USE CASE

# DUELING DEVELOPMENT MODELS

## Leveraging Well Spacing, Engineering, and WellCast for Insightful Analysis

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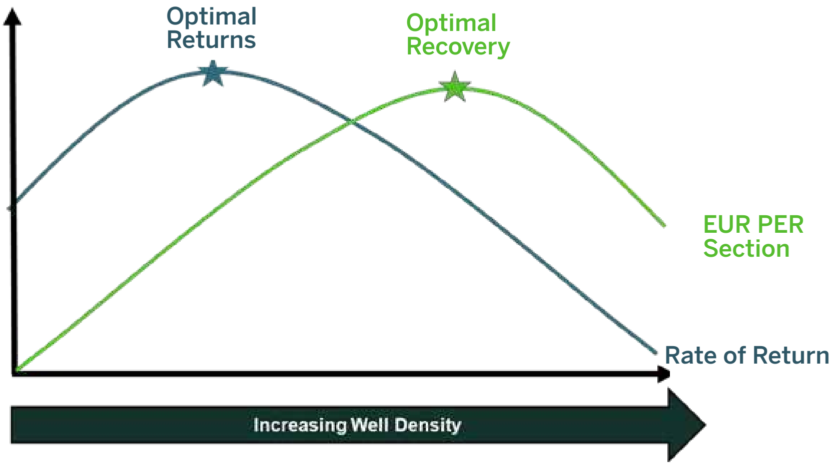
Drillinginfo

# RETURNS VS. RECOVERY

A common challenge for operators during field development planning is determining the most optimal use of acreage for a given set of existing and assumed market conditions. With the recent market shift towards rewarding free cash flow generation rather than outright production growth, this brings into question the practicality of production-focused development models.

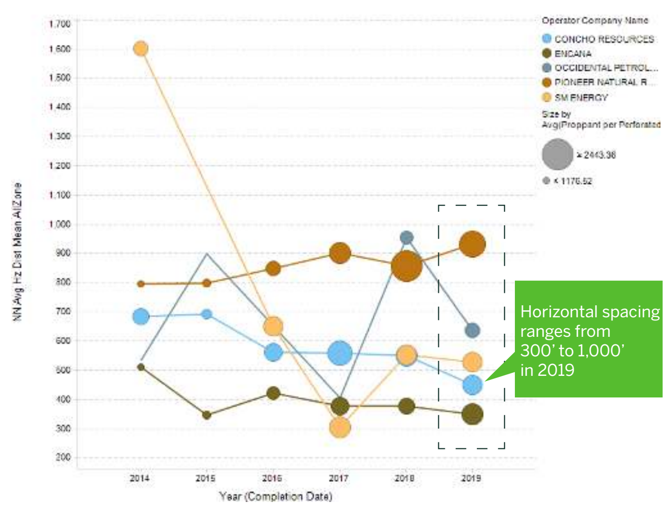



This use case seeks to illustrate the tradeoff between two different development strategies. One focuses on returns, both in the form of net-present value and rates-of-return. The other focuses on high well inventories and aerial recovery in the name of production growth. In unconventional plays, well spacing is the cornerstone of how an operator seeks to pursue their chosen development model. Wider well spacing typically favors returns, while narrower well spacing typically favors recovery.

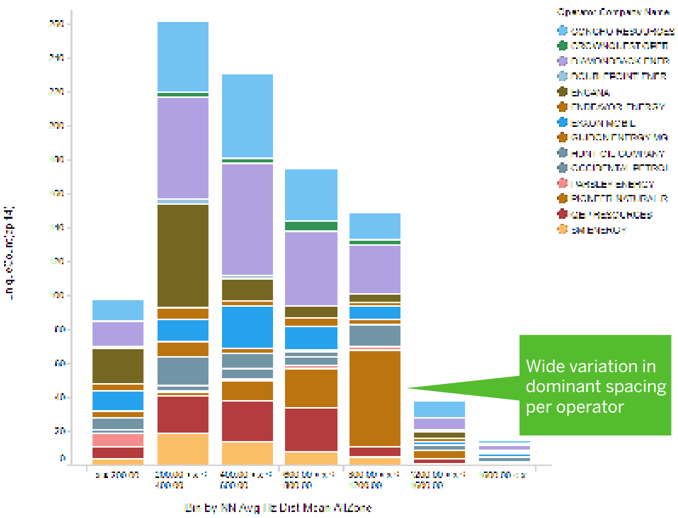
# BACKGROUND

Using Well Spacing and WellCast, this use case quantitatively shows how development strategy affects well productivity and economics.

