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Beating the Best

Eight Characteristics of Winners in the Shale Arena

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Eight Characteristics of Winners in the Shale Arena

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AT A GLANCE

Numerous energy companies have sought to exploit the vast gas and oil reserves bound in U.S. shale rock. For some of these companies, the financial results of their efforts have been disappointing, however. A critical reason for this is that many of these companies have tried to apply or adapt conventional upstream processes, operating models, and cultures to what is, fundamentally, a very different business.

Optimized Operations Are Crucial to Success

Shale development has its own distinct underlying economic principles and requirements for success. This holds especially with regard to operational performance—which, for many companies, can prove to be the linchpin that determines success or failure, particularly in today's low-oil-price environment.

Winning Companies Display Common Characteristics

BCG has identified eight operational characteristics that are common to winning players in the shale arena. These companies are return driven; employ "factory model" operations; possess basin-specific expertise; emphasize standardized design and execution; stress unrelenting cost management; engage in collaborative, cross-functional teaming; practice performance management for accountability; and have a culture of continuous improvement.

Over the past 10 to 15 years, many energy companies, including nearly all of the majors and numerous independents, have tried to jump on the "shale train" to take advantage of the glut of natural gas and oil locked in tight U.S. rock. While the resulting surge in development—in 2013, the U.S. overtook Saudi Arabia and Russia to become the world's largest producer of hydrocarbons—has been a boon to the U.S. on multiple fronts, the financial results for some of the involved companies have been less than stellar, even discounting the effects of the recent plunge in oil prices.

A critical factor behind this is that many of these companies have tried to apply or adapt conventional upstream processes, operating models, and cultures to what is, fundamentally, a very different business. Shale development has its own distinct underlying economic principles and requirements for success. This holds especially with regard to operational performance—which, for many companies, can prove to be the linchpin that determines success or failure, particularly in today's low-oil-price environment.

What does it take to optimize operational performance in the shale arena? Through our casework and industry analysis, we have defined what we consider the most mission-critical levers. Deployed together, they can deliver significant, potentially game-changing financial results, including a 25 to 30 percent savings in well costs and a near doubling of wells' lifetime production. Companies that can execute on these fronts will be well positioned to thrive when oil prices rebound; players that cannot, or that cannot act quickly enough, might find themselves fodder for consolidation.

Shale development has its own distinct underlying economic principles and requirements for success—especially with regard to operational performance.

Separating the Best from the Rest

Over the past three years, The Boston Consulting Group has developed an Unconventional Performance Database comprising operational and financial data for many companies operating in North American shale basins. (See the sidebar "Tracking the Performance of Companies Operating in North American Shale Basins.") The database was designed to offer an outside-in view of basin characteristics and operators' results and to provide insight into what drives company performance. Unlike many outside-in benchmarking studies, BCG's Unconventional Performance Database ties its findings to audited financial reports and publicly reported production data to ensure the data's validity.

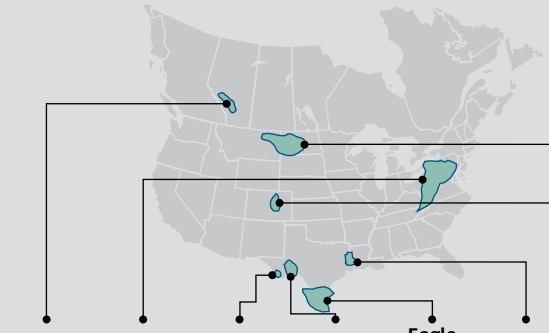
Our database reveals that there are material differences in the returns offered by individual basins, reflecting differences in the respective basins' geological charac-

TRACKING THE PERFORMANCE OF COMPANIES OPERATING IN NORTH AMERICAN SHALE BASINS

BCG's Unconventional Performance Database (UPD) consists of comparative financial and operational performance data for many companies operating in North American shale basins. It covers eight basins and reserves in the U.S. and Canada—Bakken, Delaware, Duvernay, Eagle Ford, Haynesville, Marcellus, Midland, and Niobrara—and includes at least five major players operating in each. We built the UPD from the investors' perspective, looking at where capital was invested and the returns were generated. We focus on variables that are critical determinants of companies' financial results, including development capital costs, production, price realization, operating expenses, and general and administrative expenses. Unlike many outside-in benchmarking studies, we tie our findings to audited financial reports and statements and publicly

BCG's Unconventional Performance Database Includes Detailed Basin Characteristics

Selected data and projections for basins



	Duvernay	Marcellus	Delaware	Midland	Eagle Ford	Haynesville	Niobrara	Bakken
Play	Liquids	Gas	Liquids	Liquids	Liquids and gas	Gas	Liquids	Liquids
Started production[1]	2013	2006	2008	2008	2009	2007	2011	2006
Status	Nascent	Large, maturing	Upcoming	Upcoming	Large, maturing	Status quo	Upcoming	Large, maturing
Reserves (Bboe)[2]	2.2	33.2	6.6	10.0	18.6	7.9	4.5	9.9
Expected production growth (Mboe/d)	+1,611% 22 → 380	+128% 1,716 → 3,915	+395% 269 → 1,330	+381% 409 → 1,967	+96% 1,739 → 3,415	+9% 907 → 985	+294% 213 → 839	+65% 939 → 1,548
	2013 2023	2013 2023	2013 2023	2013 2023	2013 2023	2013 2023	2013 2023	2013 2023

