The Eagle Ford basin playbook: Focusing on capital efficiency

Moving the US shale revolution forward
With its breadth of experience in working across the crude oil, natural gas, and chemicals value chain, Deloitte helps clients uncover data-driven insights to inform vision, strategy, and decision making; drive operational excellence and prudent capital management across the portfolio of a company; identify, analyze, and perform due diligence for acquisition opportunities; transform business models to capture new growth opportunities; and apply technologies and analytics to achieve business goals. Reach out to any of the contacts listed at the end of this document for more information.
## Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Executive summary</td>
<td>2</td>
</tr>
<tr>
<td>Eagle Ford: Several wins, many losses</td>
<td>5</td>
</tr>
<tr>
<td>Formation quality matters, but . . .</td>
<td>7</td>
</tr>
<tr>
<td>. . . so does completion design</td>
<td>9</td>
</tr>
<tr>
<td>A three-step approach for operating optimally in the Eagle Ford</td>
<td>11</td>
</tr>
<tr>
<td>Amid changes, opportunities remain</td>
<td>18</td>
</tr>
<tr>
<td>Appendix</td>
<td>19</td>
</tr>
<tr>
<td>Endnotes</td>
<td>22</td>
</tr>
</tbody>
</table>
Executive summary

The discovery of the Hawkville field in the Eagle Ford basin in 2008 transformed South Texas, making it one of the hottest economic development regions in the country. Although the early focus was on gas-rich zones, economic prospects and geological variability of the basin enhanced as activity started moving toward wet and oil-heavy zones. Five years ago, however, the Eagle Ford boom came to a halt due to the bust in oil prices and a shift in drilling activity toward western Texas, the Permian basin.

While the Eagle Ford basin has started to make a comeback—current oil and natural gas production of 2.5 million barrels of oil equivalent per day (MMboed) is at a three-year high—debates about its operational and performance ceiling and slow-paced/inconsistent recovery continue even now. Given shale’s nascent development and the basin’s less-than-expected performance, it seems it’s time for shale operators to reevaluate their long-held conventional beliefs and strategies in shales.

Perhaps operators need to renew their results in the basin through a blend of statistical and analytical aspects, covering source rock and completion design of each well. This new understanding could not only assist in unearthing

Our four-part article series, Moving the US shale revolution forward, aims to study the learning curves, unearth success factors, and identify operational well-enhancement opportunities for US shale operators. The analysis is based on Deloitte’s statistical interpretation of reported well-level geological, engineering, and productivity data. The analysis focuses on aggregate performance indicators across the plays. It is intended to complement, not replace, companies’ sophisticated geological and field planning models of their own operations. The opportunities highlighted in these articles are at a well level, as against at the overall field/portfolio level. Given the heterogeneity of shale geology, operators could use this analysis to identify specific factors to explore in their own proprietary drilling, completion, and operations data.
OVERVIEW OF THE EAGLE FORD BASIN

Measuring 400 miles long and 50 miles wide along the Texas Gulf Coast, the Eagle Ford basin is spread over 12,000 square miles in South and central Texas. The basin has a recoverable reserve base of 8.5 billion barrels of oil, 66 trillion cubic feet (Tcf) natural gas, and 1.9 billion barrels of natural gas liquids.

The Eagle Ford's two major zones—Upper and Lower—together drive its capacity, having a varying thickness of 100–600 feet across the play. While the Austin Chalk reservoir, which overlies the Eagle Ford formation, was where activity in this region commenced, the lower Eagle Ford zone has mainly been the area attracting recent development (see figure 1).

Formation depth for the basin tapers from the north toward the south of the basin, causing shifts in subsurface pressures and thus changing resource structures, from oil-heavy in the north-west to wet gas condensate and finally gas in the south. Organic, rich calcareous shales, laminated dolomitic shales, and occasional reworked ash beds form this basin, which is also the source rock for the Austin Chalk.

FIGURE 1

The Eagle Ford play map

Source: US Energy Information Administration, Updates to the EIA Eagle Ford Play Maps, December 2014.
new opportunities but also simplify the complexity of tapping into these opportunities. In this paper, we attempted one such assessment, using geological and completion design data of 17,000 wells drilled in the Eagle Ford basin over the past decade.

**Key highlights**

- Superior formation quality is a value add but not the sole performance differentiator in the Eagle Ford—about 60 percent of drilled wells in Tier 1 zones of the Eagle Ford had an initial 180-day productivity (normalized to 10,000 feet perforated interval) of less than 1,000 barrels of oil equivalent per day (boed).

- Owning and drilling in superior formations is advantageous only if wells are optimally engineered & completed (E&C). Only 40 percent of completed wells had designs in the optimal operating range in the Eagle Ford basin.

- Over- or under-engineering of wells is one problem; an imbalanced prioritization of completion variables is another. With perforated interval, proppant type, and fluid loading influencing productivity by 85 percent in the basin, Eagle Ford operators need to moderate their overenthusiasm for expensive treatment types.

