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Value over volume: Shale development in the era of cash

Despite rising production, most US shale producers are showing negative free cash flow. To improve capital efficiency, they need to optimize development strategies for economic value, not volume.

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The US unconventional sector has been in growth mode for years. Liquids production has risen by 5.1 million barrels per day since 2013, 85 percent of which has come from independents.[1] In a previous article, we showed how this growth was a direct response to investor demand,[2] with share prices for independents strongly correlated to production growth—but not earnings or cash flow, which has consistently been negative. With the growth phase now at an end, operators need to focus on delivering value by improving their capital efficiency.

Shifting development priorities

During the growth-at-all-costs era, operators poured their energy, science, and capital into delivering what investors expected. That meant maximizing initial rates for new wells, often at the expense of economic metrics, such as net present value (NPV) and free cash flow. This approach drove aggressive decisions on production levers, such as well design, spacing, and choke protocols during early well life. The combined effects of these strategies have left many operators unprepared for the era of cash.

In our work with shale producers, we have identified areas in which a growth-oriented mind-set can lead to the wrong outcome for value. Operators should carefully study the relationship between production rate and economic value in these areas:

— **Well design.** Instead of basing design decisions on initial rate and defaulting to excessively long laterals and oversize completions, operators should plan around economically optimal completion design, lateral length, and spacing, accounting for parent–child relationships and long-term recovery.

— **Frac interference.** Tight spacing, large completions, and hopscotching development plans—often essential in retaining operatorship—have led to widespread frac interference that hinders base production. To maximize value, operators should embed frac-hit avoidance into

their development-planning processes and take steps to protect base production by monitoring, tracking, and mitigating frac interference across a range of levers.

— **Drawdown.** A bias toward initial rates and a disinclination to study the effects of drawdown may have resulted in reserve losses and suboptimal economics. Operators need to test aggressive and conservative drawdown strategies under controlled conditions and optimize with respect to well economics rather than default to open chokes.

All three of these areas pose new challenges on which experts have yet to reach consensus, unlike conventional topics in petroleum engineering that have benefited from decades of research. The best approach for operators is to experiment actively with their wells to optimize for economic value instead of defaulting to maximum rate.

Another driver of value creation is forecast reliability. The desire to meet investors' growth expectations has led operators to set aspirational production targets and optimistic forecasts that they are reluctant to adjust—and often miss. By contrast, operators with a value mind-set regard accurate forecasting as critical in maintaining investors' confidence.

Operators need to take steps in each of these areas to improve their capital efficiency and sustain investors' confidence in their ability to deliver value.

1. Right-size well designs

The first step to increasing capital efficiency is to ensure that the recipe for well design maximizes economic value. The US averages for the main design parameters—namely, lateral length, fluid volume, and proppant loading—have steadily increased year by year, driving a large increase in production per well and pushing up capital outlays (Exhibit 1). The other main inputs, stage spacing and cluster spacing, have also shifted to more capital-intensive designs, although these data are not publicly available in most states.
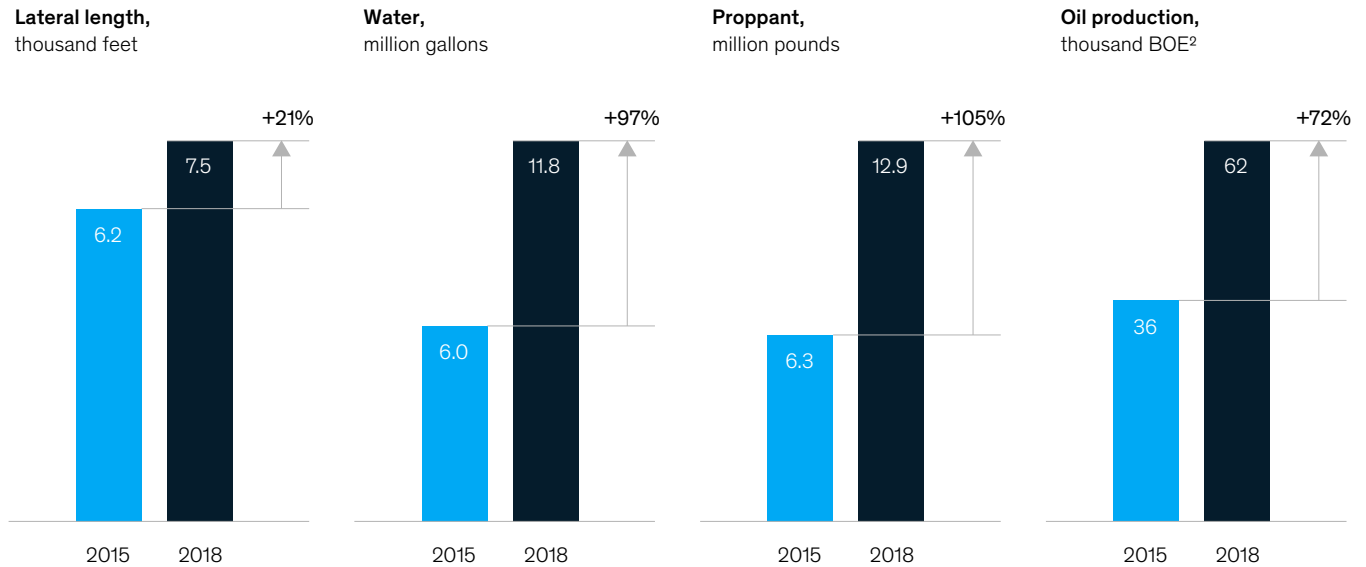
Exhibit 1

