Independent Statistics & Analysis
U.S. Energy Information Administration

Trends in U.S. Oil and Natural Gas Upstream Costs

March 2016

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Summary

The profitability of oil and natural gas development activity depends on both the prices realized by producers and the cost and productivity of newly developed wells. Prices, costs, and new well productivity have all experienced significant changes over the past decade. Price developments are readily observable in markets for oil and natural gas, while trends in well productivity are tracked by many sources, including EIA's Drilling Productivity Report which focuses on well productivity in key shale gas and tight oil plays.

Regarding well development costs, there is a general understanding that they are sensitive to increased efficiency in drilling and completion, which tends to lower costs, shifts towards longer wells with more complex completions, which tends to increase them, and prices for oil and natural gas, which affect markets for drilling and completion services through their effect on drilling activity. However, overall trends in well development costs are generally less transparent than price and productivity trends. Given the role of present and future cost trends to determining future trajectories of U.S. oil and natural gas production under a range of possible future price scenarios, it is clearly important to develop a deeper understanding of cost drivers and trends.

To increase the availability of such cost information, the U.S. Energy Information Administration (EIA) commissioned IHS Global Inc. (IHS) to perform a study of upstream drilling and production costs. The IHS report assesses capital and operating costs associated with drilling, completing, and operating wells and facilities. The report focuses on five onshore regions, including the Bakken, Eagle Ford, and Marcellus plays, two plays (Midland and Delaware) within the Permian basin[1], as well as the offshore federal Gulf of Mexico (GOM). The period studied runs from 2006 through 2015, with forecasts to 2018.

Among the report's key findings are that average well drilling and completion costs in five onshore areas evaluated in 2015 were between 25% and 30% below their level in 2012, when costs per well were at their highest point over the past decade.

Based on expectations of continuing oversupply of global oil in 2016, the IHS report foresees a continued downward trajectory in costs as drilling activity declines. For example, the IHS report expects rig rates to fall by 5% to 10% in 2016 with increases of 5% in 2017 and 2018. The IHS report also expects additional efficiencies in drilling rates, lateral lengths, proppant use, multi-well pads, and number of stages that will further drive down costs measured in terms of dollars per barrel of oil-equivalent ($/boe) by 7% to 22% over this period.

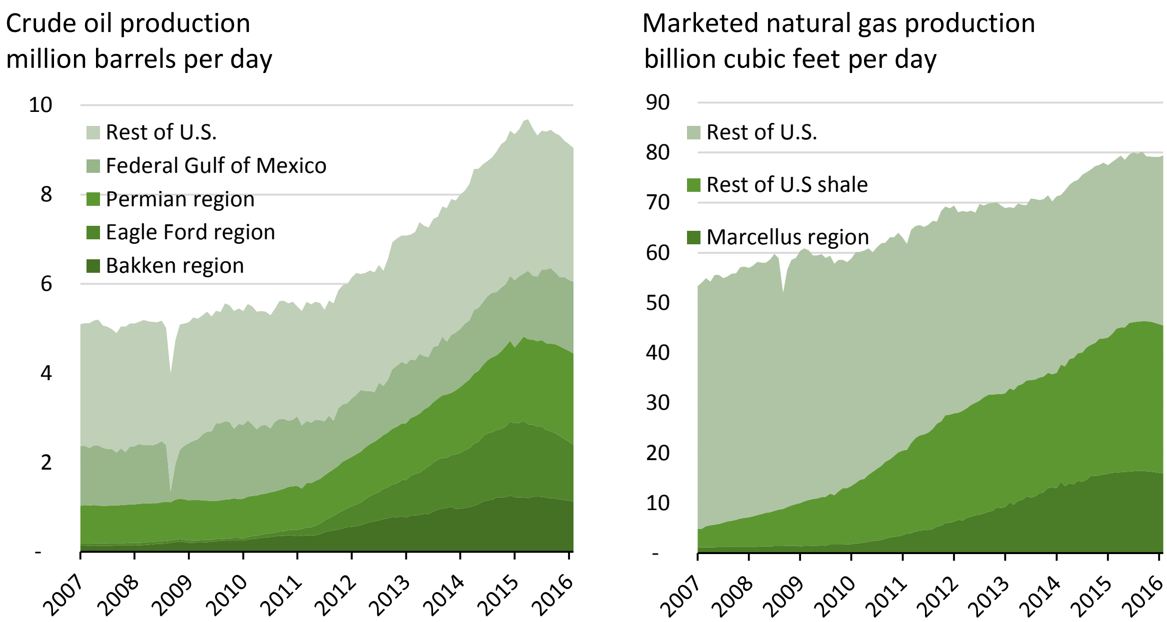
EIA is already using the observations developed in the IHS report as a guide to potential changes in near-term costs as exploration and production companies deal with a challenging price environment.

[1] The Bakken is primarily located in North Dakota, while the Marcellus is primarily located in Pennsylvania. The Eagle Ford and the two Permian plays (Midland and Delaware) are located in Texas.

Onshore costs

Costs in domestic shale gas and tight oil plays were a key focus of EIA's interest given that development of those resources drove the major surge in crude oil and natural gas production in the United States over the past decade, as shown in Figure 1. The IHS report documents the upstream costs associated with this growth, including increases associated with the demand for higher drilling activity during expansion and decreases during the recent contraction of drilling activity.

Figure 1. Regional shale development has driven increases in U.S. crude oil and natural gas production



Source: U.S. Energy Information Administration *Drilling Productivity Report* regions, *Petroleum Supply Monthly*, *Natural Gas Monthly*
Note: Shale gas estimates are derived from state administrative data collected by DrillingInfo Inc. and represent the U.S. Energy Information Administration's shale gas estimates, but are not survey data.

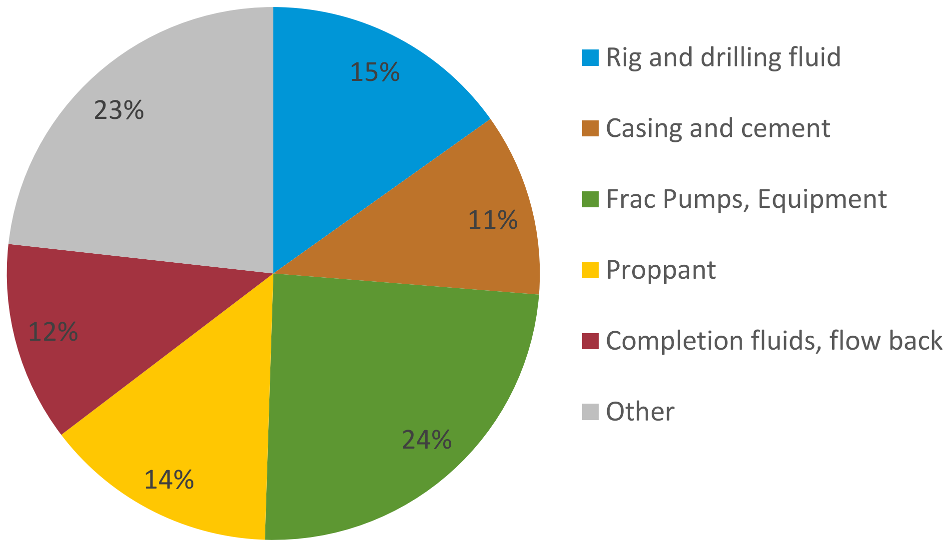
The IHS report considers the costs of onshore oil and natural gas wells using the following cost categories: land acquisition; capitalized drilling, completion, and facilities costs; lease operating expenses; and gathering processing and transport costs. Total capital costs per well in the onshore regions considered in the study from $4.9 million to $8.3 million, including average completion costs that generally fell in the range of $ 2.9 million to $ 5.6 million per well. However, there is considerable cost variability between individual wells.

Figure 2 focuses on five key cost categories that together account for more than three quarters of the total costs for drilling and completing typical U.S. onshore wells.[2] **Rig and drilling fluids** costs make up 15% of total costs, and include expenses incurred in overall drilling activity, driven by larger market conditions and the time required to drill the total well depth. **Casing and cement** costs total 11% of total

[2] Typical U.S. onshore wells are multi-stage, hydraulically fractured, and drilled horizontally. The costs identified relate, in part, to the application of those technologies.

costs, and relate to casing design required by local well conditions and the cost of materials. **Frac Pumps, Equipment** costs make up 24% of total costs, including the costs of equipment and horsepower required for the specific treatment. **Proppant** costs make up an average of 14% of total costs and include the amount and rates for the particular type of material introduced as proppant in the well. **Completion fluids, flow back** costs make up 12% of total costs, and include sourcing and disposal of the water and other materials used in hydraulic fracturing and other treatments that are dependent on geology and play location as well as available sources.

Figure 2 Percentage breakdown of cost shares for U.S. onshore oil and natural gas drilling and completion

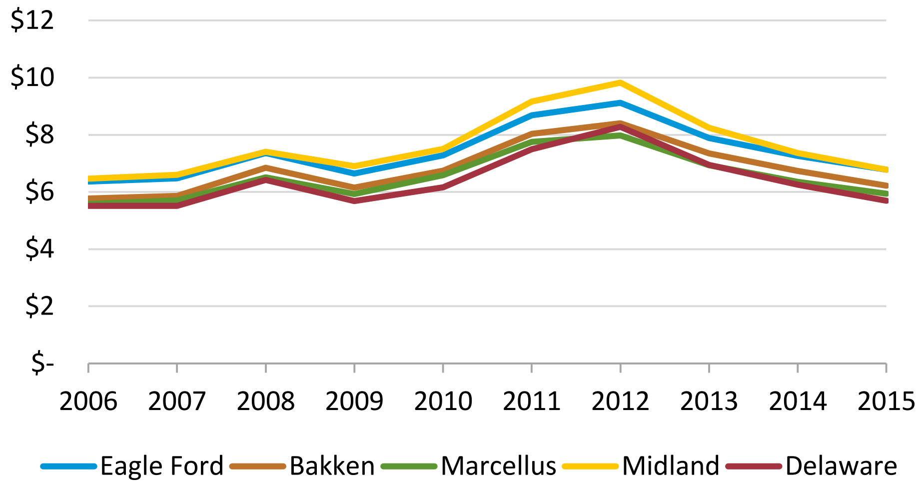


Source: IHS *Oil and Gas Upstream Cost Study commissioned by EIA*

Over time, these costs have changed. For example, drilling and completion cost indices shown in Figure 3 during the period when drilling and drilling services industries were ramping up capacity from 2006 to 2012 demonstrate the effect of rapid growth in drilling activity. Since then, reduced activity as well as improved drilling efficiency and tools used have reduced overall well costs. Changes in cost rates and well parameters have affected plays differently in 2015, with recent savings ranging from 7% to 22% relative to 2014 costs.

Figure 3. Average well drilling and completion costs for the 5 onshore plays studied follow similar trajectories

Cost by year for 2014 well parameters
$ million per well



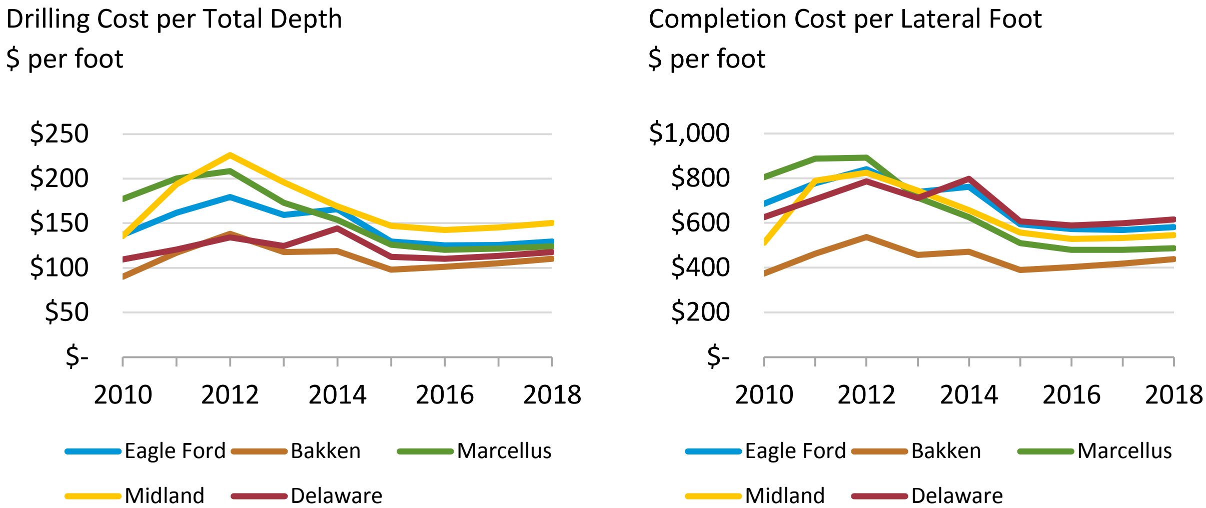
Note: Midland and Delaware are two plays within the Permian basin, located in Texas and New Mexico
Source: IHS *Oil and Gas Upstream Cost Study commissioned by EIA*

The onshore oil and natural gas industry continues to evolve, developing best practices and improving well designs. This evolution resulted in reduced drilling and completion times, lower total well costs, and increased well performance. Drilling technology improvements include longer laterals, improved geo-steering, increased drilling rates, minimal casing and liner, multi-pad drilling, and improved efficiency in surface operations. Completion technology improvements include increased proppant volumes, number and position of fracturing stages, shift to hybrid fluid systems, faster fracturing operations, less premium proppant, and optimization of spacing and stacking. Although well costs are trending higher, collectively, these improvements have lowered the unit cost of production in $/boe.

The cost variations across the studied areas arise primarily from differences in geology, well depth, and water disposal options. For example, Bakken wells are the most costly because of long well lengths and use of higher-cost manufactured and resin coated proppants. In contrast, Marcellus wells are the least costly because the wells are shallower and use less expensive natural sand proppant. Figure 4 shows, by region, how costs for well vertical and horizontal depths have dropped over time, driving some of the efficiency improvements characteristic of U.S. domestic production over the past decade.

The Bakken play has consistently had the lowest average drilling and completion costs of the basins and plays reviewed in the IHS report. Improvement in drilling rig efficiency and completion crew capacity helped drive down drilling costs per total depth and completion costs per lateral foot, since 2012. Recent declines are partly a result of an oversupply of rigs and service providers. Standardization of drilling and completion techniques will continue to push costs down.

Figure 4. Cost per vertical depth and horizontal length



Note: Midland and Delaware are two plays within the Permian basin, located in Texas and New Mexico

Source: IHS *Oil and Gas Upstream Cost Study commissioned by EIA*

Offshore costs

There are fewer than 100 deepwater wells in the Gulf of Mexico. Unlike onshore shale and tight wells that tend to be similar in the same play or basin, each offshore project has a unique design and cost profile. Deepwater development generally occurs in the form of expensive, high-risk, long-duration projects that are less sensitive to short-term fluctuations in oil prices than onshore development of shale gas and tight oil resources. Nevertheless, recent low commodity prices do appear to have reduced some Gulf of Mexico offshore drilling.

Key cost drivers for offshore drilling include water depth, well depth, reservoir pressure and temperature, field size, and distance from shore. Drilling itself is a much larger share of total well costs in offshore development than in onshore development, where tangible and intangible drilling costs typically represent only about 30% to 40% of total well costs.

According to the IHS report’s modeling of current deepwater Gulf of Mexico projects, full cycle economics result in breakeven prices that are typically higher than $60/b. Low oil prices force companies to control costs, increase efficiencies, and access improved technologies to improve the economics in the larger plays. Efforts are underway to renegotiate contract rates and leverage existing production infrastructure to develop resources with subsea tiebacks. Consequently, the IHS report forecasts a 15% reduction in deepwater costs in 2015, with a 3% per annum cost growth from 2016 to 2020. The large cost reduction in 2015 is most notable in rig rates because of overbuilding.

Approach

The IHS report includes the following analyses and results:

- Assessment of current costs and major cost components
- Identification of key cost drivers and their effects on ranges of costs
- Review of historical cost trends and evolution of key cost drivers as well designs and drilling programs evolved
- Analysis of these data to assess likely future trends, particularly for key cost drivers, especially in light of recent commodity price decreases and related cost reductions
- Data and analyses to determine the correlations between activities related to drilling and completion and total well cost

Appendix - IHS Oil and Gas Upstream Cost Study (Commission by EIA)

The text and data tables from the IHS *Oil and Gas Upstream Cost Study* are attached.

FINAL REPORT

Oil and Gas Upstream Cost Study

DT007965, CO Task Assignment
Definitization Letter FY2015 #4

Prepared For:

Energy Information Administration (EIA)

October 8, 2015

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I. Introduction

The Energy Information Administration, (EIA) commissioned IHS Global Inc. (IHS) to perform a study of upstream costs associated with key basins and plays located in the United State, namely the Bakken, Eagle Ford, Marcellus, Permian Basin and deep water Gulf of Mexico (GOM). As explained by EIA, one of the primary purposes of this study is to help EIA analysts with cost analyses and projections that the organization is required to provide. Consequently, the study focused on the most active areas, and the results include the following:

- Determining current costs and major cost components,
- Identifying key cost drivers and their impact on range of cost,
- Reviewing historical cost trends and evolution of the key cost drivers as well designs and drilling programs have evolved,
- Analyzing the relevant data to determine future trends, particularly for key cost drivers in light of recent commodity price decreases and related cost reductions, and
- Providing data and analyses to determine the correlations between activities related to drilling and completion and total well cost

IHS based this study on 2014 costs. However, the collapse of oil prices in late 2014 has forced reduction of many upstream costs, thus modifying the cost structure. Consequently, this report addresses future cost indices, including cost reductions for 2015, and how key cost drivers will continue to play a role in changing costs.

This report begins with a discussion of summary results for the selected onshore basins and deep water Gulf of Mexico, and then addresses methodologies and assumptions. The body of the report is comprised of detailed discussions of costs for each basin, including the deep water Gulf of Mexico. A large data set is also available in conjunction with this report, which includes many additional graphs and charts not included herein. These are listed in the Appendix.

A. Background to the Study

As a result of low oil prices, US onshore oil field development had nearly come to a standstill by the year 2000. However, relatively stronger natural gas prices encouraged the drilling of vertical wells in conventional natural gas plays and some development of coalbed methane. The shale boom began with the Barnett Shale taking off in 2004, employing modern unconventional drilling and completion techniques such as horizontal drilling and complex hydraulic fracturing (fracking). These techniques evolved as they spread to other plays such as the Haynesville in Northern Louisiana, the Fayetteville in Northern Arkansas and the Marcellus Shale in Pennsylvania and West Virginia. Increasing natural gas prices from 2001 through 2008 also fueled this evolution.

While natural gas prices collapsed in 2008, oil prices, which had begun an upward trajectory early in the decade, dropped as well. However, unlike natural gas, oil prices quickly rebounded, driving operators to explore new opportunities in search of oil plays and liquid-rich gas plays containing associated condensate and natural gas liquids (NGLs). New plays such as the Eagle Ford and Bakken became profitable by drilling and fracking horizontal wells, tapping into the shale source rocks of earlier productive plays.

At the same time, deep water and deep formation areas offshore, once prohibitively expensive to explore or develop had new technology and strong oil prices to encourage more difficult operations. Moving into deeper water was accompanied by technical and commercial challenges, as was drilling into deep formations with high temperature and high pressure (HTHP). However, with large deep water discoveries, such as Jack in 2004, deep water exploration and development in the Gulf of Mexico spurred ahead.

Since the advent of unconventional plays, drilling and completion of wells have continued to evolve with their associated costs increasing commensurately. For example, short lateral lengths of just 1000 to 2000 feet have increased substantially to as much as 10,000 feet in some plays. Proppant use and intensity of hydraulic fracturing have also increased, resulting in huge increases in well performance. This evolution has led to significantly higher well cost (on average greater than 6 million dollars (MM$)/well). However the associated productivity gains have offset these costs, resulting in lower unit costs per barrel of oil equivalent (Boe) and providing better returns on investment. Operators continue seeking the optimal return through two means: 1) persistently driving down actual costs by increasing efficiency, and 2) trying to optimize unit costs ($/Boe) by finding the right balance between high-cost completion design and enhanced performance.

In 2011, as commodity prices stabilized, we saw a large uptick in drilling, resulting in shortages of supply and increased costs. To combat this trend, some operators became more vertically integrated into field services and supplies. For example, some companies purchased or developed sand mines, water treatment facilities, gas processing plants, pipeline infrastructure, or even drilling rigs to have primary access to services that could ensure lower costs.

By 2014, as plays became delineated and the better performing areas were identified, the Bakken, Eagle Ford, Permian Basin and Marcellus plays emerged as the most significant contributors to the unconventional oil and natural gas supply and capital expenditure within the U.S. The oil price collapse of 2014 forced changes upon the market, including capital cost reductions, downsized budgets and more focused concentration on better prospects within these plays. Some offshore capital costs (such as rig rates) were also being reduced, but unlike unconventional plays where capital expenditures can be turned on and off relatively quickly, offshore development and budgeting is a longer term proposition. Therefore, we may not see substantial changes in offshore activity levels unless low prices persist for several years.

This study focuses on areas of intense current and forecasted activity that will have a material effect on future production and capital expenditure; these include four onshore plays or basins, namely the Bakken, Eagle Ford, Marcellus and Permian Basin, as well as the deep water Gulf of Mexico. No attempt is being made to provide an apples-to-apples comparison between the onshore and offshore basins, as the mode of capital operating expenditure is vastly different. Since this comparison is not practical, onshore and offshore basins are discussed separately throughout the report.

B. Scope and Approach

Upstream costs analyzed within this study include capital and operating costs associated with drilling, completing and operating wells and facilities. Some pipeline costs are included in the offshore analysis. The analysis uses cost modeling that incorporates the following taxonomy.

Onshore

1. <u>Drilling</u> – Within onshore basins drilling comprises about 30-40% of total well costs. These costs are comprised of activities associated with utilizing a rig to drill the well to total depth and include:
    a. *Tangible Costs* such as well casing and liner, which have to be capitalized and depreciated over time, and
    b. *Intangible Costs,* which can be expensed and include drill bits, rig hire fees, logging and other services, cement, mud and drilling fluids, and fuel costs.
2. <u>Completion</u> – Within onshore basins completion comprises 55-70% of total well costs. These costs include well perforations, fracking, water supply and disposal. Typically this work is performed using specialized frack crews and a workover rig or coiled tubing and include:
    a. *Tangible Costs* such as liners, tubing, Christmas trees and packers, and
    b. *Intangible Costs* include frack-proppants of various types and grades, frack fluids which may contain chemicals and gels along with large amounts of water, fees pertaining to use of several large frack pumping units and frack crews, perforating crews and equipment and water disposal.
3. <u>Facilities</u> – Within onshore basins facilities construction comprises 7-8% of total well cost. These costs include:
    a. Road construction and site preparation,
    b. Surface equipment, such as storage tanks, separators, dehydrators and hook –up to gathering systems, and
    c. Artificial lift installations.
4. <u>Operation</u> – These comprise primarily the lease operating expenses. Costs can be highly variable, depending on product, location, well size and well productivity. Typically these costs include:
    a. *Fixed lease costs* including artificial lift, well maintenance and minor workover activities. These accrue over time, but are generally reported on a $/boe basis.
    b. *Variable operating costs* to deliver oil and natural gas products to a purchase point or pricing hub. Because the facilities for these services are owned by third party midstream companies, the upstream producer generally pays a fee based on the volume of oil or natural gas. These costs are measured by $/Mcf or MMbtu or $/bbl and include gathering, processing, transport, and gas compression.

Offshore Deepwater

The rig and related costs account for 90-95% of total well costs, for both drilling and completion and primarily includes the day rate of utilizing drilling ship or a semi-submersible drilling rig for drilling, completing the well, and all other rig related costs, such as drilling crew, fuel, consumables, support vessels, helicopters, logging, cementing, shore base supplies, etc.

1. Drilling – The drilling activity itself comprises about 60% of total offshore well D&C cost. These costs are comprised of activities associated with drilling the well to total depth and include rig hire fees, drilling bits, logging, casings, liners and other services, cement, mud and drilling fluids, fuel costs, offshore support services and other services.
2. Completion – Within offshore basins, this comprises less than 40% of total well costs. These costs are comprised of completion rig hiring, well perforations and testing, completion fluid, transportation/logistics, well stimulation and sand control, and well head equipment.
3. Injection Wells – For a typical field, additional wells are drilled to reinject produced water and/or gas in order to maintain reservoir pressure.
4. Facilities – Production facilities are another major expense and may include one or more of the following:
   a. *Floating facilities,* such as tension leg platforms (TLP), Spars or Semisubmersible platforms. These facilities may include topsides, production equipment, such as compressors, separators and processing units, and capabilities to drill additional wells.
   b. *Sub-sea tiebacks* to production facilities with customized sea floor assembly and riser connecting platforms.
5. Operation – Operation costs are primarily comprised of the lease operating expenses, which can be highly variable depending on product mix, water depth, distance from the shore, facility size and configuration. These costs are typically accrued and estimated on a monthly basis. Costs include:
   a. *Variable operating costs*, which may consist of costs associated with delivery of oil and gas products to a purchase point or pricing hub when products leave the operator-built pipeline and enter a transportation system controlled by a third party. Since the upstream producer pays a fee based on the volume of oil or gas, costs are measured by $/Mcf or MMbtu or $/bbl.
6. Transport - For new field development, a pipeline will be required to tie into existing infrastructure from the production facilities. Such capital expenditures are borne by the producer.

Cost Modeling

In the cost modeling, a rate was applied to determine the total cost of an item by determining a well or facility configuration and the amount of material or labor required for each major item. The cost for each item was summed up to obtain the total well or facility cost.

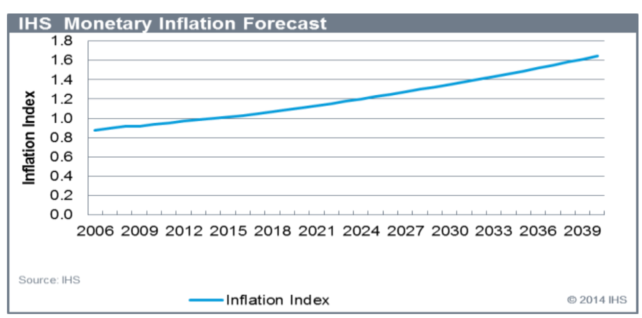


Figure1-1: Historical and forecasted inflation

All costs and calculations are based on incorporating the inflation rate and are determined using nominal dollars. We believe that eliminating inflation provides a better method for determining costs going forward, especially for offshore facilities where construction and implementation can take many years. While no adjustments to costs were made for inflation, we have included historical and forecasted inflation rates in the event the reader desires to back-calculate costs by removing inflation (see Figure 1-1).

II. Summary Results and Conclusions – Onshore Basins/Plays

A. Basic Well Design and Cost for 2014

Total well capital costs within the four onshore basin/plays (plays) are grouped by drilling, completion and facilities (see Figure 2-1) and range from $4.9 MM to $8.3 MM.   An additional $1.0 MM to $3.5 MM in lease operating expenses may be incurred over a 20-year well life cycle and a similar amount may be incurred for gathering, processing and transport (GPT) costs over the life of the well. Play location, well dimension, completion, (hydraulic fracture) intensity and design determine the ultimate cost per well. Well type (oil/gas), location, performance or amount of production and longevity determine total operating expense.

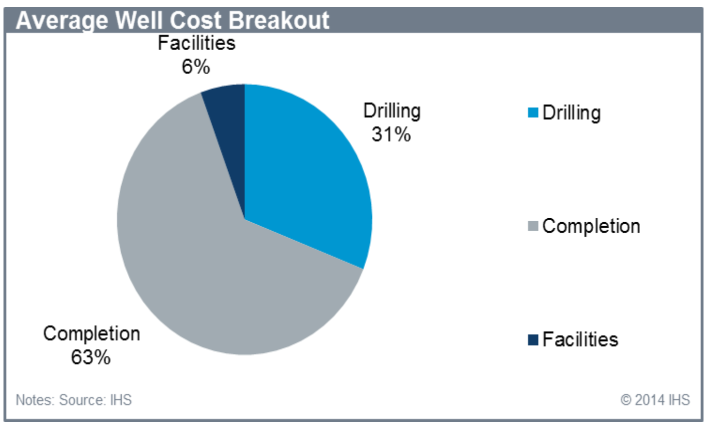


Figure 2-1: Allocation of drilling and completion

Drilling costs include rig rental, tubulars such as casing and liner, drilling fluids, diesel fuel and cement. Total well cost can vary greatly from play to play and within a play depending on such factors as depth and well design.   Average horizontal well drilling costs range from $1.8 MM to $2.6 MM and account for 27% to 38% of a well's total cost. Before the expansion of horizontal drilling within unconventional plays, drilling costs ranged from 60% to as much as 80% of a well's cost.

Completion costs include completion liner and tubing, wellhead equipment, source water, water additives, sand proppant, completion and perforating crews and pumping equipment rentals.   Average completion costs generally fall in the range of $2.9 MM to $5.6 MM per well, but some are higher, thus making up 60% to 71% of a well's total cost. Completion costs in North America have risen sharply over the last decade due to horizontal drilling, in particular due to lateral lengths becoming longer and completions becoming larger and more complex each year.

Oil and natural gas field facilities costs include separators, flow lines, evaporation pits, batteries, roads and pumps or compressors to push product to gathering lines. They generally fall in the range of several hundred thousand dollars and make up just 2% to 8% of a well's costs. Often several wells are drilled consecutively on a drilling unit or pad where each well benefits from economies-of-scale as more wells share the same facilities. Alternatively, wells may be drilled one to a pad as operators try to hold acreage by production by drilling as few wells as possible.

Operating expenses – Due to variability, operating costs are addressed for each play. A general discussion pertaining to the three major operating cost categories is addressed below:

- *Lease operating expense:* These costs are incurred over the life of a well and are highly variable within and between the plays. Oil plays, for example, have particular activities such as artificial lift that make up a large portion of the cost, whereas natural gas prone plays do not. Lease operating expenses range between $2.00 per Boe to $14.50 per Boe, including water disposal costs. Wells with more production will generate more cost over the life of the well. Deeper wells in oil plays will generate more costs than shallower ones.
- *Gathering, processing and transport:* These costs are associated with bringing each mcf of gas or barrel of oil to a sales point. Fees are governed mostly by individual contracts that producers enter into with third-party midstream providers and can be highly variable. Typically, operators with larger positions within a play are able to negotiate better rates. Each product has its own set of requirements and associated costs:
  - Dry gas, which requires no processing, incurs the lowest costs at approximately $0.35/Mcf for gathering and transport to a regional sales point with a differential to Henry Hub price ranging from $0.02 to $1.40 per mcf.
  - Wet gas includes NGLs that require fees for processing, fractionation and transport. Associated gas within the oil plays is generally classified as wet gas and requires processing as well. Gathering and processing fees typically range from $0.65 to $1.30 per Mcf. Fractionation fees range from $2.00 to $4.00 per bbl of NGL recovered. NGL transportation rates range from $2.20 to $9.78 per bbl.
  - Oil and condensate can be transported through gathering lines at a cost ranging between $0.25 and $1.50 per bbl. Trucking is much more expensive with costs ranging between $2.00 and $3.50 per bbl. Operators will also need to transport oil longer distances to refineries, either by pipeline or by rail which creates a price differential to the play ranging from $2.20 to $13.00 per bbl.
- *Water disposal*: Most of the flow-back water disposal expenses from fracking operations are included in capital costs. After 30-45 days (when most of the flow back water has been removed) these expenses would then be classified as operational and would include residual flow-back water and formation water. Specific expenses are related to the water-oil or water-gas ratios and disposal methods and include reinjecting water into water disposal wells, trucking and recycling programs. Thus, costs are highly variable, ranging from $1.00 to $8.00 per bbl of water.
- In addition General and Administrative costs (G&A) are included as operating expenses and can add an additional $1.00 - $4.00 per boe.

Land acquisition – There are typically four ways that operators are able to acquire an acreage position in one of these plays, and each may greatly affect the overall cost of operation:

- *Aggressive entrant* – The Operator acquires a large land position (usually over 100,000 acres) within a play based on initial geologic assessments before the play begins to develop and long before the play is de-risked or pilot programs begin. Although operators are able to acquire land quite cheaply ($200 -$400 per acre), those who follow this strategy often acquire land in speculative plays that never become economic, and hence incur a substantial risk that the development of the acreage will never come to fruition.

- *Legacy owner* – Because the plays discussed herein generally occur in mature basins with historic conventional production, operators basically inherit an acreage position in the play by virtue of already being a participant in conventional production. While this may save substantial costs, these operators may not have necessarily landed in the sweet spots or better areas of the play.
- *Fast follower* – Operators who do not have the capacity to lease land may choose to form a Joint Venture (JV) with a company who has an acreage position. This will typically occur after the play has been de-risked and appears to be viable. However, at this stage sweet spots may not be completely delineated and operators could end up with a sub-standard position. Costs will typically be 10 to 20 times higher in this scenario than for initial entry. Depending on the number of acres required per well, this could add additional costs of $1 - $2 MM per well.
- *Late Entrant* – Typically late entrants will be motivated to enter a play once the sweet spot has been delineated and the play completely de-risked. They will pay a premium of 3 to 4 times that of the fast follower which will include potential drilling locations as well as producing wells. In order to meet economic thresholds, these operators will be looking for tight down spacing, stacked laterals and other upside potential.

While acquiring land in any of these plays can add substantial upstream costs, each operator pursues the strategy that they believe will provide the best financial returns. For purposes of this study we will address this issue in each play by providing historical transaction costs and an estimated well spacing to determine the added cost that theoretically could be added to the cost of each well for an operator entering a play during a specific year. We should bear in mind, however, that once the money has been spent to acquire a land position, the acquiring operator will treat these as “sunk” costs and therefore when performing “go-forward” economics these costs will not be included.

B. Geological and Technical Considerations by Play

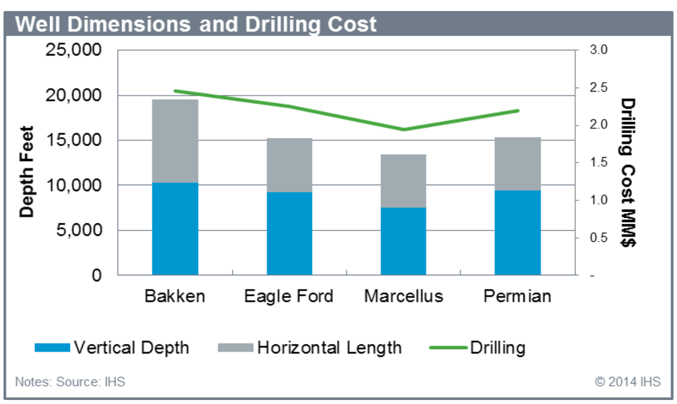


Figure 2-2: Depth and drilling cost by play

The close relationship of average horizontal well depth (including both the vertical and horizontal portions) and the respective drilling costs for each play is portrayed in Figure 2-2. While the amount of fluid and proppant in each play greatly influences the overall completion costs, the correlation of proppant and fluid volumes to completion cost is not as strong (see Figure 2-3). Other factors such as pressure, use of artificial proppants and frack stage spacing also influence completion costs.

Since its inception, the Bakken play has been known for long wells and big completions. The average true vertical depth (TVD) of 10,000 feet is fairly constant throughout the play where drilling costs average $2.4MM, but is slightly deeper in frontier areas where drilling costs are $2.6MM. Although the Bakken was the first play to move to long lateral lengths of approximately 10,000 feet with as many as 30- 40 frack stages, the use of proppant and fluid per foot is much lower than other plays. While average proppant use is lower than other plays, costs

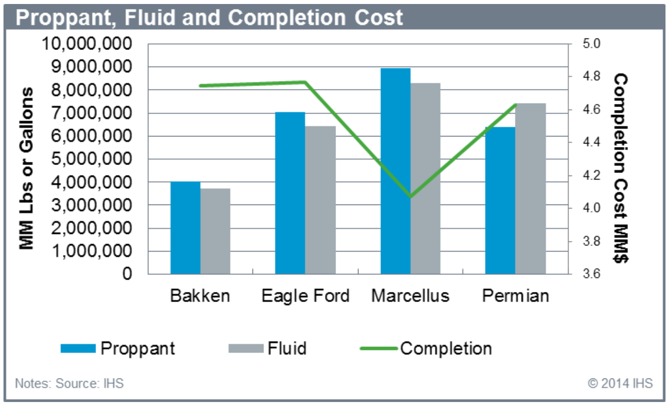


Figure 2-3: Proppant and completion cost by play

are comparable, as the Bakken uses more of the higher-cost artificial and resin coated proppants, which drive the completion costs from $4.4 MM to $4.8MM. Moderate to high pressure gradients also drive completion costs higher and require the use of a higher artificial proppant mix.

Unlike the Bakken, true vertical depths in the Eagle Ford vary greatly from 6,000 feet in shallow oil-prone areas to more than 11,000 feet in the gas-prone areas. Lateral lengths are fairly constant, averaging 6000 feet. Overall, drilling costs range from $2.1 MM to $2.5 MM. Like the Bakken, proppant costs per pound are higher due to heavy reliance on artificial proppant. Completion costs range from $4.3 MM in the more oily areas to $5.1MM in gas prone areas. Overall, pressure is high in this play, but more so in the deeper gas prone areas, which also drive completion costs and artificial proppant use up.

Wells in the Marcellus are shallower, averaging 5,000 to 8,000 feet in depth with a lower formation pressure gradient. Lateral length is highly variable, ranging from 2,500 to 7,000 feet. While operators would prefer to drill the longer laterals, smaller leases and drilling units don't always allow this to happen. Drilling costs are fairly uniform ranging from $1.9 MM to $2.1 MM. Proppant costs in the Marcellus are low as less-expensive natural proppant is popular. However proppant amounts are higher in the Marcellus than in other plays and are highly variable, resulting in completion costs ranging from $2.9MM to $5.6MM.

The Permian Basin contains two primary sub-basins, the Midland Basin and Delaware Basin, many diverse plays and complicated geology of stacked formations in desert conditions. Most unconventional wells are horizontal with expensive completions, similar to the Eagle Ford (averaging $6.6 MM to $7.6MM), but may be small vertical wells accessing the stacked pay zones in the Sprayberry costing only $2.5 MM per well. Formation depths vary from 7,000 to 10,000 feet. Lateral lengths and frack designs differ largely by region and play with completion costs ranging from $3.8 MM to $5.2 MM. High proppant use is the norm.

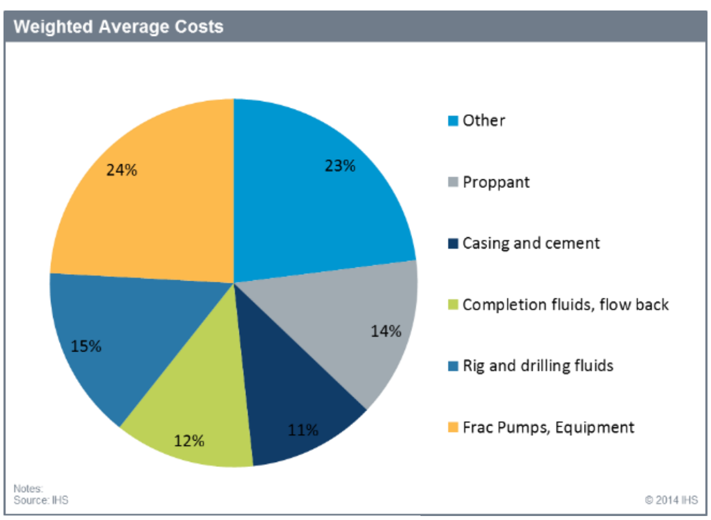


Figure 2-4: Primary cost

C. Key Cost Drivers

Overall, 77% of a typical modern unconventional well's total cost is comprised of just five key cost categories (see Figure 2-4):

- Drilling Related Costs: (1) rig related costs (rig rates and drilling fluids), and (2) casing and cement.
- Completion Related Costs: (3) hydraulic fracture pump units and equipment (horsepower), (4) completion fluids and flow back disposal, and (5) proppants.

(1) Rig related costs are dependent on drilling efficiency, well depths, rig day rates, mud use and diesel fuel rates. Rig day rates and diesel costs are related to larger market conditions and overall drilling activity rather than well design. Rig related costs can range from $0.9 MM to $1.3 MM making up 12% to 19% of a well's total cost.

(2) Casing costs are driven by the casing markets, often related to steel prices, the dimensions of the well, and by the formations or pressures that affect the number of casing strings. Within a play, well depths are often the most variable characteristic for casing with ranges of up to 5,000 feet. Operators may also choose to run several casing strings to total depth or run a liner in lieu of the final casing string. Casing costs can range from $0.6 MM to $1.2 MM, making up 9% to 15% of a well's total cost.

(3) Frack pumping costs can be highly variable, but are dependent on horsepower needed and number of frack stages. The amount of horsepower is determined by combining formation pressure, rock hardness or brittleness and the maximum injection rate. Pumping pressure (which includes a safety factor) must be higher than the formation pressure to fracture the rock. Higher pressure increases the cost. The number of stages, which often correlates with lateral length, is important since this fracturing process, with its associated horsepower and costs, must be repeated for each stage. These total costs (for all stages) can range from $1.0 MM to $2.0 MM, making up 14% to 41% of a well's total cost.

(4) Completion fluid costs are driven by water amounts, chemicals used and frack fluid type (such as gel, cross-linked gel or slick water). The selection of fracking fluid type is mostly determined by play production type, with oil plays primarily using gel and natural gas plays primarily using slick water. Water sourcing costs are a function of regional conditions relating to surface access, aquifer resources and climate conditions. Water disposal will normally be done by re-injection, evaporation from disposal tanks, recycling or removal by truck or pipeline, each with an associated cost. Typically about 20-30 percent of the fluids flow back from the frack and require disposal. Operators typically include the first 30-60 days of flow back disposal in their capital costs. These costs can range from $0.3 MM to $1.2 MM making up 5% to 19% of well's total cost.

(5) Proppant costs are determined by market rates for proppant, the relative mix of natural, coated and artificial proppant and the total amount of proppant. Proppant transport from the sand mine or factory to the well site and staging make up a large portion of the total proppant costs. Operators use more proppant when selecting less costly proppant mixes, which are comprised of mostly natural sand as opposed to artificial proppants. A higher mix of artificial proppants has often been used for very deep wells experiencing high formation pressures. Overall the amount of proppant used per well is increasing in every play. These costs can range from $0.8 MM to $1.8 MM making up 6% to 25% of well's total cost.

D. Evolution of Costs during the Past Decade

Markets and their Drivers – Cost Indexing

Cost indexes show the relative costs of equipment and services over time (Figure 2-5). This analysis assumes an index value of 1 for the cost of a given item during 2014. Future and historical increased rates will be greater than 1, whereas lower rates will be less than 1.

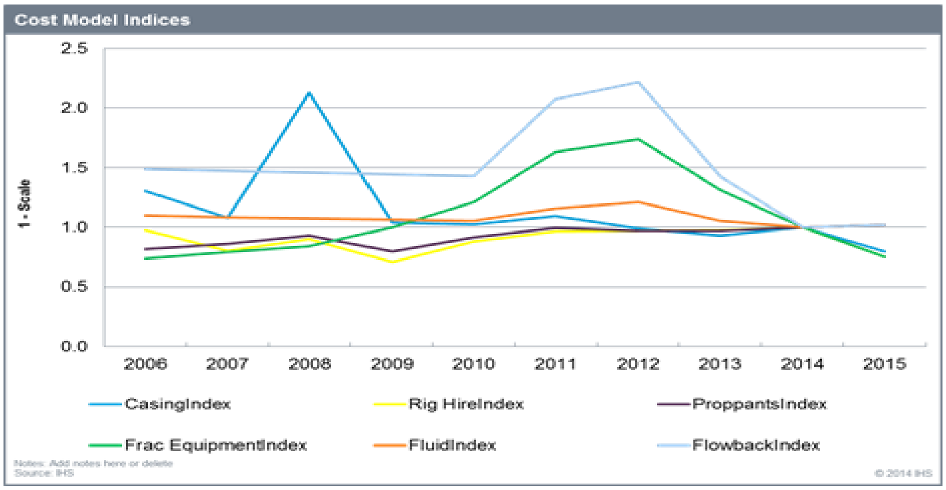


Figure 2-5: Historical nominal indices of key cost drivers

The price spike for casing in 2008 was a result of increased global demand for steel while there was a temporary steel shortage. From 2010 to 2012 the industry expanded faster than the services and tools industries could keep up with, thus driving up costs rates, primarily for frack fluid volume, water disposal and frack pumping units. As these services increased to meet demand, their costs decreased significantly. From 2012 onward, improvements were also made to other services related to well completions, such as additional water treatment plants, injection sites, proppant mines, more efficient fracks and more experienced personnel. As a result, cost rates receded for some items and dropped even faster moving into 2015. Further depressing the tools and services markets today are low oil and natural gas commodity prices, which are causing drilling and completion activity to wane.

As Figure 2-5 shows, supply shortage is inelastic in the short term. Sharp increases in activity, where essential services are in short supply, will spike costs until one or more of the following occurs: (1) the cost increase has stifled the development pace enough to bring supply and demand back into balance, thus forcing the service provider to lower its rates, (2) new methods are employed to avoid the cost; or (3) an expansion of supply eventually catches up with demand as observed during the 2012-2014 period. An example of new methods being employed relates to the first wells drilled in the shale plays, which were completed primarily with completion rigs. Over time the completion practice evolved to the use of coiled tubing, which was a response to increasing completion rig rates, as well as a response to slow completion times, as coil tubing speeds up the completion process. During 2014 the market had achieved a balance between supply and demand for most services. However with the drop in oil prices and consequent drop in wells being drilled and completed, there is an over-supply of oil-field services. This sharp contraction in demand is expected to lower prices significantly for many services as we will discuss in this study.

Services in each of the plays experienced similar shifts in cost rates as many of the cost items, such as proppants and oil field tools and tubulars, were able compete across multiple plays. Play specific-cost changes are related to services that are more regional in nature, such as rigs, water and pumping units, which are not typically moved over long distances between plays.

Changes in Well and Completion Design and Application of Key Technologies

Over the past decade specific changes in technology have been employed to both reduce costs and increase production. While costs may go up, the resulting performance benefit far outweighs the cost.

Technology improvements related to drilling:

- Longer laterals (increase performance).
- Better geosteering to stay in higher-producing intervals (increase performance),
- Decreased drilling rates (decrease cost),
- Minimal casing and liner (decrease cost),
- Multi-pad drilling (decrease cost), and
- High-efficiency surface operations (decrease cost).

Technology improvements related to well completion:

- Increase amount of proppant – superfracks (increase performance),
- Number and position of frack stages (increase performance),
- Shift to Hybrid (cross-link and slick water) fluid systems (increase performance),
- Faster fracking operators (decrease cost),
- Less premium proppant (decrease cost), and
- Spacing and stacking optimization (increase performance).

Applying each of these factors leaves a footprint on increased capital efficiency, yet the specific effect of each is difficult to measure, particularly against the backdrop of geological influences that also have a profound influence on cost and performance. Nevertheless, the cumulative results, as discussed below, are outstanding.

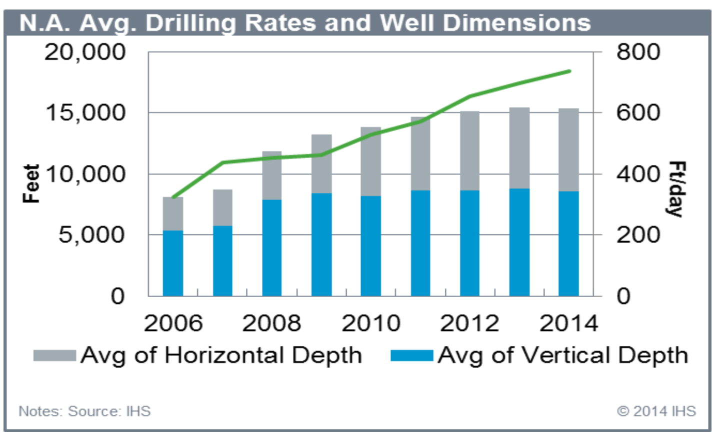


Figure 2-6: Historical drilling trends

Lateral length: While this study focuses primarily on horizontal drilling, we acknowledge that the shift from vertical to horizontal wells is the most important change to occur over the last decade, allowing for greater formation access while only incrementally increasing the cost of the well. Over the past decade, lateral lengths have increased from 2,500 feet to nearly 7,000 feet and, at the same time, we have seen nearly a three-fold increase in drilling rates (feet/day) (see Figure 2-6). This increase in efficiency is leading to overall downward pressure on drilling costs for each well, even though lateral lengths may be increasing.

Completions: Within each play, larger amounts of proppant, fluid and frack stages are being employed to drive up production performance (Figure 2-7). We also note that cheaper proppant and slightly less water per pound (lb.) of proppant are being used to combat costs. With the well completion schemes evolving and growing over time, we would expect performance to also increase. Average stage length has decreased from 400 to 250 feet which allows more proppant to be used.

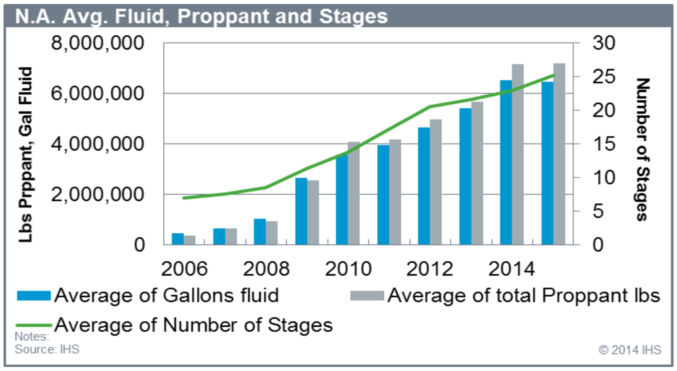


Figure 2-7: Historical completion trends

Often, only a few operators will use a particular cost saving or production performance improvement technique. As others observe success with the new techniques, they will often adapt it to their well and completion design. For example, the use of more, lower cost proppant was initially attempted by only a handful of operators in the Bakken, but is catching on and is becoming the preferred completion method in the play. Similarly, we would expect a continued evolution of well design in the future as operators look for ways to become more efficient in an environment of lower oil prices.

Multi-well pads and higher surface operation efficiency: Multi-well pad drilling allows for maximization reservoir penetration with minimal surface disturbance, which is important in areas that are environmentally sensitive, have little infrastructure, or in mountainous areas with extensive terrain relief. Operational costs are reduced as this allows operators to check wellhead stats (pressure, production, etc.) on numerous wells in the same location. Most pads are situated with 4 - 6 wells, but some are planned for 12, 16, or even 24 wells where there are multiple stacked zones. With the surface locations of wells on a pad being close to each other, mobilizing rigs from one well to another is also more efficient. Walking rigs, automated catwalks, and rail systems allow rigs to move to the next location in hours, not days. Facilities can be designed around pads, thus further reducing costs.

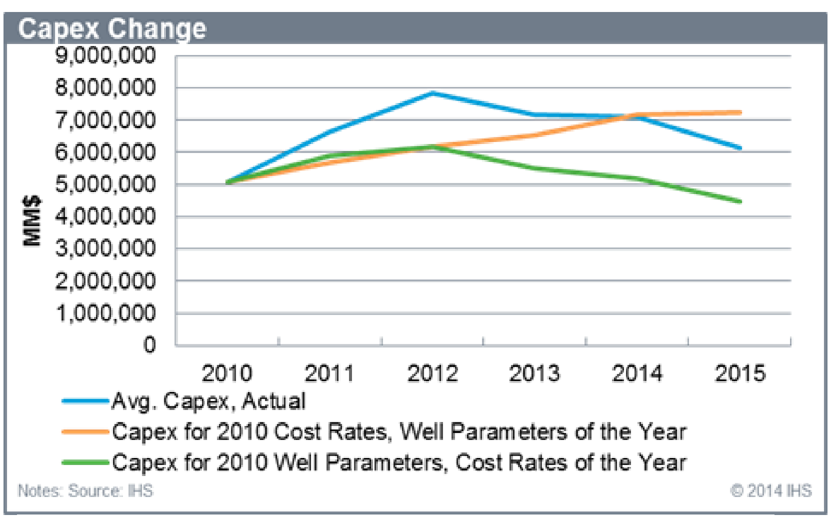


Figure 2-8: Change in historical well cost comparison

Improved Water Handling: As water resources become more and more scarce, operators are being forced to come up with better solutions for the amount of water used for each well, especially in arid regions, such as the Permian Basin and the Eagle Ford in South Texas. This is also important in environmentally sensitive areas. Many companies are using recycled water for drilling and completion operations instead of having water trucked in or out. Using recycled water also reduces operators' costs. For example, Apache was paying upwards of $2.00 per barrel to dispose of water in the Permian Basin, but pays only $0.17 per barrel to recycle.

Combining Indexing and Changes in Well Design to Track Historical Well Costs

Historical changes in overall well and completion costs can be attributed to changes in cost indices, as well as changes in well design parameters. Figure 2-8 shows both the effect of well design and indexing on total well costs:

- Avg. Capex, Actual – The Avg. Capex, Actual is the average total nominal well cost for each year as it actually occurred. Note that overall costs are actually coming down, despite more complex well designs of recent years. However a well still costs more in 2014 than 2010.
- Capex for 2010 Cost Rates, Well parameters of the year – This is comprised of the 2010 cost rates being applied to the average well design of a given year. Note that had we held 2010 rates steady, the actual cost of a well drilled in 2014 would have gone up slightly. If cost rates had not come down since 2010, well costs would have grown by 40% due to the longer laterals and increased use of proppant.
- Capex for 2010 Well Parameters, Cost Rates of the Year – This is comprised of well parameters of 2010 with cost rates for the given year being applied. Note that the more simple well design of 2010 would have cost about the same in 2014 when applying yearly index rates, but would have cost much less than the more complex well design of 2014.

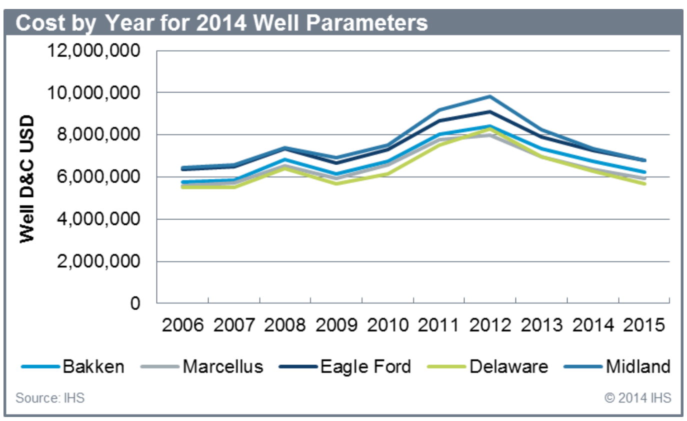


Figure 2-9: Historical comparison of cost using current well design

When a back-costing exercise is performed we see a similar story unfold within each play, as a well with a 2014 design drilled back in 2010 would have cost roughly the same (see Figure 2-9). Between 2010 and 2012, well cost rates increased along with well dimensions and completion intensity. This exacerbated the increases in well cost, but improvements to efficiency and improving well services and tools markets since 2012 have helped overall well costs come down since then.

Overall Trends by Major Cost Component

Recent drilling costs make up a much smaller portion of total well costs compared to prior years for all plays, as shown in Figure 2-10. This is due both to the growth in completion programs and associated costs as well as efficiency gains, such as the drilling penetration rate improvements.

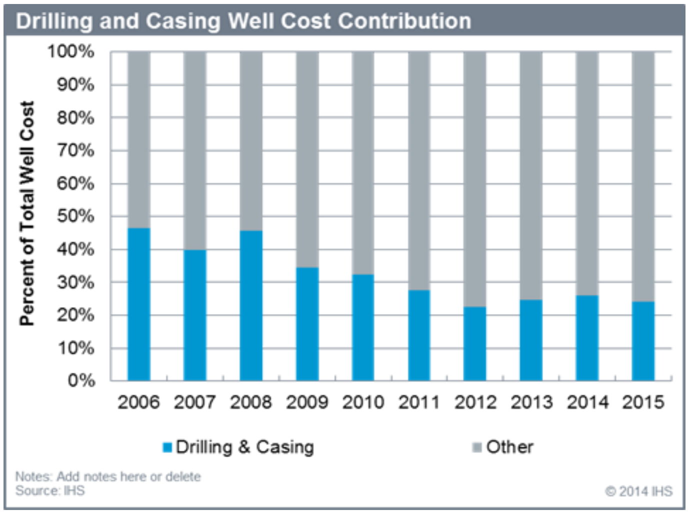


Figure 2-10: Contribution of drilling and casing

Casing programs have been constant since play inception, as geology and total depth dictate their use and the most efficient designs are determined as the first wells are being drilled. Tubular costs, as a percentage of total well cost, peaked during 2008 when there was a steel shortage in the global market. Shortly after 2008, casing rates dropped, while the increases in other cost drivers have made casing costs much less significant than in the past.

Frack pumping costs in 2015 have been reduced in most plays down to 2010 levels despite much larger completions with more stages. Nominal rates have dropped by over 40% from their high in 2012, while the number of stages has increased from an average of 20 to 25.

