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Evaluating Refrac Economic Potential and Primary-Infill Relative Well Performance in Permian Organic Shales

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Abstract

Barba (2015) proposed a methodology for integrating petrophysically derived OIP values with decline curve analysis to estimate the recovery factors for organic shales in the Midland Basin. Since that study a number of improvements have been made to the petrophysical models and over 1500 wells have been analyzed for OIP in the Permian Basin to date. Recovery factors have been consistently higher with higher proppant loading, higher fluid loading, and closer cluster spacing. A subsequent study (Barba and Leshchyshyn 2017) evaluated refrac potential in Permian Basin organic shales using the recovery factor technique. The purpose of this new study is to apply the learnings subsequent to these initial studies to estimate recovery factors for refrac candidates using the current “best practices” refrac designs using operator provided individual well production data.

A second objective is to provide a means to normalize production comparisons between infill and primary wells. Various estimates of 20 to 40 percent EUR losses have been made (Elliot and others) for infill wells when primary wells do not receive dynamic pressure restoration treatments to mitigate the generation of asymmetric fracs. Where consistent recovery factors are observed for “best practices” wells this metric can then be applied to all wells independent of offset production using the estimated oil in place. This eliminates the need to use offset well production for the base case type curve EURs as the offset analog wells used to generate the type curves may not have been completed using current “best practices.” The use of the recovery factor technique there should provide a better estimate of the economic value to the drilling

spacing unit (DSU) of proper dynamic pressure restoration treatments for primary wells when they are fully protected from offset infill well fracture driven interactions. It can also be used to determine the effectiveness of “preload” treatments that do not fully restore the original in-situ stress conditions in the primary wells. The recovery factor method can provide a vehicle for performance comparison among various forms of intra-stage diversion such as XLE, diverter, and engineered completions. The refrac economic analysis will include detailed completion cost estimates assuming extreme limited entry fracs through expandable liners which should provide the most consistent recovery factors at the lowest overall cost (Barba and Villarreal 2019). This should maximize the probability that refrac treatments will become mainstream in the operators capital allocation process when all of the economic benefits are considered. Once the process can be consistently applied with economic results the potential to book PV20 behind pipe reserves becomes a reality and that will provide a major economic benefit for the right price (zero except for the cost of the reserve audit). In this low price environment operators need to use all of the available tools out there to survive and refracs should be strongly considered to be part of their tool kit.

Introduction

The study involved the analysis of 196 producing wells and 36 openhole vertical well logs. Individual well production data was provided by the operators and allocation of lease production was thus not necessary. The primary finding from the study is that close cluster spacing wells with high proppant and fluid loadings have relatively consistent recovery factors just below that which is observed in solution gas drive reservoirs (P50 of 13.7% from the study vs 15% for conventional matrix permeability reservoirs) (Fig 1).

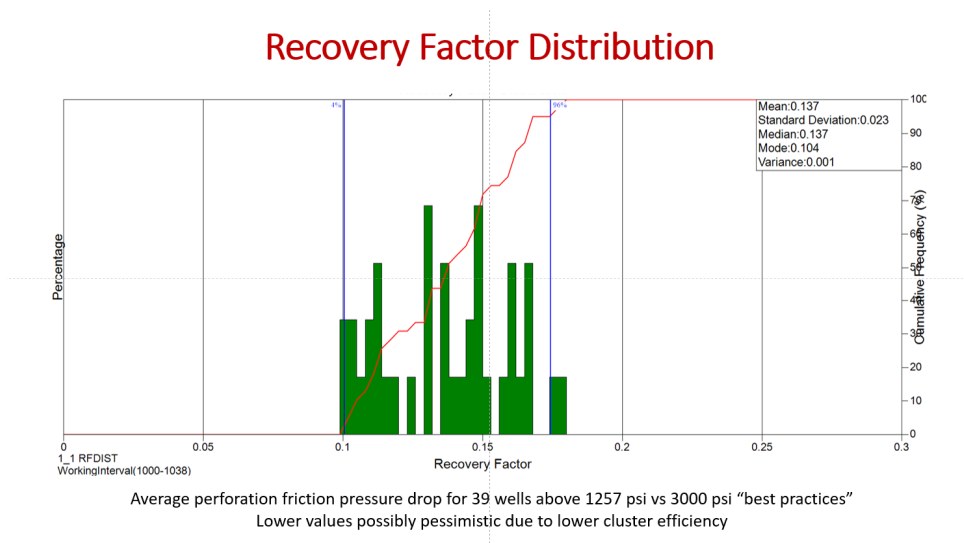


Figure 1 Distribution of the 39 wells used in the model calibration

With clusters less than 20 ft apart the SRVs are approaching a continuous permeability network that emulates the matrix in conventional reservoirs. The second is the importance of in-situ stress layers above and below the lateral with respect to producing heights. When producing heights are clear the recovery factors for close cluster spacing wells is very consistent. Only

wells with clear producing heights were used in the estimation of recovery factors, there were 49 of the 196 wells that were used for the recovery factor statistics and 39 of those with close cluster spacings for model calibration. An example of a well with a clear producing height can be seen in Fig 2. The upper and lower extent of the producing height is clearly defined by the thick tight carbonate streaks.