Average initial well rates have been increased through more capital-intensive designs.

Average statistics per well[1]

Lateral length, thousand feet	Water, million gallons	Proppant, million pounds	Oil production, thousand BOE[2]

[1]Unconventional wells in United States, excluding Gulf of Mexico offshore and western United States, by production start year.
[2]Barrels of oil equivalent. Average production per well in first 3 months.

Source: RS Prism; McKinsey analysis

Each design parameter has a positive correlation to both production volume and cost, with an optimal point for economic value. Exhibit 2 summarizes results for leading operators in one subbasin. As the exhibits show, most of the wells have been designed to maximize initial production, with the result that they exceed the optimal economic value for each parameter, depressing capital efficiency. The exception in this example is cluster spacing, in which increasing the investment above the current average yields economic benefits.

A better approach is for operators to characterize the optimal economic value for each parameter and then combine the results into a recipe that is repeatable, with continual testing and impro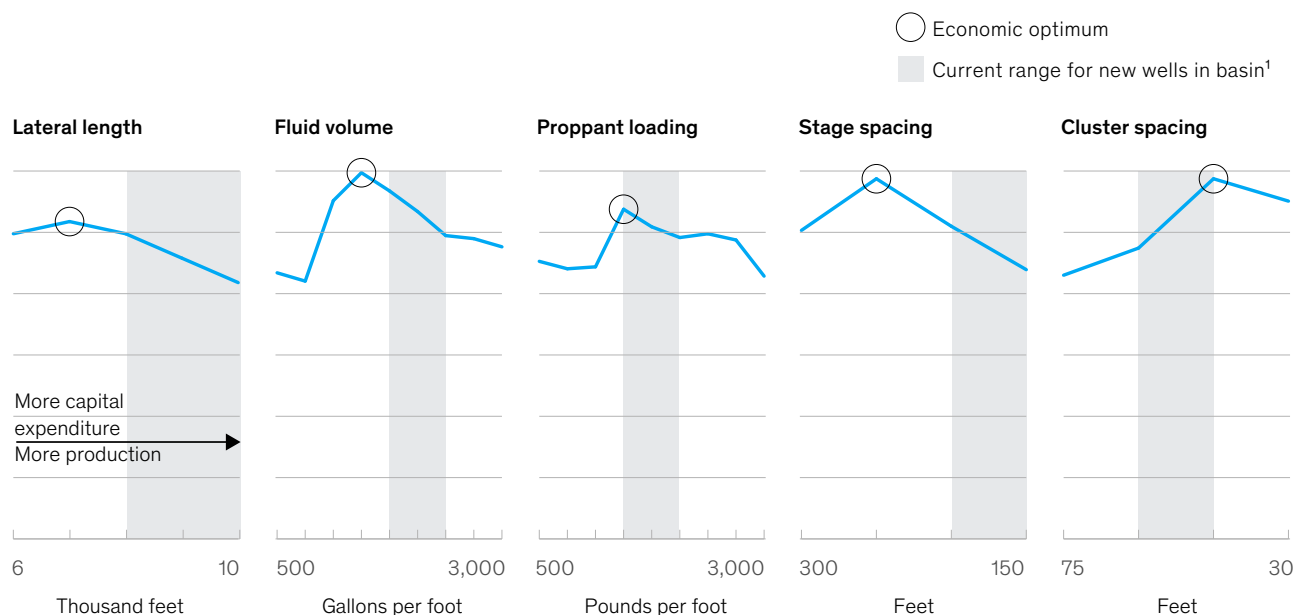vement, across hundreds of inventory locations. To augment the physics-based modeling that engineers use to optimize their designs, we recommend that operators adopt a data-driven approach that uses statistical or machine-learning capabilities and incorporates all analog wells—including those of offset operators—from their basins. With such an approach, engineers can consider larger data sets as they test their designs, quickly update them as other operators experiment nearby, and then overlay the designs on spacing analyses to optimize total section development.