- A few operators in the basin have developed a unique, simple, and effective completion strategy for themselves. Their winning formula: Optimize the major cost component (i.e., perforated interval) and maximize contact with the reservoir rock through targeted proppant and fluid intensity.

- An optimal completion design strategy could increase capital efficiency of Eagle Ford operators by 19 percent, which, if achieved, could not only sustain their economics irrespective of energy price movements but also revive operators’ and investors’ interest in this prolific resource.
The discovery of the Hawkville field in South Texas by Petrohawk Energy led to the first commercial production from the Eagle Ford shale in 2008. In just 10 months, the company assembled approximately 160,000 acres, and its first horizontal well in the basin produced 7.6 million cubic feet (MMCF) of natural gas and 250 barrels of liquids per day. The successful results and a wide range in the basin’s depth from 4,000 feet to 14,000 feet, along with excellent petrophysical properties, suggested that the basin had the right ingredients for a promising shale reservoir.

In just a few years, Eagle Ford became the fastest-growing shale basin, surpassing even the Permian by producing close to 3 MMBoed in 2014. More than 50 percent of Eagle Ford’s cumulative production came from three counties: Karnes, DeWitt, and La Salle (see figure 2). The basin attracted all types of operators due to its highly balanced oil-to-gas production mix of about

**FIGURE 2**

**Maturing growth in the Eagle Ford basin**

With 50,000 full-time job additions and contributions of over US$25 billion to the South Texas economy in 2013, David Porter, the then Railroad Commissioner of Texas said, “The Eagle Ford Shale has the potential to be the single most significant economic development in our state’s history.”

However, with the sharp fall in oil prices, things changed. The drop in the basin’s rig count, from 218 in June 2014 to below 100 by July 2015, resulted in a precipitous fall in the addition of new producing wells in the Eagle Ford. By August 2017, the basin’s production fell to about 2 MMBoed and it still remains 20 percent below its peak.

Considering the basin’s prolific resource base, how can Eagle Ford operators make a strong comeback and sustain their economics irrespective of the price cycles they are in? What can operators learn from their and peers’ underperformance (in terms of well productivity)? To what extent has their performance been affected by their beliefs (i.e., about location or formation quality)?
Formation quality matters, but . . .

Typically, a good starting point in understanding the basin is to map high-quality drilling locations that have a higher production potential. To identify these locations, or Tier 1 zones, an understanding of the geology, or the formation quality of rocks, is essential. In the Eagle Ford basin, our geospatial analysis on the formation quality score (refer to Deciphering the performance puzzle in shales) of each drilled well in the basin reveals three Tier 1 zones (refer to the methodology for more details), with the rest of the acreage termed as Tier 2/3 zone:

- First, northwest of the play, covering Dimmit, Webb, and La Salle counties
- Second, the central section, covering McMullen, Atascosa, and Live Oak counties
- Third, on the northeastern side, covering DeWitt, Karnes, and Gonzales counties

Certainly, every operator would like to own and drill in these high-quality zones. But does owning high-quality zones guarantee productivity for everyone? As our research suggests, it is incorrect to assume that wells outside these zones are always less productive than the rest. In fact, only 40 percent of the drilled wells in the Tier 1 zones had an initial 180-day productivity of more than 1,000 boed per 10,000 feet perforated interval. On the other hand, close to 45 percent of the wells drilled outside the Tier 1 zones had a well productivity of more than 1,000 boed (figure 3), suggesting that formation quality alone cannot guarantee superior well performance.

The same is also evident from the fact that well productivity differs significantly both across the Tier 1 zones and within a zone. For example, average well productivity in the third Tier 1 zone is twice (about 1,700 boed) that of those in the first two Tier 1 zones. Similarly, within the third Tier 1 zone, more than 20 percent of wells have a productivity of below 1,000 boed. Although well productivity is slightly better in thicker formations (the Lower Eagle Ford), these formations also have both productive and less-productive wells.

Rather than undermining the importance of source rocks and faulting the nascent learning curve of operators, our analysis highlights a huge opportunity for course correction in the Eagle Ford—especially after learning that performance can be delivered across the zones, even from the nontrending counties/rocks. So, what really explains the underperformance of wells, both in good and not-so-good formations, and what is the size of the opportunity if underperformance is addressed? What propels results across formation types?
FIGURE 3
The ‘how’ before the ‘where’

Note: (a). The acreage quality mapping is purely based on statistical interpretations of available formation data in the Eagle Ford basin. (b). The productivity numbers are normalized to 10,000 feet perforated interval.

