

Quantifying Drilling Efficiency

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Abstract

This paper examines the methods used to measure drilling efficiency and the difficulties encountered when using various data sources. The analysis examines the technologies used before, during, and after rotary rig operation which shape overall productivity results. The research also reviews the reasons why modern rigs are more efficient and where the industry is headed in the future. Finally, the paper provides guidance for analysts and modelers when applying efficiency parameters.

Background

Many analysts attribute recent increases in domestic oil and gas supply^{1, 2, 3} to improved drilling efficiency. Efficiency is defined as a metric of productive output for a given a set of inputs. This paper discusses how drilling efficiency is measured, the difficulties and ambiguities associated with productivity measures, and the technologies that have improved drilling efficiency. The analysis focuses on the operational factors shaping efficiency and is not a review of drilling costs. Reduced drilling costs are one of the implications of improved efficiency.

Prior to the 1990s, most wells were drilled vertically. Since then, more and more wells are being drilled horizontally, particularly the highly-publicized shale wells. Horizontal wells have risen from about 9 percent of total wells drilled in the early 1990s to over 50 percent in 2010. This trend has advanced to the point where one natural gas service provider⁴ has introduced a proprietary index to adjust the rig count for efficiency gains to better predict future natural gas production. The traditional ways of viewing drilling efficiency are changing.

Drilling is a 3-step process. Operation of the physical drilling rig represents the middle step. Of equal or greater importance in the process are activities and decisions immediately preceding and following rotary rig operation. The drilling rig by itself does not cause either successful well outcomes or dry holes. Successful outcomes arise from the synergies between rig activity and the augmenting steps.

Traditional Methods for Assessing Drilling Productivity

Measuring and quantifying the factors shaping drilling performance is difficult due to the availability of timely data, some of which is proprietary. Numerous factors impacting performance can vary from location to location and from rig to rig. Also, aggregate drilling data is problematic due to the range of information collected that may combine

¹ "U.S. crude oil production rose 7.4% last year, energy report says," PennEnergy, <http://www.pennenergy.com/index/articles/newsdisplay/142979329.html>.

² "U.S. Natural Gas Reserves May Have Doubled, Secretary Chu Says," Bloomberg, April 6, 2010, <http://www.businessweek.com/news/2010-04-06/u-s-natural-gas-reserves-may-have-doubled-secretary-chu-says.html>.

³ "U.S. natural gas production reaches highest level in 30 years," Star-Telegram, May 28, 2010. <http://www.star-telegram.com/2010/05/28/2225254/us-natural-gas-production-reaches.html>.

⁴ "A New Era in Rig Productivity," Bentek, <http://www.bentekenergy.com/BPI.aspx>.

disparate regions such as the offshore with onshore regions. Data typically lags and the use of aggregated data can mask emerging trends.

Efficiency measures can cover time, distance, performance, productivity, and financial parameters including:

- Footage drilled per hour
- Days to depth (drilling days)
- Footage drilled per rig
- Wells drilled per rig
- Success rates (or dry holes)
- Reserves added per well
- Reserves added per rig
- Production per well
- Dollars per foot
- Energy consumption

One common measure of drilling efficiency is the ratio between annual footage drilled and the number of “active” rigs. This is the total footage drilled yearly for oil wells, gas wells, and dry holes divided by the number of active rigs operating during a study year. However, results depend on establishing a representative “active” annual rig count which is an imprecise and subjective task. Baker Hughes,⁵ Smith,⁶ ReedHycalog (Now NOV),⁷ Schlumberger,⁸ and IADC⁹ publicly report the number of active and available rigs with supporting details covering drilling applications, depth capabilities, power ratings, etc. For the ReedHycalog census, data is not available for 1953, 1954, and 2002 due to extenuating business circumstances and the analyst must use judgment in estimating the missing data points. For services type operations such as work-overs, the Cameron web site provides the Guiberson-AESC Service Rig count.¹⁰ Each organization has its own criteria establishing when and how to count a rig’s reported status as active, available, moving, performing work-over, stacked, retired, the intended drilling trajectory (vertical, directional, horizontal), etc. For example, Baker Hughes defines a rig “at work” until it reaches its target depth while Schlumberger includes related operations such as logging, cementing, running casing, well testing, etc.

Figure 1 presents the annual average footage drilled per rig (blue bars) and the corresponding rig utilization rate (red line) using data from the EIA *Annual Energy Review 2008* and National Oilwell Varco (NOV), respectively. The average footage drilled per rig has nearly doubled from 100,000 feet per rig in the early 1980s to over 200,000 feet by 2008, the last year for which corresponding footage and rig count data is available. The total drilled footage includes oil wells, gas wells, and dry holes. While Figure 1 represents an industry average, individual rig footage per year can vary

⁵ Baker Hughes Investor Relations, Rig Counts, Rig Count FAQs, http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm.

⁶ Smith, Rig Activity, [http://www.smith.com/\\$53722c42-5095-45af-b97b-e8c6dd035e60](http://www.smith.com/$53722c42-5095-45af-b97b-e8c6dd035e60).

⁷ NOV Downhole, 56th Annual Rig Census, <http://www.nov.com/>.

⁸ Schlumberger Worldwide Rig Count, <http://www.apps.slb.com/rigcount/World/Country/Default.aspx>.

⁹ International Association of Drilling Contractors (IADC), Statistics on IADC Membership and the Worldwide Rig Fleet, page 22 of 2010 Membership Directory.

¹⁰ Guiberson-AESC Service Rig Count, <http://www.c-a-m.com/content/dps/drl/rigcount/index.cfm>.

considerably. *The Land Rig Newsletter*¹¹ conducted a survey of the top 75 drilling rigs operating in 2004 and found that the top rig drilled over 461,000 feet while the 75th place rig drilled over 221,000 feet that year, which is considerably higher than the 155,000 foot average for the nearly 1,200 rigs covered by the survey.

