From risk to reward:
Realizing value in the shale M&A market
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With hundreds of operators growing production at high rates, the US oil and gas (O&G) shale market would appear ripe for consolidation and value creation. Against all odds, the trend of consolidation in shales has gained strength year over year, with M&A deals totaling $300 billion since 2014 and average price per acre paid by buyers crossing $49,000 in 2019.\(^1\)

However, since their acquisition, more than 50 percent of these shale deals have delivered below-average financial and shareholder gains.\(^2\) Although the lack of capital discipline in the past and the way an acquisition is financially structured could have influenced the performance of a deal, our analysis of the top 100 shale deals by value suggests that:

- **Buying in high-potential geology has merits, but it shouldn’t supersede the strategic rationale of dealmaking and value investing.** Seventy percent of the deals by value happened in tier 1 zones at a 2–4x premium but achieved 10 percent lower productivity (normalized to a 10,000-ft. perforated interval) than deals in tier 2 and 3 zones.

- **Learning by experimenting with new well designs is a trait of many successful buyers, but only if these designs are optimal and, even so, they do not have to always be extensive.** Fifty-four percent of buyers after the acquisition followed an intense and expensive completion design strategy (with longer laterals and more proppants) but realized an average productivity of less than 1,100 boed.

- **Acquiring adjacent acreage lowers operating costs, but there is a scope for buyers to extend these gains further by optimizing below-surface planning.** On average, 15 percent of operational cost savings were realized by buyers that built a contiguous acreage position, but the savings couldn’t fully offset the up-front capital burn for most.

With extreme price volatility and growth uncertainty returning to oil markets amid global slowdown concerns, unlocking superior value in shales will only get tougher in 2020 and thus will require a future-proof acquisition strategy and a renewed focus on operational excellence.
A strong buying momentum in US shales

While the US upstream M&A deal count was down in 2019, deal value with shales as a primary asset of exchange reached a five-year high of $83 billion, led by Occidental’s purchase of Anadarko (figure 1). In fact, the weighted-average price paid by buyers crossed $49,000 per acre in 2019, the highest ever, dismissing the flat-to-falling productivity trend and tight cash flow situation of shale operators. Although the falling deal count seems to highlight a gradual softening, mega-deals at high valuations generally imply that big players continue to make serious bets on the future of US shales.

Consolidation through M&A is often a necessity in the fragmented shale business, as it can be an effective way for both buyers and sellers to streamline their portfolio and enhance operational efficiency. In line with the production trend, the exchange of assets is primarily happening in the Permian and Eagle Ford basins, which together accounted for about 50 percent of the US O&G shale deal activity in 2019. The capital-intensive nature of shales is also triggering a need for alternative sources of capital—joint ventures (JVs) to share investment and risks or a DrillCo structure where an investor is brought in to fund an agreed share of capital costs.

An interesting trend, which has been appearing lately, is the buying of interest for royalty rights—which could signal that buyers are more willing to make a safe bet on production growth rather than on the economics of shales. About 25 royalty deals took place in 2018 and 2019, with the majority by Viper Energy Partners, a subsidiary of a Permian-focused, independent exploration and production (E&P) company. Although most royalty sellers are private landowners, a few shale operators are also selling their in-demand royalty interests just to cut down their overall debt, earning $65,000 to $100,000 per acre.

Figure 1. M&A trend in US shales (2014–2019)

Source: Deloitte analysis based on data from Enverus DrillingInfo database.
Most of the buying was value-destructive

But is this ongoing consolidation creating value for buyers and their stakeholders? Our analysis of the top 100 shale deals by value since 2014 shows mixed results, with more than half the deals realizing below-average operational (free cash flow) and shareholder (total shareholder returns) gains. In terms of deal value, 35–45 percent of deals turned out to be value-destructive, operationally or financially (figure 2).