Sources: BCG's Unconventional Performance Database; Rystad Energy.
Note: Bboe = billions of barrels of oil equivalent; Mboe/d = thousands of barrels of oil equivalent per day. Any apparent discrepancies in totals are the result of rounding.
[1]Refers to the year that daily production first exceeded 10,000 barrels of oil equivalent per day.
[2]The sum of probable and possible reserves as of May 2014.

reported production data to ensure the data's validity. Our objective is to break down companies' financial results for a given unconventionals program (that is, a group of wells in one part of a play) into the main drivers of value and help identify performance "hot spots."

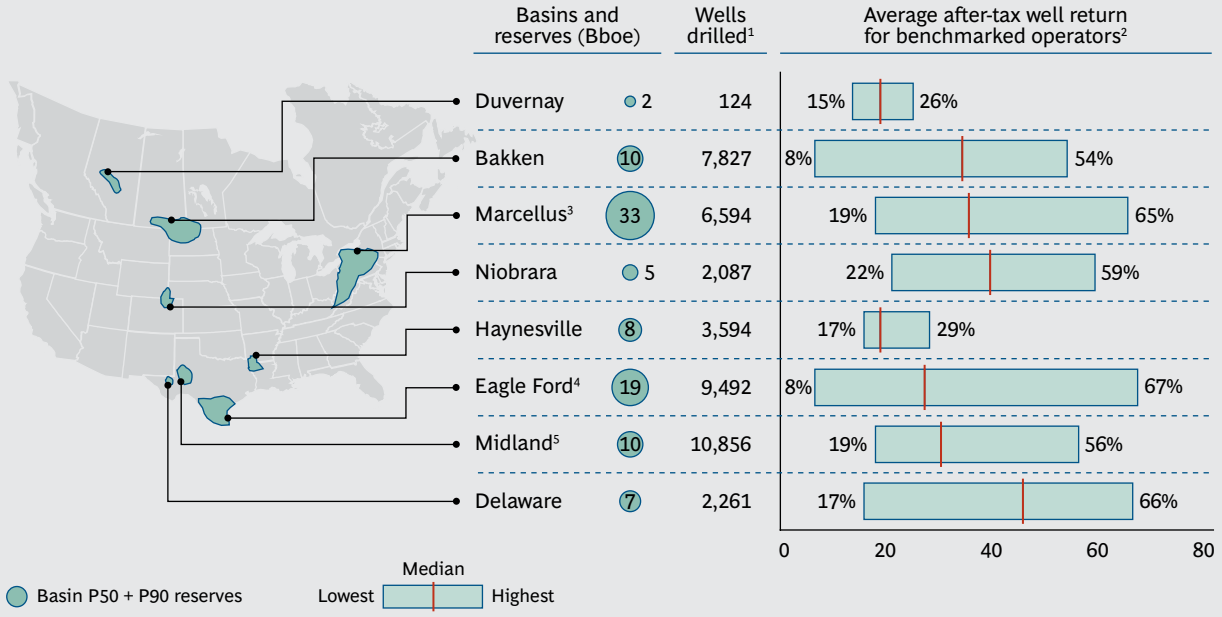
The database also includes basin parameters (such as production forecasts and operating-cost benchmarks) and basin-specific well characteristics. (See the exhibit "BCG's Unconventional Performance Database Includes Detailed Basin Characteristics.") Those include, for each operator, the average well's cost, vertical depth, lateral length, number of fracture stages, 30-year estimated ultimate recovery, 30- and 90-day initial production rates, composite type curves, and other characteristics.

teristics, development and infrastructure requirements, potential products, local market pricing, and other factors. More striking, however, are the enormous differences in financial results between the top- and bottom-performing players within each basin or reserve. (See Exhibit 1.) In the Marcellus Shale, for example, the average after-tax return on wells ranged from 19 percent for the bottom performer to 65 percent for the top performer.[1] Such divergence is also evident in smaller, less developed basins: in the Delaware Basin, for example, the bottom-performing company had an average after-tax well return of 17 percent, while the top performer had a return of 66 percent. For top performers, this difference is equivalent to a savings of $2 million in capital costs per well (in a basin where well costs, on average, range from $6 million to $8 million) and a doubling of wells' estimated ultimate recovery (EUR), or lifetime production.[2]

These differences in financial returns are partly driven by variations in the geological characteristics of the companies' holdings. But they also, critically, reflect sizable differences in the technical and operational practices, and the cultural norms and behaviors, embraced by the various companies as each strives to find an optimal balance between dollars spent on development efforts and dollars earned through recovery.