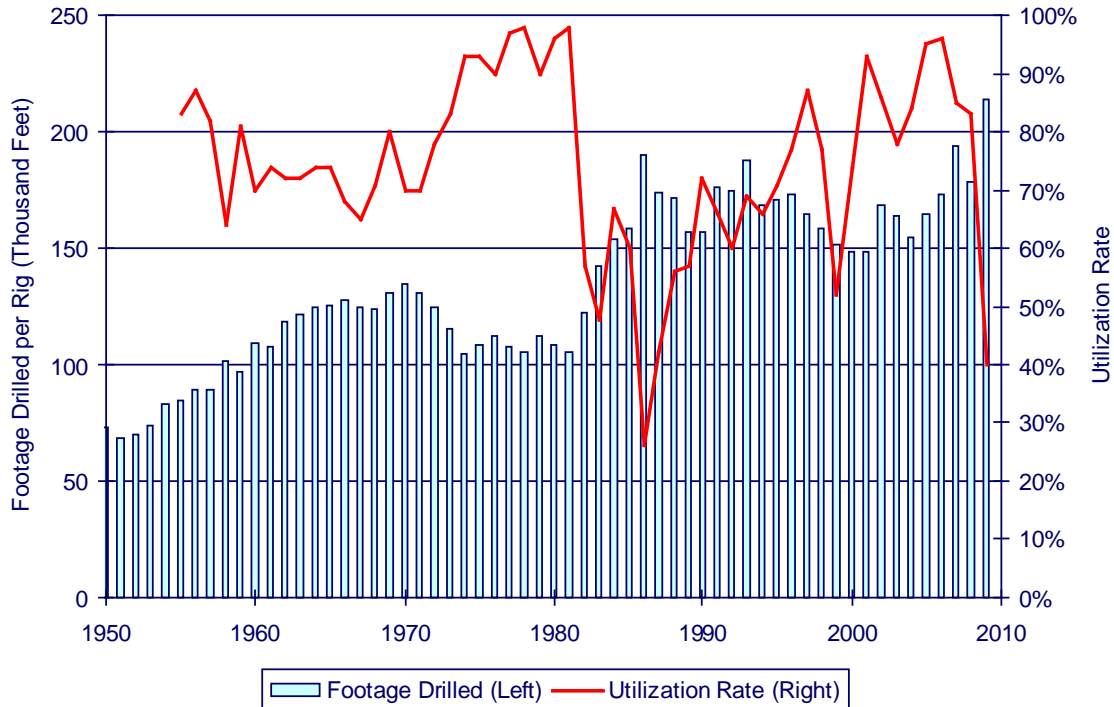


Figure 1. Total Annual Footage Drilled Per Rig (Oil, Gas, Dry Holes) Shows Long-Term Progress; utilization rate shows an inverse correlation to footage drilled

Such rig drilling footage variation exists partly due to the total time the bit was “turning to the right” and because more-experienced crews and higher-spec rigs perform significantly better than the average results depicted. Conversely, during periods of peak rig demand and utilization (e.g., the early 1970s through the early 1980s), older rigs and less experienced labor reduced overall efficiency. Not surprisingly, efficiency typically increases when the least efficient rigs are stacked (low utilization rate). There appears to be a loose inverse relationship between high utilization rates and lower footage rates.

Other causes for the year-to-year variation in footage include the rock hardness of the geologic formations being drilled, whether the footage drilled is vertical or horizontal, and the type of drill bit being used. Prevailing oil and gas prices also tend to encourage or discourage drilling activity.

Ranking performance on a footage basis often favors rigs drilling shallower wells since the rate of penetration is higher in shallower depths. Depending on depth, a rig can frequently complete a well before the drill bit wears out and requires time for

¹¹ “Most Active Individual Land Rigs, 2004,” *The Land Rig Newsletter*, Vol 27, No. 2, February 28, 2005.

replacement. Drilling time also increases geometrically with well depth confounding interpretation of drilling efficiency between wells. Over time, well footage can expand or contract depending on attractiveness of oil and gas prices, so historical point comparisons may not necessarily be valid over a long term.

Figure 2 presents the number of wells drilled annually per rig and is derived from well and rig counts reported in the EIA *Annual Energy Review 2008*. Although the overall trend is up, there have been periods of declining performance as illustrated here and in the footage-drilled chart (Figure 1) presented earlier. The recent plateau around a 30-wells per rig level since the mid-1990s might be attributed to deeper wells and wells having longer and/or more laterals in recent years.

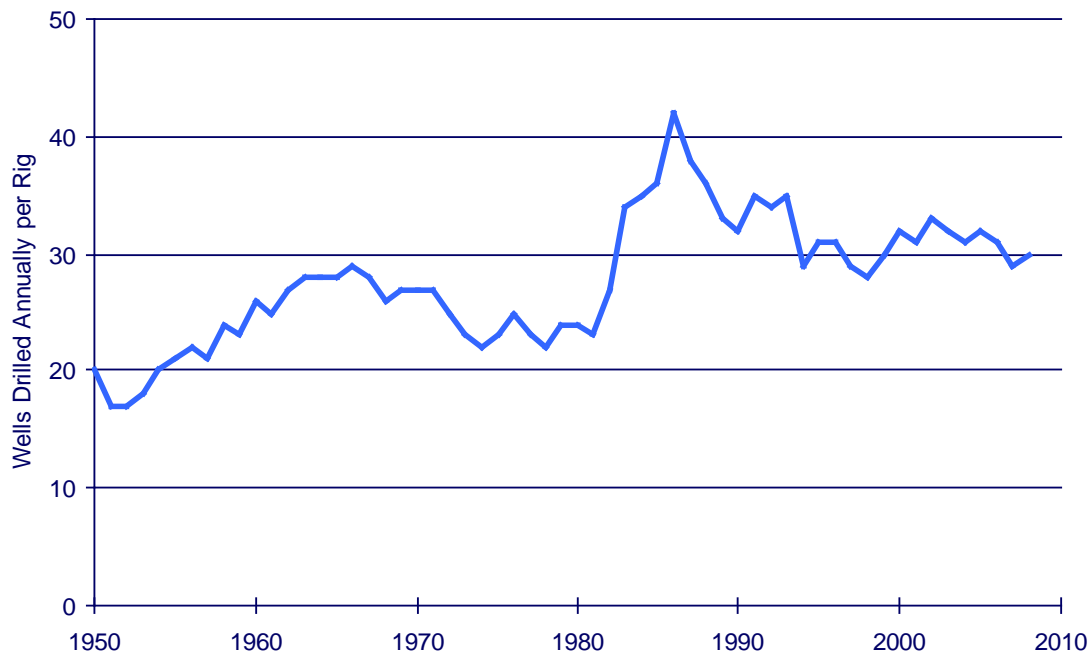


Figure 2. Annual Wells Drilled per Rig Illustrate a Plateau in Recent Years

Other than using aggregate industry rig counts, there are other time-based measures to gauge drilling efficiency when applied to a single rig. These measures include: Spud-to-Rig-Release; Spud-to-Spud (between wells); Spud-to-Sales; Footage per Day; Footage per Rig, Rig-Days, and Rotating-Hours.¹² Closely related to the footage per day metric is Rate of Penetration (ROP) which is used by drillers as a gauge of progress while performing a job. All these measures are highly project specific, site specific, and cover a limited time duration.