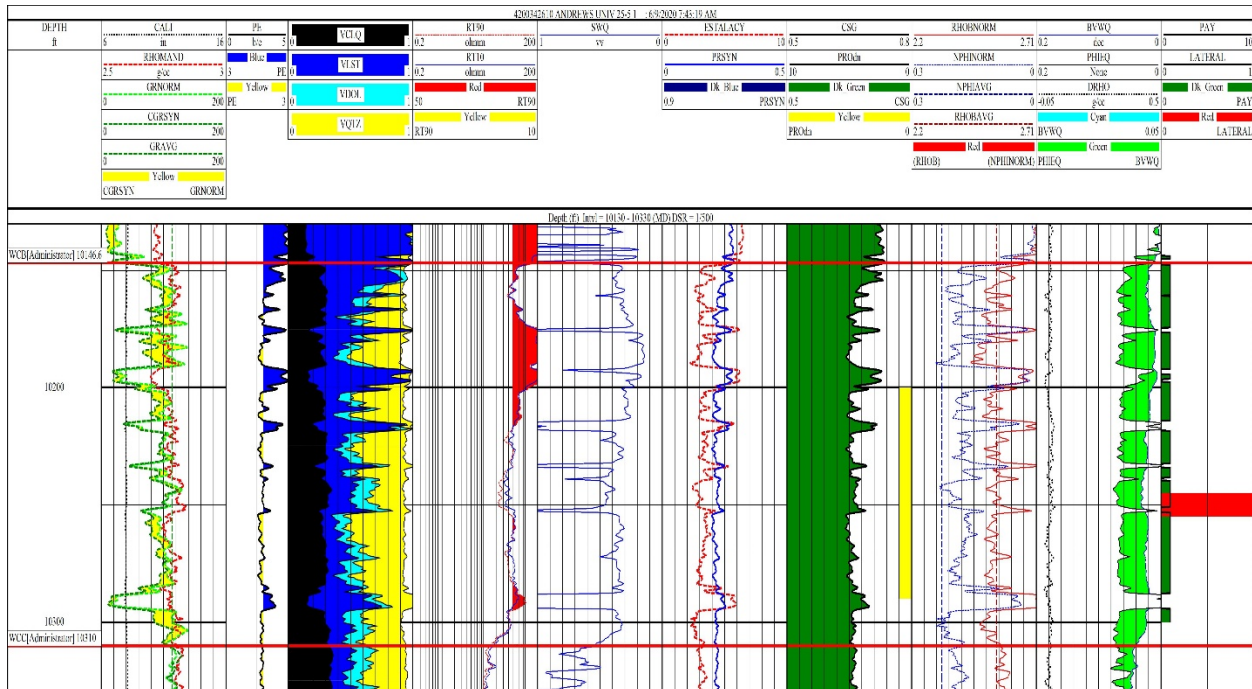


Figure 2 Stress Barriers vs Drainage Height

All wells with less than 20 ft cluster spacing were reviewed for data quality to calibrate the model. Wells with over 20 ft cluster spacing were evaluated as well and 10 wells with good quality data and larger spacings were used for the refrac economic analysis case study. A preliminary analysis of the remaining wells in the database suggested that wells with over 40 ft cluster spacing had the highest refrac potential and 39% of the wells in the Southern dataset had over 40 ft spacing. The average recovery factor for the 10 well sample of over 40 ft spacing wells was 4.6% or 33% of the new well expected recovery factor. The average cluster spacing for the refrac candidates in the 10 well sample was 56 ft.

To meet the second objective of facilitating production comparisons between infill and primary wells the P50 recovery factor can be used in lieu of offset production declines where completions may or may not have been optimized. The largest area for improvement observed in the close cluster spacing calibration dataset was in the diversion process where average perforation pressure drops were generally lower than the current “best practice” of 2500 to 3000 psi (Haustveit et al 2020 and Murphree et al 2020). The average pressure drop observed in the 39 well calibration dataset was 1257 psi. In defense of the operators the most recent study on limited entry prior to the 2018 work done by Liberty Resources suggested 600 to 700 psi pressure drops were adequate for diversion (Wutherich and Walker 2012). If the production loss in an offset infill well is calculated from a wells with low cluster efficiency from inadequate

diversion the comparison may not be valid. The relatively low delta p from the dataset could also explain some of the scatter in the recovery factor data with the lower values possibly having lower cluster efficiency. The proximity of the P50 value to a widely accepted recovery factor for solution gas drive reservoirs suggests the 13.7% value should be reasonable for these comparisons. In theory if there are no gaps in the SRV the value should be close to 15% since the fracs create permeability and flow is limited outside the SRV. In one case in the Eagle Ford where the cluster spacing was reduced to the 7.5 ft per cluster drainage width (Fig 3) indicated by an offset pressure monitoring well (White 2018) the operator resumed 15 ft spacing subsequent to the 7.5 ft cluster spacing test.

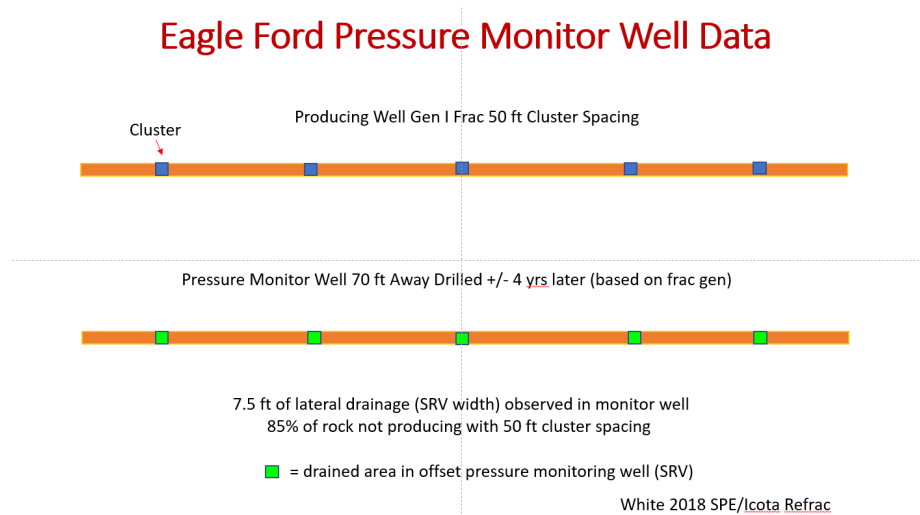


Figure 3 Eagle Ford Drainage Width from Pressure Gauge Data

100% SRV coverage of the wellbore (emulating a 15% recovery factor matrix perm conventional rock) may not be possible unless clusters are spaced closer than is practical and hence the lower than 15% value is supported by this anecdotal data. Additional support for this is provided by Xiong et al (2020) where simulations indicated the theoretical maximum recovery factor with 10 ft spacing to be 13.5%. The green dot of Fig 4 indicates the study results for close cluster spacing wells (13.7%) and the red dot is the 4.6% value obtained from the 10 well sample with over 20 ft spacing (56 ft average). Both are very close to the values predicted by the comprehensive simulation work done by Xiong Et al.