Due to the large number of operators and the highly competitive nature of the Midland Basin, a wide variety of development strategies are being pursued. The result is a wide range of well spacing patterns and distances, but relatively less variation in well design. For the purposes of this use case, the Lower Spraberry Shale in Martin County will be focused on in order to limit the impact of geologic variations on analysis of well performance.



While there are many operators that seek to develop wells at many different well spacings, there appear to be two dominant development approaches taken by operators in this example. One approach pursues a wider well-spacing development program. The other is pursuing relatively narrower well spacing development.



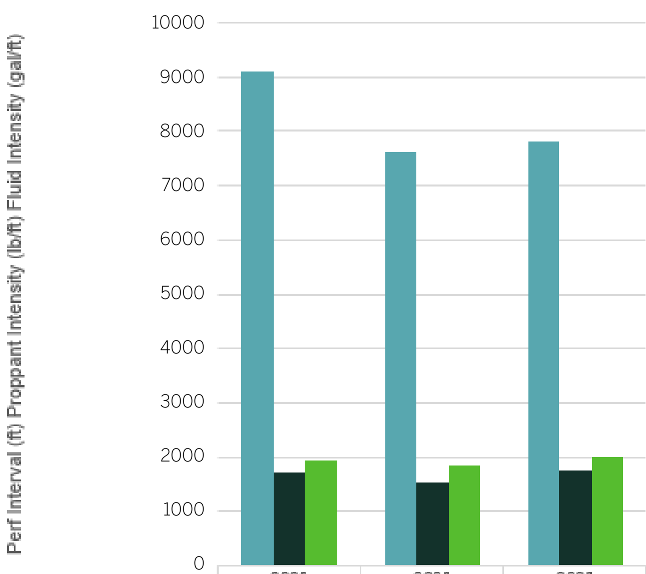

As mentioned, there is a tradeoff between recovery (EUR) and returns (IRR/NPV) as operators change spacing. However, well spacing selection also impacts reported well inventories, reserves bookings, assumed net asset value, and many other aspects of a company. With such wide-reaching implications, understanding impacts and selecting a well spacing that aligns with corporate strategy and goals is crucial.

# METHODOLOGY

## Well Selection

For this analysis, only Lower Spraberry Shale wells located in Martin County, Texas were selected. Wells were further filtered to only include wells completed after the beginning of 2016 to control for more recent advancements in completion technology.

Completion Attributes for Spacing Groups




| | 880ft | 660ft | 330ft |
|---|---|---|---|
| Perf Interval (ft) | 9113 | 7632 | 7799 |
| Proppant Intensity (lb/ft) | 1736 | 1542 | 1743 |
| Fluid Intensity (gal/ft) | 1932 | 1848 | 2016 |

After analyzing the distribution of the data, wells were placed into three groups based on their average horizontal spacing: 1) 880 feet, 2) 660 feet, 3) 330 feet. All groups contained at least 25 wells with EUR and completion values that fell within a P10/P90 ratio aligned with SPEE Monograph 3 standards. This ensured that each bin contained no outlier values that could potentially skew the results. The resulting groups all had very similar median proppant intensity, fluid intensity, and perforated interval values. At this time, additional completion variables were not included.

## Normalization

While each group did have similar median proppant intensity, fluid intensity, and perforated interval values, individual wells varied slightly from one another and required normalization to ensure consistency when constructing a type curve for each spacing group.

| Attribute | Value |
|---|---|
| Perf Interval (ft) | 10,000 |
| Proppant Intensity (lb/ft) | 1,750 |
| Fluid Intensity (bbl/ft) | 46 |

Table 1

Using WellCast, the group of wells from Well Spacing were normalized to a shared set of parameters. Wells were normalized to a proppant intensity of 1,750 lbs/ft, a fluid intensity of 46 bbls/ft, and a perforated interval length of 10,000 feet [Table 1]. Normalizations were applied to the production of wells as linearly, that is, 1:1. For example, if a well's lateral length was 9,000 feet, the production of the well would be shifted up by 11% to match the assumed perforated interval length. This allows for the construction of an effective P50 type curve for each group.

## Economic Assumptions

Both single well and project economics for this study employed the same set of parameters shown in Table 2. These parameters, except for assumed well cost, were chosen to match parameters used in the generation of type curve areas from Dynamic Basin Studies. All economics were run before federal income tax (BFIT).