Source: Deloitte analysis based on Enverus Drillinginfo database, accessed June 1, 2019.
Owning and drilling in top-quality shale acreage is advantageous only if wells are optimally engineered and completed (E&C). Getting the E&C part right in shales, however, isn’t easy, as shale operators have only 10–15 years of experience in completing a shale well, as against operators with decades of completion experience in conventionals. But one thing that hampers their learning curve is the notion that an optimum E&C design is one with longer laterals, more proppants, more fluids, etc.

Explained the other way around, popular wisdom implies that simpler, less-intense E&C designs leads to underperformance of a well.

Our analysis of the E&C designs of all underperforming wells in both tiers (Tier 1 and the rest) and landing zones (Eagle Ford Upper and Eagle Ford Lower), however, challenge this notion. In fact, underperforming wells have both simple and intense designs, reflected in the wide range of their completion parameters (see figure 4). There

**FIGURE 4**

**Nonperformers across the completion design range**

**Completion design range for nonperforming wells in Tier 1 zones of Eagle Ford**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proppant loading (lbs/ft)</td>
<td>452–2,295</td>
<td>8,000</td>
</tr>
<tr>
<td>Fluid loading (bbls/ft)</td>
<td>13–55</td>
<td>100</td>
</tr>
<tr>
<td>Perforated interval (ft)</td>
<td>3,800–10,088</td>
<td>16,000</td>
</tr>
<tr>
<td>Well spacing (ft)</td>
<td>190–2,500</td>
<td>5,500</td>
</tr>
</tbody>
</table>

**Completion design range for nonperforming wells in Tier 2/3 zone of Eagle Ford**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proppant loading (lbs/ft)</td>
<td>311–2,595</td>
<td>8,000</td>
</tr>
<tr>
<td>Fluid loading (bbls/ft)</td>
<td>13–56</td>
<td>100</td>
</tr>
<tr>
<td>Perforated interval (ft)</td>
<td>3,160–8,500</td>
<td>16,000</td>
</tr>
<tr>
<td>Well spacing (ft)</td>
<td>225–4,900</td>
<td>5,500</td>
</tr>
</tbody>
</table>

Note: The range of each variable represents the average value of bottom 10 percent and top 10 percent wells.

Source: Deloitte analysis based on Enverus Drillinginfo database, accessed June 1, 2019.
are more than 1,000 underperforming wells with perforated interval of more than 7,500 feet in both the tiers and landing zones. Similarly, there are about 3,000 underperforming wells with proppant loading of less than 1,000 lbs/feet. In fact, there is notable design divergence in nonperforming wells from the same operators, reflecting the challenges faced by many in the well delivery process.

Apart from the over- or under-engineering of wells, an imbalance among many E&C variables is another problem. For example, in DeWitt county, there are about 250 over-engineered underperforming wells where notable imbalance amongst E&C variables is quite apparent. The outcome: An operator with wide-ranging well performance in the same county/formation, resulting in higher cost, reduced efficacy of well spacing, and less productive and suboptimal portfolio of wells overall.

While it may be difficult to find a single E&C design that fits all shale wells, are there some completion variables that explain productivity better? Could there be an ideal design “range” for each variable in a formation?
A three-step approach for operating optimally in the Eagle Ford

Optimizing completion designs for horizontal shale wells is a highly complex and technical subject, and the efficacy of these designs is largely dependent on the availability of data at the minutest possible levels and the cognitive basin knowledge of asset managers. Instead, consider a three-step approach that combines statistical processes and interpretations to complement technical design models specifically built for operators (see figure 5).

- Step 1: Identify significance of each completion variable (random forest)
- Step 2: Discover ideal design combinations and ranges (cluster analysis)
- Step 3: Model the significance and ranges into well type curves (well curves)

FIGURE 5
Methodology to enhance completion design strategy

Step 1
Understand the formation and outline the statistical relevance of productivity drivers in the area of interest

Methodology used: Random forest modelling on engineering and productivity data split by formation quality

Step 2
Identify the optimal design parameter range that has delivered the best results with the least complexity in the identified zone

Methodology used: Multilevel cluster analysis with lateral length as base cluster and other parameters as subclusters

Step 3
- Conduct well performance scenario modeling by normalizing the designs to the optimal range along with their significance coefficient
- Identify the most optimal operating point that maximizes O&G recovery per unit well cost

Methodology used: Well performance predictive modelling using design parameters from step 2 and parameter effectiveness from step 1

Note: Refer appendix for detailed methodology on each step.
Source: Deloitte analysis.
STEP 1: UNDERSTAND THE SIGNIFICANCE OF EACH COMPLETION VARIABLE

Indisputably, shale operators have registered tremendous gains in production due to enhanced and larger completion designs in the Eagle Ford. The broader “positive” relationship between completion design and well productivity is accepted by operators, but which completion variables better explain productivity is still an area of debate. It’s not that Eagle Ford operators aren’t tweaking their designs; it’s just that these tweaks are largely targeted at making designs more intense (e.g., more proppants and fluids).