Wolfcamp Recovery Factor vs Cluster Spacing



Fig. 10—Recovery efficiency based upon the dual-porosity model at the end of year 30.

Xiong SPE 199721 2020 HFTC

Figure 4 Recovery Factor vs Cluster Spacing with Field Data Points

Methodology Employed

The basic work flow involved estimating the original oil in place for the estimated drainage height and width and comparing that to the EUR from decline curve analysis. Once the OIP is determined and a consistent relationship between close cluster spaced optimized well production and OIP for the assumed drainage area is established the upside for a refrac can be estimated from the difference between the 13.7% P50 EUR and the current cumulative production can be determined. This volume we are calling “refrac EUR” is then converted to a monthly decline using offset type curve monthly decline rates. In the spreadsheet the IP is varied using the goal seek function until the 25 year cumulative production agrees with the refrac EUR. The cost of the refrac is calculated using an optimized close cluster spacing completion, 15 ft cluster spacing in the Permian with a 6 BPM rate per cluster and 3000 psi pressure drop across single perforation clusters. The 6 BPM rate should be validated with P3D frac modeling but in most cases the producing height may not change significantly with rates higher than 6 BPM. The optimization issue is critical as the model requires consistently high cluster efficiency to provide predictable results. If XLE is not used all bets are off with regard to forecasting well performance. The additional benefit XLE provides is the lower cost completion out of all of the possible perforating strategies. Phased perforating with more than one hole per cluster and pumping more than 6 BPM per cluster can significantly increase the completion cost with minimal benefit unless the P3D frac modeling indicates a sub-optimal frac without higher net pressures. If increased net pressure is shown to be needed after modeling the frac it is recommended initially to increase fluid viscosities with HVFR before going to a higher rate. Single cluster simulations at 6 BPM should be run first to determine vertical coverage and if increases in rate do not increase the vertical coverage the lower rate will be more cost effective. With a properly designed XLE treatment the single cluster simulations should be realistic as fluid entry is relatively uniform into all clusters (Haustveit 2020). The single hole per cluster should create a single fracture with the minimum possible near wellbore friction providing the maximum possible energy into each cluster. Total rate is maximized by using expandable liners to isolate

the existing perforations and net pressure is maximized with the use of HVFR. In the 10 well case study the optimized completion AFEs were 25% lower than the actual frac costs obtained from the University Lands database for recent close cluster fracs primarily due to the use of XLE. The 15 ft clusters with 6 BPM had 14 single hole perf clusters (210 ft) while operators in the area using +/-15 ft cluster spacing are limiting their cluster count to 10 per stage. There is no reason to reduce the number of clusters with XLE, Murphree et al with SM Energy (2020) showed with fiber optic warmback data that stage lengths could be increased 25% with no decrease in cluster efficiency. In the area SM operates many “optimized” treatments use ten 15 ft clusters and the 25% increase would most likely have been from 150 ft to 187.5 ft, however as long as a 3000 psi pressure drop with 6 BPM/cluster is achieved there is no physical limit on stage lengths. Weddle et al (2018) reports that their Bakken completions typically have 350 ft stage lengths with 15 clusters and one of their senior executives related in 2020 that 500 ft stages have been successfully tested as well.

EUR Estimation Process

The availability of individual well declines to estimate EURS was a key ingredient for the study as the majority of the time studies done by consultants and service companies use public data which is on a lease basis for Texas oil wells. In some cases leases contain a large number of wells and only sporadic annual tests are available to make the allocation. While data vendors insist that the allocated data is useful Fig. 5 suggests it is not.

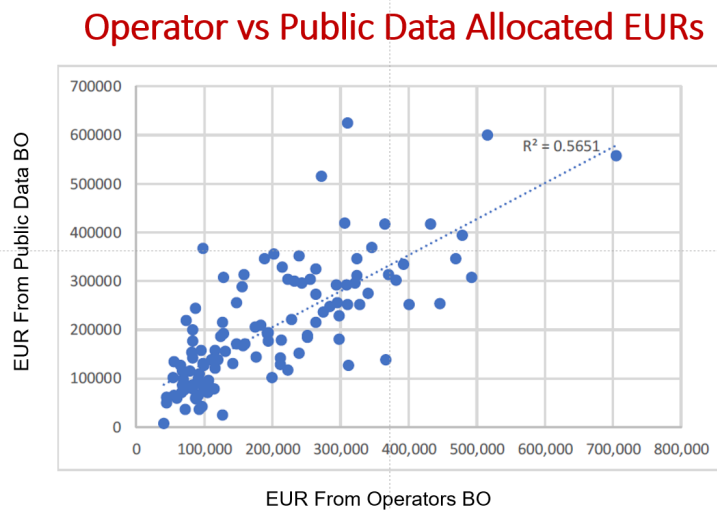


Figure 5 Public Data EURs vs Operator EURS

The plot presented compares the operator provided data to allocated production data from a major data vendor. The best that can be said about allocated production is that sometimes it can be in agreement with the measured. Of course the same can be said for a broken watch which agrees with the correct time twice a day. In many cases the disagreement can be off by a factor

of three. The quality of the allocated public data is not adequate to estimate recovery factors to the degree of accuracy required. This limits the effectiveness of recovery factor studies using public data and most operators do not share internal studies for competitive purposes. The EURs are typically estimated using decline curve analysis and an appropriate model. Arps is typically used if adequate producing time is available and Duong is used for shorter time frames. A 25 year time frame is used for the forecast.