Exhibit 3 shows how applying a machine-learning model to one subbasin revealed a clear economic optimum for fluid and proppant loading, given lateral length, stage spacing, and cluster spacing. For the purpose of optimizing well design for economic

Exhibit 2

Designing wells for optimum economic value rather than maximum production often requires less capital expenditure.

**Average economic performance per well for operators
in 1 subbasin,** net present value

◯ Economic optimum

▨ Current range for new wells in basin[1]

| Lateral length | Fluid volume | Proppant loading | Stage spacing | Cluster spacing |

More capital
expenditure
More production →

| 6   10 | 500   3,000 | 500   3,000 | 300   150 | 75   30 |

| Thousand feet | Gallons per foot | Pounds per foot | Feet | Feet |

[1] Incorporates all horizontal multistage fractured wells targeting 1 formation within a subbasin since 2015.

Source: RS Prism; McKinsey analysis

value, capital efficiency is defined in terms of barrels produced in 12 months per $1,000 of capital (this metric can be adjusted, but it is important not to use the short periods of initial production—often 30 days—commonly used in the industry). Such an approach can serve as a first step toward full development optimization that accounts for well spacing, well count, and total recovery.

Operators should take deliberate steps to counteract the bias toward initial rates that pervades all levels: engineering design, operations, and corporate strategy. To communicate the right priorities to everyone in the organization, dashboards and scorecards should highlight economic metrics above production ones, and explicit targets should be set for value rather than for rate per well.

2. Protect the base

When coupled with tight well spacing, aggressive fracturing treatments have led to an unintended consequence in the form of frac interference (impairment of the base production of existing wells due to the fracturing of new wells). Frac interference covers everything from the degradation of existing fracture networks to the mechanical damage of wellbores when fluid hits producers and is most pronounced during the infill drilling of areas that exhibit partial depletion. This can result in both impairment of the parent wells and poor stimulation of the child wells.

These issues add a layer of complexity to the process of optimizing well spacing and completion design. With more child wells drilled each year than parent wells are, development plans must be

Exhibit 3

Machine learning can be used to determine the optimum fluid and proppant loading for capital efficiency.