Although M&A deals in 2018 and 2019 were slightly more value-accretive than in the past, sustained weakness in oil market fundamentals and a challenging macro, geopolitical, capital market environment have tested the ability of even these value buyers to generate adequate returns. On the other hand, a few deals have indeed created value for buyers since their acquisition—for example, Cimarex’s improved operational and financial performance since its acquisition of Resolute Energy in late 2018. Even so, real factors explaining shale’s success, both organically and inorganically, remain unknown.

So, what makes an acquisition successful or unsuccessful? An assessment of a shale deal would typically center around what and where assets are bought (formation), what the acquirer does with the assets (drilling and designing), and what synergies it achieves with its existing assets and infrastructure, if any (surface efficiencies). With more than half of the deals being value-destructive, where did things go wrong?

Figure 2. Financial and shareholder returns of top shale buyers

Notes: FCF accretive/nonaccretive: Gains above or lower than industry average, latest reported quarter (Q3 2019) over the following quarter after the deal completion date.

TSR accretive/destructive: Gains above or lower than S&P E&P index, latest value (December 3) over the value on the deal announcement date.
Since 2014, 70 percent of shale deals by value have targeted buying tier 1 acreage across the basins—in fact, nine out of the top 10 deals were in tier 1 (or primarily in tier 1). And with so many buyers chasing tier 1 acreage—according to our acreage grading of the top 100 deals since 2014—the dollar per acre paid by buyers for tier 1 deals was two to four times the tier 2 and 3 deals (table 1). Paying a premium for tier 1 acreage is typically justifiable only if it guarantees above-average operational performance. Unfortunately, that hasn’t been the case.

According to our post acquisition analysis of buyers’ performance in the acquired counties, productivity (IP-180 adjusted for a 10K perforated interval) of tier 1 buyers was at par or even below that of some tier 2 and 3 buyers. In some cases, well productivity of tier 2 and 3 buyers was about 10 percent higher than their tier 1 counterparts. The result: Tier 1 buyers had to grapple with a double whammy of a high acquisition price and average or below-average well performance.

More than 40 percent of all drilled wells outside the “sweet spots” of Western Delaware reported IP 180 rates of More than 1,000 boed, while the Eagle Ford had a comparable number of high-performing wells in both Tier 1 and Tier 2/3 acreages. This indicates that geology is important but not the sole performance differentiator for shales.

To know more about these findings, visit our study: Moving the US shale revolution forward.

Table 1. M&A deal trend and performance by quality of acquired acreage

<table>
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<tr>
<th>Deals' formation quality</th>
<th>Percentage of deal value</th>
<th>Percentage of deal volume</th>
<th>Valuation ($/acre)</th>
<th>IP 180 (boed)*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tier 1</td>
<td>37%</td>
<td>32%</td>
<td>46,461</td>
<td>1,081</td>
</tr>
<tr>
<td>Primarily Tier 1</td>
<td>33%</td>
<td>22%</td>
<td>26,657</td>
<td>1,069</td>
</tr>
<tr>
<td>Primarily Tier 2</td>
<td>18%</td>
<td>24%</td>
<td>9,600</td>
<td>946</td>
</tr>
<tr>
<td>Tier 2</td>
<td>12%</td>
<td>22%</td>
<td>13,959</td>
<td>1,167</td>
</tr>
</tbody>
</table>

*IP 180 rates are normalized to a 10,000-foot perforated interval.
Note: Tier 1 and 2 tagging is based on the formation quality index of areas.
Source: Deloitte analysis based on data from Enverus DrillingInfo database.
Considering the Permian tends to be the most sought-after and costliest basin, nonperformance has squeezed buyers in that basin the most. For instance, about 50 percent of buyers in the basin had productivity of below 1,000 boed, despite paying $40,000–50,000 per acre (figure 3). Luckily, some buyers entered the Permian before the race began in 2015. Noble Energy, for example, acquired Rosetta Resources—which had most of its acreages in tier 1 zones of the Delaware (southeast of Reeves) and western Eagle Ford basins—for about $9,000 per acre. An early entry not only reduced Noble’s acquisition cost, but also gave it enough time to learn and optimize its well design and completion strategy—its normalized productivity from these acquired acreages has been around 1,600 boed.

