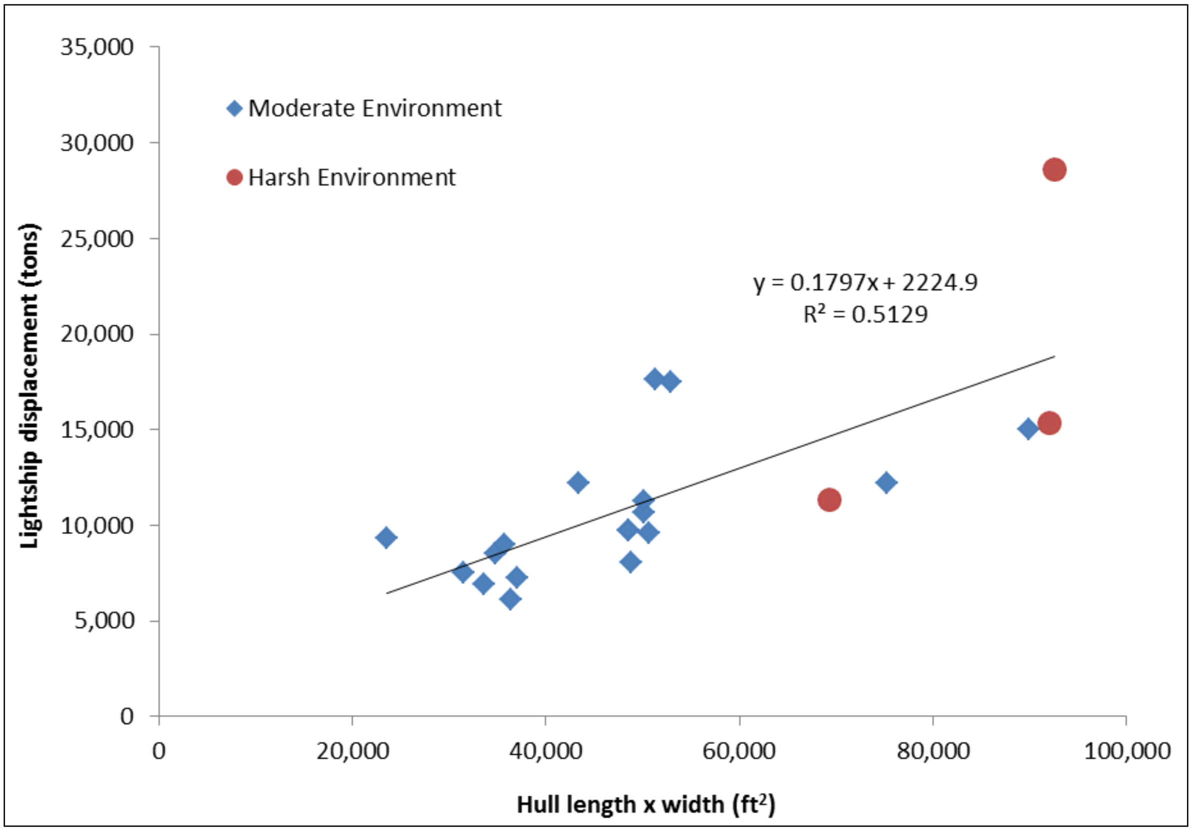


Figure K.4. Relationship between hull dimensions and rig weight.

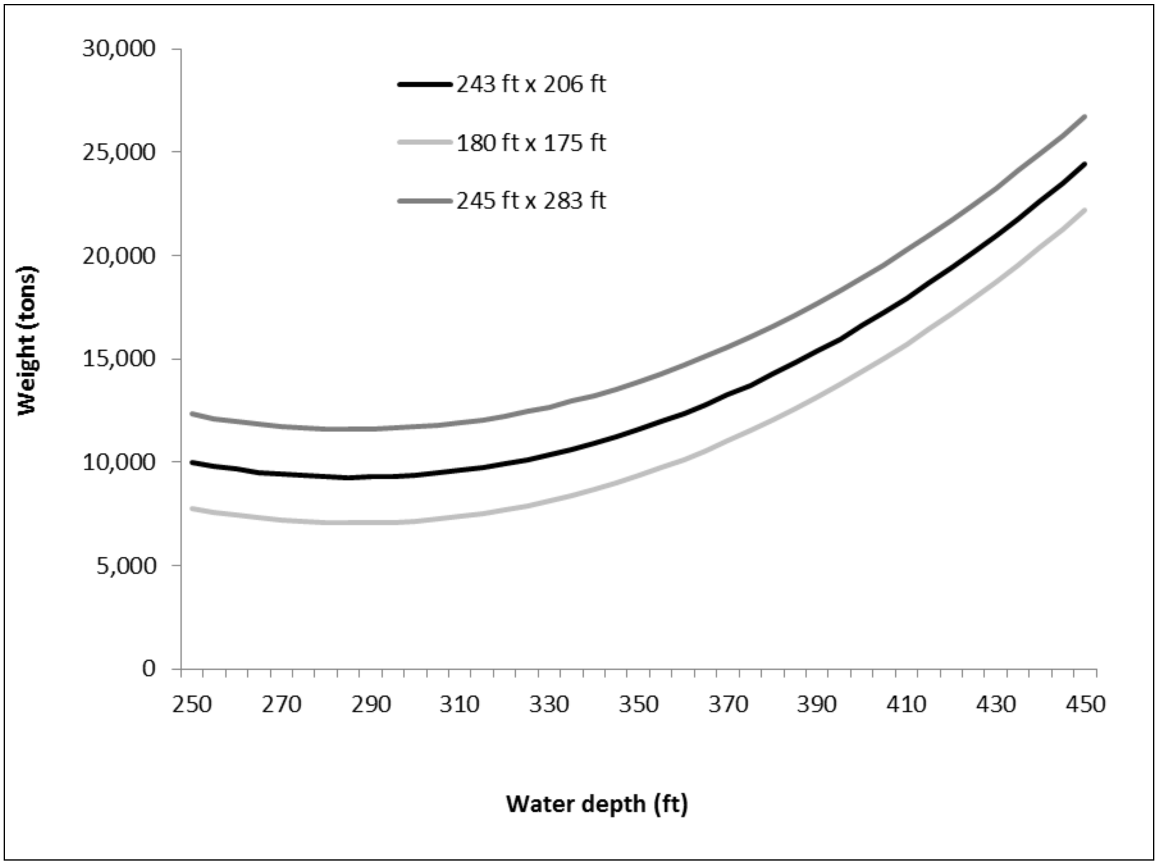


Figure K.5. Model relationship between water depth and predicted weight for rigs of different length and breadth.

APPENDIX L

CHAPTER 12 TABLES AND FIGURES

Table L.1.

Market Share (in Percent) of Rig Equipment Suppliers in U.S. Jackup Rig Construction, 2000–2010

Supplier	Engines	BOP	Topdrive	Rotary	Mudpumps	Derrick	Manufacturing locations
Caterpillar	95						Indiana, Georgia
Wartsilla	5						Europe
Woolslayer						33	Oklahoma
Loadmaster						33	Louisiana
NOV		17	50	50	15	34	Texas
Cameron		66					Louisiana
Hydril		15					Texas
Lewco			50	50	85		Texas

Source: RigLogix, 2011.

Table L.2.

Rig Construction Cost Estimation Modules

Module	Sub-module	User input	Model assumptions	Adjustment factor
Labor		Capital costs	Productivity, hourly wages	Shipyard earnings index
Material	Steel	Lightship weight	Weight distribution, steel price	Steel mill products index
	Generators/engines	Installed power	Price per kW	Machinery and equipment index
	Other material	Capital costs	Fixed percentage	All finished goods
Rig kit			Fixed price	Ship and boat building index
Drilling equipment			Fixed price	Oil field equipment index
Returns on investment		Capital costs	Fixed percentage	

Table L.3.

Construction Costs of U.S. Jackup Rigs, 1996–2011

Rig	Construction cost (million $)	Order year	Inflated cost (2010 million $)
Rowan Gorilla VI	208	1996	305
Rowan Gorilla VII	220	1997	314
*ENSCO 105**	110	2002	142
Bob Palmer	240	2000	326
*Tonala**	117	2002	151
Scooter Yeargain	95	2001	126
Bob Keller	100	2002	129
Hank Boswell	100	2002	129
Offshore Courageous	87	2005	101
Panuco	133	2005	154
Offshore Defender	87	2005	101
Offshore Resolute	143	2005	166
*Ocean Scepter**	150	2005	174
Offshore Vigilant	93	2005	108
Rowan Mississippi	165	2005	191
JP Bussell	125	2004	149
Atwood Aurora	177	2006	198
Offshore Intrepid	143	2006	160
Ralph Coffman	165	2005	191
Tuxpan	190	2007	204
Rowan EXL I	175	2007	188
Rowan EXL II	175	2007	188
Rowan EXL III	175	2007	188
Joe Douglas	200	2007	215
Rowan EXL IV	175	2007	188
Perforadora Central I	195	2011	191
Average			180

Note (*): Non-LeTourneau design

Source: Data from RigLogix, 2011; Colton, 2011.

Table L.4.

Average Cost of Jackup Rigs Built in the U.S. by Water Depth and Class, 1996–2011

Water depth (ft)	Number	Average cost (million $)	Standard deviation (million $)
300	4	133	11
350	13	164	38
375	5	176	27
400	3	270	68
550	1	326	
Rig Class			
KFELS B Class	2	147	6
KFELS B Class (Super)	1	174	
LeTourneau 240C	3	199	14
LeTourneau Super 116	5	127	33
LeTourneau Super 116E	8	188	15
LeTourneau Super Gorilla 219-C	2	309	6
LeTourneau Super Gorilla XL 224-C	1	326	
LeTourneau Tarzan Class 225-C	4	133	11

Source: Data from RigLogix, 2011; Colton, 2011.

Table L.5.

Cost of Labor at U.S. Shipyards, 2002–2009

Year	Number of employees	Total compensation ($1000)	USD per employee	Inflated USD per employee	Inflated USD per h**
2009	100,372	7,597,040	75,689	75,689	37.8
2008	106,049	7,074,944	66,714	70,263	35.1
2007	96,955	6,186,983	63,813	69,795	34.9
2006	85,262	5,111,697	59,953	68,398	34.2
2005	84,407	5,028,646	59,576	70,769	35.4
2004	87,111	4,904,367*	56,300	68,925	34.5
2003	86,155	4,799,634*	55,709	71,647	35.8
2002	87,152	4,694,721*	53,868	69,922	35.0

Note: (*) Total compensation estimated as payroll plus 30%. (**) Assumes employees work an average of 2,000 hours per year.
Source: USDOC, Census, 2009.

Table L.6.

Labor Requirements per Unit of Shipment Value, 2002–2009

Year	Inflated shipment value ($1000)	Number of employees	USD of shipment value per h labor*
2009	21,801,484	100,372	109
2008	22,192,036	106,049	105
2007	18,833,866	96,955	97
2006	16,657,923	85,262	98
2005	16,225,604	84,407	96
2004	16,073,195	87,111	92
2003	16,659,085	86,155	97
2002	16,598,108	87,152	95

Note: (*) Assumes employees work an average of 2,000 hours per year.
Source: USDOC, Census, 2009.

