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Institutionalizing drilling and completions efficiency in US unconventionals

US shale drillers lead the world—but even so, investing to improve drilling efficiency, well design, and back-office functions can deliver returns that far outweigh the costs.

by Robert Belanger, Jeremy Brown, Tom Grace, and Zach Kimball

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This article was written before the COVID-19 pandemic and the collapse in oil prices, but during booms and busts alike, our message to operators remains the same: achieving profitability requires an unrelenting focus on capital efficiency.

Unconventional drilling has come of age, and US independents are more effective than ever. Average feet drilled per day has risen by nearly 20 percent since 2015,[1] a testament to the technical advances fueling the shale revolution. Yet unconventional exploration and production (E&P) companies have consistently suffered negative cash flow and weak balance sheets, even during upswings.[2]

To achieve financial sustainability, companies need to focus on capital efficiency across the value chain. The recent collapse in oil prices brings a sense of urgency to this endeavor. Previous articles have outlined steps to improve capital efficiency in well design and development planning[3] and to sustain base production.[4] In this article, we consider how to embed capital efficiency in well delivery—an activity that accounts for 80 percent of capital spending—and suggest tactical improvements for independents to adopt. Although some may not see a need to increase their investment in operational excellence and cost management, our experience indicates that the value created more than justifies the money, time, and effort involved.

Capital efficiency can also help operators unlock their inventory. For most of them, only about 20 to 30 percent of inventory is classified as tier one, usually corresponding to a breakeven oil price below $40 per barrel.[5] To unlock the remainder, they need to improve returns on invested capital (ROIC) through cheaper drilling and faster spud to sales.

Creating value in well delivery

Drilling performance varies considerably from one operator to another. Within the Delaware basin, for example, top-quartile operators achieved average drilling progress of 620 feet per day over the course of a well program in 2019, while their third-quartile peers managed only 400 feet per day, leaving them with an improvement opportunity of more than 50 percent.[6] Although geological differences may explain part of the shortfall, such a broad spread in a single basin suggests that inefficiencies in equipment, technologies, or operational practices are also to blame.

In addition to these drilling differentials, another indicator of operational inefficiency is the prevalence of drilled uncompleted wells, or DUCs (see sidebar, "Tackling inefficiencies from DUCs").

Operators have four main levers they can pull to improve returns:

— *Accelerate production.* Better planning or operations performance can improve spud-to-sales time, bringing revenue forward in time. The benefits from an individual well may be small, but they can add up to significant value across a portfolio, especially for operators with a high cost of capital.

— *Optimize cost of carry.* Better planning in areas such as rig to frac spread rate and scheduling can allow operators to reduce the number of DUC wells needed to ensure smooth well delivery, thereby also reducing the amount of capital tied up in inventory.

— *Reduce input costs.* Instead of applying the same standards for equipment and services across the board, operators can adopt fit-for-purpose specifications and confine high-spec equipment to uses where it is needed for technical or safety reasons.

— *Elevate operational performance.* Eliminating long-tail wells by improving reliability, reducing

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1 According to an analysis of data from RS Prism for US drillers.
2 See Jeremy Brown, Florian Christ, Tom Grace, and Sehrish Saud, "Paths to profitability in US unconventionals," McKinsey & Company, August 2019.
3 See Jeremy Brown, Florian Christ, and Tom Grace, "Value over volume: Shale development in the era of cash," October 2019, McKinsey.com.
4 See Jeremy Brown, Florian Christ, and Tom Grace, "Sustaining the base: A new focus in shale's quest for cash," October 2019, McKinsey.com.
5 According to an estimate from McKinsey Energy Insights.
6 Calculated using the top and third quartiles of average feet drilled per day for operators with at least ten wells with a 2019 spud date; based on data from RS Prism.

Tackling inefficiencies from DUCs

Drilled uncompleted wells (DUCs) are sometimes used as an operational buffer or drilled to retain a lease, but otherwise this pre-investment of a significant portion of project capital is seldom done by design, and would be considered unacceptable in other capital-intensive industries. The backlogs reported by many companies point to scheduling flaws, a lack of pumping services, infrastructure gaps, capital shortfalls, abrupt capital reallocation, or other weaknesses in development planning and operations management.