There were winners and losers in tiers 2 and 3 also. But it pinched less due to lower acquisition costs in these two tiers. Additionally, a few buyers took the risk of acquiring in tiers 2 and 3 but ended up realizing above-average productivity—a best-case scenario for any shale buyer. For example, Ovintiv Inc. realized productivity in excess of 1,900 boed from its acquisition of Freeport-McMoRan’s Eagle Ford acreage in 2014, which lies outside the tier 1 zone of Karnes county.

Figure 3. Acreage valuation (left) and post-acquisition performance (right) mapped on formation quality (Permian basin)

Source: Deloitte analysis based on data from Enverus DrillingInfo database.
Productivity is guided by the effectiveness of a well completion strategy, which varies by tiers, basins, and even within a formation. The problem is often that the relationship between productivity and completion intensity is either assumed or portrayed as linear—that is, higher productivity is achieved only if the well is drilled longer. The same linearity has been apparent in the M&A trend, with most buyers going for intense completion designs after their acquisition. In many cases, it seemed that expensive acquisition in tier 1 was justified by buyers through longer laterals and higher proppant loading. But did it pay off?

According to our analysis of the top 100 buyers’ completion strategy in acquired counties, 54 percent of the buyers, accounting for 65 percent of deal value, had an engineering and completion intensity index above 0.5 (US average). But the average productivity of their wells was 1,090 boed, which was just at par with the productivity realized by buyers that followed a less intense design strategy. Therefore, it seems that not only did some buyers pay a premium for their purchases in tier 1 zones (figure 4), but they also spent a lot of money in designing complex or overengineering wells without achieving the expected productivity.

Companies that paid high valuations followed an intense completion design strategy to extract more resources. However, a below-average productivity profile reveals that these buyers faced the double whammy of high acquisition cost ($/acre) and development cost (D&C cost) with no significant outcome.

To know more about these findings, visit our study: *Moving the US shale revolution forward*
The level of operational capital burn, for instance, was significant for overengineered wells. Our benchmarking analysis of 2,800 wells drilled by buyers in the Permian—against ideal completion design ranges in the basin—reveals that nearly 63 percent of buyers’ wells were either over- or underengineered in the basin, increasing hydrocarbon recovery per well cost by 16 percent overall (figure 5).

Although many buyers missed this optimization opportunity, there were a few who realized this and course-corrected their design strategy in the early phase of their buying. About 23 percent of the top 100 buyers followed a cautious approach toward well design, yet realized a superior well performance. For example, Apache and Marathon acquired certain acreages in the tier 2 zone of the Delaware basin and drilled shorter lateral wells (4,800–5,200 ft.) with a range-bound loading of proppants (2,000–2,400 lbs./ft.) and fluids (43–50 bbl/ft.). This strategy of aligning well designs with rock type helped them realize a superior productivity of 1,300–1,600 boed.

Figure 5. Optimization opportunity in the Permian basin
Well designs of buyers in the acquired acreages benchmarked against optimal ranges (2,800 wells)

<table>
<thead>
<tr>
<th>In range</th>
<th>Slight deviation</th>
<th>Underengineered</th>
<th>Overengineered</th>
</tr>
</thead>
<tbody>
<tr>
<td>52%</td>
<td>11%</td>
<td>26%</td>
<td>11%</td>
</tr>
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Permian buyers could have improved the capital efficiency of their acquired acreages by 16% by optimizing well designs.

