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Optimizing Unconventional Completion Designs: A New Engineering and Economics Based Approach

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Abstract

The completion design process for most horizontal wells in shale reservoirs has become a statistical evaluation process, rather than an engineering-based process. Our paper presents an alternative approach using an engineering approach to define the reservoir properties and the effectiveness of the fracture treatments. We then use these results in an economic analysis that allows the engineer to be predictive with respect to how capital is spent in the completion process.

This paper presents a methodology for both the evaluation of the reservoir and the design of the well completion where the engineer can make economic decisions and determine the change in the return on investment as a function of the change in capital expenditure. The engineer can then be able to "optimize" the completion and fracture treatment designs based on Net Present Value, Return on Investment or any other economic parameter desired. We use a rate transient analysis approach to estimate reservoir and fracture properties. We present case histories in the paper, and the interpretation of the production analyses of these case histories yields information about the formation permeability and the effective lengths and number of hydraulic fractures created during the completion process.

With knowledge of the reservoir and fracture properties in hand, the engineer can then determine the "optimum" completion design for future wells. This understanding can be achieved much quicker and for much less money than the cost to drill the number of wells necessary to make statistical analysis meaningful. The results of the case histories indicate that many completion designs are not in the "optimum" range. Too much capital is being spent increasing stage count when it should be going to increased effective length. The focus on early-time production has ignored the effect that more fractures has on ultimate recovery.

The results and conclusions in this paper will run contrary to much of the direction most unconventional completion designs have been evolving over the past 5 to 10 years. A much greater emphasis on achieving increased effective lengths will be demonstrated and that increased stage count can prove detrimental to

economic success over the well's life. Processes in the paper will also prove valuable for smaller operators that do not have a large well counts that are usually required to achieve a meaningful statistical evaluation.

Introduction

In the beginning of the shale revolution, wellbore lengths of 3-4,000 ft. with stage lengths of 150-200 ft. were quite common. As the shale revolution progressed, the tendency has been to use longer wellbores, more stages, more clusters per stage and create more, short fractures. It was observed that even though the cost to drill and fracture treat these wells increased substantially, the wells would begin at an initial production rate (IP) of much more than the wells with fewer stages and clusters. At first, these higher IPs were thought to be an indication of increased reserves. The problem is that the large amount of capital required for longer laterals and more fracture stages has the industry always looking for new capital. The stock analysts for years told the industry they wanted to see production growth, so more length and stages fit the story line. Many companies were not focusing on their return on investment (ROI).

Another issue is can we really propagate multiple fractures from clusters within stages to a length that is required to improve ultimate recovery? Reservoir simulation can show that the high initial IP from a well that is caused by multiple short fractures may not translate into increased ultimate recovery, when compared to a well containing fewer but longer propped fractures. Mayerhofer et. al. has published several papers where they used results from micro-seismic tests, production and pressure transient tests, and fracture treatment data to history match production and pressure interference between horizontal wells. In those papers, Mayerhofer et. al. shows that to adequately match the production and pressure interference data, they had to model long, conductive fractures to connect the well. If they tried to grid their reservoir model using a matrix of natural fractures based on the micro-seismic data, they could not match the data. They had to model a few "high conductivity fractures (pipelines) between the wells to match the field data. See Figure 1

In fact, one of the Mayerhofer et. al. paper's (SPE-184848-MS) had the following conclusions:

"The following conclusions are made based on the results presented in this study.

• Numerical reservoir modeling can provide insight into the impact of well spacing, well placement, and completion parameters on well performance and estimated ultimate recovery.

• Fracture half-length has the largest positive impact on total gas production. Maintaining a 1,000 ft. fracture half-length is critical for all well spacing and placement scenarios. Therefore, reduction in fracture treatment sizes with current staging strategies would not be a viable completion strategy.

• Increased fracture conductivity is beneficial up to 20 md-ft. There appears to be no significant gas production increase above 20 md-ft. due to low system permeabilities, thus providing validation to continue with slickwater-type treatments.

• The prudent development strategy is prioritizing cluster efficiency through enhanced diversion and perforation/staging strategies and optimizing a combination of PV10 and ROR, which will affect well spacing and/or parallel versus staggered lateral landing strategies."

We are all familiar with what the industry calls “fracture hits”. Fracture hits occur when a company is fracture treating a well and the hydraulic fracture propagates into an adjacent well. These fracture hits are so common that the topic fills the literature and the agenda at many technical conferences. If one uses a fracture treatment propagation model to examine possible reasons for such fracture hits, it becomes obvious that, due to the increased stresses that occur when we “push the earth apart”, it is virtually impossible to propagate multiple fractures that are close together for any great distance. Figure 2 shows the result of such modeling for a single stage with 4 fractures initiated simultaneously. As the two fractures on the outside begin to grow, the act of pushing the earth apart increased the stresses so that the width of the two fractures in the middle are restricted. Since flow rates down a fracture is roughly proportional to the width squared, the middle fractures each only take about 8% of the injection fluid.

However, this physical limit to fracture propagation is even more pronounced as one models multiple stages and clusters. In Figure 3, we see two cases, with different cluster spacing. The simulation shows that if you add more clusters closer together, you might get several very short fractures but there will be a few that dominate the system. In both scenarios, there are some fractures that propagate much further from the wellbore than most of the fractures.

The problem the industry is facing is quite intriguing.

1. Should we go with more clusters, more stages and shorter fractures to obtain a high IP, but at a high capital cost? Or

2. Should we use increased well spacing with fewer stages, but create longer fractures at a lower capital cost to improve the Return on Investment?

The investment community has been pushing for #1 for a decade. However, with so many companies having trouble paying off debt, the investment community is now switching their commentary to #2.

In this paper, we provide a technical way to develop a shale reservoir to achieve a better profit, rather than just focusing on the Initial Production Rate. (IP).

Methodology

To compare the success of different completion and treatment designs we will calculate the economic outcome of predicted producing rates over a ten year well life to the well costs required to achieve those rates. A 10% discount rate will be used to calculate Net Present Value, thus giving some advantage to early time producing rates. Two economic studies will be performed; the first being a parametric study of varying reservoir permeability, the second is a study of existing oil wells in Wyoming which have been history matched and from the derived reservoir and completion properties, the completion designs have been optimized.

Well costs in horizontal, multi-stage wells is heavily weighted to the completion side. There are many different costs that go into the completion. Some are fixed (well site construction and production facilities for example), some are time dependent (surface equipment rentals, well site supervision, working tank rentals, etc.) and some are volume dependent (water usage & transportation, proppant usage

& transportation, perforating guns, zonal isolation plugs, chemicals, etc.). Depending on how fracturing service providers have been contracted, their costs can be either time dependent or stage dependent or a combination of both. In the following economic evaluations we believe we have used a minimal estimate of the incremental cost on a per stage basis.

Production decline behavior in wells, in general, follows the movement of created pressure transients through the reservoir by the reduction of pressure at the wellbore, causing hydrocarbons to be produced. It is the rate of production and production totals over time that create the revenue to pay for the investment made in the wellbore. It is the formation properties and the configuration of fractures and no-flow boundaries that create the shape of the production history.

The optimization process in a vertical, single reservoir well is a relatively straightforward process. Using a reservoir simulator to predict the production that will come from a formation with a known permeability, porosity, water saturation, net pay, pressure and fluid properties, we can determine the revenue the well will produce over time. Using a fracture simulator to predict the created, propped and effective length of the induced hydraulic fracture we can determine the quantity and treatment design of the fluids and proppants needed to achieve these lengths, and thus know the cost versus effective length. Combining these we see in Figure 4 that an economic optimum of the Net Present Value can be found and thus determine the treatment design that should be pumped. This process becomes more successful and reproducible if we measure the results from previously completed wells and confirm the assumed properties we are using in our process.

Unconventional reservoirs and completions present a new set of issues. Now the wellbore is horizontal and there are multiple fractures which are transverse to the wellbore. These fractures are spaced apart and each one has created a pressure transient once production begins. Figure 5 shows a portion of a horizontal wellbore with multiple fractures. Fortunately, the pressure transients initiated through each fracture moves very, very slowly. There will be no-flow boundaries between each of these fractures that these pressure transients should encounter first. Flow will be linear into the fractures until this occurs. The time it takes the pressure transient to encounter the transient from the adjacent fracture is dependent on the distance it must travel and the permeability of the reservoir (and other formation and fluid properties). In these reservoirs the time these adjacent transients meet may be days or months. At this point the production decline behavior changes from an approximate one-half slope on a plot of the log of production versus the log of time to an approximate unit slope. This we will refer to as the transitional flow period.