We believe that there is no single optimal approach to achieving best-in-class performance on these fronts. Rather, it is important to focus on the company's internal rate of return (IRR) per well—that is, what the company gets out of each well versus what it puts in—and then look for cross-functional opportunities to improve it. (Optimizing gel loading and proppant type in hybrid fracs in order to reduce stimulation costs without harming production is an example of such opportunities. Another example is rightsizing artificial-lift designs to reduce capital expenditures.) Best-in-class operators buttress this orientation with a culture of continuous improvement and structured mechanisms that enable them to constantly test, learn, and improve, thereby boosting well IRR even further and on an ongoing basis.

Exhibit 1 | Companies' Financial Returns Vary Considerably



Source: BCG's Unconventional Performance Database.
Note: Return calculations are based on incremental economics, excluding acquisition and midstream costs. Calculations assume New York Mercantile Exchange strip prices as of December 1, 2014: a West Texas Intermediate oil price of $70 per barrel and a Henry Hub natural-gas price of $3.97 per thousand cubic feet in 2015. Includes horizontal wells only across all basins unless specified. Bboe = billions of barrels of oil equivalent. P50 + P90 refers to the sum of possible and probable reserves.
[1]From 2006 through 2013.
[2]Taxes and royalties differ within basins and by state.
[3]Includes both the southwest and northeast Marcellus.
[4]Includes oil and wet gas and condensate acreage wells only.
[5]Includes both vertical and horizontal wells.

Eight Operational Characteristics of Winning Shale Players

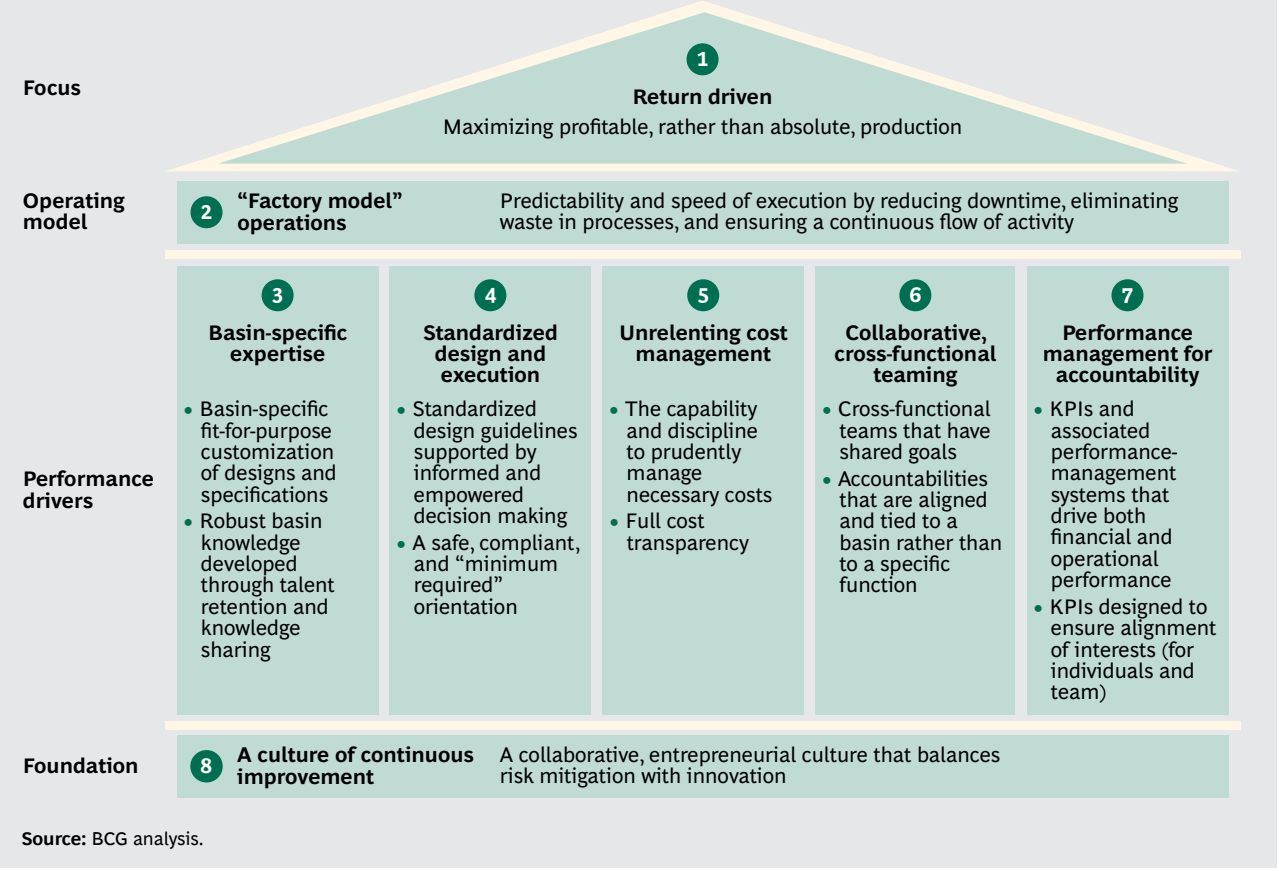
What defines companies that have achieved operational excellence in the shale space and are thriving as a result? Below we discuss eight characteristics common to winning businesses. (See Exhibit 2.)