There are recent examples for the Fayetteville and Haynesville shales illustrating industry application of these metrics. For Southwestern Energy, in the Fayetteville shale, field time required to drill a well dropped from 20 days in first quarter 2007 to 11 days by

¹² Janwadkar, Sandeep, "Keys to Unconventional Success," Baker Hughes, January 7, 2009, http://files.shareholder.com/downloads/BHI/69297774x0x270440/070471f4-3d63-4fea-bf39-08c06c56712f/UBS_Unconventional.pdf.

the second quarter of 2009.¹³ This improvement enabled the number of wells drilled per rig to increase from 18 to 33. Likewise, Petrohawk Energy Corporation decreased drilling days in the Haynesville shale from 69 days in the first quarter of 2009 to 52 days by the fourth quarter of 2009.¹⁴ One theory is that gains of this nature are the result of a short-term “learning curve” at the company or play level rather than an efficiency trend across industry due to technology.

As these examples illustrate, wells drilled per rig is a key performance metric used by producers and rig contractors drilling the same type of well in a given field.

Figure 3 shows the experience of EXCO Resources in the Haynesville shale over time and graphically illustrates a progression of improving efficiency in drilling days (days to depth). Notice how a steepening penetration curve decreases the number of drilling days required. For a given shale play, the drilling days range seems to be converging. The use of contract drillers is the likely mechanism through which “learning” is spread.

However, not all shales are the same and result in a different level of drilling days. Some, such as the Haynesville, require almost twice the hydraulic horsepower due to increased depth, harder rock, higher temperatures, and necessitate higher treating pressures and more advanced fluid chemistry than the Barnett and Woodford shales.¹⁵

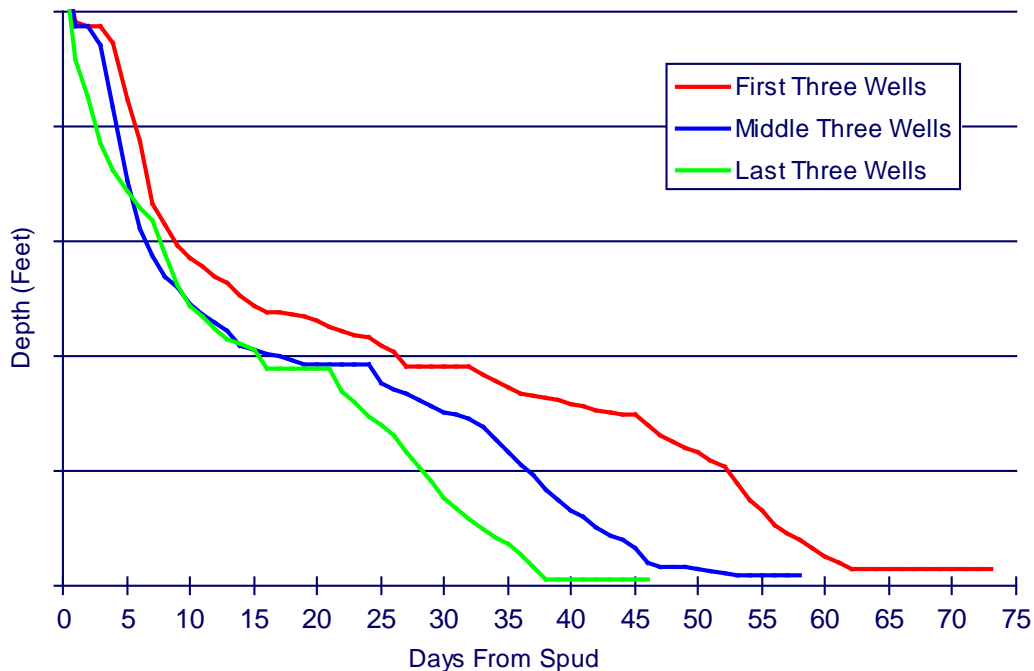


Figure 3. Haynesville Horizontal Drilling Days (Days vs Depth) Shows Productivity Gains
 Source: Data courtesy of EXCO Resources, Investor Presentation (December 2009), Slide 29.

¹³ Southwestern Energy Company, Q2 2009 Earnings Call Transcript, July 31, 2009, <http://seekingalpha.com/article/152977-southwestern-energy-co-q2-2009-earnings-call-transcript>.

¹⁴ Petrohawk Energy Corporation Presentation, Howard Weil 38th Annual Energy Conference, March 23, 2010, Slide 15, <http://www.petrohawk.com/ir/presentations-events.aspx>.

¹⁵ “U.S. Shale Gas; An Unconventional Resource. Unconventional Challenges,” White Paper, 2008, Halliburton, page 4, <http://www.halliburton.com/ps/default.aspx?navid=1413&pageid=2867>.

Behind-the-Scenes Preparation Work

Often overlooked in the overall drilling process is the necessary preparatory work to guide drilling to a successful conclusion. A particular gauge of drilling efficiency (and success rates) is minimizing the number of dry holes incurred. There are two common metrics for determining a dry hole percentage: (1) the ratio between dry holes counted to the total wells drilled, or (2) the ratio of footage comprising dry holes to the total footage drilled. Both measures yield similar results as shown in Figure 4. Success rates, in turn, relate directly to the reserves added per well and indirectly to the reserves the rig is credited with adding.