Table L.7.

Weight Distribution of Selected Jackups

	Massie and Liu, 1990	Cassidy et al., 2004	William et al., 1999	PetroProd, 2009; Yang et al., 2002	Global Chimaks, 2009
Rig type	Generic	Generic	Generic	CJ70	F&G L780
Environmental design	Moderate	Harsh	Harsh	Harsh	Moderate
Hull mass, tons (%)	5,000 (41)	17,577*(65)	17,700* (73)	11,221 (39)	4,219 (58)
Leg mass, tons (%)	1,400 (34)	3,141 (35)	2,123 (26)	2,255 (24)	585(24)
Machinery, tons (%)	3,000 (25)			10,614 (37)	1,270 (17)
Lightship (tons)	12,200	27,000	24,069	28,600	7,267

Note: (*) Includes machinery.

Table L.8.

Steel Grade Distribution of a 300 ft Moderate Environment Jackup

Steel Grade (ksi)	Weight (tons)	Percent of total weight (%)	Use
34 to 51	5,130	53	Hull, jackhouse, cantilever
72 to 90	652	7	Jackhouse, hull, cantilever, legs, spudcans
100	2,254	23	Legs
Total steel weight	8,036		
Total weight	9,700		

Source: Industry personnel.

Table L.9.

Installed Power of Selected Jackup Rig Designs

Rig	Installed Power (kW)
LeTourneau Super 116E	8,015
KFELS Super B Class	9,145
Gusto MSC CJ70	10,500
Gusto MSC CJ46	8,600
KFELS N Class	9,600
LeTourneau 240C	9,150

Source: Specification sheets.

Table L.10.

LeTourneau Super 116E Rig Kit Costs

Year	Kit cost (million $)	Number of kits	Rig cost (million $)	Kit percent of cost (%)	Inflated kit cost (million $)	Builder
2005	26	5	90–50	18–30	33	Keppel AmFELS
2007	40	1	168	24	44	Lamprell
2007	60*	4	175	33	66	Keppel AmFELS
2009	92*	2			92	Petrobras
2009	40	1	180	22	40	Petro Vietnam

Note (*): Includes drilling equipment.
Source: Industry press.

Table L.11.

Contract Costs of Jackup Drilling Equipment

Supplier	Buyer	Contract year	Contract scope	2010 cost* (million $)
Varco	Hyundai Heavy Industries	2001		37
National Oilwell	Global Sante Fe	2001		28
National Oilwell	COSL	2004		42
Varco	Gulf Drilling International	2004	BOP, topdrive, drawworks, pipe handling, derrick, mud pumps, solids control, drilling control	22
Varco	ENSCO	2004	BOP, topdrive, drawworks, solids control, pipe handling	20
Varco	Keppel	2004	Solids control, topdrive, drilling control	15
Aker	Maersk	2005	Derrick, BOP handling	18
TTS Energy	Jurong	2007	All drilling equipment	71
EMER	Yantai Raffles	2007	Drilling equipment, cantilever	33
TSC	Yantai Raffles	2010	Drilling and power systems	39
TTS Energy	DSIC	2010		38
TTS Energy	Jurong	2011	All drilling equipment	62
TSC	Yantai Raffles	2011	Drilling and power systems	29
Average				35

Note (*): Data inflated using the BLS Oil and Gas Field Machinery Equipment price index.
Source: Industry press.

Table L.12.

Costs of Selected Jackup Rig Drilling Equipment in 2010

Equipment	Unit cost ($1,000)	Typical number	Total Cost ($1,000)
Top drive	3,312	1	3,312
BOP	2,650	2	5,299
Choke manifold	1,332	1	1,332
BOP handler	814	2	1,627
Mud pump	1,920	3	5,759

Note: Modified from Robertson, 2003 using the BLS oilfield equipment price index.
Source: Robertson, 2003; USDOL, BLS, 2011b.

Table L.13.

Labor Cost Estimates for a Hypothetical LeTourneau Super 116E Jackup in Million U.S. Dollars

	Labor cost		
Productivity ($ value/hour)	34 ($/h)	36 ($/h)	38 ($/h)
90	62	66	69
100	56	59	62
110	51	54	57

Table L.14.

Steel Costs for a Hypothetical LeTourneau Super 116E Jackup

Total weight (tons)	Component	Proportion of lightship weight (%)	Unit cost ($/ton)	Cost range (million $)
12,575	Legs	20–30	4,000–7,000	10.0–26.4
	Hull	40–60	700–1,100	3.5–8.3
	Misc. steel	5–10	1,000–1,500	0.6–1.8
	Total			14.1–36.5

Table L.15.

Distribution of Construction Costs for a Hypothetical LeTourneau Super 116E

Component	Cost range (million $)	Proportion of total costs (%)	Industry estimate (million $)
Labor	51–69	31–42	50–55
Rig Kit (including leg steel)	25–45	15–27	35–40
Drilling equipment	25–50	12–30	40
Hull and miscellaneous steel	4–10	2–5	
Engines	4–6	2–4	50–55
All other material	33–41	20–25	
Profit	8–16	5–10	
Total	145–237		175–190

Source: Authors' estimates; Holcomb, 2011; Smith, 2011.

Table L.16.

Jackup Drilling Rig Market Revenue in Million U.S. Dollars

	Annual delivery value	Three-year average	Vicksburg three-year average	Brownsville three-year average
2000	305			
2001	314			
2002	142	254	206	47
2003	326	261	213	47
2004	277	248	151	98
2005	129	244	194	50
2006	129	178	128	50
2007	356	205	137	67
2008	986	490	208	283
2009	351	564	228	336
2010	768	702	177	525
2011	403	507	135	372
Average	374	365	168	194

Source: Authors' estimates.

Table L.17.

Estimated Employment in the U.S. Jackup Rig Construction Industry

Year	Revenue ($ million)	Employment (FTE) Productivity 90 $/h	Productivity 100 $/h	Productivity 110 $/h
2002	254	1,411	1,270	1,155
2003	261	1,450	1,305	1,186
2004	248	1,378	1,240	1,127
2005	244	1,356	1,220	1,109
2006	178	989	890	809
2007	205	1,139	1,025	932
2008	490	2,722	2,450	2,227
2009	564	3,133	2,820	2,564
2010	702	3,900	3,510	3,191
Average	507	2,817	2,535	2,305

Source: Authors' estimates.

Table L.18.

Jackup Related Full Time Equivalent Employment

	LeTourneau		AmFELS	
Productivity ($ revenue/hour labor)	90	110	90	110
2000	1146	938	263	215
2001	1185	970	263	215
2002	837	685	543	444
2003	1076	880	280	229
2004	711	582	280	229
2005	763	624	374	306
2006	1154	944	1570	1285
2007	1269	1038	1867	1527
2008	983	805	2915	2385
2009	752	615	1719	1406
2010	398	326	1770	1448

Source: Authors' estimates.

Figure L.1. Drilling equipment; clockwise from upper left; mud pumps, top drive, shale shaker, drawworks.

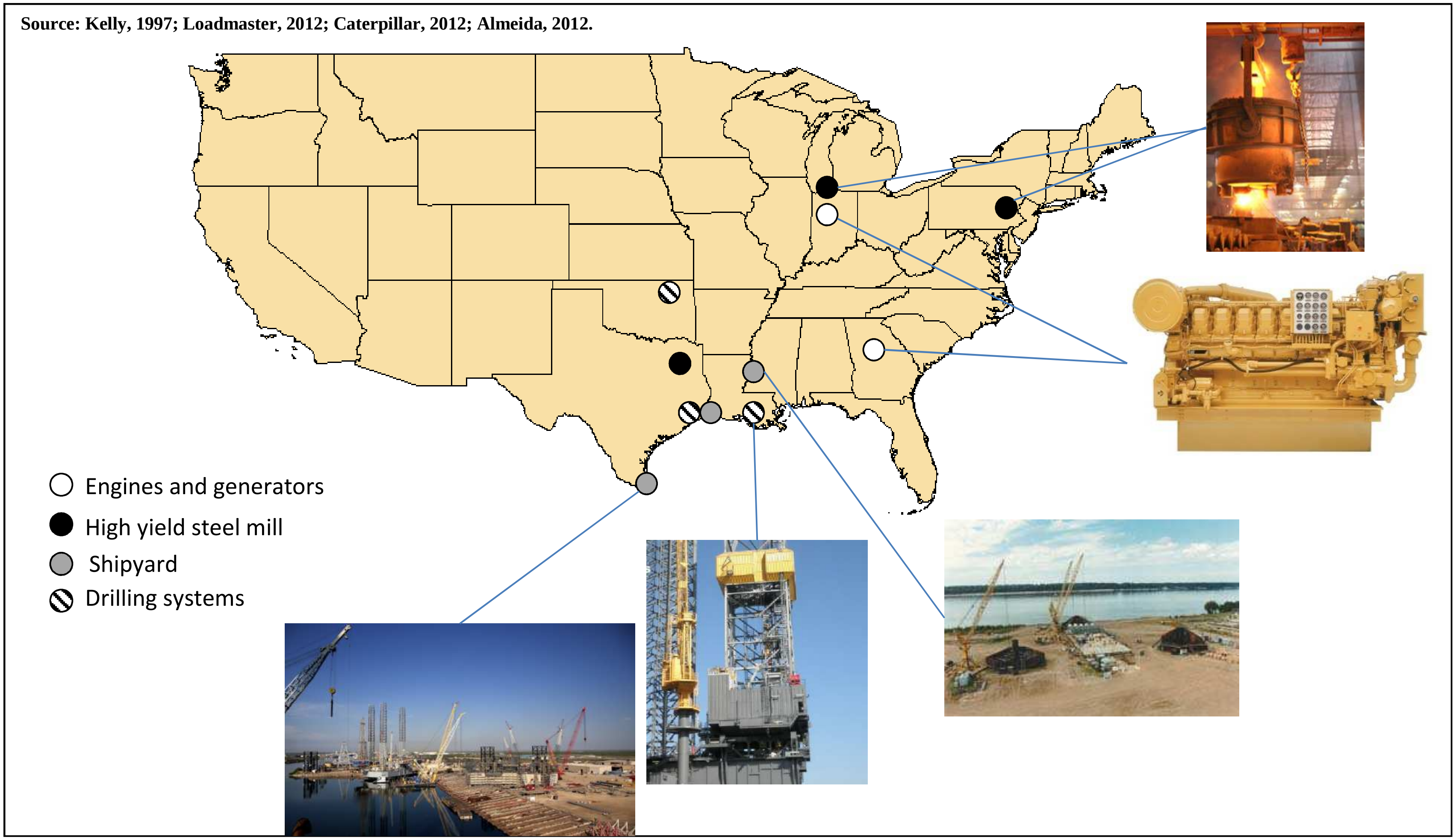


Figure L.2. Locations of major suppliers for the jackup rig industry in the U.S.