Finally, the production from outside of the rectangle formed by the wellbore length and the length of the fractures will dominate and production will be flowing as depicted in Fig. 5b. This will appear in the production decline behavior as a return to linear flow. The level of production at this point will be a function of the formation permeability.

The behavior of production decline in unconventional, horizontal, multi-stage completions is very similar basin to basin. Figures 6a & 6b show wells in the Bone Springs formation of west Texas. Noted on these graphs are the early-time linear flow, transition flow due to interference between fractures and late-time linear flow into the depleted area between the fractures. Figure 7 is an example from the Eagle Ford formation. Figure 8 is an example from the Powder River Basin Mowry formation. In all examples, the match of production using an analytical solution has been presented along with the calculated reservoir and completion properties. In Figure 8 we show that the well was initially matched in 2016 and then production was recently updated with an additional two- and one-half years of production and the initial matching parameters continued to match the additional data.

Parametric Study

A simple parametric study was performed to determine the optimum number of stages for a reservoir of given parameters. Permeability was varied between cases to observe the change in optimum stages as permeability varies. Using an analytical solution for production versus time for horizontal wellbores with transverse hydraulic fractures in an infinite-acting reservoir, we projected the production for four reservoir permeabilities (1000, 500, 250 & 100 nD) and varying the number of created fractures from 10 to 100 given the reservoir and production conditions in Table 1. Producing time was limited to 10 years.

Figure 9 shows the resulting production decline curves for each grouping of 10 created fractures along the lateral for the 1000 nD case. This graph indicates that as the number of created fractures increases, the early time production increases. However, as the spacing between fractures decreases, production declines more rapidly, earlier. Figure 10 shows the 10-year cumulative production versus the number of created fractures along the lateral for all 4 permeability cases. The graph indicates that as the number of created fractures increases, the incremental increase in 10-year cumulative production declines, meaning less incremental oil is recovered as fracture spacing decreases.

Table 1
Parametric Study
Reservoir & Production Properties

Net Pay =	100	feet
Porosity =	10%	
Sw =	30%	
Lf =	150	feet
Pi =	5000	psi
Pwf =	750	psi
Bo =	1.2	RB/STB
Oil Viscosity =	0.5	cps
Lateral Length =	7500	feet
Oil Net Value =	50	$/bbl
Stage Cost =	50,000	$
Fixed Well Cost =	2,500,000	$

To determine the point at which the cost of creating an additional fracture becomes greater than the value added to the well economics by that fracture we have created Figure 11 for each of the reservoir permeability cases. This graph shows the incremental NPV added from each additional fracture as the number of fractures created increases. The cost of creating a fracture is plotted over the data and the point at which the value added is less than the cost of creating the fracture there would obviously be no reason to spend the money to create that fracture. The graph indicates that the maximum number of profitable stages is about 48 stages for the 1000 nD case and about 77 stages for the 100 nD case.

Figure 12 shows the cumulative discounted cash flow for each of the 10 stage groupings of the 1000 nD case. This graph shows that the 50 Stage case has the maximum NPV. This agrees with Figure 11 and demonstrates that the increased cost of placing more than 50 stages is more than the added value from those fractures.

Lastly, Figure 13 shows the calculated NPV for all of the permeability cases and the cost of the well as stage count increases. The maximum NPV point is easy to see for each case. The results show that as the reservoir permeability increases, the number of stages needed to optimize well economics decreases, given the other reservoir inputs. The key is to understand the diminishing economic return as the number of stages increases. To do this we need to characterize each previous completion we have in our field for reservoir permeability, effective fracture length and the number of effective fractures we are creating per stage.

Results of Producing Wells Analysis

The authors have performed production evaluations and completion optimization determinations across many of the current producing unconventional reservoirs. To demonstrate the process and results using actual producing wells we have selected six wells in the Powder River Basin producing from the Mowry formation and operated by EOG. All technical data is from public sources or derived from public data. Economic data, such as costs and revenue, are based on the author's experience.

Table 2 shows a summary of the data gathered from public sources. Well names, date of first production, lateral lengths, number of stages completed, volume of fluid used and weight of sand used are all detailed. The monthly producing history for each of these wells was also obtained. A graph of the oil producing history is presented in Fig. 14. Five of the six wells have produced in excess of four years. One is a recent completion.

Table 2

Lease Name	Well Number	Date Production Start	Lateral Length feet	Stages Pumped	Fluid Pumped bbls	Sand Pumped lbs
ARBALEST	248-16H	7/1/2012	3400	23	43,079	845,251
BOLT	1-35H	6/1/2013	7767	41	194,947	14,558,253
MARYS DRAW	210-23H	7/1/2013	3527	23	87,446	7,105,792
BLADE	200-2116H	10/1/2013	6283	36	161,953	11,276,063
ARBALEST	26-2234H	8/1/2014	7210	42	153,357	9,916,450
BALLISTA	204-1102H	6/1/2018	8962	55	452,793	26,316,507

The first step is to history match the production history of each well using the analytical model. An example of these matches are presented in Fig. 15 for the Bolt 1-35H and Fig. 16 for the Arbalest 26-2234H. The average effective fracture half-length was found to be 140 feet and the formation permeability to be 1500 nD for the Bolt 1-35H and 95 feet and 900 nD for the Arbalest 26-2234H. Also, the match indicated that only one effective fracture was created for each stage. Fig. 17 shows an attempted match of the Bolt 1-35H using two effective fractures per stage pumped and the late-time data does not match. To look at the sensitivity of the results Fig. 18 presents the production data with a change to the matched effective half-length by both a 20% increase and a 20% decrease. Both show a poorer fit of the data. Fig. 19 shows the sensitivity to matched permeability. Both are poorer fits in late time. Table 3 summarizes the results of all six well matches.

Table 3

Lease Name	Well Number	Date Production Start	Lateral Length feet	Stages	Fluid Pumped per Stage gallons	Sand Pumped per Stage lbs	Matched Effective Lf feet	Matched Permeability nD
ARBALEST	248-16H	7/1/2012	3400	23	78,666	36,750	70	1600
BOLT	1-35H	6/1/2013	7767	41	199,702	355,079	140	1500
MARYS DRAW	210-23H	7/1/2013	3527	23	159,684	308,947	110	700
BLADE	200-2116H	10/1/2013	6283	36	188,945	313,224	95	1400
ARBALEST	26-2234H	8/1/2014	7210	42	153,357	236,106	95	800
BALLISTA	204-1102H	6/1/2018	8962	55	345,769	478,482	205	1700

The results of the production history matching will next be used to determine the relationship between treatment size and effective fracture half-length. Two plots were prepared, Figs. 20 and 21. These graphs show the relationship between sand pumped per stage versus average effective half-length and fluid volume pumped per stage versus average effective fracture half-length. Both graphs show good trend. These trends will be used to project the cost of a treatment stage versus effective fracture half-length created, shown in Fig. 22. By knowing this cost relationship to effective half-length an incremental economic analysis can be performed for any treatment size and number of stages for any of these wells or a future well of a given permeability and lateral length.

Using a software program that enables us to perform the predictive production evaluation for any number of stages pumped and any effective fracture half-length we can generate a matrix of predictive revenue from any completion scenario. Knowing the incremental cost of the size of the treatment pumped and the number of stages pumped we can generate the cost of any completion scenario. Therefore, we can generate the economics of every case. Fig. 23 shows a map of Net Present Value for the Bolt 1-35H well. A black dot shows the point indicating the number of stages pumped (41) and the effective fracture half-lengths achieved (140). A white dot is shown where the optimum number of stages (33) and an increase in effective fracture half-length to 205 feet is located. Fig. 24 summarizes the economics for the actual and improved completion scenarios. The improved completion design decreases well cost by $151 thousand, increases NPV by $1.64 million and increases the ten- year oil recovery by 34 thousand barrels of oil. The increased effective fracture half-length will also mean that fewer wells will be needed to be drilled to develop the land.

By having the knowledge of reservoir permeability and created effective fracture half-length through production evaluation, tremendous cost savings and increased profit can be achieved when developing a field. The knowledge of effective fracture half-length is especially useful in spacing wells to reduce interference as was noted in the previously sited paper by Mayerhofer.