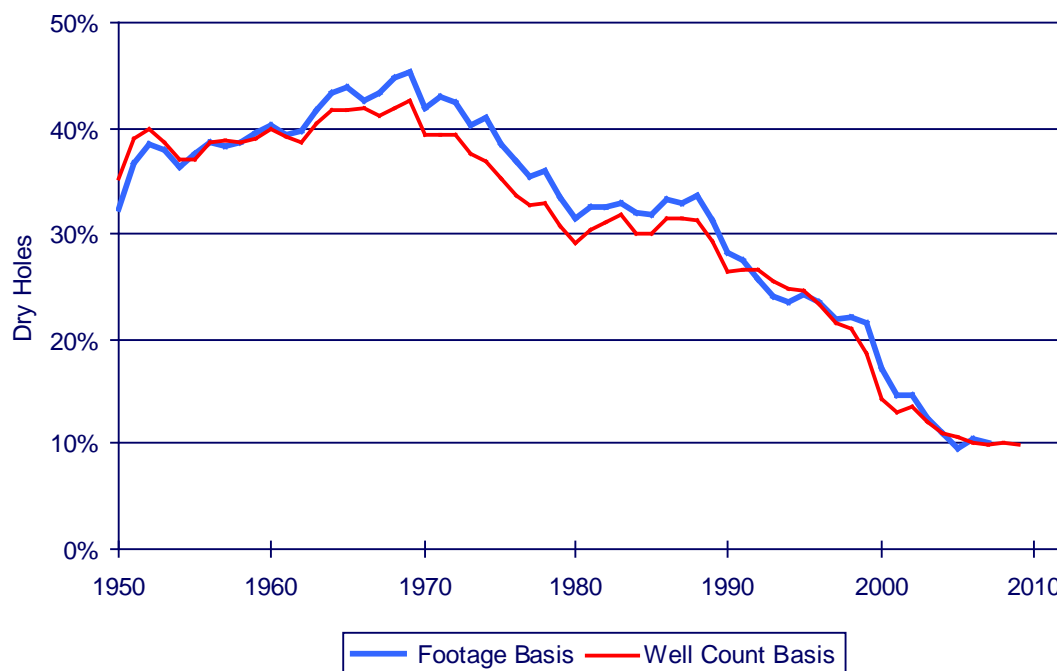


Figure 4. Dry Holes (Footage and Well Count Basis) Show Parallel Trends

The “dry hole” metric has dropped from a level of over 40 percent in the 1960s to about 10 percent today. Much of the reduction is attributed to improved exploratory techniques from knowledge gained with 2-D and 3-D seismic and other emerging monitoring and analysis tools. A “dry hole” well in some cases is not necessarily due to a lack of hydrocarbons but is one that can’t produce sufficient hydrocarbons to be commercially profitable. With the advent of shale drilling in recent years, riskier wildcat drilling is being replaced with more certain “exploratory” situations where the existence of hydrocarbons is already known. Some say that shale drilling is now more akin to a manufacturing process wherein wells are drilled and completed with assembly line repetition.

Technology, such as rotary steerable systems (RSS),¹⁶ has been the catalyst for improved accuracy allowing drillers to better home in on their target the first time. Another emerging support technology is the use of satellite data to show oil field thermal

¹⁶ Bryan, Cox, Blackwell, Slayden, Naganathan, “High Dogleg Rotary Steerable System: A Step Change in Drilling Process,” Society of Petroleum Engineers, 2009, SPE paper 124498.

anomalies to pick attractive spots for drilling.¹⁷ These and similar tools allow drillers to precisely orient well bores in reservoir “sweet” spots. Microseismic technology¹⁸ allows drillers to place horizontal laterals perpendicular to the natural fractures in a formation to maximize production.

Another possible performance metric is reserve additions per active drilling rig as illustrated in Figure 5. One would expect that technology advancement would result in positive sloping performance curves over time. However, a number of seemingly contradictory long-term and short-term trends are in operation for both oil and gas. The natural gas curve shows a gradual long-term decline, which contradicts recent reports of increasing gas reserves and success in the shales. On an industry aggregate level, this measure is difficult to interpret due to the mix of diverse reserve additions added through the drill bit in exploratory mode, field extension mode, and reserve revisions booked as a result of outside factors including price changes. A few delineation wells in a field can also affect the statistics influencing reserve additions per well. In-fill drilling and uncompleted wells also cloud data trends between adjacent years.

Curiously, the crude oil curve in Figure 5 exhibits both up and down trends. The 2001 peak is likely to arise from contribution of early deepwater offshore drilling performance.

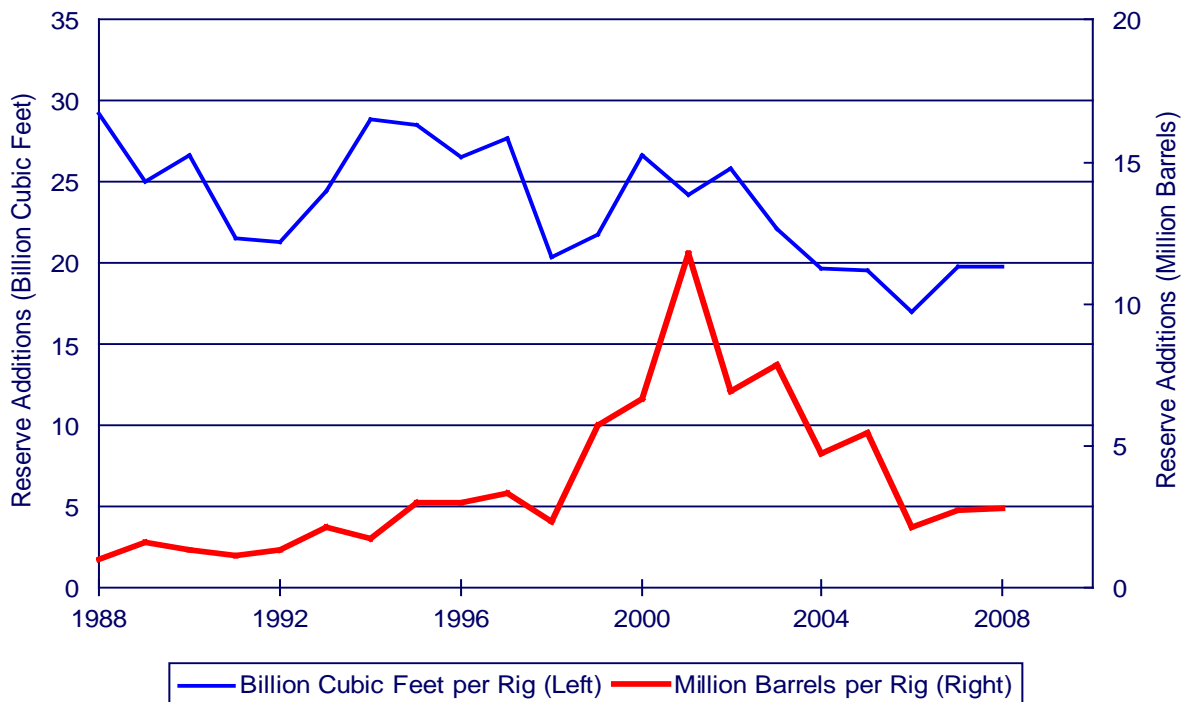


Figure 5. Multiple Reserve Addition Trends Within Aggregated Data

¹⁷ Gupta, Ravi P., Chakraborty, Rupam, Awasthi, Arun K., “Satellite data can cost effectively show oil field anomalies,” *Oil & Gas Journal*, November 2, 2009, http://www.ogj.com/index/article-display/4237979508/articles/oil-gas-journal/volume-107/Issue_41/Exploration_Development/Satellite_data_can_cost_effectively_show_oil_field_thermal_anomalies.html.