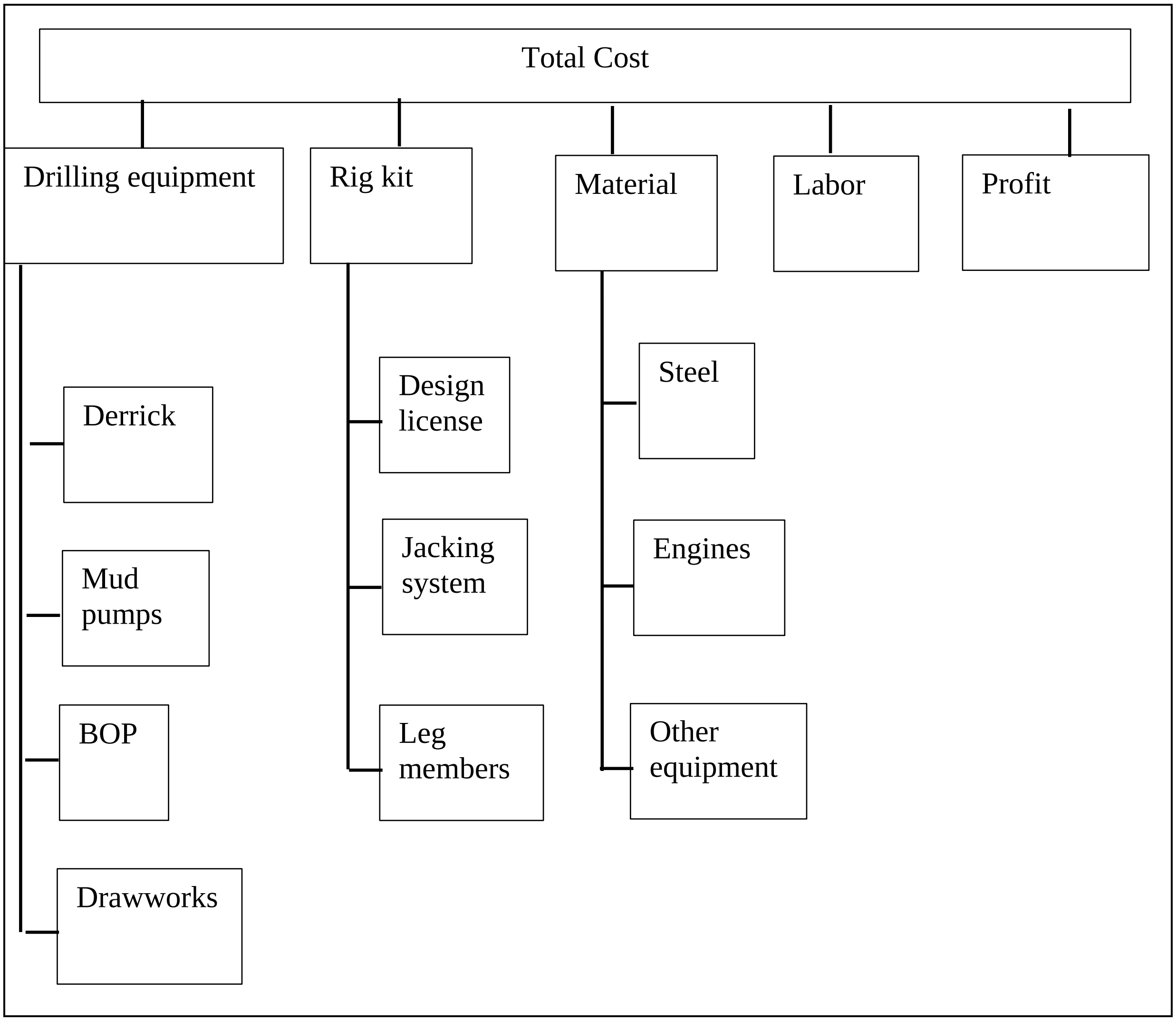


Figure L.3. Distribution of capital costs for jackup rig construction.

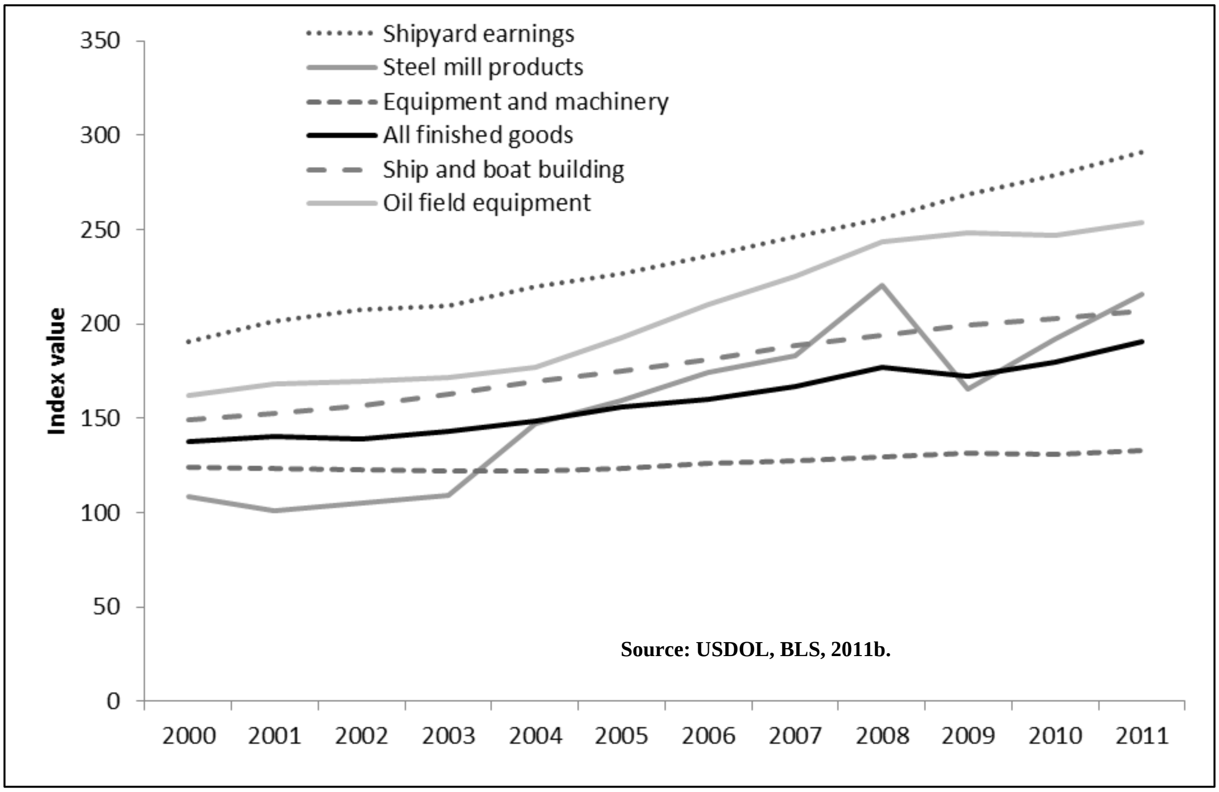


Figure L.4. BLS producer price indices related to jackup construction, 2000–2011.

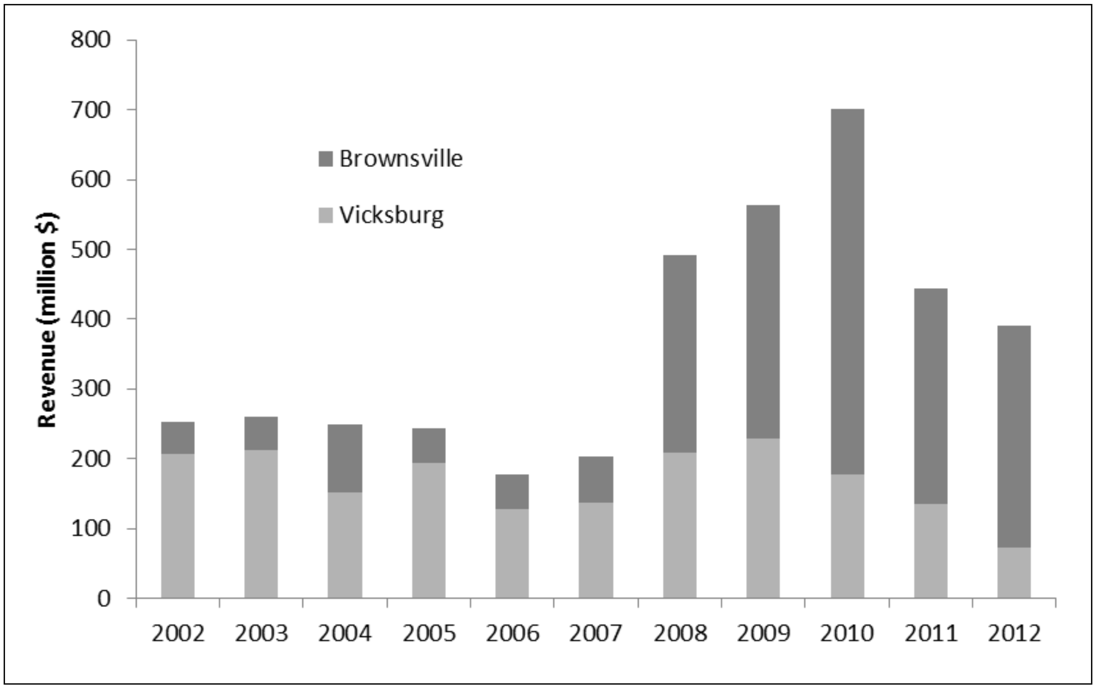


Figure L.5. Jackup construction revenue generated by Brownsville and Vicksburg shipyards, 2002–2012.

APPENDIX M

CHAPTER 13 TABLES AND FIGURES

Table M.1.

Construction Cost Distribution for Jackups and Floaters

	Floaters*		Jackups*	
	Cost (million $)	Proportion (%)	Cost (million $)	Proportion (%)
Steel	25–60	<10	15–40	10–20
Labor	50–120	10–15	15–55	10–30
Drilling equipment	100–200	20–30	20–70	10–30
All other equipment	100–200	20–30	35–50	20–30
Profits	50–75	<10	10–25	<10
Total	500–700	100	175–225	100

Note: (*) Estimates are for a typical $500 -$750 million floater and a $175-225 million jackup.

Table M.2.

Jackup Design Class Properties and Newbuild Cost in 2011

Design	Number	Price (million $)	Water depth (ft)	Harsh	VDL (tons)
Friede & Goldman JU-2000E	11	190–220	400	Y	7,000
LeTourneau Super 116E Class	12	159–210	200–375	N	3,750
KFELS B Class	20	180–210	350–400	N	4,500
PPL Shipyard Pacific Class 400	3	190	400	N	3,750
Friede & Goldman JU-2000A	4	220–229	350	Y	4,500
Friede & Goldman JU-3000N	6	220–245	400	N	7,000
KFELS Super A Class	5	230–260	400	Y	7,000
LeTourneau 240-C Workhorse	3	194–257	400	N	3,000
GustoMSC CJ70	3	500–530	492	Y	7,000

Source: Jefferies and Company, Inc., 2011; Industry press.