Summary

It has been the author's experience over the past 7 years that a very large majority of unconventional reservoir horizontal wells with multi-stage hydraulic fractures have production decline curves with similar behavior. This decline curve behavior can be evaluated with analytical or numerical models to characterize the average reservoir permeability, effective fracture half-length and the number of effective fractures along the wellbore. It appears that a considerable portion of the wells we have analyzed have shown that only one or two effective fractures are found per stage pumped. The knowledge gained through characterizing these completions and reservoirs can lead to finding the economic optimum completion design for future wells. As a result of our work, we can conclude the following:

Conclusions

1. Significant cost savings and increased per well profit can be realized by analyzing fracture treatment data and production data to characterize both the hydraulic fractures created and the reservoir properties as input into an economic model.

2. The production decline behavior of unconventional wells can be analyzed using an analytical solution to characterize average permeability, average effective fracture half-length and number of effective fractures created.

3. Knowledge of effective fracture half-length and formation permeability can aid in the spacing of wells in field development.

4. Knowledge of treatment size versus effective fracture half-length can lead to increased hydrocarbon recovery and improved well economics by designing the optimum fracture treatments for specific formation properties

5. Our analyses over the past few years leads us to the conclusion that many operators are using too many fracture treatment stages and too many clusters per stage to maximize initial production (IPs) rates at the expense of net present value and return on investment.

6. In many reservoirs, increasing well spacing, reducing the number of stages, and creating longer hydraulic fractures will result in a better return on investment.

Acknowledgements

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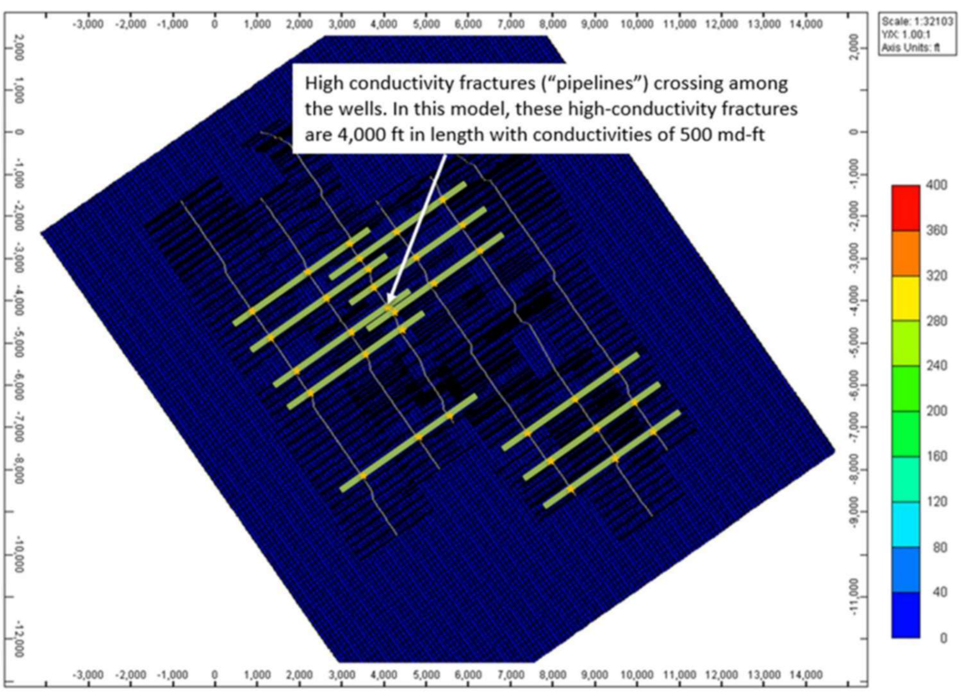
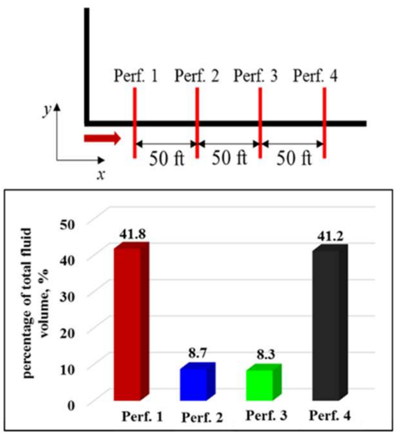


Figure 1 - from SPE-184848-MS

Propagation of Four Fractures

Four fractures propagating simultaneously in a single stage

Uniform stress, properties, and treatment, no effects of NFs and near-wellbore tortuosity



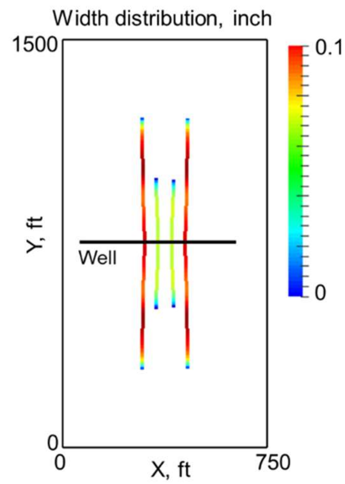
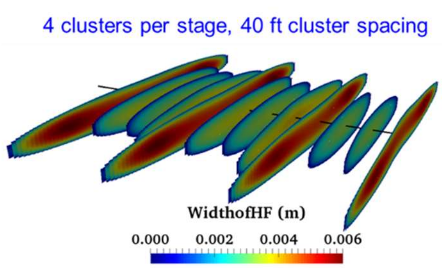


Figure 2 from SPE Paper 174869

Fracture propagation

- **Homogeneous stress state**
- **Stress shadow effects from intra-stage and inter-stage**
- **Low cluster efficiency**



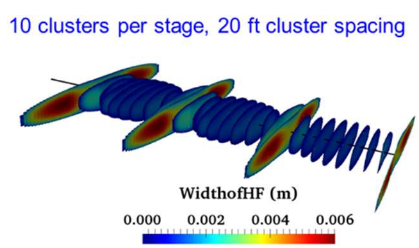


Figure 3 from Dr. Wu at TAMU research meeting in 2019

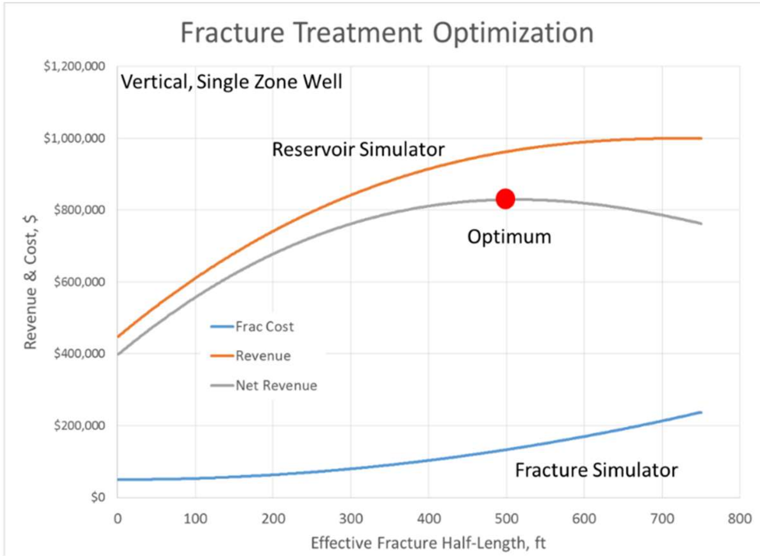
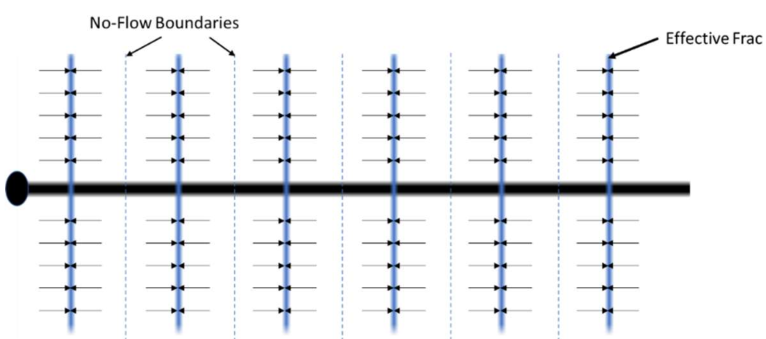


