Scientific approach applied to multi-well pad development in Eagle Ford shale

As the inventory of single-well pads in North American shale plays continues to build, the industry needs to determine: 1) What is the optimum spacing for an in-fill well; 2) Where should new multiple in-fill wells be drilled? An engineered approach enhances play economics and ensures maximized recovery with the least capital expenditure.

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Optimizing well spacing, placement configuration and stimulation design are key issues that need to be solved, as the industry enters the next phase of unconventional reservoir development. The design and evaluation strategy for these second-generation wells, which will be drilled next to depleted sections of the reservoir, requires a deeper understanding to minimize unproductive overlap and maximize recovery.

EAGLE FORD LITHOLOGY

The Eagle Ford has good reservoir-quality rock, but the challenges associated with completing in-fill wells persist. The Eagle Ford has five distinct lithostratigraphic sections (A–E). The B-unit is subdivided into two separate categories. The B1-B2 unit (Donovan 2010) has high total organic carbon (TOC) content, whereas the B3-B5 zones have a higher content of smectite and kaolinite ash beds. To develop a fully optimized multi-well pad strategy, it is critical to account for these ash beds, because they impede vertical fracture conductivity, by creating pinch points when hydraulic fractures propagate through weak formation bedding planes in sections with a higher frequency of ash bed occurrence.

Unconventional fracture model. The Eagle Ford is naturally fractured, and within these planes of weakness, shear failure occurs during hydraulic fracturing. An unconventional fracture model (UFM) was developed to simulate this failure mechanism, to understand the complex interaction between hydraulic fractures and natural fractures.

The UFM simulation showed crossing occurs, if the compressive stress acting perpendicular to the frictional interface is sufficient to prevent slip at the moment when the tip of the hydraulic fracture contacts the interface, and the induced stress on the opposite side is sufficient to initiate a tensile fracture.

The model solves an array of equations governing fracture deformation, height growth, fluid flow and proppant transport, in a complex fracture network with multiple propagating fracture tips. In comparison, the traditional hydraulic fracture evaluation technique through planar fracture modeling overestimates fracture length and ignores the impact of natural fractures.

UFM can be integrated into a reservoir-centric software platform that combines hydraulic fracture modeling with dynamic reservoir simulation and geomechanical finite element modeling, that form an essential part of the workflow study.

Single-well pads. In the Eagle Ford, there is a high inventory of single-well pads that has led to significant pressure depletion near the parent well. This pressure drop alters the in-situ stress field. Reduction in the magnitude of the principal horizontal stresses is accompanied by re-orientation of the stress field to maintain geomechanical equilibrium. These in-situ stress changes have considerable impact on the hydraulic fracture geometry generated at offset, second-generation “child wells,” Fig. 1.

Depleted pressure sinks created from parent well production lead to asymmetric hydraulic fracture growth from child wells. This asymmetric fracture behavior is detrimental to both parent and child wells. Parent wells can suffer from “frac hits,” which often result in production loss and the need for wellbore cleanout.

CASE 1: IN-FILL WELL SPACING

Determining the optimal well spacing is critical to optimizing hydrocarbon production from multi-well pads in unconventional plays. In this study, the three most common scenarios of 400-ft, 600-ft, and 800-ft spacing between the parent and child well are evaluated. It is assumed that all of the three child wells
The child wells are landed in the B1-B2 lithostratigraphic unit. In case 1, the impact of ash beds on parent and child well production is ignored. The child wells are built into the updated 3D model with heterogeneous reservoir pressure and in-situ stress profile, based on the parent well production over a 400-day period. The completions design for the three child wells is the same as that for the parent well. The hybrid stimulation treatment design for the child wells is also similar to the parent well. The discrete fracture network (DFN) network that is used for complex fracture modeling was expanded with the inclusion of the parent well hydraulic fracture network (HFN). This accounts for the presence of additional planes of weakness created from stimulating the parent well.