Table M.3.

Semisubmersible Design Class Properties and Newbuild Cost in 2011

Design	Number	Price (million $)	Water depth (ft)	Harsh	VDL (tons)	Displacement (tons)
GVA 7500-N	2	526–709	10,000	Y	8,250	62,000
F&G ExD	3	599–771	7,500–10,000	N	10,000	58,000
Ensco 8500	2	537–560	8,500	N	8,000	
CS-50 MkII (N)	2	510–526	9,843–10,000	Y	6,800	47,000
Sevan Drilling 650	3	526–685	10,000	N	22,000	61,000
GM 4000	2	460–560	1,640–4,000	Y	5,000	42,000
GVA 4000 NCS	2	565	1,640	Y		60,000

Source: Jefferies and Company, Inc., 2011; Industry press.

Table M.4.

Drillship Design Class Properties and Newbuild Cost in 2011

Design	Number	Price (million $)	Water depth (ft)	Harsh	VDL (tons)	Displacement (tons)
DSME 10000	2	579	10,000	N	24,000	112,000
DSME 12000	6	590–782	10,000–12,000	N	24,000	112,000
GustoMSC P10000	11	590–630	10,000–12,000	N	20,000	75,000
GustoMSC PRD12,000	1	632	12,000	N	15,000	45,000
Samsung 10000	17	638–820	10,000–12,000	N	22,000	105,000
Samsung 12000	8	550–650	10,000–12,000	N	22,000	105,000
Stena/Samsung	1	1,150	7,500	Y	19,000	108,000
Huisman GT-10000	2	550–585	10,000	N	20,000	60,000

Source: Jefferies and Company, Inc., 2011; Industry press.

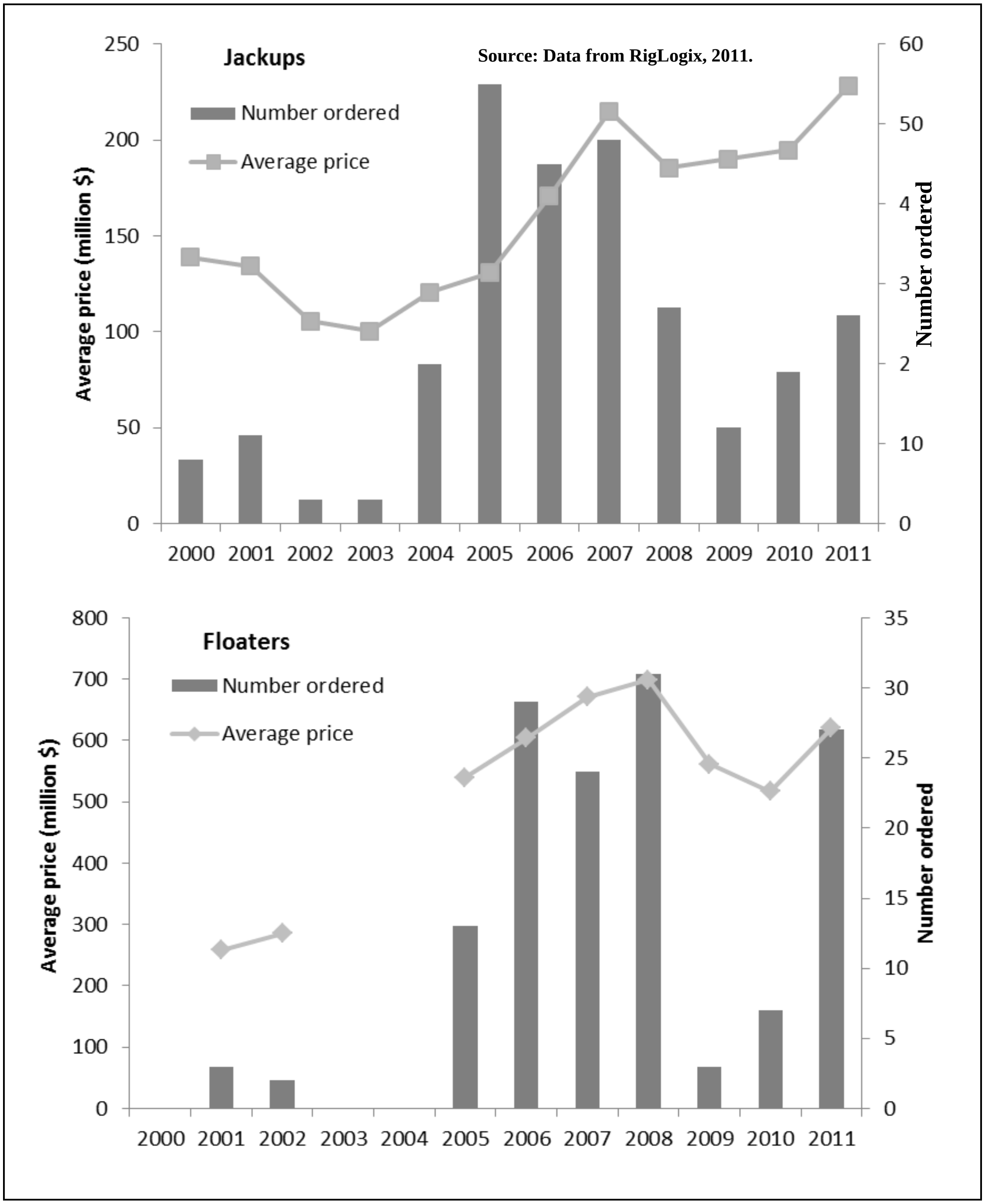
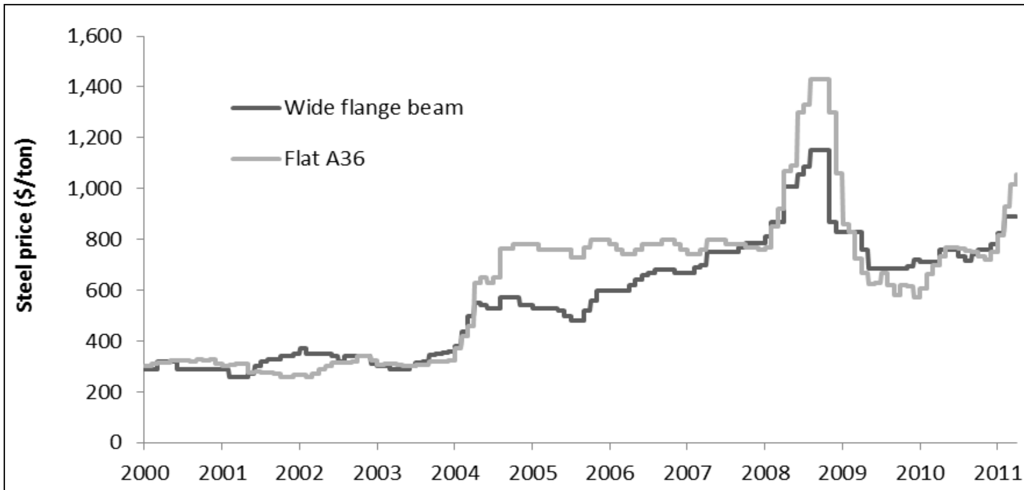
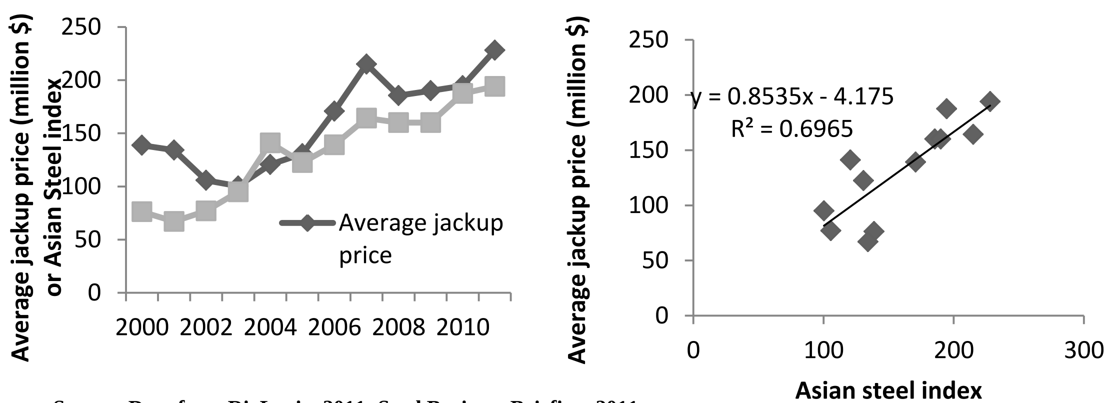


Figure M.1. Number and cost of worldwide jackup and floater orders, 2000–2011.



Source: Data from Steel Business Briefing, 2011.

Figure M.2. Domestic U.S. steel prices 2000–2011.



Source: Data from RigLogix, 2011; Steel Business Briefing, 2011.

Figure M.3. Asian steel index and average world jackup prices, 2000–2010.

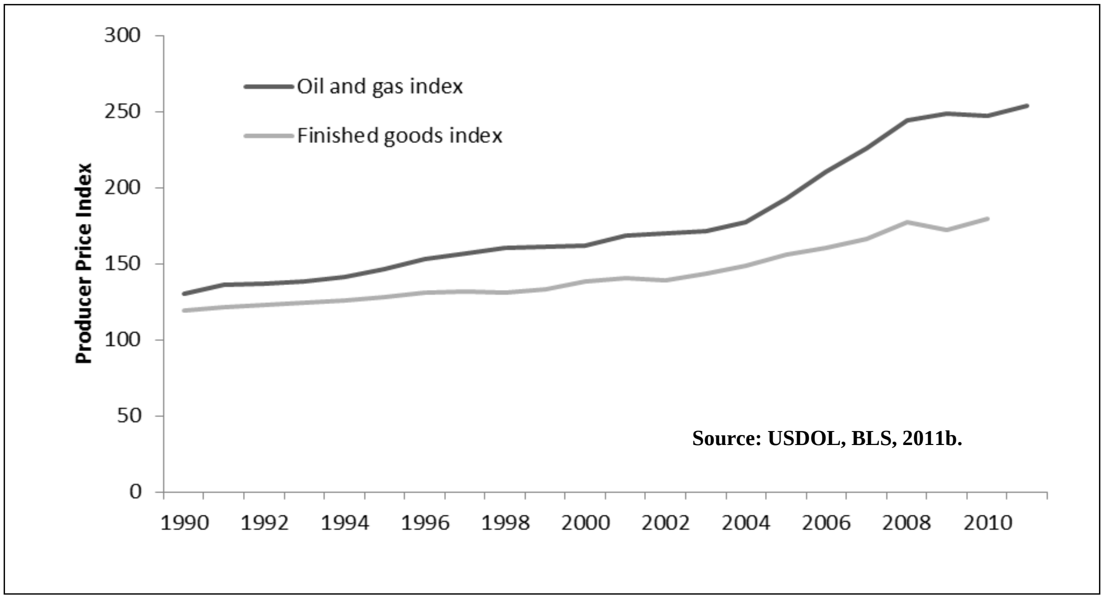


Figure M.4. BLS oil and gas field machinery equipment producer price index, 1990–2011.