The argument that DUCs allow operators to quickly turn wells to production when prices rise is flawed. The best way to manage inventory is to dial back on capital deployment before drilling begins, not after, especially now that spud-to-sales is measured in weeks, not months, as it was at the beginning of the shale boom.

Some level of DUC inventory is unavoidable, but holding more than what is needed to smooth out operational variability destroys value. Drilling a well uses working capital, and if operators take months or years to convert it to cash, they incur an economic "capital charge": their cost of capital multiplied by the level of their working capital. For example, an operator with a 10 percent cost of capital, which spends $10 million on building a DUC inventory that won't be turned to production for a year, has destroyed at least $1 million in value. In fact, delaying cash flow from production can destroy far more value than this; depending on the production level, the extent of the delay, and the price environment, the value destroyed could exceed a company's capital charge.

By institutionalizing this way of thinking in their operations and development planning, companies can improve their capital efficiency. Addressing the root causes that lead to DUC wells can not only help them reduce the impact of DUCs on their balance sheets but also enable them to cut costs more widely and accelerate cash flows from production.

nonproductive time (NPT), and so on is key to performing more consistently. Having a small number of outliers—wells with a mean development time 50 percent longer than average—can inflate unit capital costs and reduce capital throughput.

Exhibit 1 illustrates how value is created in the well-delivery process, as measured by ROIC. Translating this framework into practical actions is not always straightforward in a complex value chain with multiple levers that operators can pull. Real improvement comes from squeezing efficiency from every step of the process, from bit to procurement office.

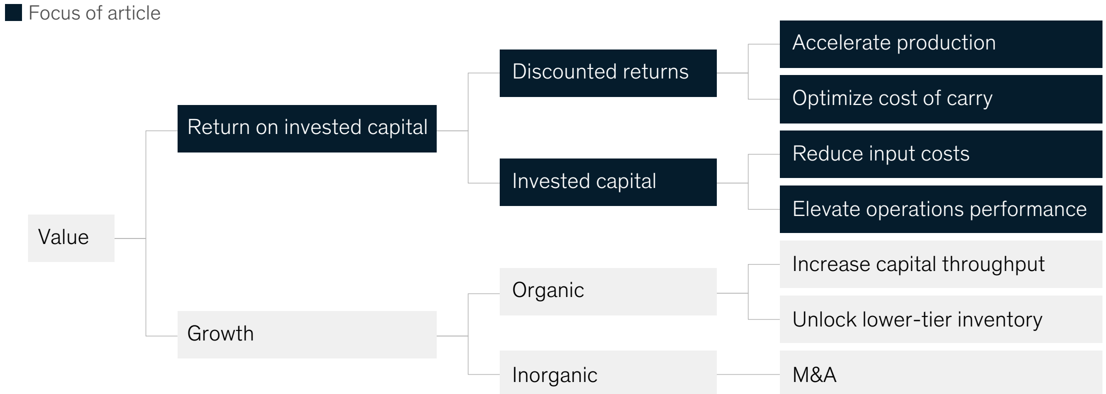
Drawing on our experience of supporting independents in their performance-improvement efforts, we've identified the three actions that can deliver the greatest impact: improving drilling efficiency, optimizing well design, and strengthening back-office functions. Let's examine each of these in turn.

Improving drilling efficiency

Reducing days from spud to sales creates value by accelerating production and improving operations performance. To tap into this value, companies must improve planning and scheduling, reduce NPT, increase operational efficiency, and adopt simultaneous operations.

Exhibit 1

Operational excellence in well construction drives value creation.



The wide range of drilling performance across operators within a given basin demonstrates that most operators have considerable room for improvement. In a survey of nine small operators in the STACK[7] play, average drilling rates ranged from 20 to 47 feet per hour. On a well 15,000 feet deep, that translates into a difference of 23 days in spud-to-rig release, providing slower drillers with a major opportunity to cut costs and accelerate cash flows.

Even top-quintile operators can reduce rig days per well by more than 20 percent. Exhibit 2 illustrates the systematic approach taken by one leading independent to target every aspect of bringing a well online, including technical innovation and the alignment of service providers' incentives to speed up drilling and completion. Our experience indicates that operators should pay particular attention to the following:

— *Technical advances.* Top operators constantly pilot new techniques involving agitators, dissolvable plugs, wellhead cement hangers, and the offline make-up of bottom-hole assemblies (BHAs). As well as solving problems in slow outlier wells, they focus on improving the overall speed and consistency of well delivery.