OIP Estimation Process

The two areas studied were in the Central and Southern Midland basin. The study involved gathering all of the available openhole log data surrounding the producing wells and estimating original oil in place for each geological bench. The results for each bench were used to determine if there were any trends in pay quality across the study area to be able to extrapolate the OIP estimates between petrophysical control points. The basic OIP estimation process is described in detail by Barba (2015), with the major differences being the height estimation and the drainage area assumption. In the 2015 study the producing heights were assumed to be +/- 100 ft above the 55 ft propped heights or a constant 150 ft (Barba 2015) and the drainage assumed a 7500 ft lateral drained 160 acres. In this study the heights were estimated from the rock properties log and P3D frac model simulations and the drainage width was assumed to be 660 ft. The 330 ft half length for the drainage was based on the Rate Transient Analysis work done by Xiong et al (2019). Anecdotally operators have seen a +/-15% reduction between EURs of 880 ft spaced wells and 660 ft spaced wells so the 660 ft width may be conservative in terms of expected production. It is possible that there were well interference issues with this comparison and the operator that related the comparison was not using XLE which provides a uniform SRV across the stage minimizing interwell interference between the current 880 ft spaced wells in the area (Haustveit 2020). For this exercise a key issue is consistency and the 330 ft length should be a reasonable assumption across the board. The agreement between the study results and the work done by Xiong et al (2020) suggests that the drainage area assumption is probably reasonable.

Rock Properties Analysis and Producing Height Estimation

The landing zones were correlated using operator provided data combined with high resolution structure maps to address the lack of accurate tops in the horizontal producers. Public data was used initially however numerous disagreements between the operator landing horizons and the public data resulted in the exclusive use of operator provided data. The producing height was estimated from the relationship between the lateral and the rock properties from triple combo log data tied to dipole sonic data. Barba and Meyer (1993) described the process for the Spraberry trend in-situ stress and 3D frac modeling. The basic process involves correlation high coherence (>90%) Poisson's ratio data from the dipole sonic with triple combo inputs with the result being a 2 ft bed resolution in-situ stress profile. In cases where the stress layers were not clear the height was not estimated. In no case was the entire bench stimulated, case in point is the well presented in Fig. 2. The operator was using the OIP for the bench (Wolfcamp B in this case) for an estimate of the expected production and the actual results were about half of the expected recovery from the petrophysical analysis. The Wolfcamp B in that area was 159 feet thick,

however the stress barriers limited the producing height to 90 ft. The petrophysical estimate of OIP was reasonable for the actual producing height but not for the bench as a whole which the operator was mapping.

The key deliverable to provide a benchmark for expected performance from completions with close cluster spacing and high proppant and fluid loadings. In the 196 well dataset there were 90 wells with close cluster spacing analyzed and 49 had clearly defined stress layers. An example of a well with well defined stress layers is shown as Figure 2. A distribution of the producing heights is shown in Figure 5. There were several wells (primarily Lower Spraberry shale) where there were no significant stress layers in the proximity of the lateral. If a 200 ft producing height was assumed these wells had recovery factors in the 13-14% range possibly validating that as a maximum possible drainage height.

Producing Height Comparison Permian Wolfcamp

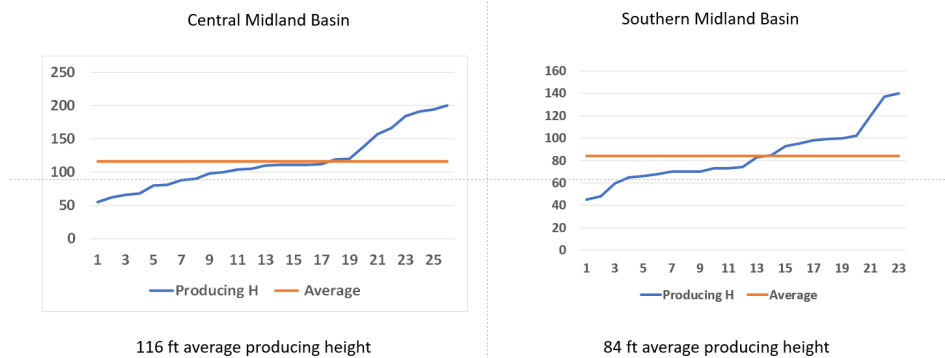


Figure 6 Producing Height Distribution

There were no true shale barriers in any of the wells, in all cases the confining layers were tight carbonates. Going forward it is recommended that either the simple single cluster modeling of a single fracture be done to estimate the height or possibly a more sophisticated multi cluster model to incorporate stress shadowing effects on fracture height. The rock properties log for one of the refrac candidates is shown in Fig. 7. Examples of the single cluster MFRAC model runs for that well are shown in Figs. 8 through 10.