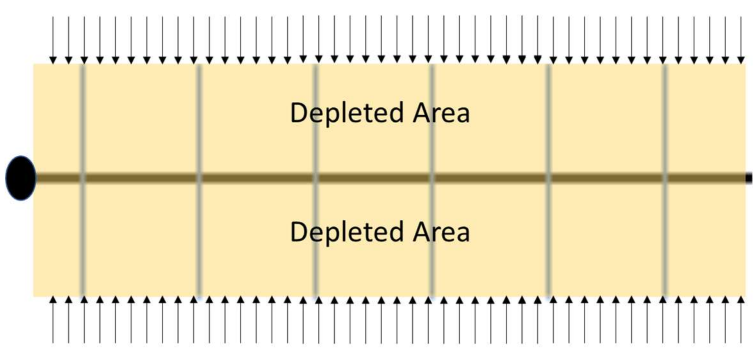
Figure 4 – Optimizing Fracture Treatment Design in Vertical, Single Interval Wells



$$Early\ Time\ Productivity \approx A\sqrt{k}$$

Where:
A = Effective Fracture Face Area
k = formation permeability

Figure 5a – Example of Early-time Flow Behavior



$$Late\ Time\ Productivity \approx f(k)$$

Where:
k = formation permeability

Figure 5b – Example of Late-time Flow Behavior

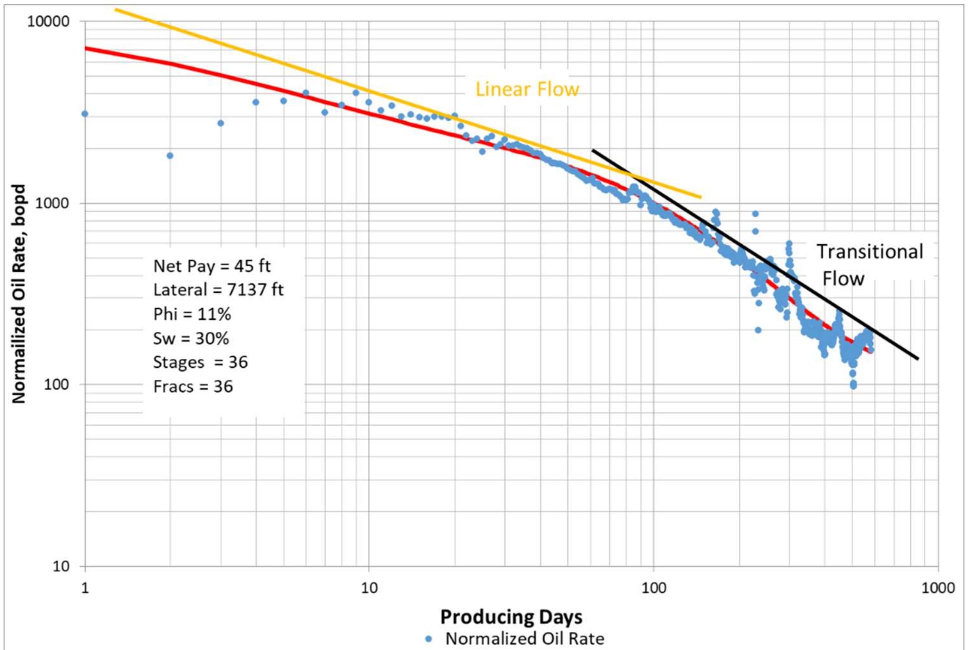


Figure 6a - Example of Production Behavior - West Texas Bone Springs Well 1

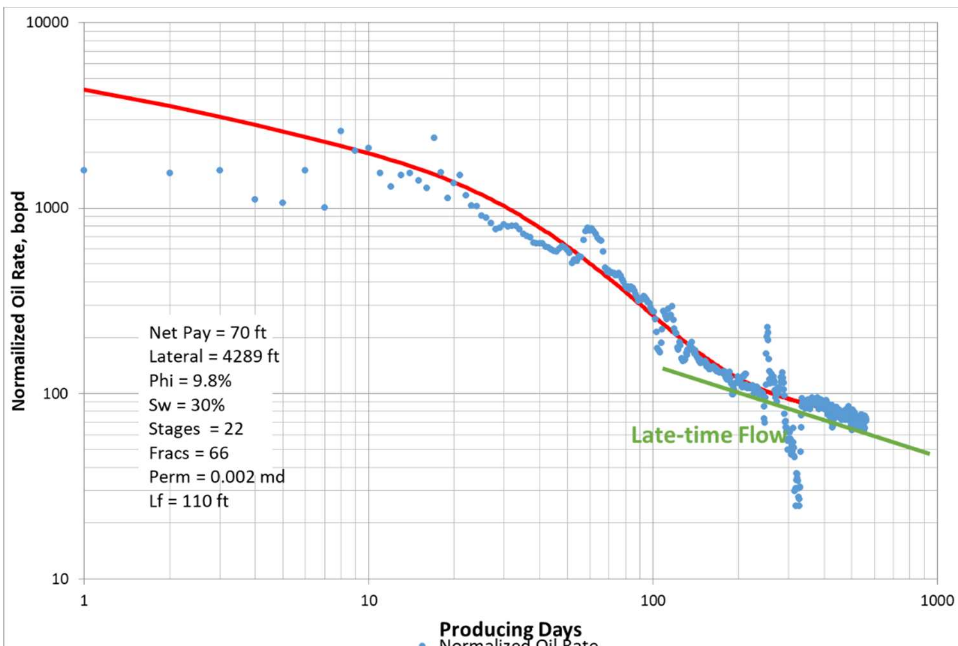


Figure 6b - Example of Production Behavior - West Texas Bone Springs Well 2

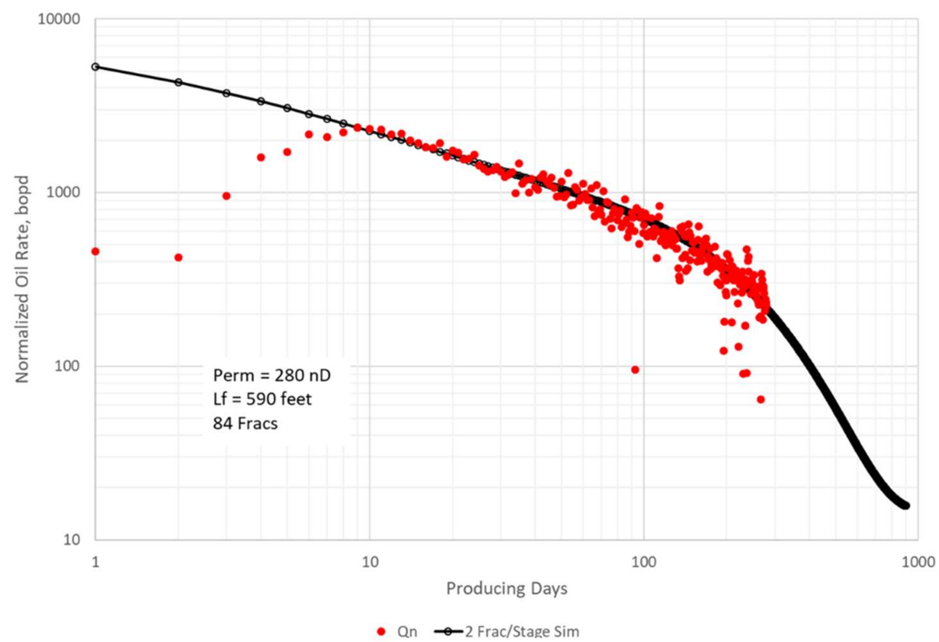


Figure 7 – Example of Production Decline in Horizontal, Multi-stage wells – EagleFord formation