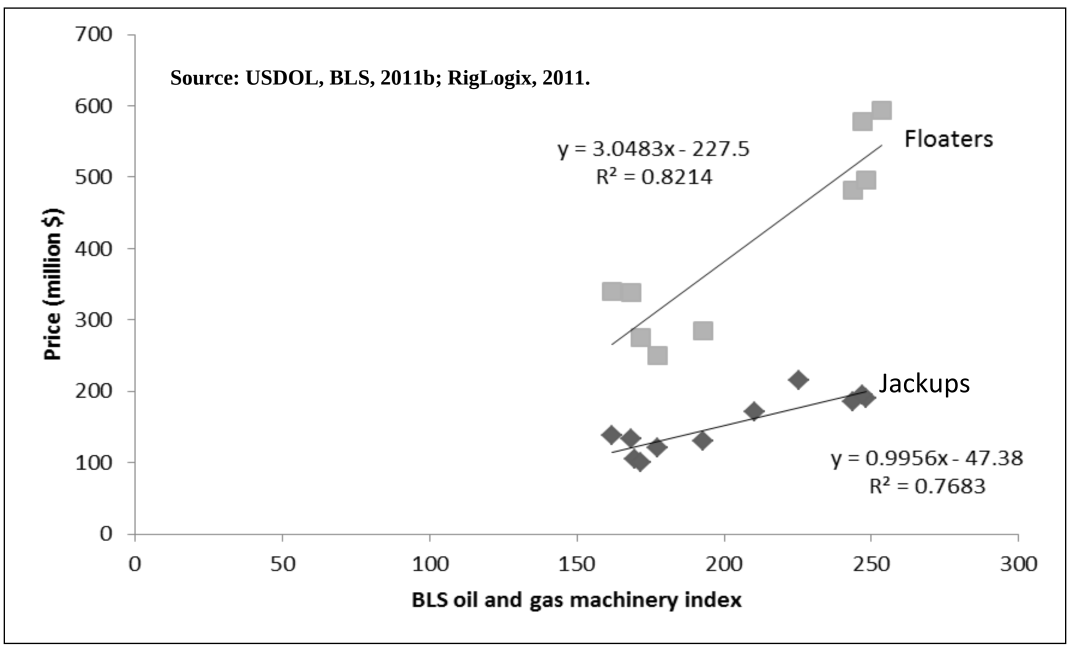


Figure M.5. Relationship between the BLS oil and gas machinery equipment index and global jackup prices.

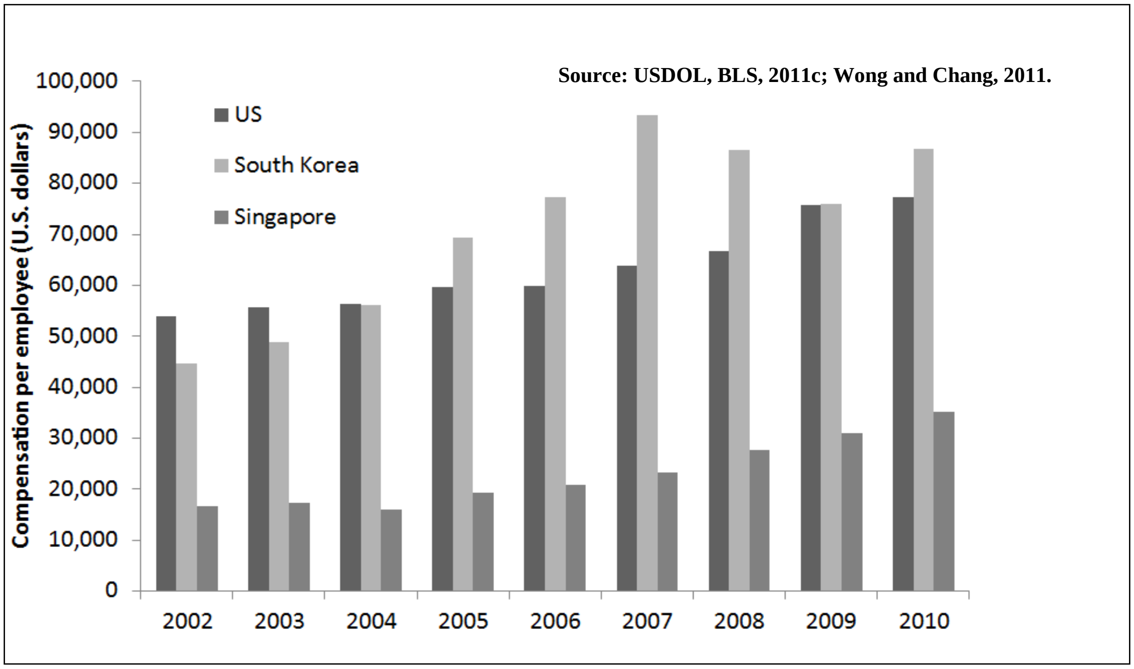


Figure M.6. Annual compensation in U.S., Korean, and Singaporean shipyards, 2002–2010.

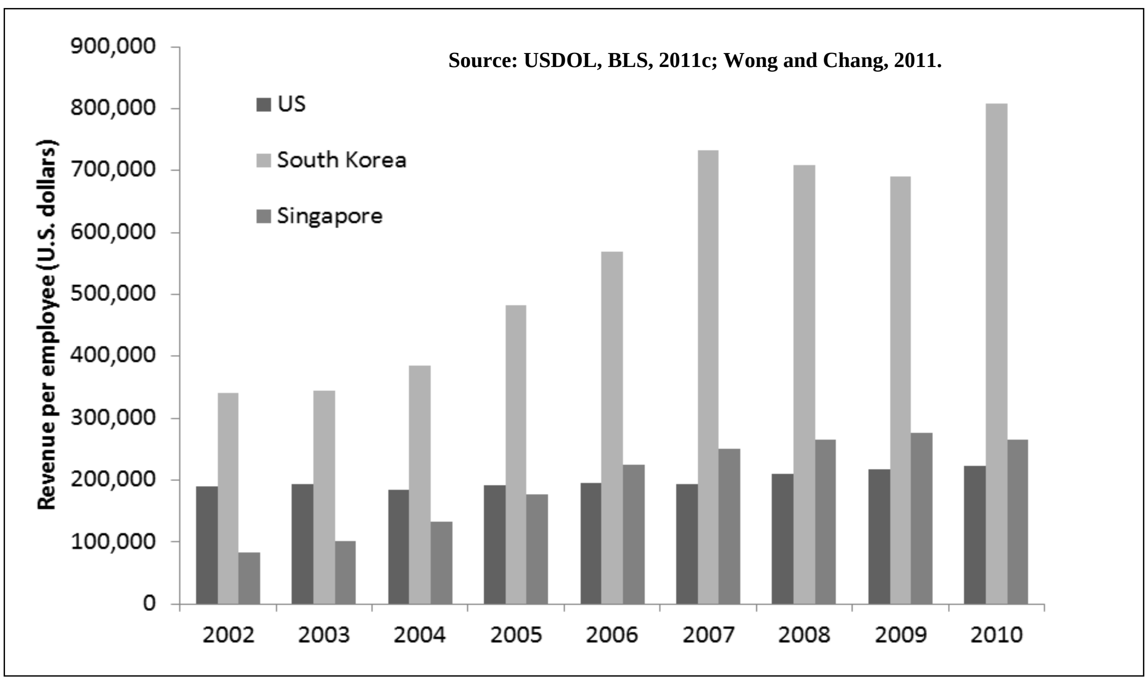


Figure M.7. Productivity in the shipbuilding sector in the U.S., Korea, and Singapore, 2002–2010.

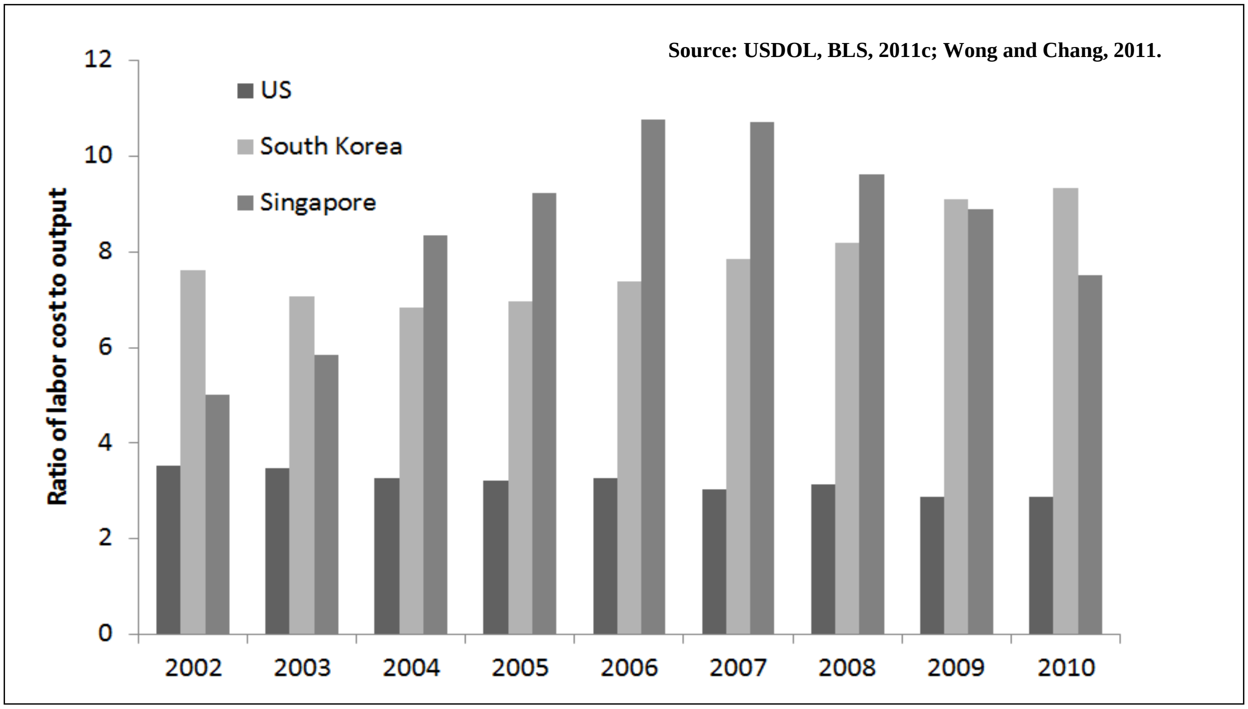


Figure M.8. Revenue generated per U.S. dollar spent on labor in U.S., Korean, and Singaporean shipyards, 2002–2010.