Well 9 MFRAC 9 BPM/Cluster Slickwater

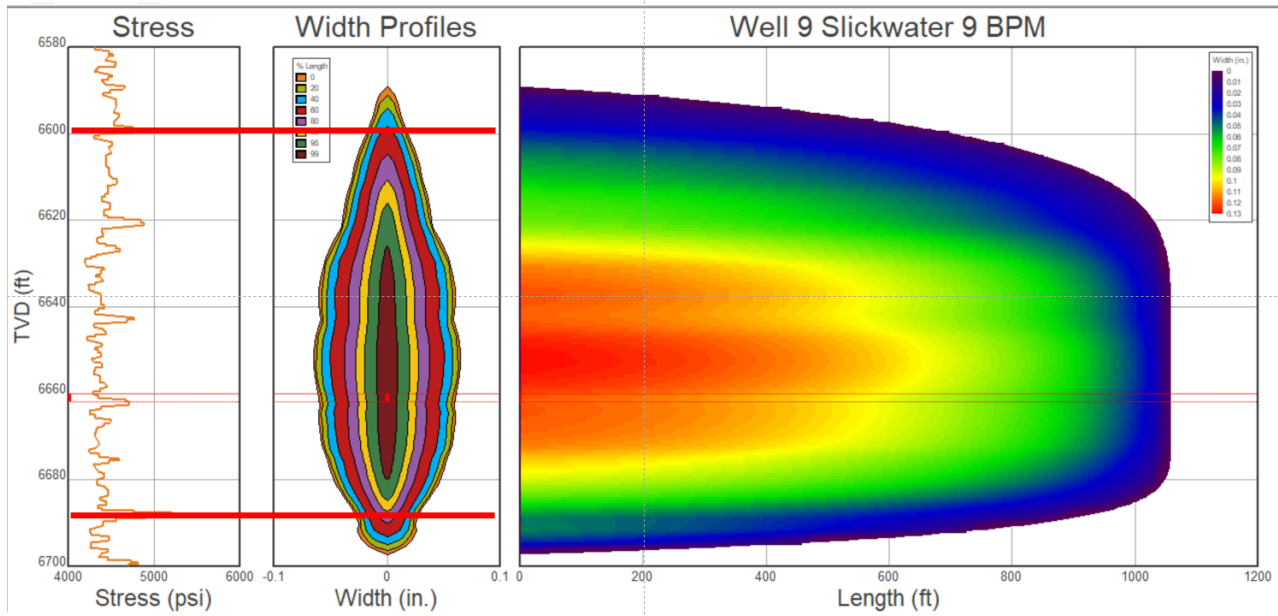


Figure 9 9 BPM Run with 1cp Slickwater

Well 9 MFRAC 9 BPM /Cluster 12 cp HVFR

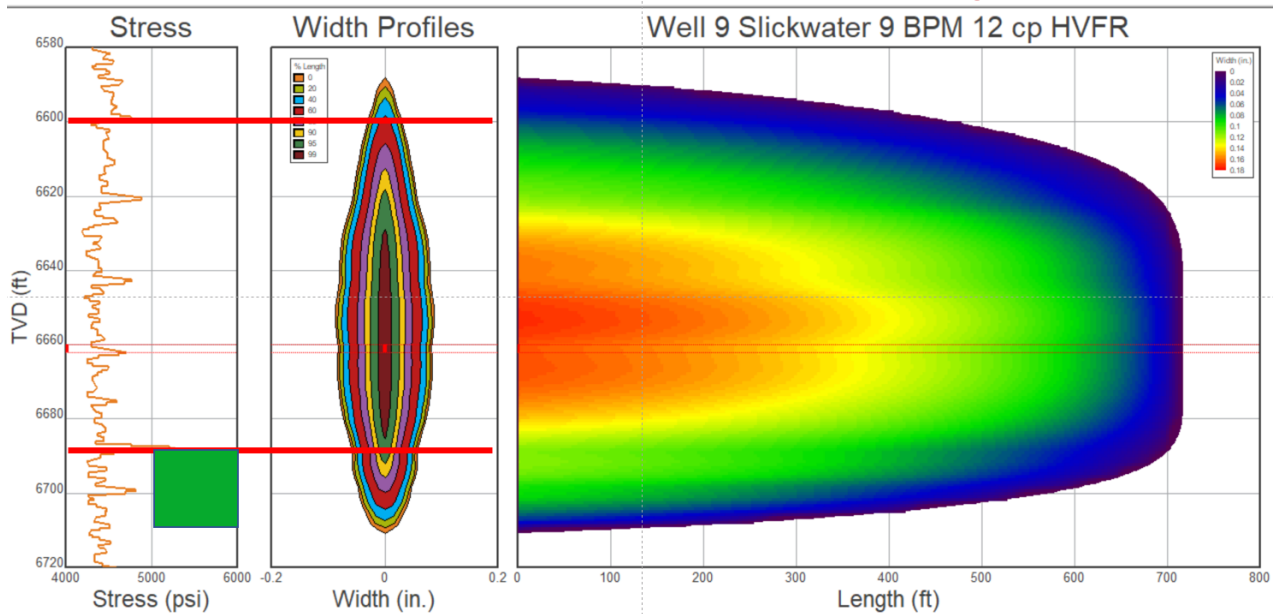


Figure 10 9 BPM Run with 12 cp HVFR

The rate per cluster was increased from 6 to 9 BPM with 1cp slickwater and the height did not change significantly. As mentioned earlier if additional net pressure is needed to access more drainage height HVFR should be modeled with the 6 BPM rate to determine if the net pressure increase is adequate at the lower rate (Fig. 10). The similarity in created heights between the 6