**First 12 months' oil production
per $1,000 of capital expenditure,**[1] barrels/$

Lateral length	7,000 feet
Stage spacing	250 feet
Cluster spacing	45 feet
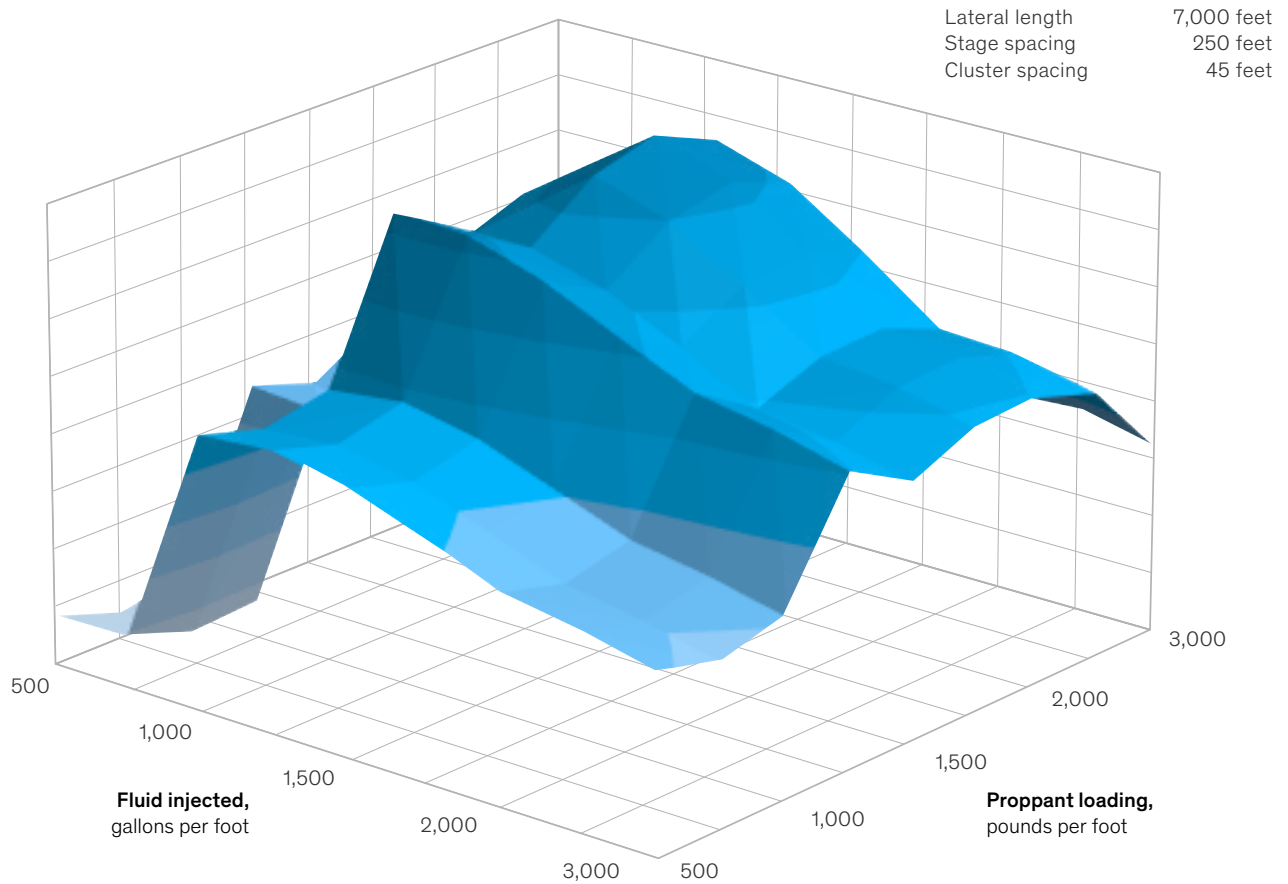
[1] Machine-learning-model predictions for well-design combinations in 1 subbasin.

designed to prevent and minimize these losses. To understand the advantages and disadvantages of different mitigation techniques, operators should take a structured approach like that shown in Exhibit 4, which shows the decision table for one operator in one subbasin.