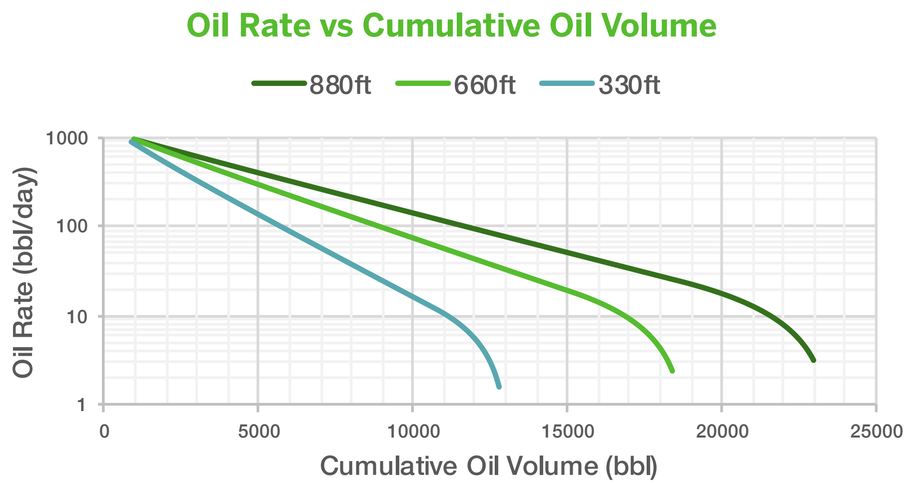
| Attribute | Value |
|---|---|
| Discount Rate | 10% |
| Economic Limit | 20 yrs |
| Est Drilling Cost | $2,123,000.00 |
| Est Completion Cost | $4,786,333.00 |
| Working Interest | 100% |
| Net Revenue Interest | 80% |
| Shrink | 33% |
| Yield (bbl/Mcf) | 5.50 |
| Oil Price ($/bbl) | 50.00 |
| Gas Price ($/Mcf) | 3.00 |
| NGL Price ($/bbl) | 20.00 |
| Oil Differential ($/bbl) | 1.00 |
| Gas Differential ($/Mcf) | 1.00 |
| Oil Opex ($/bbl) | 5.00 |
| Gas Opex ($/Mcf) | 0.65 |
| Oil Sales Tax | 8.1% |
| Gas Sales Tax | 11% |
| Federal Income Tax | 0% |

Table 2

Assumed well drilling and completions costs were sourced from publicly disclosed drilling and completions cost data in University Lands' records. To ensure appropriate drilling and completions cost assumptions for the assumed well design and target formation, the drilling and completions cost data was mined and joined on a well-level to engineering variables. The resulting dataset was queried to a subset of wells with similar well design parameters in the Lower Spraberry Shale.

### Type Curves

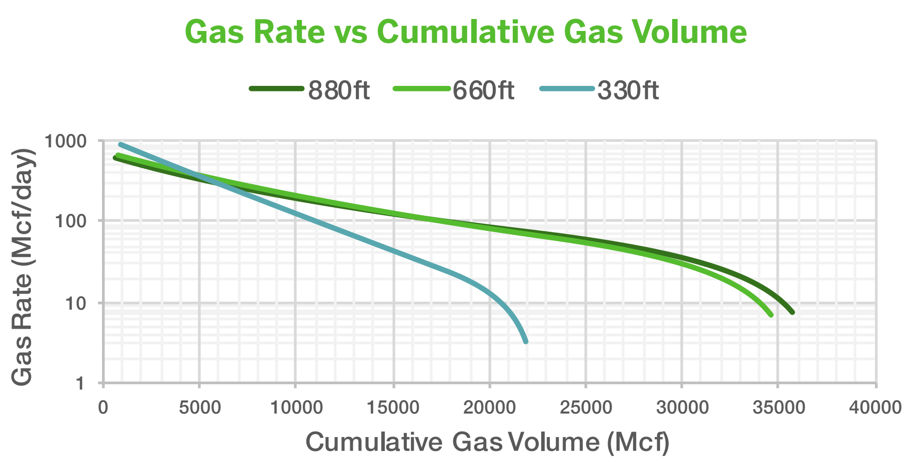
Using the normalized production data for each group, both oil and gas P50 type curves were created using WellCast. Assumptions used for curve fitting include b-factor between 1 and 1.4, initial decline between 10% and 99%, 7% terminal decline rate, and 30 year well life.




# SINGLE WELL RESULTS

### EUR and Economics

The first part of the analysis will focus on single well results. Using the type curves, economic and EUR values were determined for each spacing group yielding both the chart and plot below. For a single well, wider spacing shows superior single well IRR and NPV with diminishing returns as spacing increases beyond 880 feet. Narrower spacing shows increasing well interference through increasing EUR degradation below 330 feet.