Hydraulic fracture geometry for child wells is governed by the updated in-situ stress profile generated from finite element modeling (FEM) and the updated DFN, along with other dynamic and static reservoir and fluid properties. The hydraulic fracture simulation results show asymmetric hydraulic fracture growth toward the pressure sink created from the parent well production for each of the three wells, Fig. 2. These simulation results correlate well with observations made from microseismic data for similar wells in the Eagle Ford shale and other unconventional plays.

Asymmetric growth of hydraulic fractures from the child wells toward the pressure sink is seen to decrease with an increase in well spacing. UFM simulation results show hydraulic fractures from the child wells turn and do not grow into the depleted pressure sink because of in-situ stress re-orientation. The degree of such re-orientation has a significant impact on hydraulic fracture geometry for the child wells, and is a function of in-situ stress anisotropy.

A full 3D, black oil, single-porosity dynamic reservoir simulator is used to run hydrocarbon production prediction scenarios for the next 400 days, from both the parent well and three child wells, while considering the depleted reservoir pressure and altered fluid saturations from the parent well production. The same pressure/volume/temperature (PVT) model, compaction and relative permeability curves, as those used for the parent well simulation, are used for running the three prediction scenarios under the same BHP control settings for a fair comparison.

Reservoir simulation results showed that the child well, 600 ft away from the parent well produces approximately 80% of the parent well’s total oil production in the first 400 days, while the child well 400 ft away produces about 70%, and the one 800 ft away produces almost the same volume of oil as the parent well, Fig. 3. The child well 400 ft away from the parent well produces the least amount of oil among the three child wells. This lower production from the nearest child well is due to well interference and asymmetric hydraulic fracture growth toward the pressure sink created from the parent well production. As the distance from the parent well is increased from 400 ft to 800 ft, asymmetrical hydraulic fracture growth reduces, and reservoir
pressure support increases, translating into better performance from the child wells drilled farther away.

However, by drilling farther away, certain reservoir sections might be left undrained, as seen from a 3D pressure depletion map for the child well drilled 800 ft away from the parent well. Therefore, it might be better to drill child wells 600 ft away from the parent well, under similar reservoir conditions.

CASE 2: MULTI-WELL STRATEGIES

As learnings evolved, it became apparent that a new multi-well pad development strategy was required. To achieve the objective, engineers viewed the multi-well pads as a single system and compared them to configurations under different conditions of reservoir pressure and frequency of ash beds. Configuration A is to drill two child wells 600 ft and 1,200 ft from the parent well in the B1-B2 unit, the same lithostratigraphic section of the Eagle Ford where the parent well is landed, Fig. 4a. Configuration B stacks one child well 600 ft away and 95 ft above the parent well into B3-B5. The second child well is landed 1,200 ft away from the parent well in the B1-B2 unit, Fig. 4b. Since optimizing multi-well pad development is a multi-variable problem, the two well placement configurations are compared for the four scenarios described below.

Scenario 1, minimal impact of ash beds and depleted reservoir pressure. In this scenario, the two multi-well pad development configurations are evaluated, while assuming that there is no significant reduction in vertical conductivity of the fractures at the interface of the B1-B2 and B3-B5 units, due to ash beds. Reservoir pressure depletion from the parent well production, and the associated alteration of in-situ stresses, are taken into account. This scenario is offered to demonstrate an optimized multi-well configuration for the Eagle Ford and other unconventional plays, where frequency of ash beds is low. The enhanced seismic-to-stimulation workflow described earlier is used to perform integrated hydraulic fracture modeling and dynamic reservoir simulation for both configurations A and B.

It is assumed that the child well completions and stimulation treatment design is the same as that of the parent well. UFM simulation results show asymmetric hydraulic fracture growth toward the depleted pressure sink for child wells 600 ft away, in both multi-well configurations A and B. However, because in configuration B the well is stacked in B3-B5 unit, the simulated fractures are relatively more symmetrical. The asymmetric growth of the simulated complex fractures toward the pressure sink is reduced for the farthest child well, 1,200 ft away from the parent well in both the configurations. Hydraulic height growth of the simulated complex fractures covers the entire B1-B2 and B3-B5 units.