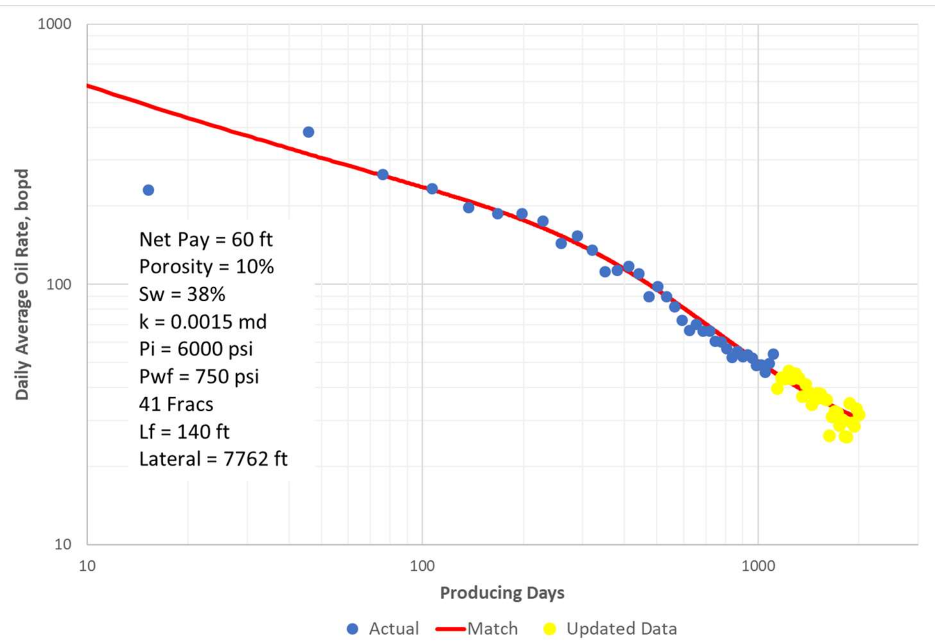


Figure 8 - Example of Production Behavior - PRB Mowry Well

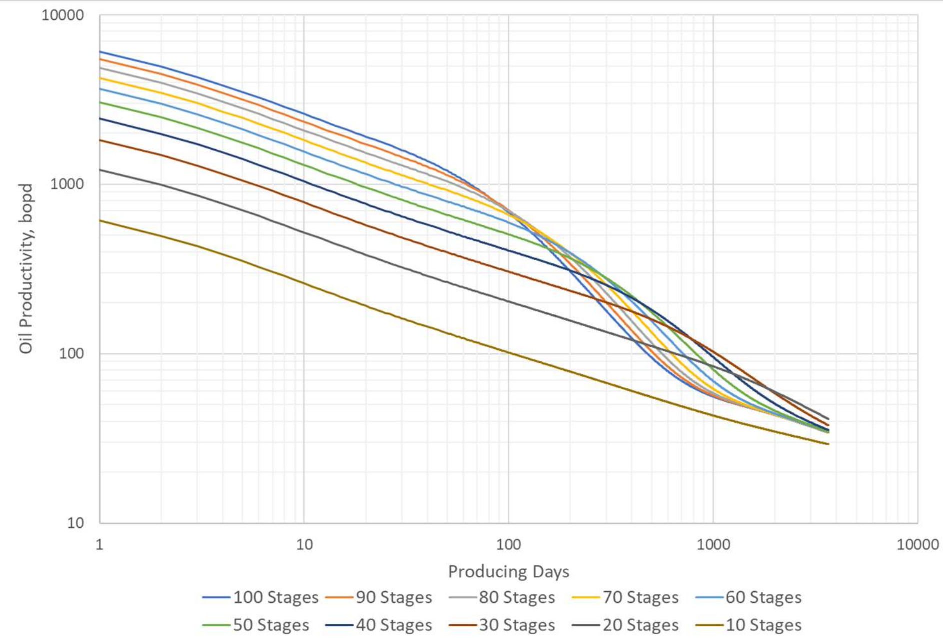


Figure 9 - Production Decline Curves - Parametric Study 1000 nD Case

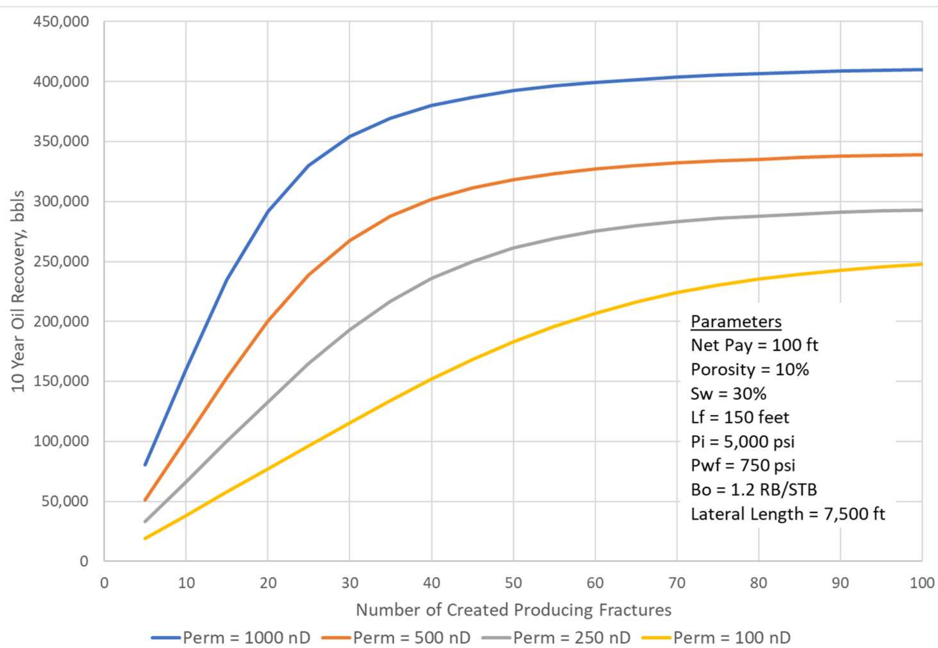


Figure 10 - Ten Year Cumulative Oil Recovery v. Created Fractures

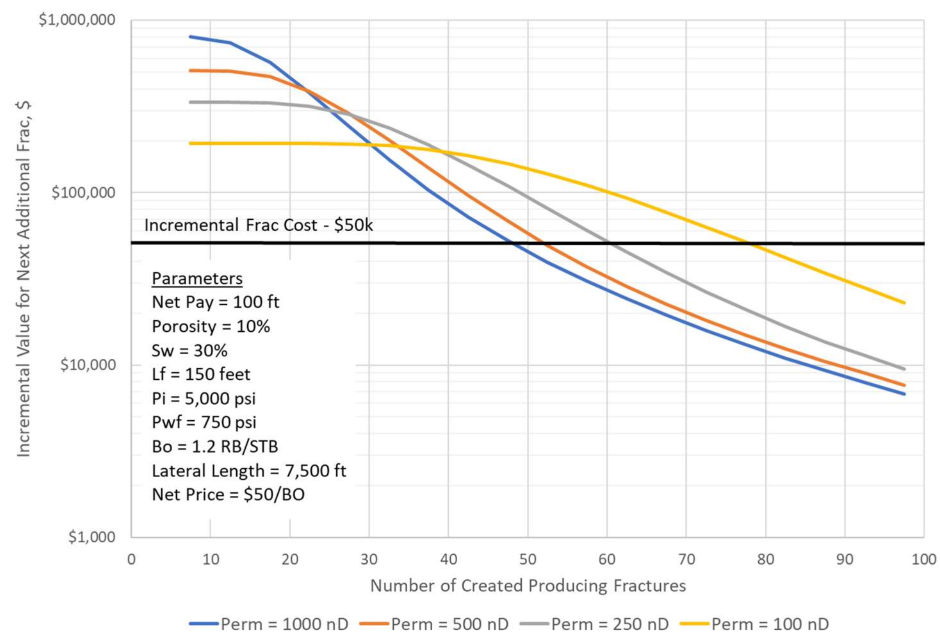


Figure 11 - Incremental Values Added by Next Fracture - Parametric Study