APPENDIX N

CHAPTER 14 TABLES AND FIGURES

Table N.1.

Newbuild and Replacement Cost and Selected Sample Statistics in 2009

		Newbuild			Replacement		
		Drillship	Semi	Jackup	Drillship	Semi	Jackup
Cost (million $)	Average	672	553	225	470	366	142
	Standard deviation	53	102	104	114	87	32
	Coefficient of variation	0.08	0.18	0.46	0.24	0.24	0.23
Water depth (ft)	Average	10,135	8,333	362	8,256	4,352	293
	Standard deviation	1,585	2,192	42	2,815	2,902	71
	Coefficient of variation	0.16	0.26	0.12	0.34	0.67	0.24
Age (yr)	Average				16	24	24
	Standard deviation				12.4	10.8	10.1
	Coefficient of variation				0.78	0.45	0.42

Note: Newbuild statistics based on 39 jackups, 35 semis and 37 drillships. Replacement statistics based on 282 jackups, 149 semis and 35 drillships.
Source: Jefferies and Company, Inc., 2009; Industry press.

Table N.2.

Newbuild Jackup and Semisubmersible Average Costs by
Water Depth and Environmental Design Conditions in 2009

	Water depth (ft)	Harsh (million $)	Moderate (million $)
Jackups	≤ 300	-	171 (7)
	300–350	240 (2)	173 (13)
	350–400	465 (1)	213 (12)
	≥400	530 (3)	-
Semis	≤ 2,500	375 (3)	-
	2,500–7,500	633 (1)	542 (3)
	≥7,500	585 (9)	563 (19)

Note: Sample sizes in parenthesis.
Source: Jefferies and Company, Inc., 2009.

Table N.3.

Newbuild Costs by Country of Shipyard in Million U.S. Dollars in 2009

Rig type	Water depth (ft)	Harsh	India	US	China	Singapore	UAE	Korea	Italy	Average
Jackup	≤350	Y	240 (2)							240
		N	182 (1)	178 (5)		163 (5)	174 (9)			172
	350–400	Y				465 (1)				465
		N		223 (2)		212 (10)				213
	≥400	Y			607 (1)	473 (2)				530
		N								
Semi	≤2,500	Y			375 (3)					375
		N								
	2,500–7,500	Y						633 (1)		633
		N			574 (2)	480 (1)				542
	≥7,500	Y			557 (5)			623 (3)	615 (1)	585
		N			604 (9)	517 (7)	547 (3)			563
Drillship	7,500	N						683 (5)		683
	10,000	Y						1,500 (1)		1,500
		N						676 (23)		676
	12,000	N			616 (2)			700 (6)		681

Note: Sample sizes in parentheses.
Source: Jefferies and Company, Inc., 2009; Industry press.

Table N.4.

Models of Jackup Newbuild Costs

Cost (million \$) = $\alpha_0 + \alpha_1$HARSH + α_2WD + α_3WD^2							
Model	α_0	α_1	α_2	α_3	R^2	Model p	SE
A	1248**	140.4**	-6.88**	0.011**	0.91	**	31.5
B	-209.9**	171.7**	1.128**		0.83	**	42.9
C	-16.0	163.38**		0.0016**	0.85	**	40.1
D	0	159.9**	-0.146	0.002**			39.8
E	0	201.6**	0.54**				47.7
F	0	167.8**		0.0015**			39.7

Note (*): p is less than 0.05; (**): p is less than 0.01. Terms without asterisks are not significant.

Table N.5.

Models of Semisubmersible Newbuild Costs

Cost (million \$) = $\alpha_0 + \alpha_1 WD + \alpha_2 YEAR$						
Model	α_0	α_1	α_2	R^2	Model p	SE
A	-50.3	0.025**	38.1*	0.39	**	81.2
B	0	0.024**	33.6**			79.5

Note (*): p is less than 0.05; (**): p is less than 0.01.

Table N.6.

Jackup Newbuild Costs by Design Class

Cost (million \$) = 213** + α_1DESIGN	
Class	α_1
MSC CJ70	394.0**
F&G 2000A	27.0*
	-41.6**
KFELS ModVB	-11.3
KFELS N class	270.0**
LET 116	-33.8**
LET 240	9.5
MSC CJ 46	-55.0**
Pacific Class 375	0.0**

Note (*): p is less than 0.05; (**): p is less than 0.01.

Table N.7.

Jackup Replacement Cost Models

Cost (million \$) = $\alpha_0 + \alpha_1 WD + \alpha_2 WD^2 + \alpha_3 HARSH + \alpha_4 YEAR$								
Model	α_0	α_1	α_2	α_3	α_4	R^2	Model p	SE
A	-1243.7**		0.0005**	10.6**	0.674**	0.70	**	17.5
B	-1567**	0.282**		10.6**	0.818**	0.68	**	18.0
C	0		0.0006**	10.6**	0.04**			18.2

Note (*): p is less than 0.05; (**): p is less than 0.01. Terms without asterisks are not significant.

Table N.8.

Semisubmersible Replacement Cost Models

Cost (million \$) = $\alpha_0 + \alpha_1$WD + α_2YEAR + α_3HARSH							
Model	α_0	α_1	α_2	α_3	R^2	Model p	SE
A	-4121 **	0.020**	2.2 **	23.8**	0.69	**	48.3
B	0	0.023**	0.13**				52.4

Note (*): p is less than 0.05; (**): p is less than 0.01.

Table N.9.

Drillship Replacement Cost Models

Cost (million \$) = $\alpha_0 + \alpha_1$HARSH + α_2WD						
Model	α_0	α_1	α_2	R^2	Model p	SE
A	204.4 **	196**	0.031 **	0.65	**	67.2
B	0	234.7*	0.053**			94.0

Note (*): p is less than 0.05; (**): p is less than 0.01. Terms without asterisks are not significant.

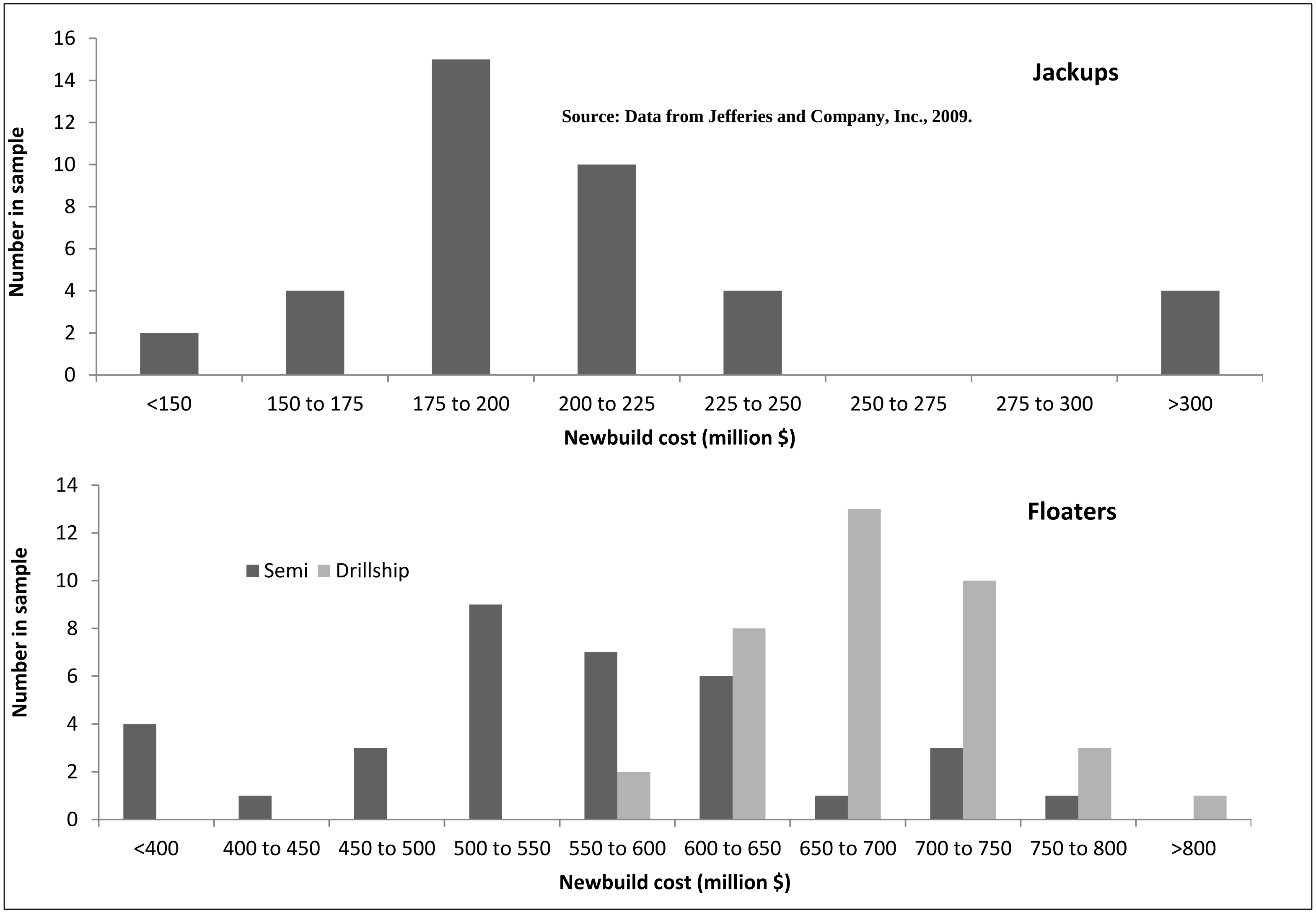


Figure N.1. Distribution of jackup and floater newbuild costs.