BPM simulation and the 9 BPM simulation lends credence to the 6 BPM rate being adequate in this particular case. Further validation of the 6 BPM rate is the experience with the WellsX frac system that pumps fly ash with fresh or KCL water with a single C&A unit pump truck (Barba 2018). Fracture driven interactions have been observed over 1000 ft away in the Olmos formation and post frac fluid rates have been as high as 400 BPD. The FDI's were slightly offset from the maximum principal stress azimuth as there was a major well mapped fault in the field suggesting that a complex fracture network was obtained with the thin gel free fluid. Production results have been very good in most cases suggesting a conductive fracture network was created with the fly ash. The discovery well for the process was a Bakken well where a cemented liner was being run into a previous openhole completion. The operator was unable to get the cement to set and thought the treatment was a failure. Subsequent to the failed attempt the well was opened up and it turned out to be one of the better producers in the area. The theory is that even when fracing with essentially cement (fly ash is a major component) the cracks plug off initially then a small diameter "ullage" is created at the top of the crack with infinite conductivity. 42 wells have been fraced with the system to date and results have typically been positive. With the trend toward more 100 mesh and microproppant there may be some similarities between the WellsX treatments and organic shale fracturing with regard to the plugging mechanism and creation of the highly conductive ullage above the proppant pack. All treatments have been pumped at a maximum of 6 BPM since only a single pump truck is used and to date none of the treatments have screened out. It is a testament to the 6 BPM rate per cluster recommended for organic shales probably being adequate to create a highly conductive complex fracture network. This allows for stage lengths to be increased when using XLE with the number of clusters determined primarily by the total pump rate divided by the 6 BPM number. The pressure drop can be controlled by the hole diameter, typically 0.45 to 0.50 single entry holes per cluster will provide the 3000 psi pressure drop when the math is done.

Estimate monthly production decline from incremental oil/gas and type curve

The OIP per acre value is multiplied by the P50 recovery factor of 13.7% and the cumulative production from the refrac candidate is subtracted from that value to obtain a refrac EUR. This value is entered into a spreadsheet that has a % decline by month table obtained from a multiwell type curve for Wolfcamp recent completions with optimized treatments. The IP is varied using the Excel "Goal Seek" function until the 25 year cumulative production agrees with the refrac EUR. Gas production is accounted for with a GOR input. When the wells are above the bubble point the GORs tend to be fairly consistent and a constant multiplier can be applied to the oil production. In some of the Southern wells the GOR increased over time and in those cases a separate decline for the gas production was needed.

Analyze economics of refrac using the current NYMEX price strip and "best practices" completion

The economic analysis spreadsheet used to calculate the refrac expected decline curve requires a cost input, and a key part of that is determining the number of stages required. With a 5.5 inch liner original completion with a 4.1 inch ID expandable liner in the study area an 85 BPM pump rate is possible. Barba and Villarreal (2019) presented a comparison between mechanical isolation methods and makes a strong case for the use of expandables vs 3.5 inch upset or 4 inch

flush joint cemented liners. The expandables will be higher cost on the front end artificially raising the AFE by \$120,000 for a 7500 ft liner over the cost of a 3.5 inch cemented liner. With the combination of the expandable and XLE, however, the total stage count can be significantly reduced over the cemented liners that cannot achieve the 85 BPM rate. In the study are 10 refrac candidates were analyzed and well costs were obtained from the University Lands public database. The operators in the area were using 15 ft spacing and 10 clusters per stage with 40 holes ranging from 0.36 inches to 0.40 inches. At the typical frac rates the pressure drop across the perfs averaged 1257 psi. The AFE for the close cluster spacing recent wells with 150 ft stage spacing averaged \$3.965 million in comparison to a 37 stage 210 ft stage spaced XLE frac for \$3.271 million (18% lower). The AFEs were from Q4 2017 and Q1 2018 when proppant prices were 3x current prices and water costs 2x current prices and overall prices were approximately 15% higher than the present time. Anecdotally one operator that participated in a recent webinar where refrac costs were discussed (post price crash) indicated their frac costs in 2019 were historically in the \$4.5 million range and they questioned our +/- \$3 million preliminary estimate. The \$3 million estimate assumed that under the current depressed service market the historical Q4 2017-Q1 2018 cost used (\$3.5 million) would be 15% lower. A key part of this comparison is the much shorter stage lengths the operator was employing than we were recommending with XLE. A review of the operators completion reports for the area in the University Lands database indicated they had 50 stages for a 7325 ft lateral for a 146.5 ft stage spacing. With an optimized completion using XLE and 210 ft stage spacing the stage count can be reduced to 35 or 15 fewer stages. With an estimated variable stage cost of \$59,000 the \$4.5 million AFE would be reduced to \$3.6 million. These numbers are for a new completions, for a refrac the cost of the liner (\$80/ft) needs to be added to the AFE for the economic analysis.

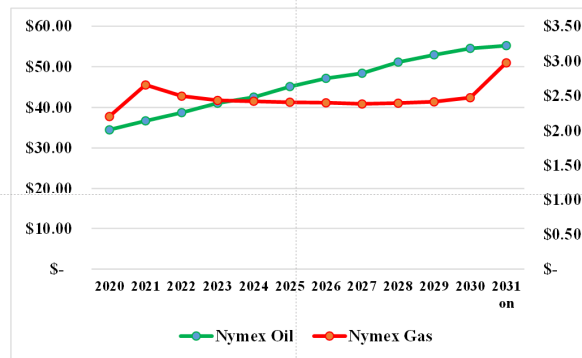
A common concern that this highlights is the observation that the industry has been going to shorter and shorter stage lengths and that shorter stage length is mistakenly assumed to be a “best practice” in itself. That is not the case provided the XLE technique is properly applied (Murphree et al 2020). In that study done by SM Energy in the NE Midland Basin they showed with fiber optic data that increases of 25% in stage length with XLE employed resulted in the same or higher cluster efficiency than shorter stages. They also independently confirmed the work of Haustveit et al (2020) that suggested the 2000 psi guideline originally proposed by Weddle et al (2018) for the Bakken needed to be increased to 3000 psi for the Permian organic shales. They also found that using intrastage diverter was not as effective as XLE in maximizing cluster efficiency. If XLE is not employed and phased perforating is used for each cluster shorter stages are needed to maximize cluster efficiency. The current “best practice” recommended is to use XLE with a single hole per cluster. XLE pressure drop calculations suggest the optimum diameter is in the 0.45 to 0.5 inch range.