Return Driven

Even if you have the "best rock in the region" (that is, the area of the formation that has the best recovery potential by virtue of its thickness, rock-fracture characteristics, and so on), it may not make economic sense to drill it if the basin is hard to access owing to restrictive geography (for example, if the basin is ringed by mountains) or lacks critical infrastructure, such as usable roads, sufficient water sources and pipelines, and midstream access. Shale development is not about maximizing absolute production; rather, it is about maximizing *profitable* production. Hence, the aim is to optimize development capital and costs per barrel. Developing a play that has lower estimated recoverable reserves—but has the necessary roads, pipeline infrastructure, water-delivery options, and so forth—can often be more profitable than pursuing a play that has significantly higher reserves but lacks the necessary infrastructure.

The calculus here is thus vastly different than it is in conventional exploration and production (E&P), where margins are significantly higher and identifying the single

EXHIBIT 2 | Eight Operational Characteristics of Winning Shale Players



Source: BCG analysis.

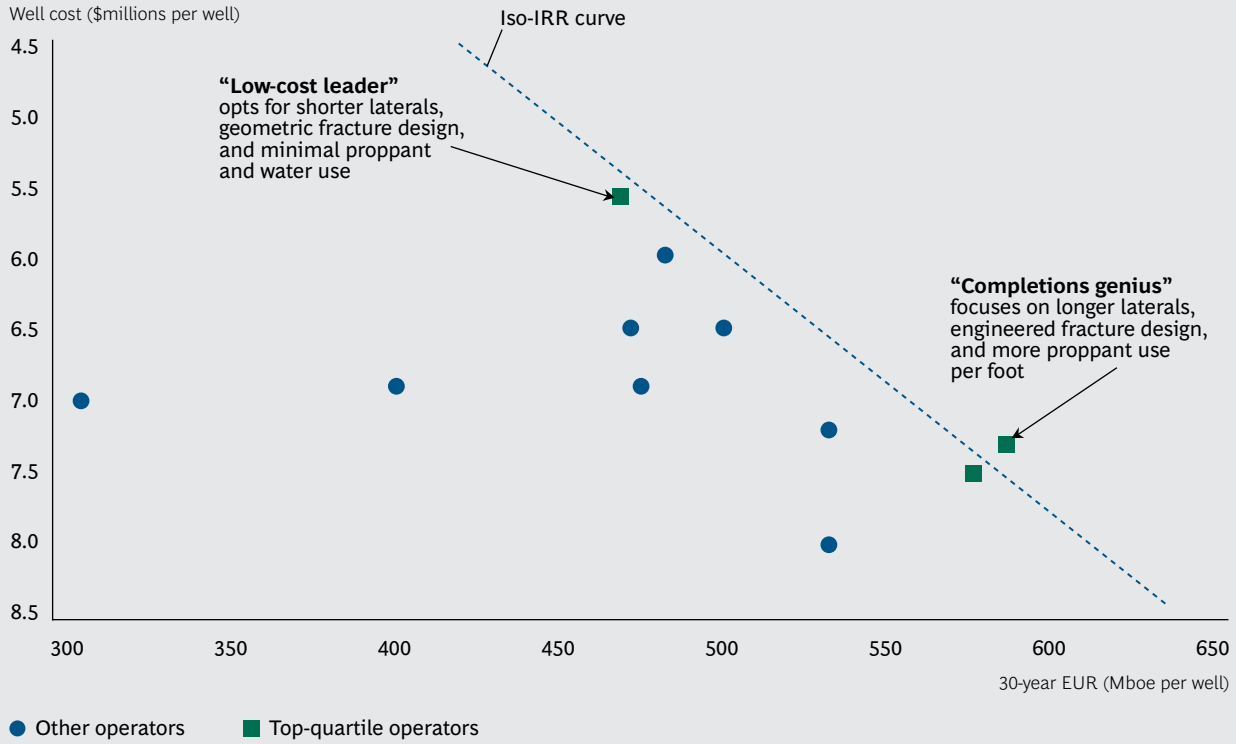
bottom-hole location with the most reserves is the most critical driver of success. In the shale arena, once you know that reserves are present, success is more about spending money wisely across many wells. And, given shale's lower margins, every penny counts—so being able to use existing infrastructure, for example, can make the difference between making or losing money on a well.

In fact, companies must orient themselves toward viewing *every* decision they make through the lens of return. Some of the most successful players, for example, build well pads and facilities assuming a ten-year life cycle for their wells. Other companies construct more robust, more sustainable (and more expensive) facilities assuming a 30-year life cycle. Given that a shale well may see 60 to 75 percent of its total lifetime production in the first ten years of operation, however, the question must be asked: is the extra money worth it? Players focused on the return on every invested dollar often say no. More important, they know to do the math to inform their decision rather than simply assuming that the 30-year well and related facilities will be worth the additional investment.