As proppant amounts have grown, their contributions to costs have increased in importance when determining total well cost in all plays except the Bakken (contribution to total well cost in the Bakken has been variable from year to year). The Eagle Ford has also seen more expensive proppant mixes used each year, making proppant costs much more important today than in prior years.

Fluid cost contributions were the greatest in 2012 when cost rates were highest. Since then, the rates have come down by 60%, and fluid costs have contributed far less in recent years despite increased fluid amounts currently used. The addition of gel use in some instances impacted total fluid cost, but even this was overcome by improved cost rates.

Evaluating Effectiveness of Completion Design, Overall Trends in Cost/Boe

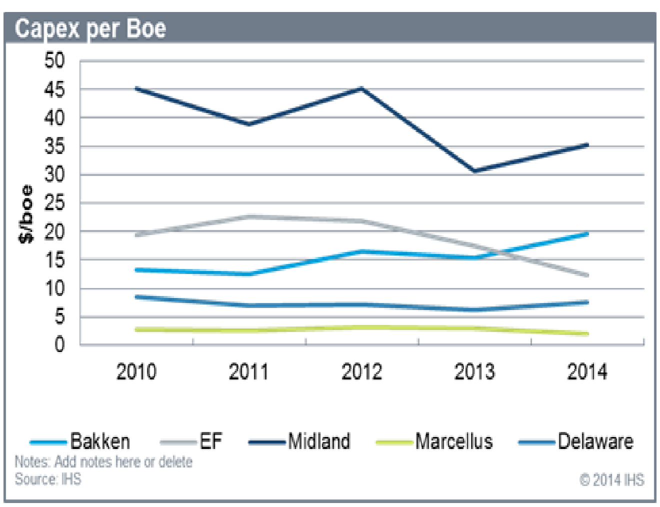


Figure 2-11: Historic capex unit costs ($/boe) by play

While additional well completion complexity has increased costs, the aim of operators is to reduce capital unit costs ($/Boe) needed to develop the hydrocarbons by substantially increasing the production performance. This has proved to be quite successful in the Midland, and Eagle Ford plays. In contrast, the Bakken and Delaware have not substantially improved; with unit costs remaining flat (see Figure 2-11). In these instances, the goal of increased completion complexity may be just to maintain the current unit costs, as there are a number of factors that can degrade production performance, such as tighter down spacing or less desirable prospect selection.

E. Future Cost Trends

Expected Cost Reductions

Oil prices, which had recently made a modest recovery, once again took a nose dive and, consequently, IHS revised its oil price and production outlooks downward. WTI will remain below $45 for most of the remainder of 2015 and will rise only slightly during 2016 (see Figure 2-12). Root causes underlying this reduced forecast include:

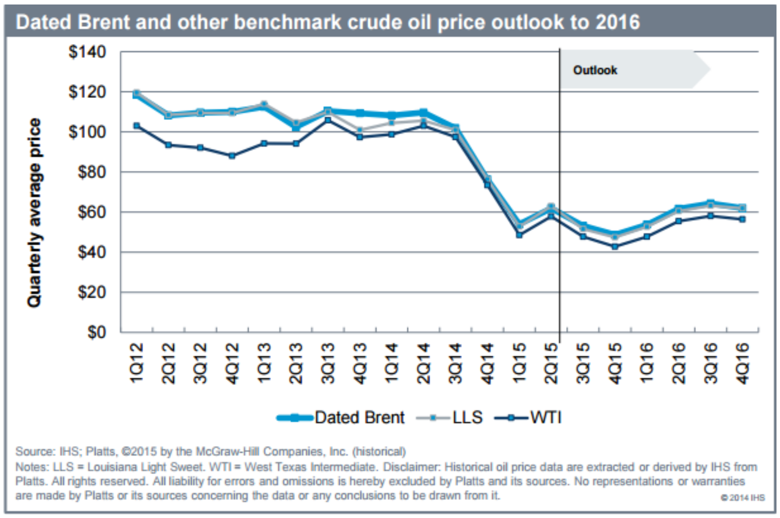


Figure 2-12: IHS historical and forecasted oil prices

- High US and OPEC production levels,
- The return of Iranian oil to the world oil markets, and
- Weak demand growth worldwide, particularly in China.

Consequently, oversupply will continue for the next 12 months and narrow in the second half of 2016. Forecasted lower production (see Figure 2-13) will result primarily from an extended cut back in drilling, and could become even deeper if prices fail to recover.

This has led to a downward trajectory in costs. In 2015, total well costs will drop by 15% - 18%, on average, from 2014 levels and are expected to drop another 3-5% in 2016. The dramatic drop in oil prices has precipitated a huge reduction in drilling and completion services fees. During the third quarter of 2014, which is the period that this cost analysis represents, there were approximately 770 rigs actively drilling in the four plays. Over the next several months this count plummeted to only 350 as of July 2015 (Figure 2-14). Prices, which are currently at under $50/bbl, are expected to go lower, and IHS does not anticipate a price recovery to begin until mid-2016. World-wide production levels are still out of balance with demand expectations, and the higher cost U.S. unconventional plays will bear the brunt of reductions in production as the markets seeks a new balance between supply and demand. This means

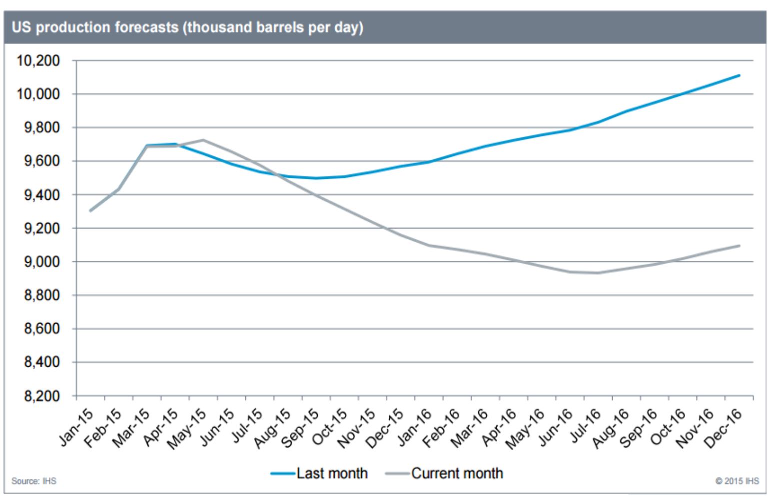


Figure 2-13: Revised production projection

that rig counts will fall even farther, resulting in continued downward pressure on costs for drilling and completion services.

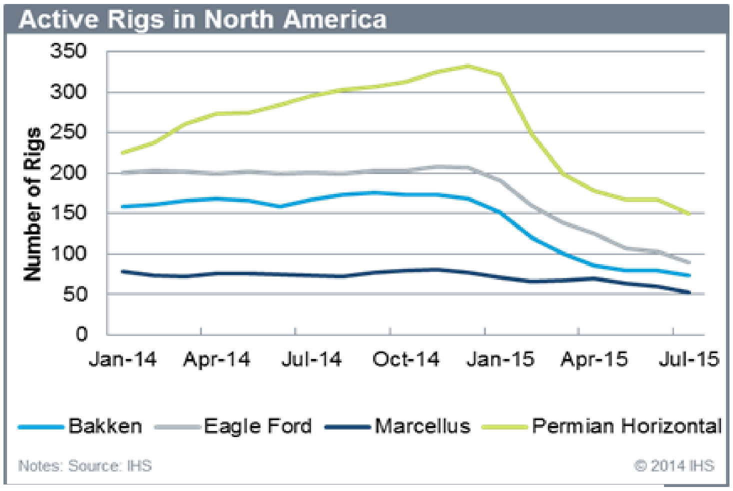


Figure 2-14: Monthly rig count by play

Primary cost drivers

Services such as pumping equipment and specialized drilling rigs with 1,000 to 1,500 horse power (Hp) are primarily used for unconventional play development. Supply of these services has expanded in recent years to accommodate the high industry activity; thus there is currently a huge supply overhang, which will continue for several years until prices recover to higher levels. Some service companies are even expected to operate at a loss just to maintain market share and keep their skilled labor. As we anticipate cost reductions, we see the following rate changes for the five primary cost drivers (see Figure 2-15):

- Rig rates and rentals – These services were created specifically for unconventional oil and natural gas development. Thus, we expect to see reductions of 25 - 30% in 2015 from 2014 levels, with an additional 5 – 10% reduction in 2016, after which we would begin to see increases of 5% during 2017 and 2018.
- Casing and cement – Casing cost is driven primarily by steel prices, which are expected to drop by about 20% in 2015 due to general economic softness.

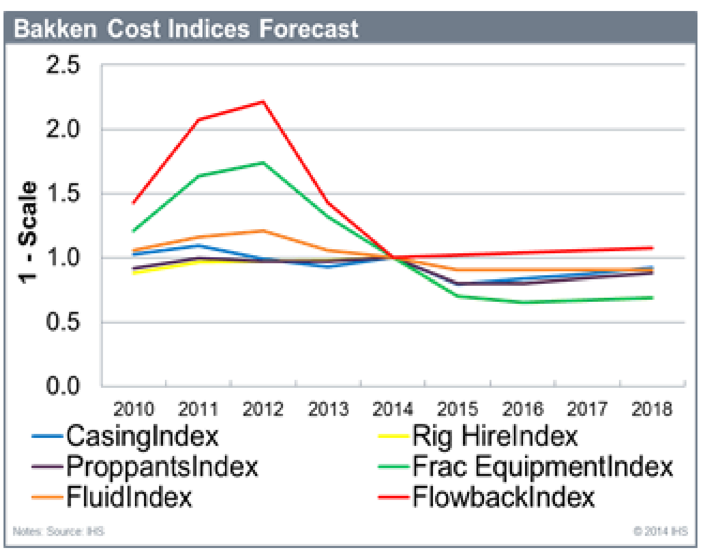


Figure 2-15: Projected cost indices of key cost

- Frack equipment and crews – Like rigs and rig crews, these are specialized for unconventional resources and no other markets currently exist for these services. We expect reductions similar to those of rig rates and rentals.
- Proppant – We see reductions of 20% in proppant costs. The majority of the proppant cost is due to transport from sand mines in Wisconsin and regional staging costs. There is little room for further cost reduction here.
- Frack fluids and water disposal - Water sourcing costs are tied to regulatory conditions and are not market based, although we expect large cost reductions in the cost of chemicals and

gels. Disposal costs will not be affected by industry activity as rates are based on long term contracts that escalate each year at around 1.8%. These factors may actually pose risks which could drive costs up.

- Other cost items will only see small cost reductions in the 5% to 10% range.

Future Well Design Trends

In a lower cost environment, continued emphasis will be made on gaining efficiencies and improving performance in order to drive down unit costs ($/Boe). Attributes of well design will become more interdependent and will continue to evolve as follows:

- Drill days - Drilling gains are ongoing and are projected to increase into 2015. Normally, we would have expected this to have leveled off by now, but drill bits continue to improve as evidenced by the increase in drill feet per day. More pad drilling will decrease rig movement times for mobilization and de-mobilization.
- Lateral length – Annual rates of increase are slowing, which may be due to limitations imposed by lease and drilling unit size and configuration. Within a given drilling unit, operators will drill their longest laterals first and then fill in the gaps with shorter laterals.
- More proppant per foot – Operators continue to push the limits as shown in Figure 2-16. Production may continue to increase as some operators are using as much as 2,000lbs/ft. An increased amount of closely spaced wells are projected as operators continue to harvest as much of the resource as possible. The extra proppant is likely to be needed in order to achieve the recovery rates required for economic success in these more closely spaced wells. Nevertheless, some evidence exists that certain plays have reached their maximum limit of how much proppant can be used per lateral foot before well production is crowded out. This may be true for the Marcellus and the Bakken where pay zones are typically thinner. As proppant levels increase, additional fluid will be needed for emplacement.

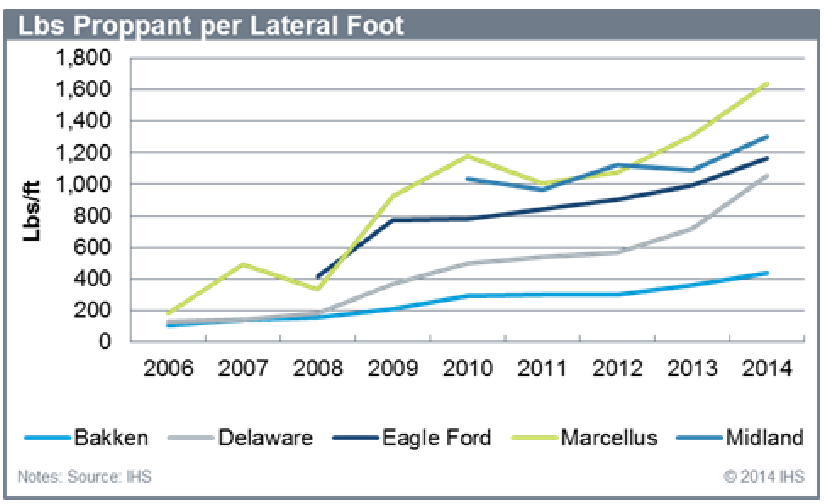


Figure 2-16: Historical trends of proppant (Lbs./Ft)

- More wells on a drill pad – Facilities costs per well will decrease as facilities are increasingly designed for the drill pad, not for the well. Other efficiencies such as water disposal, frack staging and rig movements will also eat into costs.
- Number of Stages - Operators are putting more frack stages within the lateral length as stage lengths are decreasing to around 150-200 feet (with more closely spaced perforation clusters) in order to accommodate the increased proppant amounts being used. Changing the configuration is also improving production performance.

- Natural Proppants - Proppant amounts are expected to increase in all plays. However, proppant types will move toward cheaper natural proppant, except in the Eagle Ford where proppant mixes are becoming more weighted toward artificial sand.

Future Cost Projections

Each play will be affected differently by the changes in cost rates and well parameters going into 2015, with savings ranging from 7% to 22%. **Average** well costs will be affected as follows:

- Bakken well costs were $ 7.1 MM 2014, but will drop to $ 5.9 MM 2015.
- Eagle Ford wells averaged $ 7.6 MM in 2014, but will be $ 6.5 MM in 2015.
- Marcellus wells will be $ 6.1 MM in 2015 after having an average cost of $ 6.6 MM in 2014.
- Midland Basin wells were $ 7.7 MM in 2014, but will drop to $ 7.2 MM in 2015.
- Delaware Basin wells cost $ 6.6 MM in 2014 and will drop to $5.2 MM during 2015.

Additional cost decreases will occur in 2016, but by the latter half of that year we expect to see slight recoveries in cost rates.

F. General Cost Correlations

The EIA is interested in projecting future costs by applying the parameters used, and therefore correlations between major cost drivers and the actual costs within each play need to be understood. Included within the discussion of each play is: (1) an analysis of the correlations of the well attributes associated with the major cost drivers to the actual cost of that portion of the well, and (2) a comparison of total well costs based on primary factors such as depth, amount of proppant and activity index (*e.g.* cost per foot).

Correlation of well attributes

For this analysis we calculated costs by multiplying specific well design factors by specific rates to determine the cost of each item. Total well cost was obtained by the sum of all of these subordinate costs. As mentioned in Section C above, we then identified the top drivers that contribute to the overall well cost and the contributing costs within each of these drivers; these are listed as follows:

- Pumping Units for Fracking
    - Injection rates (barrels per minute),
    - Formation break pressures (psi), and
    - Number of stages.
- Drilling
    - True vertical depth (TVD - feet),
    - Lateral length (feet), and
    - Drilling penetration rate (feet/day).
- Proppant
    - Amount of proppant (lbs.), and
    - Cost per lb. of proppant (refers to the mix of natural and artificial proppants).
- Frack fluids
    - Amount of fluid (gallons),

  - Amount of gel (lbs. per gallon of water), and
  - Chemicals (gallons per gallon of water).
- Casing and cement
  - TVD (feet),
  - Lateral length (feet), and
  - Number of casing strings.

The methodology for determining correlations between well design attributes and their associated costs is described as follows. For each attribute: (1) we determined a range of well design inputs for 2010 through 2015 (using well data distributions and other applicable information) and projected these ranges through 2018; and (2) calculated P10, P25, average, P75 and P90 values for each year from these data distributions. We then applied the rates for each well design input to calculate a total cost for that well design input. By comparing well design inputs with the resulting costs, an R-squared value was generated based on the correlations between each "P" value and the resulting "P" cost for each attribute. The results of this analysis will be presented for each individual play.

Total well cost per unit

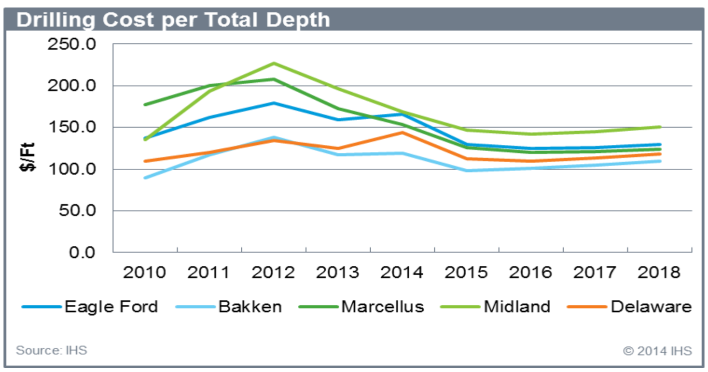


Figure 2-17: Drilling cost rate per foot

We have demonstrated that there is a strong correlation between well size, complexity and costs. Also, we note that the recent large declines in cost are due to a drop in activity. This decrease is partly due to an oversupply of rigs and service providers, but may also be a function of reduction in the number and amount of services being performed. For each play we will provide over time the following "unit costs" as based on the following relationships.

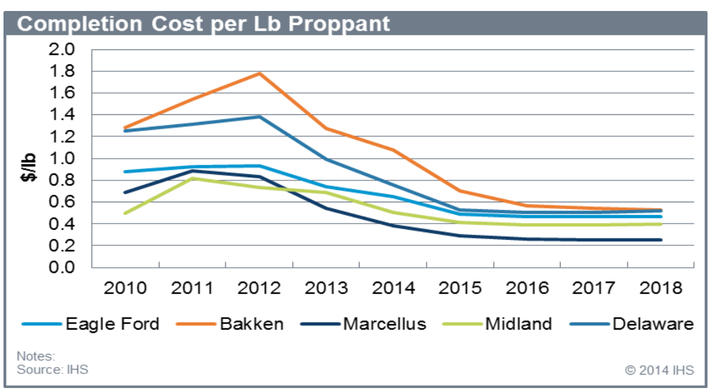


Figure 2-18: Completion cost rate per lb. of proppant

Total Drilling Cost

- Cost per foot
- Cost per activity index

Total Completion Cost

- Cost per unit of proppant
- Cost per break pressure
- Cost per stage
- Cost per activity index

Figures 2-17 and 2-18 portray play level comparisons for simple unit costs. Drilling unit costs per foot are the highest in the Midland Basin and lowest in the Bakken, while completion unit costs per lb. of proppant are highest in the Bakken and lowest in the Marcellus. These figures also illustrate that while unit costs fall within relatively narrow bands for each play, other factors also influence costs as well. Thus relying entirely on a single relationship to determine total cost is likely to be misleading.

G. Key Take-Aways

- In the current longer than expected low commodity price environment, operators face the challenge of improving project economics and maintaining production growth at the same time. The demand for new technology to bring the cost down is important; however, the majority of cost savings have resulted from operators negotiating better rates with service providers.
- Cost reductions have been occurring since 2012 as the supply of rigs and other service providers, such as fracking crews, grew to meet the demand for these services. This cost reduction was accelerated in 2015, when massive reductions in drilling resulted in a vast over-supply of services relative to the demand.
- **Increased technology**: Many advances in technology, such as geosteering, higher proppant concentrations and closer spaced frack stages are increasing the overall cost of wells. However, increased performance lowers the unit cost of production, which more than offsets the increased expense of applying this technology.
- **Increasing efficiency:** Service companies are seeing increased pressure from E&P companies to reduce costs and improve efficiencies. For example, the number of drill days has decreased dramatically in each play.
- **Operating Costs:** The high variability of operating costs for lease operation, gathering, processing and transport, water disposal and G&A offers operators an opportunity for cost reductions in the future.
- **High-grading the production portfolio:** Companies are adjusting capital spending toward the highest-return elements of their asset portfolios, setting aside their inventory of lower-return development projects until prices recover and/or costs decline sufficiently to move project economics above internal hurdle rates. This trend is perhaps most pronounced in the US Onshore shale plays.

III. Deep Water Gulf of Mexico

Unlike onshore unconventional projects with massive manufacturing development, each offshore project has its unique design and cost profile, including significant costs like dry hole costs. Furthermore, there are fewer than 100 wells, including both exploration and development drilling, each year in GOM deep water area, as opposed to several thousands of wells drilled annually onshore.

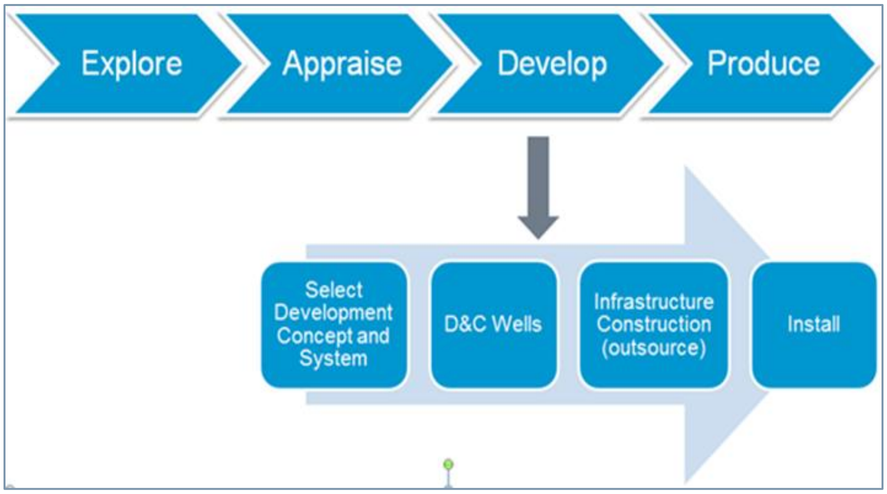


Figure 3-1: Phases of an offshore E & P cost cycle

Although the number of activities is much less than onshore, the amount of capital and time invested in deep-water GOM is comparable to onshore.

With fewer wells and much higher costs, the statistical well approach applied to onshore unconventional wells simply does not apply to deep water fields. Furthermore, the high degree of specialization and technical challenges of offshore development and long development cycles has prevented the standardization of offshore development and "cookie cutter" approaches.

A successful discovery and typical project will pass through a number of stages which will require appraisal, development and production. Depending on various factors, such as water depth, size and reservoir depth, a development concept is selected and development wells are drilled either before or after platform or tie-back installation. Before production can begin, a hook up or construction of infrastructure has to occur (see Figure 3-1). Each of these steps incurs significant capital expenditure.

A. Deep Water reserves, economics and oil price

Deep water drilling and production involves long-term, multi-billion dollar projects that take several years to complete and are less impacted by short-term fluctuations in oil prices. Offshore operators often have major project budgets for years and most projects are completed with the anticipation of higher oil prices in the future. However, longer than expected low commodity prices have begun to take a toll on GOM drilling. The industry faces the challenge of managing costs and encouraging collaboration. Nevertheless, the rest of 2015 will continue to be driven by a combination of caution and capital constraints. United States GOM activities will be heavily influenced by the perception of medium term and long term oil prices, and any changes in activity levels are expected to lag significantly behind that of onshore unconventional plays.

Core plays in the Deepwater US GOM include the Plio/Pleistocene, Miocene, Miocene sub-salt, Lower Tertiary, and Jurassic. Future US GOM deep water production growth will come primarily from three plays—the Miocene sub-salt, the Lower Tertiary, and the Jurassic. Each of these three growth plays offers different opportunities based on a company's risk tolerance, skill set, materiality requirements, and available capital. Nevertheless, since 2004 approximately 13,500 MMBoe of newly discovered reserves in these plays is either being developed or is awaiting development (Figure 3-2).

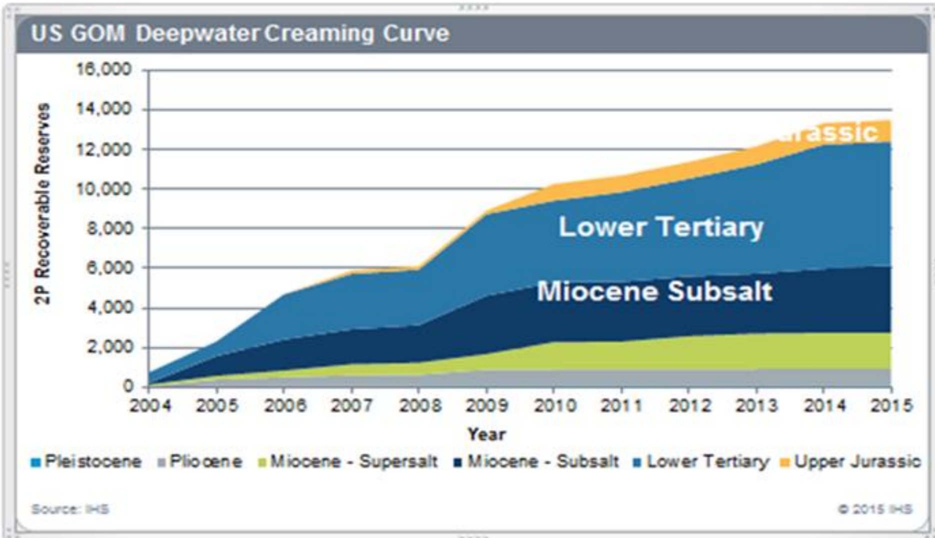


Figure 3-2: Creaming Curve (reserve additions) by deep water play

As compared to other growth plays in the deep-water GOM—the Lower Tertiary and the Jurassic—development of the Miocene sub-salt has advanced because of the proximity to existing infrastructure, which facilitates a lower commercial threshold to resource development, and more rapid development of resource discoveries. On the other hand, the largest growth plays from a volume perspective (the Lower Tertiary and the Jurassic) face challenges in a sustained low oil price environment due to constrained commerciality caused by deeper water depth and lack of infrastructure (Figure 3-3). Most of the Lower Tertiary and Jurassic fields are over 150 nautical miles (nm) from the shore and are well outside the extensive existing pipeline infrastructure and platform. From a forward looking perspective, an assessment of IHS modeled US GOM deep water sanctioned projects with estimated start dates between 2015 and 2021 reveals that a majority of projects have an estimated forward development wellhead breakeven price below $50/bbl. However, evaluating full cycle economics, the majority of the projects breakeven prices are above $60/bbl, which puts unsanctioned projects at a great risk of cancellation or suspension. In a sustained low oil price environment, companies must control costs, increase efficiencies, and access improved technologies to further improve the economics in the larger frontier growth plays.

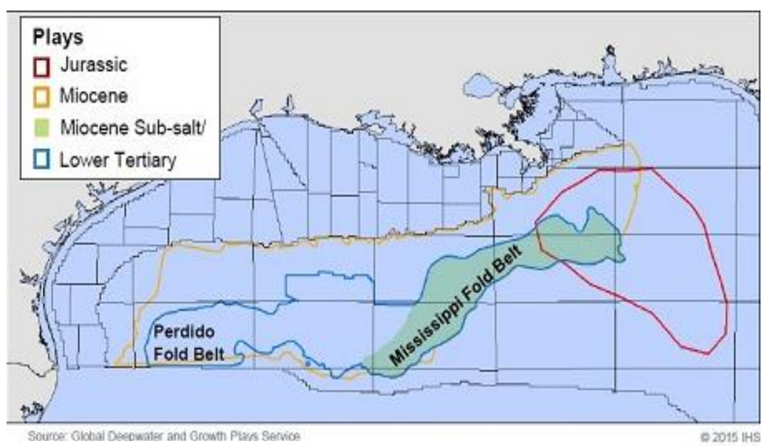


Figure 3-3: GOM deep water play boundary

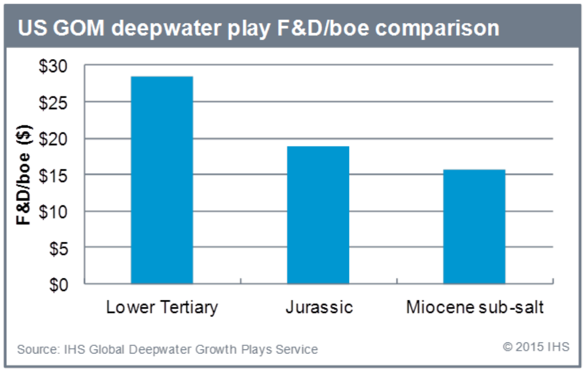


Figure 3-4: F&D cost by play

Figure 3-4 is a comparison of estimated costs across the three US GOM deep water growth plays (based on 2014 cost environment) and shows that the Lower Tertiary has the highest overall costs on a per barrel basis. The Jurassic play has more favorable costs on a per Boe basis than the Lower Tertiary due to a slightly higher than average field size and better well productivity. The Miocene sub-salt has smaller fields and lower development costs, which stem from high well productivity and proximity to existing infrastructure.

When studying the full cycle project economics, after taking into account operating cost and the fiscal system under the late 2014 cost environment, most of the deep-water U.S. GOM current and future projects are forecast to be uneconomic at oil prices below $50/bbl. However, from a forward development perspective, most of the current US GOM deep water projects will go forward as a significant amount of capital has been invested and operators are vigorously renegotiating their respective contracts to secure the lower rates.

Furthermore, as part of the response to a lower commodity price environment, many of the large operators in the deep water U.S. GOM have been revisiting development options and scenarios, with a near-term focus on leveraging existing production infrastructure to develop discovered resources via lower subsea tieback development costs. Infrastructure options tend to flourish within the conventional Miocene deep water play; however, in more remote areas—such as the Lower Tertiary play—the relative scarcity of production hubs and infrastructure provides fewer tieback options, which can act as a constraint to field development.

B. Deep Water Cost Overview - Drilling

Each GOM deep water discovery has its own set of features which influences the development scheme and costs, ranging from geology, field size, water depth, proximity to other fields, reservoir depth and pressure, hydrocarbon product, to operator preferences. The typical development scope in the GOM deep water includes the following: drilling and completion, field development (which is primarily related to the equipment and infrastructure installation, such as production platform installation and subsea tieback, platform construction and float over), and pipeline layout.

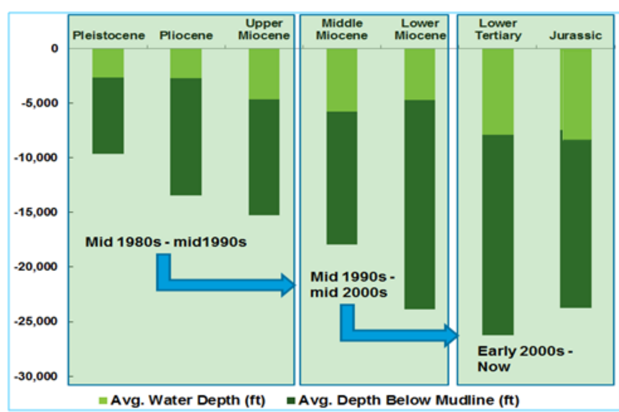


Figure 3-5: Water depth and well depth by major play

Well depth, reservoir quality, productivity, water depth and distance to infrastructure are key drivers to drilling and completion costs. Of the three major plays, both water depth and well depth are shallower in the Miocene area (Figure 3-5), and thus the Miocene has the advantage over the other growth plays due to its higher estimated well productivity and relatively shallower reservoir depth (20,000 - 24,000 feet SSTVD). The average drilling and completion for Miocene wells is approximately $120 MM (Figure 3-6); however Miocene subsalt costs could be much higher, given the complex geology and unpredictability of the play.

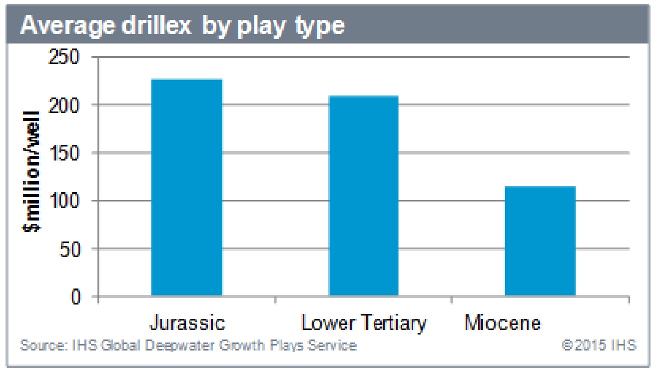


Figure 3-6: Well cost by major play

The Lower Tertiary has experienced the most technical challenges due to the combination of water depth, well depth, high temperature, high pressure, and geological features of the subsalt. Therefore, it inevitably experiences higher well costs. Jurassic projects are located in the deepest water depth, which results in the highest well costs of the GOM at about $230MM (Figure 3-6)

C. Deep Water Cost Overview – Development Concept

Each GOM deep water field discovery has its own set of features which influences costs, including field size, water depth, proximity to other fields, reservoir depth and pressure, hydrocarbon product, and operator preferences.

There are two types of field development in deep water: (1) standalone development and (2) subsea development. The deep water wells are either developed through standalone infrastructure, a floating production platform, or through subsea systems that tie-back to a production platform.

Since 2004, 35 deep water floating production platform systems (FPS) have been built and deployed in the GOM deep water, bringing the total to over 50 deep water production infrastructures (Figure 3-7) in the GOM. Tension Leg Platform, Spar, and Semisubmersible are three major types of floating facilities that perform processing and handling of production from deep water fields. Only one Floating Production Storage Offloading system (FPSO) is currently deployed in the GOM by Petrobras because of unfavorable regulation preference from the Bureau of Ocean Energy Management (BOEM).

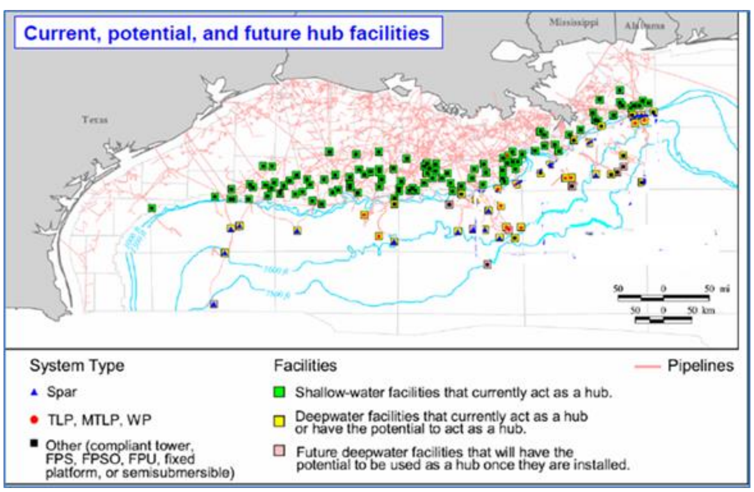


Figure 3-7: Current and future hub facilities

Water depth, production capacity, hull design, and topside design, including processing equipment and utility module, and drilling capability drive the cost of these floating facilities. The majority of facility hulls have been built in shipyards overseas, mostly in South Korea, Singapore, and Finland, to minimize construction costs. Nearly all topsides, on the other hand, are still built in the US as their technology is extremely complex.

Subsea production systems are applied in two scenarios: (1) they connect smaller fields to nearby existing infrastructure; or (2) they can be applied to an area where existing infrastructure is scarce, especially in emerging plays such as the Lower Tertiary and Jurassic.

Given the low oil price environment and the significant amount of deep water discoveries, the operators have widely adopted the hub concept, which includes several jointly developed fields, with a center floating production infrastructure to handle and process hydrocarbon product through flexible riser and subsea tie-in. The Perdido project, which went online in 2010, was the first Lower Tertiary hub brought on stream, followed by Cascade/Chinook in 2012 and Jack/St. Malo in 2014. These hubs, with the addition of the Miocene Sub-salt Lucius hub (which is expected on stream in early 2015), could provide proximity to infrastructure and accelerate the development in those frontier areas.

While breakeven prices vary across projects, Figure 3-8 shows the estimated average full cycle wellhead breakeven price by play and development concept at 2014 cost and price environment. It demonstrates that the majority of Lower Tertiary reserves have a breakeven higher than $60/bbl. Meanwhile, the greatest portions of the modeled reserves for the Miocene sub-salt play have a breakeven price below $60/bbl. Monetization is a greater constraint for those growth plays in more frontier areas of the deep water basin. The Jurassic and Lower Tertiary plays are located farther away from existing pipelines and platforms than the Miocene sub-salt. This constraint is expected to diminish over time as the plays mature and production hubs are established in currently frontier areas. In the Jurassic play, the semi-sub development of Appomattox requires a ~$60/bbl oil price to break even. However, the tieback of Vicksburg to Appomattox requires only a ~$48/bbl oil price to break even.

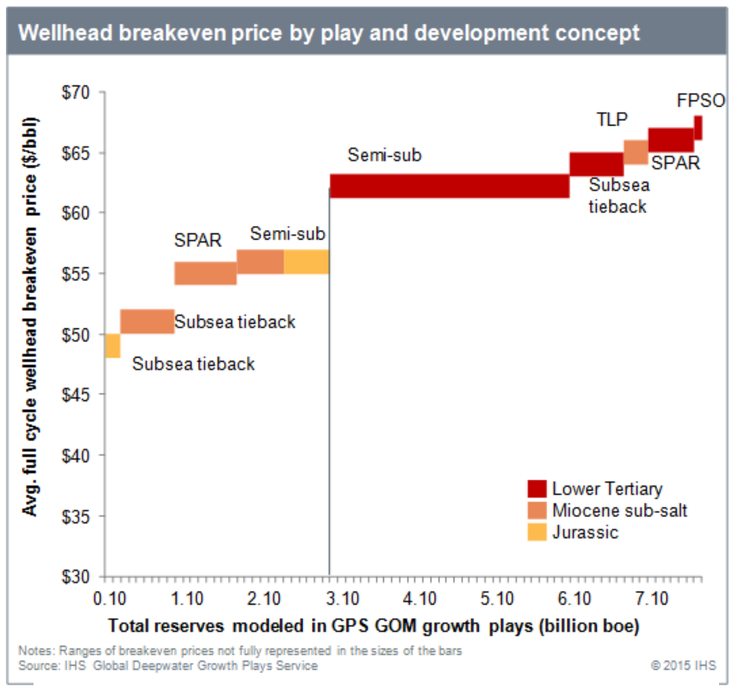


Figure 3-8: Wellhead breakeven price by play and development concept

D. Cost Outlook

Our outlook is for a 15% reduction in deep water costs for drilling and related services in 2015, followed by a marginal average increase of 3% per annum in overall deep-water costs from 2016 to 2020. This cost deflation is material in many areas impacting deep water costs—but particularly in the rig market, where a rig overbuild long forecast for 2015–16 is now colliding with reduced demand, and resulting in highly reduced rig day rates.

E. Key Take-Aways

At the current longer-than-expected low commodity price environment, the GOM deep water operators face a tremendous challenge on cost savings and are striving to attain a balance between improving project economics and maintaining production growth at the same time. The demand for new technology to bring down costs and to improve productivity has hit an unprecedented high level, especially in ultra-deep water and technically challenging areas. There are several initiatives that have been proposed and discussed in the deep water industry:

Deferring unsanctioned projects: While capex cuts have reduced scope for spending on development projects, the largest impact is likely to be felt on those projects which have yet to be sanctioned. Conversely, projects already sanctioned and under construction are less likely to be delayed or cancelled. However even in this case, the potential for deferral will increase should oil prices continue to languish.

Reducing exploration capex: Several companies have focused capex cuts on their exploration budgets, including ConocoPhillips, Marathon Oil, Murphy Oil, and TOTAL. If sustained, such a trend could have an impact on longer-term production profiles via a reduced ability to restock development portfolios and replace reserves. On the other hand, lower exploration spending will have little impact in terms of reduced production growth over the near to medium term.

Increasing efficiency: Service companies are seeing increased pressure from E&P companies to reduce costs and improve efficiencies. To the extent that operators and their partners can be successful in this endeavor, E&P companies may still have the ability to proceed with key projects but at reduced levels of investment.

Industry standardization: Besides subsea standardization, which is the most talked about piece of the cost saving puzzle, standardization of delivery schedule, procurement and maintenance could help lower costs. Today, most of the operators use various equipment designs, which often change for follow-on orders for a given project. The sporadic and unpredictable nature of these orders can add significantly to project costs.

Sticking to the timeline: Delay due to changes in requirements mid-project is currently one of the biggest drivers of lower returns on some offshore projects. This directly contributes to both cost overrun and production startup deferral.

Subsea boosting technology: Lower oil prices have prompted the operators to evaluate the alternatives such as installing subsea boosting systems on the sea floor for existing producing fields to improve production recovery instead of pursuing new field development projects. The operators are forced to face the dilemma of evaluating the economics of drilling new wells versus applying subsea boosting pumps on existing wells, and as a result, subsea boosting technology has come back in the spotlight.

IV. Methodology and Technical Approach

A. Onshore Basins

IHS took the following steps to prepare the cost estimates for the onshore basins:

Sub-play definitions

IHS defined sub plays for each basin or play by locating the geographic areas in each play that shared similar depth ranges, hydrocarbon type (predominately oil or natural gas), depth range, and production performance. For the Permian Basin, we selected the most active and productive unconventional oil plays. Well costs and cost ranges were determined for each sub-play.

Calculating well costs for each sub-play

IHS determines onshore unconventional well costs using its North American well cost model, which was developed over several years during the height of the unconventional shale revolution and represents costs as of third quarter 2014. Costs are determined by creating a typical well design for each sub-play and multiplying each cost item or parameter by a nominal unit rate:

- Rates: IHS maintains a database which captures service and tool cost rates from each play in North America.
- Well parameters for each sub-play are determined from IHS well data for recent wells of 2013 and 2014 vintage belonging to the sub-play. For example some of these parameters include vertical depths, horizontal lengths, casing programs, proppant amounts and types, fluid amounts and types, and drilling days (See Figure 4-1 for detailed listing).
- The costs for each item are then determined by multiplying the amount or number of units pertaining to a well parameter by the rate.

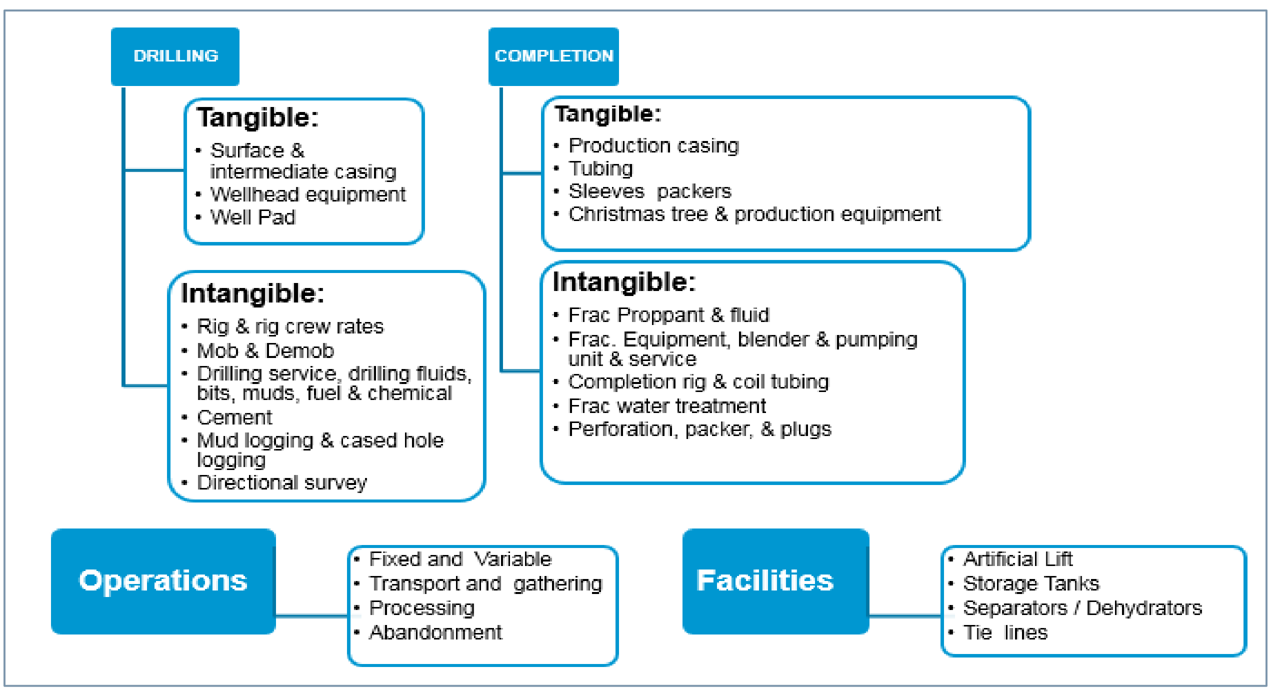


Figure 4-1: Cost components used in the cost model to derive total well cost

Operating costs consist of gathering, processing, transportation, and water disposal and fixed well or lease operating costs, but unlike capex, these items are mostly determined by the locality of the play or sub play and are a function of infrastructure, the need for processing and other contractual arrangement between operators and providers. Each operating cost rate in the model is researched based on reports by media and direct contact with operators and is captured at the play level.

Benchmarking Costs with Published Data

In order to ensure accuracy of cost estimates, IHS researches the total well costs and any other data available from operator reports and investor presentations and compares it to the costs calculated by the cost model. These reported comparisons are included in the detailed cost discussion for each play.

Key Cost Contributors or Drivers

After costs for each sub-play were determined, major cost-contributing drivers were determined by grouping together some of the smaller capital cost categories in order to consolidate the analysis to a more manageable level of 11 categories (see Figure 4-2). The five largest categories comprising approximately 75- 78% of the total well costs and 81% of total drilling and completion costs (excluding facilities) were selected for further analysis. The remaining cost attributes were grouped together into "other" (see Figure 4-3).

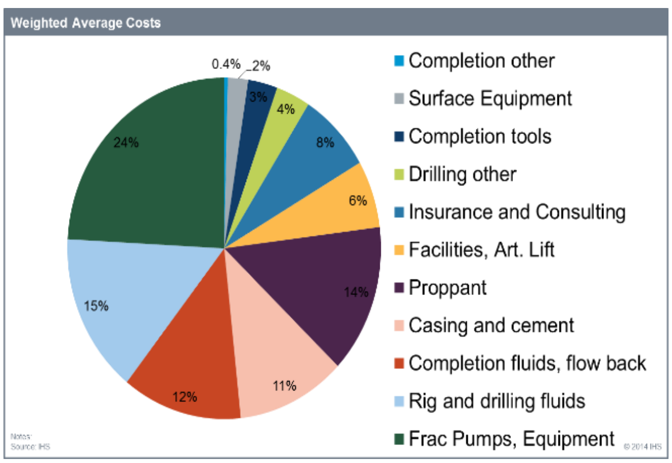


Figure 4-2: Detailed well cost components

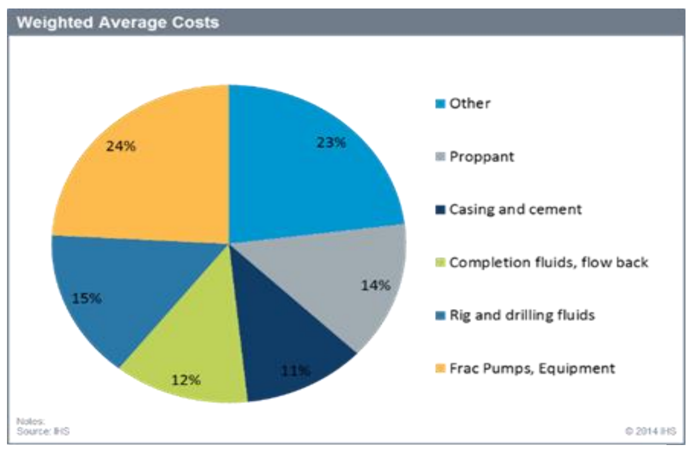


Figure 4-3: Key cost drivers

Range of Costs

Within each basin, play, and sub-play, well drilling and completion attribute data pertaining to each of the five major cost categories or drivers was extracted for each well from the IHS well database. Data analysis was performed on the distributions to calculate high cost (P10), low cost (P90) and arithmetic averages of each attribute. Using rates from the cost model, a cost was assigned to each P10, P90 and average attribute value. Since raw data was extracted from the database, filters were applied to remove obviously anomalous data points and recompletion and sidetrack data that would have misled the study. The P10 data points extracted represent the high cost well inputs and the P90 data points represent the low cost well inputs.

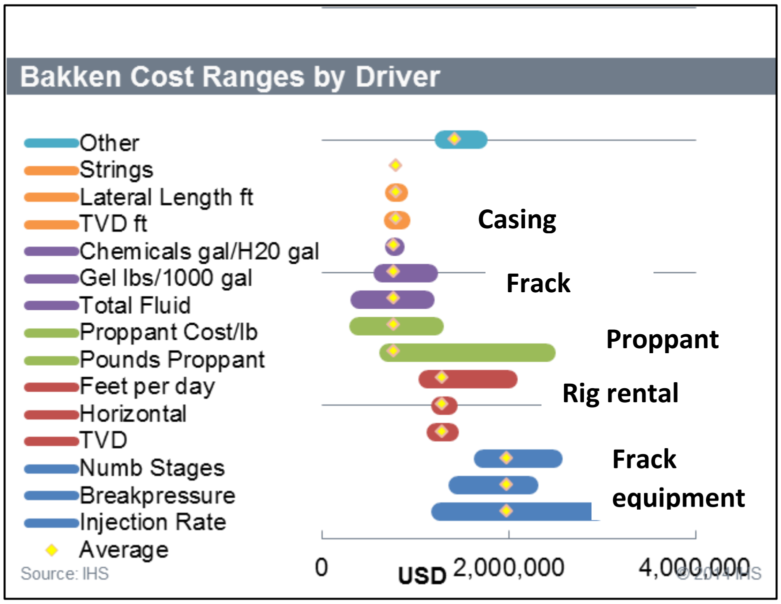


Figure 4-4: Attributes pertaining to each key cost driver

Additionally, the selection of P10 and P90 data points was intended to cut off what are expected to be outliers in the data. Figure 4-4 is a typical illustration of the well attributes that pertain to each of the five main cost categories or drivers and their ranges within the total cost of each category.

The extent to which a well parameter drives costs is determined by how much the cost of a well, with the average characteristics, changes when moving a single input to the P10 and P90 values. This creates a range of costs representing the distribution for a given parameter.

Historical Costs

Determining historical costs is similar to the determination of 2014 costs, in that both nominal rates and specific well parameters are determined and multiplied together to obtain the cost for each well parameter.

To determine historical rates, IHS maintains nominal capital cost rate indices for onshore field development in the CERA Capital Cost Index report describing historical changes to cost rates for general items such as casing, cement, mud, rigs and labor. In addition, we have developed rate indices specific to onshore North America unconventional wells for frack fluid chemicals, gel, frack equipment, proppant and water. These historical rate indices are based on historical data provided through research, industry contacts and manufacturers as well as reported drilling rig day rates and proppant costs per lb.

IHS also maintains an operating cost index similar to the capital cost index and we have supplemented this with rates specific to North American unconventional wells. For each year beginning in 2006, these historical indices are applied to historical well parameters to determine the cost for each attribute and cost category for each year.

In order to determine historical ranges of cost, well attributes were captured from the data going back as far as 2006 or at the beginning of play inception. The distribution of data for each attribute within each given year was analyzed to determine the P10, P90 and average needed to determine historical cost range for each year, in a similar fashion as described for the 2014 cost model and analysis. Additionally, the IHS cost indices were applied to the 2014 cost model rates to create historical cost distributions for each year. Combining the historical well parameters with the historical cost rates historical well costs and their distributions were determined annually.

Future Costs Rates

This study includes projections through 2018 of nominal capital cost rate changes with special focus on the differences between 2014 costs, which were analyzed in detail, and 2015 costs, which are today's reality given the recent collapse in oil prices. Onshore unconventional well cost rate forecasts rely on insight developed through interaction and leveraging of analysis from its specialist legacy companies such as PFC and PacWest, as well as identifying and projecting certain trends. Assumptions, described in the onshore summary portion of this report were vetted with research peers to provide a view consistent with other IHS outlooks. We assume that price forecasts for oil will remain low through mid-2016 with only modest recoveries through 2018; this implies industry activity will continue to drop off and may not fully recover in the near term, thus sharply reducing rig rates and frack crew rates, which are two of the five cost category drivers being analyzed.

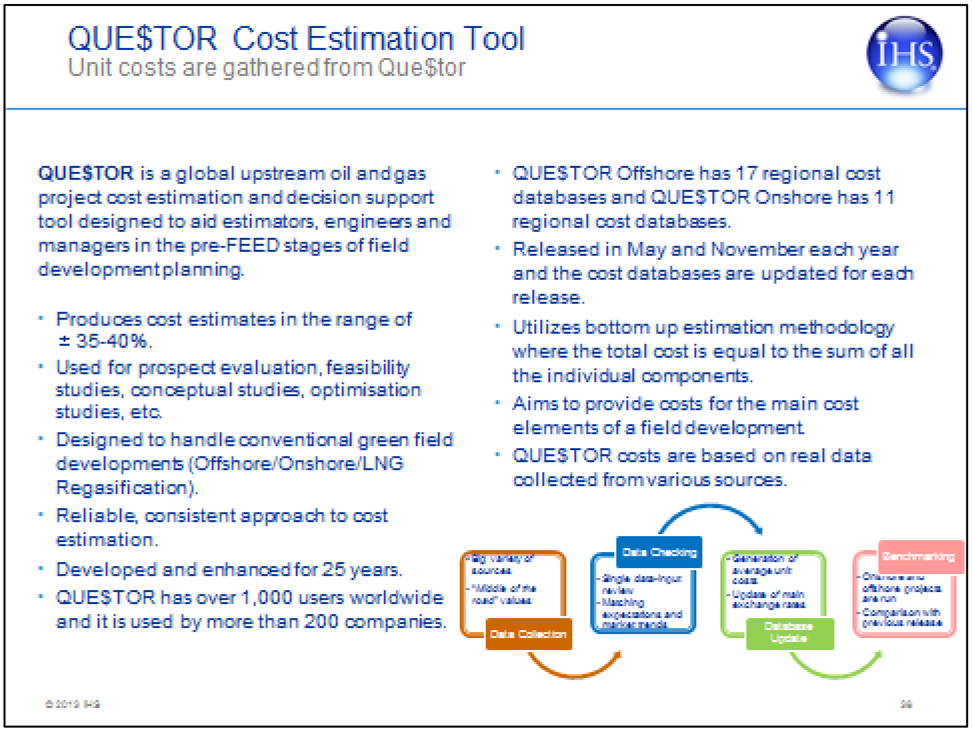
Future well cost trends were developed by noting salient changes over time in key well attributes, such as proppant usage. These were combined with future cost rates to project costs into the future. Forecasted well parameters assumed mostly linear trends given the last few years unless there was a reason to assume otherwise.

Cost Effectiveness

In order to assess cost effectiveness, a relationship between well total cost and well performance was required. To evaluate well performance, well production curves were developed for each sub-play in order to calculate estimated ultimate recovery (EUR) for each vintage year beginning in 2010 through 2014 and thereafter forecasting EURs for wells to be drilled from 2015 to 2018 based on current trends. Total well costs were divided by the respective EURs for each given year and sub-play to determine a unit cost as $/Boe.

B. Offshore Deep Water

Deep water field development costs, with granular data describing each component of the project, are difficult to obtain. This is unlike shale plays where applications for expenditure (AFE) and drilling and completion (D&C) costs are often touted by operators for each of their respective plays. Offshore Deep Water Gulf of Mexico data has far fewer wells and fewer operators to produce data, which is mostly quoted at the project level without any breakout between D&C, infrastructure, installation/hookup, etc. In order to shed light on the costs of deep water developments, IHS produces a field development costing software *Que$tor* to provide the breakouts and estimate costs by component. Supplementing this is industry media research and experience which provides confirmation of total cost and component costs for some project models. However, due to market changes or cost overruns the reported and estimated figures are subject to change. Que$tor provides a relatively reliable industry standard for cost analysis and lends itself well to IHS capital and operating cost index forecasts when certain cost data is in short supply.



IHS Questor is a tool developed over the last 25 years by engineers for engineers in order to assist in assessing and managing the potential cost of a field development for green fields. Used by more than 200 companies worldwide, it is designed for pre-FEED work and is able to produce full cycle costs within 35-40% without many assumptions other than development concept, reserves and a few commercial parameters for distances to shore, etc. Que$tor is comprised of databases of field and reservoir properties to provide expected values of parameters when data is unavailable and also contains a detailed cost database for each component in a field development for everything from rigs to pipelines. Field level and reservoir characteristics are sourced from the IHS EDIN E&P activity database which documents all events and qualities of fields throughout their lives. The cost data that Que$tor uses comes from industry reports and direct contact with operators, which means Que$tor costs are more or less reflective of actual cost data. Que$tor then applies a series of algorithms using the field characteristics and the relevant cost data to produce cost for each development component at a granular level.