— *Relationships with service providers.* Operators that align service providers' incentives with their performance goals achieve faster drilling and completion times. They cultivate long-term relationships with providers that can offer strong performance management, use performance-based contracts with defined incentives, or adopt contracting structures where the service provider shares execution risk, with appropriate financial penalties.

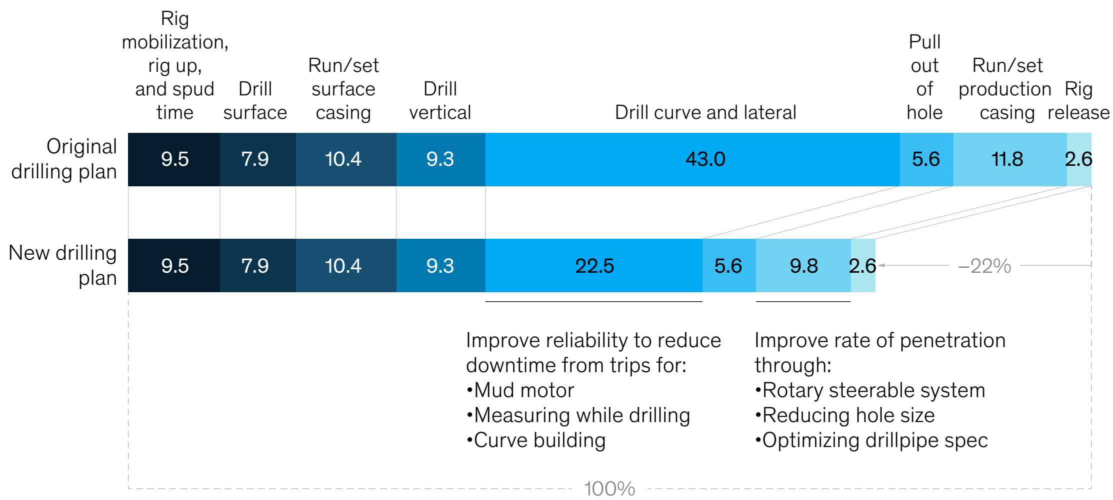
— *Simultaneous operations.* In an environment of high-pressure hydrocarbons, simultaneous operations can be a risky endeavor, but with the right approach, it can improve the timeline for bringing a well to sales. Take a typical completion, which requires a two-hour perforating run with the frac crew standing by. Once perforating is complete, the crew is free to pump the 60- to 90-minute treatment, but it must then wait another two hours while the next stage is perforated. To streamline operations, operators can complete wells two at a time (doubles) or three at a time (triples). The need to deploy two perforating crews increases operational risk, but experienced operators and service providers can manage this additional

[7] Sooner Trend Anadarko Basin Canadian and Kingfisher Counties.

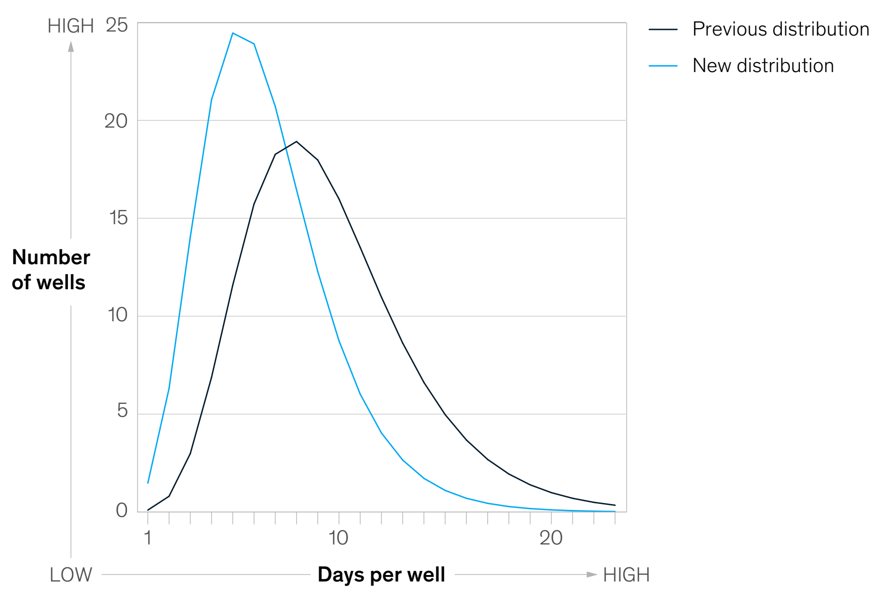
Exhibit 2

A systematic efficiency program at one leading onshore driller reduced rig days per well by 22 percent.