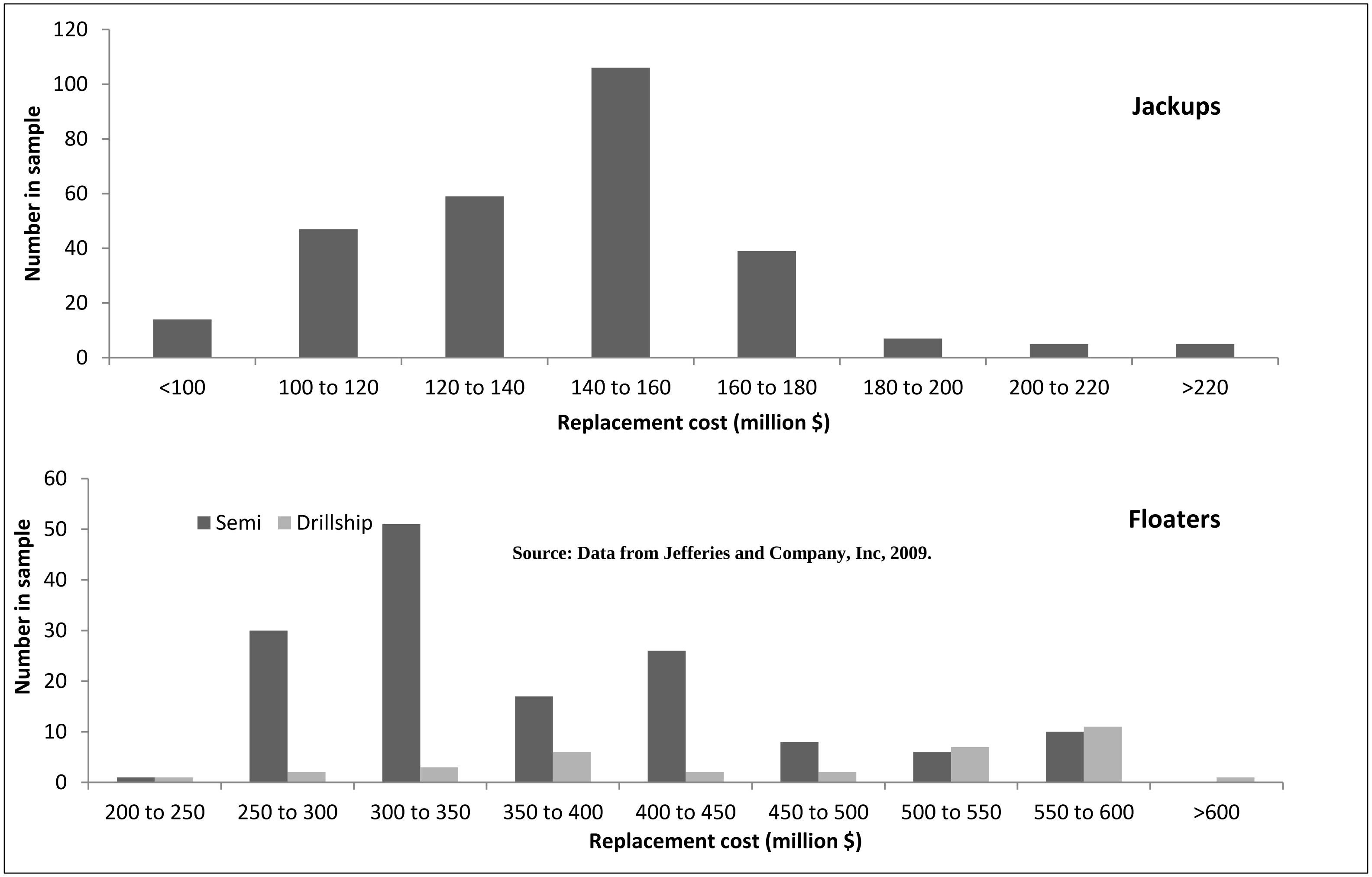


Figure N.2. Distribution of jackup and floater replacement costs.

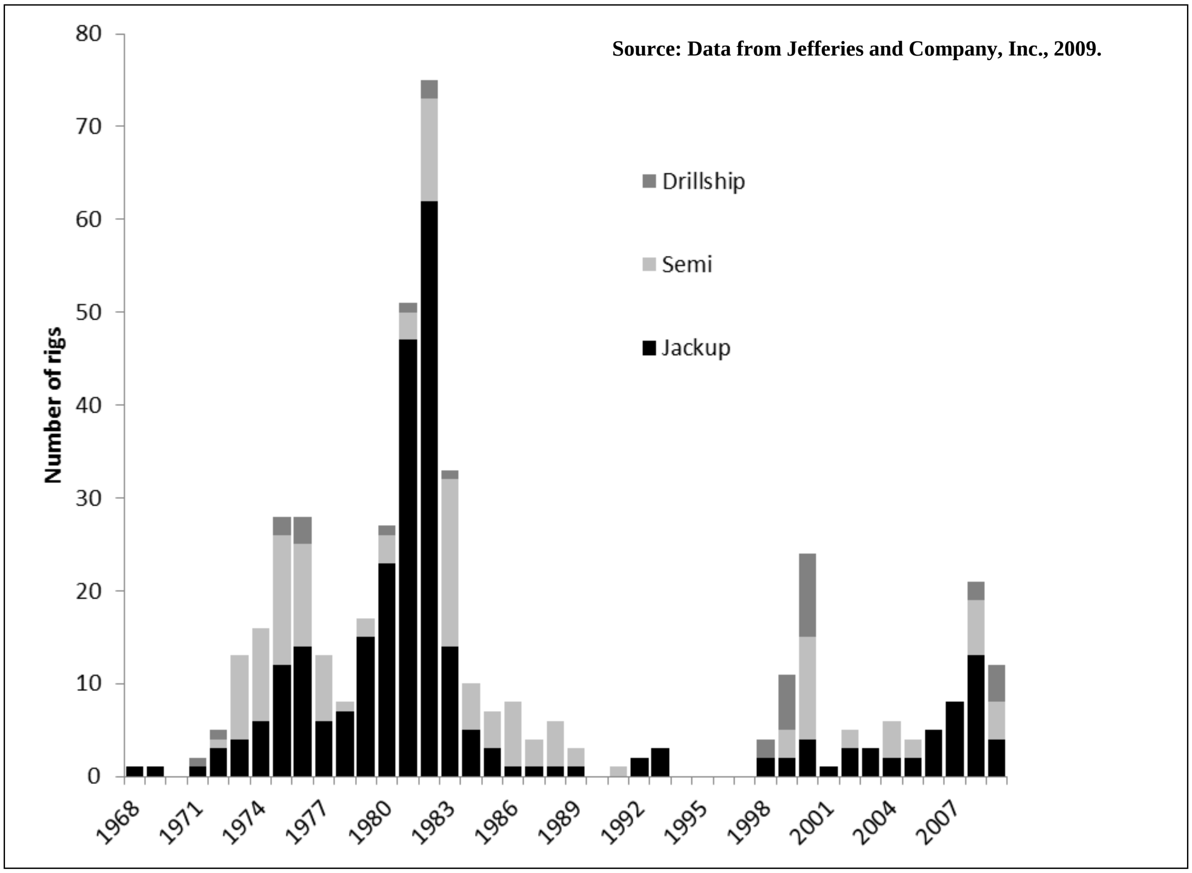


Figure N.3. Distribution of jackup, semisubmersible, and drillship ages for the 2009 rig fleet.

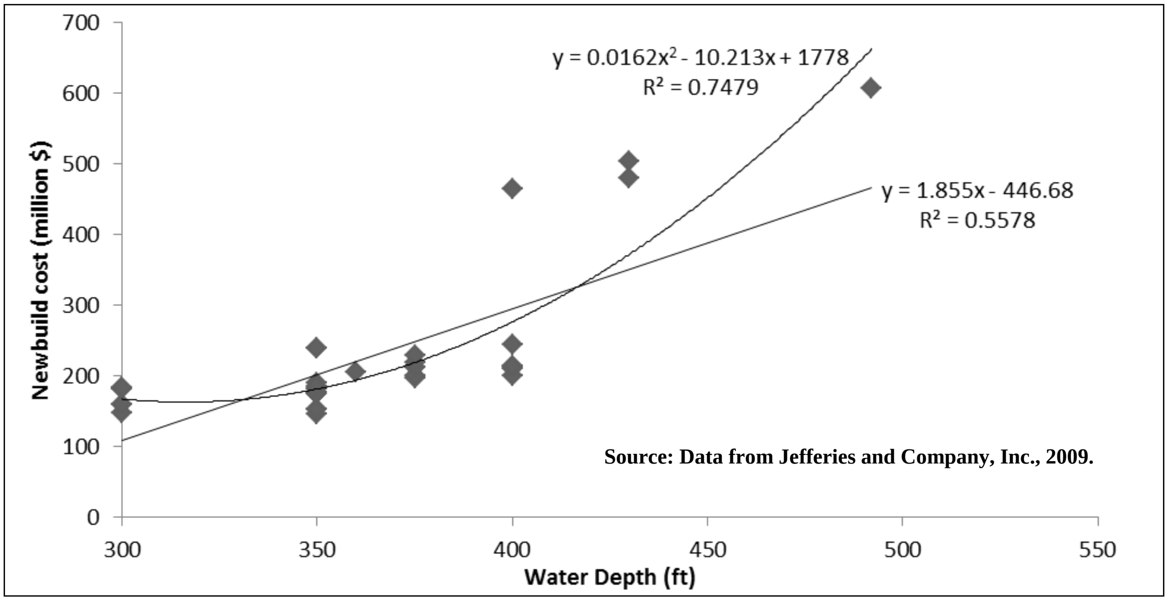


Figure N.4. Relationship between water depth and cost in jackup newbuilds.

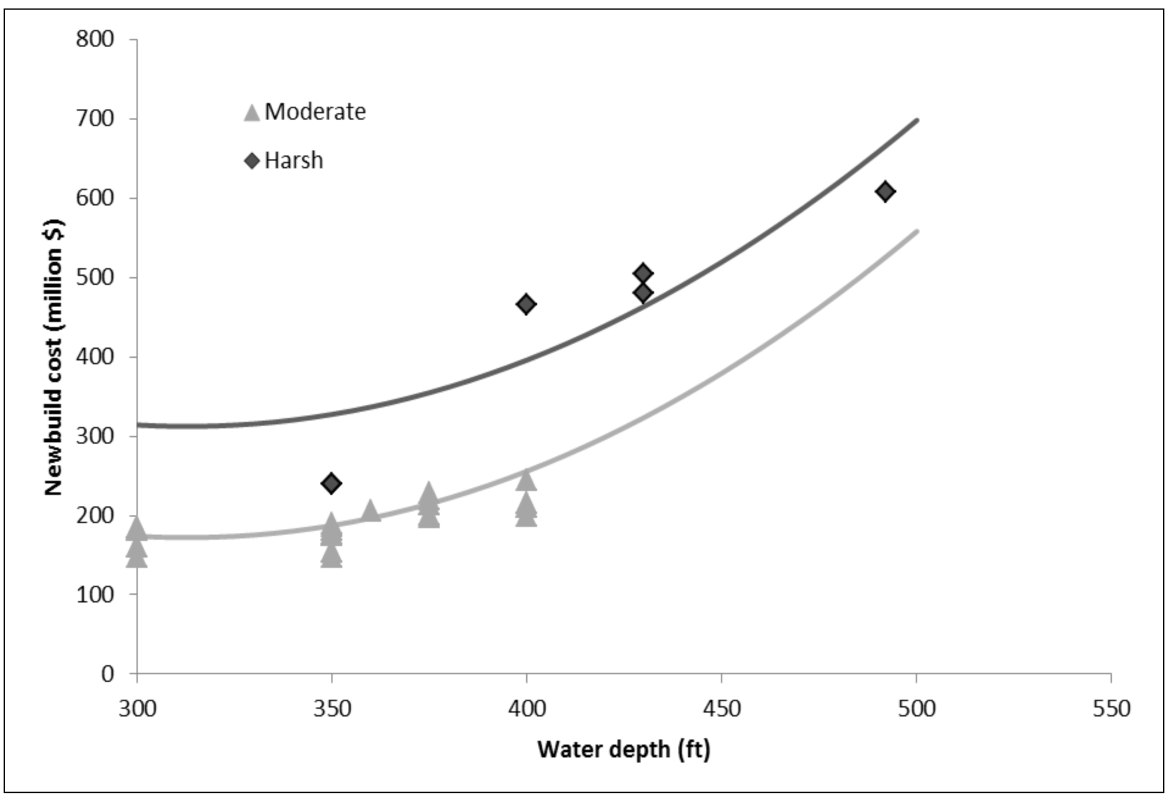


Figure N.5. Newbuild cost model A output containing water depth and water depth squared terms. See Table N.4 for model A parameters.

