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

URTeC 2662

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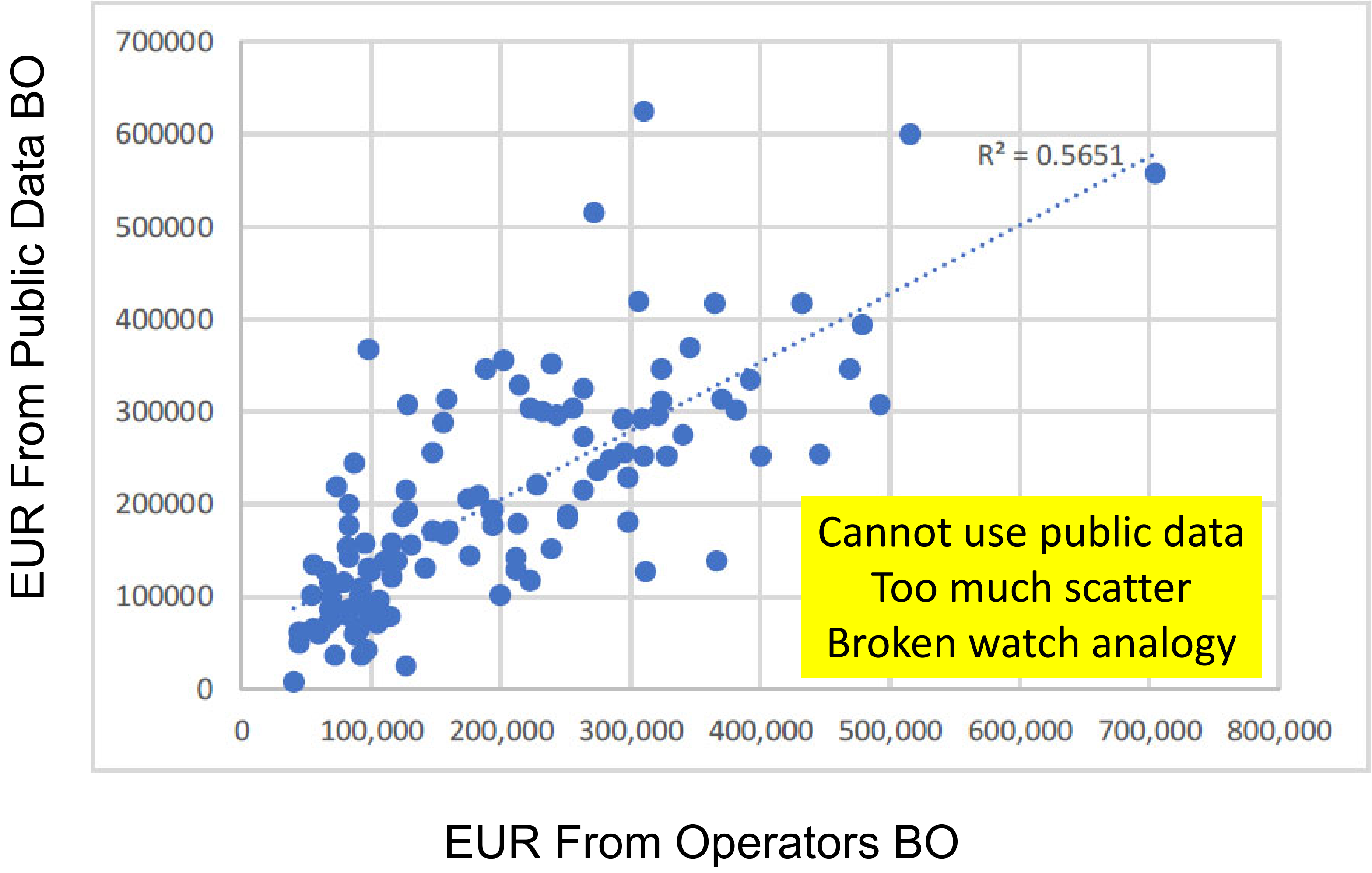
Executive Summary

- The purpose of this study is to estimate recovery factors for refrac candidates using the current “best practices” refrac designs using operator provided individual well production
- The basic process is to analyze recent completions with close cluster spacing high proppant and fluid loading wells to determine the expected production increase from an optimized refrac treatment
- The study involved the analysis of 196 producing wells and 36 openhole vertical well logs from the Midland Basin
  - 39 of the 196 wells had clear producing heights and close cluster spacing and were used to estimate the “best practices” average RF
- Individual well production data was provided by the operators and allocation of lease production was thus not necessary.