¹⁸ “Going live with microseismic downhole monitoring,” *Engineer Live*, http://www.engineerlive.com/Hydrographic-Seismic/4D_Fixed_Installation_Seismic/Going_live_with_microseismic_downhole_monitoring/20798/.

Also possibly influencing this outcome is a tendency for larger fields to be discovered first which contributes to positive additions. As the remaining smaller fields have subsequently been discovered since 2001, this has resulted in a series of declining contribution to oil reserve additions. Also occurring after 2001 has been a general increase in the total footage drilled, the rig utilization rate, and the number of oil and gas wells drilled.

These factors imply that reserve additions are more closely aligned with well counts than the number of rigs that happened to be utilized to drill the wells. Thus, factors removed from the control of drilling rigs actually shape reserve additions.

Given the limitations of aggregate data, focusing on particular play areas can lessen statistical “noise” but not completely eliminate it. Three well-known shale plays include the Barnett, Haynesville, and Marcellus. As a proxy for these 3 shales, one can use industry data for Texas Railroad Districts 5 & 6, North Louisiana, and Pennsylvania for reserve additions and associated rig counts to collectively calculate reserve additions per rig for these combined regions as shown in Figure 6. The regional reserve additions are from EIA *Natural Gas Navigator* data while the rig count is from Hughes-Christensen (Baker Hughes). Of interest to the analyst or modeler, since 1995 the overall Billion Cubic Feet (Bcf) added per rig has increased, but with a decline in the last several years. Despite being more narrowly focused, the localized data shown in Figure 7 also contains vertical wells, recompletions, and workovers which distort the desired horizontal-only drilling impacts. It should also be noted that the Barnett shale has included an increasing quantity of “non-core” area drilling over time which are contributing to diminishing returns and a weakening of the composite proxy curve.

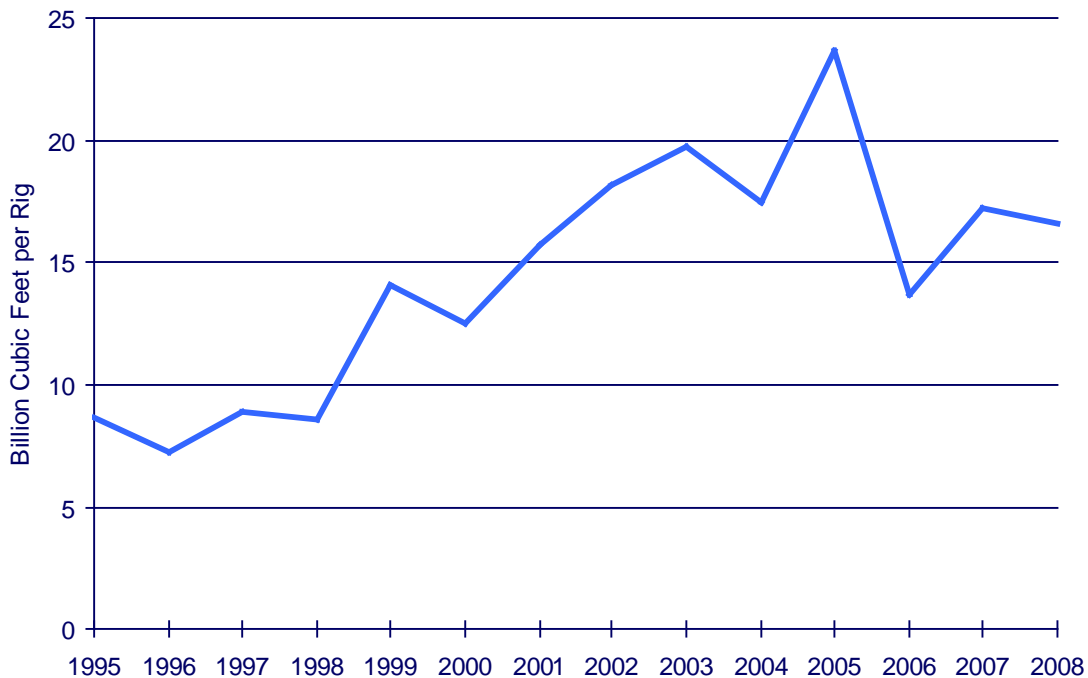


Figure 6. Gas Reserve Additions per Rig in Barnett, Haynesville, and Marcellus Plays
Key shale plays: Tx RRD 5 & 6, North Louisiana, Pennsylvania.

Why Modern Drilling Rigs Are More Efficient

Improved efficiency can be achieved through the effective management of effort to improve productivity. The old adage “time is money” applies here with results showing up as lower drilling costs per foot and cost per well. Drillers and producers rely on five basic strategies to increase productivity and lower costs: (1) Minimizing Non-Productive Time (NPT), (2) Working Faster, (3) Working Smarter, (4) Making Better Decisions, and (5) Tailoring Rig Design for Purpose. The strategies are inter-related and highlighted below:

(1) Minimizing Non-Productive Time (NPT)- The basic concept is for the rig to spend more time working and less time waiting. In the drilling business, waiting time is nonproductive time. Reducing NPT is addressed through rig design and efficient work practices. One way for a rig to minimize NPT is to spend more time drilling and less time in transit. For the drilling rig itself, NPT is time the drill bit is not “turning to the right.” Once drilling is finished, the cycle begins again on the way to the next location.

Rigs are now being designed to disassemble, move 100 miles, and rig up in 48-hours.¹⁹ Another concept is moving rigs by sliding²⁰ on a drilling pad, in which well-to-well rig moves are possible in less than 2 hours. New rigs are designed with fewer and simpler electrical connections to facilitate rig up and rig down. Design features often involve reduced weight components and safety rails that fold for faster rig moves between sites. Other time and cost savers include rigs designed for assembling at ground level to avoid the use of a crane.