The unit cost database in Que$tor is based on Q3 2014 cost collection. For example, deep water rig day rates, such as semisubmersible and drill ship representing GOM Q3 2014 contracts. The other unit costs, such as Christmas tree, casing, tubing, cementing, logging, and wellhead equipment also reflect Q3 2014 cost. We selected five projects in GOM deep water representing typical reserve size, and field development plan from three plays, Miocene super salt and subsalt, Lower Tertiary, and Jurassic. The reserves, well depth, water depth, well productivity, reservoir pressure and temperature are plugged into the Que$tor model to generate drilling and completion cost. Production platform costs are modeled based on water depth, capacity, and the platform type. Subsea tieback and pipeline layout cost and are also modeled based on the distance to the host platform and detailed field design.

For forward looking cost estimates, we rely on the IHS rig rate forecast, capital cost index to forecast future development cost.

For high-level play level breakeven prices, development costs, and regional development scenario outlook, we use guidance from “IHS Global Deepwater and Growth Plays Service”, which is an analytical research service providing play-level analysis of the commercial development of currently developing resources, and highlighting both materiality and value potential in each play area.

V. Bakken Play Level Results

A. Introduction and sub-play description

The Bakken oil play is located in the Williston Basin of North Dakota and Eastern Montana. Producing formations include both the Bakken and Three Forks, which are fairly uniform throughout the basin and occur at approximately 10,000 foot depths. Horizontal drilling began at Elm Coulee Field in the early 2000's and then moved to Sanish-Parshall in 2007 as that sweet spot was delineated. Two additional areas, namely the New Fairway, emerged with unique factors that have influenced drilling and completion costs (see Figure 5-1).

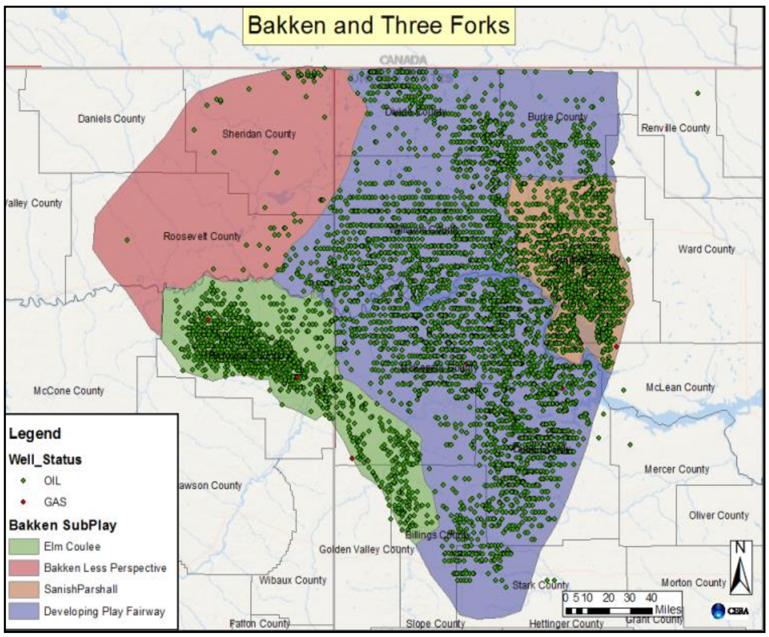


Figure 5-1: Location of Bakken Three Forks sub-plays

Drilling in the play has increased steadily since play inception (figure 5-2). Production ramped up quickly to 1.2 MM barrels/day, but has leveled off as oil prices have plummeted. Rig counts that once exceeded 200 have fallen to the mid-eighties in recent months due to the oil price decrease. The play is located a long distance from oil markets and have limited infrastructure access to both oil and gas markets due to the recent significant production increases. Natural gas issues have been mostly overcome by partial flaring of excess associated gas, development of new gas plants and gas take-away capacity. Oil transportation has relied on rail for nearly 50% of oil production in order to reach markets on the east and west coast.

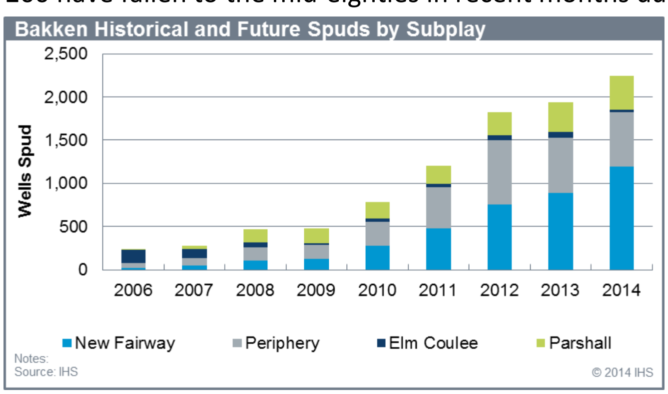


Figure 5-2: Drilling history of each Bakken sub play

B. Basic Well Design and Cost (2014)

Total Bakken Cost

Total well costs range from $7.5 MM to $8.1 MM as shown in Figure 5.3. The consistency in TVD, lateral length, pressure and completion design amongst the sub-plays is reflected in similar costs amongst the sub-plays for drilling and completion. Exceptions include the Elm Coulee field with lateral lengths of just 8,600 feet which are shorter and use less proppant, thus reducing completion costs, and the New Fairway which has a greater TVD, and thus has higher drilling costs.

Comparison with Published Data

The average Bakken well cost of $7.8 MM compares with published costs reported by operators in 2014 as follows:

- Operators reported costs range from MM$ 6.5 to MM$ 9.6 with Oasis reporting the lowest and Continental reporting the highest.
- EOG and SM Energy averaged over MM$ 9 with EOG's minimum being MM$ 8.
- Hess and Halcon wells were approximately MM$ 8 with Hess achieving their lowest cost wells at MM$ 7.2.
- Elm Coulee - Continental reported costs of MM$ 7 to 8.5.
- Periphery - Operators reported cost of MM$ 7 to 9.
- Parshall - Operators reported cost of MM$ 6 to 8.
- New Fairway - Operators reported costs between MM$ 7 and 9.6.

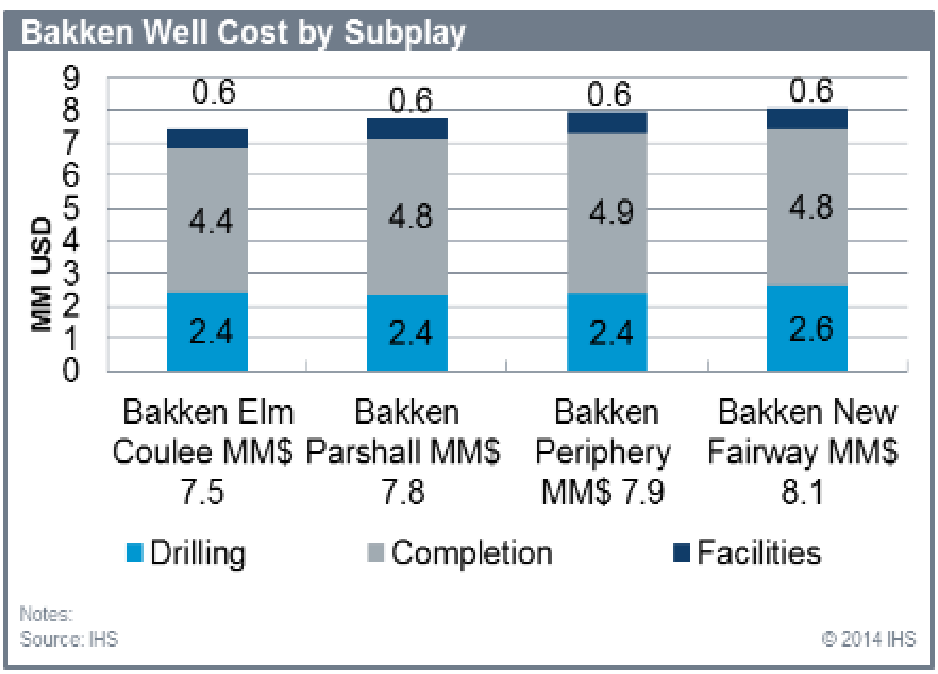


Figure 5-3: Total Bakken cost by sub-play

General Well Design Parameters

Table 5-1 summarizes well design parameters for each sub-play. Proppant mixes, amounts and horsepower drive costs, and we note that Parshall uses the most horsepower and proppant, but less artificial proppant. Casing programs are uniform with a conductor pipe, two strings and a liner generally used. Artificial lift soon after the well comes on stream is the common practice.

Well Parameters	Unit	Elm Coulee	Parshall	New Fairway	Periphery
TVD	Ft	10,069	10,169	10,905	10,030
Horizontal	Ft	8,630	9,018.90	9,513	9,670
Formation pressure	Psi	6,042	6,102	6,543	6,018
Frack stages	#	25	30	30	31
Frack break pressure	Psi	9,969	9,763	10,469	9,629
Pumping rate	Bpm	50	55	46	45
Horse Power	Hp	14,049	15,135	13,573	12,213
Casing, liner, tubing	Ft	31,504	32,494	35,108	32,849
Drilling days	Days	27	24	26	25
Natural proppant	MM Lbs.	1.86	4.13	3.77	1.78
Artificial proppant	MM Lbs.	1.86	0.46	0.42	1.78
Total Water	MM gal	2.89	4.37	3.63	3.3
Total Chemicals	Gal	144,497	218,649	181,413	164,968
Total Gel	Lbs.	115,598	43,730	36,283	32,994

Table 5 –1: Properties of typical wells in each sub-play used to calculate costs

Wells in Elm Coulee are drilled to just over ten thousand feet vertical depth and have lateral lengths averaging 8,600 feet. The long lateral lengths are more than sufficient for large completions with 25 stages using over 3.7 MM lbs. of proppant and nearly 3 MM gallons of fluid. Proppant mixes here are fairly expensive with a heavy use of resin coated mixed with natural sand. Completion fluids are nearly always gel based, which is typical of oil plays.

Wells in Parshall are drilled to nearly 10,200 feet vertical depth and have lateral lengths over 9,000 feet. Long lateral lengths support 30 stages using over 4.6 MM lbs. of proppant and nearly 4.4 MM gallons of fluid. Despite using resin coated and ceramic proppant, mixes here are fairly inexpensive due to the fact that they are heavily weighted to natural sand. Completion fluids are mostly gel with some wells completed using slick water.

Wells in Periphery are drilled to over 10,000 feet vertical depth and have lateral lengths of nearly 9,700 feet. Long lateral lengths support 31 stages using over 3.5 MM lbs. of proppant and nearly 4.4 MM gallons of fluid. Despite using few proppants for the large number of stages, proppant cost is high with heavy use of ceramic sand. Completion fluids are mostly gel with some wells completed using slick water.

Wells in New Fairway are drilled to over 11,000 feet vertical depth and have lateral lengths over 9,500 feet. Long lateral lengths support 30 stages using over 4.2 MM lbs. of proppant with over 3.6 MM gallons of fluid. Proppant cost is not high as wells use mostly natural sand and 100 mesh. Some wells use ceramic proppant which would drive up the well cost significantly. Completion fluids are mostly gel with some wells completed using slick water.

Within the Bakken operators use the sliding sleeve technique, instead of the traditional plug-and-perf fracking procedure, for fracking wells while reducing completion costs.

C. Operating Costs

Operating costs are highly variable ranging from $15 to $37.50 per boe (Figure 5-4) and are influenced by location, well performance, and operator efficiency.

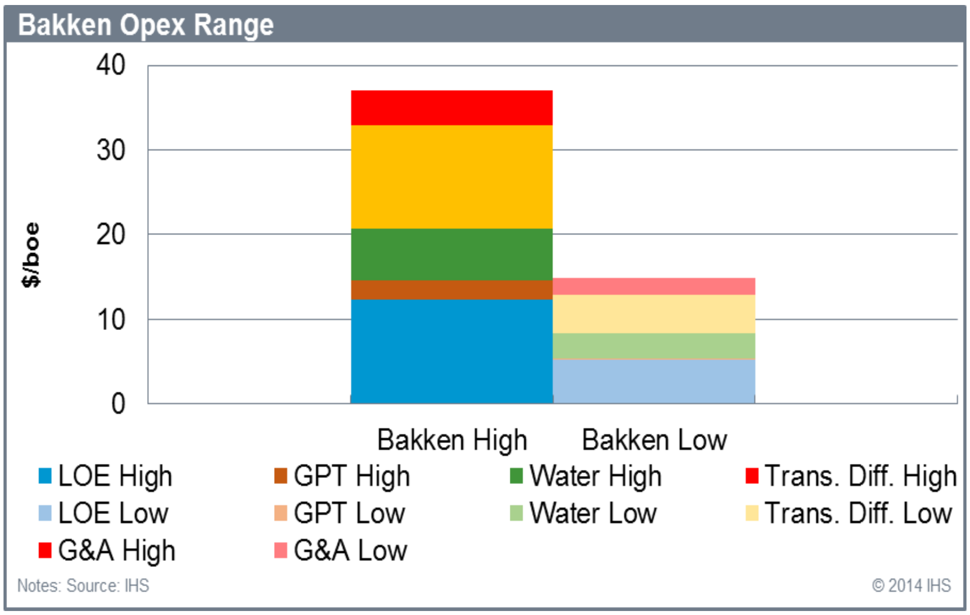


Figure 5-4: Range of operating expenses

Lease Operating Expense (LOE)

Most of the Bakken lease operating expenses (LOE) incurred relate to artificial lift and maintaining artificial lift. However, a few companies are able to nearly avoid most of these costs. Another major cost for LOE is water disposal, as the Bakken produces 0.75 to 1.0 bbl. of water for every bbl. of oil that is produced. Direct labor and other costs are fairly small relative to the rest of the costs, but are similar to other plays. The Other category contains common costs like pumping, compression, and other recurring types of costs, which are mostly determined by the cost of energy to run them (figure 5-5).

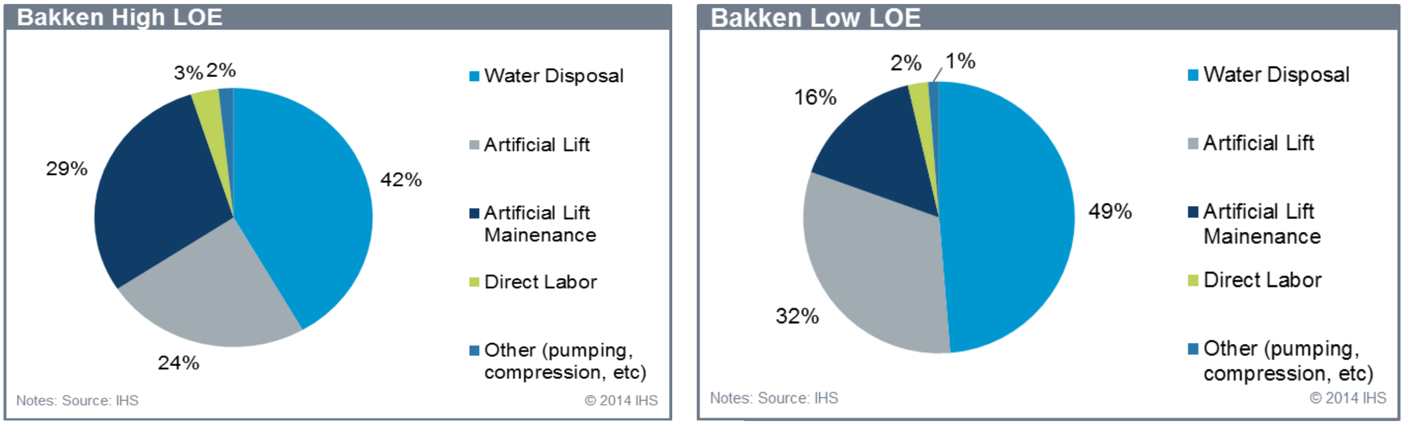


Figure 5-5: Breakout of LOE costs

Gathering, Processing and Transport (GPT)

Oil is sent by either pipeline or rail to several destinations after being transported to a loading area. The range of costs or differential incurred depends on whether transport is by rail or pipeline. Train transportation is the only option for transport to the east or west coast and can cost $10-$13 per barrel, while pipeline transport to the gulf can save much as $5 per barrel or more. The breakout of GPT costs is presented in Table 5-2.

Gas has had very few market options, due to the fact the Bakken area was not as productive as other regions of the U.S. during the major conventional field developments and pipelines are limited. Gas plants and pipelines are being built, thus reducing gas flaring. As of 2014, gas was still flared for up to 30% of the wells. This activity is expected to result in 100% marketed gas in the near-term. Current gas processing, fractionation and transportation rates are in line with other plays despite being limited in availability. Access to markets is in fairly close proximity with destinations for product in Chicago, Edmonton, and other northern markets.

	Units	Bakken High	Bakken Low
Gas Gathering	$/mcf	0.35	n/a
Gas Processing	$/mcf	0.75	n/a
Short Transportation Oil	$/bbl.	0.35	0.2
Long Transportation Gas	$/mcf	0.25	n/a
Long Transportation Oil	$/bbl.	12.50	6.25
Long Transportation NGL	$/bbl.	12.50	n/a
NGL Fractionation	$/bbl.	3.50	n/a
Water Disposal	$/bbl. water	8.00	4.00

Table 5-2: Breakout of GPT costs

G&A Costs

G&A costs range between $2.00/ boe and $4 .00/boe. These may increase during 2015 due to layoffs and severance pay-outs, but will be reduced over time due to staff reductions

Cost changes in 2015

Table 5-3 below summarizes operating cost changes that we expect to see between 2014 and 2015 going forward.

Item	Change	Description of change for 2015
Gas Gathering	-4%	Current contracts are sticky, but additional gas infrastructure will allow for more gas to be marketed. This will increase the cost rate for those who flare, but this will net a higher value.
Gas Processing	-4%	Current contracts are sticky, but additional gas infrastructure will allow for more gas to be marketed. This will increase the cost rate for those who flare will now pay this, but this will net a higher value.
Short Transportation Oil	-3%	Improved pipeline infrastructure will allow for less trucking.
Short Transportation Gas	-5%	Improved infrastructure will allow for more piping of production, but many operators will incur the same costs as 2014.
Long Transportation Oil	-10%	Lower rail activity and improved infrastructure will drive this improvement.
Long Transportation NGL	-5%	Improved infrastructure will allow for more piping of production, specifically a 5% decrease, but many will incur the same costs as 2014.
NGL Fractionation	0%	No change expected.
Water Disposal	+1.80%	Many water disposal contracts have fixed rates. Some of this will escalate based on PPI or another index. Only companies that dispose of their own water will see savings
G&A	+5%	Severance package/payments due to layoffs are increasing G&A despite lower future operating cost. Savings will not be realized until 2016.
Artificial Lift	-10%	Oil field services rates are dropping due to lower activity and lower input costs rates like energy.
Artificial Lift Maintenance	-10%	Oil field services rates are dropping due to lower activity and lower input costs rates. Maintenance will now be avoided in some cases where it was profitable at higher prices. Companies that pay a fixed maintenance may not see better rates in 2015 unless they are able to renegotiate.
Direct Labor	-3%	Saving here will be due to fewer operational employees.
Other (pumping, compression, etc.)	-10%	Energy costs savings.

Table 5-3 Changes in operating expense going forward

D. Leasing Costs

Lease acquisition costs will depend on if the operator has secured acreage before the play has been de-risked, as explained in Chapter 1. Figure 5-6 provides recent transaction costs per acre and the incremental cost to each well that is incurred.

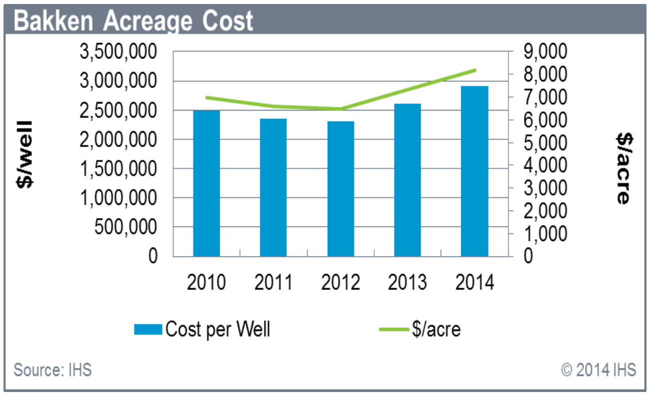


Figure 5-6: Historical leasing costs

We are assuming that each lateral is going to require 640 acres and that two stacked laterals can be drilled, one in the Bakken and the other in the Three Forks, for a net requirement of 320 acres per well. Approximately 10-20% of the acres acquired will not be utilized. Ultimately we begin to see that paying $6500/acre will add up to an additional $2.5 MM per well.

E. Key Cost Drivers and Ranges

Overall, 74% of a typical Bakken well's total cost is comprised of five key cost drivers (see Figure 5-7):

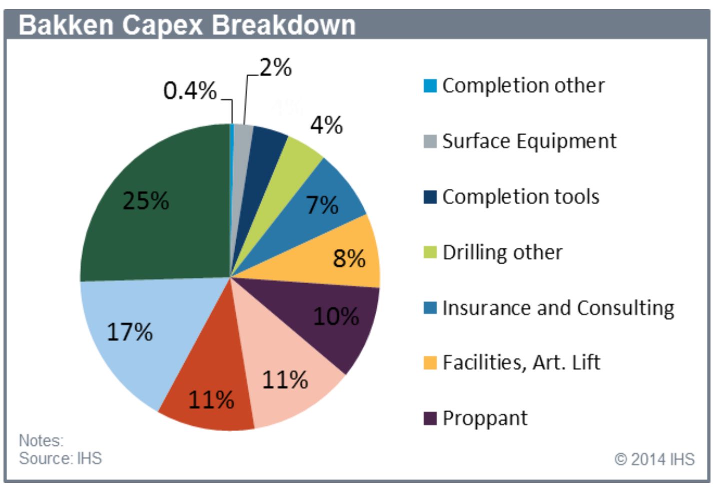


Figure 5-7: Bakken capex breakdown

- **Drilling:**
  - rig related costs (rig rates and drilling fluids) – 17% or $1.32 MM
  - casing and cement – 11% or $0.86 MM
- **Completion:**
  - hydraulic fracture pump units and equipment (horsepower) – 25% or $1.95 MM
  - completion fluids and flow back disposal – 11% or $0.86 MM
  - proppants – 10% or $0.78 MM

Range of Costs and Key Drivers

Various cost attributes are classified within each of the five major key drivers as shown in Figure 5-8. The total cost for each of these five cost drivers is portrayed with P10/P90 ranges created for each of the contributing attributes pertaining to such range. These ranges are intended to portray variation and uncertainty.

Pumping costs, which is the most costly driver, exhibits the most variation; suggesting that significant deviation from the norm could add or decrease significantly from the total drilling cost. Injection rates have a range of 31 bpm to 72 bpm, which has the largest effect on pumping costs creating a range of MM$ 1.6; with possible cost increases over the average by $ 0.9 MM or cost decreases over the average by $ 0.7 MM.

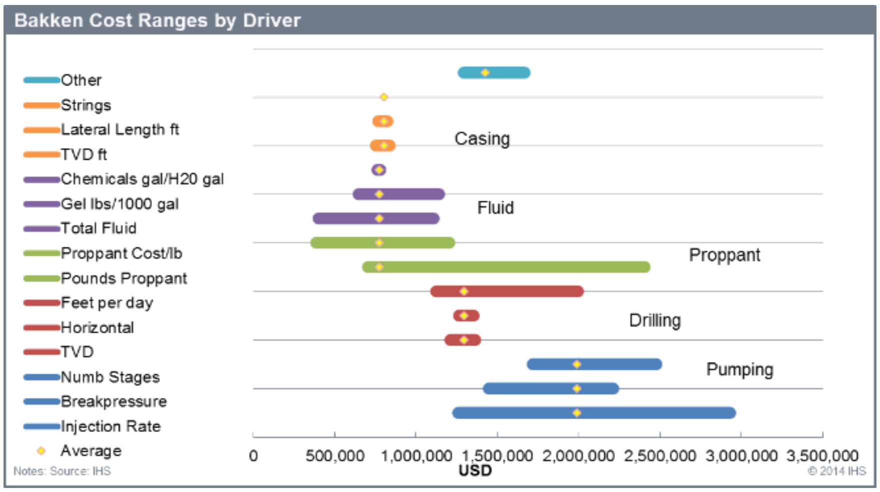


Figure 5-8: Range of cost for attributes underlying key drivers

Drilling penetration rate variability, from 411 Ft/d to 965 Ft/d, creates a drilling cost range of $ 0.9 MM; with possible cost increases of up to MM$ 0.7 for wells that drill slowly or cost decreases of up to $ 0.2 MM for drilling faster than the average. Drilling penetration rates are skewed toward faster drilling, as it is actually quite rare for a well to be drilled at the slower end of the distribution.

The proppant amount variability, from MM lbs. 3.5 to MM lbs. 12, creates a proppant cost distribution of MM$ 1.7, with the potential to lower costs by just MM$ 0.1 and raise costs by MM$ 1.6. Most wells use proppants at the lower end of range. The fluid cost range for total fluid amount is MM$ 0.7, with the potential to raise costs over the average by $0.3 MM or lower them by $ 0.4 MM (with fluid amounts ranging from 1.9 MM gallons to 5.3 MM gallons). The range of vertical depths in the play, from 9,263 feet to 11,147 feet, creates a casing cost range variation of just $ 0.1 MM. Upward or downward cost movement in this category is negligible.

F. Evolution of Historical Costs

Historical Well Costs

Between 2008 and 2009 steel costs rose significantly. This created a spike in 2008 that was followed shortly thereafter by a drop due to oil price decreases in the latter part of that year (see Figure 5-9).

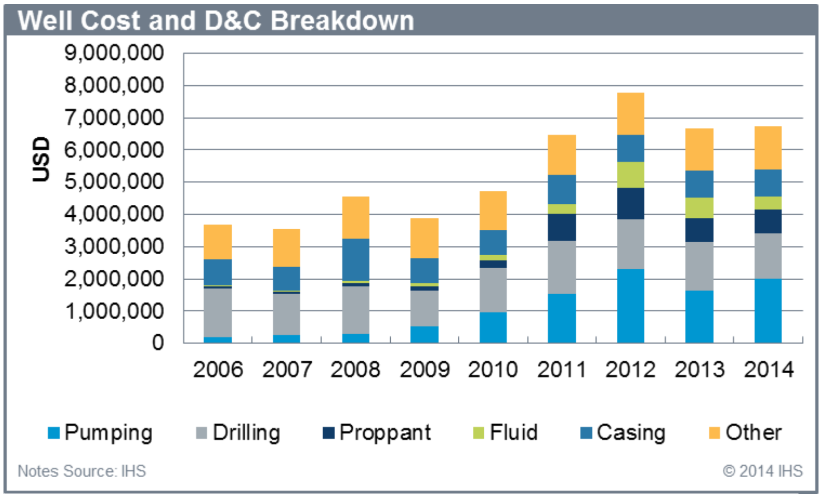


Figure 5-9: Historical nominal well cost by major cost driver

Between 2010 and 2012 nominal well costs in the Bakken remained under $ 5 MM until horizontal development throughout the US took off in 2011 and costs such as rig rates and frack crew rates began to rise. The 2011 and 2012 years saw huge price increases, approximately $ 1.5 MM per year. Because of rising rig rates, drilling costs have increased despite improved drilling efficiencies. Proppant and fluid costs increased 60% to 70% and continued to increase year-on-year. The number of stages, lateral length and increased proppant (with commensurate fluids and chemicals) further fueled cost increases. With increased activity, water sources and disposal facilities were limited. Along with greater numbers of stages, proppant and fluid, associated pumping costs grew and were further exacerbated by shortages in completion service labor and equipment. Casing costs have remained fairly flat throughout the entire period.

As the service industry grew to meet demand between 2013 and 2014, rates for pumping equipment and fluids subsided and overall costs decreased. Nominal costs in 2013 dropped by about $1.0 MM, but stayed fairly constant in 2014.

Changes in Well and Completion Design

Between 2006 and 2011, lateral length steadily increased until it reached its current length of just less than 10,000 feet. On the other hand proppant per well has grown steadily year over year and feet per stage has decreased more slowly. This suggests that fluid and proppant concentrations in each stage are increasing (Figures 5-10 and 5-11). Despite downward pressure on rates from 2013 to 2014, the additional proppant per well in year 2014 contributed to a slight increase in cost for a well.

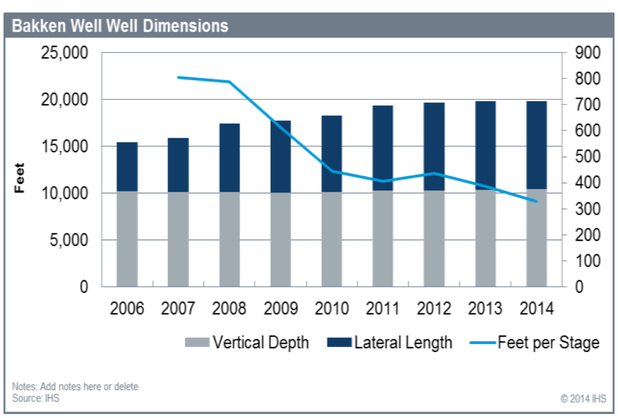


Figure 5-10: Lateral length and total depth

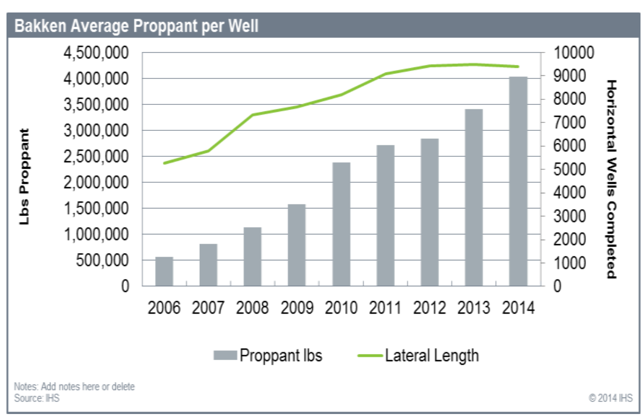


Figure 5-11: Proppant per well history

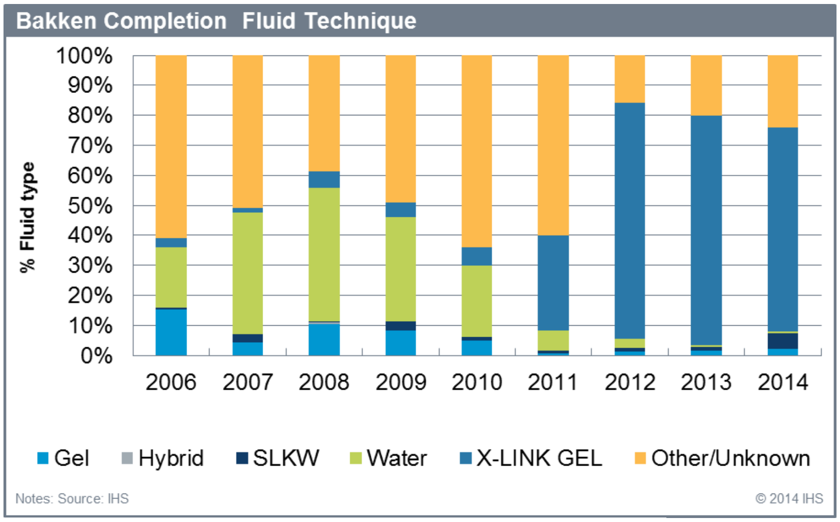


Figure 5-12: Change in frack fluid use over time

The mix of frack fluids has evolved over the years, beginning with predominately water fracks. Almost immediately in 2011, operators switched to X-link gels (Figure 5-12). At the same time information gathering improved. Well EURs increased from 381 kBoe in 2010 to 544 kBoe in 2011. This suggests that x-link gel fracks and additional proppant were having a positive impact on performance and that the additional capex was paying off. Overall, play Capex cost per Boe dropped from $13.24 per Boe in 2010 to $12.48 in 2011, which is the year that X-link gels were first used. Since that time there has been some erosion in performance.

There have been recent decreases in lateral lengths, as it appears that 9,000-10,000 feet is the best balance between cost and EUR. The overall decrease in average EUR from 451 kboe in 2011 to 391k in 2013 is likely due to drilling wells outside sweet spots due to higher oil prices. At the same time efficiencies in drilling and completions have reduced costs from 2012 to 2013 (Table 5-4). In 2014, EURs again began to increase and we see the trend continuing as operators become more selective in their drilling locations due to lower oil prices.

Year	$/Boe	EUR -Boe
2010	15.79	298,129
2011	14.32	451,013
2012	19.06	407,423
2013	17.05	390,842
2014	15.67	425,627

Table 5-4: Drilling and Completion Unit Cost

Some of the performance increase may be due to operators applying larger and larger amounts of proppant (see Figures 5-13 and 5-14). However this may not be as effective as hoped for, as the EUR per unit of proppant is decreasing. In other words the amount of proppant used is increasing faster than performance improvement. The evidence suggests that despite the use of improved technology the performance increases have more to do with site selection. Furthermore applying technology will only allow operators to “tread water” as they struggle to maintain performance and at the same time attempt to reduce their costs per boe.

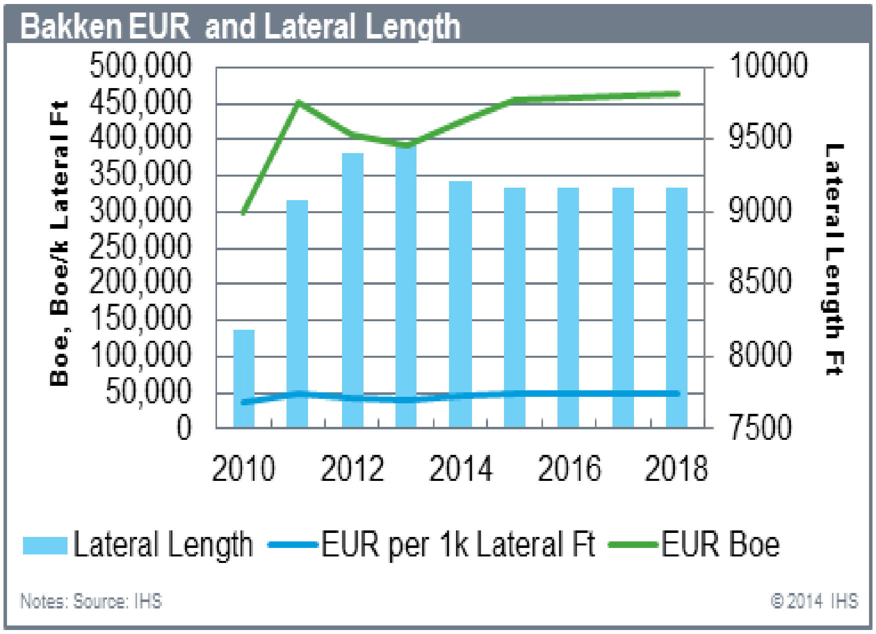


Figure 5-13: Change in frack fluid use over time

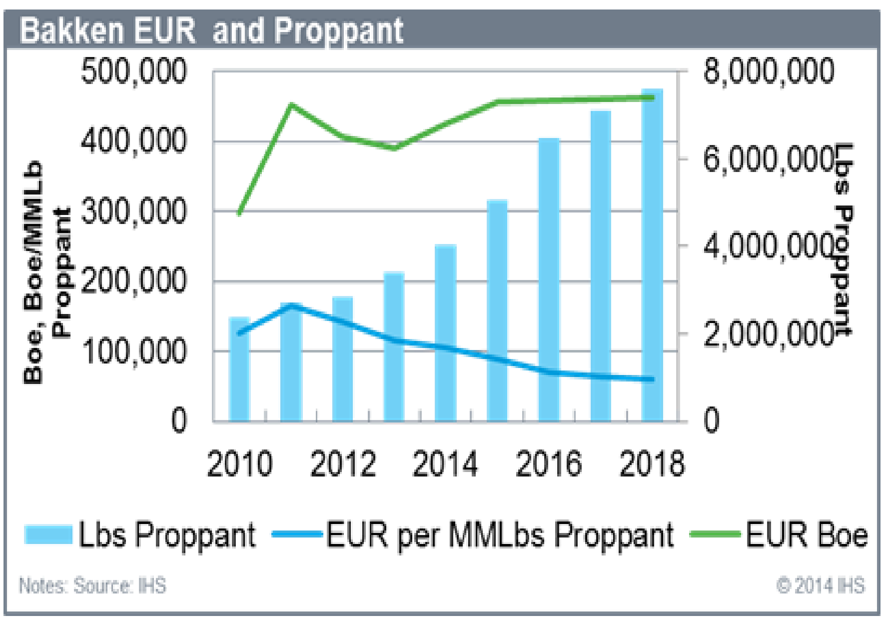


Figure 5-14: Change in frack fluid use over time

G. Future Cost Trends

Cost Indices

Bakken development activity is dropping sharply with little chance of recovery soon. Active rigs in the play are in the mid-eighties and expected to drop into the mid-60s by the end of the year. Because the Bakken is relatively infrastructure-constrained and much of the transport of oil is by rail, there is a huge differential of $6-13 compared to WTI. This will only further depress activity. Also, being a regional market for services, equipment such as rigs and pumping units will not be able to move easily to other areas, thus putting more pressure on service providers. Overall, cost rates are decreasing from 2014 levels by 20% during 2015, and will drop another 3-4% in 2016 (see Figure 5-15).

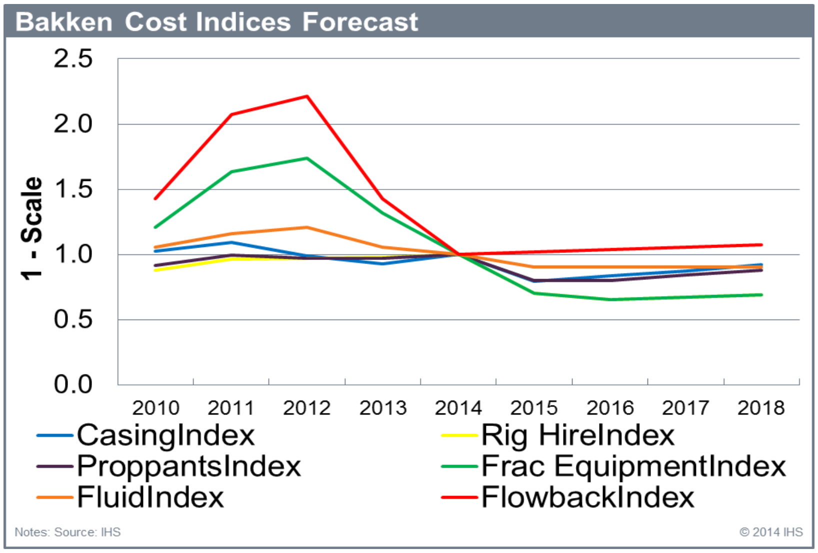


Figure 5-15: Indices for major cost drivers

Pumping and drilling rig cost rates are dropping and are expected to be 25 – 30% lower by the end of 2015, with another 5% decrease in 2016. Rates will begin to recover in late 2016, but will stay low through 2018. Proppant costs will drop by 20-25% in 2015, largely due to decreases of 35-40% at the mine gates. The impact on fluid will be less. Due to a forecasted drop of 20% during 2015 in the price of steel, tubulars, and other fabricated materials will also cost less.

Changes in Well Design

Despite the challenging environment operators will continue to lower unit costs ($/Boe). The following trends are expected to continue:

- Lateral length - Average lateral length has not moved much during the past four years and is projected to remain relatively constant at 9,200 feet (see Figure 5-16). Vertical depths should also remain fairly constant.

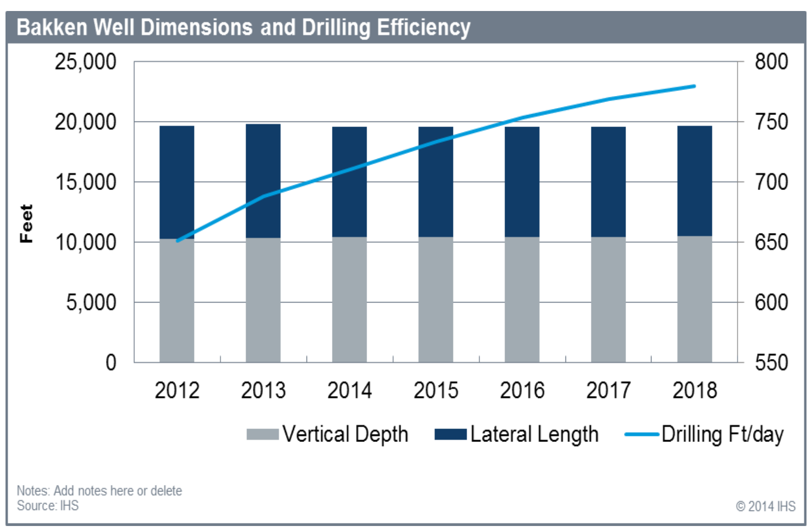


Figure 5-16: Historical and forecasted total depth

- Stages - The average number of stages is projected to increase from 28 to 32 in 2015 and by 2018 should reach nearly 40 (see Figure 5-17) and because lateral lengths are not projected to change, we can expect that stage spacing will tighten considerably.

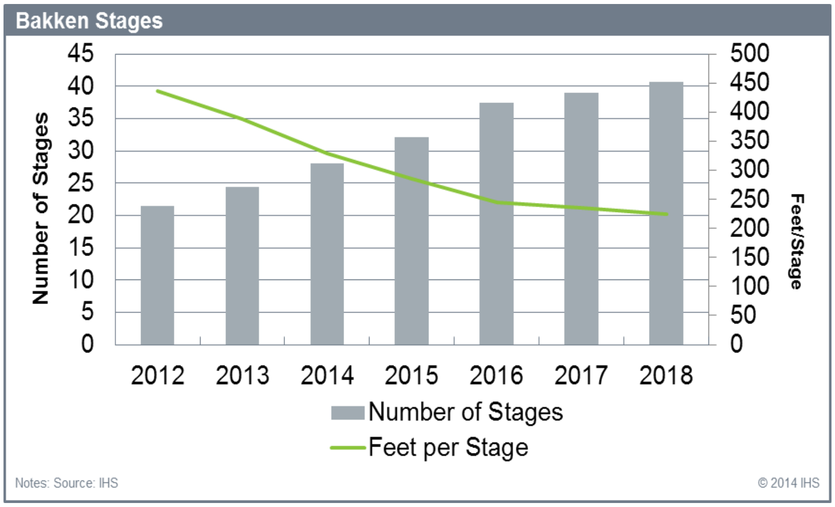


Figure 5-17: Historical and forecasted stages

- Drilling efficiencies - These have already been optimized and any changes here will be small with average drillers achieving 780 Ft/d by 2018. This is up 10% from 710 Ft/d in 2014 (figure 5-16).
- Proppant - Proppant amounts will increase from 450 Lbs./Ft in 2014 to 550 Lbs./Ft by this year and will steadily increase to 820 Lbs./Ft by 2018. This is still relatively light compared to the 1200-1400 Lbs./Ft we see in other plays (Figure 5-18). Proppant mix is expected to be focused more heavily on natural proppants in order to afford more total proppant. Average fluid use is expected to increase proportionately. Gel and chemicals used are expected to remain the preferred option going forward as completion fluids types have been fixed for some time.

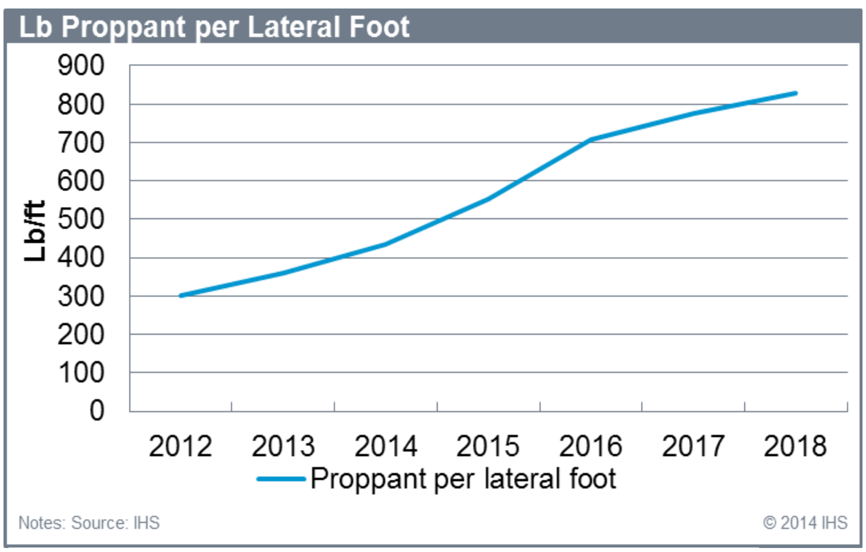


Figure 5-18: Historical and forecasted proppant

- More wells being drilled on single drill pads – As more wells occupy single drill pads we can expect potential cost savings from shared facilities and other related items, such as roads, mud tanks, and water disposal systems. Of the total well cost, $1.1 MM is based on sharing costs amongst four other wells. Table 5-5 illustrates how future drill pad configurations could save money. For example, there are currently two stacked zones, namely the Bakken and Three Forks, which are considered potential targets. Pilot programs have been completed for two additional Three Forks zones, bringing the potential zones to four. Additional testing has also been completed for tighter spaced wells, thus the potential exists for up to 16 wells to be drilled from a single pad, which could save potentially $825,000 per well. These savings are not likely to apply throughout the play, but will be focused more in localized areas. Nevertheless this illustrates potential savings.

	Stacked Horizons	Distance between wells	Wells per pad	Cost of items related to pad - 2014	
Modeled	2	3240 feet	4	$ 1,100,000	Modeled Cost
Traditional View	2	3240 feet	4	$ 1,100,000	Development Cost
Potential upside	4	1320 feet	16	$ 275,000	Potential New Cost
Difference	2	2	4	$ 825,000	Potential Savings

Table 5-5: Potential savings from additional wells being drilled from a single pad

Future Well Costs

Future changes in overall well and completion costs are quantified in forecasted indices, and are combined with projections in future well design parameters to project future costs. Figure 5-19 shows both the effect of well design and indexing on recent historical costs beginning in 2012 and future well costs through 2018:

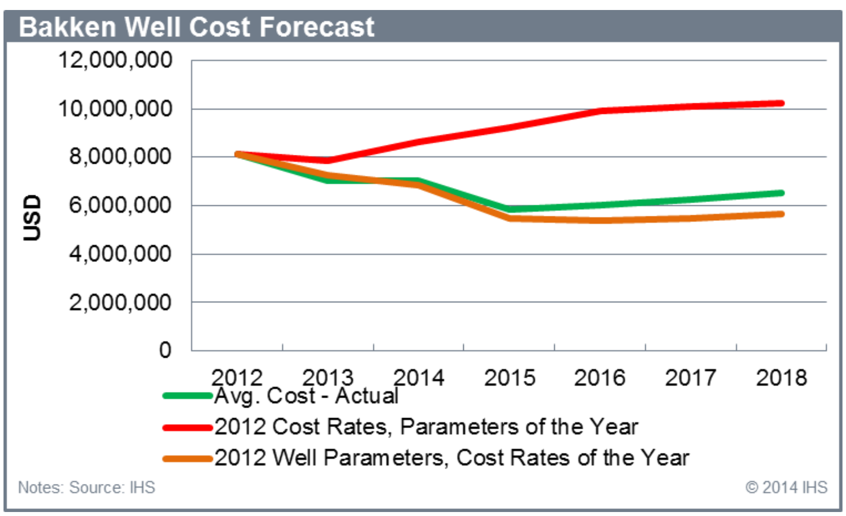


Figure 5-19: Comparison of actual future costs with forecasted

- Avg. Capex, Actual – This captures the average nominal total well cost for each year as it actually is expected to occur. Note the acceleration of the rate declined in 2012, despite more complex well designs of recent years which are expected to continue.

- Capex for 2010 Cost Rates, Well parameters of the year – This captures the application of 2012 cost rates to the average well design of a given future year. Note that had we held 2012 rates steady through the forecast period, the actual cost of a well drilled in 2018 would have cost $3.8 MM more due to the longer laterals and increased use of proppant.
- Capex for 2010 Well Parameters, Cost Rates of the Year – This represents the application of well parameters of 2012 with cost rates for the given year. Note that the more simple well design of 2012 would have cost less by 2018 if the current and future indexing was applied.

This illustration helps us see the effect of cost indices and well design changes using 2012 as a baseline. The gaps shown in Figure 5-19 between 2012 Well Parameters (orange) and 2012 average cost - actual (green) illustrate the impact of more complex well design on cost. The gap between average cost, actual (green), and 2012 Cost Rates (red) shows the much higher impact of the declining cost indices.

In conclusion, costs are forecasted to continue to decrease with light recoveries beginning in 2016. Given that we expect rate decreases within each major cost driver, we can expect little change in the relative contribution of each (Figure 5-20).

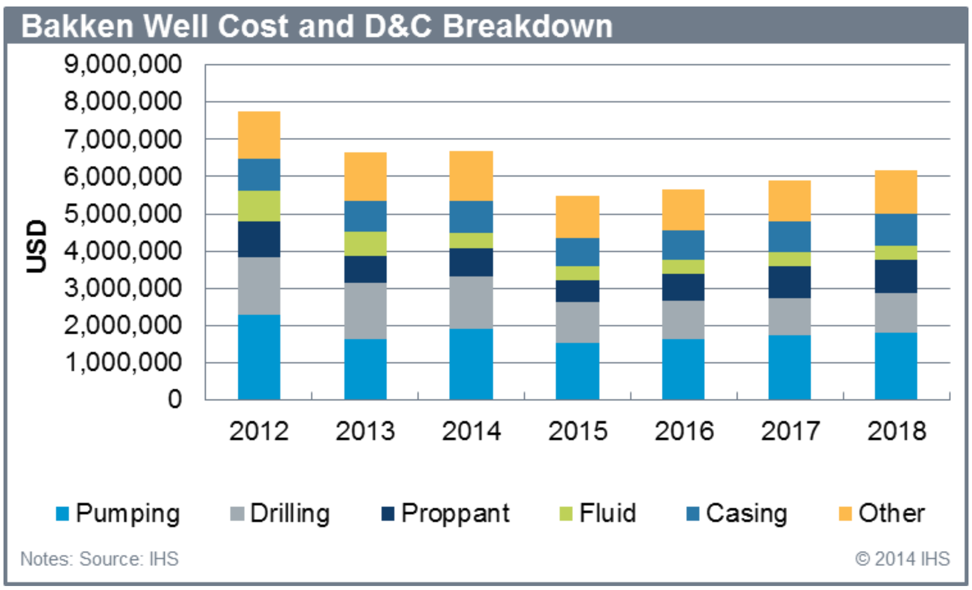


Figure 5-20: Bakken historical and future nominal costs by major cost driver

H. Cost Correlations and Major Cost Drivers

Some relationships between well design and cost are stronger than others. As already mentioned, each cost component was calculated by measuring the units or amount of a particular well design attribute and multiplying it by the rate. An analysis of the well design factors contributing to the five primary cost drivers was conducted for the period of 2010 through 2018. During that time, both the rates and character for well design attributes changed, rather dramatically in some cases.

When comparing the well design parameter with the cost for that well design parameter over the specified time period, an R2 value was generated showing the correlation or relative influence as shown in Figure 5-21. This figure also suggests that for each cost category, there is one well parameter that is most influential. Fluid costs are guided the most by variance in gel quantities, drilling costs correlate highly with drilling efficiency, proppant costs are influenced the most by the cost per lb of proppant and pumping costs are influenced the most by injection rate. Figure 5-21 also illustrates the relative importance of each well design parameter as it relates to the total cost of the well.

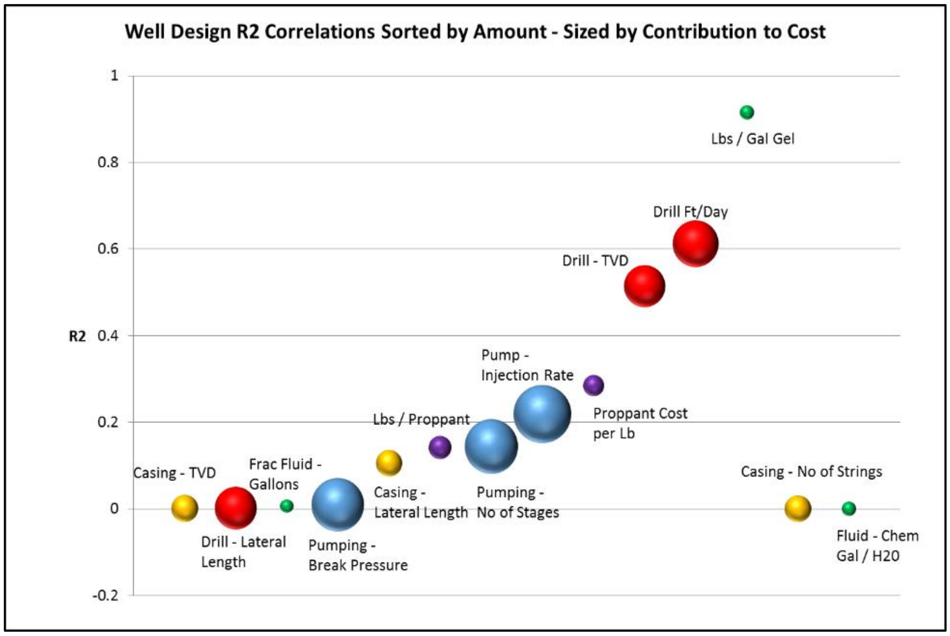


Figure 5-21: Bakken historical and future nominal costs by major cost driver

Cost per Unit

Depth of well and well bottom hole pressure influence drilling costs. As noted in Figure 5-22, these have been declining due primarily to a decrease in both rig rates since 2012, which has been accelerated in 2015, and an increase in drilling rates per day. We expect this to level out in the years ahead as rates stabilize and drilling efficiency gains begin to level out.

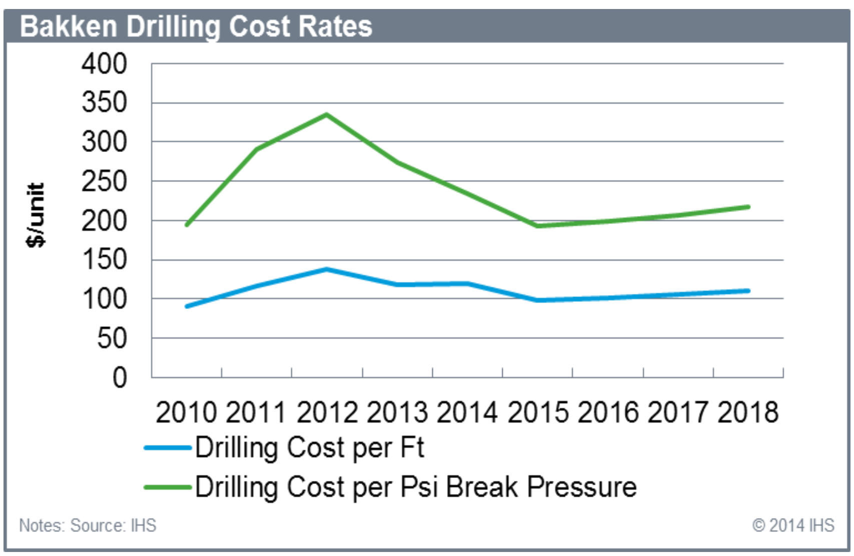


Figure 5-22: Bakken historical and future costs by major cost driver

This same decrease in costs for completion is also evident, although costs per unit of proppant will continue to drop even after 2015 (figure 5-23). This is likely due to using larger doses of natural proppant in lieu of the more expensive artificial proppant. As operators use more frack stages per well, the economies of scale will also continue to reduce costs here as well.

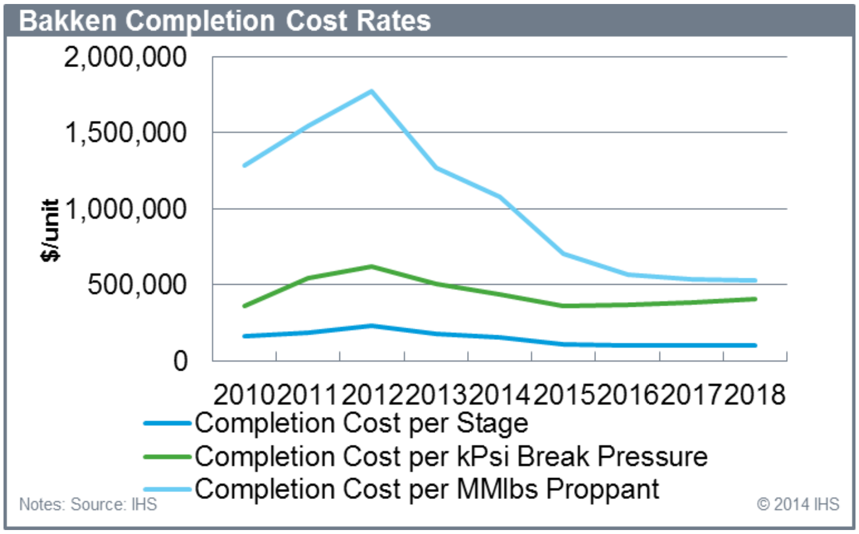


Figure 5-23: Bakken historical and future nominal costs by major

I. Key Take-Aways

Performance concerns: Over time the Bakken has achieved greater efficiencies in well design and implementation due to the drop of cost rates for the same activities and well design features. Wells have also become more complex and will continue to do so in the future. However, the Bakken benefits only marginally from greater production performance per well, as measured by average well EUR. Design and inputs into Bakken wells will grow. However well performance is likely to lag behind this since the application of more proppant is not substantially increasing EURs. With the collapse of oil prices in late 2014, operators have increasingly focused on better site selection. This factor may be overwhelming any increases in performance due to technological improvement. Going forward waning prospect quality and in-fill drilling may also contribute to decreased production performance and this will likely increase unit costs.