Among several completion variables that are consistently reported by operators, five generally stand out—perforated interval, proppant quantity, fluid loading, proppant type, and treatment type (see figure 6). The random forest technique, a popular decision-making and ensemble method to build predictive models, statistically highlights the significance of each of the five variables in explaining well productivity across the Eagle Ford. Remarkably, the first three variables—perforated interval, proppant quantity, and fluid loading—influence productivity by more than 85 percent, but with significant divergence across the tiers/zones.

Proppant loading per perforated interval seems to be the primary driver of productivity (significance of about 33 percent) across the Eagle Ford, in both Upper and Lower zones. Equally important are fluid volumes (significance of about 30 percent) as they carry the proppant and help to create the fracture. However, both proppant (sand, resin, ceramic) and treatment types (slickwater, crosslink, hybrid, linear gel) seem to have low significance (about 11–14 percent in aggregate) in explaining the productivity in the basin. What does this mean for operators in the basin? How do these numbers corroborate with the basin’s closest peer, the Permian?

Like in the Permian, there is a mature congruence between the statistical significance of completion variables and the action of companies in the Eagle Ford, at least on proppant types. In both the Eagle Ford and the Permian, for example, the significance of proppant type is between 2–6 percent and only 9–10 percent of wells spud since 2016 used expensive proppants (ceramic and resins).

Treatment types, on the other hand, are still in the early phase of experimentation, even in the Eagle Ford. Although our results highlight its low relation in explaining productivity, operators across the basins continue to experiment with new stimulation treatments: hybrid, linear gel, or crosslinked gel. About 50 percent of wells drilled in the past three years used non-slickwater as a fluid in the Eagle Ford. But some private operators are increasingly gravitating toward 100 percent slickwater (with little or no polymer), which, although constrained by local water availability, is a cost-effective fluid.
STEP 2: IDENTIFY OPTIMAL DESIGN RANGES

After identifying the significance of each completion variable, the next step involves narrowing down the wide range of completion designs or identifying an ideal operating range for each variable. As both high- and low-productive wells are on both ends of the design spectrum, an ideal design would be the one that delivers the highest productivity with least design complexity/intensity (and thus cost). Our multilayered cluster modeling approach, with perforated interval (the biggest cost component) as the primary cluster and other parameters as subclusters, reveals ideal operating ranges of high-productive wells in each tier/zone (see figure 7).

Since 2016, the largest cluster of high-productive wells has been within a perforated interval of 4,600–6,800 feet in Tier 1 zones, despite many companies holding continuous acreages in the area. In the Lower Eagle Ford (Tier 1), these high-productive wells saw proppant quantities in the range of 1,900–3,000 lbs/feet with slickwater fluid pumped at 25–61 barrels (bbls)/feet. In the Tier 2/3 zones, however, the range is much wider between the Upper and Lower Eagle Ford.28 In the Upper Eagle Ford, for example, proppant and fluid intensity is high and operators use a finer proppant mesh size of 100.29 Such a high variance confirms both challenges and opportunities in ascertaining a right completion design—high productivity at the right intensity and cost—for operators.

Note: (a). Perforated interval (PI), Proppant loading (PL), Fluid loading (FL), Proppant type (PT), Treatment type (TT). (b). The low variance of statistical significance amongst zones is due to averaging out of data from various formations or counties. (c). The above relevance coefficients are based on the variables fed to the model and may change significantly if more relevant metrics are added.

Source: Deloitte analysis based on Enverus Drillinginfo database, accessed June 1, 2019.
(Note: These ranges can, and should, be narrowed down further at a county and specific landing zone by feeding proprietary completion data and triangulating it with in-depth rock and formation understanding of operators/vendors.)

FIGURE 7
Popular design ranges of high performers

<table>
<thead>
<tr>
<th>Design parameters</th>
<th>Tier 1</th>
<th>Tier 2/3</th>
<th>Tier 1</th>
<th>Tier 2/3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Perforated interval (ft)</td>
<td>4,650-6,400</td>
<td>4,450-6,900</td>
<td>4,600-6,800</td>
<td>4,000-5,900</td>
</tr>
<tr>
<td>Proppant loading (lbs/ft)</td>
<td>1,927-3,047</td>
<td>1,610-3,020</td>
<td>1,700-3,200</td>
<td>2,040-3,450</td>
</tr>
<tr>
<td>Well spacing (ft)</td>
<td>&lt;700</td>
<td>&lt;940</td>
<td>&lt;460</td>
<td>&lt;680</td>
</tr>
<tr>
<td>Proppant type</td>
<td>Sand</td>
<td>Sand</td>
<td>Sand</td>
<td>Sand</td>
</tr>
<tr>
<td>Treatment type</td>
<td>Linear gel and slickwater</td>
<td>Slickwater and linear gel</td>
<td>Slickwater and linear gel</td>
<td>Slickwater and linear gel</td>
</tr>
<tr>
<td>Proppant mesh size</td>
<td>Blend of 30/50 and 40/70 or 100 with either 40/70 or 30/50</td>
<td>30/50 or blend of 100 with 30/50 or 40/70</td>
<td>30/50 or blend of 100 with 30/50 or 40/70</td>
<td>100, 40/70, or blend of 100 with 40/70 and 30/50</td>
</tr>
</tbody>
</table>

Note: * range for hybrid and linear gel, ** range for slickwater.