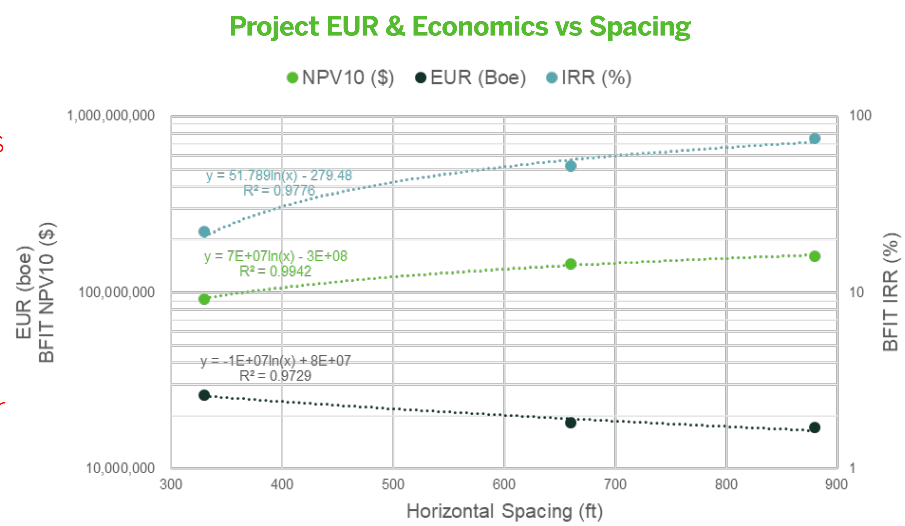

Based on qualitative observations when performing additional analysis during the well-selection phase of the project, some attempts had been made at smaller completion designs in the narrower spacing intervals. While this was not evaluated in detail for this analysis, smaller completion designs may shift the curves for this type of analysis.

# PROJECT RESULTS

## EUR and Economics

The second part of this analysis focuses on project results. For this project, a single bench acreage position of 10,000 net acres was assumed and using the assumed lateral length and horizontal spacing, the acre spacing for each well was determined. Dividing the acreage position by the acre spacing, an inventory for each spacing group was calculated and a constant completion rate of two wells per month was assumed to build a drill schedule.

On a project basis, wider spacing shows optimal IRR and NPV at 880 feet spacing, with diminishing returns beyond 880 feet. Narrower well spacing shows superior recovery on a project bases, with 35% higher EUR at 330 feet as compared to 880 feet. This suggests that the lower single well EURs at 330 feet are outweighed by the larger number of locations available at this spacing. However, this incremental recovery gain comes at the cost of a 75% reduction in NPV10 and a 238% reduction in IRR as compared to 880 feet spacing.




| Spacing | Effective Wells per Section | Acre Spacing | Number of Wells | BFIT NPV10 | % Change NPV10 | BFIT IRR (%) | % Change IRR | EUR (boe) | % Change EUR |
|---|---|---|---|---|---|---|---|---|---|
| 330 | 16 | 151 | 66 | $92,035,361 | - | 22 | - | 26,196,422 | - |
| 660 | 8 | 303 | 33 | $145,968,755 | 59 | 52 | 136 | 18,326,031 | (30) |
| 880 | 6 | 404 | 25 | $161,358,959 | 75 | 75 | 238 | 17,107,342 | (35) |

## Project Scenarios

Frequently, operators must consider the implications of changing well spacing from a previously planned well spacing. This use case seeks to illustrate an "up-spacing" scenario and a cost reduction scenario as an operator considers moving from one well spacing to another while also considering some constraints.

The first scenario, an up-spacing scenario, considers a case where an operator is considering changing well spacing from 330 feet to 660 feet or 880 feet while also trying to preserve the overall PUD volumes booked for the asset. Using WellCast, we can tweak the number of acres for the well schedule and determine how much additional acreage the operator will need. The resulting analysis shows that in order to maintain the same project EUR with 330 feet well spacing, 4,550 (+45%) additional acres are need when moving to 660 feet well spacing and 5,350 (+52%) additional acres are needed when moving to 880 feet well spacing.