Our view of frac-interference mitigation is that prevention is better than cure. Losses are best avoided through careful development planning to m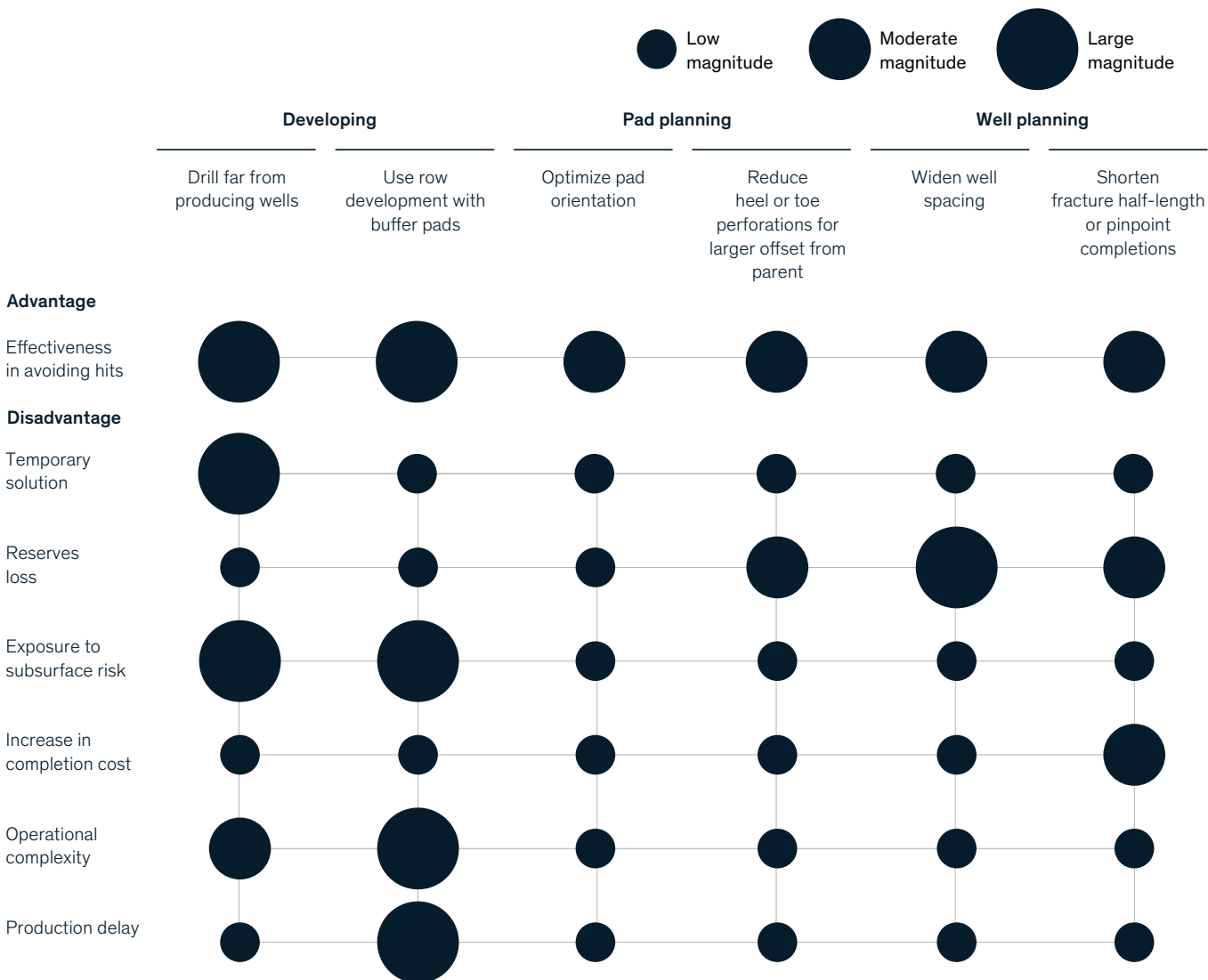inimize interactions. Operational levers, such as parent-well preloading or refracturing, should be used when necessary but not as the principal mitigation tools. Although many operators have succeeded with preloading, it always carries a risk that production will not be fully restored. Moreover, not all wells—especially not all new ones—are candidates for refracturing.

As seen in the example in Exhibit 4, the operator prioritized row development for open acreage while planning pad orientation to minimize toe–

Exhibit 4

Operators should incorporate frac-interference mitigation into their development plans.

Example operator decision table[1]

Legend: ● Low magnitude ● Moderate magnitude ● Large magnitude

	Developing		Pad planning		Well planning	
	Drill far from producing wells	Use row development with buffer pads	Optimize pad orientation	Reduce heel or toe perforations for larger offset from parent	Widen well spacing	Shorten fracture half-length or pinpoint completions
Advantage						
Effectiveness in avoiding hits	Large	Large	Moderate	Moderate	Moderate	Moderate
Disadvantage						
Temporary solution	Large	Low	Low	Low	Low	Low
Reserves loss	Low	Low	Low	Moderate	Large	Large
Exposure to subsurface risk	Large	Large	Low	Low	Low	Low
Increase in completion cost	Low	Low	Low	Low	Low	Large
Operational complexity	Moderate	Large	Low	Low	Low	Low
Production delay	Low	Large	Low	Low	Low	Low

[1] Decision-table results will differ by subbasin.

toe arrangements and tightly spaced parallel infilling. Row development, as depicted in Exhibit 5, mitigates frac interference through sequential pad development, leaving buffer pads around completing wells. This technique offers logistical synergies, if operational complexity can be managed.