In drilling mode, NPT includes pulling out of the hole to change drill bits, inserting additional joints of drill pipe, and conducting logging operations to evaluate progress. One technology to partially avoid these issues is thru-the-bit-logging which avoids the time required to pull the drill string.

(2) Working Faster- Rig time is one of the more expensive aspects of drilling costs. The drill bit is the single equipment component most impacting the rate at which a well progresses to total depth (TD). The holy grail of drilling metrics is Rate of Penetration (ROP). ROP is simply a measure of how fast a rig is drilling the hole. The measurement parameter is rate over time -- feet drilled per time unit, whether expressed in hours or days. Higher penetration rates imply quicker drilling progress and less time (and cost) being consumed. The top performing bits drill faster and farther. Use of synthetic fluids in drilling muds also improves bit penetration.²¹ The drilling mud provides a conduit for removing the cuttings developed by shearing rock into a hole. Another time-saving strategy involves well design utilizing smaller bore holes enabling drilling smaller diameter holes with smaller drill bits.

The factor most affecting ROP is the physical characteristics of the rock (lithology) at various depths. Changing lithologies at various depths also create a set of variables that

¹⁹ Global Energy Services, Product Brochure, http://www.glb-energy.com/pdf/GES%20Brochure%20TM%204-28pm_v9.pdf.

²⁰ “Land rig technology advances,” Hart E&P, February 1, 2007. <http://www.epmag.com/archives/features/240.htm>.

²¹ Sparkes, Dan; Lee, Burney, “Synthetic fluid increases ROP by as much as 117%,” Drilling Contractor, May/June 2004.

affect bit durability. Other factors influencing ROP and durability include mud condition, weight on the bit (WOB), and rotary speed (RPM) of the bit.

Traditionally there is an inverse relationship between ROP and durability; that is, higher penetration rates result in less durability while greater durability occurs at a cost of lower ROP. Improved bit life determines how often a bit must be changed and often eliminates the incremental bit trip, and resultant delays and lost time.

The manner in which a drill bit is run (speed and loading) can have more effect on drilling performance than the particular bit design selected. Drilling rates may vary between two wells using identical bits. Drilling hazards can trigger unproductive time and include situations such as unexpected high or low penetration, excessive bit wear, elliptical hole, collapsing hole, fluid loss, fracturing the formation, blowouts, stuck pipe, collapsed casing, or junk in the hole. Drilling cannot be rushed since careless haste can cause time-wasting consequences. A particular challenge is protecting the formation without destroying it. This involves optimizing WOB and RPM settings to yield the best penetration rate. Fewer drilling days are the result of better bit design and increased hydraulic horsepower (HHP). Drilling challenges are overcome with improved drill bit technology.²²

(3) Working Smarter- These strategies cover sequential activities, parallel operations, and utilizing technology to monitor progress and avoid problems. One management strategy is focusing on the best-perceived wells and high-grading rig crews.

A particular approach is the “mixed fleet”²³ concept whereby contractors capitalize on the strengths of different types of drilling rigs performing in sequence. A lightweight hydraulic top-drive arrives first on a site and drills conductor holes and presets casing. Then a larger, more-robust rig drills the deeper segment of the hole. Each rig does what it does best to reduce time and cost. Still another concept, based on parallel operations, is a rig designed with multiple well centers and fitted with movable function-specific tools.²⁴

One efficiency strategy is identifying “sweet spots” by utilizing measurement-while-drilling (MWD), logging while drilling (LWD), and through-the-bit-logging (TBL) technology to gather data and foresee problems that may be unfolding. Better data helps make better decisions. It is not so much the technology itself but the selection of applicable technologies and combinations of technologies that increase the likelihood of successful outcomes.

(4) Making Better Decisions- Management and planning decisions have significant impacts on the metrics contributing to improved efficiencies. One fundamental decision involves pad drilling where a number of separate wells are drilled from the same location (pad). This reduces rig travel and set-up time and increases efficiencies by enabling rigs

²² “New Drill Bit Technology – The Deep Trek Program,” National Driller, November 1, 2006, http://www.nationaldriller.com/Articles/Feature_Article/c3fd796fd00ae010VgnVCM100000f932a8c0.

²³ “Mixed Fleet: A New Approach to Making Money in the Oil & Gas Market,” Atlas Copco.

²⁴ Springett, Frank, National Oilwell Varco, “Driven by ‘crisis,’ rig design based on parallel operations, aims to change drilling process,” Drilling Contractor, May 17, 2009, <http://drillingcontractor.org/new-concept-land-rig-design-based-on-parallel-operations-2661>.

to work in a single specific area and avoids the time and cost of clearing land and building roads. Other decision points involve making the proper choice in selecting correct motors and bits to drill the curve and the well lateral.

An additional but lesser utilized strategy is the use of multi-lateral drilling -- drilling multiple horizontal laterals from one vertical wellbore. Still another technique is drilling new laterals from existing wells. The length, number, and layout of laterals have a profound influence on production and economics. Pinnate drilling is a form of multi-lateral horizontal drilling in which a number of multi-lateral horizontal wells are drilled in a pattern similar to the veins on a leaf. Once completed, all the laterals produce into a single vertical borehole. Another highly-specialized layout is having 3 or 4 parallel laterals all originating at the same vertical wellbore, like tines on a fork. The potential for new laterals in existing well bores adds reserves and production but makes well-count data confusing for the energy analyst.

(5) Tailoring Rig Design for Purpose- Moving beyond traditional drilling activities has created a demand for higher spec rigs including special fit-for-purpose rigs specifically designed for targeted shale plays, horizontal drilling, and also suited for pad-site drilling.

New rig technology incorporates AC induction motors (adopted from the offshore) which are efficient and quiet. AC motors are brushless, implying less maintenance, and are more suited for hazardous locations. AC motors also provide accurate speed and torque control and have the advantage of sustaining full torque at zero speed and supplying maximum rated horsepower over a range of turning speeds compared to older DC motors where power varies with speed. Another technology includes Programmable Logic Control (PLC) which is a small, highly specialized digital computer that improves motor and fuel efficiency and enhances power distribution. This enables greater control of drilling torque and ROP resulting in faster and better holes.

Rig technology development has always focused on minimizing the use of manual labor on a drilling rig. Automated pipe handling systems have been a fixture on offshore rigs for years, and this technology is now being adopted to land rigs. In addition to time savings, the use of automated iron roughnecks (for connecting and disconnecting drill pipe) and booms to move pipe onto the rig floor also have the added benefit of increasing safety and reducing lost-time accidents.