Share of days, by drilling stage, % of original drilling plan days



Forecast campaign drilling days by well



risk through strict protocols and active communication. Simultaneous operations can almost double the completion efficiency of a frac crew, reducing the level of DUCs required, cutting completions costs, and accelerating production.

Optimizing well design

Using design-to-value principles reduces input costs and improves operations performance. Our work with independents indicates that even top-quintile operators can reduce their drilling costs by 20 to 25 percent by adopting clean-sheet designs

The common thread linking drilling efficiency, well design, and back-office functions is that deploying engineering and corporate resources delivers value—in the form of cash acceleration and the compounding effects of inventory expansion.

based on the minimum specifications required to deliver wells safely. The first step should be to eliminate "gold-plating," or overspending on high-spec equipment, by considering the choice of equipment and services afresh. Even simple ideas such as switching from name-brand equipment and materials to cheaper alternatives can deliver significant value.

Other cost opportunities may emerge that are specific to an operator's acreage. Examples include reducing the number of casing strings and using corrosion-resistant casing only to the depth at which it provides benefits, such as the kickoff point, rather than extending it further. Another cost-limiting technique is the use of spudder rigs, which drill and cement surface casing more cheaply than the high-horsepower rigs needed for horizontal sections.

Changes like these may seem too small and insignificant to justify the time and effort involved in adapting a design to a particular well, but they add up over time and have a material effect at the portfolio level.

Strengthening back-office functions

Unconventional E&Ps born in boom times have built their organizations around technical and operational capabilities that deliver wells while minimizing overhead—in the sense of any and all corporate functions. Wanting to stay lean to survive downturns, many operators expanded their operations without scaling their logistics and procurement. However, today's cost leaders empower these functions and ensure that they collaborate closely with well-delivery teams to reduce input costs, improve operations performance, and accelerate production. Two areas in particular need attention:

— *Procurement excellence.* Leading independents deploy specialized procurement professionals with the expertise and capacity to optimize supply chains and negotiate better outcomes. These operators also set up cross-functional negotiating teams of engineers, operations staff, and procurement professionals to drive cost savings through product bundling, lean operations, or specialized service agreements. For example, bundling drill bits with cement services and coiled tubing can deliver a win–win for both operator and service provider. Blending technical expertise with negotiating skill, these teams provide bottom-up "should cost" models for equipment and services. They also specify the minimum level of service needed for drilling and completions, the number of repetitions required, and the commercial feasibility of proposed contracts.

- *Supply-side hedging.* The upstream oil and gas business is fraught with risk. Operators are exposed to commodity prices for critical raw materials for building wells, such as steel, sand, water, and cement, yet the value they derive for the volumes they produce can change at a moment's notice. The use of financial instruments is not the only way to de-risk commodity exposure. Many oil companies purchase water rights and drill water wells for stimulation; other companies trade drill bit for shovel and integrate sand production into their business. Commodity risk can be further mitigated by using hedges for steel and cement as well as the more common hedges protecting oil, gas, and natural-gas-liquid production.

To empower corporate functions while staying lean, operators need to strengthen their talent-management capabilities by adopting value-based principles from other industries. For example, they can use dynamic talent allocation to shift resources from drilling and completion during high-price cycles to production maintenance in low-price cycles, thereby helping to develop and retain their best talent.

The common thread linking drilling efficiency, optimal well design, and stronger back-office functions is that deploying engineering and corporate resources delivers value—in the form of cash acceleration and the compounding effects of inventory expansion—that exceeds the costs directly incurred. Companies may hesitate to spend money and time on look-back analyses, technology evaluations, and procurement studies, but the return on these investments can be high.

To achieve positive free cash flow, independents must take all the steps at their disposal, even in areas of perceived strength, such as operational efficiency. By following the recommendations outlined, they can improve their returns on invested capital, accelerate cash, and unlock their lower-tier inventory.

Robert Belanger, **Jeremy Brown**, and **Zach Kimball** are consultants in McKinsey's Houston office, where **Tom Grace** is a partner.

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