Economic decline is diminished by the drop in oil prices. Substantial cost savings will be achieved for the next several years. This is due to the decreased rates operators have secured from service providers and not necessarily gains in efficiency. Nevertheless we will continue to see incremental efficiency gains as operators continue to reduce drill cycle times and drill more wells from single pads.

Influential well design parameters: When modeling well costs in the Bakken the accuracy of some well attributes may be more important than others when estimating costs. Gel quantities, injection rates, cost per pound of proppant, and drilling efficiency are the key attributes whose change over time has greatly influenced costs and caused the most variance.

Decreasing costs: Rates for various materials and services peaked in 2012 when demand for high horsepower rigs (1000-1500) were in short supply and fracking crews were scarce. As the supply of these items increased to meet this demand, rates decreased and led to overall cost decreases. This is despite increases in the amount of proppant and number of stages. This began a general downward trend which has accelerated in recent months by as much as 20% due to a very large over supply of these services.

Operating Costs: There is substantial variability in operating expense. Water disposal, long haul transport, and artificial lift expenditures are the highest cost items. Given this variability, we would expect some operators to make substantial improvement. Due to the nature of the services provided, operating cost reductions will be much less than capital reductions going into 2015. Currently, about 45% of Bakken crude is transported by rail. The difference between long haul transport and pipeline transport could save an additional $5-$7 per barrel. However, there are no pipelines to either the east or west coast. Some operators see an advantage to selling into these markets.

VI. Eagle Ford Play Level Results

A. Introduction and sub-play description

The Eagle Ford is both an oil and gas play located in South Texas' Gulf Coast Basin. Since the formation gently dips (or descends) to the southeast, vertical depths range between approximately 5,000 to 13,000 feet. Oil and volatile oil is found to the northwest, with gas pre-dominating in the deeper regions to the southeast. Four sub-plays, each with their own cost issues, have been identified and include: Low Energy Oil, Northeast Core, Western Curve and Grassy Edge (see Figure 6-1). Recent activity has been centered in the oil dominated Northeast Core and the gas dominated Western Curve with over 3,500 wells being completed in the play during the past two years (see Figure 6-2).

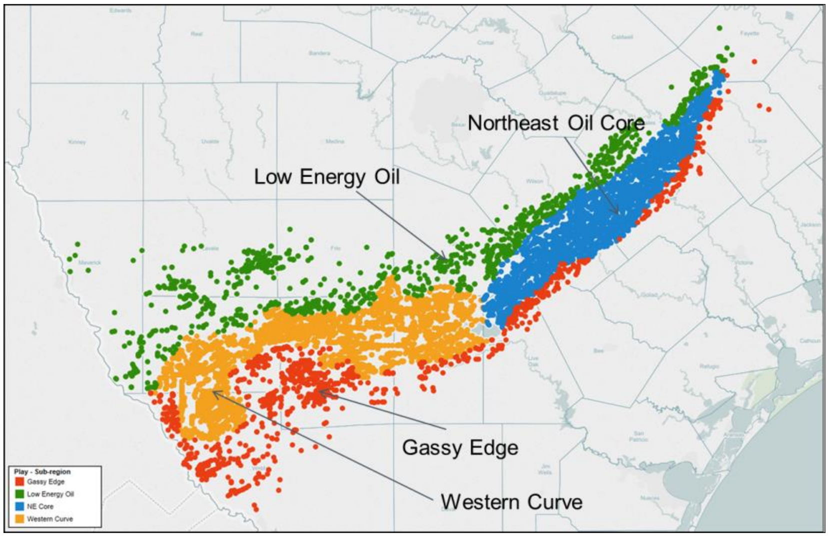


Figure 6-1: Location of Eagle Ford and its sub-plays

The play is located proximate to oil markets located in Texas and also has great access to local gas and NGL infrastructure and markets. Consequently, production of both oil and gas has ramped up quickly to over 1.5 MM bbls of oil and 6 Bcf of gas per day. Production growth is beginning to taper off, but not as severely as in the Bakken as operators focus solely on the better performing areas.

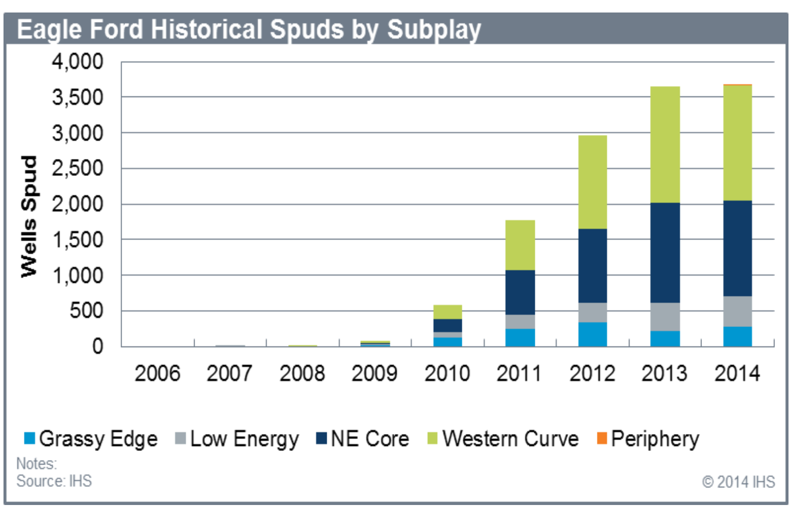


Figure 6-2: Historical wells by sub-play

B. Basic Well Design and Cost (2014)

Total Eagle Ford Cost

Total well costs range from $6.9 MM to $7.6 MM, as shown in Figure 6-3. Drilling costs are lower in the shallower Low Energy and oil prone Northeast Core sub-plays located to the north and west. Completion costs are highest in the gas-prone Gassy Edge and Western Curve plays where pumping rates are highest. However, all areas in the Eagle Ford use similar proppant and fluid amounts.

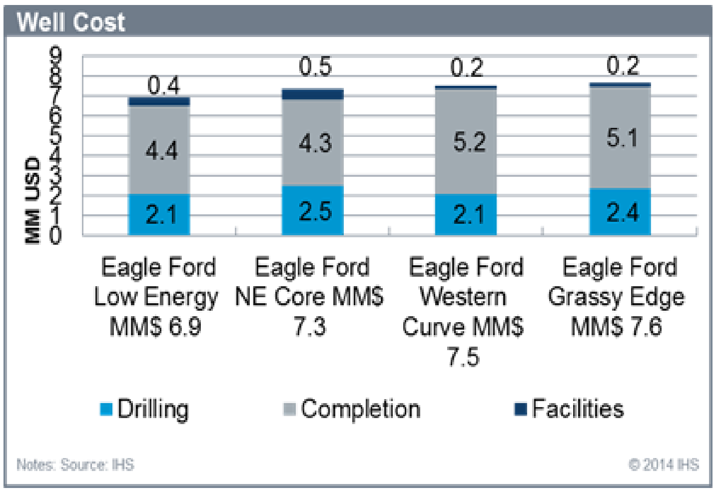


Figure 6-3: Total Eagle Ford cost by sub-play

Comparison with Published Data

The average Eagle Ford cost of $7.5 MM compares with published costs reported by operators in 2014 as follows:

- Operators reported cost from MM$ 5.9, EOG, to $ 9.6 MM, Swift
- EP Energy reported $ 7.2 to 7.3 MM
- Chesapeake reported $ 6.1 MM
- Low Energy – Rosetta and EOG reported $ 5.5 to 6 MM
- NE Core - Marathon reported cost of $ 7.3 MM
- Western Curve - Operators reported cost of $ 5.5 to 7.2 MM
- Grassy Edge - Operators reported costs between $ 7 and 7.6 MM

General Well Design Parameters

Table 6-1 below summarizes well design parameters for each sub-play, proppant mixes, amounts, and horsepower drive cost. We note that the Gassy Edge and Western Curve use the most horsepower. Casing amounts reflect the variation in total depth and consist of a conductor pipe, and three intermediate strings. Artificial lift is applied soon after the well comes on stream, but only in oil-prone Low Energy and NE Core.

Well Parameter	Unit	Low Energy	NE Core Energy	Western Curve	Gassy Edge
TVD	Ft	8,098	10,857	8,476	9,290
Horizontal	Ft	6,264	5,469	5,819	6,655
Formation pressure	Psi	4,859	6,514	5,086	5,574
Frac stages	#	19	22	20	18
Frac break pressure	Psi	6,802	9,120	7,120	7,804
Pumping rate	Bpm	57	70	95	96
Horse Power	Hp	10,929	17,994	17,994	21,116
Casing, liner, tubing	Ft	27,089	34,169	26,592	31,430
Drilling days	Days	18	20	18	20
Natural proppant	MM lbs	4.93	7.04	5.11	5.02
Artificial proppant	MM lbs	2.21	n/a	2.19	1.67
Total Water	MM gal	5.89	5.71	6.18	6.85
Total Chemicals	Gal	441,793	256,958	294,130	342,575
Total Gel	Lbs	58,906	57,102	5,883	6,851

Table 6 – 1: Properties of typical wells in each sub-play used to calculate costs

Wells in the Low Energy area are drilled to just over 8,000 feet vertical depth and have lateral lengths averaging nearly 6,300 Ft. Lateral lengths are fairly long, with 19 stages using over 7.1 MM Lbs. of proppant and 5.9 MM gallons of fluid. Proppant mixes here are fairly high cost with a substantial component of ceramic sand. Completion fluids are sometimes gel-based, which is typical of oil plays, but many wells are still completed with slick water, particularly in the gas plays.

Wells in the Northeast Core area are drilled to nearly 10,900 feet vertical depth and have lateral lengths averaging 5,500 Ft. Lateral lengths are just over standard length using over 7.0 MM Lbs. of proppant and over 5.7 MM gallons of fluid with 22 frack stages. Proppant mixes here are low cost, using only natural sand with some of it being 100 mesh. Completion fluids are often gel based, but some slick water is also used.

Wells in the Western Curve area are drilled to nearly 8,500 feet vertical depth and have lateral lengths averaging over 5,800 Ft. Proppant and fluid amounts are 7.3 MM Lbs. and 6.2 MM gallons of fluid with 20 frack stages. Proppant mixes here are high cost, consisting of a large portion of ceramics along with natural sand. Completion fluids are almost always slick water-based.

Wells in the Gassy Edge area are drilled to nearly 9,300 feet vertical depth and have long lateral lengths averaging over 6,600 Ft. with 18 frack stages. Proppant and fluid amounts are 6.7 MM Lbs. and 7.2 MM gallons of fluid. Proppant mixes here are fairly high cost, typically using a large portion of ceramics along with natural sand. Completion fluids are often slick water-based with very few using gel fracks.

C. Operating Costs

Operating costs are highly variable, ranging from $9.00 to $24.50 per boe (see Figure 6-4) and are influenced by play type, location, well performance and operator efficiency. Overall, these are about $5 to $8 lower than in the Eagle Ford, due primarily to market proximity.

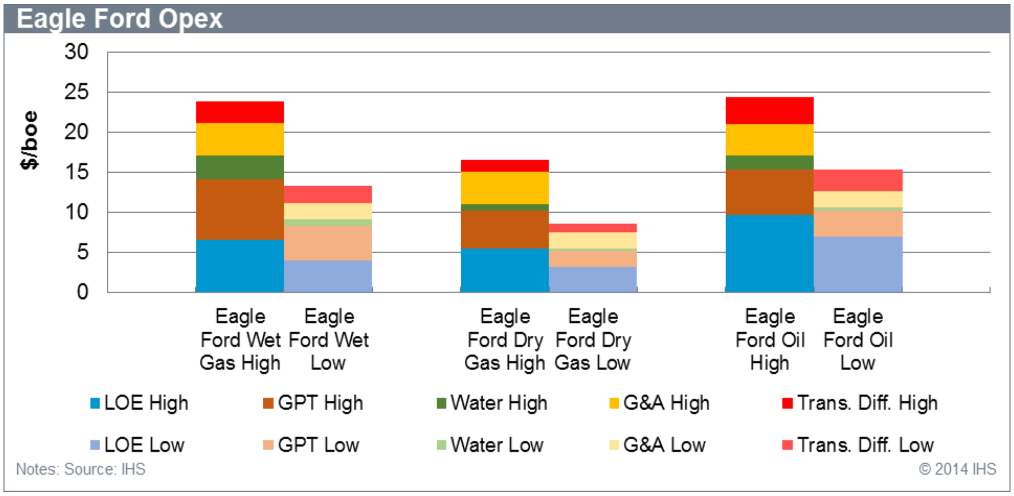


Figure 6-4: Operating expenses in each Eagle Ford Sub-play

Lease Operating Expense (LOE)

Most of the Eagle Ford Oil's leases operating expenses (LOE) are related to artificial lift and maintaining artificial lift. However the gas plays in the Eagle Ford do not share this cost and are dominated by water disposal and labor costs. Therefore, LOE costs in the gas plays will be only 60 to 70 percent of those in the oily portions of the Eagle Ford. Water disposal is a major cost in the Eagle Ford as water production rates are higher than other plays. The Other category contains common costs, such as pumping, compression, and other recurring types of costs. The other recurring types of costs are mostly determined by the cost of energy to run them and are generally negligible. However they make up a larger share of the total cost for the gas plays (see Figures 6-5a and 6-5b).

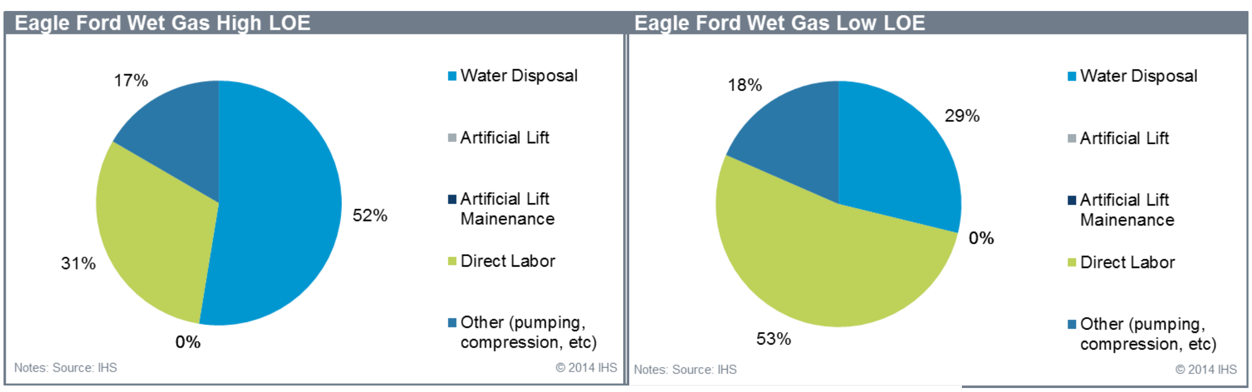
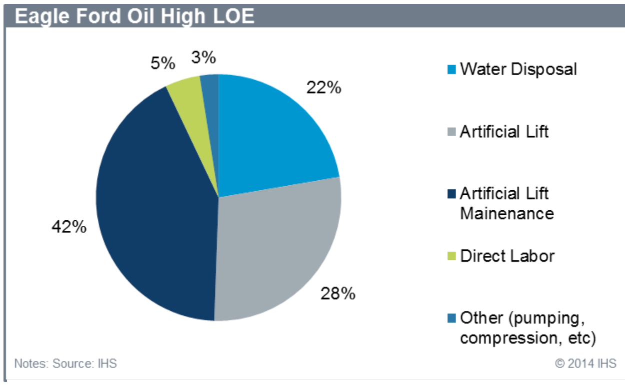


Figure 6-5a: Lease operating expense for Eagle Ford Gas wells



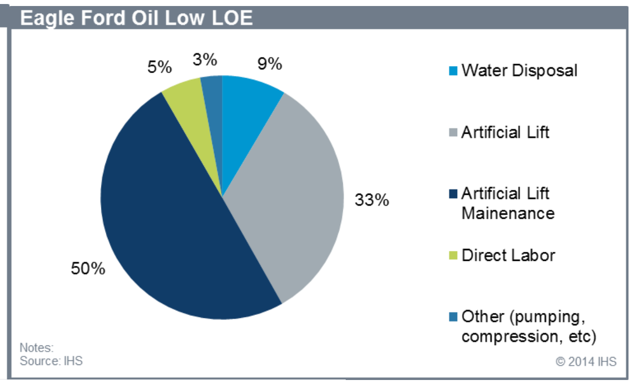


Figure 6-5b: Lease operating expense for Eagle Ford Oil wells

Gathering, Processing and Transport (GPT)

Oil has several market options with substantial pipeline infrastructure, but close access to the gulf coast. The breakout of the GPT costs is presented below in Table 6-2.

	Units	Eagle Ford Wet Gas High	Eagle Ford Wet Gas Low	Eagle Ford Dry Gas High	Eagle Ford Dry Gas Low	Eagle Ford Oil High	Eagle Ford Oil Low
Gas Gathering	$/mcf	0.60	0.35	0.80	0.35	0.60	0.35
Gas Processing	$/mcf	0.70	0.30	n/a	n/a	0.70	0.30
Short Transportation Oil	$/bbl	2.50	0.75	n/a	n/a	2.50	0.75
Long Transportation Gas	$/mcf	0.30	0.20	0.25	0.2	0.30	0.20
Long Transportation Oil	$/bbl	3.50	3.00	n/a	n/a	3.50	3.00
Long Transportation NGL	$/bbl	2.70	2.20	n/a	n/a	2.70	2.20
NGL Fractionation	$/bbl	2.94	2.52	n/a	n/a	2.94	2.52
Water Disposal	$/bbl w	3.50	1.00	3.50	1.00	3.50	1.00

Table 6-2: Breakout of GPT costs

Refineries make for low transportation differentials of around $2.00/boe, even when trucking oil and natural gas liquids. Short haul transportation for oil is the most variable and is determined by proximity to delivery points.

Eagle Ford gas infrastructure benefits somewhat from prior conventional development, as well as from close proximity to end markets and ongoing development of new infrastructure. No real issues related to gas marketing are evident. Some companies benefit from vertical integration and build their own gathering systems and gas processing plants. NGL fractionation fees are similar to other areas, but fees for long haul transport of NGL's are low due to close proximity to the Mont Belvieu market.

G&A Costs

General and administrative costs will decrease over time. However this cost is expected to increase slightly in 2015 for many companies as they have reduced their labor force and are paying severance compensation.

Cost changes in 2015

Table 6-3 below summarizes operating cost changes that we expect to see between 2014 and 2015 going forward.

	Change	2015
Gas Gathering	-3%	The operators that operate their own gathering systems will find that they are saving from lower energy costs, but saving for others will be marginal.
Gas Processing	-3%	The operators that operate their own processing plants will find that they are saving from lower energy costs, but saving for others will be marginal.
Short Transportation Oil	-3%	Little savings are expected as there were no issues in prior years. However as much production is hauled locally by truck, some savings on fuel costs will be seen. Pipeline costs may not drop much.
Long Transportation Gas	-3%	Lower energy costs will allow for slightly better rates in 2015.
Long Transportation Oil	-3%	Those who truck will see saving, but piped oil will not see any savings.
Long Transportation NGL	-3%	Better energy cost rates will help lower NGL transportation costs.
NGL Fractionation	-5%	Fractionation charges have been high but decrease as fuel costs are low.
Water Disposal	+1.80%	Many water disposal contracts have fixed rates and some of this will escalate based on PPI or another indexes. Only companies that dispose of their own water will see savings.
G&A	+5%	Severance package/payments due to layoffs are increasing G&A despite lower future operating cost. Savings will not be realized until 2016.
Artificial Lift	-10%	Oil field services rates are dropping due to lower activity and lower input costs rates such as energy.
Artificial Lift Maintenance	-10%	Oil field services rates are dropping due to lower activity and lower input costs rates. Maintenance will now be avoided in some cases where it was profitable at higher prices. Companies that pay a fixed maintenance may not see better rates in 2015 unless they are able to renegotiate.
Direct Labor	-3%	Saving here will be due to fewer operational employees.
Other (pumping, compression, etc.)	-10%	Energy costs savings.

Table 6-3: Changes in Eagle Ford operating costs 2014 to 2015

D. Leasing Costs

Lease acquisition costs will depend on if the operator has secured acreage before the play has been de-risked, as explained in Chapter 1. Figure 6-6 provides recent transaction costs per acre and the incremental cost to each well that is incurred. Some caution needs to be exercised while interpreting this chart as recent transactions are relatively minor. Furthermore many of the exchanges involve purchase of producing wells, which is not represented in this chart. We note that some operators, such as Devon and Marathon, have paid handsomely for prime acreage in the Northeast Core oil play, with per acre charges in the $32,000 to $72,000 range.

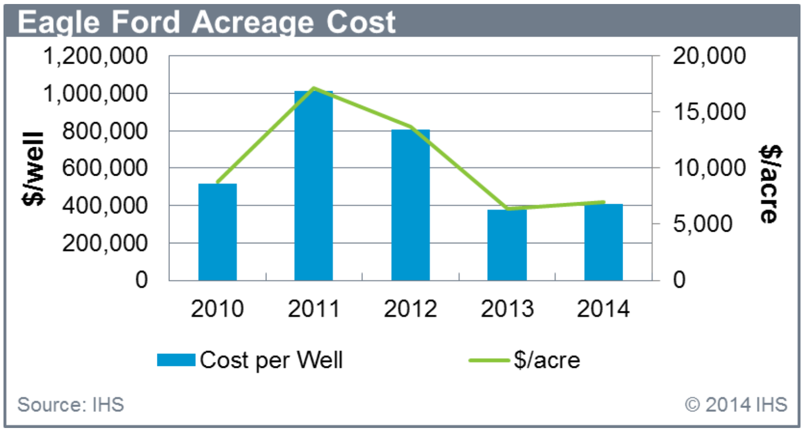


Figure 6-6: Eagle Ford acreage cost

We are assuming that each lateral is going to require 50-80 acres and that two stacked laterals can be drilled in some of the areas for a net requirement of 50-60 acres per well. Approximately 10-20% of the acres acquired will not be utilized. Ultimately we begin to see that paying $7,000/acre for 50 acres will add up to an additional $0.4 MM per well.

When we consider the more extreme cases of paying approximately $50,000/acre in the oil producing sweet spots, we can expect two to three stacked laterals on a 53-acre area, for approximately 20 -30 acres per well. This still adds an additional $1.0 MM to $1.5 MM to the cost of each well.

E. Key Cost Drivers and Ranges

Overall, 74% of a typical Eagle Ford well's total cost is comprised of five key cost drivers (see Figure 6-7):

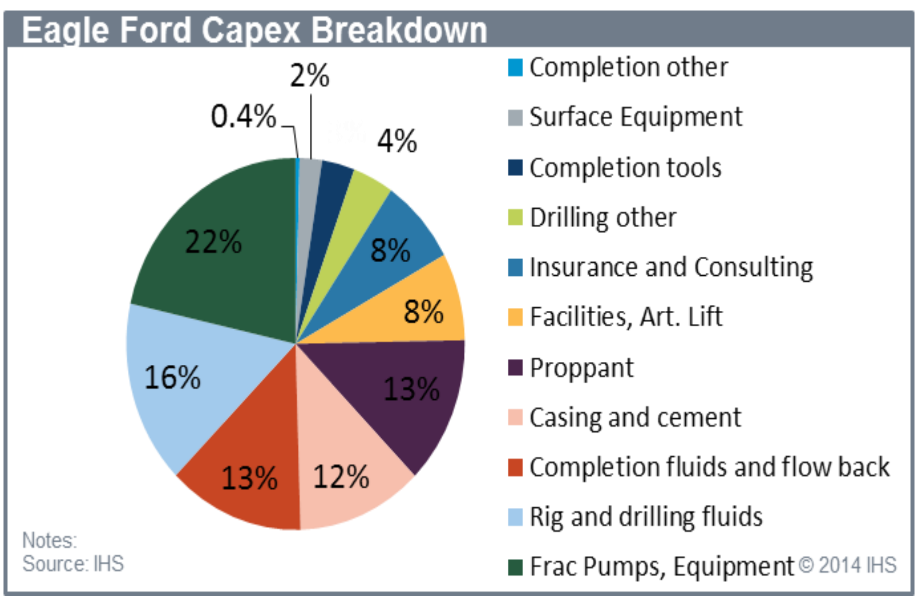


Figure 6-7: Eagle Ford capex breakdown

- Drilling:
  - Rig related costs (rig rates and drilling fluids) – 16% or $1.2 MM
  - Casing and cement – 12% or $0.9 MM
- Completion:
  - Hydraulic fracture pump units and equipment (horsepower) – 22% or $1.65 MM
  - Completion fluids and flow back disposal – 13% or $0.98 MM
  - Proppants – 13% or $0.98 MM

Range of Costs and Key Drivers

Various cost attributes are classified within each of the five main key drivers as shown in Figure 6-8. The total cost for each of the five key cost drivers is portrayed with P10/P90 ranges created for each of the contributing attributes pertaining to such range. These ranges are intended to portray variation and uncertainty.

Pumping costs, the most costly well component on average, are variable with each of the primary components contributing substantially to differences in total well cost. Due to variability found in the data, formation break pressures have a range of 5,933 psi to 10,664 psi, which has the largest effect on pumping costs. This creates a range of $ 1.1 MM, with a potential to increase costs over the average by $ 0.7 MM and decrease costs by $ 0.25 MM.

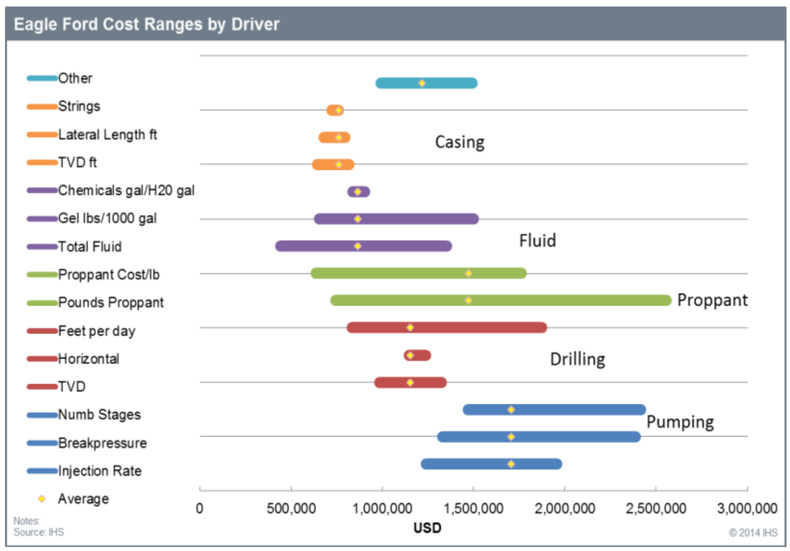


Figure 6-8: Range of cost for attributes underlying key drivers

Drilling penetration rate variability, from 387 Ft/d to 1,526 Ft/d, creates a drilling cost range of $ 1.0 MM, increasing costs by up to $ 0.7 MM for wells that drill slowly and lowering costs by up to $ 0.3 MM for drilling faster than the average. Drilling penetration rates are skewed toward faster drilling since is actually quite rare for a well to be drilled at the slower end of the distribution.

The proppant amount variability, from 3.4 MM Lbs. to 11.6 MM Lbs., creates a proppant cost distribution of $ 1.8 MM, with the potential to lower costs by just $ 0.7 MM and raise costs by $ 1.1 MM. Most wells will use amounts of proppant on the lower end of the spectrum. However, it is common for wells to use large amounts too. The fluid cost range for total fluid amount is $ 0.9 MM, potentially raising costs over the average by $ 0.5 MM and lowering costs by $ 0.4 MM (with fluid amounts ranging from 3.3 MM gallons to 10.1 MM gallons). The range of vertical depths in the play, from 7,758 Ft. to 11,109 Ft and creates a casing cost range of just $ 0.2 MM. Upward or downward cost movement in this category is mostly negligible, but is out of the control of the driller.

F. Evolution of Historical Costs

Historical Well Costs

Between 2008 and 2009: Steel costs rose significantly and created a spike in 2008 that was followed shortly by a drop due to oil and gas prices weakening in the later part of that year.

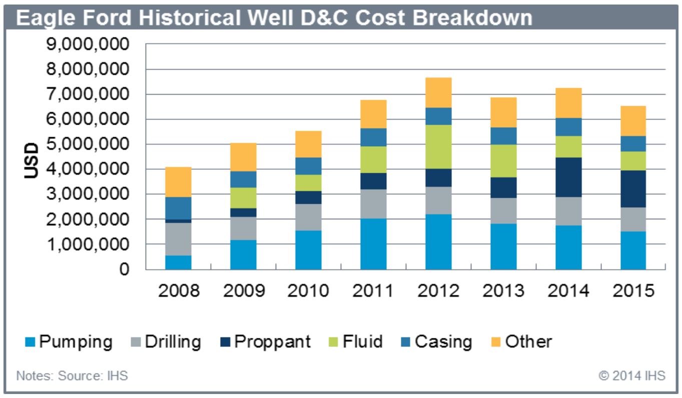


Figure 6-9: Historical nominal well cost by major cost driver

Nominal well costs have grown year-on-year, except for 2013 despite increasing frack intensity and well dimensions, when fluid source and disposal options improved along with completion service rates (See Figure 6-9). The rising costs in the Eagle Ford from 2008 to 2012 were a result of increasing costs rates for completion, particularly for completion fluids. Since 2012 well dimensions continued to increase, but cost rates improved for fluid and frack pumps. Proppant costs have continued to rise, especially while moving into 2014. This is not solely due to the growth of the amount of proppant used, but also the mix of proppants have increased in average price from $0.14/Lb. to $0.22/lb. as more completions relied on artificial proppant. Casing and drilling prices have been fairly constant in recent years with slight variations due mostly to cost rates and improvements to drilling efficiency.

Between 2006 and 2011, lateral lengths steadily increased until they reached the current length of just less than 6,000 feet (Figure 6-10). Proppant per well has grown steadily year over year, but feet per stage has remained constant, which suggests that fluid and proppant concentrations in each stage are increasing (Figure 6-11). Despite downward pressure on rates from 2013 to 2014, the additional proppant per well in year 2014 contributed to a slight increase in cost for the well.

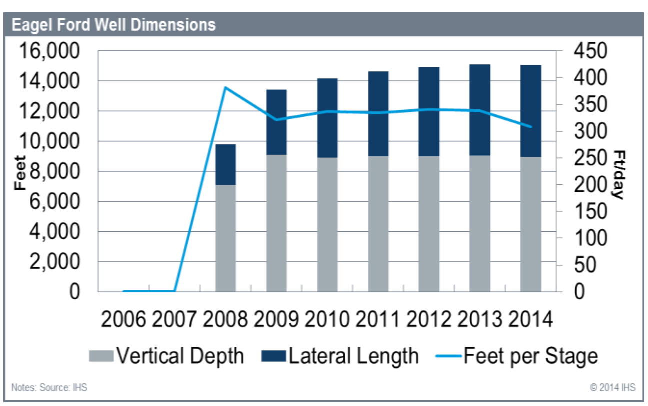


Figure 6-10: Lateral length and total depth

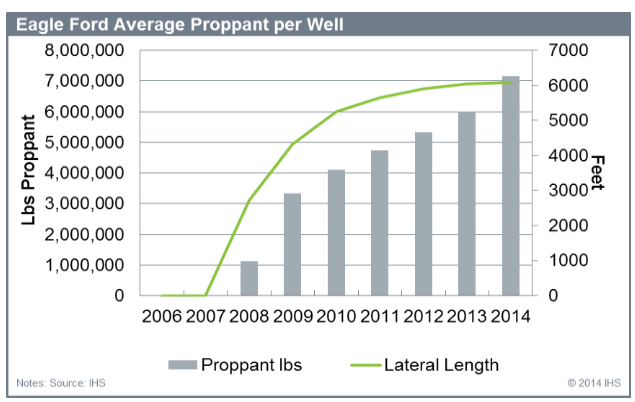


Figure 6-11: Proppant per well history

Changes in Well and Completion Design

The mix of frack fluids has evolved over the years, beginning with predominately water and slick water fracks. Then almost immediately in 2011 operators switched to X-link gels with a few still using slick water. The predominance of X-link gel appears to be a function of drilling more oil wells compared to gas which typically used slick water (see Figure 6-12). Well EURs have increased from 217 kBoe in 2010 to 515 kBoe in 2014. This suggests that X-link gel fracks and additional proppant had a positive impact on performance and that the additional capex was paying off. Overall play well cost per Boe has improved from 2010 at $25.54/Boe to $13.84 in 2014 (see Table 6-4). Most of the improvements came during a time when cost rates were going down and performance was increasing dramatically.

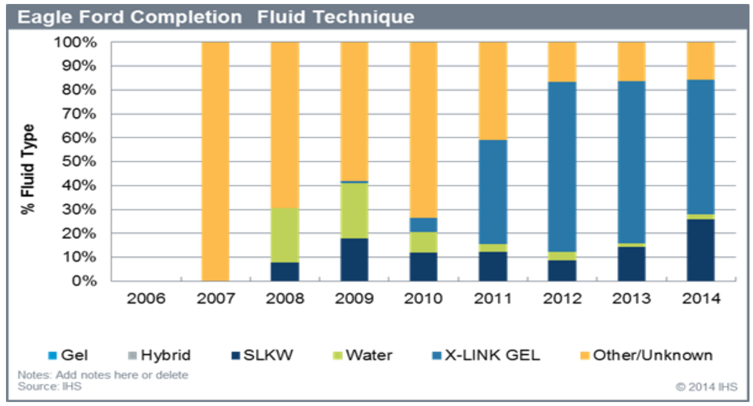


Figure 6-12: Change in frack fluid use over time

Year	$/Boe	EUR -Boe
2010	25.54	216,958
2011	29.79	227,252
2012	28.08	272,400
2013	21.76	315,541
2014	13.84	514,700

Table 6-4: Vintage drilling and completion unit cost

With lateral lengths holding steady at 6,000 feet, performance has increased per lateral foot, particularly from 2013 to 2014 (Figure 6-13). This overall increase in average EUR from 227 kboe in 2011 to 315 kboe in 2013 is likely due to slightly longer laterals and increases in proppant (Figure 6-14). At the same time efficiencies in drilling and completing have also reduced costs since 2011 (Table 6-4). In 2014, EURs rose dramatically and we see the trend continuing as operators are more selective in both their oil and gas drilling locations due to lower commodity prices.

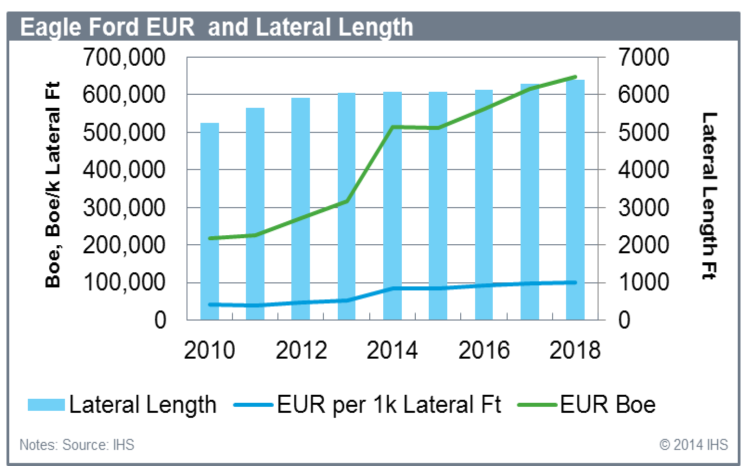


Figure 6-13: EUR per lateral foot

Some of the performance increase is due to incremental increases in proppant usage, as boe per proppant also increased in 2014. Nevertheless, despite the use of this technology the performance increases are much more related to site selection and overall prospect quality. The sweet spots have been delineated and operators will drill the best areas as they attempt to reduce their costs per boe.

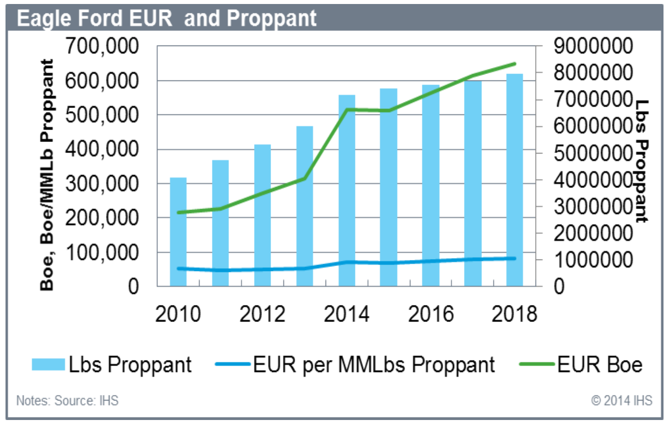


Figure 6-14: EUR per Lb. proppant

G. Future Cost Trend

Cost Indices

Eagle Ford development activity is dropping sharply with little chance of recovery soon. Active rigs in the play are currently about 100 and expected to drop into the high-70s by the end of the year. Because the Eagle Ford is near to Gulf Coast oil refineries, its production is able to fetch the WTI price easily. Services and equipment, such as rigs and pumping units, may be able to move into the Permian Basin, but there will be a surplus there as well. However, this may relieve some pressure on cost reduction. Overall, cost rates will decrease from 2014 levels by 22% during 2015, and will drop another 3% in 2016 (Figure 6-15).

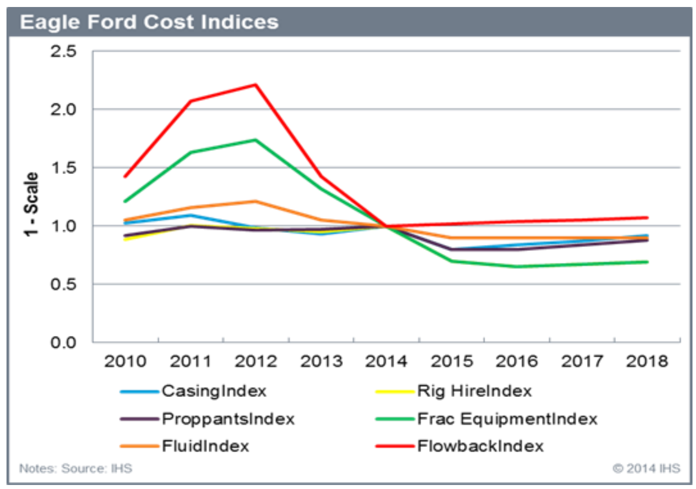


Figure 6-15: Indices for major cost drivers

Pumping and drilling costs rates are dropping and are expected to be 25 – 30% lower by the end of 2015, with another 5% decrease in 2016. Rates will begin to recover in late 2016, but will stay low through 2018. Proppant costs will drop by 20-25% in 2015, largely due to decreases of 36-40% at the mine gates. The impact on fluid will be less. Due to a forecasted drop of 20% during 2015 in the price of steel, tubulars, and other fabricated materials will also cost less.

Changes in Well Design

Despite the challenging environment, operators will continue to lower unit costs ($/Boe). The following trends are expected to continue:

- Lateral length - Average lateral length has slowly crept upward during the past four years and is projected to grow to 6,400 feet (Figure 6-16). Vertical depths should also remain fairly constant.
- Stages - The average number of stages is projected to remain the same in 2015, but should reach 22 by 2018 (Figure 6-17). Furthermore, although lateral lengths are projected to change, we can expect that stage spacing reductions will outpace lateral lengths.
- Drilling efficiencies - These have already been optimized and any changes here will be small with average drillers achieving 1075 Ft/d by 2018, up from 994 Ft/d in 2014 (Figure 6-16).
- Proppant - Proppant amounts will increase from 1,178 Lbs./Ft in 2014 to 1,215 Lbs./Ft by the end of this year and will flatten out until 2018 (Figure 6-18). This is consistent with other plays. Proppant mix is expected to be focused more heavily on natural proppants in order to afford more total proppant. Average fluid use is expected to increase proportionately, but at a slower rate than proppant. Gel and chemicals used are expected to remain the same going forward as completion fluids types have been fixed for some time.
- More wells being drilled on single drill pads – As more wells occupy single drill pads we can expect potential cost savings from shared facilities and other related items, such as roads, mud tanks, and water disposal systems. Of the total well cost, $1.35 MM is based on sharing costs amongst four other wells. Table 6-5 illustrates how future drill pad configurations could save money. For example, historically there was one zone, namely the lower Eagle Ford, which was considered a potential target. Operators are currently completing wells in

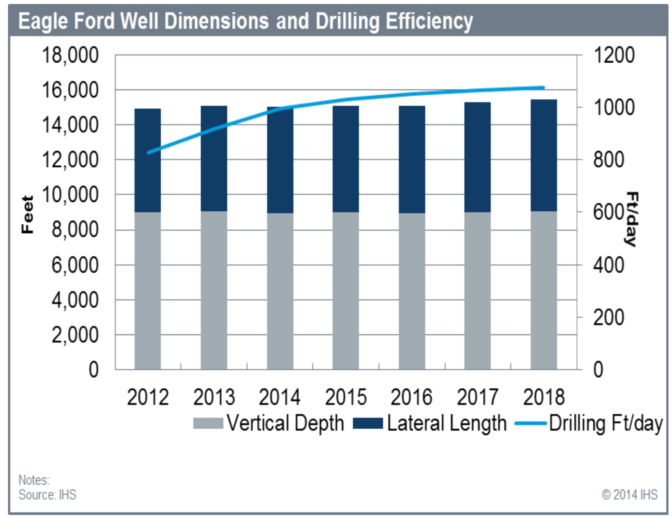


Figure 6-16: Historical and forecasted total depth

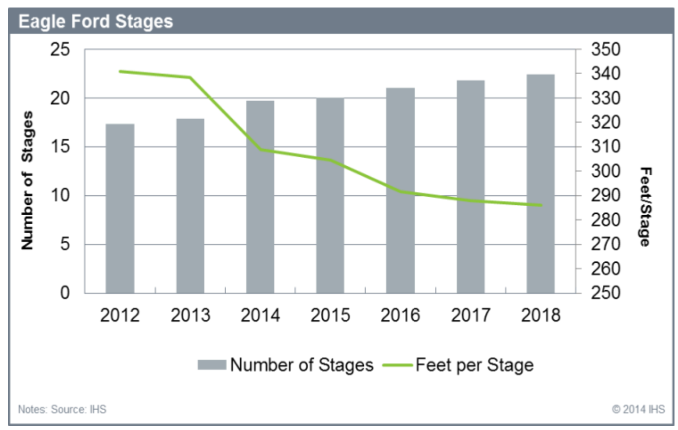


Figure 6-17: Historical and forecasted frack stages

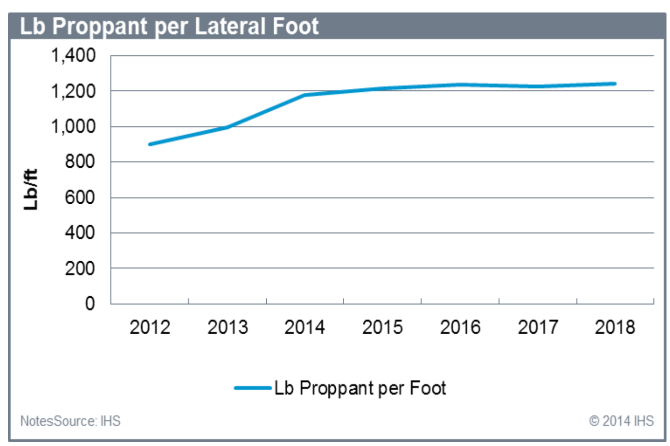


Figure 6-18: Historical and forecasted proppant

at least one additional zone in the upper Eagle Ford / Austin Chalk, bringing in another potential zone. Pilot programs have also been completed for tighter spaced wells. Thus the potential exists for up to 16 wells to be drilled from a single pad, perhaps even more. This could save potentially $900,000. These savings are not likely to apply throughout the entire play, but are becoming a common practice in the NE Core area. Other similar areas may emerge as well, illustrating additional potential savings.

	Stacked Horizons	Distance between wells	Wells per pad	Cost of items related to pad - 2014	
Modeled	**1**	**1320 feet**	**8**	**$ 1,350,000**	**Modeled Cost**
Traditional View	**1**	**660 feet**	**8**	**$ 1,350,000**	**Development Cost**
Potential upside	**2**	**450 feet**	**24**	**$ 450,000**	**Potential New Cost**
Difference	**1**	**1.5**	**3**	**$ 900,000**	**Potential Savings**

Table 6-5: Potential savings from additional wells being drilled from a single pad

Future Well Costs

Future changes in overall well and completion costs are quantified in forecasted indices, and are combined with projections in future well design parameters. Figure 6-19 shows both the effect of well design and indexing on recent historical costs beginning in 2012 and future well costs through 2018:

- Avg. Capex, Actual – This captures the average nominal total well cost for each year as it actually is expected to occur. Note the acceleration of the rate declines from 2014 to 2015 despite more complex well designs of recent years which are expected to continue.
- Capex for 2012 Cost Rates, Well parameters of the year – This captures the application of 2012 cost rates to the average well design of a given future year. Note that had we held 2012 rates steady through the forecast period, the actual cost of a well drilled in 2018 would have cost over MM$ 3.2 more due to the longer laterals and increased use of proppant.

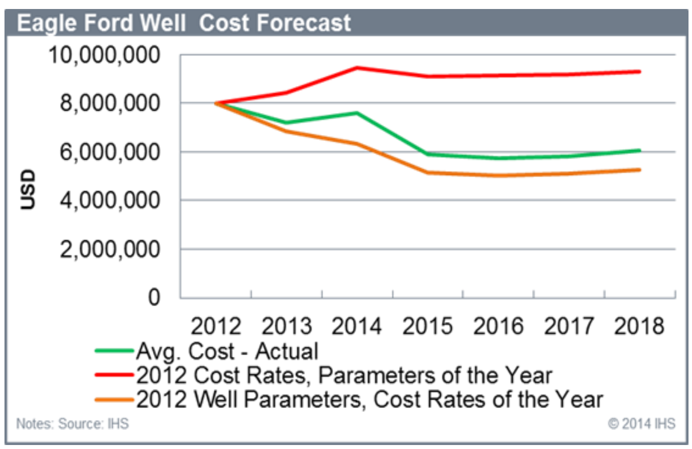


Figure 6-19: Comparison of actual future costs with forecasted indices

- Capex for 2012 Well Parameters, Cost Rates of the Year – This represents the application of well parameters of 2012 with cost rates for the given year. Note that the more simple well design of 2012 would have cost about $MM 0.7 less by 2018.

This illustration helps us see the effect of cost indices and well design changes using 2012 as a baseline. The gap between 2012 Well Parameters (orange) and 2012 average cost - actual (green) illustrates the impact of more complex well design on cost. Whereas the gap between average cost - actual (green) and 2012 Cost Rates (red) shows the much higher impact of the declining cost indices.

In conclusion, costs are forecasted to drop in 2015 and are expected to start moving slowly upward after 2016 (Figure 6-20).

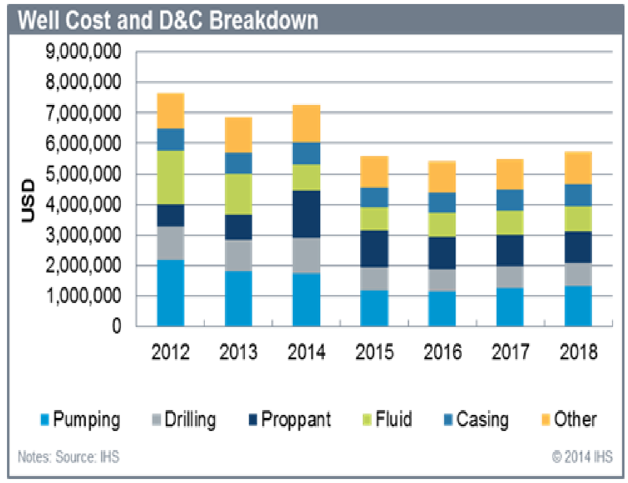


Figure 6-20: Drilling and completion nominal cost forecast

H. Cost Correlations of Major Cost Drivers

Some relationships between well design and cost are stronger than others. As already mentioned each cost component was calculated by measuring the units or amount of a particular well design attribute and multiplying it by the rate. An analysis of the well design factors contributing to the five primary cost drivers was conducted for the period of 2010 through 2018. During that time both the rates and character for well design attributes changed.

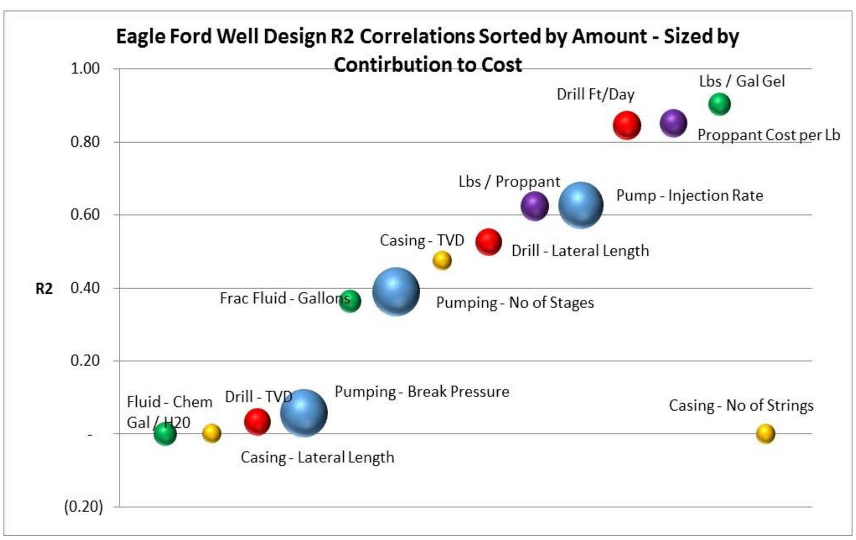


Figure 6-21: Drilling and completion nominal cost forecast

When comparing the well design parameter with the cost for that well design parameter over the specified time period, an R2 value was generated showing the correlation or relative influence as shown in Figure 6-21. This figure also suggests that for each cost category, there is one well parameter that is most influential. Fluid costs are guided the most by variance in gel quantities, which is the most influential of all well design factors. Drilling costs correlate highly with drilling efficiency, proppant costs are influenced the most by the cost per lb of proppant and pumping costs are influenced the most by injection rate. Figure 6-21 also illustrates the relative importance of each well design parameter as it relates to the total cost of the well.

Cost per Unit

Depth of well and well bottom hole pressure influence drilling costs. As noted in Figure 6-22, these have been declining due primarily to a decrease in both rig rates since 2012. Due to high rig counts in the Eagle Ford and demand for rigs, the cost rate increased slightly in 2014, increasing cost per foot and cost per psi of pressure. Falling rig counts in 2015 have accelerated these cost decreases. We expect this to level out in the years ahead as rates stabilize and drilling efficiency gains begin to level out.

This same decrease in costs for completion is also evident, although costs per unit of proppant will level out after 2015 (Figure 6-23). While more proppant per well is likely to increase, the mix of natural and more expensive artificial proppant is not likely to change. As operators use more frack stages per well, the economies of scale will also continue to reduce costs through 2015, but afterward this will level out as more proppant is used.

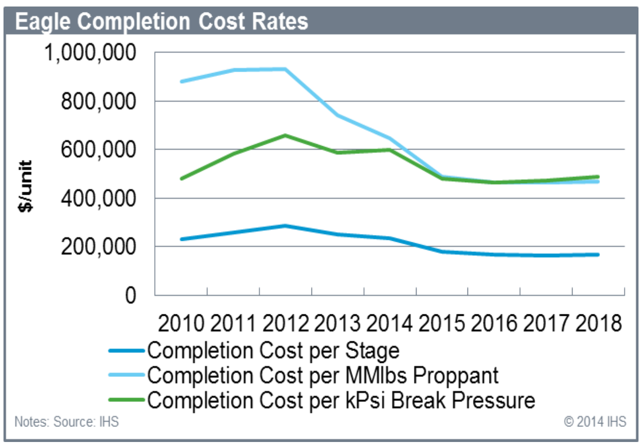


Figure 6-22: Completion cost rates

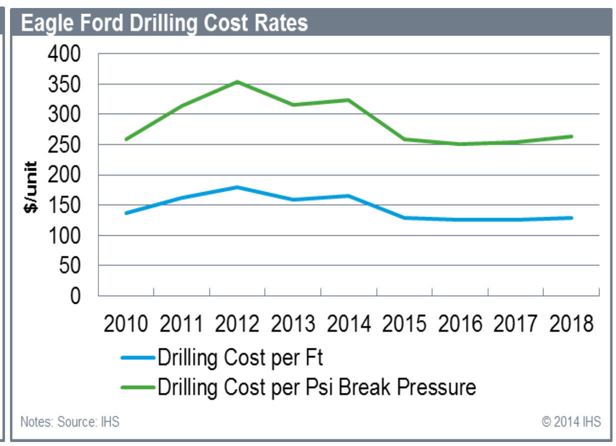


Figure 6-22: Completion cost rates

I. Key Take-Aways

Performance increases: Over time the Eagle Ford has achieved greater efficiencies in well design and implementation due to the drop of costs for the same activities and well design features. Proppant use is increasing. However unlike the Bakken, this increase in proppant usage correlates with increased production performance. Nevertheless average proppant amounts are nearly double that of the Bakken. The large increase in 2014 is attributable to both technological improvement and better site selection. With the collapse of oil prices in late 2014, operators have to continue to increasingly focus on better site selection. This factor may ultimately supersede any increases in performance due to technological improvement. As this play matures, declining prospect quality and in-fill drilling may also contribute to decreased production performance. Ultimately unit costs are likely to level out and rise within the next 3 to 4 years.

Economic performance was superb in 2014 as prices remained high and performance improved, but has now become diminished by the drop in oil prices. While substantial cost savings will be achieved for the next several years, most of this is due to decreased rates that operators have secured from service providers and not necessarily due to gains in efficiency. Nevertheless, we will continue to see incremental efficiency gains as operators continue to reduce drill cycle times and drill more wells from single pads, with as many as 12-16 wells per pad in some areas.

Influential well design parameters: When modeling well costs in the Eagle Ford, the accuracy of some well attributes may be more important than others when estimating costs. The key attributes, whose change over time has most greatly influenced costs and caused the most variance in costs, are gel quantities, injection rates, cost per pound of proppant and drilling efficiency.

Decreasing costs: Rates for various materials and services peaked in 2012 when demand for high horsepower rigs (1000-1500) were in short supply and fracking crews were scarce. However, some rate increases are evident in 2014 due to high rig counts. Ultimately the drastic reduction of over 50% in the Eagle Ford rig count contributed to a large average drop in costs of 25% . This downward trend is expected to continue for another year. However, as prices recover and activity picks up, cost increases are likely to occur at a faster rate than efficiency gains.

Operating Costs: There is substantial variability in operating expense, with water disposal, and artificial lift expenditures being the highest cost items. Proximity to markets and abundant infrastructure contribute to lower transport fees. Furthermore, differentials to WTI and HH are very low (less than 5%), making this an attractive location. Due to the nature of the services provided, operating cost reductions will be much less than capital reductions going into 2016. We can expect most future decreases to be related to reductions in artificial lift for oil wells and compression for both oil and gas wells.

VII. Marcellus Play Level Results

A. Introduction and sub-play description

The Marcellus gas play, located in the mountains of Pennsylvania and West Virginia, includes areas with wet and dry gas. Five sub-plays were identified based on high performance variations and depths in the formation. This includes: Liquids Rich, Southwest Core, Periphery, Super Core, and Northeast Cost (see Figure 7-1). Drilling within all sub-plays has leveled off in the past three years (Figure 7-2). Production began in 2007 and has ramped up quickly to nearly 16 Bcf/day, making it by far the largest gas play in North America. Consequently, the Marcellus serves an over supplied gas market which precipitated drops in gas price and increased pressure to reduce the number of wells being drilled in the play.