The need to handle casing determines the size and specifications of a rig's mast, substructure, and draw works. Some drillers are using rigs with extended mast height to utilize longer drill pipe (45' versus 30') to avoid needing to stop drilling to add joints to the drill string, which adds up over the duration of a well. Fewer drilling pipe connections avoid this unproductive time. Being able to insert drill pipe faster is intended to reduce time (and costs). In Alaska, BP is utilizing a state-of-the-art rig in the Liberty field that is 240 feet tall, enabling it to handle three jointed 90-foot pipe lengths when raising or lowering drill pipe string into the hole for changing drill bits or instruments.²⁵ Coiled tubing drilling is also popular for relatively shallow wells because it avoids having to add and subtract pipe segments when changing drill bits or instruments.

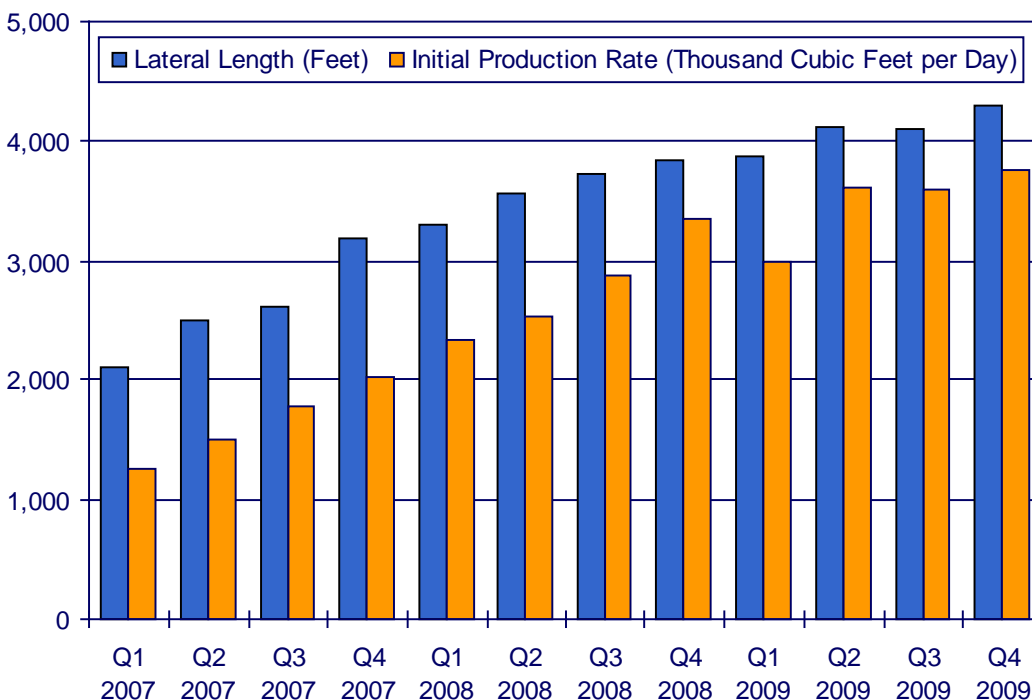
²⁵ "BP to start Liberty drilling soon," Trading Markets, April 11, 2010, http://www.tradingmarkets.com/news/stock-alert/pkd_bp-to-start-liberty-drilling-soon-903849.html.

Well Completion is the Final Step in the Drilling Process

A newly drilled well has no utility (production or payback) until it is completed. Well completion is the process of preparing a well for production through perforation, fracturing, or stimulation activities along with the system of tubulars, packers, pumps, etc. installed under the wellhead. In a shale or tight sands well, the completion process generally costs as much, if not more, than the physical rotary drilling. The completion step presents an additional opportunity to optimize production economics.

Producers can optimize potential well production by drilling longer laterals, which means more reservoir pay is in contact with the lateral. However, longer laterals increase the risk of a time-consuming mistake if something should go wrong during the drilling or fracing process. A related technique is closer lateral spacing between adjacent wells. The most widely utilized technique for better productivity is increasing the number of frac stages per well.

Figure 7. Lateral Lengths and Initial Production Rates Correlate



Note: Production decrease in the first quarter of 2009 was due to pipeline constraint.

Source: Southwest Energy Investor Presentation, Slide 12, Fayetteville Shale.

Figure 7 contains data from Southwestern Energy Company showing average lateral length and Initial Production (IP) rates for the Fayetteville shale.²⁶ Lateral lengths increased from just over 2,000 feet in early 2007 to over 4,000 feet by late 2009. These longer completions allowed IP rates to increase from 1.3 billion cubic feet per day (Bcf/d) to 3.8 Bcf/d in the same time period. As information, the dip in first quarter 2009 production shown on the graph was due to temporary pipeline take-away constraints which have since been remedied.

²⁶ Southwestern Energy Company Investor Presentation, Slide 12, April 2010, <http://www.swn.com/operations/pages/fayettevilleshale.aspx>.

Petrohawk Energy Corporation is experimenting with new well designs in the Haynesville shale to reduce surface treating pressures from 15,000 pounds per square inch (PSI) to 10,000 PSI which not only reduce well costs by the reduced compressor horsepower needed for well fracing, but opens up a larger pool of service providers resulting in more competitive bids.²⁷

The secret to success in gas shales is keeping fractures open more effectively. One Haynesville operator, Cabot Oil & Gas Corporation, keeps its wells pinched back during flowback. While this practice might not generate impressive IP rates, Cabot postulates that flowing wells back gently will keep sand in place and ensure that the formation won't collapse around the wellbore and will boost potential estimated ultimate recovery (EUR) rates. A gentle flowback operating condition is good engineering practice that has been used for decades not only for limiting sand production, but also for reducing migrating fines, which is critical in low perm formations. This practice also has the potential to defer costly compression in later years which in turn avoids adding to operating costs.

Apache Canada Ltd has applied microseismic to aid in frac work in real time in the Horn River basin. Apache used data to experiment with how different perforation patterns affected fracture propagation. In one instance the data showed an absence of growing microseismic activity which alerted Apache to switch from pumping proppant to flushing a well with water to avoid a costly sanding of the fractures.²⁸ The technology allows Apache to optimize the spacing of horizontal wells on future drilling pads.