Source: Deloitte analysis based on data from Enverus DrillingInfo database.
Over the last few years, buyers have favored acreage consolidation and contiguity—even at a high, up-front capex—to realize infrastructure savings by having centralized facilities, streamlined operations, and reduced land work. About 70 percent of deals by value were aimed at building a contiguous acreage position with an operating cost of $4.7/boe, 15 percent lower than the ones with scattered lease holdings ($5.5/boe, refer table 2). The benefits of acreage contiguity were more pronounced in the Permian, where costs were lower by 25 percent. 27

Buyers with scattered acreages had a higher operating cost, but those with high acquisition and completion costs faced the double whammy of high opex and capex intensity. For example, an independent operator entered the Permian basin by acquiring noncontiguous acreage at about $40,000/acre. The combination of a high price for a high-potential location, an intense and expensive completion strategy (E&C index 0.71), poor productivity results, and no major infrastructure savings led to a high operating cost of nearly $7.1/boe for the operator. 28

Although opex benefits from infrastructure savings are beneficial, these should not govern the entire approach of a deal or justify an undisciplined capital approach. In fact, a disciplined capital strategy and optimal well designs can give a “denominator” boost to opex savings due to improved productivity per boe. Put simply, operators and buyers should realize savings by giving equal priority to both below-surface (optimal designs and increased productivity) and above-surface measures (infrastructure savings). Parsley Energy, for example, attributes its low operating cost ($3.8/boe) in the Permian to both above-surface gains from integrated enhanced oil recovery (EOR) and water disposal systems and subsurface optimal well designs. 29

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**Table 2. Average costs and valuations of deals by buying rationale**

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<tr>
<th>Deal rationale</th>
<th>Contiguous acreage</th>
<th>Noncontiguous acreage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deal value share</td>
<td>70%</td>
<td>30%</td>
</tr>
<tr>
<td>Deal volume share</td>
<td>49%</td>
<td>51%</td>
</tr>
<tr>
<td>Valuation ($/acre)</td>
<td>38,700</td>
<td>24,200</td>
</tr>
<tr>
<td>Operating cost (LOE, $/boe)</td>
<td>4.7</td>
<td>5.5</td>
</tr>
</tbody>
</table>

Source: Deloitte analysis based on data from Enverus DrillingInfo database.
A sole focus on acquiring tier 1 acreage and the tendency to overengineer newly acquired wells in many cases explain the value destruction in the US O&G shale market. In hindsight, yes, buying at a low price would have helped. But the nascent learning curve of operators and the perils of the high growth of shales would have still challenged dealmaking in shales. Although each deal has its unique strategic importance and a time frame to create value, the below considerations could help buyers to fairly value and rightly operate the acquired assets.

**Reassess and update engineering strategy assumed at the time of acquisition**

An agile manufacturing mindset and active peer learning are advantages for all operators and buyers in shales. A buyer in shales needs to regularly reassess all its engineering and drilling assumptions—especially in the initial years of the acquisition—and ensure that they are in sync with, if not ahead of, the new shale realities.

For instance, one of the leading independent natural gas players in the United States acquired its peer in 2017 to build contiguous acreage and had assumed or planned intense future well designs (20,000-ft. lateral) at the time of acquisition. However, seeing operational challenges and performance issues, the company course-corrected its design strategy and moved to relatively shorter laterals of 12,000 feet to optimize its EUR/well cost.

**Augment financial assessment with core engineering and operational data**

Conventional dealmaking values a shale company through a financial lens (market or discounted cash flow techniques), with risk-adjusted discounts based on price volatility, technology, or regulations. However, a lack of granular operational adjustments to these techniques—critical given shale’s erratic behavior—leads to a suboptimal valuation of assets and poses a notable financial risk to either buyers or sellers. So, dealmakers could leverage analytical techniques on field data to fine-tune these valuation models and minimize the operational risk from their investment strategy.

Proved developed producing and nonproducing resources (PDP/PDNP), for instance, are valued with no or minimal operational risk discounts, but analytical adjustments based on factors such as infrastructure availability, well-design performance, geological risks, and acreage rights expiration windows could reveal the need to discount some asset values sharply. Likewise, such alterations could help some sellers get a “true value” for their proved undeveloped acreages (PUDs) as against a blanket discount on their book value.

Since the major issue plaguing the shale industry is its high capital intensity, financial and strategic considerations—such as the prompt sale of noncore assets bundled with an acquisition and an openness for agile partnership models—are typically key to successful buying in shales.
Identify and divest acquired noncore assets as a predeal consideration

With 6 percent of deals accounting for 65 percent of the total M&A deal value and $45 billion in acquired debt, these large buyers would typically look to divest “noncore” assets that come with an acquisition to free up capital. But rather than just divesting assets outside their core areas of interest, buyers would benefit from also finding noncore assets within their best basins through multidisciplinary analytics and advanced technologies (for example, microseismic monitoring and tracer analytics).