Operators with discontinuous acreage or drilling plans driven by lease obligations may find that the only levers available to them are operational ones. To prevent interference losses, they should consider advanced techniques in frac monitoring and pinpoint completion as well as preloading and refracturing.

In all cases, efforts to mitigate frac interference should be built into planning-cycle processes, with detailed plans for drilling schedules that extend over several years so that operators can compare a range of medium-term scenarios. This may require quantifying the losses caused by interference and estimating the likely impact on future campaigns. Our experience has shown that incorporating frac-hit avoidance into development plans can reduce future losses by more than 20 percent.

3. Carefully manage initial rates

The drive to meet production targets can tempt operators into flowing wells too aggressively after completion. Opening chokes can accelerate cash and may be an important temporary step during early flowback, but it is known to cause production impairment in the medium to long term by affecting fluid properties and fracture networks. These physical impacts occur in all basins, albeit with
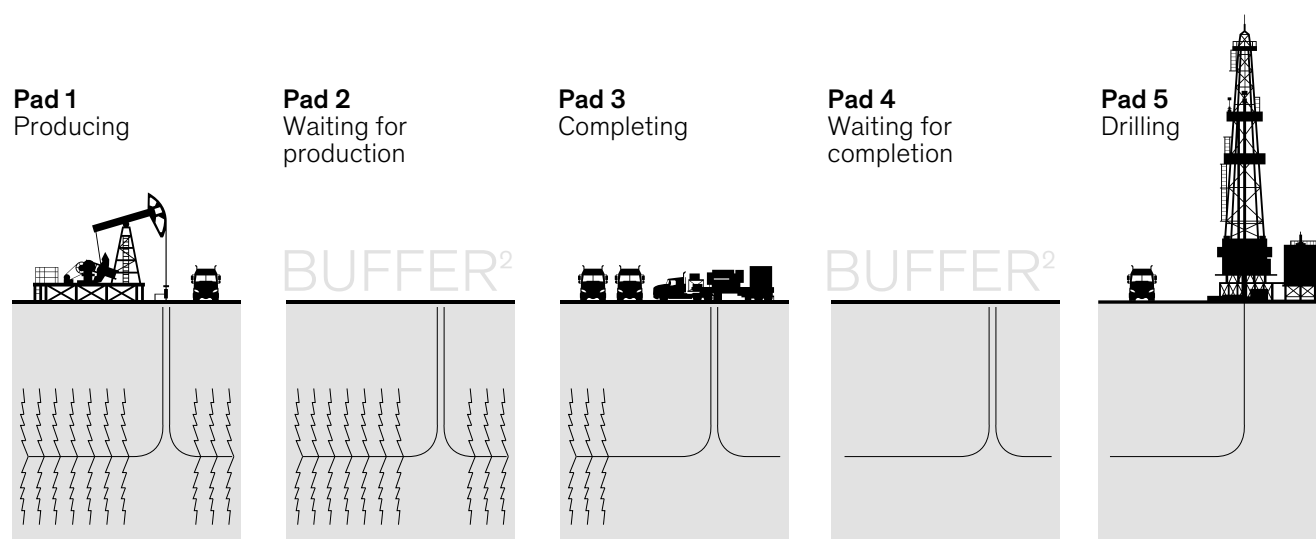
varying degrees of severity (Exhibit 6). Operators will need to conduct controlled experiments to find the best approach, since there is no universal solution across or within basins. Our experience with operators shows that optimizing choke strategies can improve NPV by 10 to 20 percent in oil and dry gas wells and by as much as 100 percent in retrograde condensate wells.

When deciding on choke protocols, operators should be guided by the economic value of each well as a function of its drawdown. Since the effect of aggressive production on downhole impairment is not well understood, operators should experiment with choke settings while monitoring pressure and rate. Established techniques, such as rate-transient analysis, will shed light on the subsurface dependencies of drawdown, especially in the identification of stimulated reservoir volume (SRV) and skin impact. However, accelerated production

Exhibit 5

Frac interference can be mitigated through sequential row development with buffer pads on either side of a completing pad.