BENCHMARKING DESIGNS OF OPERATORS

Only 40 percent of completed and producing wells in the Eagle Ford (green and light green shades) are within or close to the ideal completion ranges (see figure 8). Most of these wells are in Karnes and DeWitt, where strong subsurface characteristics are complementing simpler completion designs. Among the company groups, the top five operators and large independents have a slightly higher proportion of wells in ideal ranges compared to their smaller peers—nevertheless, the scope for improvement is significant for all.

Approximately 45 percent of producing wells in the basin had intense/complex designs and longer perforated interval (see doughnut in figure 8 with “over-engineered” marked in red), possibly to offset the basin’s relatively weaker reservoir and rock characteristics in the west (refer to Deciphering the performance puzzle in shales). Although counties in west Texas—Maverick, Dimmit, Webb, and La Salle—have thick target intervals, their less attractive rock quality has led to lower and inconsistent well performance. The result: Higher completion cost and lower-than-expected results on the productivity front.

Speaking of the rest, a few operators seems to have mastered a unique combination of completion designs. For example, one of the leading independent E&P is going for much shorter wells, perforated interval of 2,000–4,000 feet, but with much higher proppant (averaging 2,800 lbs per 10,000 feet length) and fluid intensity (57 bbls per 10,000 feet perforated interval).30 The company is saving on its biggest cost component, lateral length, without impacting its productivity (in fact, the company is maximizing its contact with the most reservoir rock). But, there are also a few operators for whom their overly simplistic designs are not yielding the desired productivity results.
FIGURE 8
The problem of suboptimal designs

<table>
<thead>
<tr>
<th></th>
<th>In range</th>
<th>Slight deviation</th>
<th>Under-engineered</th>
<th>Over-engineered</th>
</tr>
</thead>
<tbody>
<tr>
<td>Large independents</td>
<td>37%</td>
<td>9%</td>
<td>16%</td>
<td>39%</td>
</tr>
<tr>
<td>Private companies</td>
<td>15%</td>
<td>13%</td>
<td>15%</td>
<td>58%</td>
</tr>
<tr>
<td>Small independents</td>
<td>21%</td>
<td>16%</td>
<td>11%</td>
<td>51%</td>
</tr>
</tbody>
</table>

Overall: 44% In range, 30% Slight deviation, 15% Under-engineered, 11% Over-engineered

Note: (a). Slight deviation category has wells where perforated interval and either of proppant and fluid loading are close to optimal range. (b). The productivity numbers are normalized to 10,000 feet perforated interval.

Source: Deloitte analysis based on Enverus Drillinginfo database, accessed June 1, 2019.
STEP 3: IDENTIFY THE RIGHT BALANCE BETWEEN PRODUCTION AND COST

After the significance and ideal operating ranges of each completion variable are identified, the last step is to forecast a well’s performance by tweaking its completion design and comparing with its actual results. The gap or opportunity, however, isn’t just about highlighting the potential of producing higher volumes. It is actually about finding the right balance between production and cost—or rather, maximizing well recovery (estimated ultimate recovery, or EUR) per unit of well cost (drilling and completion cost).

Productivity and economic models leveraging the optimal ranges and statistical relevance of completion variables for 1,400 over-engineered wells revealed an opportunity to enhance EUR per unit of well cost by 19 percent (see figure 9). In other words, operators in Eagle Ford could have saved approximately 19 percent of their drilling and completion capex and realized a similar level...
of production from these wells. These savings could ideally be achieved by fine-tuning the currently “over-engineered” designs, where cost savings resulting from simpler designs more than offsets the fall in production. Some players with massive surface infrastructure might still do well with over-engineered wells as it brings down other cost elements but for the rest, optimizing this equation at a well level might work better.

Generally speaking, under-engineered wells should also present an opportunity to enhance recovery per unit of well cost—quite apparent in the Permian basin (refer The Permian basin playbook: Optimizing design experimentation). However, intensifying designs for these wells in the Eagle Ford doesn’t seem to improve capital efficiency—in fact, EUR/well cost fell by 12–17 percent. This also seems to affirm the point highlighted earlier that responsiveness of many mature Eagle Ford formations toward completion designs is relatively weak and hence leads to suboptimal designs on the economic front—modeling 500 under-engineered wells for superior designs led to productivity gains of 2–11 percent, but with a 25 percent increase in cost. This implies that making a lot of tweaks to under-engineered wells in the basin may not make economic sense every time.