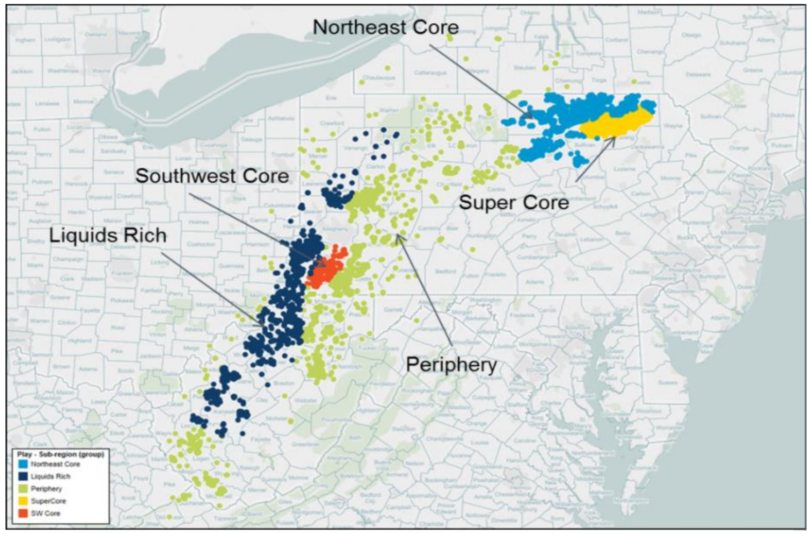


Figure 7-1: Location of the Marcellus and its sub-plays

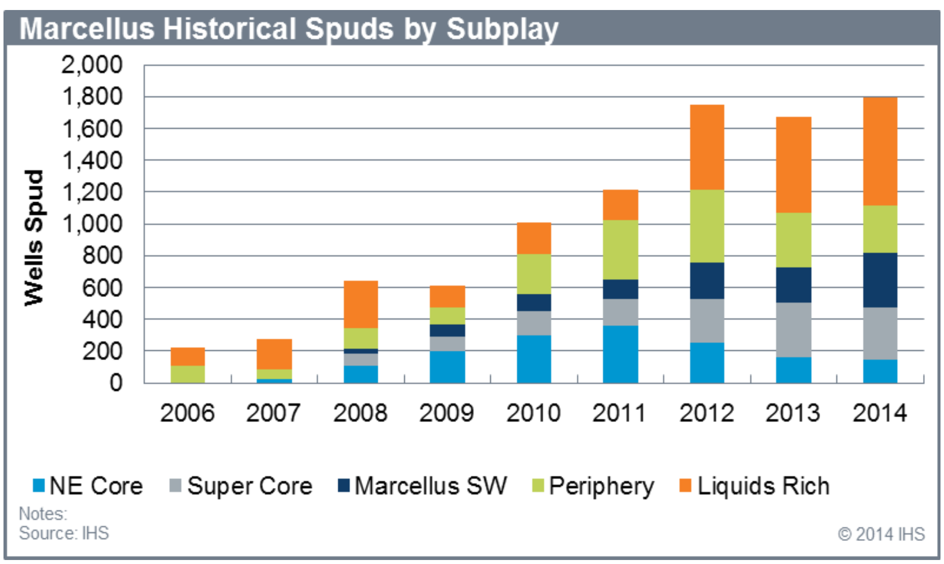


Figure 7-2: Marcellus well spuds

Much of the value derived from the Marcellus is from NGL sales, mainly from the Liquids Rich gas area where current drilling is most active. NGLs are processed locally and are either shipped to the Gulf Coast or are marketed locally. Lack of processing and transportation infrastructure is being overcome by new and projected capacity. Production is expected to continue to grow there significantly and thus more infrastructure will be needed. The Marcellus benefits from being fairly close to market. However logistically infrastructure is still lacking and transport fees are high. Also, water disposal is extremely expensive, averaging over $5/bbl in some areas.

B. Basic Well Design and Cost (2014)

Total Marcellus Cost

Total well cost ranges from $4.9 MM to $7.9 MM, as shown in Figure 7-3. Variation in lateral length and completion design amongst the plays is also reflected in highly diversified cost for drilling and completion. The SW Core and Super Core are the deepest plays. Proppant use in the Northeast Core, a highly prolific area, is about 50% that of the other plays. Hence the completion costs are much lower.

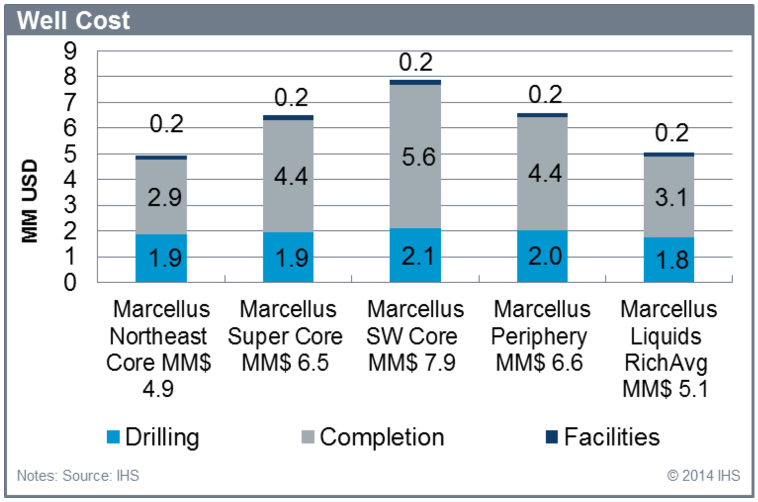


Figure 7-3: Total Marcellus cost by sub-play

Comparison with Published Data

The Marcellus has a wide range of cost. The average Marcellus cost of $6.4 MM compares with published costs reported by operators in 2014 as follows:

- Operators reported well cost ranging from $ 4.8 MM to $ 7.6 MM, with Range reporting the lowest and Consol reporting the highest.
- Rex, EQT and Talisman reported costs from $ 5.6 MM to $ 5.7 MM.
- Chesapeake reported an average cost of $ 7.3 MM.
- Marcellus NE Core – Corrizo reports 22 stage wells at a cost of $ 6.3 MM.
- Marcellus Super Core - Cabot reported costs of around $ 5.8 MM to $ 6.4 MM, depending on wells per pad, and Chesapeake reported costs of around $ 7 MM.
- Marcellus SW Core - Rice reported costs at MM$8.5, with the use of 13 MM Lbs. of proppant.
- Marcellus Periphery - Consol reported well costs of $7.6 MM, with the use of SSL technique and many more stages than the average well.
- Marcellus Liquids Rich - Range wells cost $ 4.8 MM, Rex at $ 5.6 MM and EQT at $ 5.7 MM.

General Well Design Parameters

Table 7-1 below summarizes well design parameters for each sub-play. Lateral lengths are longer in the southwestern areas of the plays than the Super Core and NE Core plays located in north eastern Pennsylvania. No artificial lift is required.

Well Parameter	Unit	NE Core	Super Core	SW Core	Periphery	Liquids Rich
TVD	Ft	7,923	7,520	7,755	7,750	6,425
Horizontal	Ft	5,379	5,044	6,550	6,570	6,258
Formation pressure	Psi	4,595	4,362	4,498	4,495	3,727
Frack stages	#	14	19	29	21	15
Frack break pressure	Psi	8,823	8,723	8,996	5,619	5,925
Pumping rate	Bpm	86	85	87	89	79
Horse Power	Hp	21,387	20,899	22,060	14,095	13,194
Casing, liner, tubing	Ft	23,851	22,715	26,680	25,558	22,243
Drilling days	Days	17	16	18	18	16
Natural proppant	MM Lbs.	4.45	10.75	8	11.6	9.93
Artificial proppant	MM Lbs.	n/a	n/a	n/a	n/a	n/a
Total Water	MM gal	3.7	8.35	8.45	10.9	8.16
Total Chemicals	Gal	240,678	459,269	422,446	490,681	408,037
Total Gel	Lbs.	n/a	n/a	n/a	n/a	n/a

Table 7 – 1: Properties of typical wells in each sub-play used to calculate costs

Wells in the NE Core are drilled to below 8,000 vertical depth and have lateral lengths averaging approximately 5,400 feet. The lateral lengths are sufficient for completion with 14 stages, using over 4.45 MM Lbs. of proppant and nearly 3.7 MM gallons of fluid. Note that frack stages for the NE Core play are less than the other Marcellus plays and proppant usage is significant in all the above listed Marcellus plays. Proppant mixes are natural and do not contain artificial proppant. Completion fluids are nearly always water based.

Wells in the Super Core are drilled to 7,520 feet vertical depth and have lateral lengths of over 5,000 feet. These lateral lengths support 19 stages using over 10.75 MM Lbs. of proppant and nearly 8.35 MM gallons of fluid. Similar to NE Core, proppant mixes are natural and do not contain artificial proppant and completion fluids are nearly always water based.

Wells in the SW Core are drilled to 7,755 feet vertical depth and have lateral lengths of 6,550 feet. The lateral lengths are sufficient for completion with 29 stages and 8.45 MM gallons of fluid. Although the SW Core uses the highest amount of the above listed Marcellus plays, just 8 MM Lbs. of proppant is used. Similar to other Marcellus plays, proppant mixes are natural and do not contain artificial proppant and completion fluids are nearly always water-based.

Wells in the Periphery are drilled to 7,750 feet vertical depth and have lateral lengths of 6,570 feet. These longer lateral lengths are sufficient for 21 stages, using 11.6 MM Lbs. of proppant and 10.9 MM gal of water. Similar to other Marcellus plays, proppant mixes are natural and do not contain artificial proppant and completion fluids are nearly always water based.

Wells in the Liquids Rich are drilled to 6,425 feet vertical depth, the shallowest of the plays, and have lateral lengths of 6,258 feet. The lateral lengths are sufficient for 15 stages, using 9.93 MM Lbs. of proppant and 8.16 MM gal of fluid. Similar to other Marcellus plays, proppant mixes are natural and do not contain artificial proppant and completion fluids are nearly always water based.

C. Operating Costs

Operating costs are highly variable in the Marcellus ranging from $12.36 to $29.60 per boe (Figure 7-4) and are influenced by play type, location, well performance and operator efficiency. Overall, this play offers both very high and very low operating costs rates.

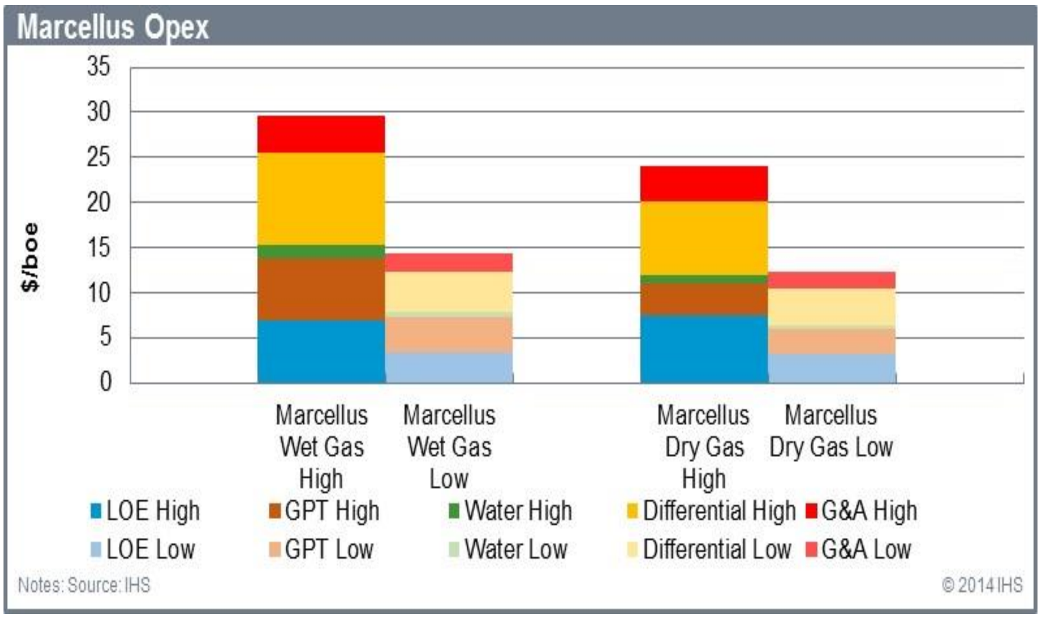


Figure 7-4: Total Marcellus cost by sub-play

Lease Operating Expense (LOE)

Most of the Marcellus' lease operating expenses (LOE) is related to labor, water disposal, and costs associated with pumps and compressors. Since the Marcellus does not produce oil, LOE costs are much lower than in other plays. Water disposal cost rates are high in the Marcellus as most water must be pushed to Ohio for disposal. However water production is fairly low, making its significance lower than in other plays. The common costs such as pumping, compression, and other recurring types of costs, which are mostly determined by the cost of energy to run them, are generally negligible. However, they make up a larger share of the total cost for the gas plays (see Figures 7-5a and 7-5b).

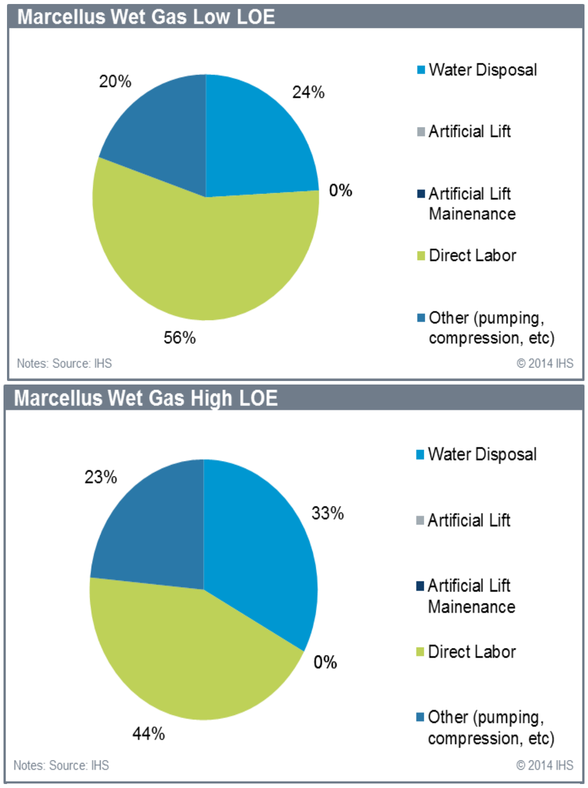


Figure 7-5a: Total Marcellus cost by sub-play

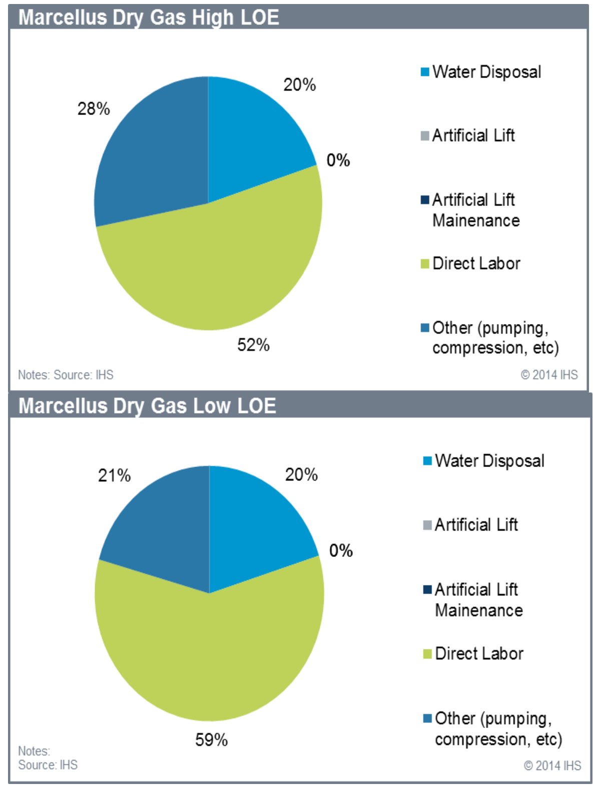


Figure 7-5b: Total Marcellus cost by sub-play

Gathering, Processing and Transport (GPT)

Condensate production is handled through battery storage and is picked up by marketers in the field. Marketers reduce payment by a large differential as production is trucked or railed to Edmonton, Alberta for use in oil sands processing.

	Units	Marcellus Wet Gas High	Marcellus Wet Gas Low	Marcellus Dry Gas High	Marcellus Dry Gas Low
Gas Gathering	$/mcf	0.60	0.50	0.60	0.50
Gas Processing	$/mcf	0.60	0.35	n/a	n/a
Short Transportation Oil	$/bbl	n/a	n/a	n/a	n/a
Long Transportation Gas	$/mcf	1.40	0.70	1.40	0.70
Long Transportation Oil	$/bbl	11.00	8.00	11.00	8.00

Table 7-2: Breakout of GPT costs

Marcellus gas infrastructure is quite substantial, but there is a supply glut in nearby hubs. Reaching the Gulf Coast markets is more complicated. However there is sufficient capacity to move production south to fetch better prices than the local differential affords. Gas marketing is based on a series of complicated arrangements that potentially allocate production to many different nodes and destinations. Dry gas in the Marcellus rarely requires processing as its raw production can meet pipeline specifications. Few companies benefit from vertical integration. Furthermore, gathering and processing is almost a monopoly as most of the capacity is owned by one company. NGL fractionation fees are similar to other areas. However, fees for long haul transport of NGL's are very high since production must be trucked to Mont Belvieu. Ethane production in this play is injected into the gas line maxing out the thermal content limit for pipelines. Transportation differentials are so high that recovered ethane often becomes a net cost. There are alternatives for Ethane in this play as Edmonton can receive production through a specialized Ethane pipeline.

G&A Costs

General and administrative costs will decrease over time. In 2015 this cost is expected to increase slightly for many companies as they have reduced their labor force and are paying severance compensation.

Cost changes in 2015

Table 7-3 below summarizes operating cost changes that we expect to see between 2014 and 2015 going forward.

	Change	2015
Gas Gathering	-2%	Most of the saving will be related to energy costs, but contract rates are sticky.
Gas Processing	-2%	Most of the savings will be related to energy costs, but contract rates are sticky.
Short Transportation Oil	n/a	Not applicable.
Long Transportation Gas	2%	Long haul transportation may go up despite benefitting from energy cost savings and more companies sending production through the same pipelines to the Gulf Coast.
Long Transportation Oil	-3%	There will be some saving for fuel costs.
Long Transportation NGL	-3%	There will be some saving for fuel costs.
NGL Fractionation	-2%	Many companies are locked into rates by contract, but new rates may benefit from the current state of shale development.
Water Disposal	+1.80%	Many water disposal contracts have fixed rates and some of this will escalate based on PPI or other indexes. Only companies that dispose of their own water will see savings.
G&A	+5%	Severance package/payments due to layoffs are increasing G&A despite lower future operating cost. Savings will not be realized until 2016.
Artificial Lift	n/a	Not applicable
Artificial Lift Maintenance	-10%	Not applicable

Direct Labor	-3%	Saving here will be due to fewer operational employees.
Other (pumping, compression, etc.)	-10%	Energy cost and maintenance savings.

Table 7-3: Changes in Marcellus operating costs 2014 to 2015

D. Leasing Costs

Lease acquisition costs will depend on whether or not the operator has secured acreage before the play has been de-risked, as explained in Chapter 1. Figure 7-6 provides recent transaction costs per acre and the incremental cost to each well that is incurred. Some caution needs to be exercised while interpreting this chart as recent transactions are relatively minor and many of the exchanges involve purchase of producing wells, which is not represented in this chart. We note that some operators, such as Warren Resources, have paid handsomely for prime developed acreage with high production at rates over $66,000 per acre.

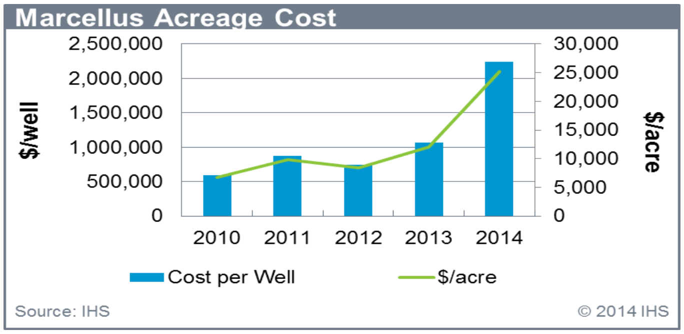


Figure 7-6: Marcellus acreage cost per well

We are assuming that each lateral is going to require 80 acres well spacing. Approximately 10-20% of the acres acquired will not be utilized. Ultimately we begin to see that paying $15,000/acre for 80 acres will add up to an additional $1.3 MM per well.

When we consider the more extreme cases of paying approximately $20,000/acre in a sweet spot with access to additional producing zones, we can expect three stacked laterals on a 160-acre area for approximately 50 -60 acres per well. This adds an additional $1.1MM to $1.3 MM to the cost of each well.

E. Key Cost Drivers and Ranges

Overall, 75% of a typical Marcellus total cost is comprised of five key cost drivers (see Figure 7-7):

- Drilling:
  - Rig related costs (rig rates and drilling fluids) – 18% or $1.15 MM
  - Casing and cement – 17% or $1.09 MM
- Completion:
  - Hydraulic fracture pump units and equipment (horsepower) – 28% or $1.83 MM

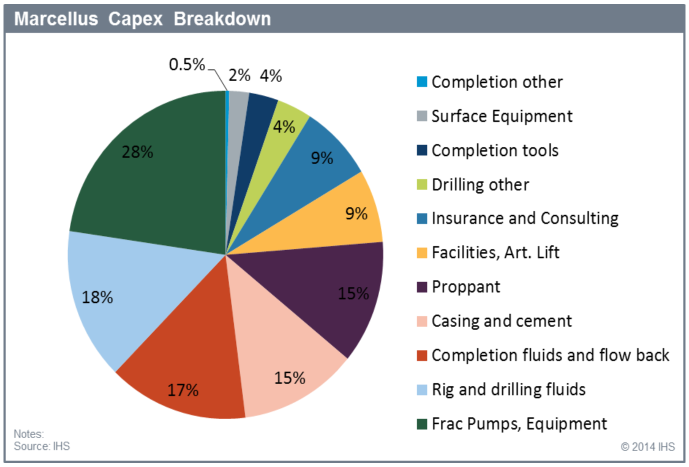


Figure 7-7: Marcellus capex breakdown

- Completion fluids and flow back disposal – 15% or $0.96 MM
- Proppants – 15% or $0.96 MM

Range of Costs and Key Drivers

Various cost attributes are classified within each of the five main key drivers as shown in Figure 7-7. The total cost for each of the five cost drivers is portrayed with P10/P90 ranges created for each of the contributing attributes pertaining to such range. These ranges are intended to portray variation and uncertainty

Pumping costs, the most costly well component on average, is quite variable, with each of the primary components of pumping cost contributing significantly to differences in total well cost. Due to variability found in the data, stage numbers have a range of 13 to 40. This has the largest impact on pumping costs, creating a range of $1.6 MM with potential increase of costs over the average by $ 0.9 MM and potential decrease of costs of $ 0.6 MM.

Drilling penetration rate variability, from 352 Ft/d to 1,193 Ft/d, creates a drilling cost range of $ 0.9 MM. This encompasses a potential increase of costs by up to $ 0.8 MM for wells that drill slowly and potential decrease of costs of up to $ 0.2 MM for drilling faster than the average. Drilling penetration rates are skewed toward faster drilling as it is actually quite rare for a well to be drilled at the slower end of the distribution. However, it does happen occasionally.

The proppant amount variability, from MM Lbs. 3.5 to MM Lbs. 12.0, creates a proppant cost distribution of $ 1.0 MM. This has the potential to lower costs by $ 0.5 MM and raise the costs by $ 0.5 MM. The fluid cost range for total fluid amount is $ 0.8 MM, raising costs over the average by $ 0.3 MM and lowering costs by $ 0.4 MM (with fluid amounts ranging from 1.6 MM gallons to 13.6 MM gallons).

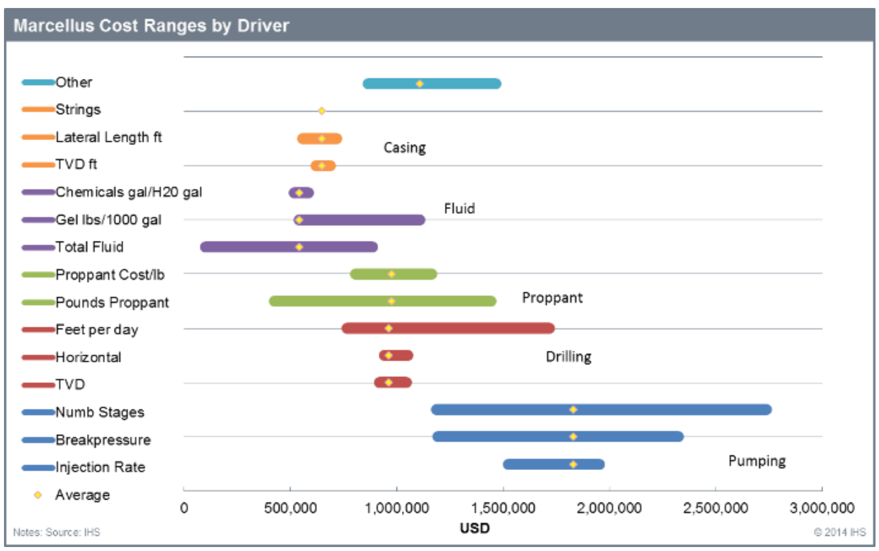


Figure 7-8: Range of cost for attributes underlying key drivers

Variance in lateral lengths also contributes to the range of fluid, proppant and the number of stages. The range of lateral lengths in the play is large, from 3,574 Ft to 7,789 Ft, but creates a casing cost range of just MM$ 0.2. Upward or downward cost movement in this category is mostly negligible, but is well within the control of the driller and higher costs in this component imply better formation access.

F. Evolution of Historical Costs

Historical Well Costs

The first wells were drilled in 2006 and were completed in a much simpler model, with very little costs being applied to completion drivers.

Between 2010 and 2012, nominal well costs steadily increased from under $5 MM to $7.4 MM. Well costs began to slightly decrease, remaining around $7.2 MM in 2013 and decreasing to $6.4 MM in 2014. Although proppant costs have increased steadily from 2012 to 2014, significant reductions are apparent in fluid and pumping costs during that same period since the cost indices for these items decreased despite increases in fluid volumes (see Figure 7-9).

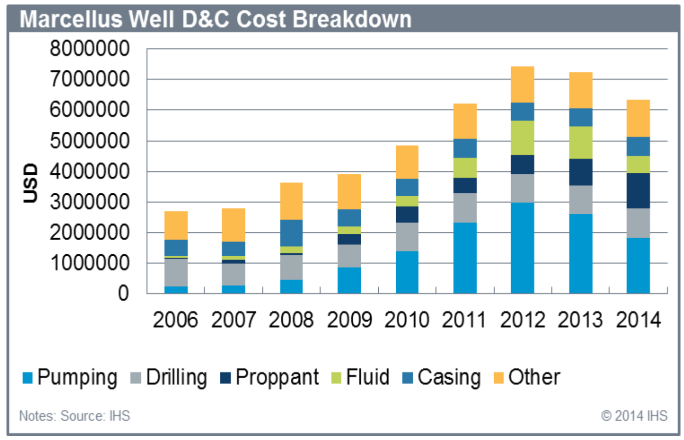


Figure 7-9: Historical nominal well cost

Changes in Well and Completion Design

Between 2006 and 2011, lateral length steadily increased until it began to level out and increase more slowly to its current length of just less than 6,000 feet (Figure 7-10). On the other hand, proppant per well has grown dramatically year over year and feet per stage has decreased steadily to its current stage width of 200 feet. This means that fluid and proppant concentrations in each stage are increasing (Figure 7-11). Despite the additional proppant per well in year 2014, downward pressure on rates from 2013 to 2014 overcame this proppant cost and costs for 2014 decreased somewhat.

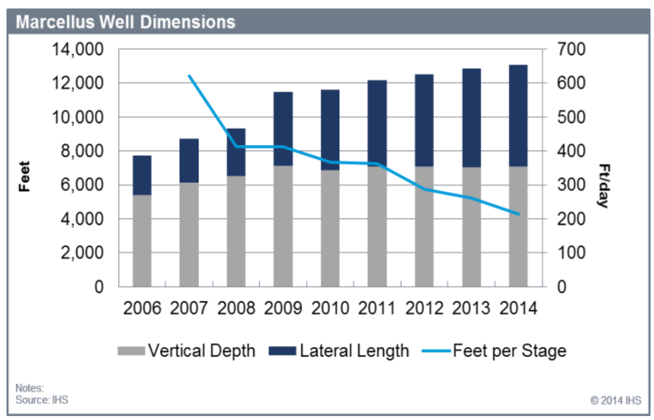


Figure 7-10: Lateral length and total depth

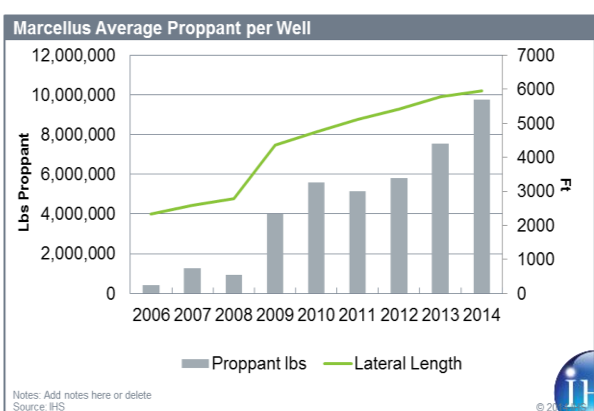


Figure 7-11: Proppant per well history

The mix of frack fluids has evolved over the years, beginning with predominately water fracks. In 2008 operators switched to the "slick water" gels. At the same time information gathering improved. In 2010 operators began using X-link gels and increased until 2013. However, it appears that slick water is becoming the fluid of choice again. Well

EURs have increased since 2010. However the cost decreases of 2014 has contributed to a unit cost of only $5.17 / boe. Please see Figure 7-12.

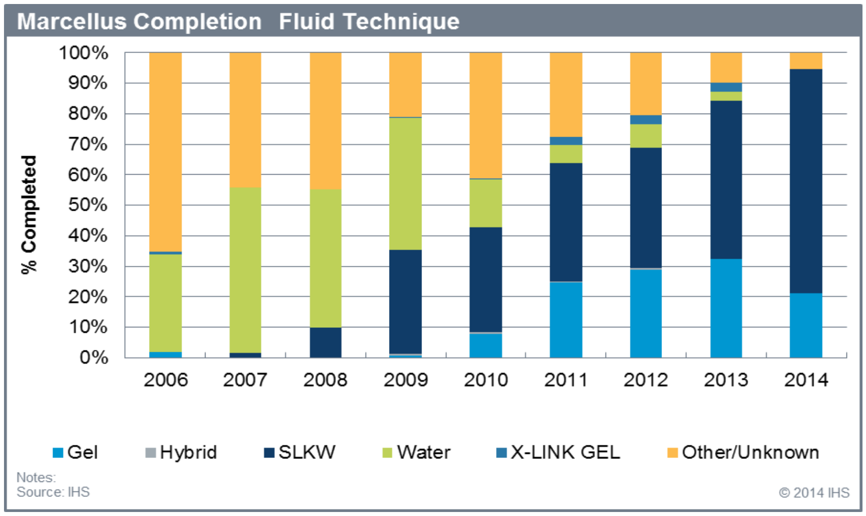


Figure 7-12: Change in frack fluid type over time

In 2014, EURs finally rose after several years of no growth despite longer lateral and increased proppant. With lateral lengths increasing each year, performance per lateral foot has barely dwindled (Figure 7-13). The overall increase in average EUR from 750 kboe in 2010 to 1,100 kboe in 2014 came largely from increased proppant combined with lateral lengths extensions (Figure 7-14). It is important to note, cost improvements are a result of improved cost rates rather than the improvements efficiencies in drilling and completions (Table 7-4).

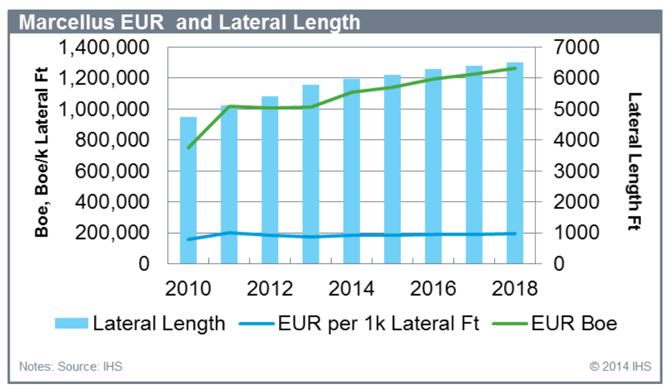


Figure 7-13: Change in EUR per lateral foot over

Year	$/Boe	EUR -Boe
2010	7.84	751,684
2011	6.87	1,015,527
2012	7.39	1,007,205
2013	6.27	1,012,928
2014	5.17	1,109,740

Table 7-2: Vintage unit costs and EUR

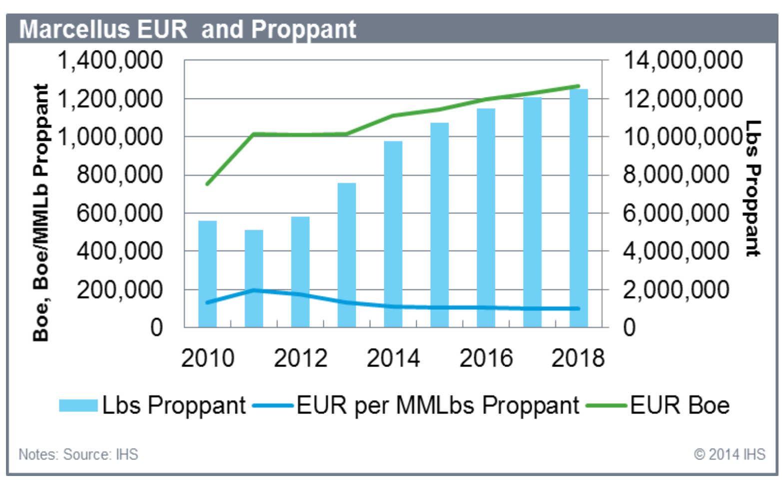


Figure 7-14: Change in EUR per lb. proppant over time

G. Future Cost Trends

Cost Indices

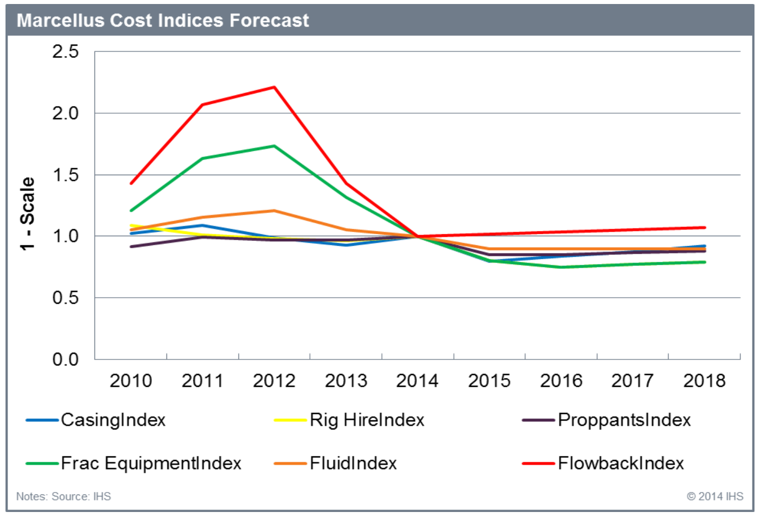


Figure 7-15: Indices for major cost drivers

Since the Marcellus is a gas play, rig activity has declined at a slower pace, drifting from the mid-70s count down to around 50. This is due to the drop in gas prices late in 2014. The count is not expected to drop much further by the end of 2015. Marcellus has a need for more infrastructure, and as it is built, new production immediately takes advantage of it. This lack of infra-structure has resulted in a discount of over a dollar per mcf compared to Henry Hub. Consequently, activity is more concentrated in the liquids rich area. Also as a regional market for services, equipment, such as rigs and pumping units, will not be able to move easily to other areas. This may idle service providers and put downward pressure on costs. Overall, costs will decrease from 2014 levels by 14-15% during 2015, with minimal decreases for 2016. See Figure 7-15.

Pumping and drilling costs rates are dropping and are expected to be 15% lower by the end of 2015, with another 5% decrease in 2016. Rates will begin to recover in late 2016, but will stay low through 2018. Proppant costs will drop by 20% in 2015, largely due to decreases of 35-40% at the mine gates. The impact on fluid will be less. Due to a forecasted drop of 20% during 2015 in the price of steel, tubulars, and other fabricated materials will also cost less.

Changes in Well Design

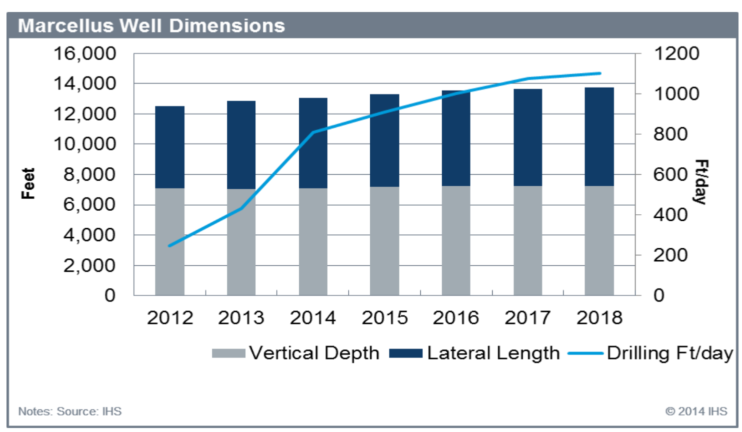


Figure 7-16: Historical and forecasted total depth

Despite the challenging environment operators will continue to lower unit costs ($/Boe). The following trends are expected to continue:

- Lateral length - Average lateral length has not moved much during the past four years and is projected to remain relatively constant at 6,000 – 6,200 feet (Figure 7-16). Vertical depths should also remain fairly constant.

- Stages - The average number of stages is projected to increase from 32 in 2015 to nearly 38 by 2018 (Figure 7-18). Also because lateral lengths are not projected to change, we can expect that stage spacing will tighten to a degree.
- Drilling efficiencies – Continuous changes here will cause averages currently at 800 Ft/day to increase as drillers will achieve over 1,000 Ft/d by 2018. (Figure 7-17).
- Proppant - Proppant amounts will increase from 1,600 Lbs./Ft in 2014 to 1,700 Lbs./Ft by the end of this year and will steadily increase to 2,000 Lbs./Ft by 2018 (Figure 7-18). Superfraccing is the norm in this play. Proppant mix is expected to be focused more heavily on natural proppants in order to afford more total proppant. Average fluid use is expected to increase proportionately.
- More wells being drilled on single drill pads – As more wells occupy single drill pads we can expect potential cost savings from shared facilities and other related items such as roads, mud tanks, and water disposal systems. Of the total well cost, $1.23 MM is based on sharing costs amongst eight other wells. Table 7-3 illustrates how future drill pad configurations could save money.

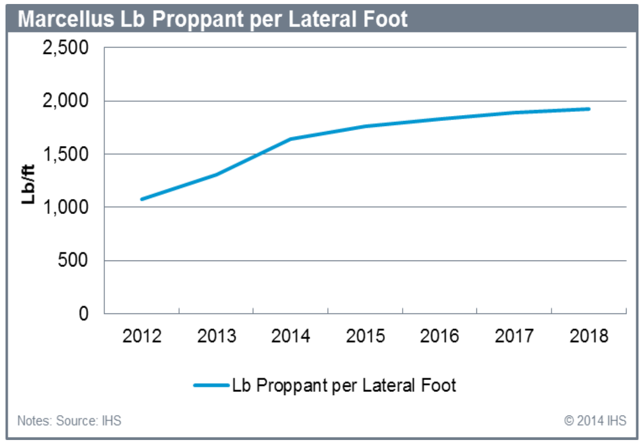


Figure 7-17: Historical and forecasted

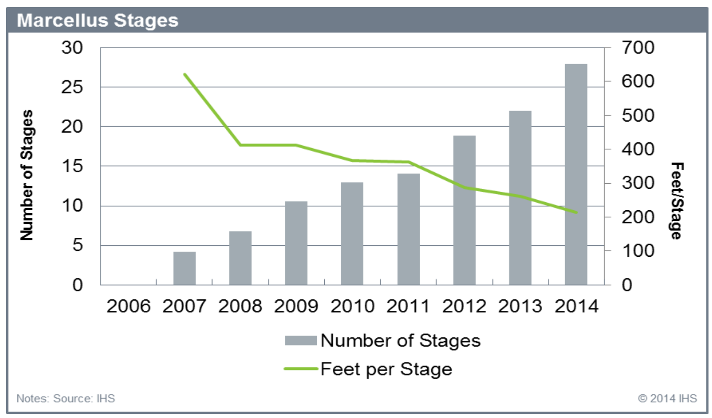


Figure 7-18: Historical and forecasted stages

	Stacked Horizons	**Distance between wells**	**Wells per pad**	**Cost of items related to pad - 2014**	
Modeled	1	660 feet	8	$1,230,000	Modeled Cost
Traditional View	1	660 feet	8	$1,230,000	Development Cost
Potential upside	2	660 feet	16	$615,000	Potential New Cost
Difference	1	1	2	$615,000	Potential Savings

Table 7-3: Potential savings from additional wells being drilled from a single pad

For example, there is currently one stacked zone in the Marcellus which is considered a potential target. New wells are being completed in the overlying Burkett Shale, which is now considered a secondary target. This could become a routine objective and thus the potential exists for up to 16 wells to be drilled from a single pad. This could save potentially $615,000 per well. These savings are likely to apply in regional markets, mainly in western Pennsylvania, but not throughout the entire play.

Future Well Costs

Future changes in overall well and completion costs are quantified in forecasted indices, and are combined with projections in future well design parameters. Figure 7-19 shows both the effect of well design and indexing on recent historical costs beginning in 2012 and future well costs through 2018:

- Avg. Capex, Actual – This captures the average nominal total well cost for each year as it actually is expected to occur. Note the acceleration of the rate declined in 2012, despite more complex well designs of recent years which are expected to continue
- Capex for 2012 Cost Rates, Well parameters of the year – This captures the application of 2012 cost rates to the average well design of a given future year. Note that had we held 2012 rates steady through the forecast period, the actual cost of a well drilled in 2018 would have cost $3.7 MM more due to the longer laterals and increased use of proppant.
- Capex for 2012 Well Parameters, Cost Rates of the Year – This represents the application of well parameters of 2012 with cost rates for the given year. Note that the more simple well design of 2012 would have cost less by 2018.

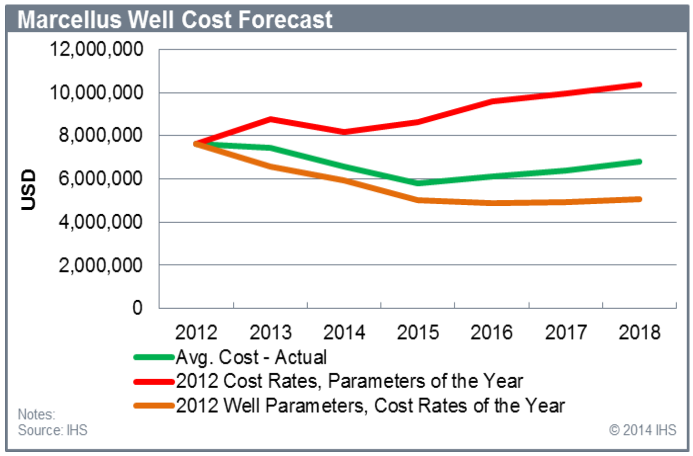


Figure 7-19: Comparison of actual future costs with forecasted indices

This illustration helps us see the effect of cost indices and well design changes using 2012 as a baseline. The gap between 2012 Well Parameters (orange) and 2012 average cost - actual (green) illustrates the impact of more complex well design on cost. Whereas the gap between average cost - actual (green) and 2012 Cost Rates (red) shows the much higher impact of the declining cost indices.

In conclusion, costs are forecasted to continue to decrease with light recoveries beginning in 2016. Given that we expect rate decreases in each major cost driver, we can expect little change in the relative contribution of each (Figure 7-20).

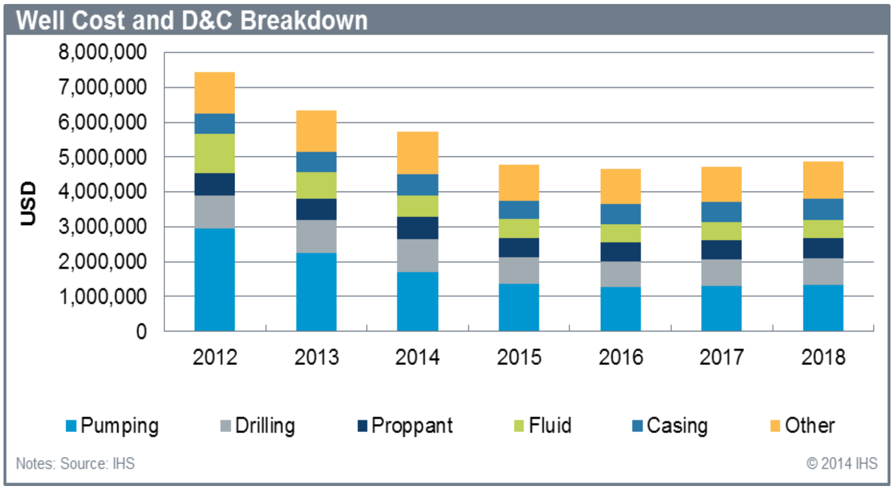


Figure 7-20 Marcellus historical and future nominal costs by major cost driver

H. Cost Correlations of Major Cost Drivers

Some relationships between well design and cost are stronger than others. As already mentioned each cost component was calculated by measuring the units or amount of a particular well design attribute and multiplying it by the rate. An analysis of the well design factors contributing to the five primary cost drivers was conducted for the period of 2010 through 2018. During that time both the rates and character for well design attributes changed, rather dramatically in some cases.

When comparing the well design parameter with the cost for that well design parameter over the specified time period, an R2 value was generated showing the correlation or relative influence as shown in Figure 7-21. This figure also suggests that for each cost category, there is one well parameter that is most influential. In the Marcellus, fluid costs are guided the most by variance in completion fluid type, drilling costs correlate highly with drilling efficiency, proppant costs are influenced the most by the cost per lb of proppant and pumping costs are influenced the most by injection

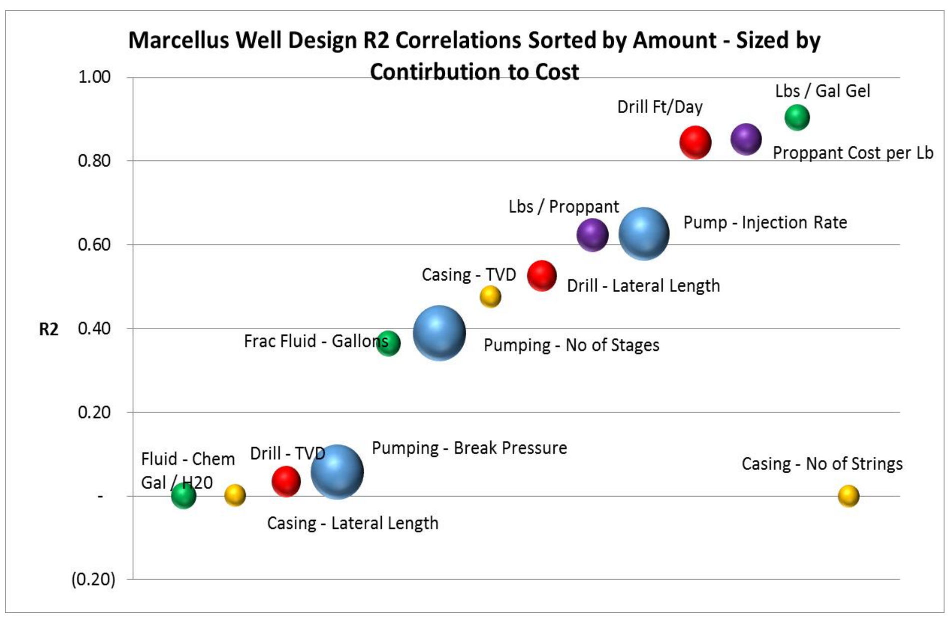


Figure 7-21: Marcellus historical and future nominal costs by major cost driver

rate. Figure 7-21 also illustrates the relative importance of each well design parameter as it relates to the total cost of the well.

Cost per unit

The well Depth and well formation break pressure correlate with drilling costs. As noted in Figure 7-22, these have been declining due primarily to a decrease in both rig rates since 2012. This has been accelerated in 2015 and an increase in drilling .We expect drilling cost per foot to remain flat in the years ahead as savings in cost rates will be overcome by slightly larger well dimensions.

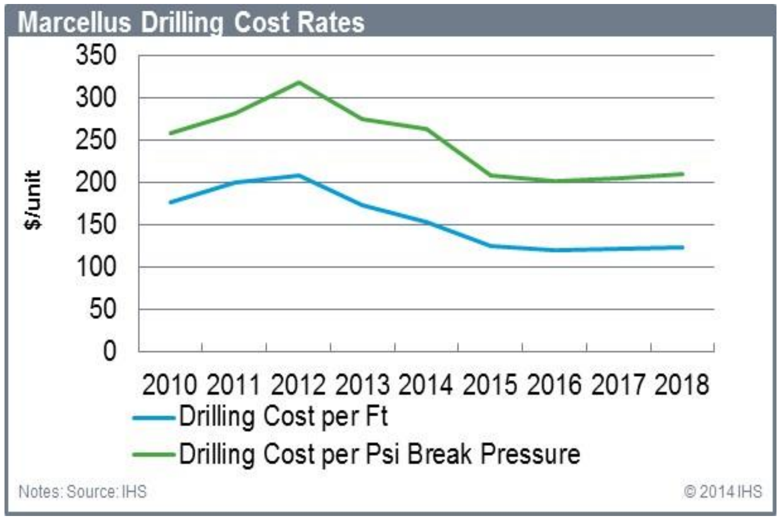


Figure 7-22: Drilling cost rates

A similar decrease in costs for completion is also evident with the cost per break pressure and cost per pound of proppant going down each year (Figure 7-23) for the Marcellus. Cost per formation break pressure may go up slightly as this may not drive as much of the cost in the future as it once did. As operators use more frack stages per well, the economies of scale will also continue to reduce the unit costs here.

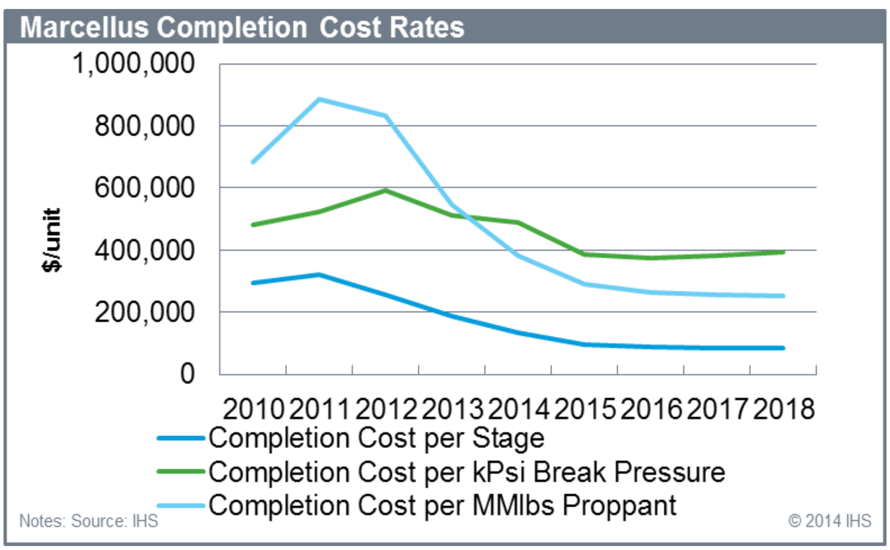


Figure 7-23: Completion cost rates

I. Key Take-Aways

Performance concerns: Over time the Marcellus has achieved greater efficiencies in well design and implementation due to the decline of cost rates for the same activities and well design features. Wells have also become more complex and will remain complex in the future, but at a slower pace. With much of the play de-risked, many areas will continue to be drilled while at lower cost rates. If production increases continue in following years the cost per boe will continue to fall. This may be hindered by a resulting drop in the local natural gas price.

Economic performance is diminished by low gas prices. Substantial cost savings will be achieved for the next several years. Slight efficiency improvements to well design are expected and completions give additional production potential.

Influential well design parameters: When modeling well costs in the Marcellus, the accuracy of some well attributes may be more important than others when estimating costs. Drilling efficiency, pounds of proppant, formation break pressure and lateral length are the key attributes in the Marcellus whose change over time has greatly influenced costs and caused the most variance in costs. In the Marcellus the greatest drivers are fluid type, drilling efficiency, the cost per pound of proppant, and slurry injection rate.

Decreasing costs: Rates for various materials and services peaked in 2012 when demand for high horsepower rigs (1000-1500) were in short supply and fracking crews were scarce. As the supply of these items increased to meet this demand, rates decreased and led to overall cost decreases. This is despite increases in the amount of proppant and number of stages. This began a general downward trend which has accelerated in recent months by as much as 20% due to a very large over supply of these services.

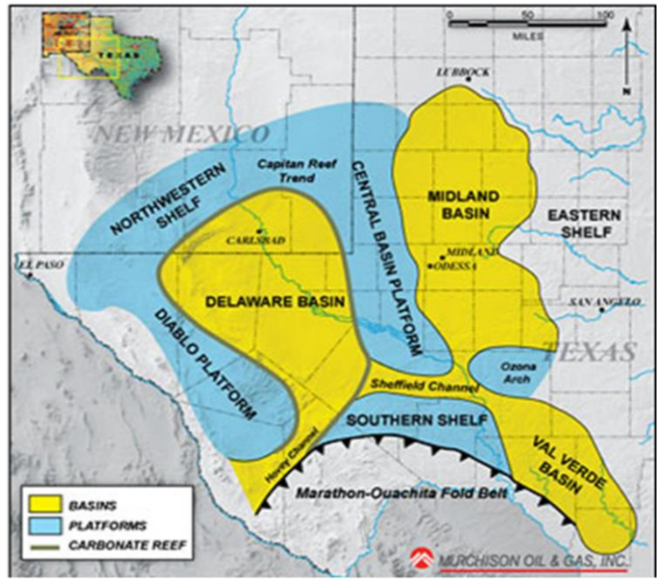
Operating Costs: There is limited variability in operating expense, with the greatest ones being water disposal, long haul transport, and gathering. Given variability is relatively low compared to other plays, we would expect few operators to make substantial improvements. Due to the nature of the services provided, operating cost reductions will be much less than capital reductions going into 2015 and will be much less than will be experienced in other plays.

VIII. Permian Play Level Results

A. Introduction and sub-play description

The Permian Basin occupies West Texas and Eastern New Mexico. For decades it was historically drilled with vertical wells to access a series of stacked formations. In recent years four plays have emerged, namely the Wolfcamp and Bone Spring horizontal plays located in the Delaware Basin, and the horizontal Wolfcamp and vertical Spraberry located in the Midland Basin (see Figure 8-1).

In this study we have not generally included the vertical wells when computing averages and trends. We have grouped the single Midland Basin play and the two Delaware basin plays. These plays are located in a remote arid desert area that suffers from water sourcing issues, but gas, oil, and liquids can still be sold locally in Texas.



From Murchinson Oil Company http://murchisonoil.com/about/permian-basin.html

Figure 8-1: Location of the Permian Basin sub-

Well costs have grown rapidly since 2012 as the number of vertical wells has fallen off sharply and have been replaced by horizontal wells with complex completion designs. Oil production is also leveling off as rigs have dropped from 330 in 2014 to 150 currently. Logistically this play is farther away from markets. However it is still closer to Cushing and the Gulf Coast than the Bakken. Recent infrastructure additions have helped offset the high transport fees that in the past hurt profitability in the region.

B. Basic Well Design and Cost (2014)

Total Permian Cost

Total well cost ranges from $6.6 MM to $7.8 MM, excluding Spraberry, as shown in Figure 8-2. Consistency in TVD, lateral length, pressure, and completion design amongst the horizontal plays is also reflected in similar costs amongst the sub-plays' cost for drilling. Completion costs are driven by lateral lengths that range from 5,000 feet in the Bone Spring to 7,200 feet in the Midland Wolfcamp. Proppant use is also much greater in the Midland Wolfcamp play.

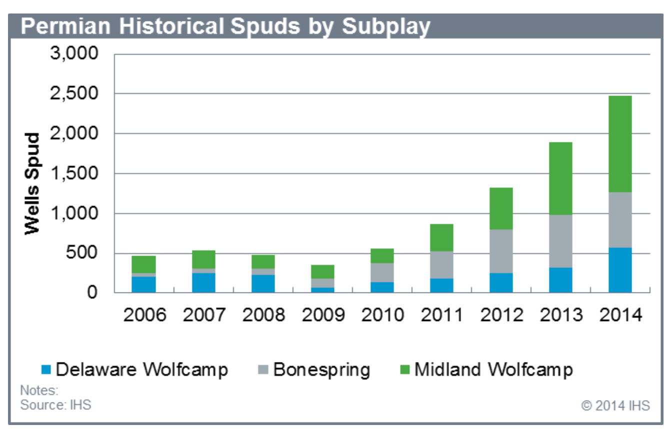


Figure 8-2: Permian historical wells

Comparison with Published Data

The average Permian cost of $7.5 MM compares with published costs reported by operators in 2014 as follows:

- Operators reported cost from MM$ 5.5 to MM$ 12.3, with Approach reporting the lowest and Energen reporting the highest.
- Concho, Laredo, EP Energy, and EOG reported cost from $ 6.2 MM to $ 7 MM.
- Rosetta reported costs of $ 8.5 MM, but these wells were very deep.
- Bone Spring - Concho reported costs of $ 5 MM to $ 7 MM.
- Wolfcamp Delaware - Operators reported cost of $ 7 MM to $ 8.5 MM.
- Wolfcamp Midland - Operators reported cost of $ 5.5 MM to $ 8.6 MM.
- Spraberry – Energen and Diamondback reported cost of $ 2.5 MM.