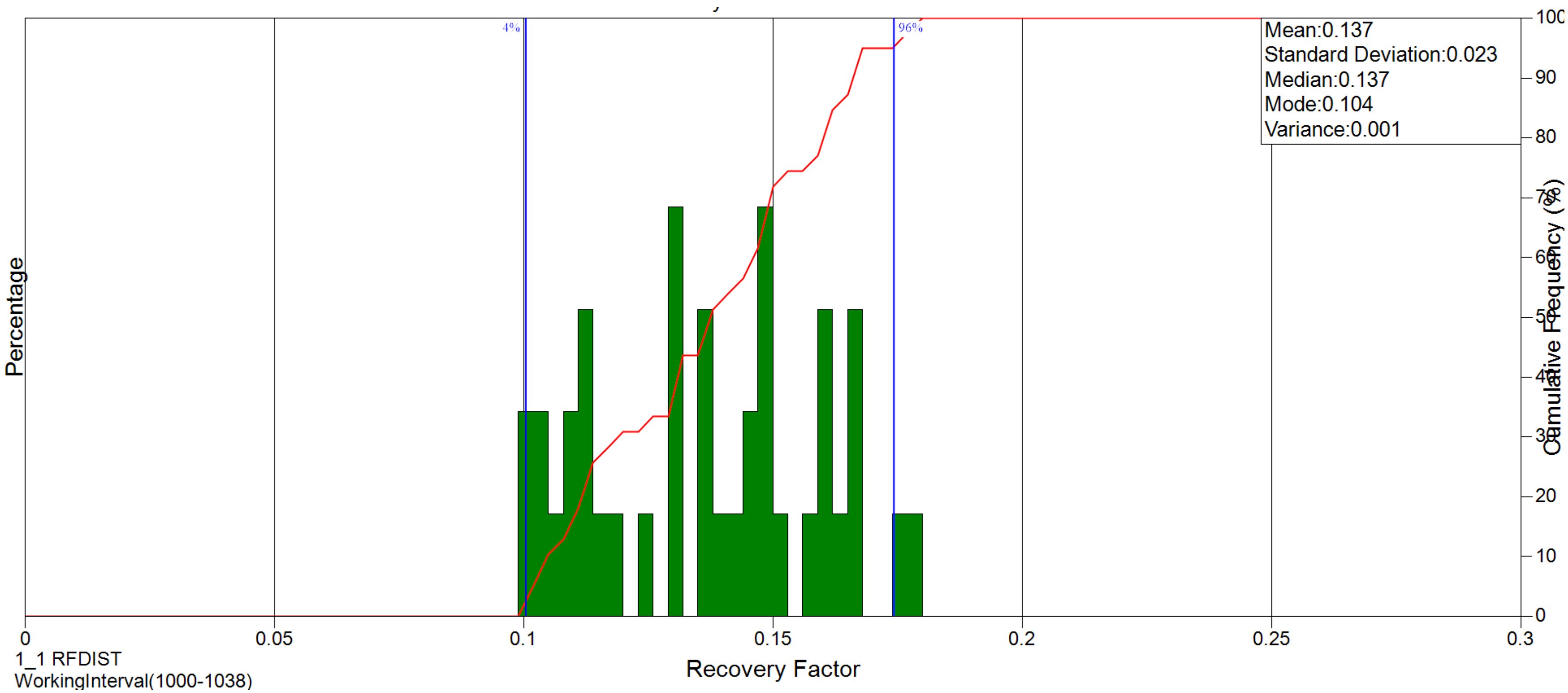
Operator vs Public Data Allocated EURs



Executive Summary

- 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 oil reservoirs
  - The P50 recovery factor of 13.7% is just below the generally accepted value of 15% for conventional matrix permeability reservoirs
- The theory is that unconventional organic shale reservoirs with SRVs approaching 100% of the rock volume should behave similarly to matrix reservoirs
- Some operators that reduced their cluster spacing below 15 ft have seen stress shadowing issues in lower modulus rock
  - It is unlikely that the SRV will ever fully emulate a low perm matrix reservoir recovery factor under primary production in Permian organic shales with a higher modulus (shadowing issues are from the EFS)

Recovery Factor Distribution



Average perforation friction pressure drop for 39 wells above 1257 psi vs 3000 psi "best practices"
Lower values possibly pessimistic due to lower cluster efficiency