Case study refrac candidate analysis Southern Midland Basin

10 wells with cluster spacings over 40 ft (average 56 ft) with reliable producing height estimates were evaluated. The producing height was estimated from the rock properties log and an original OIP was calculated for the interval. The cumulative production from the well was compared to the 13.7% recovery factor estimate to obtain a refrac EUR. The refrac cost was estimated from historical completions with close cluster spacings and adjusted to reflect the

historical cost with an optimized XLE refrac (210 ft stages). An adjustment was made to the pre-March 2020 cost based on recent market conditions. NYMEX pricing was input using the May 24, 2020 closing price for the strip (Fig. 11). Using the economic spreadsheet that allocates the refrac EUR over the 25 year period a net present value and internal rate of return was calculated for the refracs. Figure 12 has the AFE details for each candidate, and Table 1 has a summary of the results. Of the ten wells in the study seven have rates of return over 25% and are refrac candidates. The total cost for the seven well program would be \$20,518,090 and the NPV10 per well for the program ranges from \$1.9 million to \$8 million with a total NPV10 of \$26,095,768. All seven candidates should be economic on a PV10 basis for the value of the expected production. Offset refrac candidates with identical refrac EURs and costs can be valued on a PV20 basis if the guidelines in the next section are met. If all seven can be refracted successfully and economically the PV20 analysis can value the behind pipe asset value. The average PV20 for the 7 wells expected production is \$1,774,347 per well and that can be realized once the 7 well program is completed for every economic offset in the entire field.

NYMEX Strip Used in Economic Analysis



	5/24/2020	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031 on
Nymex Oil	\$ 34.50	\$ 36.69	\$ 38.71	\$ 41.04	\$ 42.52	\$ 45.11	\$ 47.15	\$48.41	\$51.15	\$52.95	\$ 54.54	55.205	
Nymex Gas	\$ 2.20	\$ 2.66	\$ 2.50	\$ 2.43	\$ 2.42	\$ 2.41	\$ 2.40	\$ 2.38	\$ 2.39	\$ 2.41	\$ 2.47	2.9745	

Figure 11 NYMEX Strip Used for Economic Analysis

Well	TVD	Lat	210 ft Stages	Prop lb	water bbl	\$ 0.0291 prop S	\$ 0.40 Water Cost	CT DO	Frac Fixed	Total Fixed	Variable/stg	Variable total	Subtotal	\$80 Liner	Total Refrac
1	6,715	7,691	37	19,227,500	461,460	\$ 559,520	\$ 184,584	\$105,400	\$ 68,850	\$ 918,354	\$35,134	\$1,286,736	\$2,205,090	\$615,280	\$ 2,820,370
2	6,912	8,130	39	20,325,000	487,800	\$ 591,458	\$ 195,120	\$105,400	\$ 68,850	\$ 960,828	\$35,134	\$1,360,183	\$2,321,010	\$650,400	\$ 2,971,410
3	6,927	7,976	38	19,940,000	478,560	\$ 580,254	\$ 191,424	\$105,400	\$ 68,850	\$ 945,928	\$35,134	\$1,334,418	\$2,280,346	\$638,080	\$ 2,918,426
4	6,979	7,970	38	19,925,000	478,200	\$ 579,818	\$ 191,280	\$105,400	\$ 68,850	\$ 945,348	\$35,134	\$1,333,414	\$2,278,761	\$637,600	\$ 2,916,361
5	6,632	8,226	39	20,565,000	493,560	\$ 598,442	\$ 197,424	\$105,400	\$ 68,850	\$ 970,116	\$35,134	\$1,376,244	\$2,346,359	\$658,080	\$ 3,004,439
6	6,917	8,128	39	20,320,000	487,680	\$ 591,312	\$ 195,072	\$105,400	\$ 68,850	\$ 960,634	\$35,134	\$1,359,848	\$2,320,482	\$650,240	\$ 2,970,722
7	6827	7,599	36	18,997,500	455,940	\$ 552,827	\$ 182,376	\$105,400	\$ 68,850	\$ 909,453	\$35,134	\$1,271,344	\$2,180,797	\$607,920	\$ 2,788,717
8	6,676	7,350	35	18,375,000	441,000	\$ 534,713	\$ 176,400	\$105,400	\$ 68,850	\$ 885,363	\$35,134	\$1,229,685	\$2,115,048	\$588,000	\$ 2,703,048
9	8,264	8,626	41	21,565,000	517,560	\$ 627,542	\$ 207,024	\$105,400	\$ 68,850	\$1,008,816	\$35,134	\$1,443,165	\$2,451,981	\$690,080	\$ 3,142,061
10	6,808	8,192	39	20,480,000	491,520	\$ 595,968	\$ 196,608	\$105,400	\$ 68,850	\$ 966,826	\$35,134	\$1,370,555	\$2,337,381	\$655,360	\$ 2,992,741
			38	19,972,000	479,328	\$ 581,185	\$ 191,731	\$105,400	\$ 68,850	\$ 947,166	\$ 35,134	\$ 1,336,559	\$2,283,726	\$639,104	\$ 2,922,830