It is important to note that there is no single "right" solution for how best to manage this business. Companies can take quite different paths to optimizing well IRR. Exhibit 3 highlights two top-quartile players operating in the Delaware Basin that

EXHIBIT 3 | Two Companies Took Different Paths to Achieving Top-Quartile Returns

Average well cost and recovery for 11 horizontal well programs of operators in the Delaware Basin



Source: BCG's Unconventional Performance Database.
Note: IRR = internal rate of return; EUR = estimated ultimate recovery; Mboe = thousands of barrels of oil equivalent. The "low-cost leader" opts for shorter laterals and simpler fracture designs (geometric fracturing, for example) and subsequently has a lower EUR. The "completions genius," in contrast, focuses on completing longer laterals with multiple, more complicated fracturing stages. Despite the different approaches, both companies had a similar IRR per well. The iso-IRR curve shows the various trade-offs between cost and output.

employ two very different operating models. The "completions genius" focuses on completing longer laterals with multiple, more complicated fracturing stages; this approach translates not only into higher costs but also into higher recovery. The "low-cost leader," in contrast, opts for shorter laterals and simpler fracture designs (geometric fracturing, for example) and subsequently has a lower EUR. But with a well cost roughly $1.7 million (or approximately 25 percent) less than that of the "completions genius," the company still has a relatively high IRR. The "low-cost leader" made a clear decision to drill a different well than the "completions genius"—but then drove out every bit of cost possible to maximize the company's return.

Underpinning both companies' strong well IRR and financial performance is excellent execution and continuous improvement on the operational front. This is a must-have for any company that hopes to thrive in this business.

The value of being return driven, even down to the individual-well level, is tangible to shareholders. EOG Resources, for example, saw its average costs per well at Eagle Ford rise from $5.25 million to $6 million from April 2010 through February 2013, bucking the general downward trend in development costs. For EOG, however, this

was by design: the company sought to optimize well returns and was willing to spend more to do so. The effort paid off: the company's EUR per well climbed from 320 Mboe, or thousand barrels of oil equivalent, to 450 Mboe, pushing the company's after-tax rate of return per well from 80 percent to more than 100 percent.[3]

How can a company tell if it is sufficiently return driven? A prominent red flag—a sign that a company has fallen off track—is development decision making that is based primarily, or solely, on geology. Another is infrastructure-related delays in the execution of a well, which would indicate that infrastructure constraints were not sufficiently considered (and addressed) up front.

Factory-Model Operations

Successful companies learn how to develop wells quickly and methodically using standardized designs and simple, "minimum sufficient" processes. For these companies, there is essentially an assembly line: bottom-hole locations are identified, permits are secured, pads are constructed, and wells are drilled and completed in quick succession. This allows the company to efficiently develop each area before moving on to the next.

Optimizing this "factory model" requires defining the operation's takt time, or the rate of production necessary to meet the company's production and earnings goals, and configuring each step in the "well factory" to meet that pace. The operator must ensure that the number of wells it drills and puts on production is consistent with those goals; this alignment can be operationalized by determining the required cycle time for each step in the development cycle and configuring the steps to ensure that there is a continuous flow of activity through the factory.

During the execution phase of the cycle, this model enables a repeatable, predictable flow of pads through execution, which optimizes resources and can lead to huge gains in efficiency. An operator running ten rigs in the Permian Basin that has a top-quartile cycle time for a four-well pad—a spud-to-POP time of 160 days—can meet its production targets with one fewer rig than an operator whose cycle time is average (approximately 200 days).[4] This translates into capital savings of about $7 million annually.

Successful companies learn how to develop wells quickly and methodically using standardized designs and simple, "minimum sufficient" processes.

Care must be taken to ensure that the factory model, once established, continues to run smoothly. If there is a structural bottleneck in the line—such as too few completion crews to keep up with the rigs, leading to a buildup of inventory—the problem must be addressed and the line rebalanced to ensure efficient, steady-state performance. The same holds if execution is not repeatable and predictable. To be sure, there will always be instances when a tool is dropped down the hole or a water-delivery mishap delays completions. But these types of disruptions should be few and far between.

Red flags indicating that the factory model is faltering include frequent hiccups in scheduling (especially problematic is excessive standby time, during which rigs or crews are idle or underutilized), little or no visibility into the next 12 to 24 months of the execution schedule, and ongoing troubleshooting of the schedule and reallocation of resources.

Basin-Specific Expertise

Most top-quartile operators within a given basin are "basin specialists," meaning that the basin constitutes a core part of their portfolio. (Top-quartile operators within a basin derive a median 15 percent of their global production from that basin; bottom-quartile players derive only 2 percent.) This focus helps these players more quickly identify and develop expertise in the most important determinants of competitive advantage within that basin. Additionally, the drivers of advantage can vary considerably among basins, given underlying differences in the basins themselves.

The goal for multibasin players is to quickly, before wasting much time and money, identify what can and cannot be translated from one basin to another.

How much do basins differ? Geologically, the differences are quite stark. For instance, in its sweet spots, Eagle Ford's formation thickness is three times that of the thickest Bakken pay zone, and its original oil in place per section is about five times that of Bakken.

Logistical challenges to development can also vary considerably among basins, depending on the basin's location, infrastructure, and local talent. The North Dakota winter affects Bakken operations enough to cause significant reductions in output, for example, while production in Texas's Eagle Ford and Permian basins remains relatively smooth. Also, nearly one-third of Bakken's natural gas must be flared owing to the lack of gas pipelines, while the amount is significantly lower in Texas.