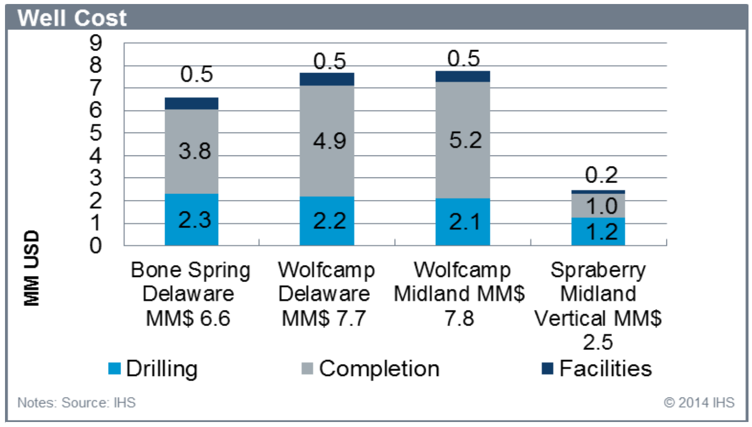


Figure 8-3: Total Permian cost by sub-play

General Well Design Parameters

Table 8-1 below summarizes well design parameters for each sub-play. Proppant mixes, amounts, and horsepower drive costs. We note that Midland Wolfcamp uses the most proppant and is almost entirely natural. Casing programs are uniform with a conductor pipe, two strings, and a liner generally used. It is common practice for artificial lift to be installed soon after the well comes on stream.

Well Parameters	Unit	Bone Spring	Wolfcamp Delaware	Wolfcamp Midland	Spraberry
TVD	Ft	9,715	10,644	7,952	8,996
Horizontal	Ft	4,967	5,578	7,257	0
Formation pressure	Psi	5,829	6,386	4,771	5,398
Frack stages	#	12	20	28	8
Frack break pressure	Psi	9,326	8,941	7,157	7,557
Pumping rate	Bpm	70	59	78	61
Horse Power	Hp	18,401	14,869	15,735	12,993
Casing, liner, tubing	Ft	29,112	32,807	29,169	22,086
Drilling days	Days	25	23	20	11
Natural proppant	MM Lbs.	3.07	4.82	8.82	0.83
Artificial proppant	MM Lbs.	1.08	1.39	n/a	n/a
Total Water	MM gal	6.21	6.25	8.74	0.77
Total Chemicals	Gal	372,587	312,658	436,836	38,545
Total Gel	Lbs.	186,294	187,595	87,367	7,709

Table 8–1: Properties of typical wells in each sub-play used to calculate costs

Wells in the Wolfcamp Delaware play are drilled over 10,600 feet vertical depth and have lateral lengths averaging nearly 5,600 feet. Lateral lengths are moderate, but still support 20 stages with over 6.2 MM Lbs. of proppant and nearly 6.6 MM gallons of fluid. The proppant mix is fairly high cost, which is primarily cheap, natural, and mixed with a lot of ceramic sand. Completion fluids are mostly gel-based with few wells completed with slick water. Surface casing is not reported in this area and it is assumed that wells use only three casing strings, completed with production tubing. The oil production in this play benefits from artificial lift.

Wells in the Wolfcamp Midland play are drilled nearly 8,000 feet vertical depth and have lateral lengths averaging nearly 7,300 feet. Lateral lengths are very long and support 28 stages with over 8.8 MM Lbs. of proppant and nearly 9.2 MM gallons of fluid. The proppant mix is low cost, which is primarily cheap natural sand with some 100 mesh. Completion fluids are either gel or slick water based. The wells are cased with a standard surface casing and three additional strings completed with production tubing. The oil production in this play benefits from artificial lift.

Wells in the Bone Spring play are drilled over 9,700 feet vertical depth and have lateral lengths averaging nearly 5,000 feet. The short lateral lengths only support 12 stages with over 4.1 MM Lbs. of proppant and nearly 6.6 MM gallons of fluid. The proppant mix is high cost with a lot of variation between wells, which is primarily cheap natural sand with significant amounts of resin coated or ceramic sand. Completion fluids are either gel or slick water based. The wells are cased with a standard surface casing and 4 additional strings completed with production tubing. The oil production in this play benefits from artificial lift.

Wells in the Spraberry play are drilled to 9,000 feet vertical depth on average with any well deviations adding just a few hundred feet to the wells' measured depth. The completion zone is fairly long for a vertical well which supports 8 stages which use only 0.8 MM Lbs. of proppant and 0.8 MM gallons. The proppant mix is low cost comprised of only natural sand. Completion fluids are either gel or slick water based. The wells are cased with a standard surface casing and 3 additional strings completed with production tubing. The oil production in this play benefits from artificial lift.

C. Operating Costs

Operating costs are highly variable ranging from $13.32 to $33.78 per boe (Figure 8-4) and are influenced by location, well performance, and operator efficiency. Costs are similar between the Delaware and Midland areas, but the Delaware may incur higher transportation costs due to its farther distance from markets.

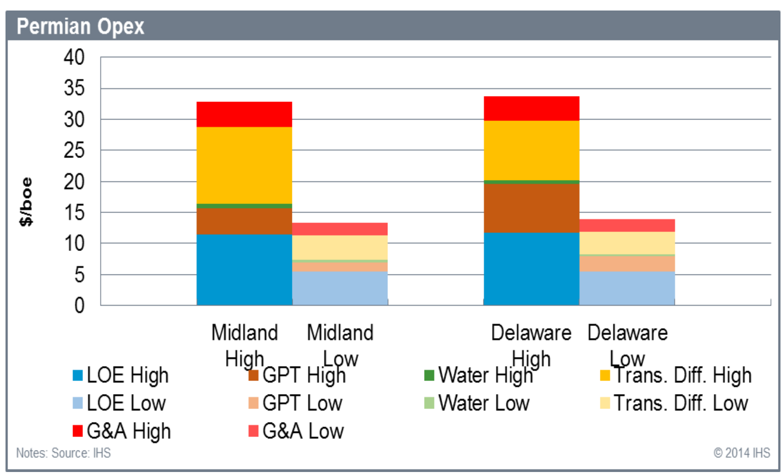


Figure 8-4: Range of operating expenses

Lease Operating Expense (LOE)

Most of the Permian lease operating expenses (LOE) incurred relate to artificial lift and maintaining artificial lift. Water disposal costs are significant, but lower than in other plays. The Permian produces just 0.2 bbl of water for every Boe that is produced. Direct labor and other costs are fairly small relative to the rest of the costs. However they are similar to other plays. The Other category contains common costs like pumping, compression, and other recurring types of costs, which are mostly determined by the cost of energy to run them (Figure 8-5).

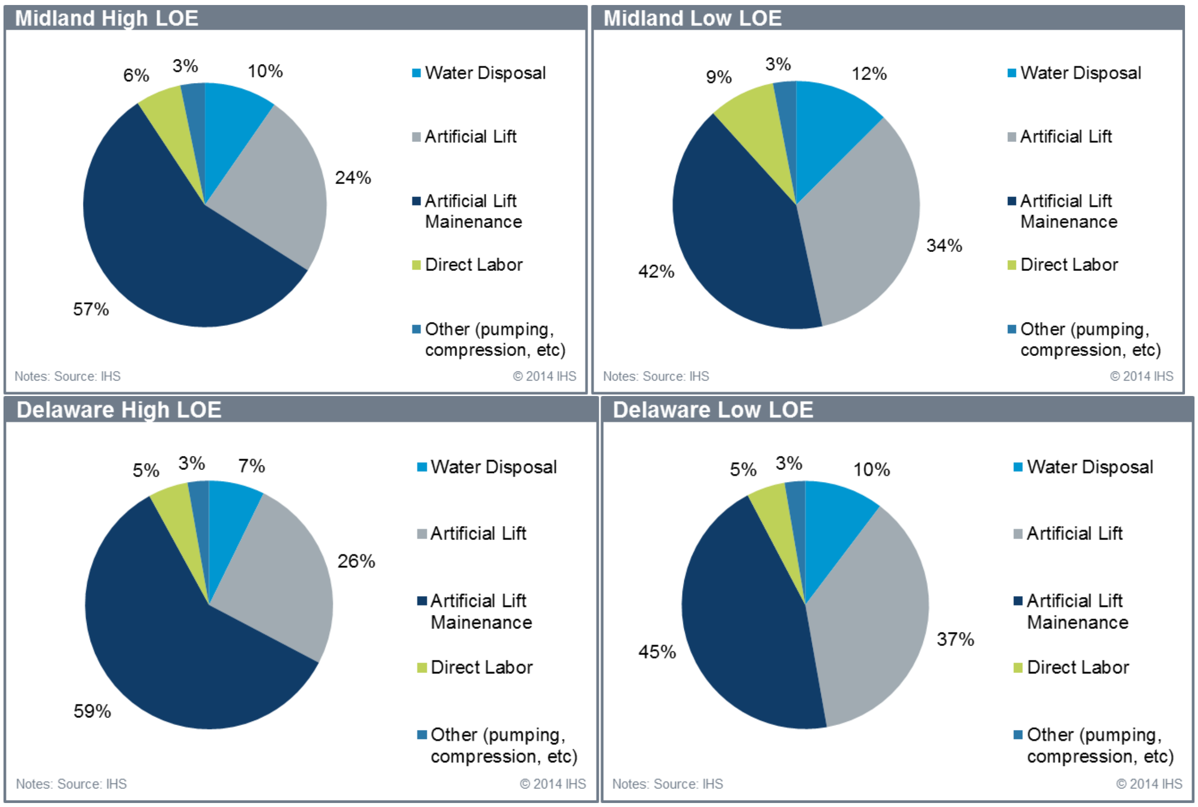


Figure 8-5: Breakout of LOE costs

Gathering, Processing and Transport (GPT)

Oil is sent by either pipeline or rail to either Cushing or the Gulf Coast. The range of costs or differential incurred depends on whether transport is by rail or pipeline. Recently, in 2015, the Permian has benefitted from additional pipeline capacity that will allow for much less use of rail, and thus bring costs down dramatically.

Gas has significant options in this play. The Permian is a region that has produced under past conventional developments and has a great deal of gas infrastructure and access to markets on the Gulf Coast. Gas plants and gathering systems are often operated by producers, which allows for low GPT costs in some cases. Current gas processing, fractionation, and transportation rates are in line with other plays, but can be higher or lower depending on commercial arrangements. See Table 8-2 for the GPT cost breakout.

	Units	Delaware High	Delaware Low	Midland High	Midland Low
Gas Gathering	$/mcf	0.80	0.40	0.6	0.4
Gas Processing	$/mcf	1.25	0.25	0.8	0.25
Short Transportation Oil	$/bbl.	3.00	0.25	2.5	0.25
Long Transportation Gas	$/mcf	0.30	0.20	0.3	0.2
Long Transportation Oil	$/bbl.	13.00	4.00	13	4
Long Transportation NGL	$/bbl.	9.78	4.13	9.78	3.04
NGL Fractionation	$/bbl.	4.00	2.00	3.6	2.25
Water Disposal	$/bbl. water	3.00	2.00	4	2.5

Table 8-2: Breakout of GPT costs

G&A Costs

G&A costs range between $2.00/ boe and $4.00/boe. These may increase during 2015 due to layoffs and severance pay outs, but will be reduced over time due to staff reductions

Cost changes in 2015

Table 8-3 below summarizes operating cost changes that we expect to see between 2014 and 2015 going forward.

Item	Change	Description of change for 2015
Gas Gathering	-3%	Current contracts are sticky, but new contracts will benefit from energy cost savings. Vertically integrated companies will benefit the most.
Gas Processing	-3%	Current contracts are sticky, but new contracts will benefit from energy cost savings. Vertically integrated companies will benefit the most.
Short Transportation Oil	-3%	Will benefit from improved fuel cost rates.
Short Transportation Gas	-5%	Improved infrastructure will allow for more piping of production, but many operators will incur the same costs as 2014.
Long Transportation Oil	-60%	Less reliance on rail given new pipeline capacity.
Long Transportation NGL	-5%	Some improvement to energy costs, but many will incur the same cost as 2014.
NGL Fractionation	0%	Little change expected.
Water Disposal	+1.80%	Many water disposal contracts have fixed rates. Some of this will escalate based on PPI or another index. Only companies that dispose of their own water will see savings.
G&A	+5%	Severance package/payments due to layoffs are increasing G&A despite lower future operating cost. Savings will not be realized until 2016

Item	Change	Description of change for 2015
Artificial Lift	-10%	Oil field services rates are dropping due to lower activity and lower input costs rates like energy.
Artificial Lift Maintenance	-10%	Oil field services rates are dropping due to lower activity and lower input costs rates. Maintenance will now be avoided in some cases where it was profitable at higher prices. Companies that pay a fixed maintenance may not see better rates in 2015 unless they are able to renegotiate.
Direct Labor	-3%	Saving here will be due to fewer operational employees.
Other (pumping, compression, etc.)	-10%	Energy costs savings.

Table 8-3 Changes in operating expense going forward

D. Lease Costs

Lease acquisition costs will depend on if the operator has secured acreage before the play has been de-risked, as explained in Chapter I. Figure8-6 provides recent transaction costs per acre and the incremental cost to each well that is incurred.

We are assuming that each lateral is going to require 80 acres for Delaware wells and 60 acres in the Midland per well. Approximately 10-20% of the acres acquired will not be utilized. Ultimately we see that paying $15,000/acre will add up to an additional $ 1 to 1.3 MM per well. Acreage costs have increased in recent transactions as the Permian has been identified as a great producer on par with the Bakken. Furthermore, much of the play has been de-risked for unconventional development.

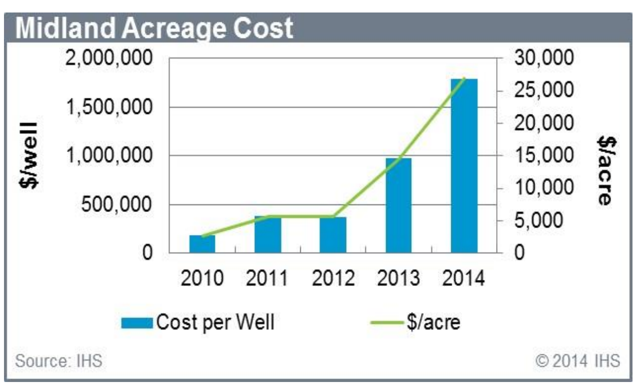


Figure 8-6: Historical leasing costs

E. Key Cost Drivers and Ranges

Overall, 74% of a typical Permian's total cost, excluding vertical Spraberry areas, is comprised of five key cost drivers (see Figure 8-7):

- Drilling:
  - Rig related costs (rig rates and drilling fluids) – 17% or $1.28 MM
  - Casing and cement – 13% or $0.98 MM
- Completion:
  - Hydraulic fracture pump units and equipment (horsepower) – 26% or $1.95 MM
  - Completion fluids and flow back disposal – 19% or $1.43 MM
  - Proppants – 17% or $1.28 MM

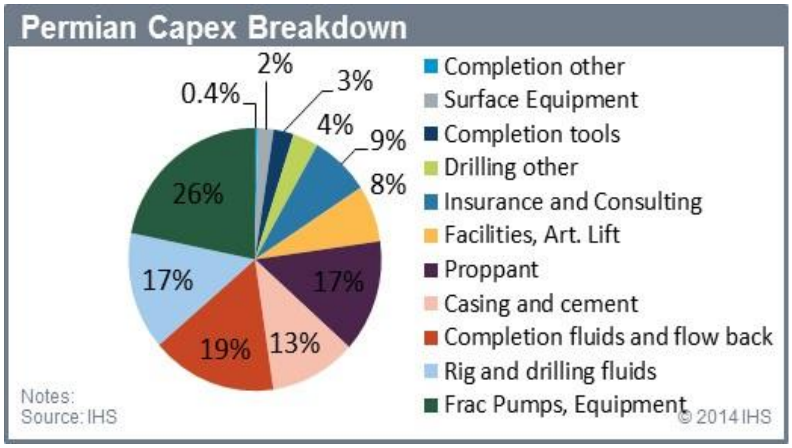


Figure 8-7: Permian spending breakdown

Range of Costs and Key Drivers

Various cost attributes are classified within each of the five main key drivers certain as shown in Figure 8-8. The total cost for each of the five cost drivers is portrayed with P10/P90 ranges created for each of the contributing attributes pertaining to such range. These ranges are intended to portray variation and uncertainty

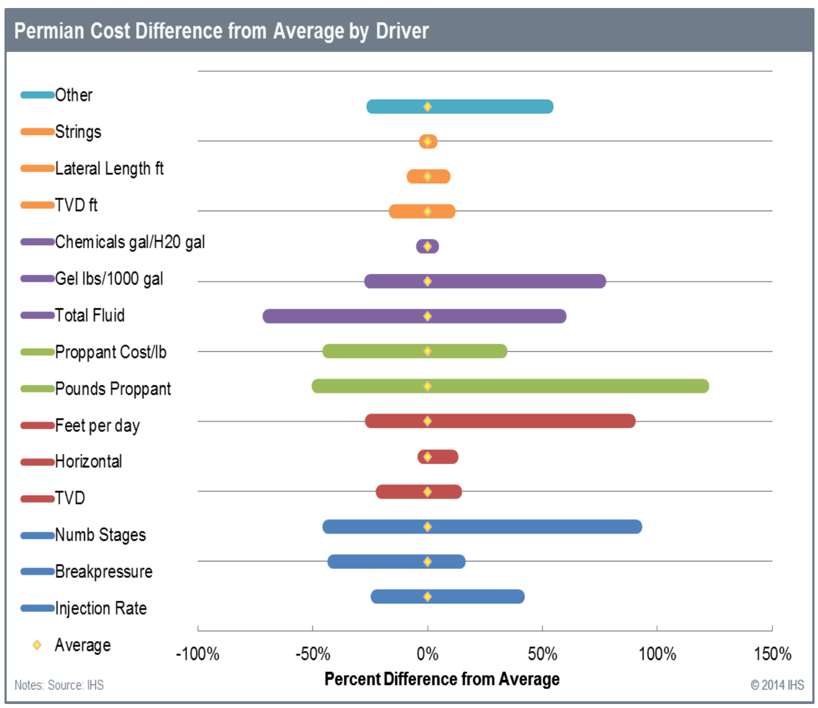


Figure 8-8: Range of cost attributes underlying key

In the Permian the pumping costs, the most costly well component on average, is highly variable with each of the primary components of pumping cost contributing to substantial differences in total well cost. Due to variability found in the data, stage numbers have a range of 11 to 37 which have the largest effect on pumping costs. This creates a range of MM$ 2.1, increasing costs over the average by $ 1.5 MM and lowering them by $ 0.7 MM.

Drilling penetration rate variability, from 279 Ft/d to 1,158 Ft/d, creates a drilling cost range of $ 1.3 MM. This incorporates potential cost increases of up to $ 1.0 MM for wells that drill slowly and cost decreases of up to $ 0.3 MM for drilling faster than the average. Drilling penetration rates are skewed toward faster drilling since it is actually quite rare for a well to be drilled at the slower end of the distribution. However this does happen occasionally.

The proppant amount variability, from MM Lbs. 3.0 to MM Lbs. 12.4, creates a proppant cost distribution of MM$ 1.7. This may potentially lower costs by $ 0.5 MM and raise costs by $ 1.2 MM. The fluid cost range for total fluid amount is $ 1.3 MM, raising costs over the average by MM$ 0.6 and lowering it by $ 0.7 MM (with fluid amounts ranging from 2.3 MM gallons to 11.7 MM gallons).

Variance in lateral lengths also contributes to the range of fluid, proppant, and the number of stages ranging from 4,401 Ft to 8,666 Ft. The range of vertical depths in the play is also large, from 6,688 Ft to 11,147 Ft, but creates casing cost range of just $ 0.2 MM. Upward or downward cost movement in this category is mostly negligible.

F. Evolution of Historical Costs

Historical Well Costs

Initially, in the Delaware Basin, wells had short lateral sections and small completions. Drilling and casing make up most of the well cost. Because of larger wells with more stages, nominal well costs in the Delaware Basin grew year-on-year until 2013 when pumping and frack fluid costs decreased due to improved completion service markets. Overall well design and completion intensity have grown with frack stages doubling since 2009 and thus increasing proppant costs. However in recent years lateral lengths have decreased. The increase in cost from 2013 to 2014 is related to increased stages with longer lateral lengths, higher power pumping, and increased formation pressures.

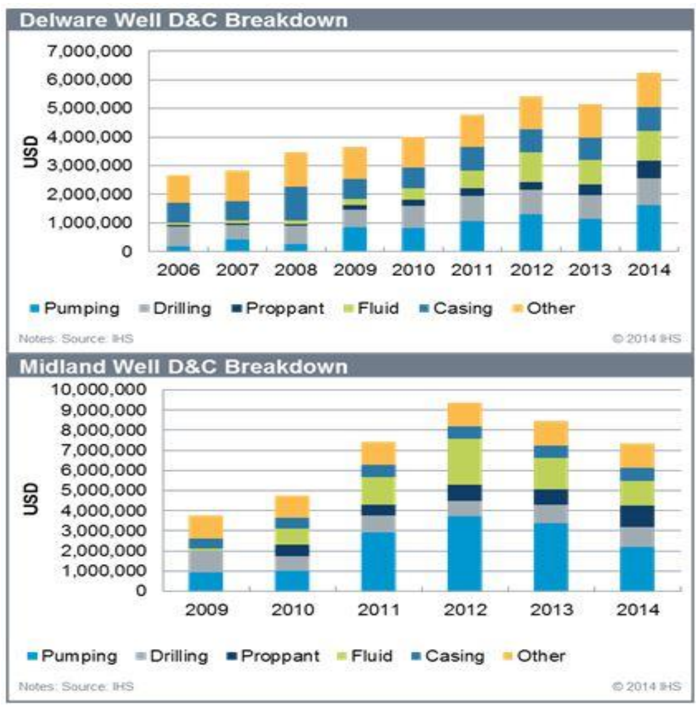


Figure 8-9: Delaware and Midland historical nominal well cost by major cost driver

Nominal well costs in the Midland area grew year-on-year until 2013 when water cost improved so much that total well cost decreased. This is despite increasing well dimensions and frack intensity. Overall, well design and completion intensity has grown with frack stages doubling since 2009 and thus increasing proppant costs. However in recent years lateral lengths have decreased. Improvements in pumping costs since 2012 are mostly attributable to more supply of frack equipment and personnel (Figure 8-9).

Changes in Well and Completion Design

Lateral lengths have increased in both basins. However, in recent years the increase has tapered off. The Delaware Basin is the exception, where lateral lengths took a big jump in 2014. This coincides with a large increase of over 2 MM Lbs of proppant in Delaware wells that year. Lateral lengths have always been large in the Midland Wolfcamp, averaging over 7000 feet, but proppant amounts which were large when the play began have soared to over 10 MM Lbs per well. This suggests that proppant concentrations are increasing.

The large increases in the Delaware Basin may suggest that operators are beginning to use similar completion techniques there as well. This will surely increase costs in the Delaware Basin. Despite downward pressure on rates from 2013 to 2014, this additional proppant per well in year 2014 (in the Delaware Basin) contributed to a slight increase in cost for the well.

The mix of frack fluids changed between 2009 and 2011 in both basins.

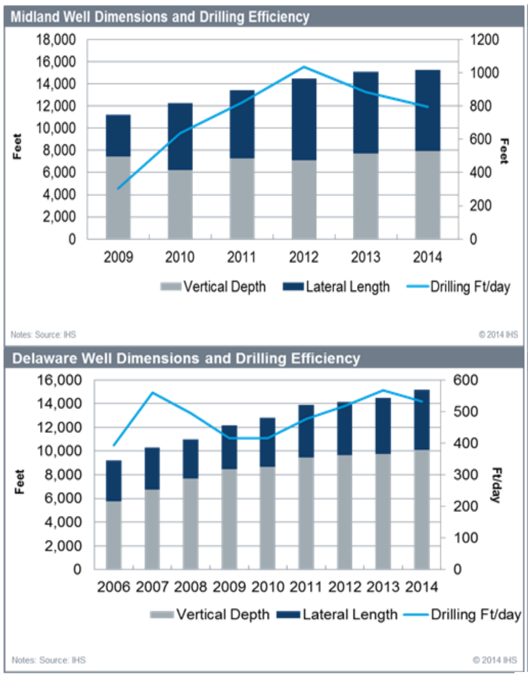


Figure 8-10: Delaware and Midland - Lateral length and total depth history

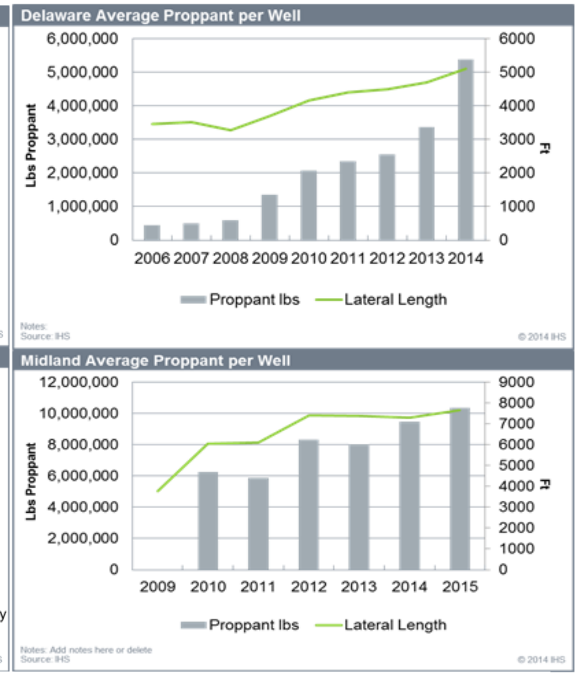


Figure 8-11: Delaware and Midland - Proppant per well history

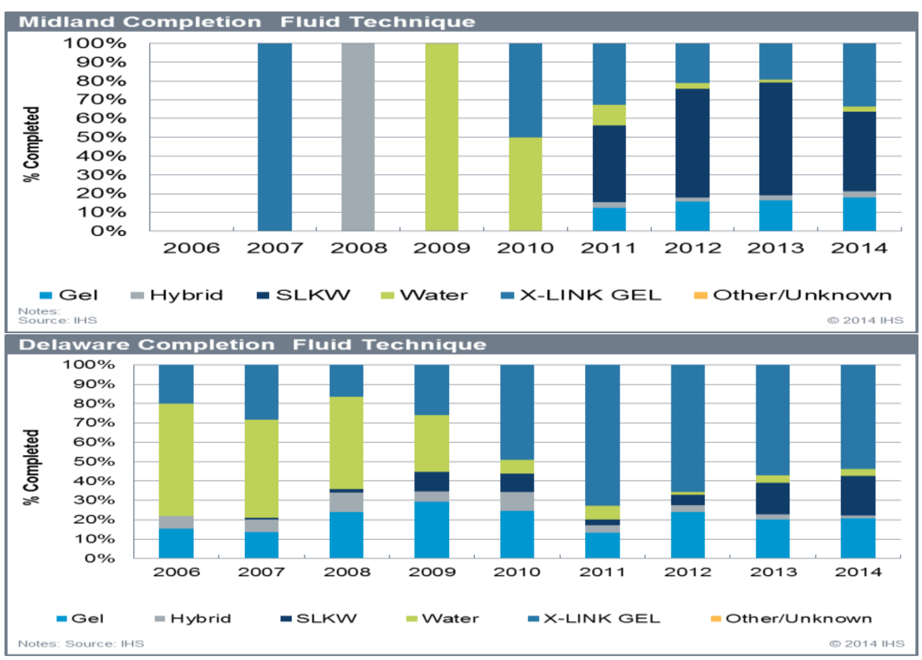


Figure 8-12: Midland and Delaware - Change in frack fluid use over time

In the Midland Basin, operators switched to X-link gels and slick water. Slick water is becoming more popular. In the Delaware Basin the more costly Gel and X-link gel are the fluids of choice.

Well EURs have improved in both basins up through 2013. This suggests that the completion programs in each basin are working. However, the unit costs ($/Boe) are fluctuating. For example in the Delaware Basin unit costs are increasing despite a large increase in EUR. In the Midland Basin a much higher EUR is required in 2012 to generate the same unit cost of just over $45 as was generated in 2010. This illustrates the need to contain and drive down costs.

Year	Delaware $/Boe	Delaware EUR -Boe	Midland $/Boe	Midland EUR -Boe
2010	12.76	314,085	55.07	86,134
2011	10.01	476,799	50.23	147,625
2012	10.62	511,043	54.56	171,834
2013	8.92	577,152	39.10	215,921
2014	9.76	641,488	39.77	185,136

Table 8-4.1: Midland Vintage Unit costs and EUR **Table 8-4.2: Delaware Vintage Unit costs and EUR**

The Midland was a fairly immature play until recently. It has experienced large improvements since 2010 in both well performance and in well economics (Table 8-4.2). Lateral length increases have staggered over the last couple of years in the Midland while EUR per well dropped (Figure 8-13). This is mostly due to exploration attempts expanding the play into less tested areas where shorter lateral lengths were used. Future Midland development will focus on the core areas and increasing lateral lengths in those areas to maximize production. Cost per boe worsened going into 2014, but this will improve going forward as less risky well locations are drilled with better well designs.

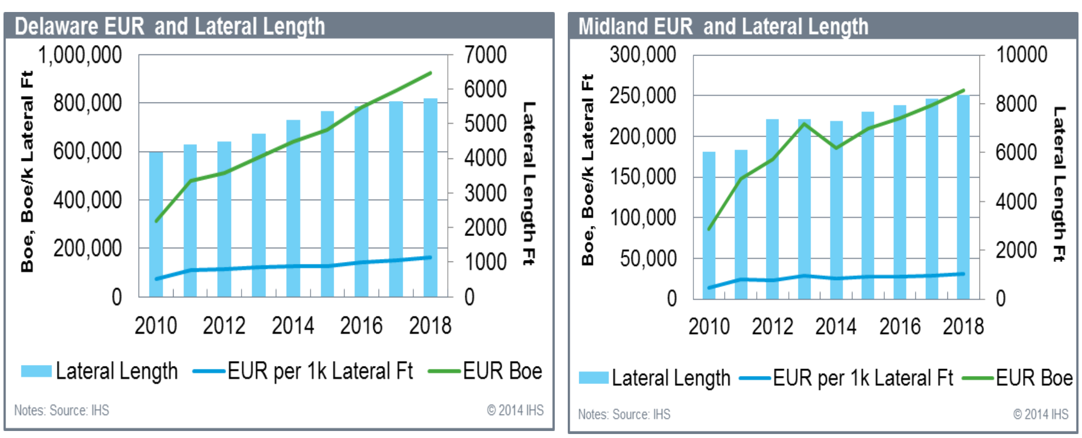


Figure 8-13: Midland and Delaware – EUR and lateral length

The Delaware, another play coming of age, holds a slightly different story where well design growth has improved the EUR per well with lateral lengths moving from 4,000 feet to over 5,000 feet (Figure 8-13). Furthermore, proppant jumped over 50% from 2013 to 2014 (Figure 8-14). However, well economics have not benefitted much. Despite increasing EUR's, the cost per Boe has grown nearly a dollar since longer laterals are being drilled with greater completion intensity. Under the new cost environment in 2015 it is expected that well design will continue to grow. This will provide even more production per well and at better economics than in the recent past.

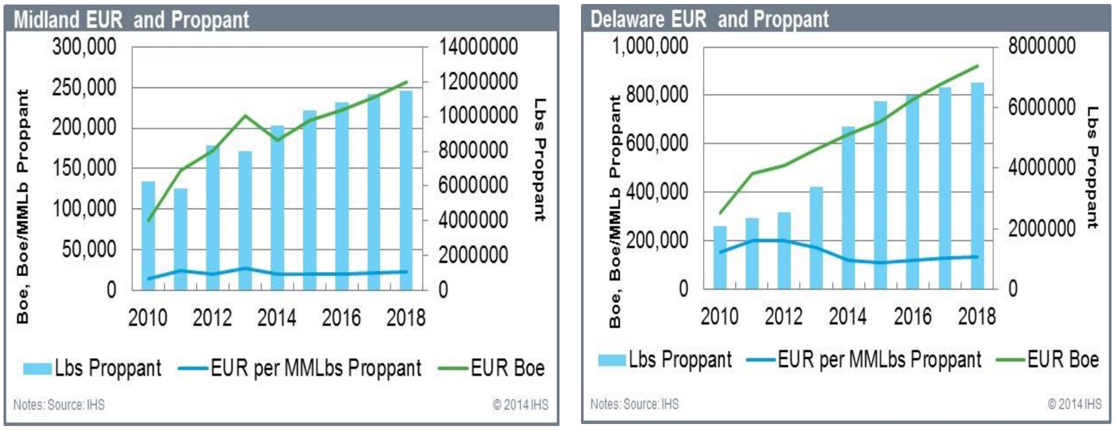


Figure 8-14: Midland and Delaware - Change in frack fluid use over time

G. Future Cost Trends Future Cost Trends

Cost Indices

Permian development activity is dropping sharply with little chance of recovery soon. Active rigs in the combined Delaware and Midland Basin plays are down to about 150 from a high of 330 in 2014. Before the oil price decline, infrastructure was not sufficient to transport oil to Gulf Coast or Cushing. There was also a large differential to WTI penalty of $6 to $12. Recent additions of take-away capacity have alleviated the bottlenecks and almost completely erased the differential penalty. This provides some cushion to the oil price decrease. Nevertheless, like other locations there is great pressure on service providers to reduce costs. Overall, costs in the Delaware Basin will decrease from 2014 levels by nearly 23% and the Midland Basin will decrease from 2014 levels by over 20% during 2015. The Delaware Basin will not see costs drop further in 2016. However the Midland Basin will drop another 1%.

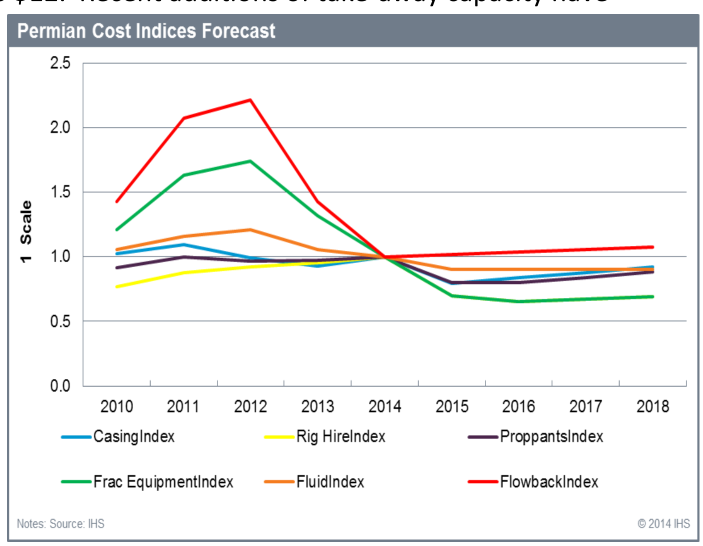


Figure 8-15: Indices for major cost drivers of the Midland and Delaware Basins

Pumping and drilling costs rates are dropping and are expected to be 25 – 30% lower by the end of 2015, with another 5% decrease in 2016. Rates will begin to recover in late 2016, but will stay low through 2018. Proppant costs will drop by 20-25% in 2015, largely due to decreases of 35-40% at the mine gates. The impact on fluid will be less. Due to a forecasted drop of 20% during 2015 in the price of steel, tubulars, and other fabricated materials will also cost less (Figure 8-15).

Changes in Well Design

Despite the challenging environment operators will continue to lower unit costs ($/Boe). The following trends are expected to continue:

- **Lateral length** – In the Midland Basin, average lateral length will increase by about 500 feet to over 8,000 feet. In the Delaware Basin some increase is also expected (Figure 8-16). Vertical depths should also remain fairly constant.
- **Stages** - The average number of stages in the Delaware Basin is projected to increase from 16 to 21 in 2015 and grow to 25 by 2018. In the Midland Basin with its longer laterals, stages will increase to 35 in 2015 and then to 40 by 2018. (Figure 8-17) Because lateral lengths are not projected to change, we can expect that stage spacing will tighten slightly.

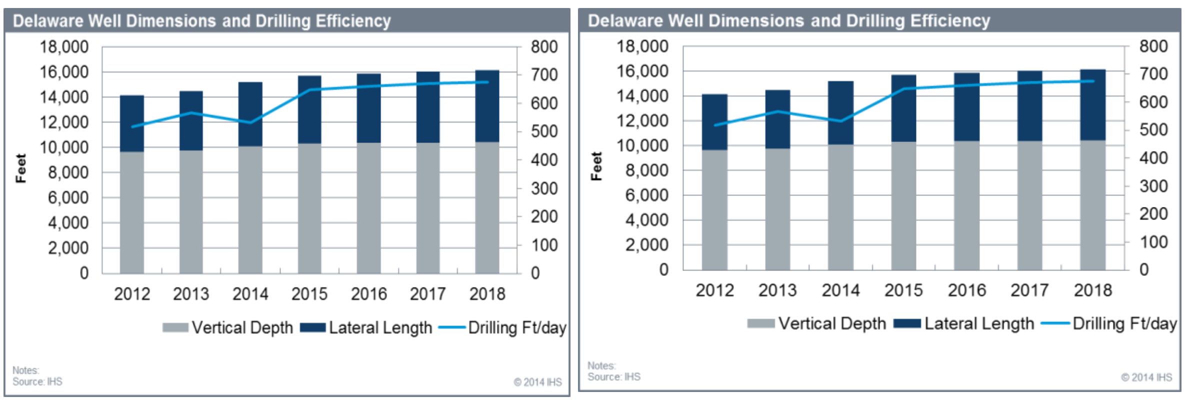


Figure 8-16: Midland and Delaware well dimensions and drilling efficiency

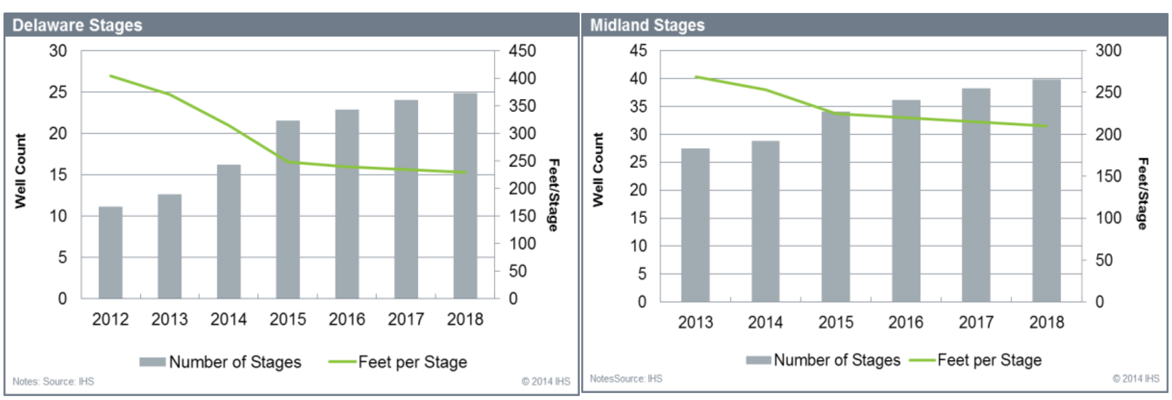


Figure 8-17: Midland and Delaware number of stages and feet per stages

- **Drilling efficiencies** – These have been sporadic and appear to already be optimized in both basins. Any changes here will be small, with average gains of about 10% in both basins by 2018. Current rates in the Midland basin approach 800 Ft/day. The rate in the Delaware Basin is about 700 Ft/day (Figure 8-16).
- **Proppant** - Proppant amounts will increase from 1200 Lbs. /Ft in 2014 to 1400 Lbs. /Ft by 2018 in the Midland Basin and from 1000 Lbs. /Ft in 2014 to 1200 Lbs./Ft t by 2018 in the Delaware Basin. This is already a high average in the SuperFrack range, so the increases are expected to somewhat taper off (Figure 8-18). Proppant mix is expected to be focused more heavily on natural proppants in order to afford more total proppant, particularly in the Midland Basin. There is a mix of slick water and X-link gel fracks. Current trends suggest that more slick water fracks may occur in the Delaware Basin and we may see more X-link gel fracks in the Midland Basin. At any rate we can continue to see a mix of these frack types.

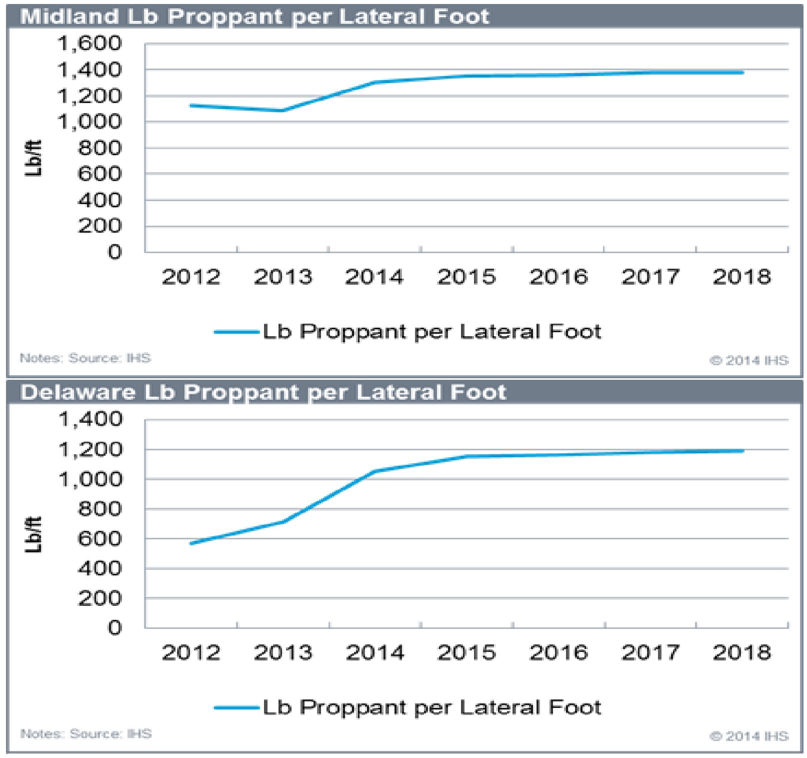


Figure 8-18: Delaware and Midland - Historical and forecasted

- More wells being drilled on single drill pads. As more wells occupy single drill pads we can expect potential cost savings from shared facilities and other related items such as roads, mud tanks, and water disposal systems. Of the total well cost, $0.8 MM is based on sharing costs amongst four other wells in both basins. Table 8-5 illustrates how future drill pad configurations could save money.
  - **Midland Basin** - We currently project that two of the multiple Wolfcamp zones could be accessed from a single pad. If we can increase access to an additional zone and double spacing to 660-foot spacing, the potential exists for up to 24 wells to be drilled from a single pad. This could potentially save $700,000 per well. These savings are not likely to apply throughout the play. These savings will be more focused in localized areas. Nevertheless this illustrates the level of potential savings.
  - **Delaware Basin** - We currently project that there is either a Wolfcamp or Bone Spring zone which could be accessed from a single pad. If we can increase access to an additional Wolfcamp zone and a single Bone Spring zone and double spacing to 660-foot spacing, the potential exists for up to 24 wells to be drilled from a single pad. This could save potentially

$667,000 per well. These savings are not likely to apply throughout the play, but will be focused more in localized areas. However, this still illustrates potential savings.

	Stacked Horizons	Distance between wells	Wells per pad	Cost of items related to pad - 2014	
Modeled	1	1320 feet	4	$ 800,000	Modeled Cost
Traditional View	2	1320 feet	8	$ 400,000	Development Cost
Potential upside	3	660 feet	24	$ 133,333	Potential Savings
Difference	2	2	4	$ 700,000	Potential Savings

Table 8-5.1: Midland Basin - Potential savings from additional wells being drilled from a single pad

	Stacked Horizons	Distance between wells	Wells per pad	Cost of items related to pad - 2014	
Modeled	1	1320 feet	4	$ 800,000	Modeled Cost
Traditional View	1	1320 feet	4	$ 800,000	Development Cost
Potential upside	3	660 feet	24	$ 133,333	Potential New Cost
Difference	2	2	6	$ 666,667	Potential Savings

Table 8-5.2: Delaware Basin - Potential savings from additional wells being drilled from a single pad

Future Well Costs

Future changes in overall well and completion costs are quantified in forecasted indices, and are combined with projections in future well design parameters. Figure 8-19 shows both the effect of well design and indexing on recent historical costs beginning in 2012 and future well costs through 2018:

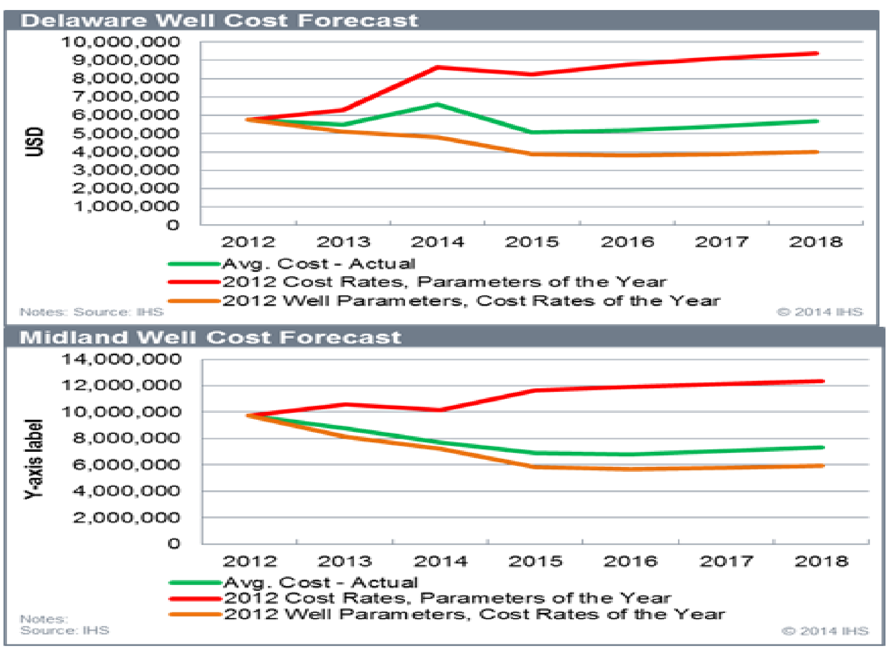


Figure 8-19: Delaware and Midland - Comparison of actual future costs with forecasted indices

- <u>Avg. Capex, Actual</u> – This captures the average total nominal well cost for each year as it actually is expected to occur. Note the acceleration of the rate declined in 2012 in the Midland Basin. The decline accelerated in 2014 to 2015 in the Delaware Basin. This is despite more complex well designs of recent years which are expected to continue

- <u>Capex for 2012 Cost Rates, Well parameters of the year</u> – This captures the application of 2012 cost rates to the average well design of a given future year. Note that had we held 2012 rates steady through the forecast period, the actual cost of a well drilled in 2018 would have cost $3.2 MM more in the Delaware Basin and $4.3 MM in the Midland Basin due to the longer laterals and increased use of proppant.
- <u>Capex for 2012 Well Parameters, Cost Rates of the Year</u> – This represents the application of well parameters of 2012 with cost rates for the given year. Note that the more simple well design of 2012 would have cost less by 2018.

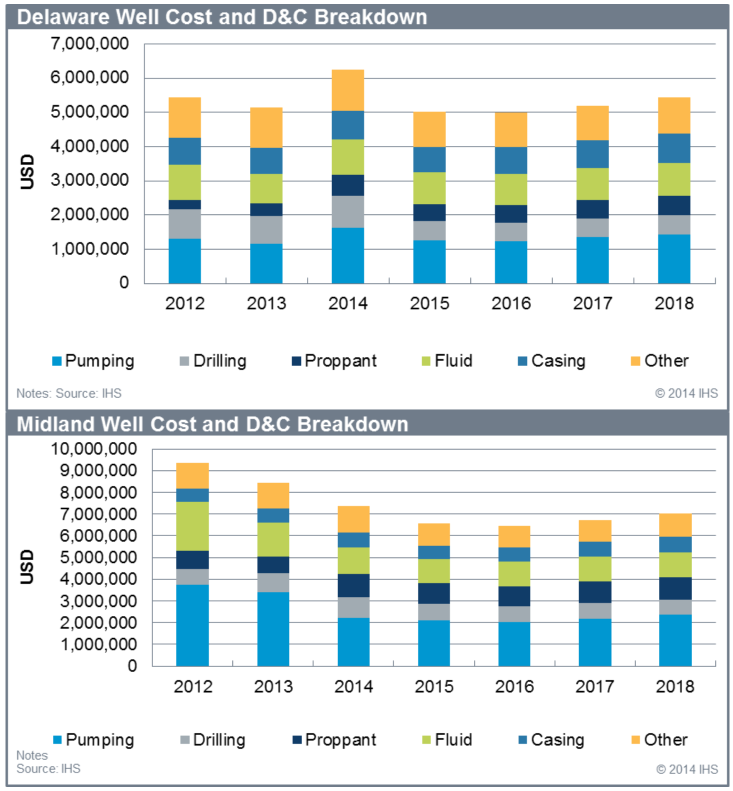


Figure 8-20: Midland and Delaware - Historical and future nominal costs by major cost driver

This illustration helps us see the effect of cost indices and well design changes using 2012 as a baseline. The gap between 2012 Well Parameters (orange) and 2012 average cost - actual (green) illustrates the impact of more complex well design on cost. The gap between average cost, actual (green) and 2012 Cost Rates (red) shows the much higher impact of the declining cost indices.

In conclusion, costs are forecasted to continue to decrease with light recoveries beginning in 2016. Given that we expect rate decreases in each major cost driver, we can expect little change in the relative contribution of each (Figure 8-20).

H. Cost Correlations and Major Cost Drivers

Some relationships between well design and cost are stronger than others. As already mentioned each cost component was calculated by measuring the units or amount of a particular well design attribute and multiplying it by the rate. An analysis of the well design factors contributing to the five primary cost drivers was conducted for the period of 2010 through 2018. During that time both the rates and character for well design attributes changed, rather dramatically in some cases.

When comparing the well design parameter with the cost for that well design parameter over the specified time period, an R2 value was generated showing the correlation or relative influence as shown in Figure 8-21. This Figure also suggests that for each cost category, there is one well parameter that is most influential. In the Midland area fluid costs are guided the most by variance in fluid amounts used, drilling costs correlate highly with lateral length, proppant costs are influenced the most by the cost per lb of proppant and pumping costs are influenced the most by formation break pressure. In the Delaware area fluid costs are guided the most by variance in fluid amounts used, drilling costs correlate highly with drilling efficiency, proppant costs are influenced the most by the amount of proppant and pumping costs are influenced the most by formation break pressure. Figure 8-21 also illustrates the relative importance of each well design parameter as it relates to the total cost of the well.

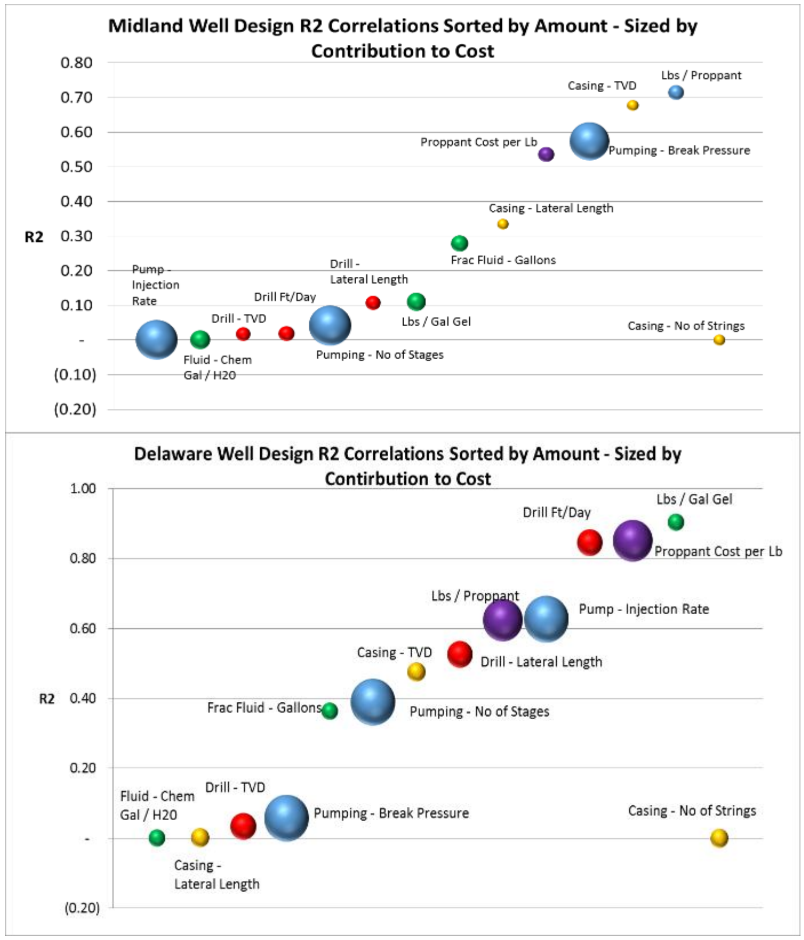


Figure 8-21: Midland and Delaware – Cost and well parameter correlations

Cost per unit

Depth of well and well bottom-hole pressure correlates with drilling costs. As noted in Figure 8-22, these have been declining due primarily to a decrease in both rig rates since 2012, which has accelerated in 2015 and an increase in drilling penetration rates. The Delaware play actually worsened in 2014 and was due to expanding drilling to riskier areas. We expect drilling cost per foot to improve over 2015. However in the years ahead higher cost rates will outpace any new drilling efficiencies.

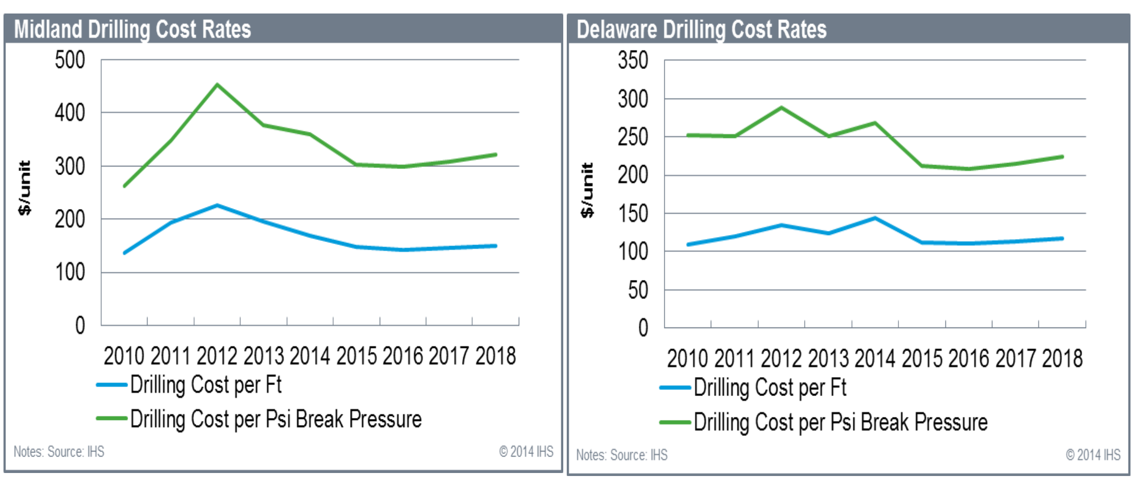
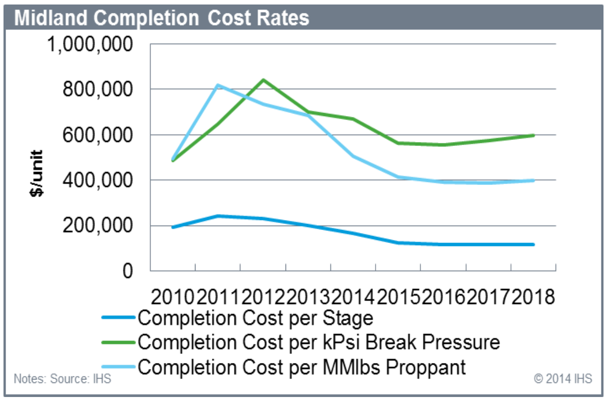


Figure 8-22: Midland and Delaware – Drilling cost rates

A similar decrease in costs for completion is also evident with the cost per break pressure and cost per pound proppant going down each year (Figure 8-23) for Permian. Cost per formation break pressure may go up slightly as this may not drive as much of the cost in the future as it once did. As operators use more frack stages per well, the economies of scale will also continue to reduce the unit costs.