To sum up, the relatively unfavorable response of rocks in the Eagle Ford basin requires a careful mapping of formation type with the best operating completion designs. Although performance enhancements in many areas are a testimony of improvements done by many operators using their technical know-how, our analysis suggests scope to further augment the learnings with an analytical understanding of the basin. The task of finding such best operating points can be quite challenging and critical in Eagle Ford, as the ranges are narrow and even a slight deviation may lead to notable economic loss.
Amid changes, opportunities remain

Subsurface characteristics of the Eagle Ford basin and, most importantly, an ongoing trend among operators across the basins for complex yet ineffective designs, validate falling drilling activity in the Eagle Ford and affirm investors’ skepticism in investing in shale companies. Certainly, this young resource merits a learning concession. However, in today’s age of resource abundance and sustained volatility in oil prices, companies that have a faster and efficient learning curve are likely to emerge as winners. Certain considerations that could enable this learning include:

- **Veer from intensity to combinations.** Add more meaning to the trend of enhancing the E&C design intensity by identifying the “right” design combinations customized to each rock.

- **Refresh the portfolio strategy rulebook.** Break away from a mindset of optimizing portfolios based on just the quality of formation and add new elements, such as experience in the field, response to various designs, and infrastructure availability.

- **Avoid herd instincts.** Appreciate the value learning from peers while recognizing shale’s erratic behavior. Although a strategy (e.g., intense Gen X completions) might look appealing, it may not make economic sense for all and could hurt project returns.

- **Replace selectivity with entirety.** Move away from selective reporting of parameters and present a comprehensive picture and report out learning progressions to build investor confidence.
Appendix

Key assumptions and considerations

• The analysis presented here is an analytical perspective to shale development and hence cannot be a replacement to sophisticated technical models.

• The formation quality zones are classified using available geological data points (gamma ray, neutron porosity, formation thickness, deep resistivity, bulk density) and these should not be directly compared with other technical formation quality maps.

• The statistical relevance of various completion variables is based on the number of variables fed to the model. These numbers would change if more data or more variables are used to build models.

• The defined optimal operating points are directional ranges aimed to highlight the divergence by each zone. These could change notably once analyzed at formation or county level and hence should not be directly leveraged for technical analysis.

• The optimal operating point reflects designs with moderate intensity and high productivity.

Hence, it should not be assumed that designs which are more intense are always less productive.

The economic well models are based on recent cost trends in each sub-basin and actual numbers may vary based on company-specific cost efficiencies.

METHODOLOGY TO DEFINE BOUNDARY OF ZONES BY FORMATION QUALITY

At first, spatial mapping of all the wells in a basin was done using surface latitude and longitude data. Further, low-formation quality wells were filtered out using the formation quality index developed in the first article, *Deciphering the performance puzzle in shales* (wells with a formation score of less than 0.55 were filtered out in the Eagle Ford basin).

A geospatial mapping tool then allowed us to manually define the boundary of the zone that comprises most of the high-quality wells and generate the latitude-longitude readings of the newly created boundary (see figure 10). This newly created geographic zone comprising high-quality wells was termed as the Tier 1 formation, while the rest was defined as the Tier 2/3 zone. Lastly, graphical overlaying with existing formation quality maps by various operators was done to fine-tune the formation quality zone boundaries.
FIGURE 10

Geospatial mapping of the Eagle Ford wells based on formation quality score

Source: Deloitte analysis based on Enverus Drillinginfo database, accessed June 1, 2019.
### Methodology used to analyze well designs

<table>
<thead>
<tr>
<th>Step</th>
<th>Details</th>
</tr>
</thead>
</table>
| **1. Factor relevance** | - Engineering & completion (E&C) and productivity data was split by zones—Tier 1 Eagle Ford and Tier 2/3 Eagle Ford  
- The factors used for modeling the statistical significance were perforated interval, proppant loading, fluid loading, proppant type, and treatment type to explain productivity as a final result  
- Random forest model was used to perform regression analysis to create multiple learning models of decision trees (based on the above factors) to explain the predictive target or ultimate result (result, that is, productivity)  
- The model was tuned by hyperparameters using grid search to enhance the accuracy of the model. Final accuracy was $R^2$ 35–40 percent |
| **2. Optimal operating range** | - The initial set of wells was filtered based on zone-wise split of data for perforated interval  
- The first cluster was formed by identifying the least perforated interval ranges for the most productive wells  
- For each perforated interval cluster in each zone, subclusters were developed, identifying the most popular value ranges for high-productive wells in a cluster  
- This cluster analysis gave optimal ranges for the combination of E&C design metrics based on maximum wells lying within such ranges  
- The wells with the least complex designs emerged as the standard optimal range of values for the established blend of metrics for each zone |
| **3. Scenario modeling** | - Identified over- and under-engineered wells in the basin for analysis and split them in 2 datasets  
- The design parameters of proppant loading, fluid loading, and perforation interval were normalized to the identified optimal ranges in Enverus Drillinginfo’s Well Cast model  
- Further, effectiveness coefficients were applied based on zones and new well type curves were generated  
- Cost models were then run to compare well economics of the actual scenario and the new normalized scenario (optimal range) to calculate the change in EUR/well cost |