Regulatory environments can also vary substantially among states, with significant implications for companies' operations. Pennsylvania's regulations for water injection and disposal, for example, differ considerably from those of Texas. This can force players to completely rethink fracturing operations, including decisions on long-distance hauling of produced water versus on-site systems for water treatment and reuse (which become more economical in an environment where transportation and disposal costs are high).

Successfully navigating the differences among basins, and the challenges those differences pose, requires more than ad hoc tactics. It requires comprehensive and integrated basin-specific strategies.

Although many basin-specific strategies, and the knowledge gleaned from implementing them, are localized, many can also be used across other basins. Whiting Petroleum, for example, was able to increase initial production rates in its Niobrara operations by more than 40 percent by implementing a fracture design ("plug and perf" completions with cemented liners) that the company had used originally in its Bakken operations. The goal for multibasin players is to quickly, before wasting much time and money, identify what can and cannot be translated from one basin to another.

Red flags indicating that a company's basin-specific expertise is not being utilized to full effect include the use of similar water strategies (for example, trucking flowback water great distances rather than exploring available nearby injection options) across basins, designs and specifications (for wellheads, for instance) that are "one size fits all," and frequent rotation of engineers and management among basins, which limits continuity and knowledge development.

Standardized Design and Execution

Top-performing players in the shale arena recognize and respect the differences between a onetime, $200 million deepwater oil well in the Gulf of Mexico and a $3 million shale well that will be repeated hundreds of times in the Permian Basin, and these companies adjust their well designs, processes, and execution practices accordingly. Best-in-class players punch out wells across a shale basin in quick succession and with excellent repeatability, largely driven by the fact that the companies are essentially drilling the same well over and over again.

Standardization of well design and execution practices allows good operators to perfect their work and become great. Top performers then optimize these strategies and tactics to become best in class. The best companies embrace a "fail fast and learn" philosophy. They also strive for, and attain, consistent execution, enabled by their use of such things as standardized (but customized to each rig) field checklists that go beyond standard operating procedures to simplify various activities. These checklists can offer additional guidance as well, such as directions for drillers on how to drill through problematic formations.

In contrast, operators that perpetually "redesign the wheel"—without having taken the time necessary to become great at building the *last* wheel—have slower development, higher costs, and operations that are less predictable, often resulting in deteriorating performance. Innovation is important in the shale space, but so is "earning the right" to innovate by first achieving sustained excellence in execution.

Successful companies in this arena are typically run with a strong business, rather than science, orientation. This means that for engineers and scientists who aspire to constantly work on unique or complex design challenges, a highly efficient shale company might not necessarily be the most satisfying place to work. (This is even more pronounced in the current depressed-price environment, when most companies' spending on "science," or research undertaken with a long-term orientation, is limited.) The game here is to define and lock down an economical design, execute it well, and consistently improve performance through incremental changes—not to experiment for experimentation's sake.

It should be noted that, properly managed, the pursuit of standardization should not restrict innovation. Rather, it should control and focus innovation while allowing the company to maintain strong, reliable performance in the field. Nimble shale operators have well-structured programs that foster controlled experimentation by internal teams that is aimed at delivering concrete business improvement through innovation.

Standardization of well design and execution practices allows good operators to perfect their work and become great.

One company, for example, encourages its completion engineers to experiment with different proppant-loading ratios in pursuit of an effective, scalable result. Once a concept is proven, the company incorporates it into its standards. The results of these efforts can be substantial. Pioneer Natural Resources, for instance, through experimentation with different completion-design parameters—including cluster spacing, rate per cluster, proppant per foot, and combination designs—developed a standard design that increased the company's EUR by 10 to 40 percent and simultaneously reduced costs.[5]

Red flags here include intensive design processes—for example, the practice of starting from scratch on well design and the need for multiple weeks or months of design work (or rework), decision making, and approvals to develop the final design. (Well designs should be about 90 percent standardized, with only relatively small tweaks needed at individual drill locations.) Other red flags include ongoing ad hoc adjustments to well designs and execution practices, resulting in reduced learning-curve benefits and inconsistent, expensive execution.

Unrelenting Cost Management

Best-in-class players in the shale arena are obsessed with controlling costs. Penny-pinching is not only a virtue in this business but also an absolute requirement for making money, especially in the current environment.

Players that manage costs best know their data inside out and up and down the organization, from the president of the company to the rig foreman in the field, and individuals are accountable for the costs they influence. Critical to being able to properly manage costs and identify potential hot spots is access to real-time cost data and a commitment to capturing and reporting it weekly, if not daily. This does not, it should be stressed, necessitate a fancy, expensive IT tool. In fact, some very successful companies collect important data through smartphone photos of signed invoices taken on the pad; the pictures are forwarded to data-entry personnel at headquarters, allowing nearly immediate data capture and tracking.