Permian Organic Shale RF vs Cluster Spacing

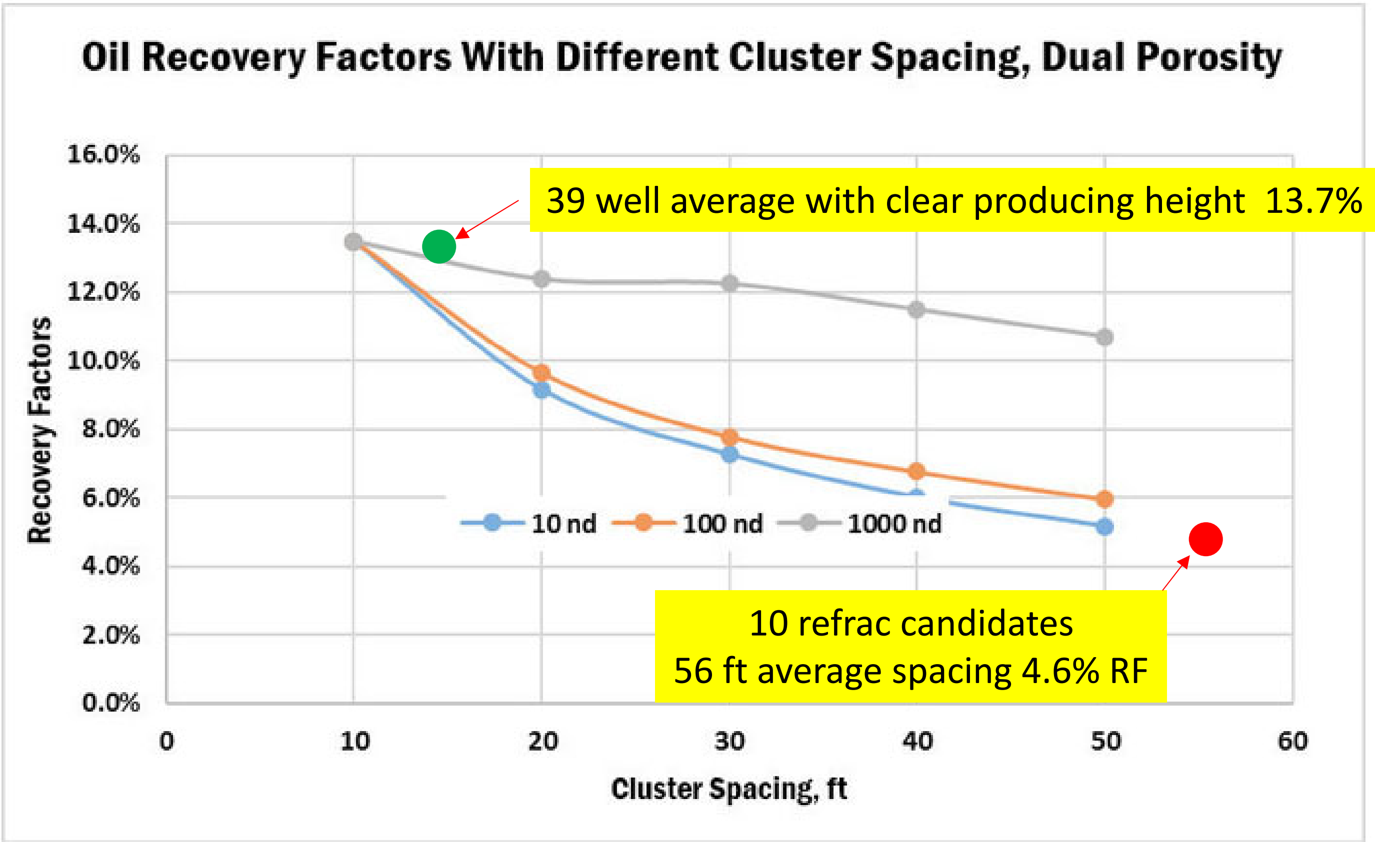
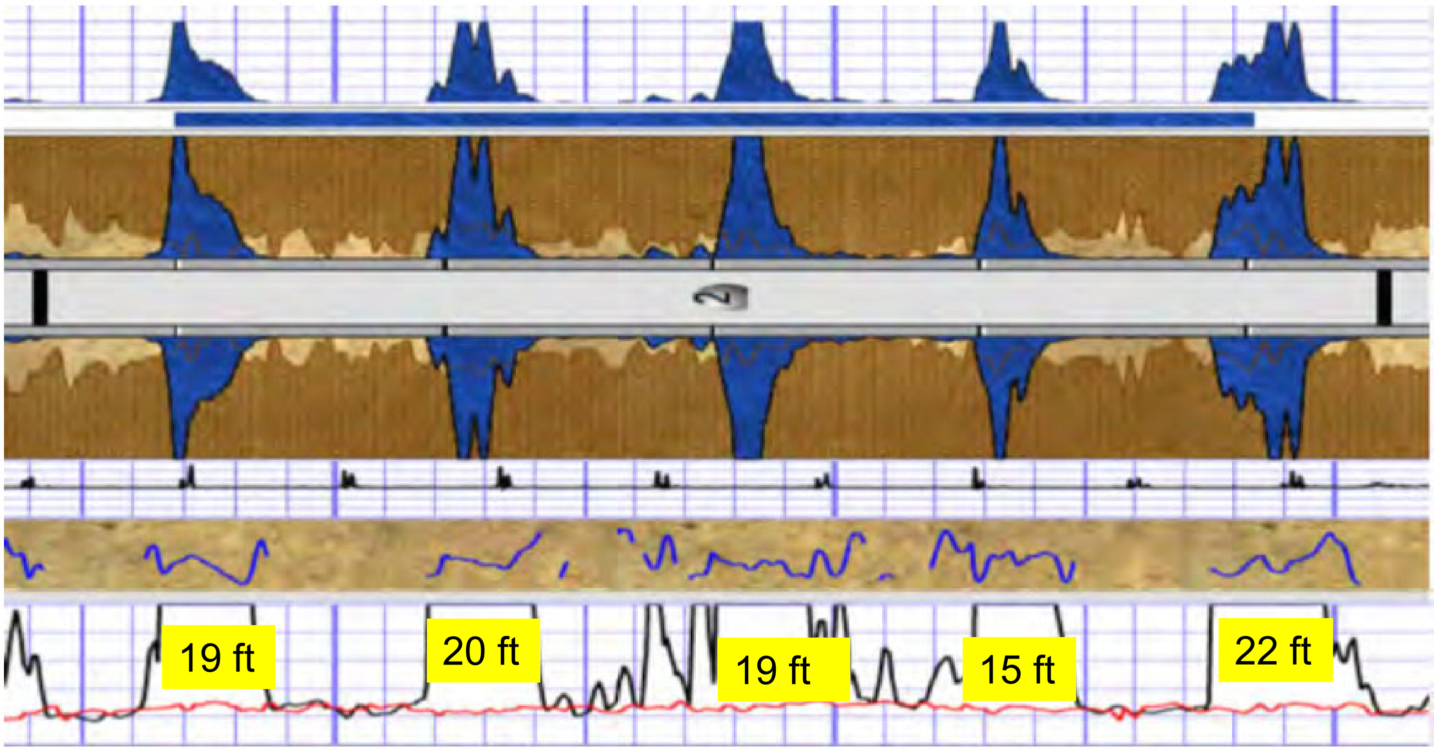


Fig. 10—Recovery efficiency based upon the dual-porosity model at the end of year 30.