*Source: Deloitte analysis.*
The Eagle Ford basin playbook: Focusing on capital efficiency

Glossary

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid loading</td>
<td>Amount of fluid pumped during the first treatment job per feet of perforated interval</td>
<td>Bbls/ft</td>
</tr>
<tr>
<td>Formation thickness</td>
<td>Isopach thickness for the geology zone extracted from an isopach map into the horizontal well</td>
<td>Feet</td>
</tr>
<tr>
<td>IP 180</td>
<td>First six months O&amp;G production per day normalized to 10,000 feet of perforation interval</td>
<td>Boed</td>
</tr>
<tr>
<td>Perforation interval</td>
<td>Difference between max perforation bottom and min perforation top of the completion; represents the gross perforation interval of the well</td>
<td>Feet</td>
</tr>
<tr>
<td>Proppant loading</td>
<td>Amount of proppant pumped during the first completion job</td>
<td>Lbs/ft</td>
</tr>
<tr>
<td>EUR</td>
<td>Total O&amp;G production recovered from a well during its entire lifecycle</td>
<td>Boed</td>
</tr>
<tr>
<td>Well cost</td>
<td>Total drilling, completion, and engineering cost incurred while developing a well</td>
<td>USD</td>
</tr>
<tr>
<td>Well spacing</td>
<td>Offset well spacing between the base well and the nearest well spud during the same year or two years prior</td>
<td>Feet</td>
</tr>
</tbody>
</table>

Source: Enverus Drillinginfo.

Endnotes

6. Ibid.
15. Ibid.
16. Ibid.
17. Ibid.
18. Ibid.
19. Ibid.
20. Ibid.
21. Ibid.
22. Ibid.
23. Ibid.
24. Ibid.
25. Ibid.
26. Ibid.
27. Ibid.
28. Ibid.
29. Ibid.
30. Ibid.
32. Deloitte analysis based on the Enverus Drillinginfo database, accessed June 1, 2019; Enverus docFinder database, accessed August 1, 2019.
About the authors

Scott Sanderson  |  scsanderson@deloitte.com
Scott Sanderson is a principal in Deloitte Consulting LLP's Oil & Gas Strategy and Operations practice, with more than 25 years of experience helping oil and gas companies define and execute strategies and operational improvements across several sectors. Notable experience includes mergers and acquisitions (M&A)—strategy, execution, and post-merger integration; portfolio optimization; new service offerings design; organization design and renewal; brand value analysis; and shareholder value-based management.

Tom Bonny  |  tbonny@deloitte.com
Tom Bonny is a leader of Deloitte’s North America Digital Upstream and Operations practice in Deloitte Consulting LLP. Bonny has over 20 years of experience, with most of it in upstream oil and gas. He has worked across the energy value chain from exploration through to production, and covered both conventional and unconventional assets, across the energy hubs of the world, including Africa, Europe, Middle East, North America, and South East Asia.

Andrew Slaughter  |  anslaughter@deloitte.com
Andrew Slaughter is the former executive director of Deloitte Research Center for Energy and Industrials. Slaughter worked closely with Deloitte’s Energy, Resources & Industrials leadership to define, implement, and manage the execution of the Center strategy; develop and drive energy research initiatives; and manage the development of the Center’s eminence and thought leadership.

Anshu Mittal  |  ansmittal@deloitte.com
Anshu Mittal is a senior research manager on Deloitte Services LP’s Research & Insights team. Mittal has close to 16 years of experience in strategic research and operational transformation across all oil and gas subsectors—upstream, midstream, oilfield services, and downstream. He has led several oil and gas signature issues and campaigns in the areas of digital and portfolio transformation for Deloitte.

Vivek Bansal  |  vibansal@deloitte.com
Vivek Bansal is an assistant manager on Deloitte Services LP’s Research & Insights team. He has more than six years of strategic research and consulting experience in the upstream and downstream subsectors. He holds an engineering degree in applied petroleum and a masters in oil and gas management.
Acknowledgments

The authors would like to thank Sandeep Vellanki and Sushmita Biswal, who led the data analytics and statistical analysis; Duane Dickson, John England, Peter Buettgen, Scott John, and Shawn Maxson for their inputs and review; and Shreya Sachin Shirgaonkar, who provided the secondary research support.