Successful players also document changes in contractor scope and materials—and any additional costs associated with such changes—in real time and demand hard and fast 30-day payment terms so that line items can be verified as soon as is reasonable. In the end, effective cost control is about capturing the data and having everyone in the company looking at it—and being held accountable for it—each and every day. The prize for getting it right can be significant. A company operating in the Permian Basin, for example, embarked on a focused, yearlong, cross-functional cost-improvement program and managed to maintain its per-well investment return despite a 25 percent drop in oil prices.

Players that manage costs best know their data inside out and up and down the organization, and individuals are accountable for the costs they influence.

There are numerous red flags indicating that a company's cost-control efforts are coming up short. These include design engineers who do not know what an extra day of rig time costs, well costs that have bloated significantly in a short time span owing to "surprise" costs, the inability to determine a current well's cost at any stage of the execution cycle and know where that cost stands versus the authority for expenditure, and the absence of cost penalties for contractors that pay off invoices 60 or more days after the invoices were issued.

Collaborative, Cross-Functional Teaming

In most companies, employees are strongly motivated to excel in their respective domains—a reservoir engineer, for example, wants to get the best out of the rock, while a drilling engineer strives for low spud-to-spud cycle times. This potential conflict comes into full play when decisions have to be made on, say, the merits of running a daylong, $100,000 quad-combo log to better understand the reservoir versus reducing cycle time by a day and, in the process, saving about $50,000 in rig and spread costs. In precisely such situations, misalignment of the interests of different

functions is evident, and quite often this organizational dynamic leads to suboptimal decisions for the company.

The whole of well performance is the sum of its parts. The best companies know this and strive to get all of their individual functions on the same page by creating common goals. When the respective functions have a shared goal and act as a single team, siloed thinking disappears, synergies are created, and the company's overall performance improves. In the above example, things would play out differently if the company had a strong cross-functional teaming ethos and cross-functional incentives (such as minimization of total capital expenditure per barrel). Were these in place, the reservoir and drilling engineers would weigh the dollars-per-barrel trade-off by estimating the incremental production possible from running a few more logs (on top of existing ones) versus the benefits of saving time and cost through uninterrupted, short-cycle-time operations. The end result would be the most optimal outcome for the company, and motivation for both sets of engineers would remain strong.

When functions have a shared goal and act as a single team, siloed thinking disappears, synergies are created, and the company's overall performance improves.

A lack of such cross-functional teaming and incentives can adversely affect the throughput of the unconventional "factory," too. If the drilling crew is measured only on drilling costs and cycle time, for example, it will strive to optimize its performance against those metrics but likely be "heads down" otherwise and not seek to work proactively with other functions. The crew will drill the hole as quickly and efficiently as possible and then pass the baton to completions, regardless of whether completions is ready to fracture the well or not. If, however, drilling, completions, and operations have a shared cycle-time metric of spud to POP, these functions will be incentivized to work together to generate the best collective performance—by, for example, proactively reaching out to the appropriate crews and managers to identify and address issues in advance.

Successful operators in the shale arena have further strengthened their cross-functional teaming cultures by rethinking typical organizational structures. Pioneer Natural Resources, for example, in an effort to promote integration and knowledge sharing, groups its engineers into "asset teams" made up of engineers from various functions, with each team led by a single, cross-functional leader. This is a stark departure from conventional oil and gas company structures of functional reporting, where there are no cross-functional managers for single assets.[6] The reason that approaches such as Pioneer's can be so advantageous is that in shale development, companies establish tens or hundreds of individual wells, spread across multiple fields and counties within a given basin, per year; this demands a regional or asset-based team setup to drive the right focus and accountability. By contrast, in a conventional deepwater operation, for example, there is typically only one field, and the respective functions' interests naturally align around that single field's development.

Red flags indicating that the company's teaming efforts are not delivering as they might include "all green" scorecards for the performance of individual functions while the performance of the overall business is struggling; arguments about where costs should be allocated, especially when they fall in the handoff between functions; significant amounts of nonproductive time between functional handoffs (for example, the handoff from drilling and completions to production) and finger-point-

ing back and forth when the functions are questioned about it; and engineers who do not know how decisions they make in the field affect well or pad economics.

Performance Management for Accountability

Successful companies in this industry are lean and nimble. But perhaps most critically, they empower their employees, including those toward the bottom of the organization chart. Staff—for example, young engineers working in the field—have clear decision-making rights and are held accountable for wrong decisions. This tends to lead to fast learning, fewer mistakes over time, and, ultimately, a more motivated workforce, as employees feel that they are trusted and contributing meaningfully.

For management, it is important to balance decentralized decision making with performance measures, compensation plans, and roles and responsibilities that are not only clearly defined and communicated but also aligned with the desired outcomes. The longer it takes for the consequences of a decision to take effect, the more difficult it is to hold decision makers accountable. Best-in-class companies make employees feel the "shadow of the future."[7] A company could, for instance, rotate drilling engineers into workover roles so that they experience, firsthand, the effects of their designs on the wells' performance.

Employees should also have reasonable and significant control over the performance measures against which they will be judged and compensated. Spud to POP, for example, is a cycle-time metric that the drilling, completions, and operations functions will all likely deem fair and relevant, given that they have reasonable control over their ability to deliver against it. For asset teams and other functions, including land and asset development, "plan to POP," which includes the permitting and planning phases, would likely be the better metric, because it would ensure that all relevant parties have "skin in the game."