Table 1 AFE Details 10 Refrac Candidates

Economic Analysis 10 Refrac Candidates

Well No	Original RF	Refrac EUR	AFE Refrac	Refrac IRR	Refrac NPV10	Refrac PUD NPV20	Current BOPD	PV10 PDP	Refrac IP BOPD
1	4.8%	126,805	\$2,820,370	12%	\$287,447	Negative	7.03	\$242,629	153
2	9.3%	157,147	\$2,971,410	18%	\$964,712	Negative	8.9	\$401,288	190
3	3.7%	166,552	\$2,918,426	21%	\$1,274,443	\$61,882	5.21	\$88,213	201
4	5.5%	189,449	\$2,916,361	26%	\$1,901,501	\$497,607	3.83	\$0	229
5	4.5%	196,476	\$3,004,439	27%	\$2,005,323	\$542,575	3.38	\$0	237
6	3.7%	200,352	\$2,970,722	28%	\$2,144,851	\$649,697	3.72	\$0	242
7	5.3%	216,582	\$2,788,717	36%	\$2,769,918	\$1,139,069	0.45	\$0	262
8	3.3%	225,824	\$2,703,048	40%	\$3,107,884	\$1,399,765	4.45	\$23,731	273
9	3.6%	355,591	\$3,142,061	66%	\$6,198,876	\$3,413,448	17.86	\$1,161,494	429
10	2.3%	422,571	\$2,992,741	91%	\$7,967,413	\$4,778,265	4.62	\$38,154	510
Average	4.0%	258,121	\$ 2,931,156	44.9%	\$ 3,727,967	\$ 1,774,347	5.5	\$ 174,768	311.6
Total		1,806,845	\$20,518,090		\$ 26,095,768	\$ 12,420,427	38.3	\$ 1,223,379	2,181

Table 1 Economic Analysis Summary

Additional economic considerations

Refracs should be analyzed using three main objectives. The first is can the production be economic at the current price deck using current costs which was discussed in the previous section. A PV10 or IRR target can be set and if the refrac exceeds the economic criteria it should be a good candidate. A second objective is the elimination of infill well asymmetric fracs from primary well pressure depletion (Elliot et al 2019). Until the recent pricing crash the primary-infill considerations alone justified the refrac even if it had a low net present value from the expected production. With many operators suspending pad operations for the near future the refrac needs to provide a positive economic benefit as a stand alone entity. A third benefit exists, though, with the ability to book behind pipe reserves for economic refrac candidates (Holroyd 2015). The first criteria proposed by Holroyd (with Denham Capital at the time of the study) is there should be a clear indication that the reserves added were incremental and not an acceleration of existing production. The second criteria is to establish a reasonable certainty that the refrac operation would be mechanically and economically successful. The third and final criteria is the operator needs to generate a large enough number of successful refracs to establish confidence in the process (assumed to be 5 to 6 based on analog derisking situations). Until the majority of the industry made the transition from “pump and pray” diverter only refracs to mechanical isolation (2016-17 time frame) the second criteria was rarely met due to the highly inconsistent results with diverters. With mechanical isolation the success rate of refracs has increased significantly and there is now a reasonable certainty that the refrac will be successful assuming the candidate selection process is properly done. The entire 10 well sample in the previous section was only producing 59 BOPD with a range from 0.5 BOPD to 18 BOPD. Acceleration of recovery (first criteria) should not be an issue with those low numbers. The PV10 of the production is very low, with most of the wells barely producing enough to cover lease operating expenses. The total PV10 for the current production from the seven wells is \$1,223,379. Post refrac expected production is another story altogether since it is not a function of the current producing rate, it is driven by the large volumes of unstimulated rock from the initial completion’s wide cluster spacing. The current industry practice is to value PUD reserves on a NPV20 basis, and with this applied the average NPV20 for the seven wells is \$1,774,347 even at the current depressed NYMEX strip. This is in comparison to the total economic value

of the current production for all seven wells of \$1,223,379. The total NPV20 for all seven wells is \$12,420,427.

The potential gain in asset value here is enormous as once the process is derisked every economic refrac candidate has an asset value that is no longer tied to current production. In the case of one of the operators whose wells we are using in the case study there are close to 150 wells with over 40 ft cluster spacing that would be screened for refrac economics. If only half of the wells are candidates the potential PV20 value of behind pipe reserves following the 7 well derisking program (AFE \$ \$20,518,090) would be \$133,076,025. If the PV10 of the production from the seven well program is added the total value to the operator after the program is successfully completed is \$159,171,793. After the seven wells are completed the only incremental cost involved to monetize the \$133,076,025 would be the cost of obtaining a third party reserve certification. Total return on the \$20.5 million refrac program would be 7.75 to 1. In a time where prices are depressed this is truly “money for nothing” as the song goes. This feature of a successful refrac program puts the returns far above that from a 7 well program drilling and completing new wells as no new PUDs will be generated by the new wells.

Conclusions

The key finding of the study is that close cluster spacing wells with optimized completions in the Permian Basin organic shales should have recovery factors close to that observed in conventional solution gas drive reservoirs (13.7% P50 vs 15% for conventional solution gas drive reservoirs). The optimization process is critical to maximizing this number and the use of XLE is mandatory to maximize cluster efficiency and the SRV. With low product prices the cost needs to be minimized at the same time which can be achieved with XLE and expandable liners (Barba and Villarreal 2019). The work flow is fairly straightforward starting with the estimation of oil in place for the expected producing height. The 13.7% number can then be applied to the OIP to obtain a refrac EUR. The EUR is allocated over a 25 year period using a type decline for the area to provide monthly production numbers for economic analysis. In the case study presented there were 7 economic candidates out of the 10 well sample analyzed, the PV10s varied from \$497,607 to \$4,778,265 and the IRRs ranged from 26% to 91%. The \$20,518,090 million expected AFE should generate a NPV10 of \$26,095,768. The biggest potential financial gain is from the potential certification of the behind pipe reserves in the offset wells, though. If only half of one operators 150 wells with over 40 ft cluster spacing are booked the present value added (20%) for the behind pipe refrac candidates is \$133,076,025 for virtually no additional cost. In a low price environment this option should be especially attractive given the limited capital budgets for all oil and gas operators as it can significantly multiply the value of a field once refracs are shown to be derisked and consistent economic results can be obtained. Refracs have the ability to add significant value to an enterprise if solid economic candidates can be identified with the recovery factor process and if they are executed using “best practices.” With the combination of candidate selection, XLE, and expandable liners it is just a matter of time before refracs become a routine part of the capital allocation process for operators across the board.

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