330 ft drainage radius assumed in recovery factor analysis

Xiong SPE 199721 2020 HFTC

50 ft Cluster Spacing Tracer Width



60% of stage not stimulated with 50 ft spacing
Predicted recovery factor from SPE 199721 6%

URTEC paper 2902960 Reagan County HFTS

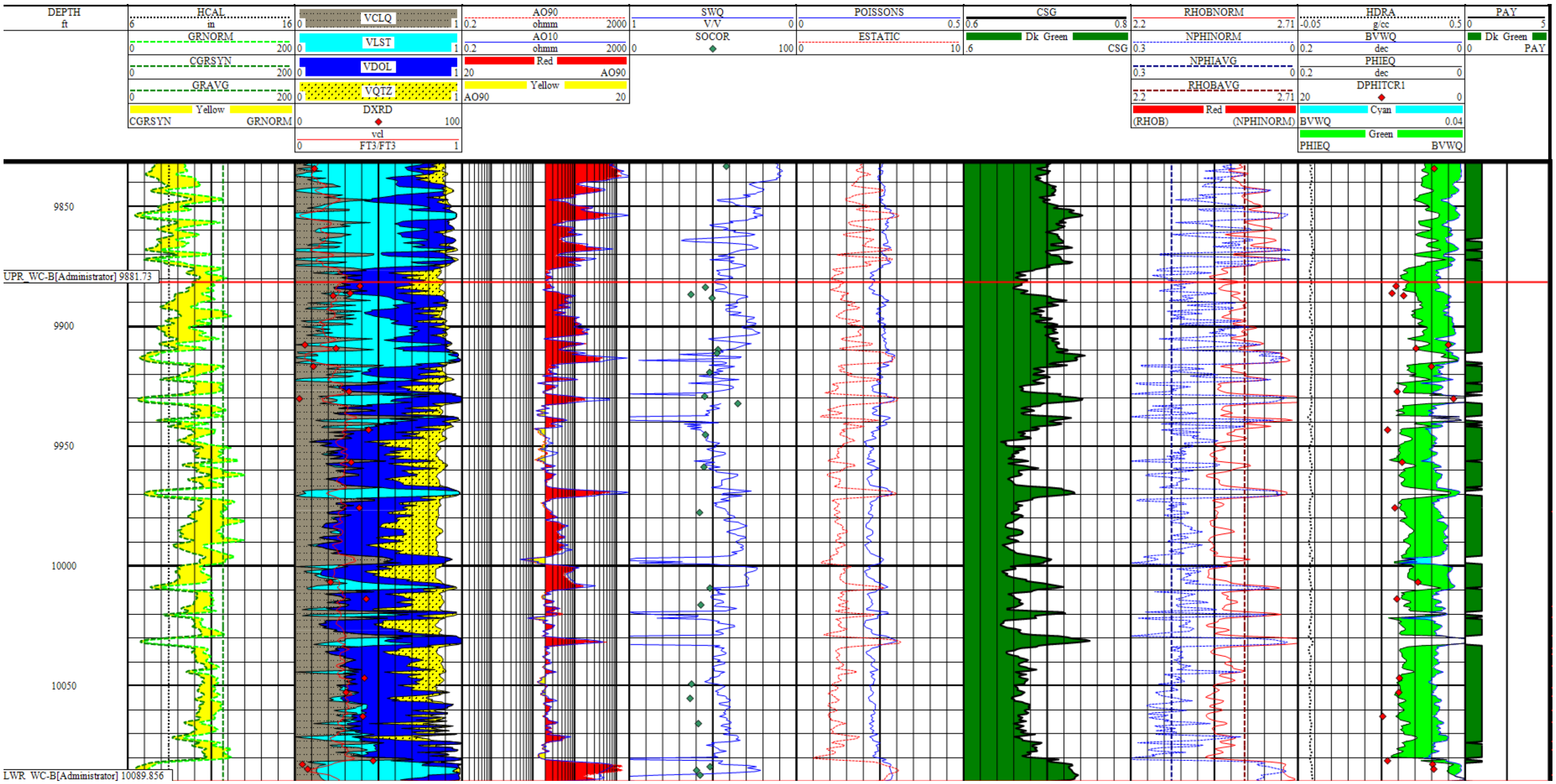
Primary-Infill Applications

- 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."
- Most of the wells in the dataset of close cluster spacings did not use XLE (1200 psi average perf pressure drop) and it is not clear which stages used diverters, cannot determine if low recovery factors are from poor cluster efficiency or a primary-infill issues
- Without XLE or diversion the cluster efficiency has been shown to average in the 59% range vs 85% for both methods
- 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.