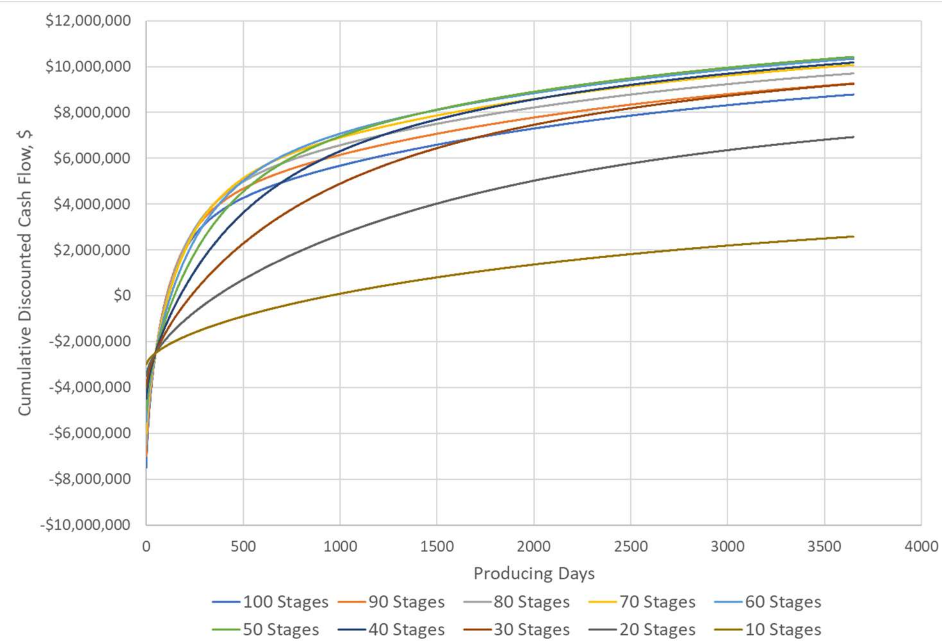


Figure 12 - Cumulative Dicounted Cash Flow - Parametric Study 1000 nD Case

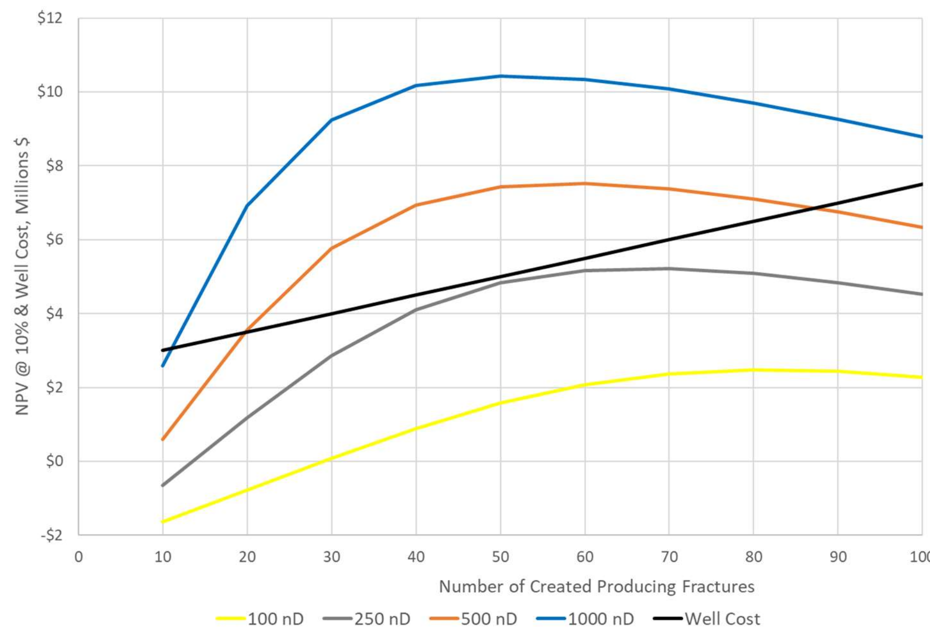


Figure 13 - NPV @10% v. Created Fractures - Parametric Study

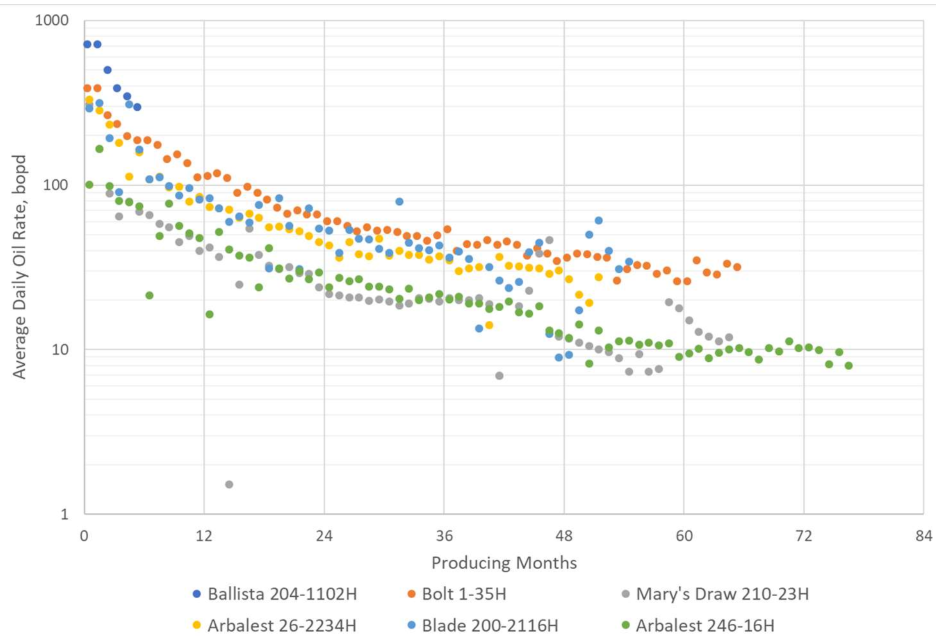


Figure 14 - Producing history from 6 Powder River Basin Mowry wells

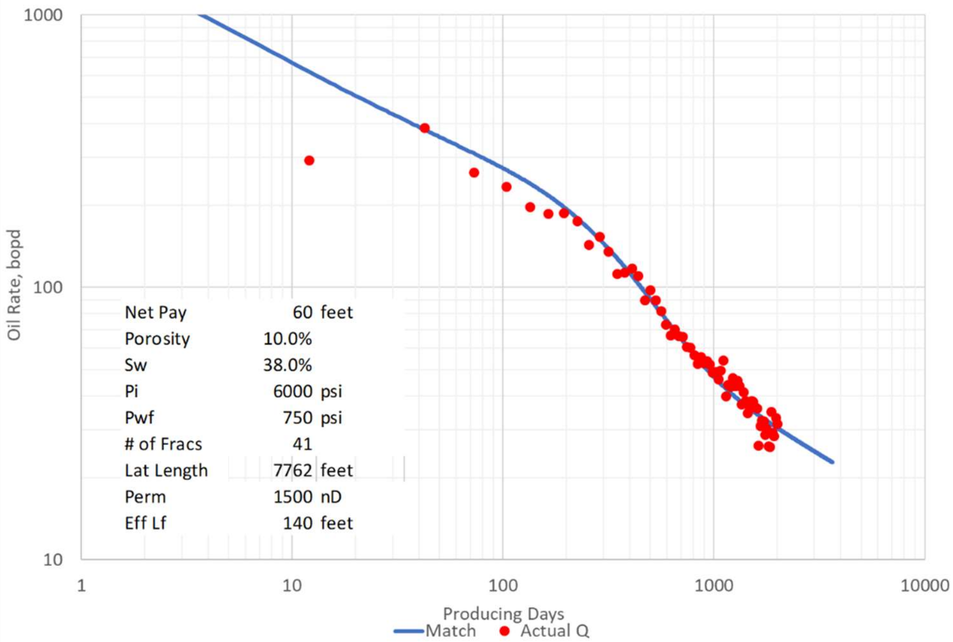