The Future: How Efficiency Gains May Compound

Future advances in drilling and completion will build upon recent innovations. While the law of diminishing returns always remains in effect and presents challenges, gains are still available to be achieved as mechanical and electrical components are slowly upgraded over time resulting in a higher-performance rig. The next game-changing transition is a swing to horizontal drilling for oil in shales.

Drilling efficiency will steadily improve as old rigs are retired and new rigs enter the work force. A drilling rig can be expected to last 20-25 years depending on utilization, maintenance, and applications. Also, drilling contractors continuously upgrade individual rig components as equipment wears out and is replaced. Upgrades typically include increased horsepower, top drives, automated equipment, etc. Presently, only a very small percentage of land rigs have automated pipe rackers. Likewise, just 14% of the U.S. fleet is AC-driven new builds.²⁹ This leaves considerable room for additional improvement to upgrade rigs as business conditions permit.

Repowering rigs with new advanced diesel engines is a popular upgrade and enables gaining additional horsepower (hp) and achieving fuel savings which can be on the order of 10 to 20-plus percent. New equipment also has the obvious additional advantages of reductions in maintenance, repairs, downtime and emissions. The new power gives the

²⁷ *Natural Gas Week*, May 31, 2010, page 18.

²⁸ "Microseismic aids Horn River frac work," OGJ, May 19, 2010, http://www.ogj.com/index/article-display/0665176246/articles/oil-gas-journal/drilling-production-2/production-operations/ior_eor/2010/05/microseismic-aids/QP129867/cmpid=EnlDailyMay202010.html.

²⁹ Rach, Nina M., "Reinvesting will pay off," Harts E&P, February 2010, page 31.

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rig contractor a competitive advantage when bidding against other rigs without the fuel, horsepower, and maintenance advantages. A good example of this practice is Big E Drilling which found that a new 1,500-hp rig was using the same or less fuel than an older 1,000-hp rig.³⁰

As recently as 2 years ago, the U.S. had about 2,000 actively working rigs, implying a 500 rig surplus at the current 1,500-level rig count. Many of these stacked rigs are candidates for efficiency modifications in an improving producer price setting. A favorable product price environment could also spur a wave of new purchases such as last occurred in 2004-2006 and would result in more upper-end rigs becoming available.

Another area for continued improvement is a reduction in time for moving rigs between locations. Look for more rigs to incorporate modular designs to minimize move time.³¹ A more radical concept is the idea of “walking rigs” which would move by themselves to new drilling locations.³² The “walking” rig has the ability to walk in any direction and turn 360 degrees. It is capable of walking 15’ in two hours with 12,000’ of pipe in the derrick.³³

A Norwegian company, Seabed Rig, has revealed plans to develop a completely automated offshore exploratory rig that would operate under water and without a crew. A prototype rig has been constructed and will be demonstrated by December 2010.³⁴ All rig operating functions would be remotely controlled from a room on a surface vessel or on land.

The offshore remains a sizeable exploratory frontier given that most of the waters have yet to see extensive activity and long lead times limit the amount of progress short term. The offshore will continue to be a ‘laboratory’ and showcase where pioneering technologies are first developed and which will later find applications in onshore plays.

Towards the middle of this century, futuristic ideas such laser drilling could materialize. Laser drilling could dramatically reduce drilling times to a matter of hours per well. The application of lasers has been contemplated for at least a decade but considerable R&D still needs to occur.³⁵ An additional advantage of laser drilling is that the beam melts the rock formation and creates a “self-casing” channel which also has further potential to reduce well completion time for shallower wells. Limitations of laser drilling are high power requirements and needed innovations to “turn corners” for horizontal drilling applications. A safety concern yet to be resolved is how to avoid igniting gas pockets encountered during the process.

³⁰ “Big E Drilling repowers two of its land rigs,” Drilling Contractor, January/February 2001, <http://www.iadc.org/dcpi/dc-janfeb01/j-bige.pdf>.

³¹ Moritis, Guntis, “Special Report: Unconventional basins require new rig types,” Oil & Gas Journal, February 1, 2010, http://www.ogj.com/index/article-display/6482137726/articles/oil-gas-journal/volume-108/issue-4/technology/special-report_unconventional.html.

³² “Walk baby, walk: New rig drills, then moves.” Houston Chronicle, March 12, 2010. <http://www.chron.com/disp/story.mpl/business/6911337.html>.

³³ Range Resources Corporation, Custom Built Rigs (Apex Series Rigs), Howard Weil 38th Annual Energy Conference, March 23, 2010, Slide 43.

³⁴ “In Disaster’s Shadow, Norwegian Firm Unveils Fully Automated Rig,” *Natural Gas Week*, May 17, 2010, page 4.

³⁵ “Laser Oil and Gas Well Drilling,” Argonne National Laboratory, U.S. Department of Energy, http://www.ne.anl.gov/facilities/lal/laser_drilling.html.

Guidance for Analysts and Modelers

Over the last 60 years, the drilling industry has demonstrated an ability to increase annual footage drilled per rig despite the ups and downs of the market. This uptrend is expected to continue with technological innovation being the enabling mechanism. Factors shaping adoption include R&D lead times, market penetration rates, market acceptance, and affordability by market players. One “headwind” working against an uptrend is resource depletion, implying deeper drilling requirements and smaller field sizes, resulting in less reserve additions per active rig even though footage drilled per rig may be increasing.

Aggregate industry annual data is too cloudy for applying accurate drilling efficiency assumptions. For the analyst projecting short-term play-level production gains, wells drilled per rig is the soundest modeling methodology to establish a well count. Similarly, for projecting reserve additions and future production, reserve additions per well is a more precise technique than using reserve additions per rig. As previously postulated, there is one degree of separation between a rig and a well and two or more degrees of separation between a rig and reserves.

The analyst and modeler should be alert to an emerging trend towards smaller choke sizes and other design changes in horizontal wells for impacts these new practices can have on IP rates and slower aggregate decline curves.

Lessons learned in drilling for gas from shale are being applied to oil drilling in shale. It took two decades to perfect drilling and production techniques for shale gas, and it likely will not take nearly as long to maximize oil production from horizontal laterals. The technologies developed for shale gas are generally transferrable to pursuing oil from shale. That knowledge is starting to be applied on a wide basis to oil-bearing shales such as the Bakken, Granite Wash, Niobrara, and Eagle Ford. A renewed push for domestic oil based on the attractiveness of oil prices will be the catalyst driving continued improvements. An ample domestic resource base will encourage continued onshore drilling for both gas and oil from shales.