We would also like to thank Samrat Das, Michael Orton, and Enrique Villareal for their comments and suggestions; Rithu Thomas from the Deloitte Insights team who supported the reports’ editing and publication; Anisha Sharma and Abe Silva for their leadership in public relations; and Sharene Williams, Andrew Haggen, Krystal McMiller, and Laurel McConn for their operations and marketing support.

Contact us

Our insights can help you take advantage of change. If you’re looking for fresh ideas to address your challenges, we should talk.

Industry contacts

**Duane Dickson**  
Vice Chairman, US Oil, Gas & Chemicals Leader | Deloitte Consulting LLP  
+1 203 905 2633 | rdickson@deloitte.com

Duane Dickson is a vice chairman and principal in Deloitte Consulting LLP’s Energy Resources & Industrials industry group, as well as the US Oil, Gas & Chemicals sector leader and the Global Chemicals & Specialty Materials Consulting leader.

**Scott Sanderson**  
Principal | Deloitte Consulting LLP  
+1 305 372 3295 | scsanderson@deloitte.com

Scott Sanderson is a principal in Deloitte Consulting LLP’s Oil & Gas practice, with more than 25 years of experience helping oil and gas companies define and execute strategies and operational improvements across a variety of sectors.

**Peter Buettgen**  
Principal | Deloitte Consulting LLP  
+1 713 982 453 | pbuettgen@deloitte.com

Peter Buettgen is a partner in Deloitte with expertise in operations and supply chain transformation.
The Eagle Ford basin playbook: Focusing on capital efficiency

Tom Bonny
Managing director | Deloitte Consulting LLP
7139822365 | tbonny@deloitte.com

Tom Bonny leads Deloitte’s North America Digital Upstream and Operations practice.

John England
Partner | Deloitte & Touche LLP
1-7135018786 | jengland@deloitte.com

John England serves as a global lead client service partner in Deloitte's Oil, Gas & Chemicals practice.

Scott John
Principal | Deloitte Consulting LLP
1-2812211195 | scjohn@deloitte.com

Scott John is a consulting principal in Deloitte with expertise in M&A and restructuring.

Deloitte Research Center for Energy and Industrials

Katherine Hardin
Executive director | Deloitte Research Center for Energy & Industrials
+1 (617) 437-3332 | khardin@deloitte.com

Katherine Hardin is the executive director for the Deloitte Research Center for Energy & Industrials, Deloitte Services LP. Hardin is based in Boston.

About the Deloitte Research Center for Energy and Industrials

Deloitte's Research Center for Energy and Industrials combines rigorous research with industry specific knowledge and practice-led experience to deliver compelling insights that can drive business impact. The Energy, Resources, and Industrials industry is the nexus for building, powering, and securing the smart, connected world of tomorrow. To excel, leaders need actionable insights on the latest technologies and trends shaping the future. Through curated research delivered through a variety of mediums, we uncover the opportunities that can help businesses move ahead of their peers.
Deloitte Insights


Follow @DeloitteInsight

Deloitte Insights contributors
Editorial: Rithu Thomas, Rupesh Bhat, Anya George Tharakan, Preetha Devan, and Aparna Prusty
Creative: Kevin Weier, Mahima Dinesh, Rajesh Nelavagilu, Tushar Barman, and Anoop K R
Promotion: Nikita Garia
Cover artwork: An Chen

About Deloitte Insights
Deloitte Insights publishes original articles, reports and periodicals that provide insights for businesses, the public sector and NGOs. Our goal is to draw upon research and experience from throughout our professional services organization, and that of coauthors in academia and business, to advance the conversation on a broad spectrum of topics of interest to executives and government leaders.

Deloitte Insights is an imprint of Deloitte Development LLC.

About this publication
This publication contains general information only, and none of Deloitte Touche Tohmatsu Limited, its member firms, or their affiliates are, by means of this publication, rendering accounting, business, financial, investment, legal, tax, or other professional advice or services. This publication is not a substitute for such professional advice or services, nor should it be used as a basis for any decision or action that may affect your finances or your business. Before making any decision or taking any action that may affect your finances or your business, you should consult a qualified professional adviser.

None of Deloitte Touche Tohmatsu Limited, its member firms, or its and their respective affiliates shall be responsible for any loss whatsoever sustained by any person who relies on this publication.

About Deloitte
Deloitte refers to one or more of Deloitte Touche Tohmatsu Limited, a UK private company limited by guarantee (“DTTL”), its network of member firms, and their related entities. DTTL and each of its member firms are legally separate and independent entities. DTTL (also referred to as “Deloitte Global”) does not provide services to clients. In the United States, Deloitte refers to one or more of the US member firms of DTTL, their related entities that operate using the “Deloitte” name in the United States and their respective affiliates. Certain services may not be available to attest clients under the rules and regulations of public accounting. Please see www.deloitte.com/about to learn more about our global network of member firms.

Copyright © 2019 Deloitte Development LLC. All rights reserved.
Member of Deloitte Touche Tohmatsu Limited