Given the stressed balance sheets of operators and current oil and natural gas prices trading near their 2016 lows, it would be best for buyers to identify and initiate the divestment process before a deal is closed—that is, seeing the divestment of acquired noncore assets as a predeal consideration against making it a postdeal afterthought. Before closing its Anadarko acquisition, for example, Occidental inked a binding sale agreement with Total to sell Anadarko’s assets in Africa for $8.8 billion. The sooner a buyer delivers on its noncore asset sales, the sooner it regains balance sheet strength and, thus, investors’ trust.

Explore partnerships that are capex-light and data-heavy and that maximize utilization of combined resources

Placing high bets on premium geology and a suboptimal development approach in acquired acreages seem to explain the underperformance of the top 100 deals from an FCF and TSR standpoint. Knowing the embryonic learning curve of many shale buyers, operating “solo” will likely add uncertainty to future growth and enhance companies’ capital risk. To tackle this, buyers could explore new forms of partnerships with peers to reduce their capital commitments, maximize utilization of their existing resources, share future economic and synergy risk, and boost basin learnings through data-sharing agreements.

For instance, Chevron established a new form of joint venture with Cimarex in the Permian basin, where the former committed undeveloped acreage in return of a share in the latter’s production (or assured cash flows) and access to its well-level data, roads, and utilities. Such agreements not only allow large leaseholders to grow production with limited capital risk, but also augment their basin understanding by leveraging the field experience of independent operators.
Endnotes

5. Enverus DrillingInfo O&G M&A database.
6. Ibid.
7. Ibid.
8. FCF accretive/nonaccretive: Gains above or lower than industry average of top 100 US S&Ps (Revenue, Dec. 3), latest reported quarter (Q3 2019) over the quarter following deal completion date; TSR accretive/destructive: Change in stock price of buyers, benchmarked higher (accretive) or lower (destructive) as against US S&P E&P index. (Latest value (Dec. 3) over the value on deal announced date)
9. Postdeal value creation is evaluated using two factors: (1) Free cash flow (FCF); (2) Total shareholder returns (TSR). From the date of an acquisition to Q3 2019, any buyer that delivers FCF growth above the US E&P industry’s FCF growth is graded as value-accretive. Similarly, any buyer that registers TSR above the S&P E&P index is graded as value-accretive. The comparison is relative and isn’t influenced by the size of a deal or a buyer.
11. Ibid.
12. Ibid.
14. Ibid.
16. Ibid.
17. Ibid.
18. Ibid.
19. Engineering and completion intensity index is a standardized scale that measures design properties of a horizontal shale well, including proppant loading, perforated interval, and fluid loading.
Ideal design ranges are defined as the ones that deliver well performance with minimal well design complexity. For more details on ideal design configuration in the Permian basin, please refer to “The Permian basin playbook: Optimizing design experimentation,” https://www2.deloitte.com/us/en/insights/industry/oil-and-gas/us-shale-revolution-playbook/permian-basin.html.

Ideal completion design ranges were ascertained using a multilayered cluster modeling approach on 18,000 shale wells in the Permian basin, where the perforated interval acted as the base cluster, while the remaining parameters like proppant loading and fluids loading were subclusters. Knowing that highly productive wells exist on both ends of the design spectrum, a good well design was defined as the one that delivers a solid productivity profile with the least design complexity for a sizeable number of wells. For more details, see “The Permian basin playbook: Optimizing design experimentation.”

Deloitte analysis based on data from Enverus DrillingInfo O&G M&A database; Enverus DrillingInfo Shales database.

Matthews, “The Merger That Made a U.S. Gas Giant is Failing.”


Deloitte analysis based on data from Enverus DrillingInfo O&G M&A database.


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