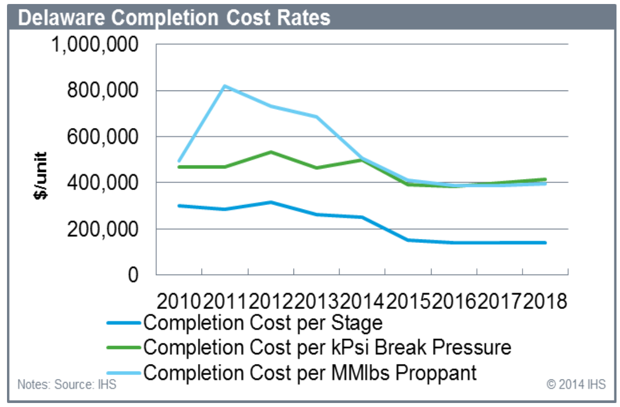


Figure 8-23: Midland and Delaware – Completion cost rates

I. Key Take-Aways

Performance concerns: Over time the Permian has achieved greater efficiencies in well design and implementation due to decrease of cost rates for the same activities and well design features. Wells have also become more complex and will continue to do so in the future. However, the Midland portion of the Permian has not benefitted as much as the Delaware. It actually performed worse in 2014 than in some prior years. With the play returning to core areas in the downturn, well performance is expected to make up for recent reductions as design and inputs into Permian wells grow. Going forward waning prospect quality and in-fill drilling may also contribute to decreased production performance and this will likely increase unit costs.

Economic performance is diminished by the drop in oil price. Substantial cost savings will be achieved for the next several years. This is due to the decreased rates operators have secured from service providers and not necessarily gains in efficiency. Nevertheless, we will continue to see incremental efficiency gains as operators continue to reduce drill cycle times and drill more wells from single pads.

Influential well design parameters: When modeling well costs in the Bakken the accuracy of some well attributes may be more important than others when estimating costs. Drilling efficiency, pounds of proppant, formation break pressure and lateral length are the key attributes whose change over time has greatly influenced costs and caused the most variance in the Delaware. In the Midland area the greatest drivers are pounds of proppant, TVD, formation break pressure and the cost per pound of proppant.

Decreasing costs: Rates for various materials and services peaked in 2012 when demand for high horsepower rigs (1000-1500) were in short supply and fracking crews were scarce. As the supply of these items increased to meet this demand, rates decreased and led to overall cost. This is despite increases in the amount of proppant and number of stages. This began a general downward trend which has accelerated in recent months by as much as 20% due to a very large over supply of these services.

Operating Costs: There is substantial variability in operating expense, with water disposal, long haul transport and artificial lift expenditures being the highest cost items. Given this variability, we would expect some operators to make substantial improvements. Due to the nature of the services provided, operating cost reductions will be much less than capital reductions going into 2015. Currently, about 45% of Bakken crude is transported by rail. The difference between long haul transport and pipeline transport could save an additional $8 per barrel and may make a large improvement to well economics going forward.

IX. Deepwater Gulf of Mexico

Each deep-water United States Gulf of Mexico (GOM) field discovery has its own set of features which influences the costs, including field size, water depth, proximity to other fields, reservoir depth and pressure, hydrocarbon product, and operator preferences. The impact on development economics is as follows:

- Well drilling costs: The cost of drilling wells in deep water is primarily driven by water depths and well depths. Technical aspects such as subsalt or, high temperature and high pressure (HTHP) environments can create challenges and drive costs up.
- Field development costs: These costs are related to the installation of equipment in a deep water environment, such as production platform installations and subsea tiebacks.
- Platform construction costs: Supplies, transportation, and installation of infrastructure are key elements affecting development economics.
- Pipeline layout costs: These include the set up and installation of hundreds of miles of deep water pipelines.

A. Description of major plays

The five core plays in the Deepwater GOM in this study are the Plio/Pleistocene, Miocene, Miocene subsalt, Lower Tertiary, and Jurassic. There is significant overlap among the plays, but the general play boundaries are outlined in Figure 9-1. The current focus of most material new field exploration is in the Lower Tertiary, Miocene subsalt, and Jurassic plays. The Lower Tertiary to Pleistocene sandstone turbidities have been historically the major exploration targets and still contain exploration potential. Currently, structural traps hold most reserves, while purely stratigraphic traps only stand for a small fraction of total reserves.

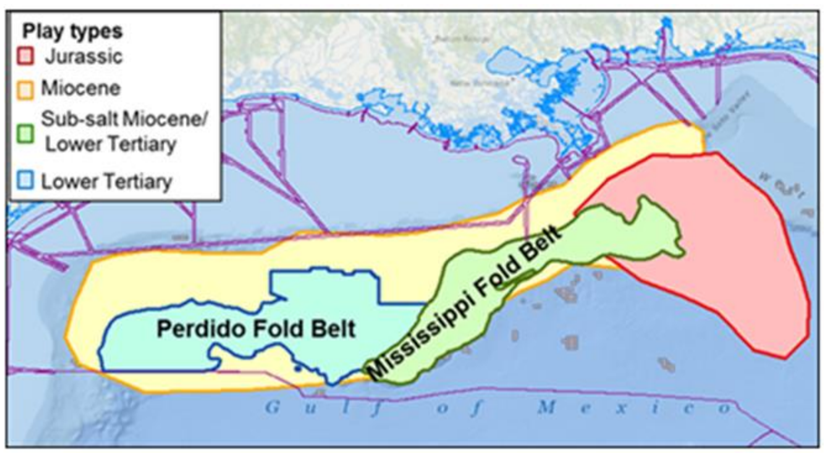


Figure 9-1: Deep water GOM major plays

Companies have moved into these three growth plays as technologies have advanced, allowing for increases in both water and drilling depths. Each growth play offers different opportunities based on a company's risk tolerance, skill set, materiality requirements, and available capital. In a sustained low oil price environment, the Lower Tertiary and the Jurassic face challenges due to constrained commerciality and high break-even costs. Companies must control costs, increase efficiencies, and access improved technologies to further improve the economics in these growth plays.

Recent drilling activities and permits

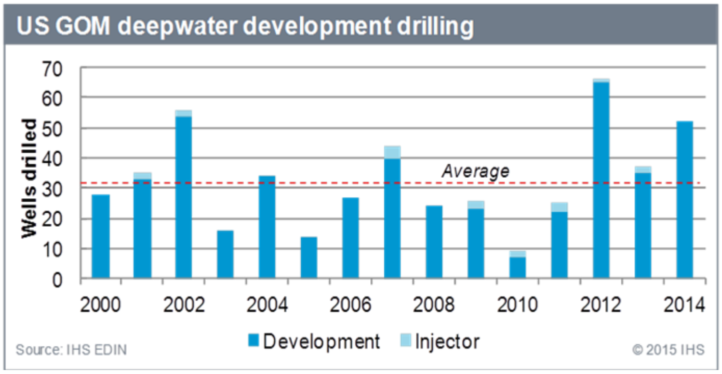


Figure 9-2: Deep water GOM development drilling

Deepwater GOM development drilling was steady until the 2010 moratorium following the Macondo incident. Activity quickly recovered after the moratorium was lifted in 2011. Figure 9-2 shows drilling surging in 2012 to compensate for drilling and production declines in the preceding years, and 2014 marked one of the highest activity levels in decades.

Exploration and appraisal drilling has responded differently than development drilling after Macondo. Figure 9-3 indicates that the return to exploration drilling post-Macondo was more gradual than development drilling as companies took the time to assess the new operating environment. Exploration drilling post-Macondo (2011-2014) has averaged 27 wells per year, with the sharpest drop occurring in the immediate aftermath of the incident. Exploration and appraisal drilling has gradually increased, reaching 47 wells in 2014, the highest level in over a decade.

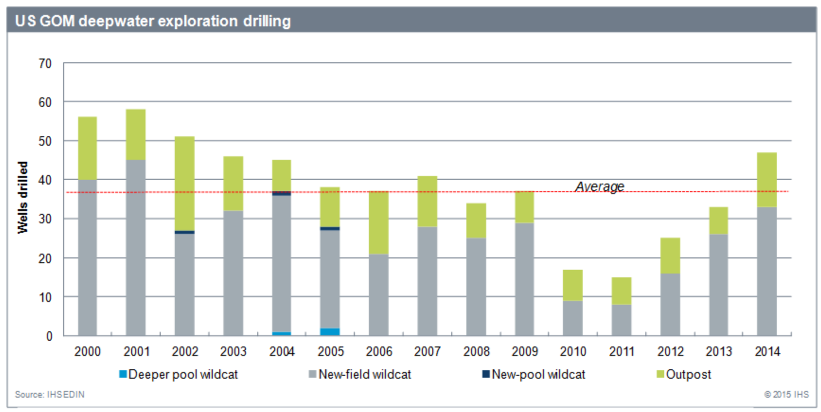


Figure 9-3: Deep water GOM exploration drilling

Permit submission data from the US BSEE (Bureau of Safety and Environmental Enforcement) is an important leading indicator of operator near-term future investment behavior in the deep water GOM. Permitting data in Figure 9-4 for 1H-2015 shows a continued drop in permit submissions, as operators have responded to falling oil prices by cutting capital expenditure. During this half year, total submitted well permits declined by 24% from 2H-2014 and 34% from 1H-2014. During this same time period, permit resubmissions—essentially revisions to existing permit requests—remain close to all-time highs, reflecting a larger regulatory burden in the GOM post-Macondo operating environment.

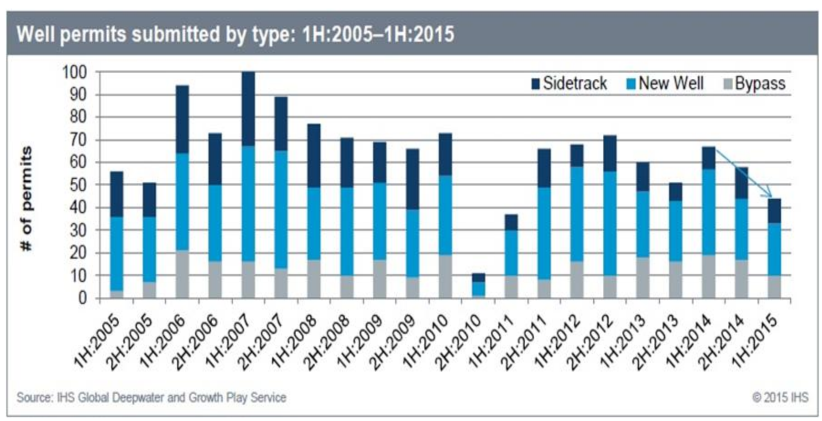


Figure 9-4: Deep water GOM wells permits

Major operators field discoveries

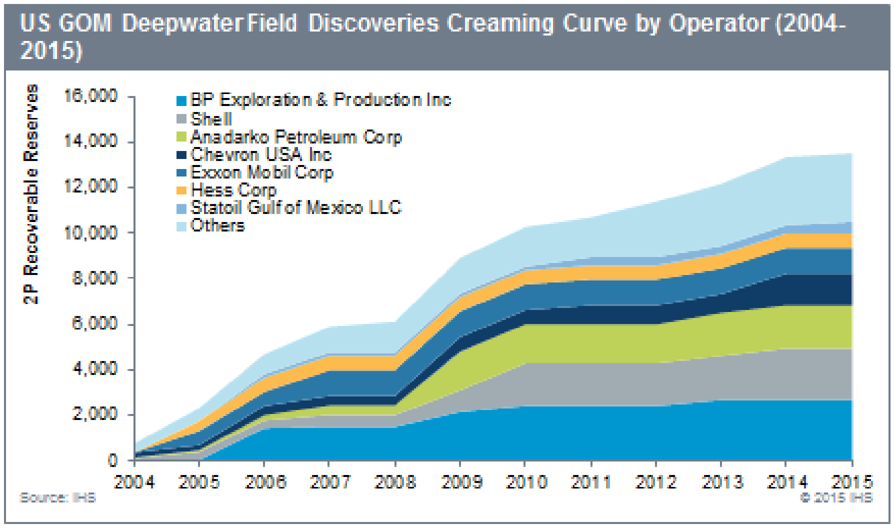


Figure 9-5: GOM deep water discoveries by operator

Most of the field discoveries since 2004 were led by six operators—Shell, BP, ExxonMobil, Anadarko, Chevron, and Hess. Figure 9-5 shows the deep water discoveries creaming curve by operator. BP has become the largest acreage holder and most dominant operator over the last twenty years and has established a significant scale advantage in the basin. BP's current development activity is focused on large Lower Tertiary play fields. Shell's current exploration focus is the frontier Jurassic play. Anadarko's significant basin presence grew following the acquisition of Kerr-McGee in 2006. The company's position is extensive, and it is building a basin portfolio of significant scale by exploring in three of the growth plays. Chevron's focus has been on the Lower Tertiary play, which provides materiality for the company and is the main focus of its current activity in the basin.

B. Deepwater development concepts

Drilling

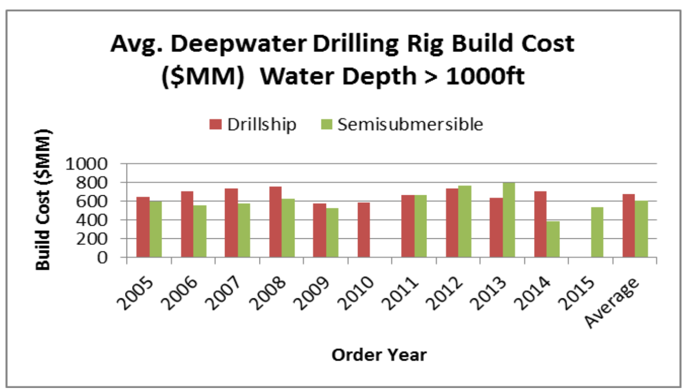


Figure 9-6: Average deep water rig build cost

There are two major types of drilling rigs for water depths of 1,000 feet and deeper: semisubmersibles and drill ships. Semisubmersibles (semis) consist of floating equipment with a working deck sitting on top of giant pontoons and hollow columns. Most semis use anchor mooring systems, although recently more semis employ computer controlled dynamic position systems (DP), which automatically adjusts with wind and waves by a global positioning system (GPS) signal received from a satellite. A drillship is a specially built vessel with a drilling derrick to drill the wells in water depths of up to 12,000 feet, and its position is also maintained by DP. A drillship has better mobility, but is less stable in rough water. It is often used in drilling exploration wells. Drillship build costs are slightly higher than semisubmersibles, and thus the day rate is higher as well. The estimated average build cost since 2005 is $600MM for semis and $650MM for drill ships (Figure 9-7).

As a deep water field enters the development phase, the development wells sometimes are drilled from the production platform with drilling modules, which include the hydraulic, electrical, and load capacity similar to floating rigs, which are positioned on the decks of the production platforms.

Field Development

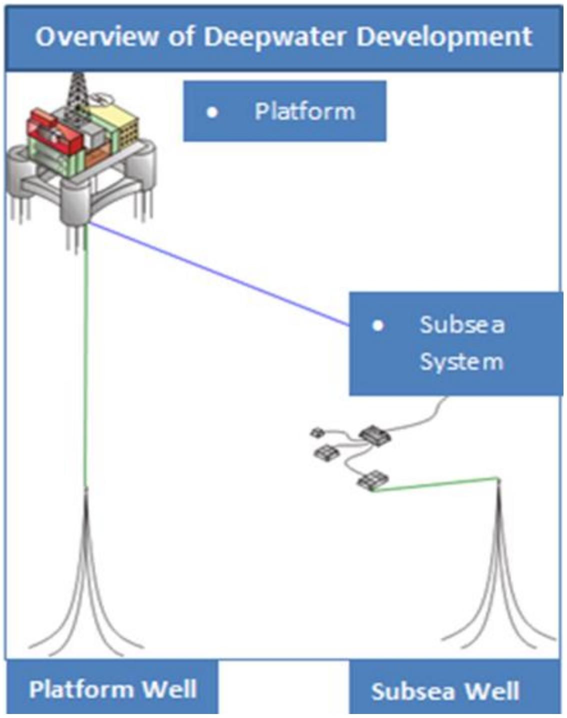


Figure 9-7: Deepwater development

The two types of field development schemes in deep water are: standalone development and subsea development (Figure 9-7). Deep water wells are either developed through standalone infrastructure, a floating production platform or subsea systems that tieback to a production platform. Subsea development systems are generally less expensive than standalone infrastructure and are more suitable for smaller fields with no nearby infrastructure. Since offshore operations now extend to water depths of 1,500 feet and deeper, which are beyond practical fixed platform limits, floating production systems now provide viable options in the deep water. Currently there are approximately 50 floating production platforms in deep water GOM, and most of them reside in 5,000 feet and shallower water depths. Infrastructure is scarce beyond 5,000 feet, especially in the Lower Tertiary area.

Selecting the right development system involves assessments of water depth, reservoir character, location, and accessibility to infrastructure. Figure 9-8 shows four major types of floating production facilities for deep-water fields: tension leg platform (TLP), spar platform, semisubmersible floating production platform (semi), and floating production storage and offloading system (FPSO).

Tension leg platforms (TLP) or extended tension leg platforms (ETLP) use a combination of pontoons and columns, are best suited for water depths of 5,000 feet and shallower, and could have either a dry tree on the platform or wet tree at the sea floor. Spar platforms float from large diameter cylinders, weighted at the bottom to keep them upright. They can be used in water depths up to 7,500 feet. Like TLPs, both dry trees and wet trees can be installed. Semisubmersible platforms, by definition, were borrowed from semi drilling rig concept and consist of semisubmersible hulls with a production facility on board. Floating platform, storage, and offloading (FPSOs) facilities are large ships made from either converted tankers or are newly built, moored with rope chain and have no drilling facility. Subsea wells are tied back to FPSOs. Production is processed, and oil is stored in the FPSO with periodical offloading and transporting via shuttle tanker. In the GOM, spars have been the most widely used production system, followed by TLPs and semisubmersible platforms.

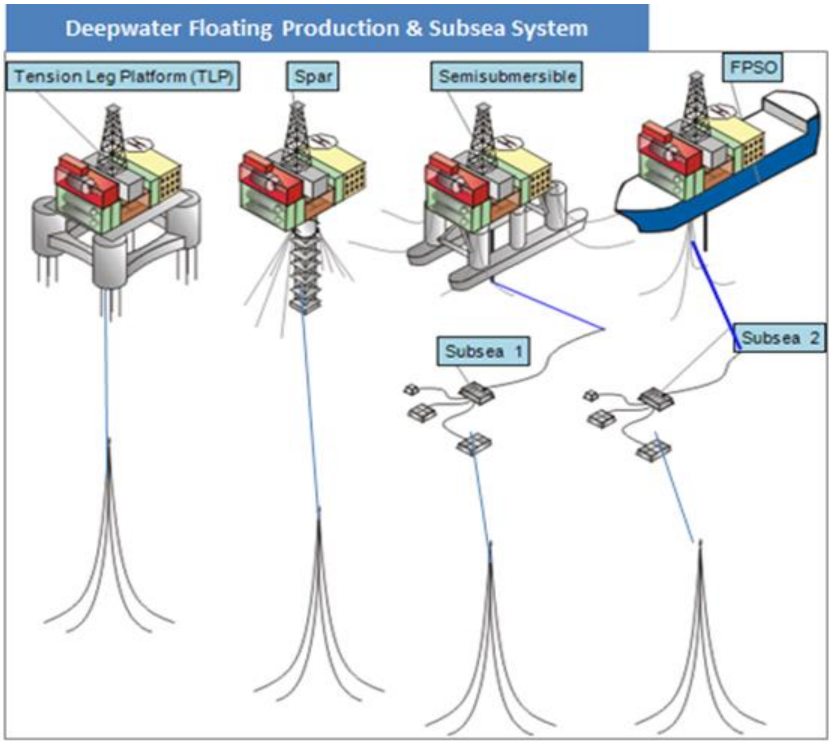


Figure 9-8: Deepwater FPS and subsea system

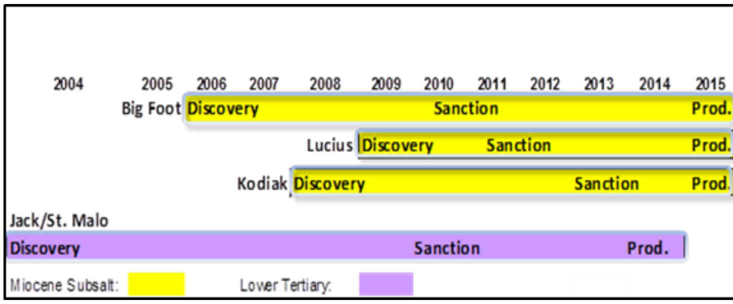
Subsea production systems are applied in two scenarios: (1) they connect smaller fields to nearby existing infrastructure; and/or (2) they can be applied to an area where existing infrastructure is scarce, especially in emerging plays. In a situation where several discoveries are located close to each other, but not reachable by directional drilling, a combination of subsea systems and central floating production platforms are applied for joint field development. Anadarko's Lucius field and Chevron's Jack/St. Malo fields are typical joint subsea system and FPS developments. Subsea systems can range in complexity from a single satellite well with a flow line linked to a deep water floater to several well clusters connected by manifold to a floating facility via flowline and flexible riser.

In addition to technical assesments, ultimate development decisions are dominated by project economic conditions, which sometimes require collaboration and joint effort between operators. The "Hub concept" has been adopted by GOM operators to jointly develop a giant central production platform as a "Host" to process and handle production from adjacent multiple fields. Independence Hub, located on Mississippi Canyon Block 920 in a water depth of 8,000 feet, is the result of a team effort of five E&P companies and one midstream energy company coming together to facilitate the development of multiple ultra-deepwater natural gas and condensate discoveries.

Recently, in response to a lower commodity price environment, many of the large operators in the deep water GOM have been revisiting development options and scenarios, with a near-term focus on leveraging existing production infrastructure to develop discovered resources through lower cost subsea tieback developments.

C. Deep water GOM project cost study

IHS selected four projects representing different plays, development concepts, and technical challenges and performed high level project cost analysis on each. All the projects included came on stream in late 2014 or 2015. Capital costs for these projects did not include seismic, leasehold capital cost, operating cost, and decommissioning. All projects are modeled using IHS QUE$TOR and cross-referenced with published cost data and project development descriptions. Costs are based on 3rd quarter 2014 cost environment adjusted by historical rig rates for exploration, appraisal, and development wells. Figure 9-9 presents a high level timeline of the projects. This analysis proves that the Miocene is the most cost competitive play and although the resources discovered in the Lower Tertiary are quite significant, the Lower Tertiary requires far more capital and takes much longer to develop.



Project	2P Reserves (Mmboe)	Est. Total Capex ($Billion)	Capex $/Boe	Opex $/Boe	Development
Big Foot	198	4.3	22	11	ETLP w/ dry tree & drilling Facility
Lucius	276	2.3	8	9	Spar & SS tie back
Kodiak	65	1.2	18	8	SS tie back (HP & HT)
Jack/St. Malo	500	12	24	17	Semi Prod. Hub & SS tieback (HP & HT)

Figure 9-9: Deepwater project overview

Chevron Big Foot Project (Miocene subsalt & TLP platform)

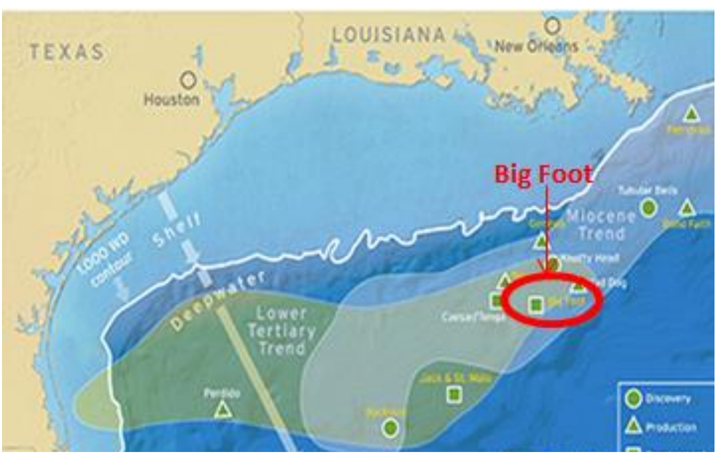


Figure 9-10: Big Foot location map

The Big Foot field is located in the Gulf of Mexico about 225 miles south of New Orleans in water depths of 5,200 feet (Figure 9-10). Discovered in 2006, Big Foot sits in the Walker Ridge area and holds estimated total recoverable resources in excess of 200 million oil equivalent barrels. The reservoir is Miocene subsalt with average well depths of about 25,000 feet SSTVD. It is expected for production to come on-stream in late 2015.

Chevron developed the field using a dry-tree floating, drilling and production facility, Big Foot ETLP (Extended Tension Leg Platform), which features dry trees and top-tensioned risers. It has full drilling capabilities including workover and sidetrack capability on the topsides and has a production capacity of 75,000 barrels of oil and 25 million cubic feet of natural gas per day. The ETLP hull was built in South East Asia, and integration took place in the US. The ETLP features a push-up type tensioner system, which allows it to withstand the harsh conditions of the area. A model test of the ETLP indicates that it would be able to withstand a 1,000-year hurricane and loop currents, which can often delay and damage installations and can be very costly.

We modeled the Big Foot development in QUE$TOR based on the development plan published by Chevron. Figure 9-11 shows the development schematic: 13 wells, including 3 water injectors drilled from the platform with dry tree on board, ETLP, and two pipelines transporting oil and gas. The D&C cost is $81 MM per well, significantly lower than other Miocene subsalt wells. In contrast, the platform cost is far more expensive than other TLPs in the GOM at $2.67 billion (63% of the total $4.3 billion project cost). The Big Foot oil pipeline is 40 miles long with a 20'' diameter and lies in depths of up to 5,900 feet. The gas pipeline is 17 miles long, and total pipeline cost is $258MM (Figure 9-12).

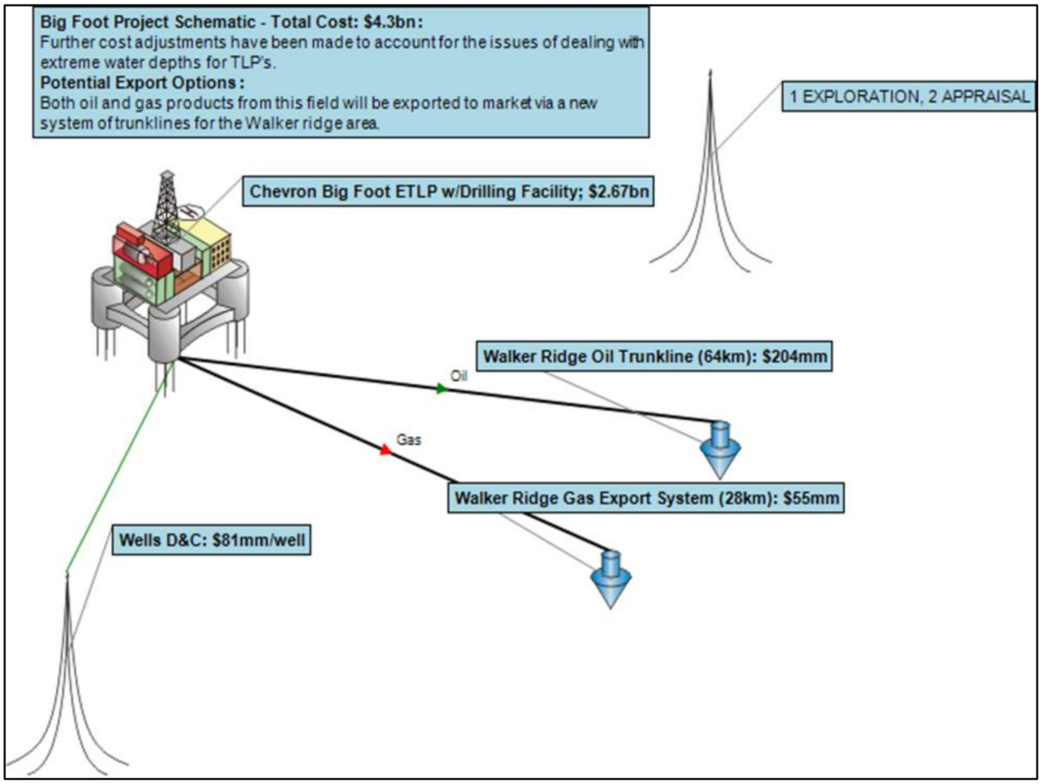


Figure 9-11: Big Foot Project Schematic

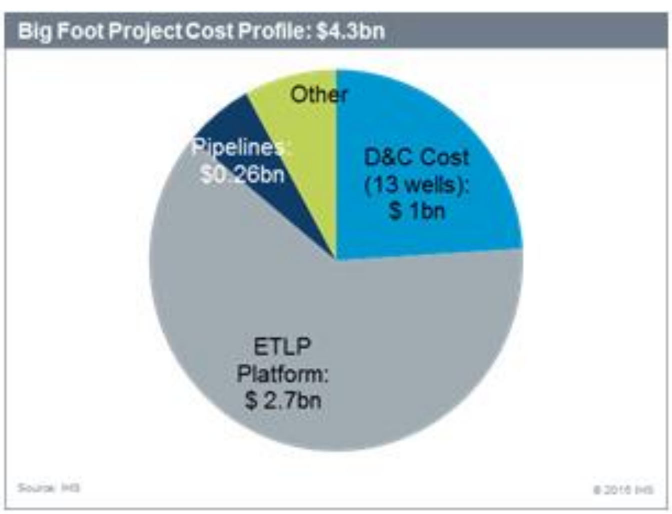


Figure 9-12: Big Foot cost profile

Anadarko Lucius Project (Miocene subsalt & Spar platform with subsea system)

The Anadarko operated Lucius oil field is located in the Keathley Canyon Block with a 7,100 feet water depth, containing approximately 276 MM Boe 2P recoverable reserves in the subsalt Pliocene and Miocene sands. Lucius produces oil and gas through a truss spar floating production facility. The spar is 605 Ft-long with a 110 Ft diameter, is installed in 7,100 Ft of water and has a capacity of 80,000 BOPD and 450 MMcfd. Six subsea wells with well depths of approximately 19,000 Ft TVD are tied back to the Lucius spar platform, making the total project scheme a combination of a production platform and subsea system (Figure 9-13). Oil produced by the Lucius spar is exported to the South Marsh Island (SMI) Area Block 205 Platform by an 18 in diameter - 145 mile long pipeline divided into three sections.

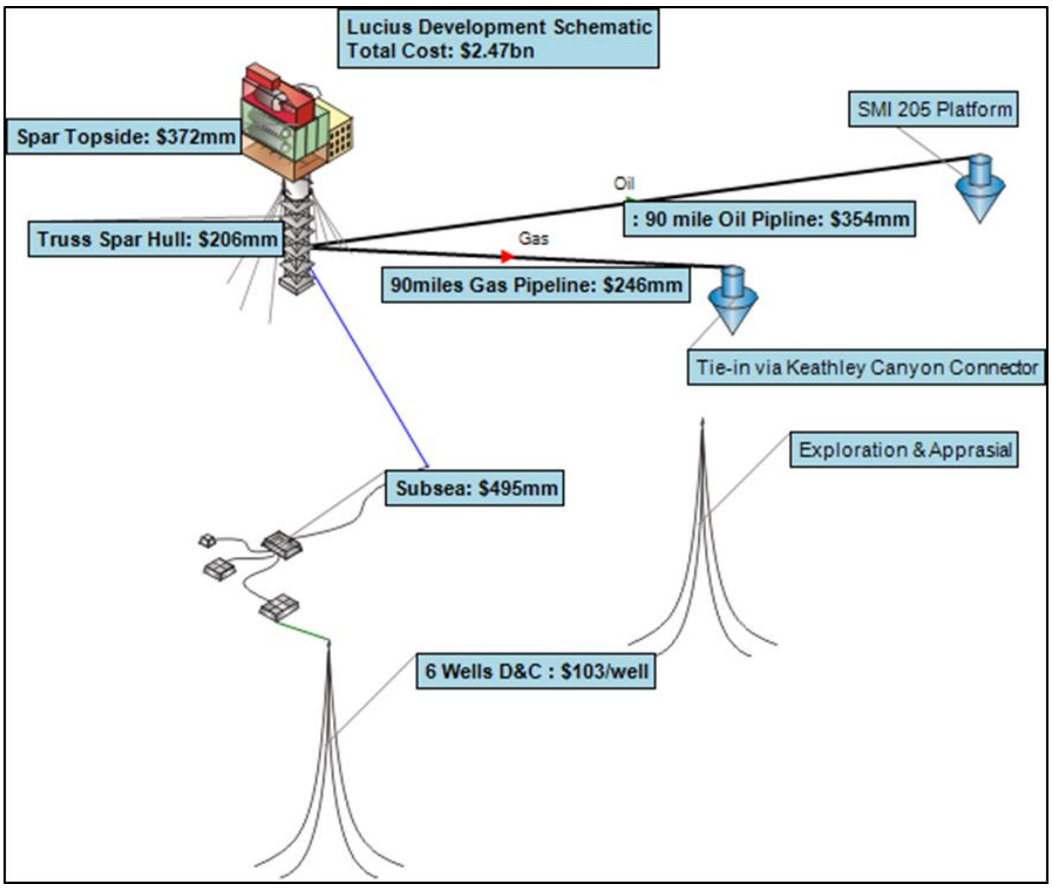


Figure 9-13: Lucius location and development schematic

The field's first oil was produced in January 2015, with total development costs at approximately $2.47 billion (Figure 9-14). D&C costs were approximately $103MM per well. The total project contains four major cost components: 6 subsea wells D&C, truss spar platform, subsea system, and pipelines. The subsea system includes one subsea cluster hosting 4 wells and two subsea satellite wells, which are all connected to a flexible riser via subsea manifold, jumper and flow line. An electrical umbilical is connected to subsea control panels and transmits information about temperature, pressure and subsea integrity, as well as electrical power to the subsea equipment.

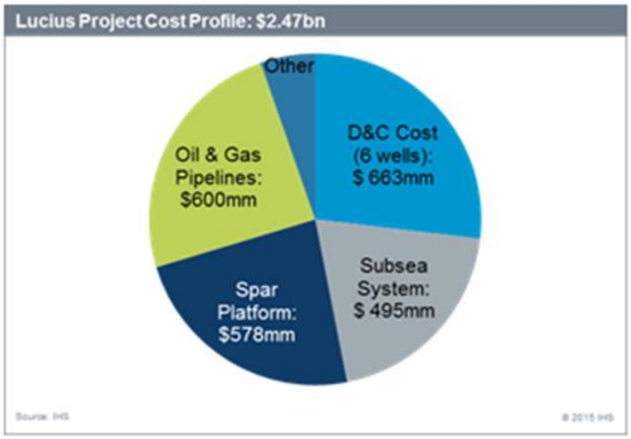


Figure 9-14: Lucius cost profile

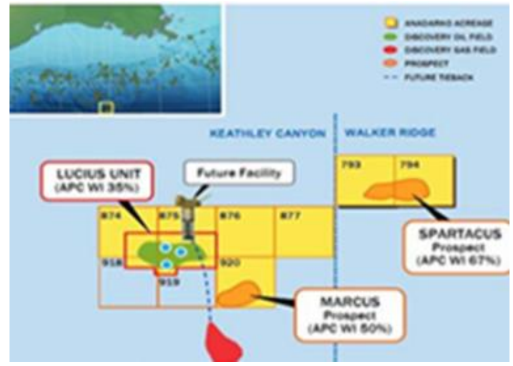


Figure 9-14a: Lucius location map

Kodiak Project (Miocene subsalt & subsea tieback HP&HT)

Kodiak is located in Mississippi Canyon Blocks 727 and 771 in water depths of 5,000 feet. The reservoir contains six pay sands in the Miocene subsalt at approximately 29,000 feet depth in high pressure and high temperature (HPHT) reservoirs. The exploratory well encountered over 380' of Middle and Lower Miocene hydrocarbon-bearing sands. Two appraisal wells have been drilled. Development plans for the field call for smart completions and subsea tieback wells to the Devils Tower Truss Spar, located 6.5 miles southeast (Figure 9-15).

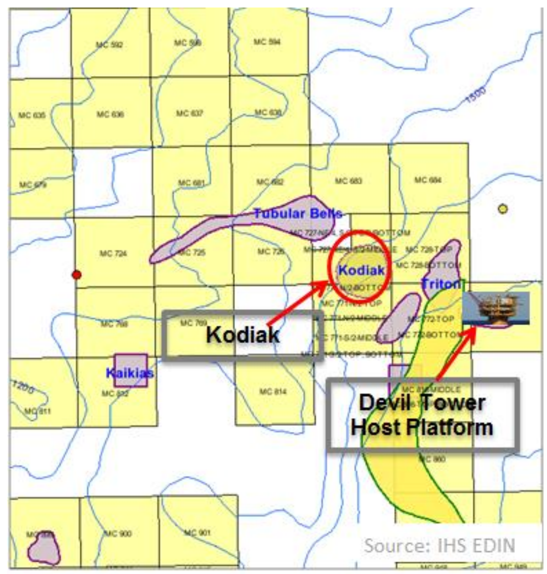


Figure 9-15: Kodiak location map

The project schematic (Figure 9-16) consists of a two-well subsea tieback to the Devils Tower truss spar in Mississippi Canyon Block 773. Ultra-deep well depth and high pressure-high temperature (HPHT) create tremendous technical challenges from drilling to subsea tieback and installation. High pressure and high temperature resistance equipment and design inevitably add 20% to 30% to the total cost. Figure 9-17 indicates that the D&C costs are estimated to be about $200MM per well. Several unique technical features are highlighted in this project. First, smart recompletion design makes sleeve changes and commingling multiple sands available with minimal well intervention and downtime once production is on-stream. Second, HPHT resistant equipment and well design are carefully calculated and selected to ensure safety and regulation compliance. All drilling and completion elements, including conductor, casing, tubing, well head equipment, BOP, mud weight, cement job, as well as frack pack design, are made to fit harsh downhole conditions. The subsea system, which includes subsea tree, flowline, and riser, also requires special designs in order to handle corrosive production fluids. The pipeline will be of a bi-metallic construction, lined with a corrosion-resistant alloy. In addition, the host platform modification is also required to handle above-normal arrival pressure and temperature. This modification includes processing equipment modification, umbilical and control system and riser tube installation, which adds about $60MM to total project cost.

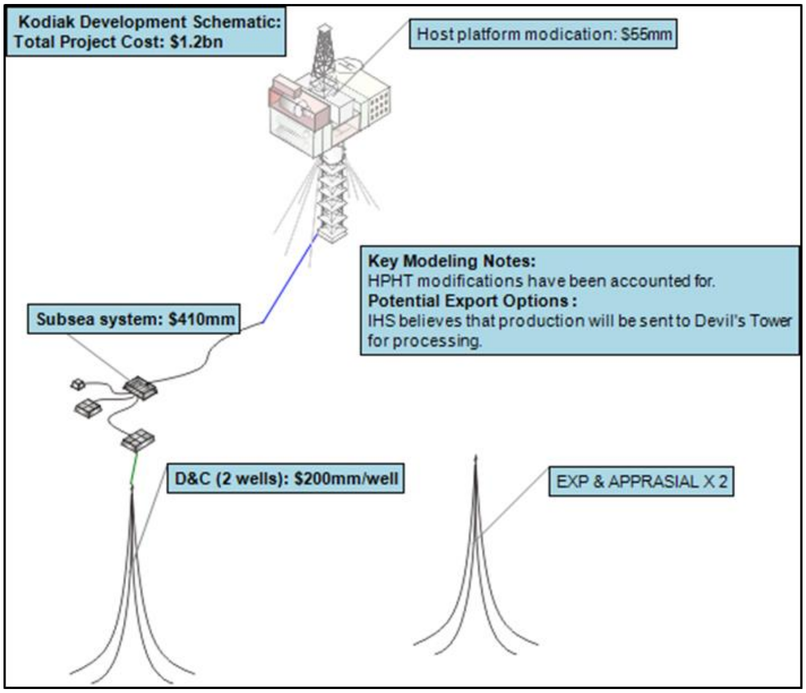


Figure 9-16: Kodiak development schematic

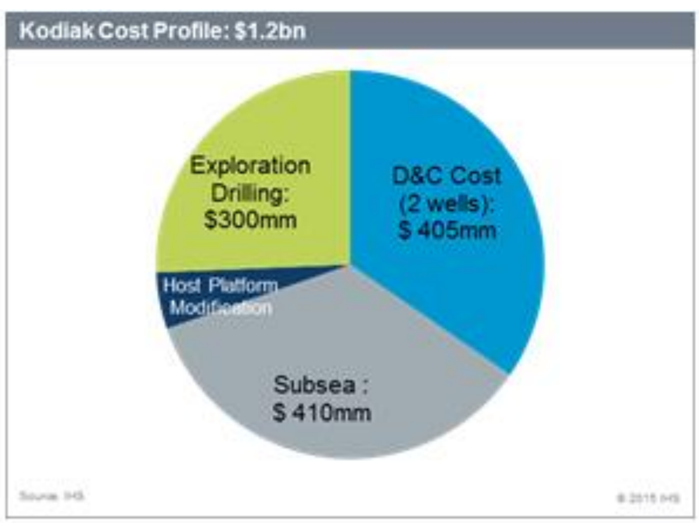


Figure 9-17: Kodiak cost profile

Chevron Jack/St. Malo (Lower Tertiary subsalt and semi platform with subsea system)

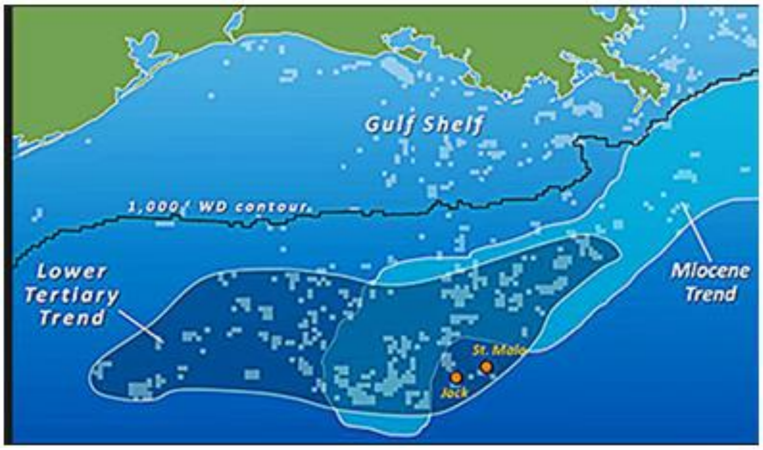


Figure 9-18: Chevron Jack/St. Malo location map

Chevron-operated Jack / St Malo deep water project comprises the joint development of the Jack and St Malo oilfields, which are situated approximately 280 miles south of New Orleans, Louisiana and 25 miles apart, in water depths of approximately 7,000 feet (Figure 9-18). Reservoir depths are in the order of 26,500 feet. Total recoverable resources of the two fields are estimated at over 500 MMBoe. First production was announced in December 2014.

Figure 9-19 shows the fields being co-developed with subsea completions flowing back to a single host floating production unit (semisubmersible) located between the fields. Electric seafloor pumps are used to assist production to the host. The Jack and St. Malo host facility has an initial capacity of 170,000 Bopd oil and 42.5 MMcfd of natural gas, with the capability for future expansion. The facility is the largest semi-submersible in the Gulf of Mexico (based on displacement) and has been designed to operate for at least 30 years. The hull was fabricated and constructed in South Korea, and topside facilities were fabricated and constructed in Ingleside, Texas. The semi platform acts as a hub for over 20 subsea wells, which are divided into one subsea cluster for the Jack field and four subsea clusters for St. Malo. Each cluster is comprised of subsea wells, manifolds, pumps and other equipment on the seafloor, and is tied back to the facility. Water injection wells and subsea booster system are also included. Several new technologies were developed and applied to develop the Jack/St. Malo fields. According to Chevron's

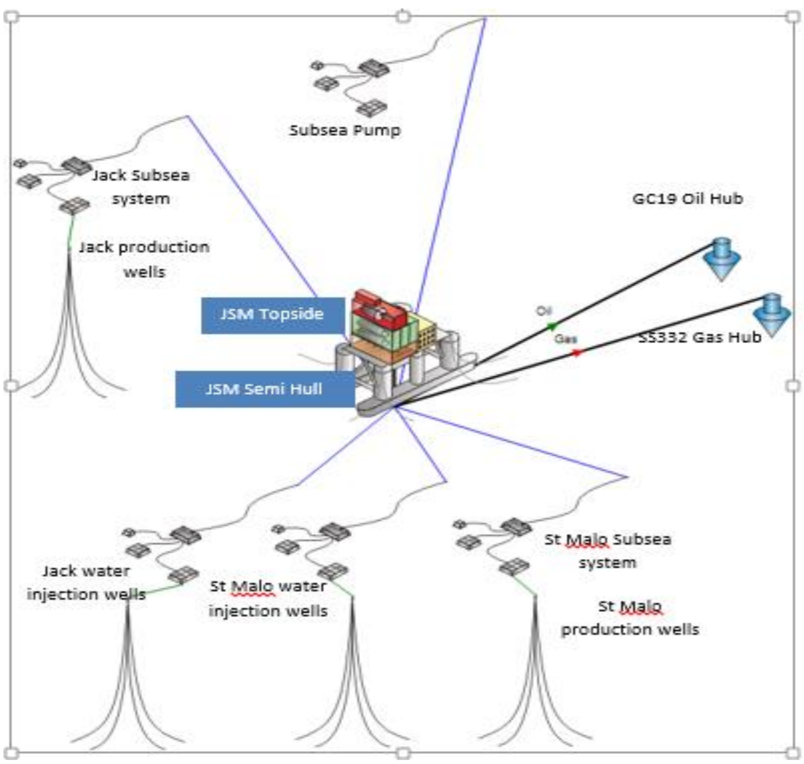


Figure 9-19: Chevron Jack/St. Malo development schematic

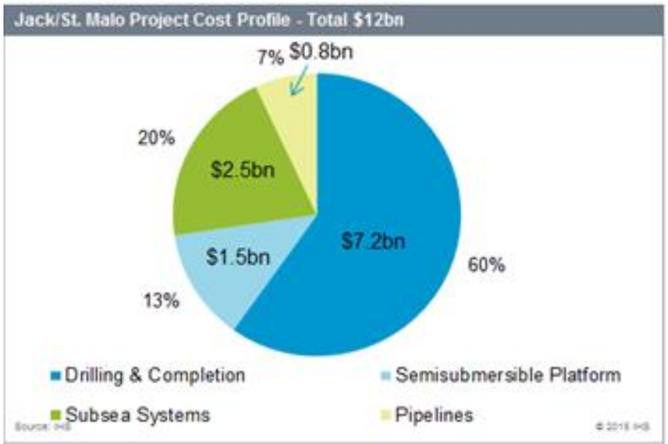


Figure 9-20: Chevron Jack/St. Malo cost profile

announcement, its subsea boosting system is ranked as the industry's largest seafloor boosting system, increasing power by 10% over the previous industry maximum and able to withstand 13,000 Psi of pressure. A single-trip multi-zone completion design is able to capture more layers of reservoir in significantly less time, saving $25MM per well based on rig time operating costs. A 140-mile, 24-inch oil export pipeline marks the first large diameter, ultra-deep water pipeline in the Walker Ridge area of Lower Tertiary trend. Figure 9-20 shows that of the total $12 billion estimated project cost, 60% will be spent on drilling and completion of subsea wells (each costing about $240MM per well, which is a typical well cost for Lower Tertiary HPHT wells). A cost of $1.5 billion is estimated for the semisubmersible platform. A $2.5 billion subsea system cost is comprised of 4 subsea clusters, 3 flowlines connecting clusters to risers, 2 flexible risers reaching the platform, 6 water injection subsea manifolds, and one subsea pump. A HPHT resistant subsea pump costs around $300MM.

D. Detail cost components and cost driver analysis

Drilling and Completion Cost

There are four major categories of deep water drilling and completion cost: (1) installation or rig and related cost; (2) materials such as casing and tubing; (3) equipment such as wellhead equipment (i.e. Christmas tree); and (4) insurance. Because deep water drilling requires a floating drilling rig, (i.e. semisubmersible or drillship) to perform the drilling operation, the day rate could be over $500,000 during a period when demand is high. It is not surprising that the rig and its related cost could account for 89% of the total D&C cost (Figure 9-21).

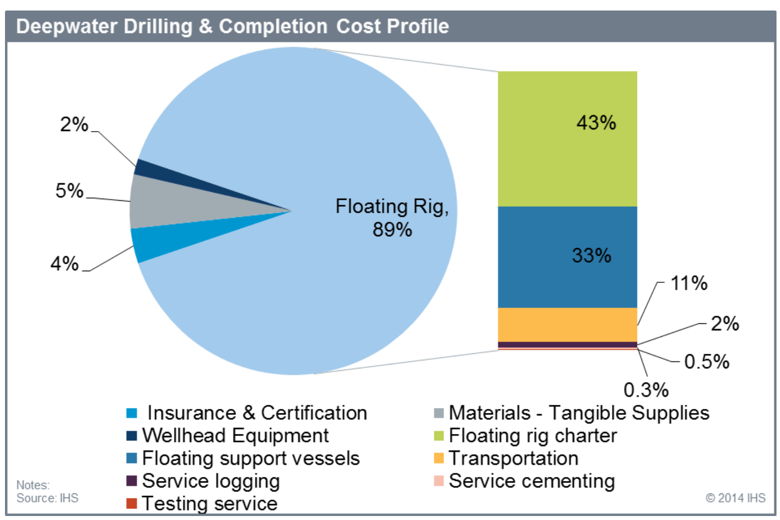


Figure 9-21: Drilling and completion cost component

Detailed components of the rig and related costs show that almost 43% are associated with floating rigs and over 33% are for support and supply vessels. The day rate and time spent onsite are key drivers to the total drilling and completion cost. Figure 9-22 shows total rig day rates vs. water depth and well depth. The water depth primarily drives the day rate as floating drilling rigs are chartered and priced based on water depth. In addition to the floating rig, support and supply vessels play an important role by providing supplies to drilling operations. Helicopter and other services such as logging, cementing, and testing also are vital to the operation and could be costly (Figure 9-23). Please note that special logging service and testing are optional for offshore development wells, but are necessary for exploration and appraisal wells in order to evaluate the reservoirs.

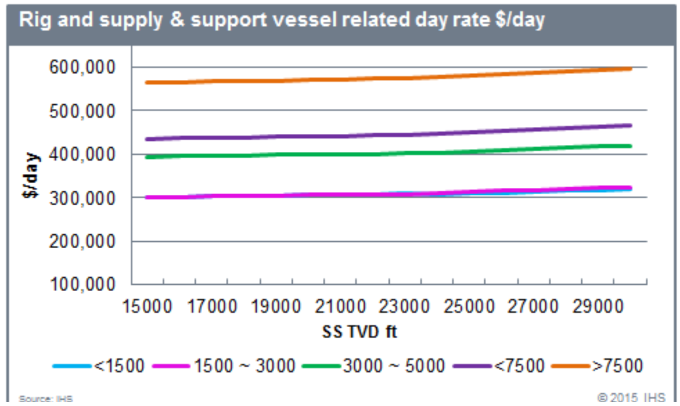


Figure 9-22: Rig & related cost vs. water depth & well depth

INSTALLATION			Location: Gulf of Mexico
	QUANTITY	UNIT RATE	COST
Floating bare rig charter	100 day	350,000	35,000,000
Floating drill crew	100 day	26,500	2,650,000
Floating marine crew	100 day	11,100	1,110,000
Floating consumables	100 day	24,100	2,410,000
Floating helicopter services	100 day	5,700	570,000
Floating support vessels	100 day	308,000	30,800,000
Floating supply base	100 day	6,800	680,000
Specialist service logging	2	880,000	1,760,000
Specialist service cementing	1	335,000	335,000
Specialist service testing	1	450,000	450,000
Transport	20 day	483,000	9,660,000
Site preparation	2 day	215,000	430,000
Total Installation		$	**85,855,000**

Figure 9-23: Installation - rig & related cost

While day rates are driven by water depth, the rig onsite service days are a factor of well depth and are often goverened by the geological and technical complexity of the reservoir. Figure 9-24 shows the correlation between rig days and well depths under regular reservoir conditions. Under technically challenging conditions, like subsalt, HPHT or overbalance/underbalance reservoirs, it will take much longer (sometimes over a year) to reach total depth of the well and may periodically require a sidetrack if tools are damaged or lost in borehole. Other factors unique to the deep water GOM environment, such as hurricanes and loop currents, can also significantly delay the drilling operation.

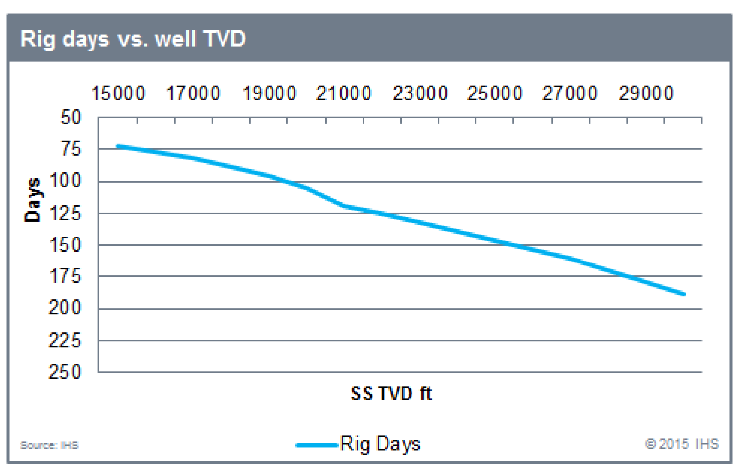


Figure 9-24: Average rig days by play by operator

Nevertheless, the combination of day rate and rig service days are unquestionably the key drivers of total drilling and completion cost. Operators work very hard to secure the rig at the best rate possible and are motivated to reduce downtime to a minimum level. Offshore transportation is also critical, given the distance from shore base. Helicopter and boat expenses, if not well-managed, could also contribute to cost overruns. Wellhead equipment, as part of tangible cost, plays an important role in the cost as well. Christmas trees can be installed either at the seafloor well head or on the production platform, serving as the dry tree. Like onshore wells artificial lifts, such as an electric submersible pump (ESP), are also commonly applied to the oil well perforation point and could cost between $3MM to $5MM. Figure 9-25 provides a glimpse of cost ranges for major components of deep water GOM. The rig cost could swing from $25MM to over $100MM depending on the water depth and well depth, as could the support and supply vessel cost. Cost for production and wellhead equipment, including ESP, ranges from $11MM to $15MM. Downhole hardware and the cost of the equipment like conductors, casing, tubing, and production liner ranges from $7MM to $13MM. Cementing and logging service costs are between $2MM to $7MM. In a nutshell, the overall drilling and completion costs at normal reservoir and well conditions are estimated between $60MM to $240MM for wells in water depths from 7,500 feet to 15,000 feet. The special well design expense for HPHT environments cannot be overlooked when estimating the cost and can add 20%-30% to the total cost.

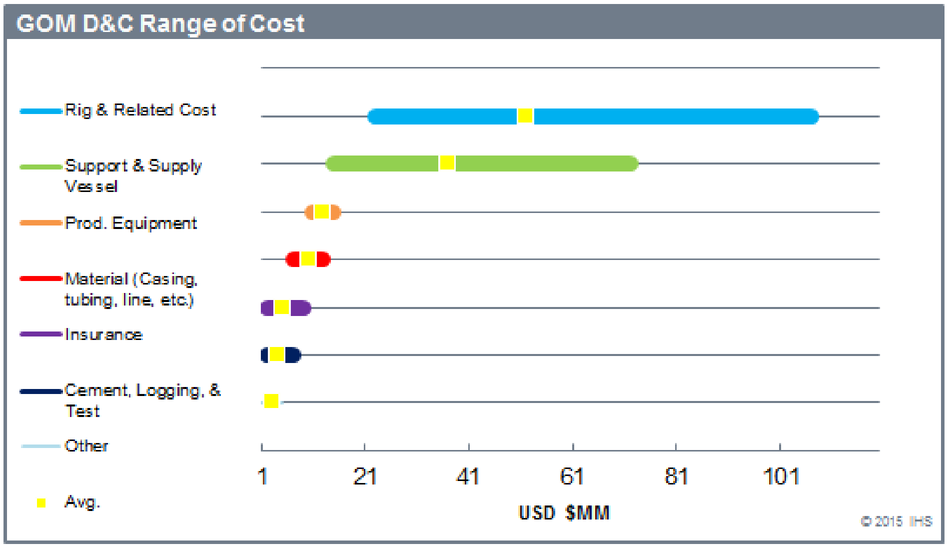


Figure 9-25: GOM deep water D&C cost range

Deepwater GOM's range of D&C cost sensitivity, shown in Figure 9-26, once more confirms rig costs can increase as much as 100% over the average cost as a direct result of rig rate and rig days. In other words, offshore deep water cost can be extremely time sensitive. Major operators' rig days could run from 150 days to almost 300 days depending on the play. Jurassic play

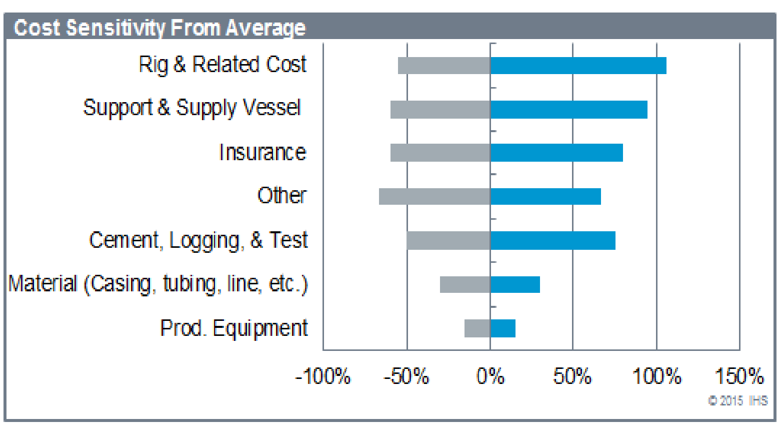


Figure 9-26: GOM deep water D&C cost sensitivity

drilling proved to be the most time consuming due to its water depth.