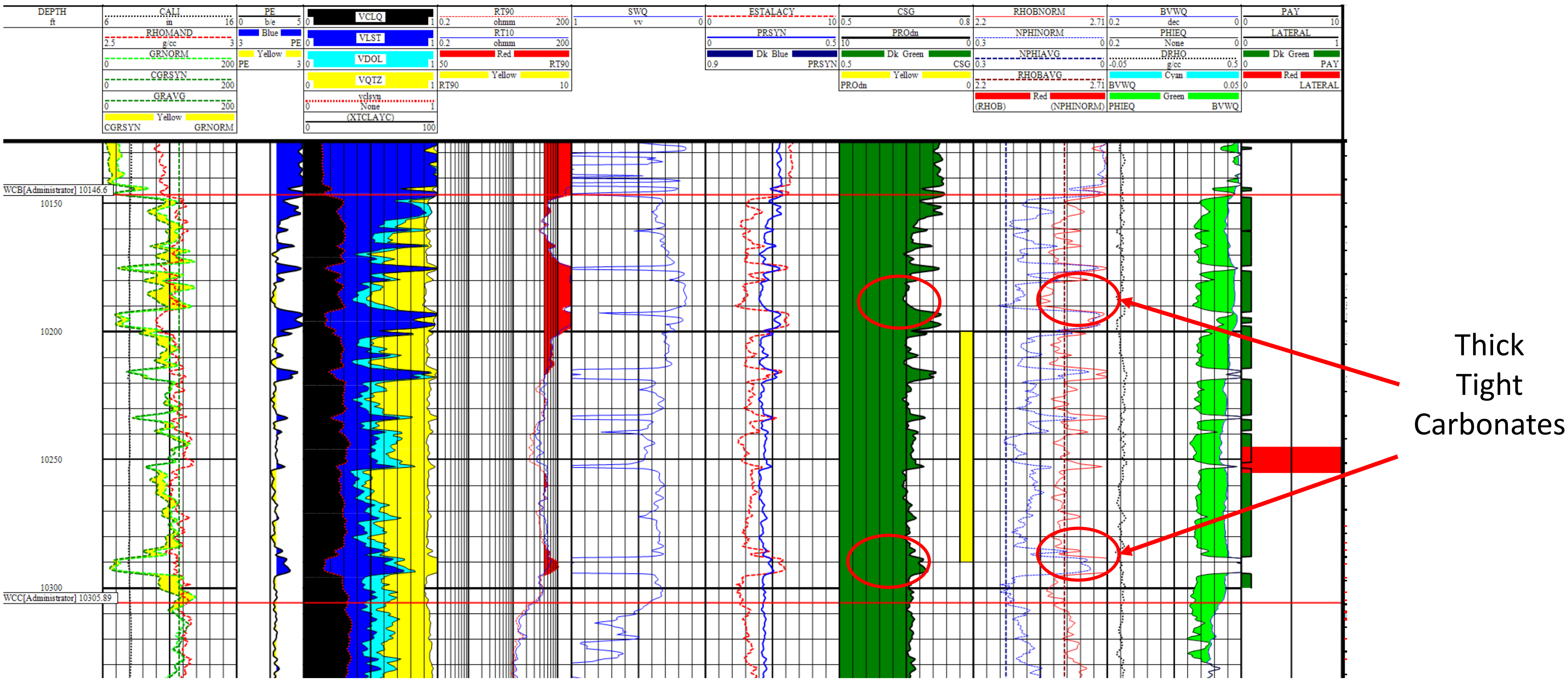
Methodology Employed

- Petrophysical analysis using normalized data calibrated to core (Barba SPE 17994 2015)
- Producing height from rock properties (SPE 25509 Barba and Meyer 1993)
- Initial heights picked manually using obvious stress layers, MFRAC P3D model used on selected wells

Normalized Analysis Tied to Core



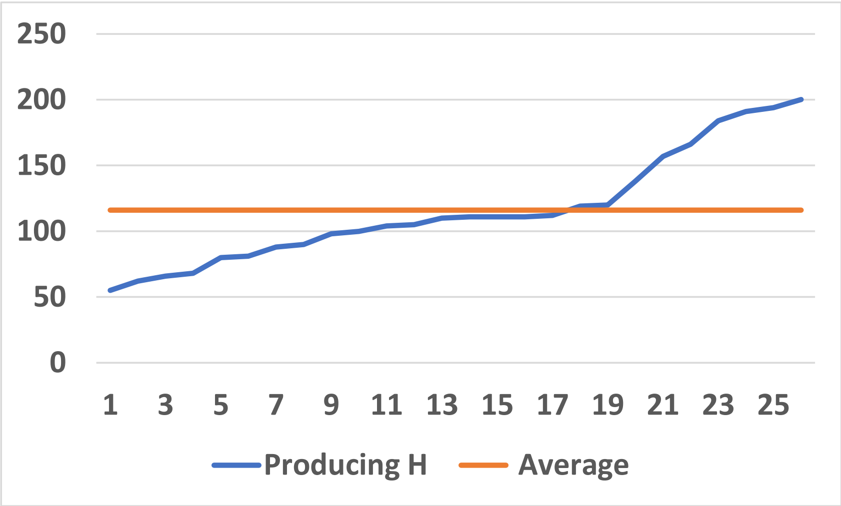
Clear Producing Height Example



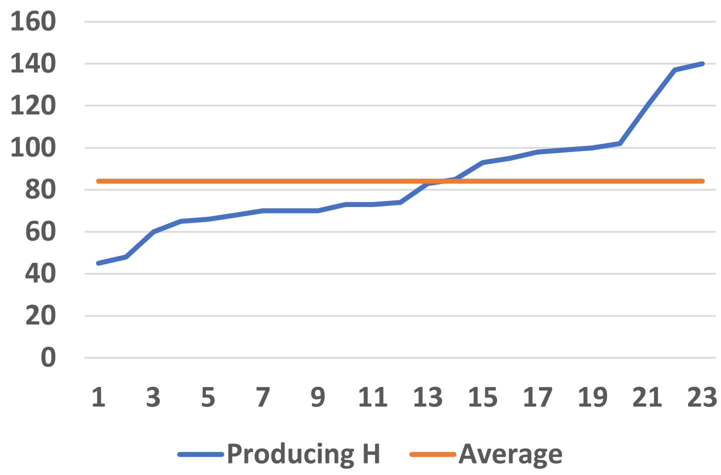
39 of the close cluster spacing wells had well defined heights, only those used for statistics