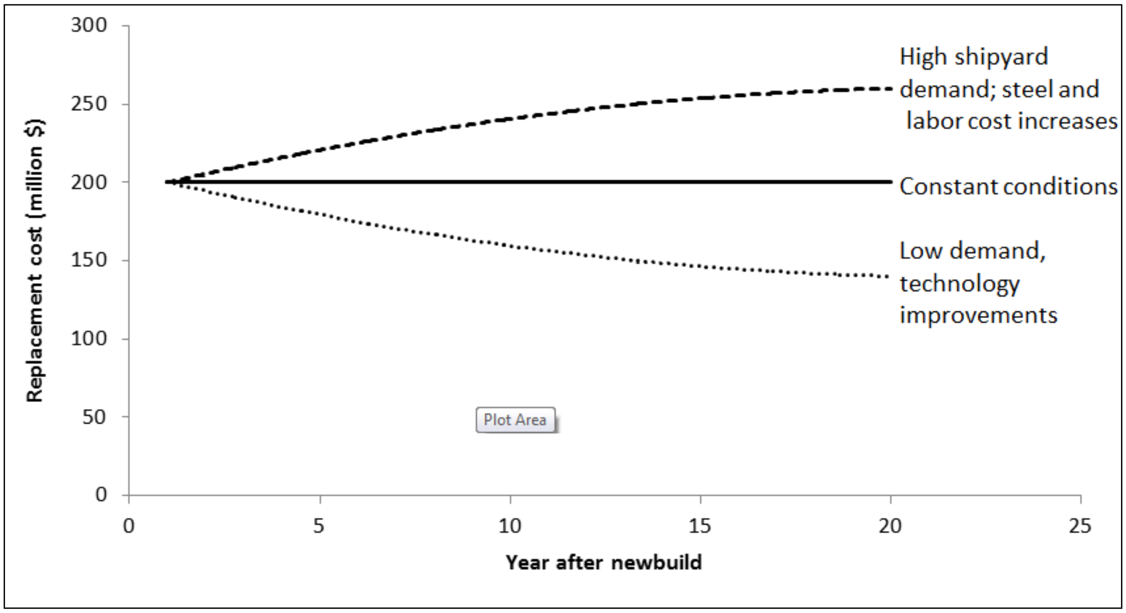


Figure N.6. Effects of time and market conditions on replacement costs.

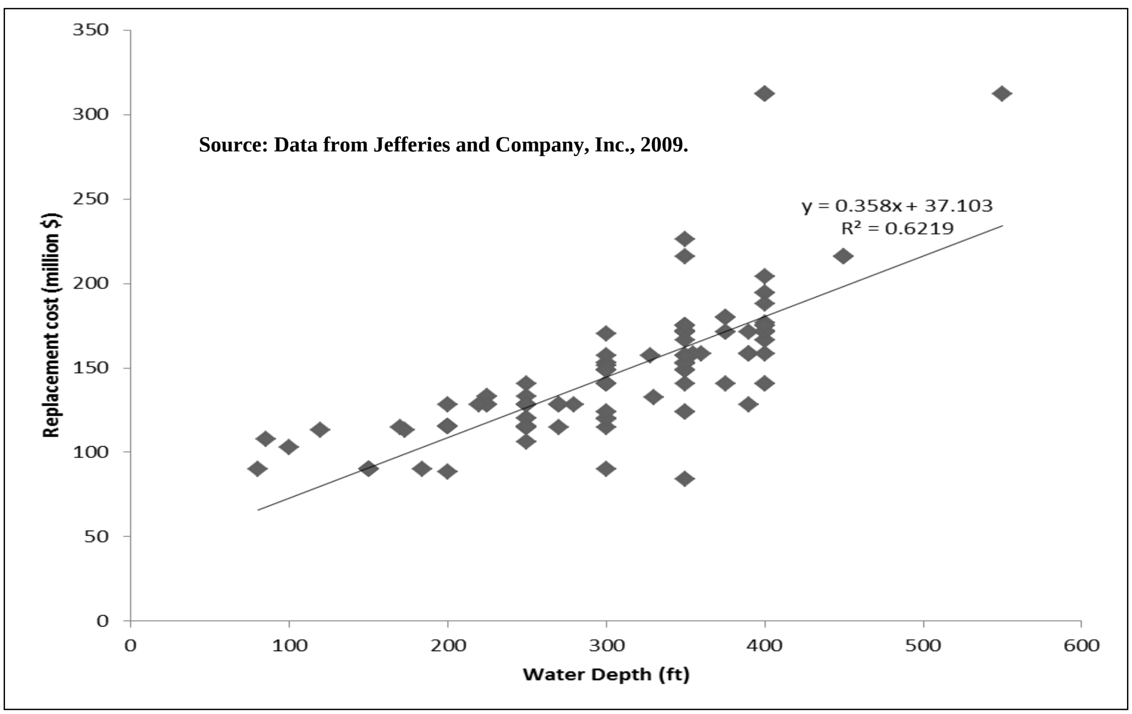


Figure N.7. Jackup replacement costs as a function of water depth.

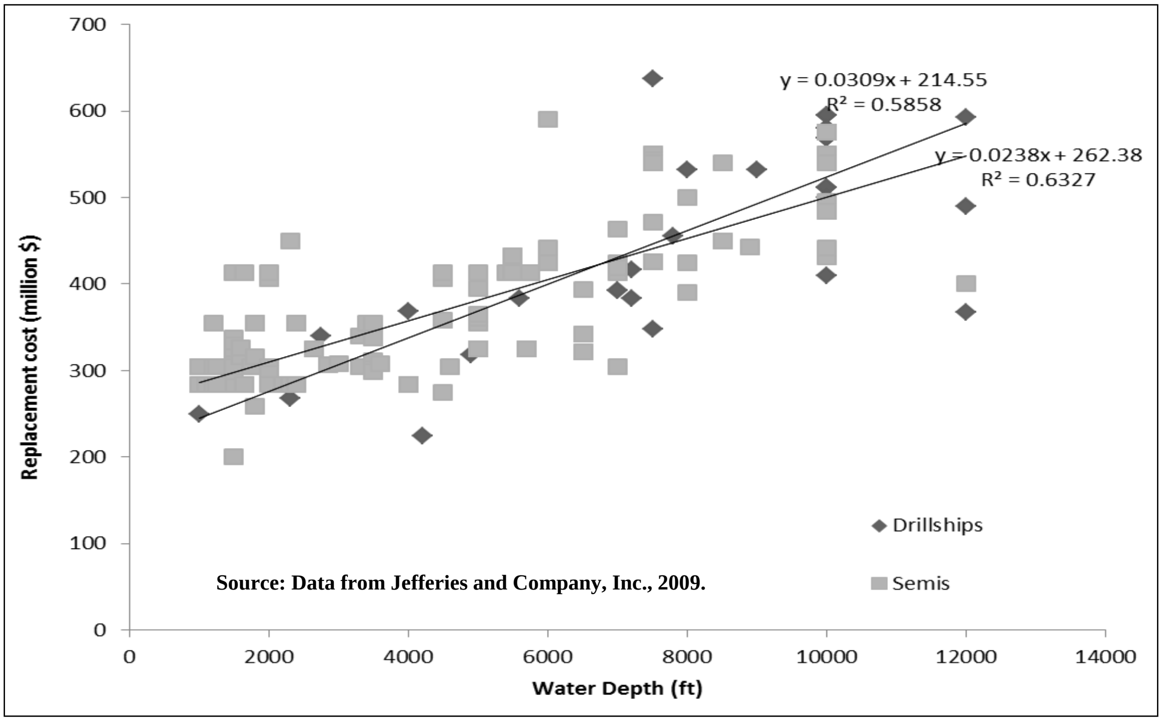


Figure N.8. Replacement costs of semisubmersibles and drillships as a function of water depth.

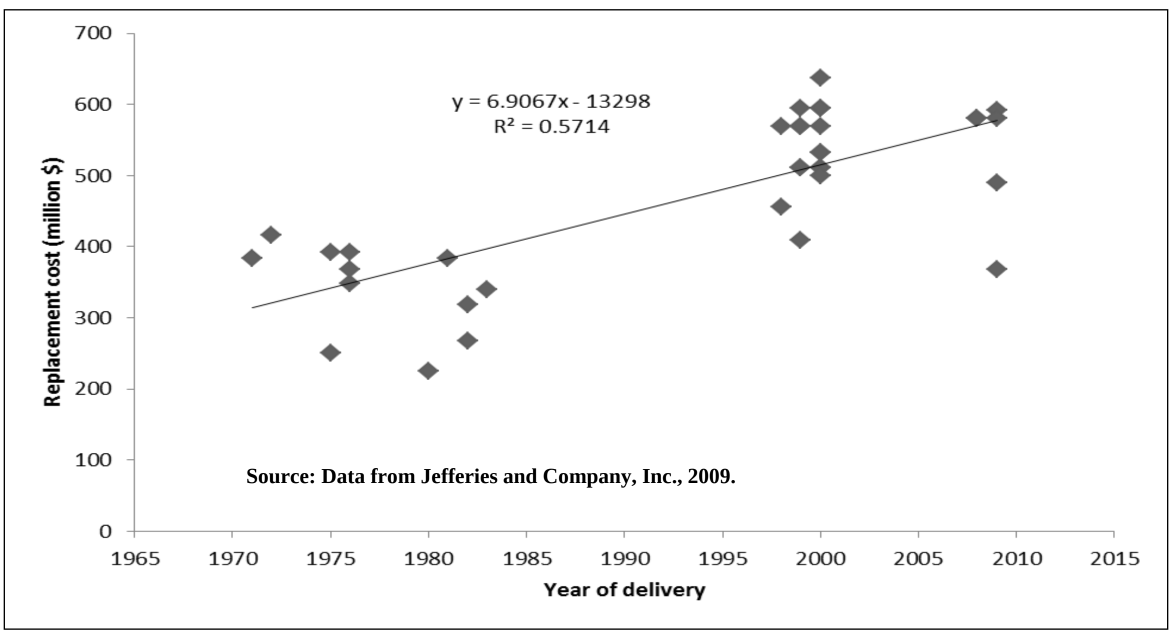


Figure N.9. Replacement costs of drillships as a function of delivery year.

The Department of the Interior Mission

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

The Bureau of Ocean Energy Management

The Bureau of Ocean Energy Management (BOEM) works to manage the exploration and development of the nation's offshore resources in a way that appropriately balances economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development and environmental reviews and studies.