Figure 15 - Production History Match Bolt 1-35H

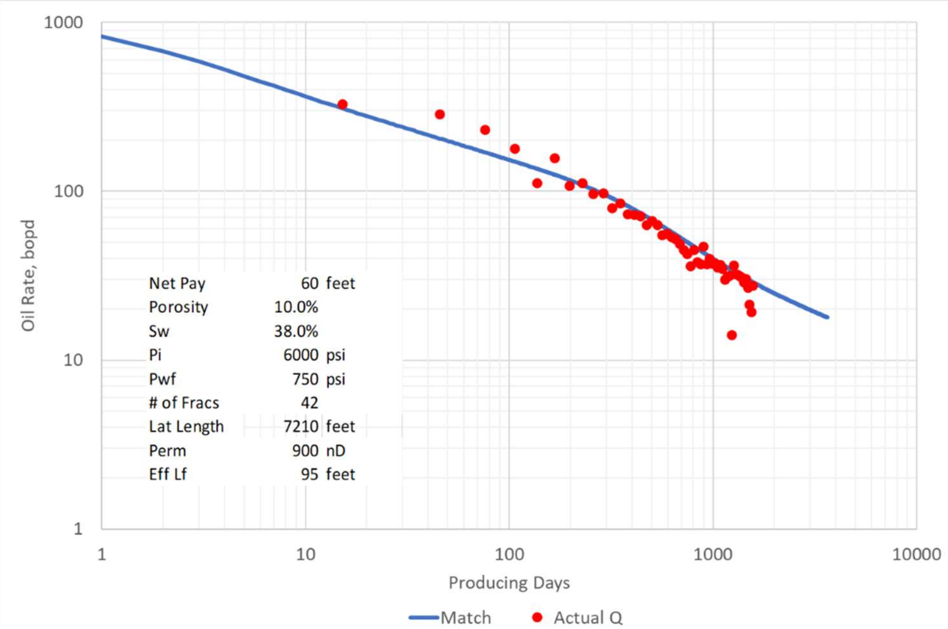


Figure 16 - Production History Match Arbalest 26-2234H

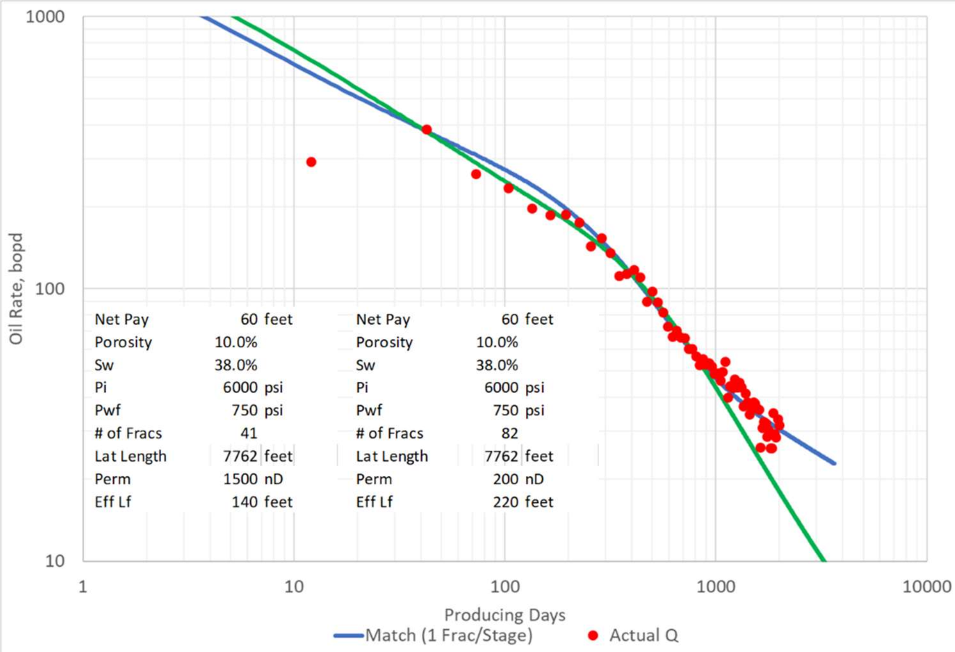


Figure 17 - Production History Match Bolt 1-35H - Compare using 2 Fracs/Stage

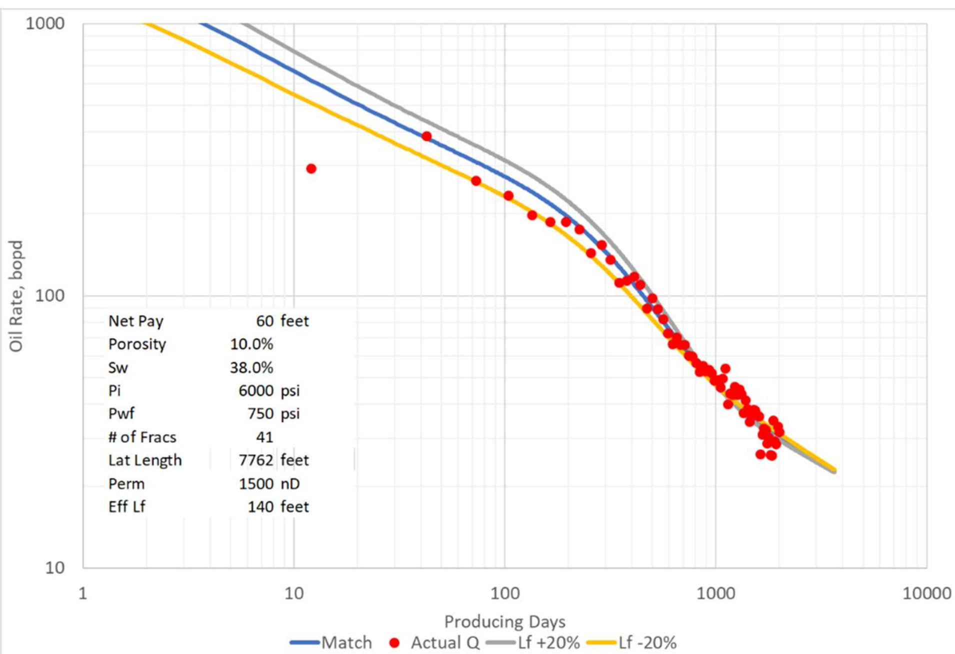


Figure 18 - Production History Match Bolt 1-35H - Sensitivity to Effective Fracture Half-Length