The second scenario, a cost reduction scenario, considers a case where an operator is trying to make development at 330 feet well spacing or 660 feet well spacing economically competitive (on an IRR basis) with 880 feet well spacing. Again, using WellCast, we can tweak the assumed cost of the project via the well cost to determine the appropriate respective reduction in cost for 330 feet and 660 feet development. Based on the results of the analysis, a 20% reduction in cost is required to make a project with wells spaced at 660 feet competitive with a project of wells spaced at 880 feet, and all with no reduction in per well productivity. Meanwhile, a 30% cost reduction is required to make a project with wells spaced at 330 feet competitive with a project of wells spaced at 880 feet.

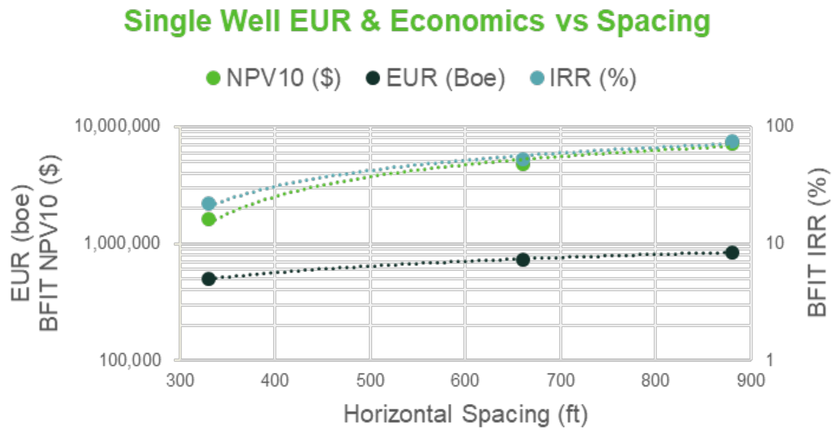
However, with high well inventories at lower well spacing, operators may be able to employ economies of scale, harnessing advances in development strategy such as row development or more favorable pricing on oilfield services. Should those savings near 20%-30% on a per well basis as compared to more expensive wells at wider well spacing (i.e. 880 feet), downspacing may prove to be highly optimized for realizing returns.

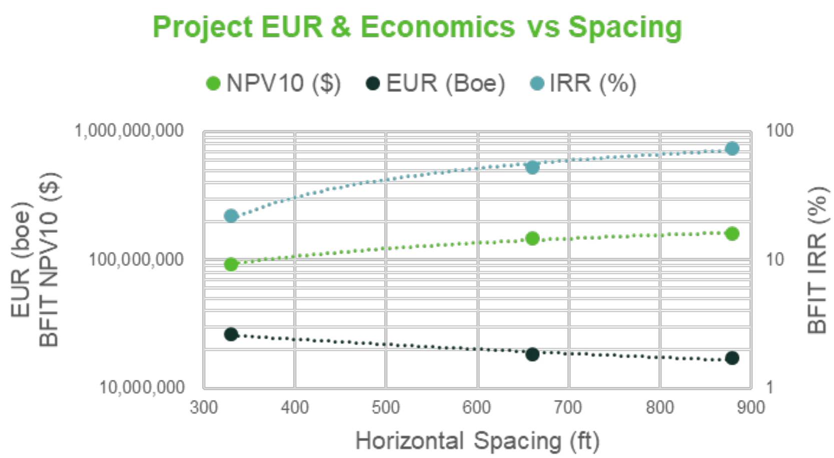
# CONCLUSIONS

Based on the insights derived using Well Spacing and WellCast, both the single well and project analyses have offered unique insights into the impacts of well spacing on recovery and returns. The single well analysis showed 880 feet to yield superior per well NPV, IRR, and EUR, with increasing single well EUR degradation through well interference as spacing narrows. While the project analysis shows that wider spacing yields higher NPV and IRR, narrower spacing shows increased recovery and significantly greater well inventory. Hence, there is trade-off between reserves and recovery when it comes to well spacing.

## USE CASE – DUELING DEVELOPMENT MODELS

Analysis of two different scenarios shows the acreage and cost implications of changing well spacing. An up-spacing scenario shows that in order to maintain the same project-level EUR as with 330 foot well spacing when up-spacing, 45% to 50% more acreage is needed when changing 660 foot or 880 foot well spacing respectively. Thus, acreage replacement and the hunt for large consolidated acreage positions accelerates with up-spacing. A downspacing scenario shows that a 20% to 30% cost reduction is required to make a project with wells spaced at 660 feet or 330 feet competitive on an IRR basis with project of wells spaced at 880 feet, assuming no change in well productivity with cost reductions.




Overall, the recent market trend towards rewarding free cash flow generation and returns clearly favors wider spacing. However, these improved returns come at the price of lower recovery and faster inventory burn rates.

### Questions?

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