Following UFM simulations for multiple wells in both configurations, the wells were put together into two unstructured grids. Reservoir simulations were performed to predict production from the two multi-well pad development strategies. The same black oil PVT model, relative permeability curves and compaction tables, as used in the parent well production simulation runs, are used in evaluating scenario 1. In the reservoir simulation performed on multi-well unstructured grids, depleted reservoir pressure from the parent well production is taken into account.

Predicted production results for a 400-day period from the two multi-well pad configurations are summarized. In this scenario, ash beds are present in low frequency and the hydraulic fractures do not pinch out at the interface of the two B units, leading to pressure depletion in both B1-B2 and B3-B5 units. Either of the two configurations can be chosen, as both the strategies are expected to produce virtually the same volume of hydrocarbons. The difference between the two configurations is that the nearest child well in configuration B is landed in B3-B5. In configuration A, the corresponding child well is in the same layer as the parent well.

In the absence of a significant stress barrier at the interface of the two B units, hydraulic fractures from this stacked child well, which is 95 ft above the parent wells, grow preferentially downward toward the pressure sink in B1-B2, rather than growing farther in length. They also remain conductive, due to a propellant settling effect. This creates comparable, effective drainage volume for the two configurations, leading to similar, overall hydrocarbon production.

Scenario 2, impact of ash beds and depleted reservoir pressure. In this multi-well pad scenario, it is assumed that rich ash beds significantly impede vertical fracture conductivity at the interface of the B3-B5 and B1-B2 units over time. These ash beds are known to hamper production from horizontal wells in unconventional plays, including the Eagle Ford.

UFM simulation results for the parent well are the same as in scenario 1. However, while carrying out reservoir simulation for the parent well, it is assumed that the ash beds completely plug-off hydraulic fractures at the interface of the two B units. This causes the parent well to produce about 34% less than the case.

Fig. 4a. Multi-well configuration A (left). Fig. 4b. Multi-well configuration B (right).
configuration B, the multi-well configuration A can produce 32% more oil than the same BHP control settings. It was determined that in a scenario where ash beds are rare, the B3-B5 unit are altered less significantly than in scenario 1.

FEM geomechanics simulation also shows that in-situ stresses in the B3-B5 unit are less altered, unlike scenarios 1 and 2. There is no depleted pressure sink, and in-situ stresses are unaltered, unlike scenarios 1 and 2.

Cumulative oil production, bbl

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<th>Elapsed days of production</th>
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This is because in configuration B, hydraulic fractures from the well landed in the B3-B5 unit and 600 ft away from the parent well. They will grow preferentially downward into the B1-B2 unit, due to the lower stresses in the region resulting from the parent well production. The portion of the hydraulic fractures that grow down remain conductive, due to proppant settling. However, because of ash beds, these portions are cut off from the well and do not contribute to production from wells landed in the B3-B5 unit.

Thus, consider a scenario where some sections of the B1-B2 unit have been depleted by parent well production and ash beds severely impede vertical conductivity of hydraulic fractures. Configuration A, in which child wells are placed in the same B1-B2 unit, is expected to perform better than configuration B.

Scenario 3, minimal impact of ash beds and virgin reservoir pressure. An historical learning from operations in unconventional fields is to drill multiple wells, to effectively drain the reservoir. However, the strategic timing of drilling operations is also imperative. A proposed strategy, in which multiple wells are drilled at the same time, when the reservoir is still under virgin pressure conditions, in varying configurations is outlined.

In this scenario, it has been assumed that the frequency of ash beds in B3-B5 is low, and no pinch-out is created at the interface of B1-B2 and B3-B5. UFM simulations are run for the parent well and all of the child wells in configurations A and B. Since all the child wells in both configurations are assumed to have been drilled and completed at the same time as the parent well, there is no depleted pressure sink, and in-situ stresses are unaltered, unlike scenarios 1 and 2.

UFM simulation results show that even under virgin conditions, when there is no pressure sink in B1-B2, hydraulic height growth of the fractures from the child well in the B3-B5 unit, as part of configuration B, is still skewed downward.