Successful companies, most critically, empower their employees, including those toward the bottom of the organization chart.

Given the nature of the shale arena—relatively short development cycles give companies ample opportunity to "get it right" and then make it even better—this business is perfect for performance-based compensation and the fostering of internal competition to drive continuous improvement and fast learning. The most successful players in this space have compensation structures that are much more variable than those of the typical conventional E&P company, giving their employees proportionately greater incentive to improve their performance. Many leading operators also hold competitions between and among cross-functional execution teams to motivate them not only to deliver to plan but also to deliver *better* (faster and cheaper) than plan, and the companies provide significant performance bonuses to teams that outperform. This results-driven model not only allows the cream to rise to the top but also attracts and retains more "cream" than compensation models that treat all employees relatively equally.

Red flags here include multiple layers of decision making; idle time on rigs as crews await decisions from the central office; higher attrition rates for young, smart talent; salary-dominant or tenure-driven compensation models, with little performance-based compensation; and more than four organizational layers from the top of the company to the bottom.

A Culture of Continuous Improvement

A crucial characteristic of winning companies in the shale space is the quest for continuous improvement, driven by a corporate culture and leadership behavior that support it. This ongoing pursuit of incremental improvement can have a significant impact on the company's performance over time. Cabot Oil & Gas, for instance, in its Marcellus operations, progressively reduced, over three years, its standard cluster spacing from 400 to 200 feet, which increased the company's EUR per 1,000 feet of lateral from 2.4 billion to 3.7 billion cubic feet. Incremental improvement is also a far more pragmatic and implementable strategy for taking the company to the next level, performance-wise, than relying solely on innovation. Step-change innovations in this space occur relatively infrequently; the trick, instead, is for companies to get great at what they do and continue to try to build on that solid base.

Fostering a culture of continuous improvement requires broad, top-down leadership support and commitment, as well as a willingness to think outside the box.

Fostering a culture of continuous improvement requires broad, top-down leadership support and commitment, as well as the willingness to think outside the box, in several important areas. One is recruiting. Recruiting programs should screen not only for the appropriate technical skills but also for a candidate's cultural fit for working in a fast-paced, factory-like environment. A company could gauge a candidate's suitability, for example, by adopting an apprenticeship model that puts the focus on learning while doing, rather than on intensive, up-front training that is not truly tailored to the shale arena.

Leadership must also commit to fostering a "fail fast and learn" mind-set. A young engineer, for example, should not be criticized for picking a new mud design that leads to slower drilling rates as long as he quickly recognizes the design's failure and shares the knowledge with other engineers. Managers should also encourage learning from all quarters, including suppliers. Management could, for instance, reward teams that collaborate closely with service-company experts to improve designs or reduce costs, or both; management could also extend incentives to suppliers through at-risk contracts.

Leadership must also support the institution of internal crowdsourcing programs that promote questioning of the status quo, especially with regard to legacy corporate practices, audits, and procedures. Such programs can have the dual benefit of improving efficiency and simplifying employees' day-to-day activities.

Red flags indicating that a company's culture is not well matched to the demands of the shale arena include fear of failure among employees (reflected in, for example, excessive time spent modeling type curves, driven by the fear of actual production deviating too much from expectations); managers who suppress suggestions for simplifying processes, such as the idea of making quality audits yearly rather than quarterly; and employee exit interviews that cite a lack of management support for change or employee fears of raising new ideas or concerns.

Other red flags include the absence of knowledge management systems that can quickly disseminate best practices and lessons learned from failures, the rewarding of "checking boxes" over critical thinking and suggestions aimed at driving improvement, and a belief among management that the company knows more than all of the competition and has nothing to learn from other players.

Unlocking high returns in the shale arena requires operational and organizational strategies much different from those that prevail in conventional development. There is no single silver bullet for success; rather, companies must excel on multiple fronts, the most critical of which are discussed in this report. Companies that can achieve this stand to realize immediate benefits—including significantly greater resilience to today's low-oil-price environment—and put themselves on a path to maximizing long-term shareholder value.

Notes

1. Return calculations are based on incremental economics, excluding acquisition and midstream costs. Calculations assume New York Mercantile Exchange (NYMEX) strip prices as of December 1, 2014: a West Texas Intermediate oil price of $70 per barrel and a Henry Hub natural-gas price of $3.97 per thousand cubic feet in 2015.
2. On the basis of prevailing prices for oil and gas (the NYMEX price for West Texas Intermediate oil for February 2015 was $50 per barrel; the Henry Hub price for natural gas was $3.90 per thousand cubic feet) at the time of writing.
3. EOG Resources, investor presentation, November 2014.
4. *Spud-to-POP time* is the time between breaking ground on a well and the well being put on production.
5. Pioneer Natural Resources, "Successful Completion Optimization of the Eagle Ford Shale," October 2014.
6. Pioneer Natural Resources, Unconventional Resources Technology Conference, August 2013.
7. See "Smart Rules: Six Ways to Get People to Solve Problems Without You," BCG article, October 2011.

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