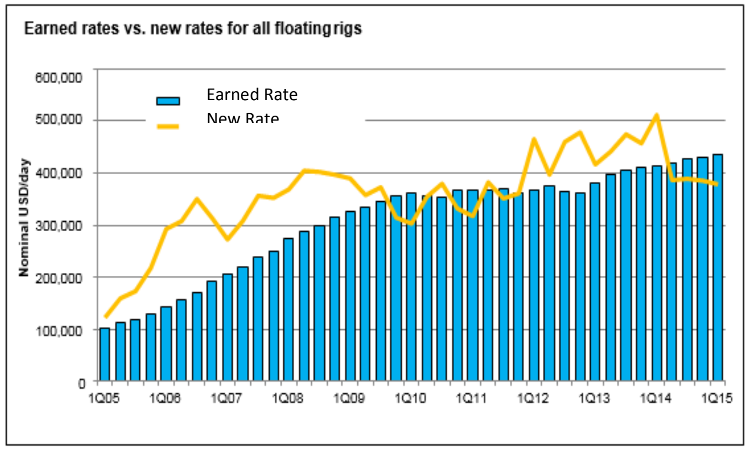


Figure 9-27: Earned rates vs. fixed rate

Rig rate is driven by supply and demand in the short term. Rig build cost has remained unchanged over the last 10 years and thus has a minimal impact on the day rate. Figure 9-27 indicates that over the last decade, the biggest rig rate drop was seen between 2010 and 2011, associated with the decreased activity following the moratorium after Macondo. While there is still significant drilling activity taking place in the deep water GOM, the short term outlook may be less encouraging. As of the first quarter of 2015, average new fixtures rates (the new contract rate) were at $378,708/d versus $436,482/d for earned rates (existing contract rate) combining semisubmersible and drillship, reflecting a 13% reduction. Earned rates represent those contracts signed a year or two ago, while fixed rates are new contract rates, representing the current market condition. Without a turnaround in new fixture day rates, this would indicate that average day rates have started declining. The number of operators looking to secure rig time in 2015 has also dropped considerably, which reflects the operator's concerns of a longer than expected price recovery. In addition, with the falling of average lead time, operators are confident that they will be able to secure rigs when needed and that new fixture rates are more likely to fall.

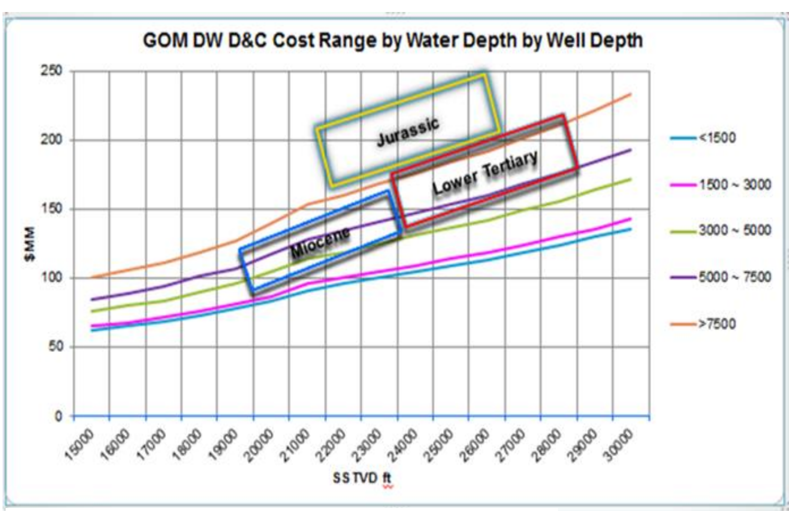


Figure 9-28: Well cost by drilling depth

In conclusion, water depth, well depth, reservoir quality and productivity are key drivers to drilling and completion cost. Of the three major plays, both water depth and well depth in the Miocene area are shallower and therefore, the Miocene has an advantage over other plays due to its higher estimated well productivity and relatively shallower reservoir depths (20,000 to 24,000 SSTVD). Most of the drilling and completion costs for Miocene wells falls between $70MM to $165MM (Figure 9-28); however, Miocene subsalt costs could be much higher given the geological complexity and unpredictability of the play. The Lower Tertiary has experienced the most technical challenges and thus higher well costs because of the play's lower permeability, deeper reservoirs (>30,000 Ft) and HPHT environment. Lower Tertiary subsalt well costs ranges between $150 to $220MM (Figure 9-28). The Jurassic is located in the deepest water depth which results in the highest well costs at about $230MM. This estimated well cost assumes a vertical well, wet tree, normal reservoir conditions with downhole electronic submersible pump (ESP), and no acid gas. If extreme well conditions are considered, such as high pressure and high temperature or acid gas and heavy oil environment, the well cost could increase by an additional 20 – 30 percent.

Field Development Concept Cost Comparison and Floating Production Platform (FPS)

Of the 130+ deep water GOM fields discovered since 2004, there are approximately 60 fields either in production, under development, or have a sanctioned and selected development plan. Defining and planning development strategy in the early phase of a project is vital to the success of projects. The development concept is primarily driven by reserve size, water depth, and infrastructure availability or proximity. In general, the subsea tieback is suitable for smaller fields if there is a platform nearby to tie-in to. Most of the time floating production platforms are needed because of either: (1) larger discovered reserves, and/or (2) no nearby infrastructure. Figure 9-29 shows the estimated total project costs for the selected 60 fields discovered since 2004 at different development concepts for different plays; these indicate the correlation between project costs, reserve size (2P) and development concept within the various plays. The subsea tieback is selected for most of the Miocene fields, with a cost range between $100MM and $1.5 billion. For associated development wells, spar and subsea tieback project costs range from $500MM to $6.3 billion, TLP and subsea project costs range from $3 billion to $7.2 billion, and semi and subsea projects costs range from $100MM to $18 billion. The most expensive projects are all located in the Jurassic play and are due to water depth and technical challenges. There is only one FPSO development in the deep water GOM, the Cascade and Chinook project operated by Petrobras, and one FPSO is under construction, which will be deployed to Stone field operated by Shell. Over the last ten years, operators in the GOM realized the importance of access to infrastructure and collaboration with each other to fully utilize the existing or upcoming infrastructure. As a result, the hub concept, which is several fields jointly developed with a center floating production infrastructure to process hydrocarbon product from tie-in fields, has been introduced and gradually adapted by major operators. The Perdido

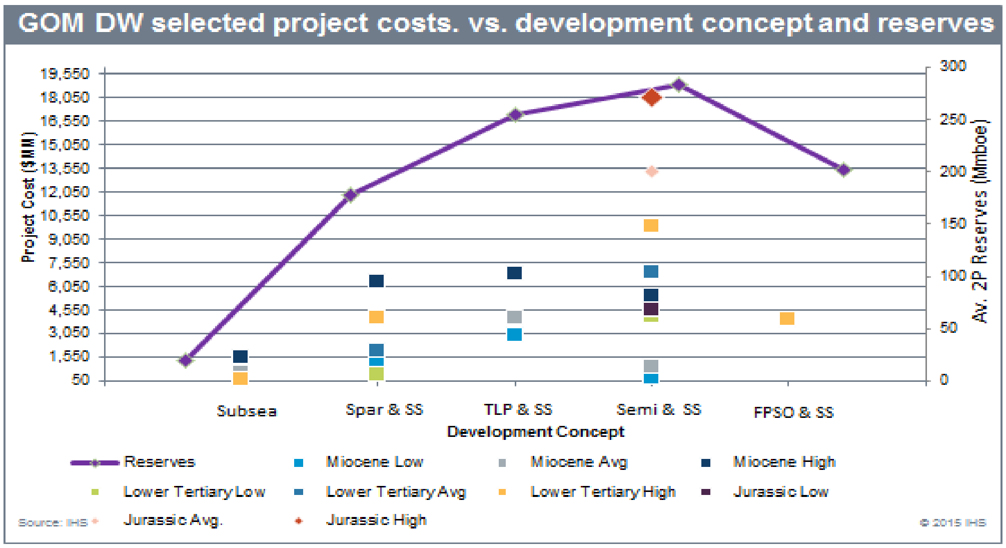


Figure 9-29: GOM deep water selected projects cost range by pay and field reserves

project, online in 2010, was the first Lower Tertiary hub brought on stream, and was followed by Cascade/Chinook in 2012 and Jack/St. Malo in 2014. These hubs, with the addition of the Miocene Subsalt Lucius hub (on stream in early 2015), could spur further Lower Tertiary development, including a number of unsanctioned Lower Tertiary discoveries that currently appear to be stalled.

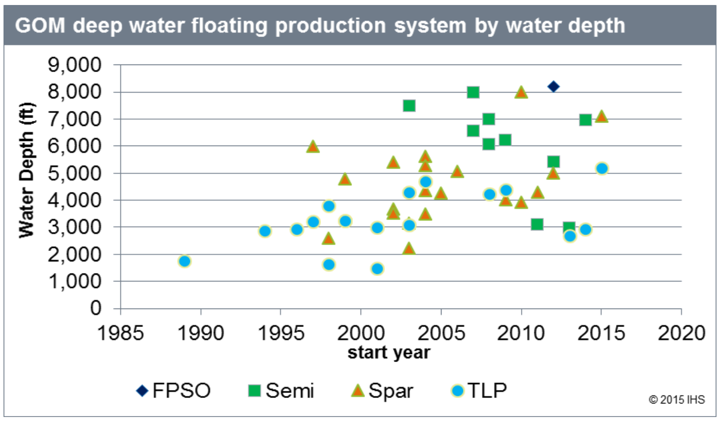


Figure 9-30: GOM deep water production system by water depth

Since 2004, there have been approximately 35 floating production platform systems (FPS) which have been built and deployed in the deep water GOM, and about 50 total deep water production infrastructures. From the 1990's onward, the overall trend of platform design has been based on deeper water depth and larger capacity (Figure 9-30).

Water depth, capacity, hull design, and topside design including processing equipment and utility modules drive the floater's cost. TLPs are mostly deployed in water depths of 5,000 feet and shallower. Spars are used in water depths from 2,000 feet to as deep as 8,000 feet. Semis are mainly deployed in water depths of 5,000 feet and deeper. Drilling facility installation also largely impacts cost. While a large number of the hulls have been built in shipyards overseas, primarily in South Korea, Singapore, and Finland, almost all topsides are still built in the US in order to maintain the integrity and complexity of the technology.

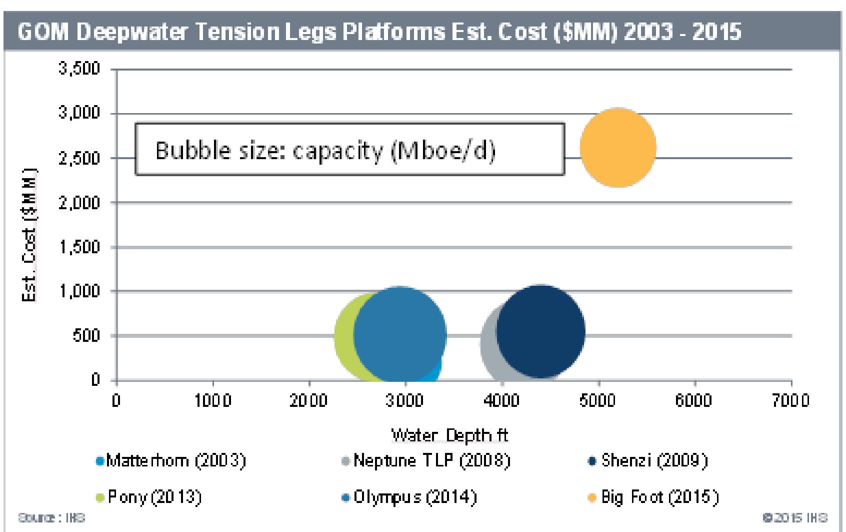


Figure 9-31: Tension leg platform costs by capacity and water depth

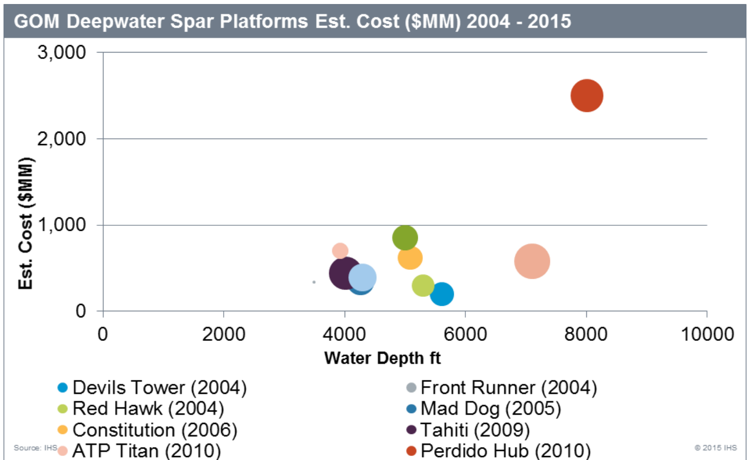


Figure 9-32: Spar platform costs by capacity and water depth

TLPs are more vulnerable to winds and loop currents and thus are less favorable in the deep water GOM compared to the spar and semi. Consequently only six TLPs have been built since 2003, most costing between $200MM to $550MM (figure 9-31). However, the one outlier is Chevron's recently built Big Foot extended TLP (ETLP), featuring a dry tree and on-board accommodations with a large number of living quarters (Figure 9-31), with an estimated cost as high as $2.6 billion.

The cost of Spar platforms varies in a relatively narrower range from $300MM to $800MM. Perdido is the exception, located in a water depth of 8,000 feet at an estimated cost of $2.5 billion with one of the largest capacities at 133Mboe/d (Figure 9-32). The capacity of spar platforms is generally larger than a TLP, and several TLPs have been designed based on the hub concept with larger capacities for future tie-in opportunities. For example, the recently deployed Anadarko Lucius spar has the highest capacity of 155 MBoe/d, presumably large enough to receive the future production from the Marcus and Spartacus fields.

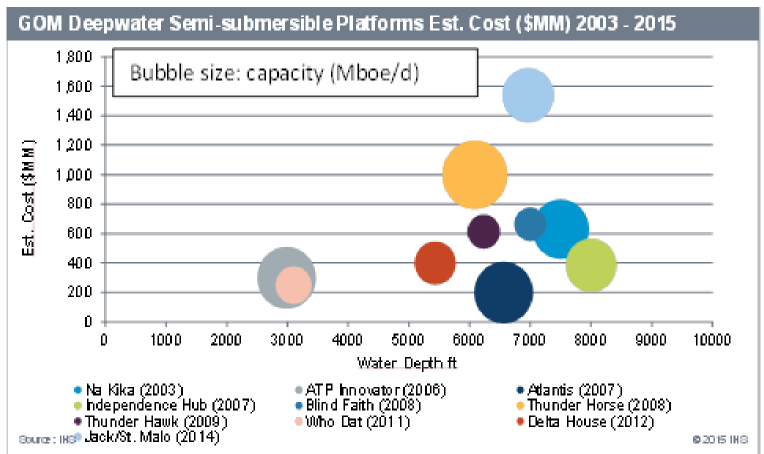


Figure 9-33: Semi-submersible costs by capacity and water depth

Semi platforms consist of a semisubmersible hull with a production facility on board and most often they also accommodate a drilling facility. Since 2004, the average newly-built semi costs about $600MM. The Jack/St. Malo platform, the most recent in service, was ranked the most expensive production facility in the GOM with a cost of $1,550 MM (Figure 9-33). It was designed as a hub to process production from multiple HPHT reservoirs in the Lower Tertiary subsalt play. Semis also have overall larger capacities when compared to TLPs and spars. Semis are generally used for larger fields. The average semi capacity built since 2003 is 145 MBoe/d, which is significantly higher

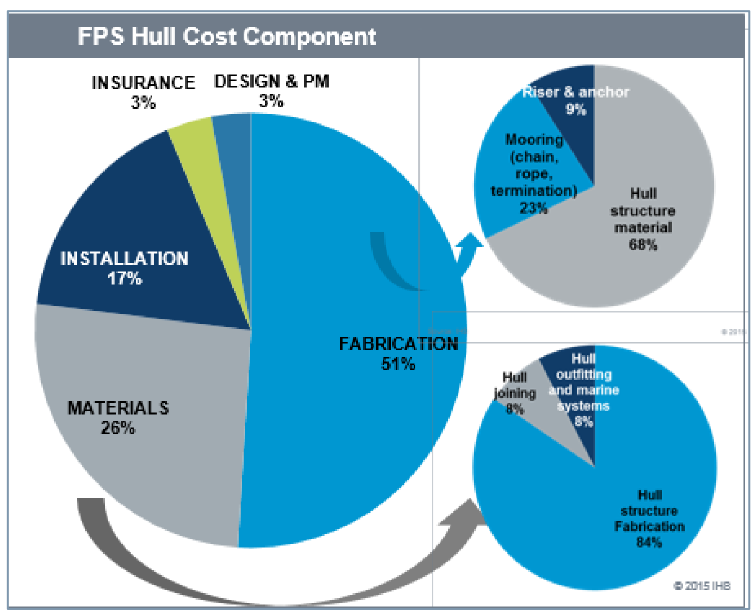


Figure 9-34: FPS hull cost component

than the average 84 MBoe/d of the TLP and 91 MBoe/d of the spar.

Regardless of the platform type, all floating production systems vary in size and shape. Their primary difference is the structure that holds them up: the buoyance or hull. FPS's have four common elements: hull, topsides, mooring, and risers. The three major cost components for the hull include fabrication, materials and installation (Figure 9-34). The majority of costs related to material and fabrication is steel purchase and cutting. While steel cost is priced at $/ton, fabrication is based on man hours needed. This explains why most of the hulls are fabricated and constructed in South Korea, China, and Singapore, where labor is less expensive. Nevertheless, the primary driver of hull cost is the cost of steel.

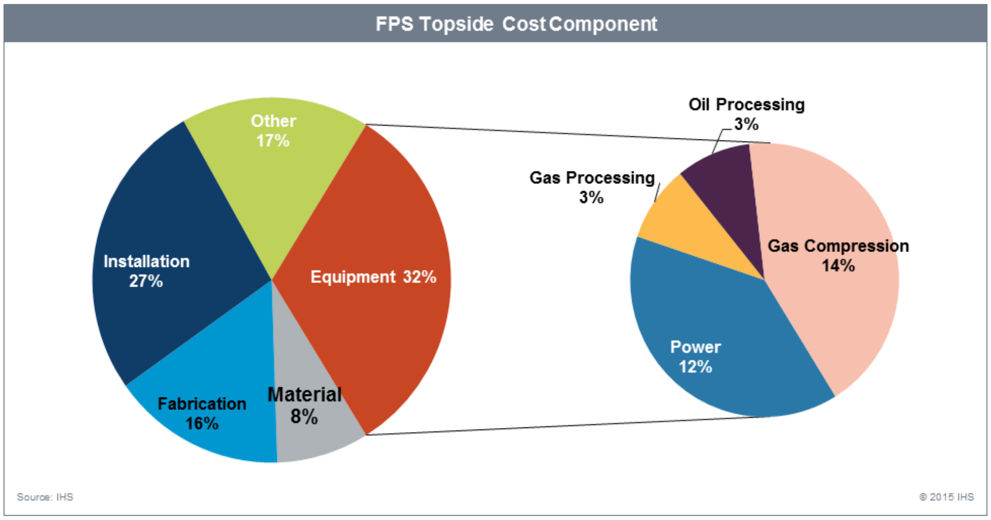


Figure 9-35: FPS topside cost component

Similarly, platform topsides also have three major cost components: equipment, installation, and fabrication (Figure 9-35), in which equipment plays the most important part. Platform equipment is comprised of oil and gas handling and process equipment, a gas compression facility, water handling, and power generation/distribution. Most spars and TLPs can accommodate a drilling facility, which adds 30% - 50% incremental cost, depending on the power of the drilling unit (Figure 9-36).

The three main cost drivers for floating production platforms are design, water depth, and topside weight and capacity. Spar designs are inherently stable due to their deep draft hulls. In addition, they tend to be much cheaper compared to TLPs and semis for water depths of 3,000 feet and deeper. For this reason, they are the most popular platform in the deep water GOM. Spars have three buoy systems consisting of truss, cell, and caisson. Truss and cell costs are similar. Caisson costs are 20% more because of the water depth it can withhold. The floating production system installed at Perdido field operated by Shell is the world's deepest production caisson spar, standing in 8,000 feet water depth. It is also the most

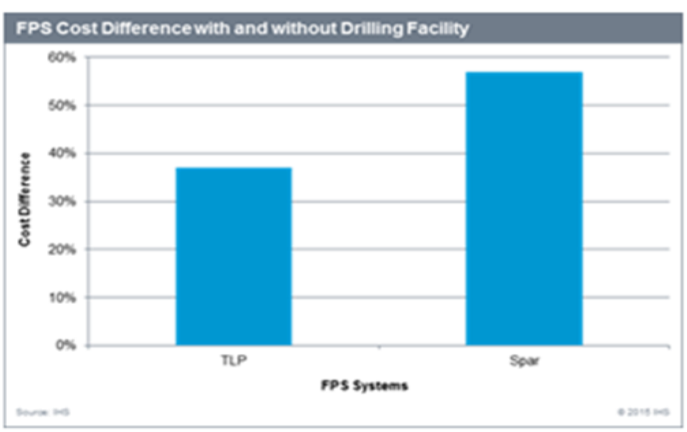


Figure 9-36: FPS cost change on adding drilling unit

expensive spar in the GOM with an estimated cost of $2.5 billion (Figure 9-32).

Most TLPs and spars can accommodate a drilling facility, with the rig type from a tender support vessel (TSV) to workover rig. The extra weight added to the topside could be from 1,500 to 2,600 tons and power can be self- contained or integrated. It costs more to add a drilling facility on spar than to a TLP because of the hull design (Figure 9-36).

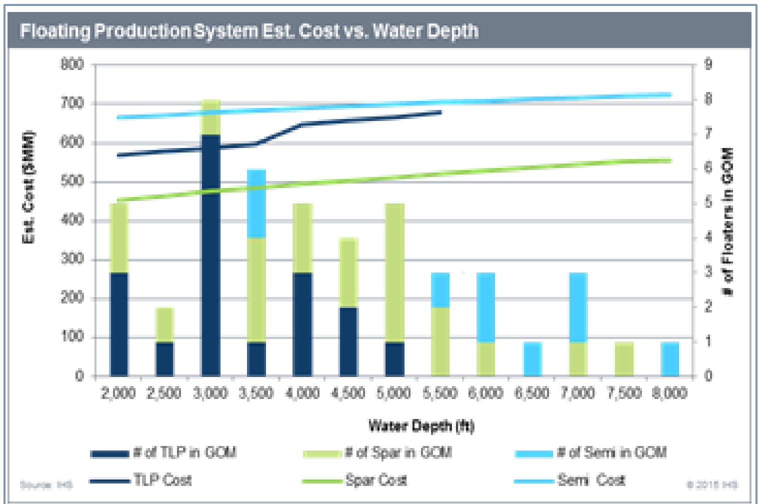


Figure 9-37: FPS cost change vs. water depth

Figure 9-37 shows the cost changes in relation to water depth and the number of FPSs actually deployed in the GOM (by water depth and type). Due to design limitations, TLPs can only withstand water depths of up to 6,000 feet. Semis are more costly because a semi vessel has to be purchased and modified first, and is less sensitive to water depth compared to a spar. Topside weight is primarily driven by capacity and the drilling facility. In the GOM, most of the TLPs are installed in about 3,000 feet water depth, and 40% of spars are concentrated in water depths between 4,500 feet to 5,500 feet. Semis are primarily used in water depths over 5,500 feet.

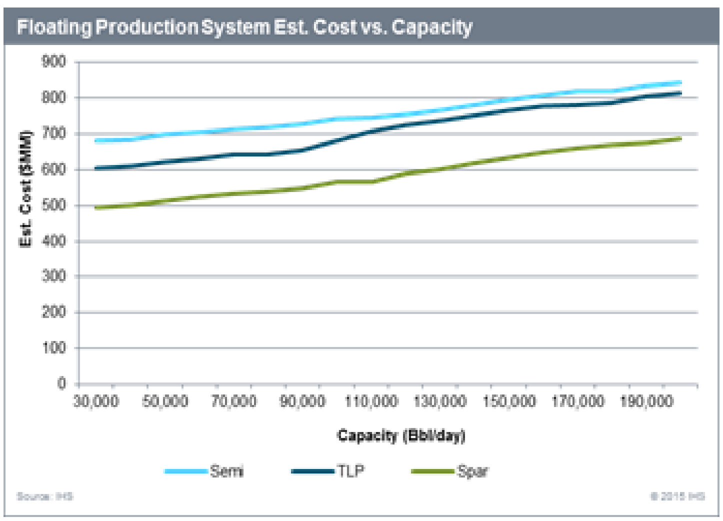


Figure 9-38: FPS cost change vs. oil capacity

The production capacity is designed based on reserve size and productivity from the tie-in fields. Figure 9-38 indicates that in the range of 30,000 bbl/d to 200,000 bbl/d, the cost can increase 39% for spars, 34% for TLPs, and 24% for semis. The highest capacity deployed in deep water GOM by FPS type are BP's Thunder Horse Semi (250,000 bbl/d), Chevron's Tahiti spar (125,000 bbl/d), and Shell's Ursa TLP (150,000 bbl/d).

The cost sensitivity chart (Figure 9-39) shows that the overall ranking of the three major cost drivers for floating production platforms: drilling facility, processing capacity, and water depth. In addition, other factors, such as the location of shipyard, installation preference, insurance and project management, also can play important parts in terms of cost control.

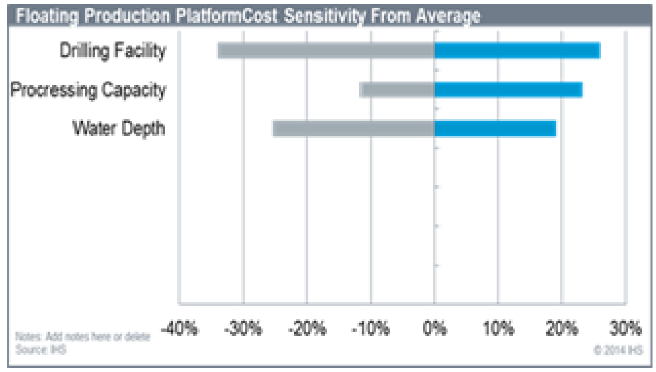


Figure 9-39: FPS cost sensitivity

Hurricanes and loop currents often cause installation delays and facility damage, inevitably adding extra cost. For example, Chevron's Big Foot TLP was severely damaged recently by a loop current while preparing for offshore hookup. Chevron estimates it will take two years to repair, thus causing significant delay to production commencement.

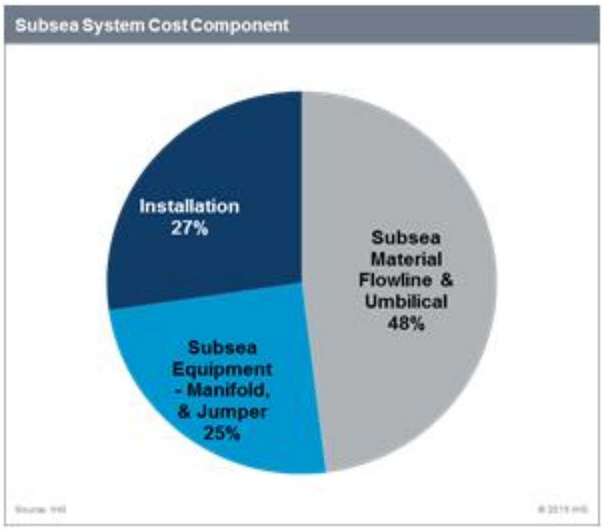


Figure 9-40: Subsea system cost component

Subsea sea systems

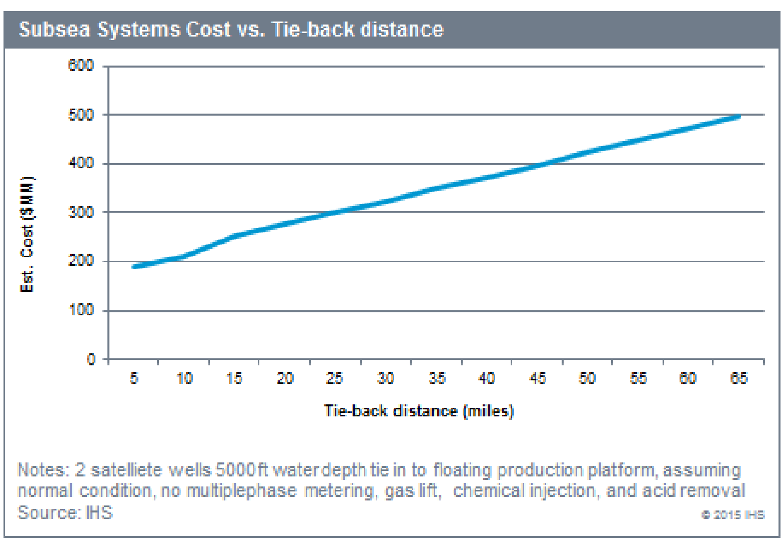


Figure 9-41: Subsea system cost change vs. tieback distance

The deep water and ultra-deep water discoveries since 2000 significantly increase the number of subsea tieback fields.   There are three major cost components for subsea systems (Figure 9-40): (1) materials, including flow line, umbilical and risers; (2) equipment, including manifold and jumper; and (3) installation. Subsea installation often requires ROVs (remote operated vehicles) to perform the operation. The umbilical, a hydraulic powered cord transferring power, chemicals and communications to and from the subsea development, is literally the lifeline to the subsea system and one of the most expensive pieces of subsea equipment.

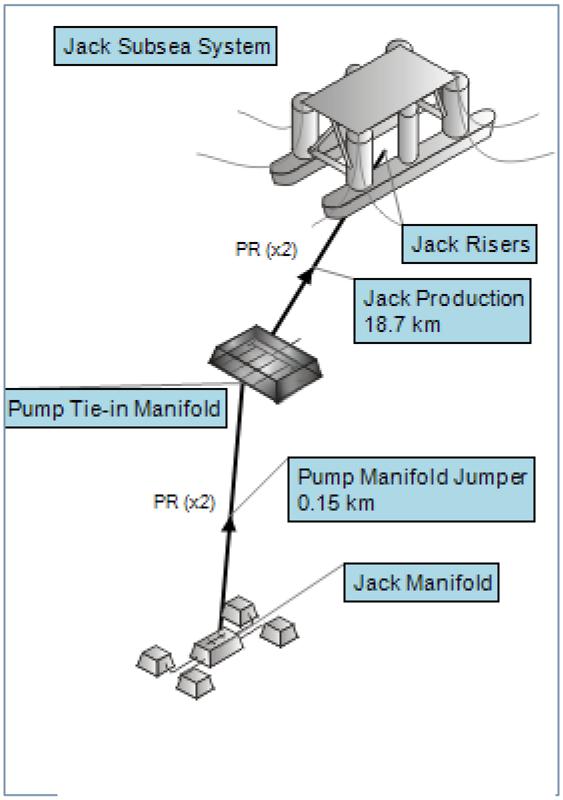


Figure 9-42: Subsea cluster system

The primary driver of subsea system cost is tieback distance to a platform, where cost increases steadily with distance. Although water depth has some impact, it is relatively small compared to tieback distance. The average subsea tieback length in the deep water GOM is 15 miles, and the longest tieback field is Shell's McMensa, consisting of a 68- mile tieback to a fixed platform developed in 1997. the total cost for two satellite wells under normal conditions, assuming there is no gas lift, water injection, chemical treatment nor acid gas removal, could range from near MM$ 200 to over MM$ 500 for a 5 mile to 65 mile tie-in distance (Figure 9-41). Other factors, such as development type (e.g., satellite or cluster) and whether a subsea booster system is installed, will have an impact on the cost as well. Chevron's Jack/St. Malo field, one of the most expensive tieback projects, includes four subsea clusters controlling 20 subsea wells and a subsea boosting system to enhance recovery.

A single well subsea tieback is designed as a satellite well with a flow line directly connected to a riser base or manifold. Multiple well clusters are designed as clusters with multiple subsea distribution units and umbilical termination assemblies connecting the production wells via connecting manifold to a flowline. The flowline then reaches to the riser base of the hosting platform, finally arriving at the topside facility through a flexible riser. Figure 9-42 illustrates the Jack field subsea system schematic with one four-well cluster and a 9 mile flowline tie-in to the Jack/St. Malo semisubmersible floating production facility. The subsea cluster system components consist of commingling and riser base manifolds, production, test, injection, gas lift flowlines, a flexible riser system, umbilical, and platform controls.

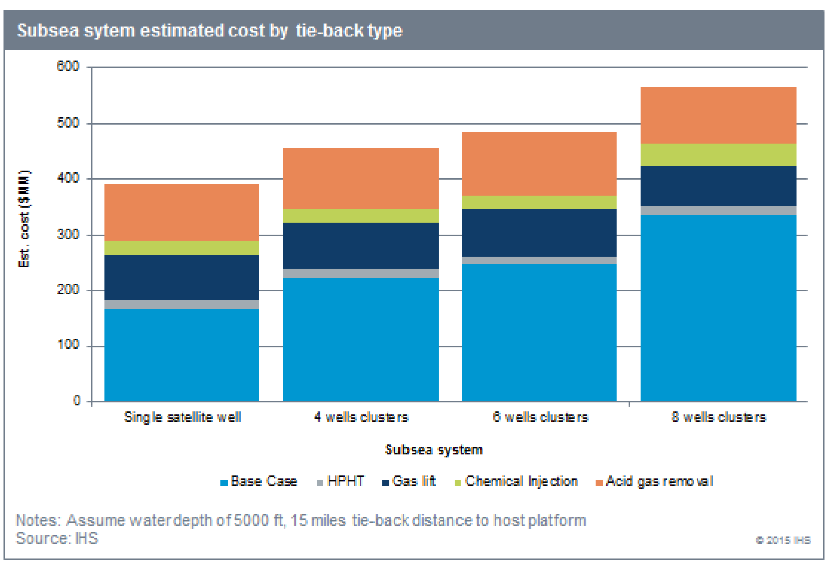


Figure 9-43: Subsea system cost feature – single well to multiple well clusters

Figure 9-43 compares the cost of different types of subsea systems, from single satellite well to multiple well clusters. They all start with the base design under normal technical conditions and assume a 15 mile tieback to a host platform and 5,000 feet water depth. Test service is also included. The incremental costs are added based on certain technical features: (1) High pressure and high temperature will add around 10% to cost as a special design is required to protect the downstream production or test service from overpressure, and (2) Chemical injection typically operates through an injection flowline (methanol injection) into a production well for hydrate suppression. The chemical injection and acid gas removal are determined from reservoir fluid characteristic and can be very costly, incurring an additional 30% - 45% in costs.

Pipelines

Once oil and gas are separated and processed through the platform, they move through an export riser to a subsea pipeline and then either tie-in to an existing platform or are transported directly onshore. The diameter of pipelines is primarily determined by pressure and flow capacity. Pipelines in deep water generally range from 12 to 30 inches in diameter. The freezing cold environment in deep water can cause the following: (1) hydrates to form in a gas line and plug the pipeline, or (2) for oil pipelines, paraffin, waxy hydrocarbons to plate the walls of an oil line. To solve these issues, most pipelines are coated with an insulating material to keep the fluid warm. Often the dehydrating treatment (i.e., methanol injection) is operated from a topside treating facility and injected into a pipeline in order to remove the hydrate and water vapours. Oil pipelines are periodically cleaned to remove wax or paraffin build-up in the pipe walls.

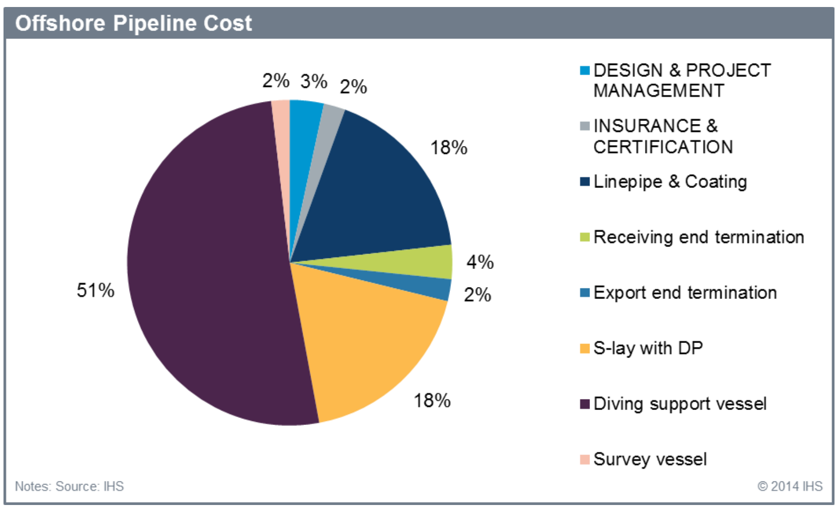


Figure 9-44: Pipeline cost component

The two major components of pipeline costs are materials and installation (Figure 9-44). Materials consist of mainly line pipe and coating. Although most of the pipelines are made from carbon steel, other types of material such as clad 316 stainless, duplex, clad 825 alloy, and CRA also could be applied in extreme harsh environments and high capacity pipelines.

INSTALLATION		Location: Gulf of Mexico	
	QUANTITY	UNIT RATE	COST
Reel-lay	0 day	310,000	0
S-lay without DP	103 day	440,000	45,320,000
S-lay with DP	0 day	620,000	0
J-lay	0 day	830,000	0
Solitaire	0 day	1,140,000	0
Diving support vessel	45 day	290,000	13,050,000
Testing & commissioning equipment	27 day	72,000	1,944,000
Trench vessel	37 day	155,000	5,735,000
Survey vessel	35 day	130,000	4,550,000
Dredge vessel	0 day	500,000	0
Rock install vessel	0 day	217,000	0
Shore approach			5,100,000
Total Installation		$	**75,699,000**

Figure 9-45: pipeline installation cost

The installation costs (Figure 9-45) are calculated based on the pipe lay spreads required to install the specific pipeline. They include a lump sum for the shore approach if needed. Each of the five pipe lay spread vessels (Reel-lay, S-lay without dynamic positioning (DP), S-lay with DP, J-lay and Solitaire) has a line item for the total time to lay the pipe and mobilize / demobilize the pipe lay vessel. The number of days required for each vessel is picked up from the installation durations form. The unit rate cost for each class of vessel includes labor, fuel, consumables and vessel support systems.

The driving support vessel (DSV) unit cost includes support services, labor, waiting on weather and consumables and is derived from the installation durations form. The duration shown in the cost sheet is the sum of the DSV installation and vessel mobilization / demobilization days.

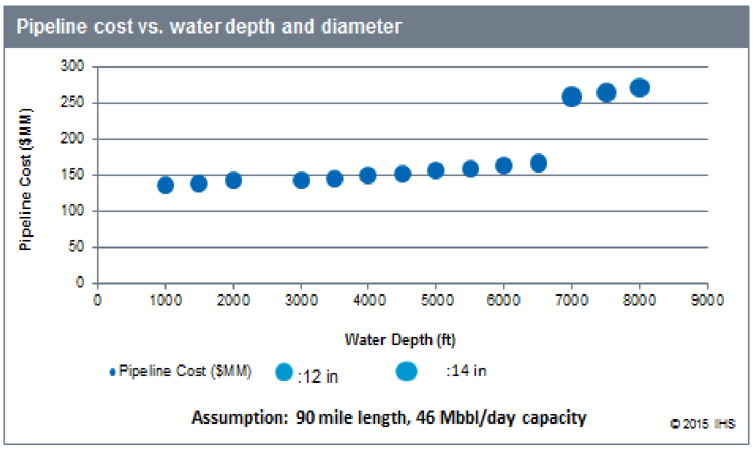


Figure 9-46: Pipeline costs vs. water depth and size

Testing and commissioning equipment is required on the DSV during testing and commissioning. The testing and commissioning duration is dependent on the pipeline diameter and length. Additional time is allowed for waiting and preparation as well as mobilization / demobilization of the equipment into the field. A trench vessel is required when either a portion or the entire pipeline is buried. The trenching duration is dependent on the buried length of the pipeline and whether there is a shore approach. The duration shown in the cost sheet is the sum of the trench activity and vessel mobilization / demobilization days.

The four main drivers for pipeline costs are water depth, length, diameter, and capacity. The typical oil pipeline technical conditions in the deep water GOM are 3,670 feet water depth, 90 mile long, 12 in diameter, and 46 Mbbl/day capacity. All four cost drivers are interdependent. For example, a larger pipeline size is required for deeper water depths (>7,000 Ft) and longer distances. Capacity requirements also impacts pipeline size.

Figure 9-46 indicates that there is a minor cost increase for water depths of 1,000 feet to 6,500 feet. However, once the water depth is greater than 7,000 feet, the cost could increase by over 50% and a larger diameter pipeline is required to sustain the high pressure environment.

On the other hand, Figure 9-47 shows a direct linear correlation between pipeline length, diameter, and cost. For

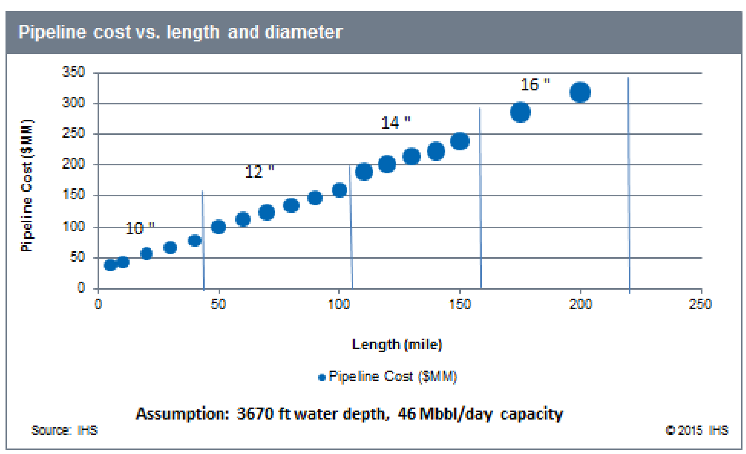


Figure 9-47: Pipeline costs vs. length and diameter

distances less than 50 miles, only a 10 inch pipeline is needed and the cost is less than $100MM. For distances between 50 to 100 miles, a 12 inch pipeline is required, and the cost reaches to $100MM to $150MM and for distances between 120 to 170 miles, at least a 14 inch pipeline is needed and cost jumps to $200MM to $250MM. Lastly, when the distance is 170 miles, at least a 16 inch pipeline is required, and the cost could reach as high as $300MM.

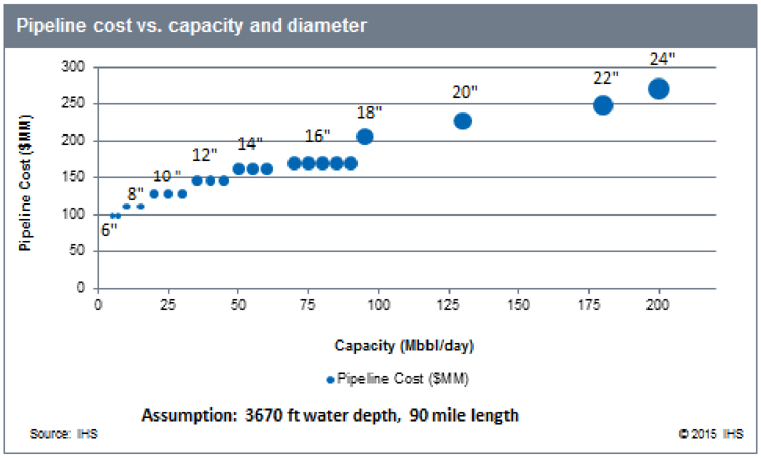


Figure 9-48 demonstrates how the costs change along with the capacity and size. The Big Foot project export pipeline, a 140 mile, 24 inch oil export pipeline marks the first large diameter, ultra-deep water pipeline in the Walker Ridge area of Lower Tertiary trend, with an estimated cost of $800MM, inclusive of a gas pipeline.

Figure 9-48: Pipeline costs vs. capacity and size

E. Decommissioning Cost

Offshore decommissioning is highly regulated by the Bureau of Safety and Environment Enforcement (BSEE). According to BSEE, the process of "decommissioning" the well consists of safely plugging the hole in the earth's crust and disposing of the equipment used to support the production. BSEE's Idle Iron policy keeps inactive facilities and structures from littering the Gulf of Mexico by requiring companies to dismantle and responsibly dispose of infrastructure after they plug non-producing wells.

Platforms generally consist of two parts for decommissioning: the topside (the structure visible above the waterline) and the substructure (the parts between the water surface and the seabed, or mudline). In most cases the topsides that contain the operational components are taken to shore for recycling or re-use. The substructure is generally severed 15 feet below the mudline, then removed and brought to shore to sell as scrap for recycling or to be refurbished for installation at another location. An alternative to onshore disposal is the conversion of a retired platform to permitted and permanently submerged platform artificial reefs, commonly referred to as Rigs to Reefs (RTR). Based on BSEE statistics, as of July 1, 2015, 470 platforms had been converted to permanent artificial reefs in the Gulf of Mexico. However, all of these are fixed platforms located in shallow water.

To date, of all the GOM offshore platforms decommissioned only two were floating production units located in water depths of 1,000 feet and deeper: ATP Innovator (semi) and Anadarko Red Hawk (spar). ATP Innovator decommissioning involved disconnecting 10 riser-umbilical and 12 mooring lines, and towing the Innovator to Ingleside, TX. The platform originally was built and converted from a Rowan deep water semi drilling rig with an estimated cost of $300MM. IHS estimated the decommissioning cost netted to scrape material is 45% of topside installation cost and 90% of semi hull installation. This is equivalent to approximately $30MM.

Anadarko's Red Hawk platform is the first cell spar deployed in the deep water GOM and made history as the deepest floating production unit (FPU) ever decommissioned in the GOM. To reduce cost and time spent hauling the structure from its location to onshore, Anadarko chose the "Rigs to Reefs" program which previously had only been applied to shallow water fixed platforms. The original cost of Red Hawk spar is estimated at $298MM and the conventional decommissioning cost is estimated at 45% of topside installation cost and 50% of spar hull installation cost. By applying the Rigs to Reefs program and sinking the hull to a nearby block, IHS estimates the decommissioning cost could be reduced by 28% to $15MM from the conventional $21MM cost.

In general, IHS QUE$TOR estimates offshore deep water well decommissioning costs to be 10% of installation cost. In other words, if installation is 90% of total D&C then decommissioning costs are 9% of total well costs.

F. Operating cost

The deep water operating cost mostly involves floating production platform operating and maintenance. Typically, a spar at 5,000 feet of water depth can have a monthly operating cost between $3MM to $4MM. A semisubmersible is more expensive to operate compared to a spar or TLP. Subsea tiebacks experience the least operating expense, and most of the cost incurred by production handling agreement (PHA) fee is paid to the host platform. For floating production platforms, the major operating cost components are platform inspection and maintenance, operating personnel, and insurance cost. GOM operators are required to purchase loss of production insurance (LOPI) to cover the production loss due to platform shut-ins and evacuations during hurricane season. Figure 9-49 provides a total lease operating cost (LOE) cost comparison of the four selected offshore projects by development concept.

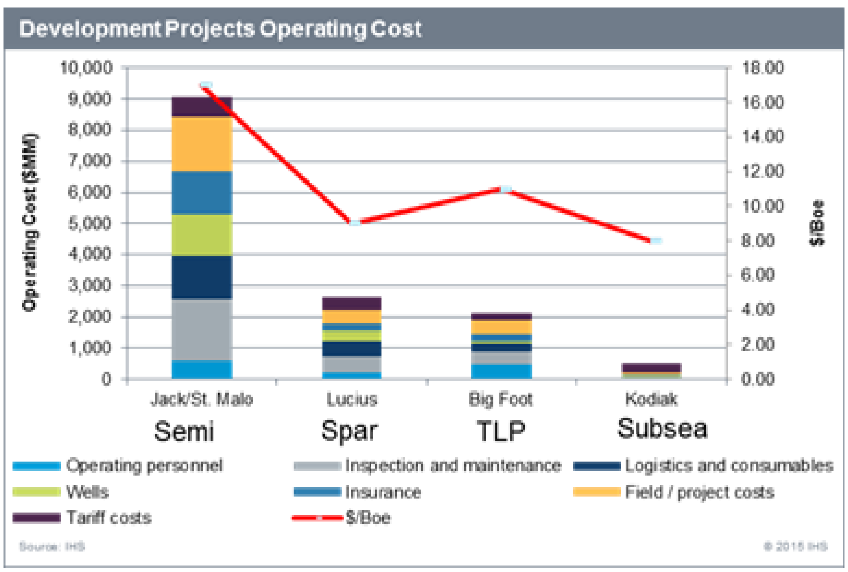


Figure 9-49: Total lifecycle project LOE costs

G. Deepwater GOM cost trends

Because of the large scale of capital investment required to develop deep water fields, deep water GOM operators are more pressured than US unconventional operators to increase efficiency and reduce cost. We estimate that an approximate 20% capex cut is required to move unsanctioned projects in the GOM Lower Tertiary play to a $60/bbl breakeven. With efficiency gains being rapidly realized in the US unconventional plays, with operators focusing only on their first-tier prospect inventory and simultaneously delivering productivity improvements, the key question for the deep water GOM is how quickly and to what degree operators can realize similar efficiencies.

IHS is projecting a 15% reduction in deep water costs in 2015, followed by a marginal average increase of about 3% in overall deep water costs from 2016 to 2020 in nominal terms. Cost deflation is material in many areas impacting deep water costs. This is particularly so in the rig market, where a rig overbuild long forecast for 2015–16 is now colliding with reduced demand and resulting in quickly falling day rates.

The three largest components of deep water capital costs are steel (~32% of deep water capital costs), equipment (~21%), and rigs (~13%). Costs associated with all three components have declined into 2015, as the deep water market reacts to a weaker oil price environment and oversupply in many segments.

Key drivers of cost reduction – drilling rig

Going forward, contrary to the increasing rig supply result from overbuild during the last few years, rig demand is falling. Operators are looking to reduce and delay expenditures to shore up portfolio returns in response to a weaker oil price.

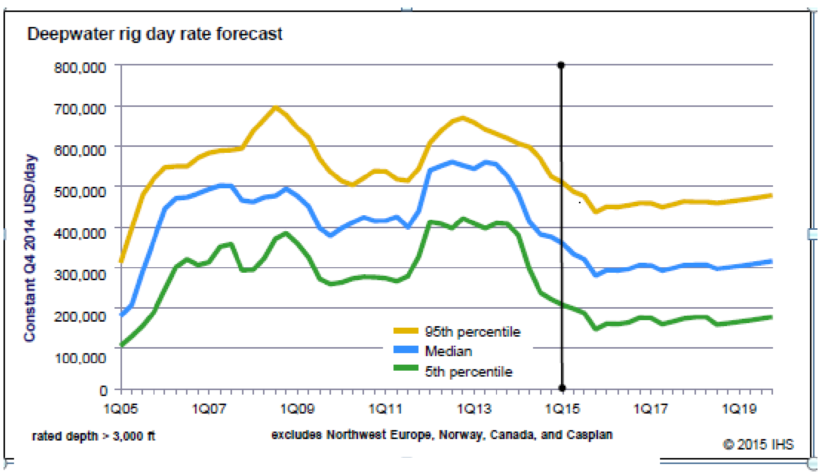


Figure 9-50: GOM deep water day rate forecast

For the 3,001 feet to 7,500 feet segment, IHS projects that fixed rates are expected to continue declining over 2015, becoming essentially flat from 2016 to 2019, and gradually recovering after 2017 (Figure 9-50).

While development drilling proceeds on a robust queue of sanctioned deep water projects, reduction in exploration spend, and therefore drilling, has more limited near-term impact on operator portfolios (making exploration easiest to cut first). Mid- to long-term implications can be quite significant if deep water portfolios are not adequately restocked with new discoveries.

The most abrupt manifestation of the supply-demand disconnect in the rig market has been the early termination of a number of rig contracts. With drilling rigs being a contracted service that cannot be repurposed, cancellations will reduce exploration plans and add to the expectation that the re-contracting of rigs with lower day rates can be achieved in an oversupply environment.

Key driver of cost reduction – steel

Steel is the largest component part for deep water project costs. Steel prices have been declining for several years as a result of oversupply. IHS suggests that steel prices are at or near their low point in

Europe, Asia, and North America, with a tepid rally likely by the end of the year. Overall, this points to the steel market being a buyer's market for at least the next 18 months.

Specific to deep water project costs, steel costs directly impact deep water costs through a number of required components that rely on steel: notably facilities, topsides, offshore loading, drilling, and subsea equipment. To assess this broad impact, the IHS Capital Cost Service's carbon steel index tracks four specific product groups: (1) line pipe, (2) structural steel, (3) concrete reinforcing bar (rebar), and (4) oil country tubular goods (OCTG), with OCTG including both tubing and casing composed of carbon steel or steel alloys. Based on this index, we are modeling about a 16% cost decrease in steel in 2015 versus 2014. Beyond 2015, a recovery in the steel market is expected, with costs increasing approximately 11% in 2016 over 2015. More modest average annual increases of about 3% are expected in 2017–20. (Figure 9-51)

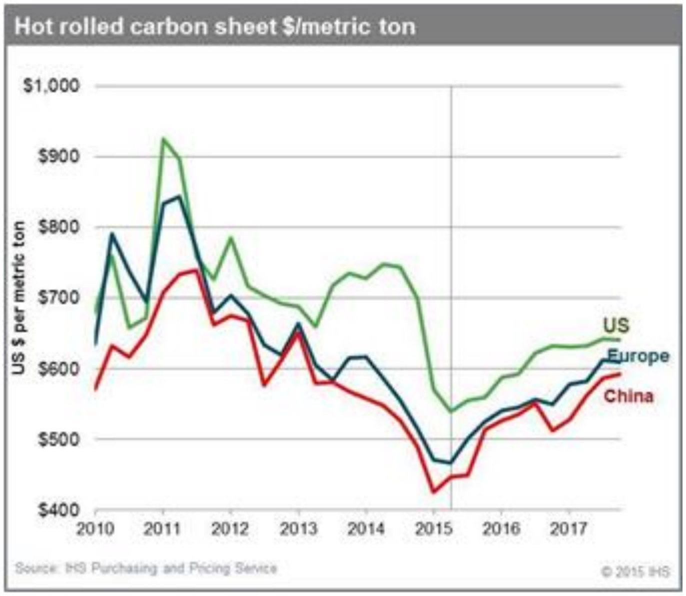


Figure 9-51: Steel cost forecast

Key driver of cost reduction – equipment

Included in oilfield equipment costs are turbines, exchangers, tanks and pressure vessels, pumps, and compressors with restrictive standards and specifications for the oil industry. IHS is projecting declines in upstream equipment costs over the next two years, followed by a moderate recovery between 2017 and 2020. As a result, in regards to deep water project modeling, we are forecasting an approximate 14% decrease in costs in 2015 compared to 2014 and a further 5% decrease in 2016. This is followed by average annual increases in equipment costs of about 5% between 2017 and 2020.

The new deep water cost base

In addition to rigs, steel, and equipment, other key (but much smaller) components of deep water project costs include engineering and project management (EPM), subsea facilities, installation vessels, bulk materials, construction labor, freight, and yards and fabrication—all of which are monitored in detail by the IHS Capital Cost Service. In aggregate, and based on all these cost elements, we are forecasting an approximate 15% decrease in non-equipment related capital costs in 2015, a 2% to 4% drop in 2016, and a modest recovery over the 2017–20 period.

Variations in cost indexes at a regional level are not insignificant. As a result, project level implications associated with this cost decrease are not uniform and tend to vary by play. Nevertheless, in aggregate within the global deep water, re-running economics for unsanctioned deep water projects with the new lower cost structure does result in an average $5–$10/Boe reduction in breakeven economics. This will not be considered an insignificant reduction as companies look to move to the next tranche of developments past Final Investment Decision.

H. Key Take-Aways

Within the GOM deep water, substantial capital cost reductions are required in some plays to deliver breakeven economics at $60/barrel, in addition to assumed reductions in operating cost. To achieve $40/barrel breakeven costs, a more substantial additional capital expenditure cut is required. This may be very difficult to achieve and many new discoveries may not be sanctioned. We estimate that an approximate 20% capex cut is required to move unsanctioned projects in the US Gulf of Mexico Lower Tertiary play to a $60/barrel breakeven, and at least a 30% cut to reach $40/barrel breakeven.

With efficiency gains being rapidly realized in the US unconventional space and with operators focusing only on their first-tier prospect inventory and simultaneously delivering productivity improvements (with one, of course, influencing the other), the key question for the deep water is how quickly and to what degree can similar efficiencies be realized given the lack of critical mass and diversity of projects.

IHS Energy is forecasting an approximate 15% reduction in deep water costs in 2015, with an approximate additional 3% reduction in 2016, and a modest recovery in nominal terms from 2017 to 2020.