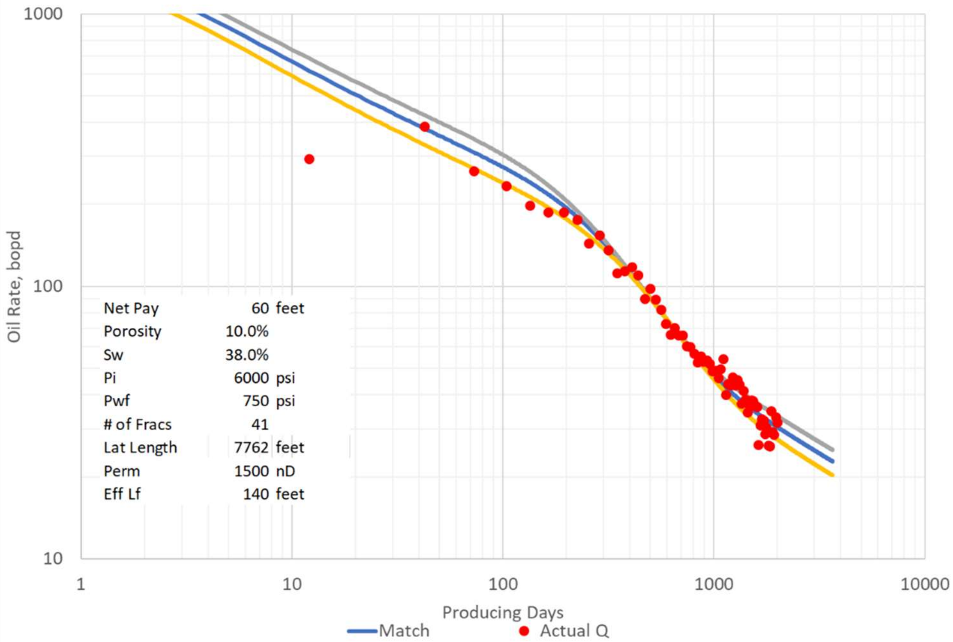


Figure 19 - Production History Match Bolt 1-35H - Sensitivity to Permeability

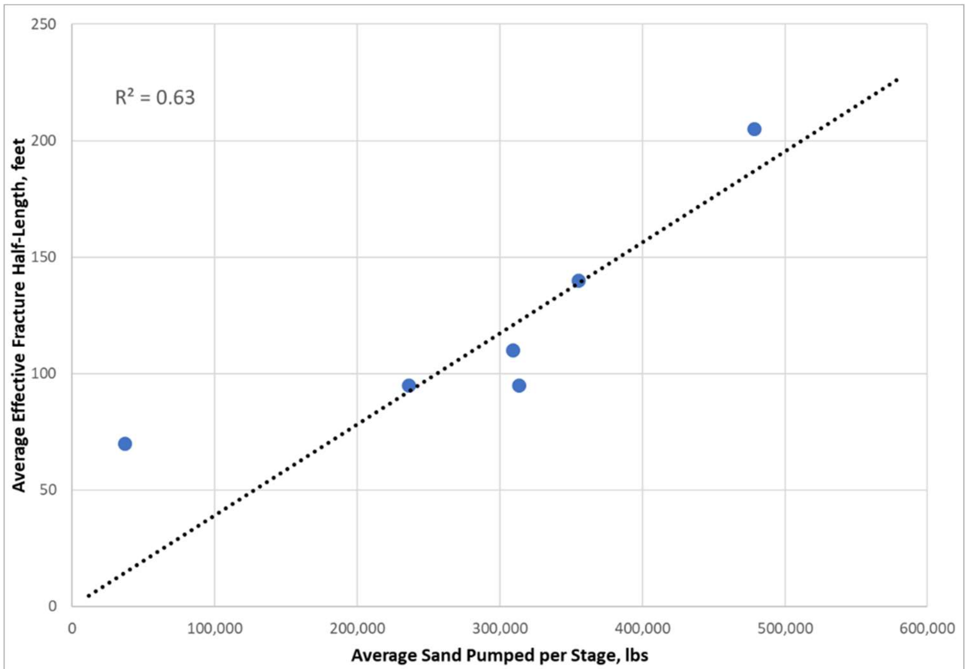


Figure 20 - Average Sand Pumped versus Matched Effective Fracture Half-Length

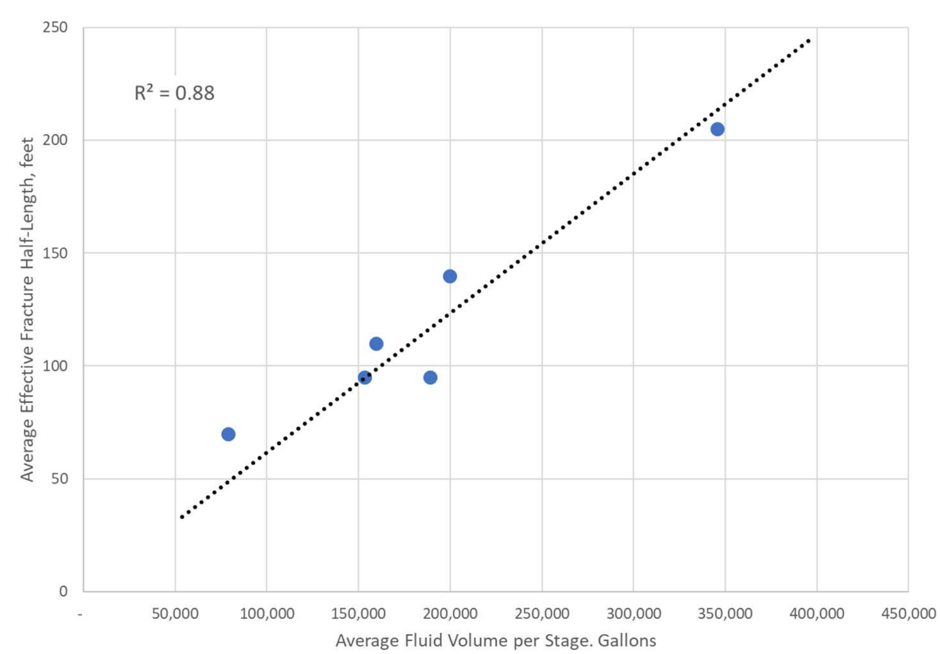


Figure 21 - Average Sand Pumped versus Matched Effective Fracture Half-Length

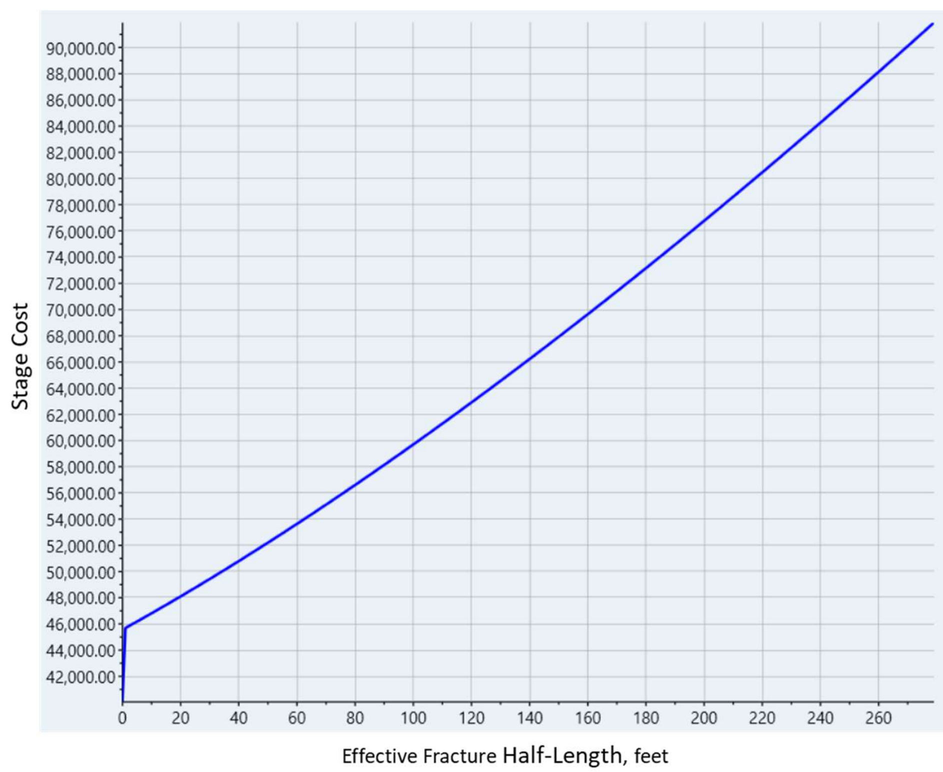


Figure 22 – Stage Cost versus Effective Fracture Half-Length Created

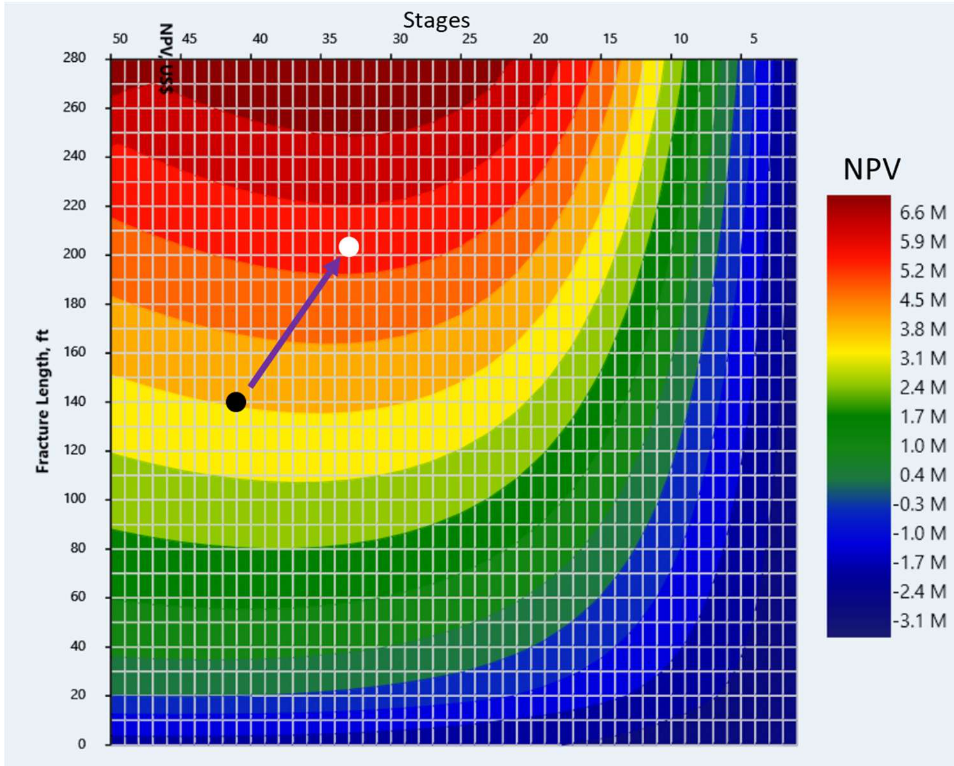


Figure 23 – NPV Outcome for a Matrix of Completion Designs

Actual Completion Design

# Of Stages	41
Entry Points	1
Effective Lf (ft)	140
Proppant Type	40/70 White Sand
Max Prop Conc. (ppg)	2.2
Stage Cost	$66,218.73
Total Well Cost	$5,464,967.74
NPV	$3,160,310.05
ROI	1.58
Hydrocarbons Produced	223,222

Improved Completion Design

# Of Stages	33
Entry Points	1
Effective Lf (ft)	205
Proppant Type	40/70 White Sand
Max Prop Conc. (ppg)	2.1
Stage Cost	$77,683.36
Total Well Cost	$5,313,550.83
NPV	$4,802,820.99
ROI	1.90
Hydrocarbons Produced	256,688

Figure 24 – Summary of Economic Outcomes