Production simulation results show that in such a scenario, where all the wells in the two multi-well configurations, A and B, are drilled under virgin reservoir conditions and ash beds are rare, both the configurations produce almost the same volume of oil. This is also evident from comparable pressure depletion profiles, after 400 days of production at B1-B2 and B3-B5, from reservoir simulations for the two configurations. The reason behind the comparable performance of the two configurations is the similar hydraulic fracture extent from the child well 600 ft away that covers the entire B3-B5 and B1-B2 units. This is due to the presence of a significant stress barrier at the top of the B3-B5 unit that prevents upward hydraulic fracture growth, resulting in comparable effective drainage volume for the two configurations.

Since, the difference in cumulative oil production from the two multi-well configurations is less than 2%, it can be concluded that in such a scenario where ash beds have minimal impact and all wells are drilled and completed under virgin reservoir conditions, either of the two multi-well pad development configurations can be adopted.

Scenario 4, impact of ash beds and virgin reservoir pressure. As in scenario 3, all the wells in configurations A and B are drilled, completed and start producing at the same time under virgin reservoir conditions. However, in scenario 4, it is assumed that the hydraulic fractures completely pinch out at the interface of the B1-B2 and B3-B5 units, due to high frequency of ash beds.
Completions and stimulation treatment designs are the same as described for the previous scenarios, and UFM simulations are run with the same settings. UFM simulation results show almost laterally symmetrical complex fracture growth, due to the absence of any depleted pressure sink covering the entire B1-B2 and B3-B5 units. Complexity of the simulated hydraulic fractures is a function of in-situ stress profile and DFN density.

Reservoir simulation results show that when ash beds impede production by pinching out hydraulic fractures at the interface of the B1-B2 and B3-B5 units, multi-well configuration B produces approximately 20% more oil than the wells placed in configuration A, Fig. 6. As seen in a vertical cross-section of the two grids, 24 wells landed in the B1-B2 unit are able to drain just the B1-B2 unit, because ash beds pinch out the conductive regions at the interface. Therefore, in this extreme case for configuration A, only the B1-B2 unit can be drained. Conversely, by placing multiple wells in configuration B, effective drainage areas can be expanded, and portions of a hydrocarbon-rich zone in the B3-B5 unit can be drained as well.

Where multiple wells are drilled together under virgin reservoir conditions, with a high frequency of ash beds at the interface of B1-B2 and B3-B5, vertical conductivity of hydraulic fractures is damaged substantially over time. In this case, the best multi-well pad development strategy to efficiently drain the reservoir is to vertically stagger wells, as in configuration B, rather than placing all wells in the same lithostratigraphic section.

RECOMMENDATIONS

Optimum well spacing is dependent on reservoir and fluid properties, completion design, time, cost and commodity price. In a situation where a parent well has been producing for a year and has depleted reservoir pressure by 50% in the near-wellbore region, and under other similar reservoir conditions, it is recommended to drill the nearest child well 600 ft from the parent well, to produce about 80% of the parent well production. It was determined that 400-ft spacing is too close and 800 ft away might leave reserves undrained.

If certain sections of a reservoir have been depleted by the parent well, it is recommended to drill in-fill wells in the same lithostratigraphic section of the Eagle Ford. Modeling shows that when there are significant conductivity barriers, the two multi-well configurations are expected to produce comparable volumes of oil. However, it is more prudent to choose configuration A, as these barriers might exist, albeit in low frequency.

In a scenario where there are significant conductivity barriers, by drilling multiple in-fill wells in the same lithostratigraphic section of a reservoir, oil production can be increased 32% over a configuration in which wells are stacked in different sections.

Under virgin reservoir conditions, vertically staggering the wells is recommended. If there are no conductivity barriers like ash beds, the difference in cumulative oil production from the two configurations is less than 2%. However, a better option is to vertically stagger in-fill wells in different lithostratigraphic sections, as such barriers might still exist albeit, in low frequency.

Analysis determined that where there are significant conductivity barriers at the interface of different sections of a reservoir, by vertically staggering in-fill wells, oil production can be increased 20% over a scenario when all wells are placed in the same lithostratigraphic section.