View of sequential development, showing heel–toe arrangement[1] (not to scale)

Pad 1
Producing

Pad 2
Waiting for production

Pad 3
Completing
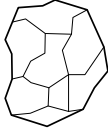
Pad 4
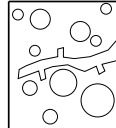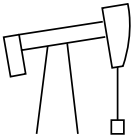Waiting for completion

Pad 5
Drilling

[1] Same concept is applicable to parallel arrangements, which may require more than 1 buffer pad.
[2] Some developments may require 2 pads as buffer.

Exhibit 6

Excessive initial rates can impair long-term recovery due to the effects of large drawdown.

Types of damage mechanisms and causes

	Rock effects	Fluid effects[1]	Inflow effects	Outflow effects
Effect	Degradation in stimulated rock volume or propped rock volume	Deliverability degradation due to fluid property effects	Reduction in formation deliverability and/or connectivity to fractures	Deliverability impacts to wellbores, lift systems, or flow lines
Physical mechanism	• Closure of unpropped fractures • Reduction in propped volume due to sand production • Proppant degradation (crushing or embedding in formation)	• Reduction in relative permeability due to multiphase flow with increasing GOR[2] or CGR[3] below P_{sat}[4] • Increase in oil viscosity due to pressure falling below P_{sat}	• Fines migration or mineral precipitation, causing impairment to fracture conductivity • Residual stimulation-fluid damage from interaction of frac fluid with reservoir, causing pore-throat blockage	• Erosion of equipment or tubing due to sand production • Fouling of downhole artificial-lift equipment due to sand production

[1] Fluid effects are inevitable during pressure depletion but can be accelerated by large drawdown.
[2] Gas–oil ratio.
[3] Condensate–gas ratio.
[4] Saturation pressure.

Source: Johan Daal, Toby Deen, and James Tucker, *Maximizing well deliverability in the Eagle Ford Shale through flowback operations*, Society of Petroleum Engineers Annual Technical Conference and Exhibition, Houston, TX, September 28–30, 2015, onepetro.org; McKinsey analysis

may justify a loss in long-term reserves from SRV degradation. In making such decisions, NPV per well should be the sole criterion.

4. Produce reliable forecasts
Independents' growth-focused business models are being undermined by a widespread inability to forecast production accurately or achieve targets. On average, operators fell short of production guidance by 4 percent in 2018, with considerable variation among companies.[3] This failure to achieve production targets comes not only because wells are underperforming but also because overoptimistic forecasting is prevalent across the sector.

Once an operator has optimized its development plans for value, it should gear its forecasts to trustworthiness so it can promote investor confidence. Following a few guiding principles will help to ensure forecasting discipline and reliability:

— **Honor actuals above all else.** Ensure that type curves and base declines used for investor guidance are kept up to date and are based on realized rates, irrespective of earlier forecasts. It is acceptable to use aspirational targets internally to drive improvement, but forecasts issued externally must reflect the most-likely outcomes

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[3] Based on analysis of actual reported production versus guidance for 28 independents.

— **Match long-term, basin-wide trends.** Assumptions about base decline should be checked against basin-wide actuals. For example, in mature plays with thousands of wells and lengthy producing histories, operators can directly fit Arps's b-factor governing long-term decline[4] for historical wells, meaning they no longer need to resort to commonly used but unvalidated rules of thumb.

— **Account for infill effects.** Forecasts should include realistic estimates for child wells and account for both depletion and frac-interference effects, which can be expected in most cases. The simplest approach is to apply a type-curve adjustment factor to child wells. A more advanced forecast can account for deferred shut-in volumes and losses from frac interference.

Implications for investors

It is time for companies operating in the core areas of mature basins to be valued according to a new set of priorities. After ten years of testing and acreage consolidation, they should be expected to deliver positive cash flows across cycles. Such a cash-flow reset may entail short-term reductions in production volumes, followed by improvement in margins. Given sector-wide shortfalls in targets, investors should rigorously challenge production forecasts and be prepared for downward adjustments. Operators that can reliably generate cash while meeting realistic targets should command a premium.

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The era of cash is forcing operators in all basins to rethink their development strategies, which depend on engineering concepts that are new to the industry and have yet to achieve consensus among experts. As the scientific understanding of completion optimization, frac interference, and drawdown optimization improves, operators must take a careful approach to development and continually test their plans to ensure that they are maximizing economic value.

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[4] Arps's b-factor is a coefficient in the standard decline-curve equation used in forecasting well production.

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