Producing Height Comparison Permian Organic Shales

Central Midland Basin



Southern Midland Basin

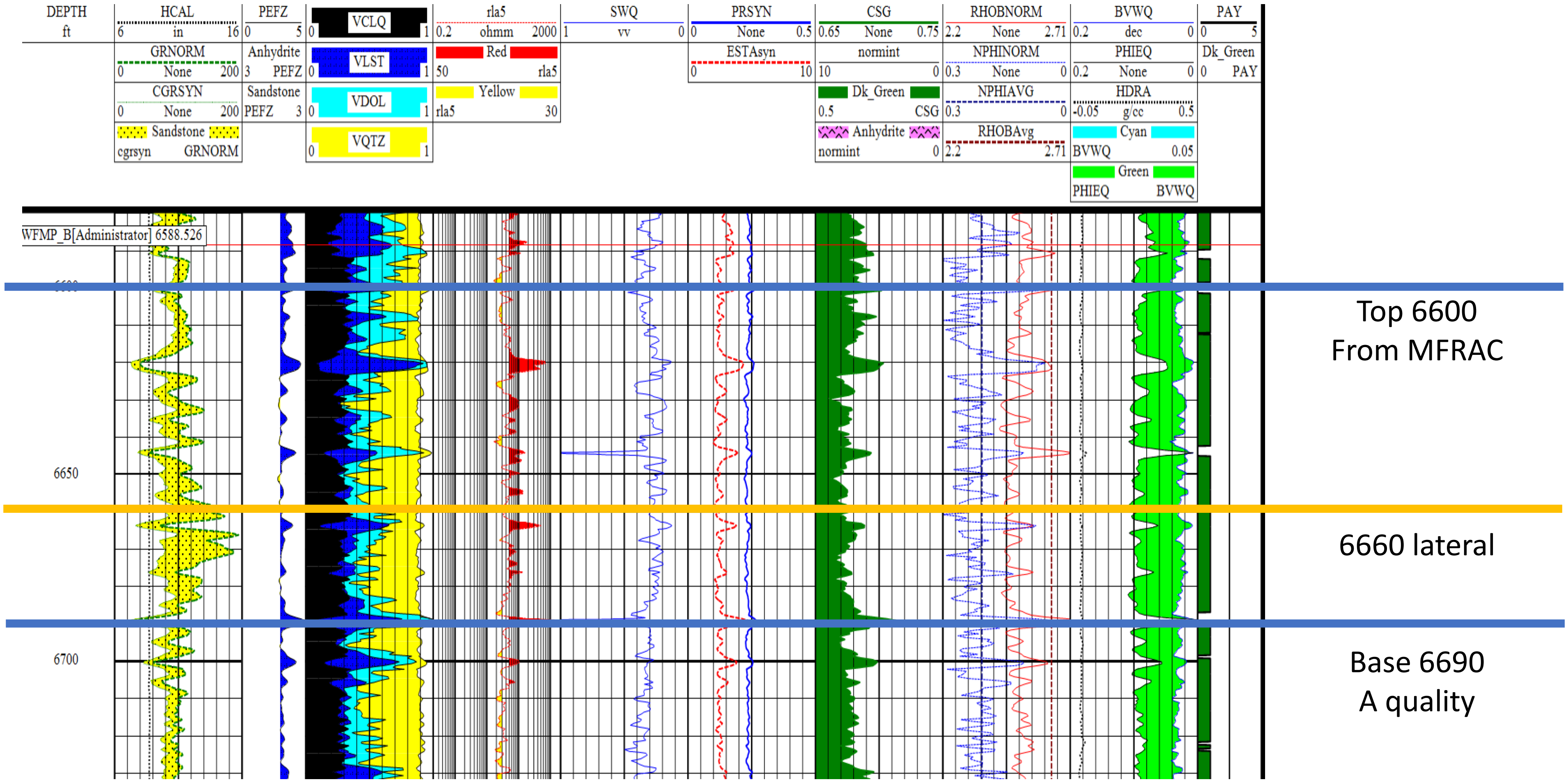


116 ft average producing height

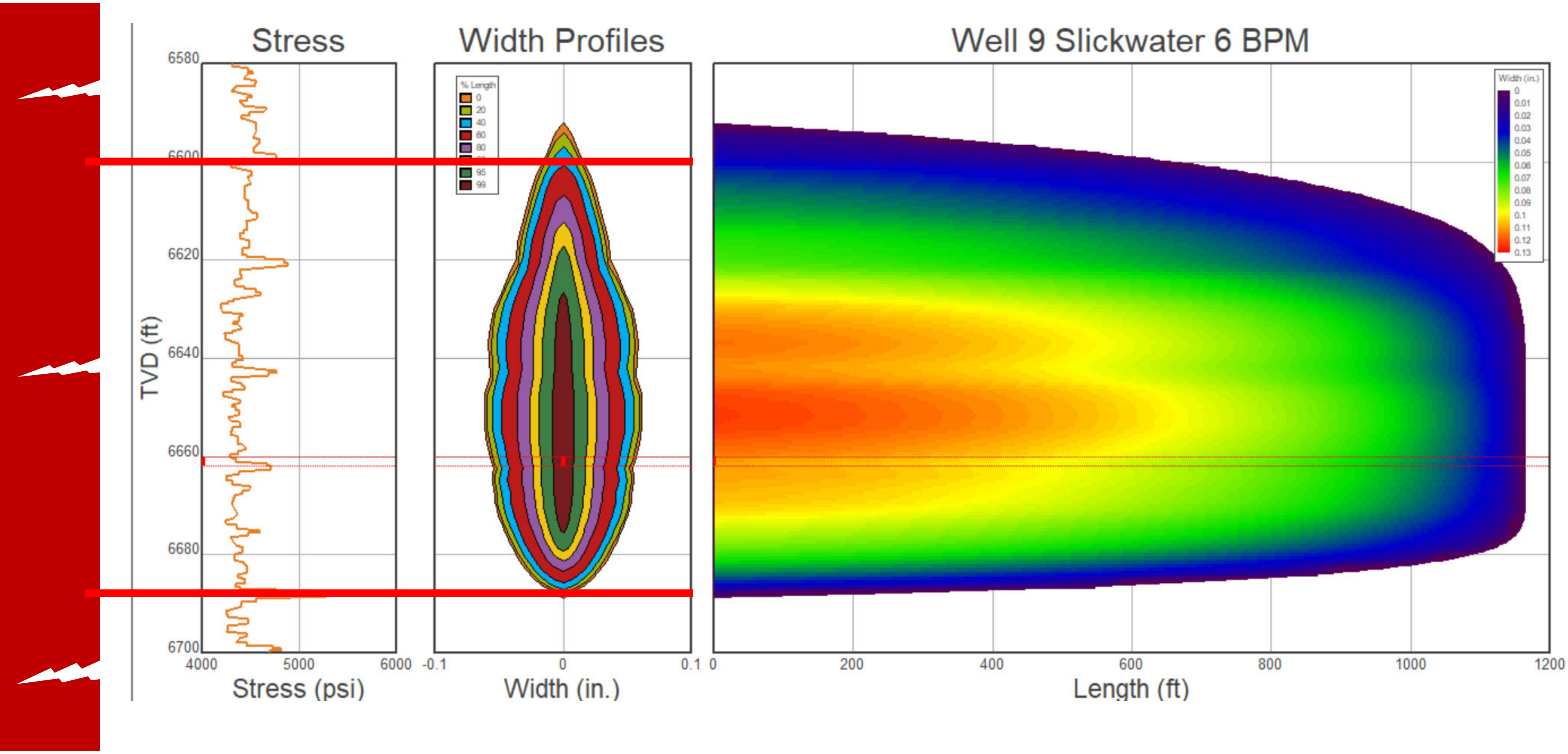
84 ft average producing height

Considerable variability in producing heights, important input to process

Well 9 Rock Properties Plot



Well 9 MFRAC 6 BPM/Cluster Slickwater



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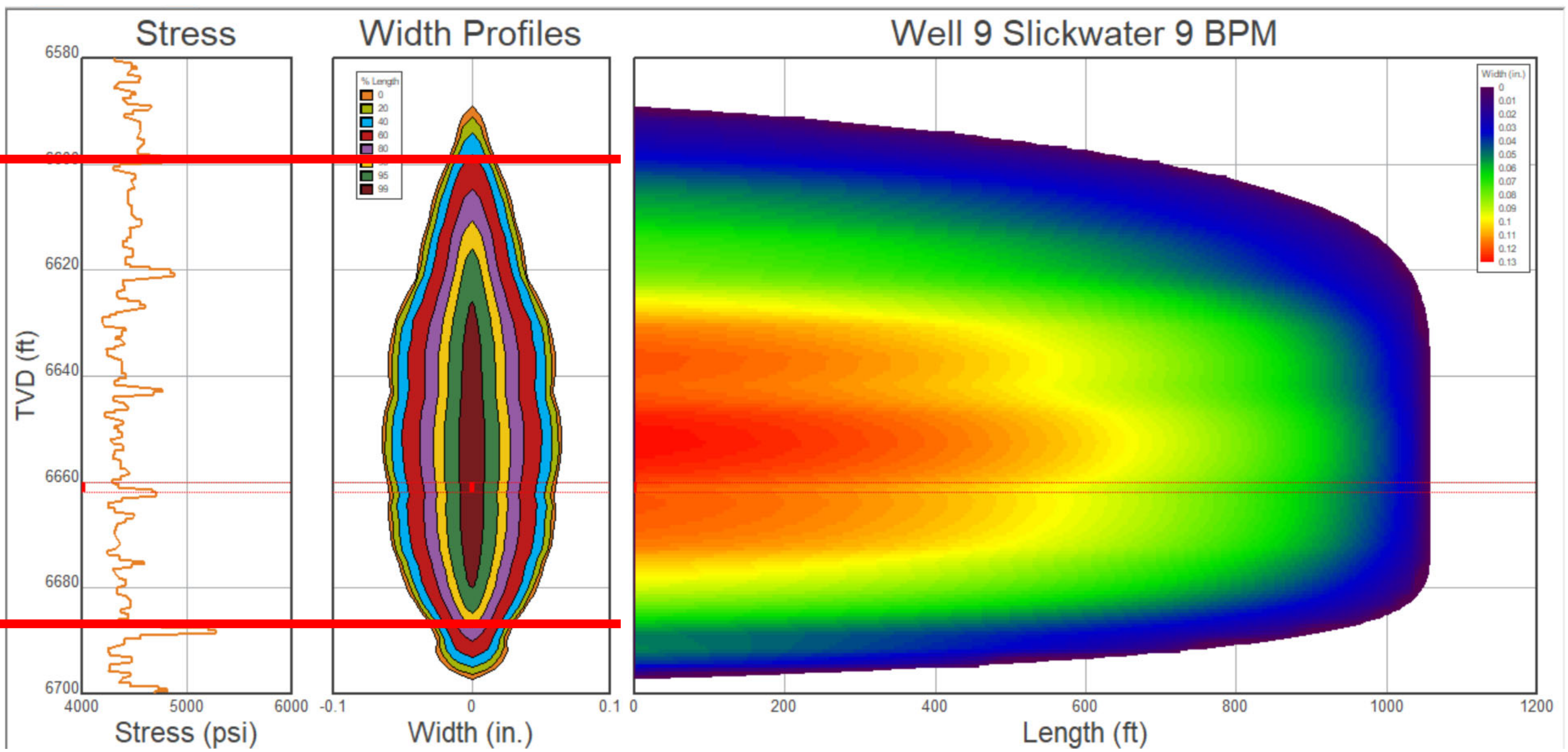
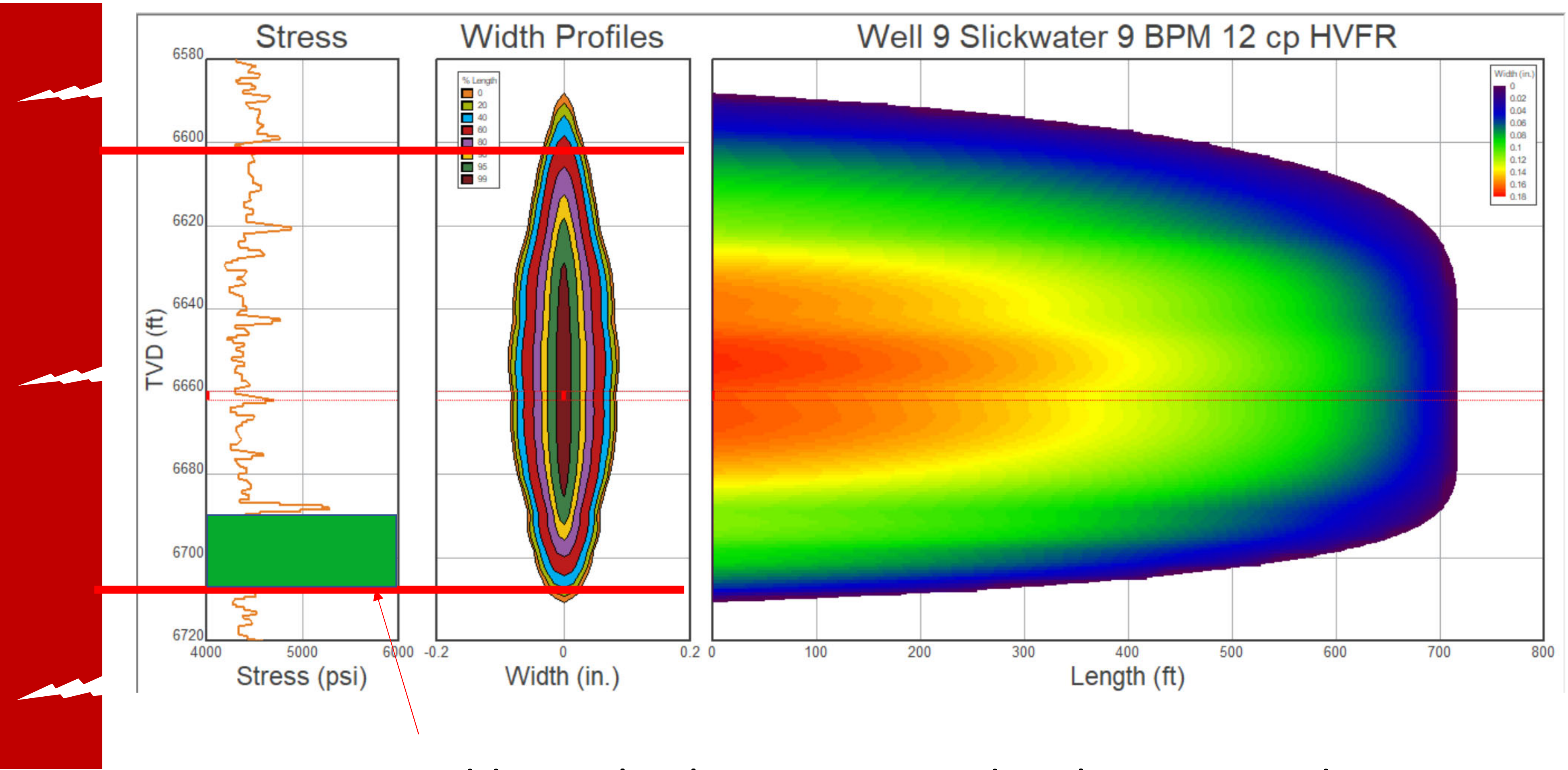


No change in frac geometry with higher rate 6 BPM vs 9 BPM = 14 clusters/stage vs 10

Well 9 MFRAC 9 BPM /Cluster 12 cp HVFR



Green = additional volumes accessed with 9 BPM and HVFR

Drainage Area Assumptions

- The recovery factors must be normalized to the lateral length and use a reasonable drainage width
- Anecdotally operators that were developing 8 wells per pattern (330 width) saw a 15% increase in production when they downspaced to 6 wells per section (440 ft width)
- Integration of RTA with reservoir modeling suggests a 220 ft drainage width but the 200 ft producing height assumption is probably low based on the height distributions (100 ft avg)
- 330 ft was used for the analysis as a result and should be used on future analyses to maintain consistency

AFE Details 10 Refrac Candidates

			210 ft			$ 0.0291	$ 0.40							$80	
Well	TVD	Lat	Stages	Prop lb	water bbl	prop $	Water Cost	CT DO	Frac Fixed	Total Fixed	Variable/stg	Variable total	Subtotal	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

Refrac cost estimate assumes XLE and expandable liners used to minimize costs

20% savings in frac cost from average 2019 costs using XLE

20% savings in total completion costs using expandable liners vs cemented casing

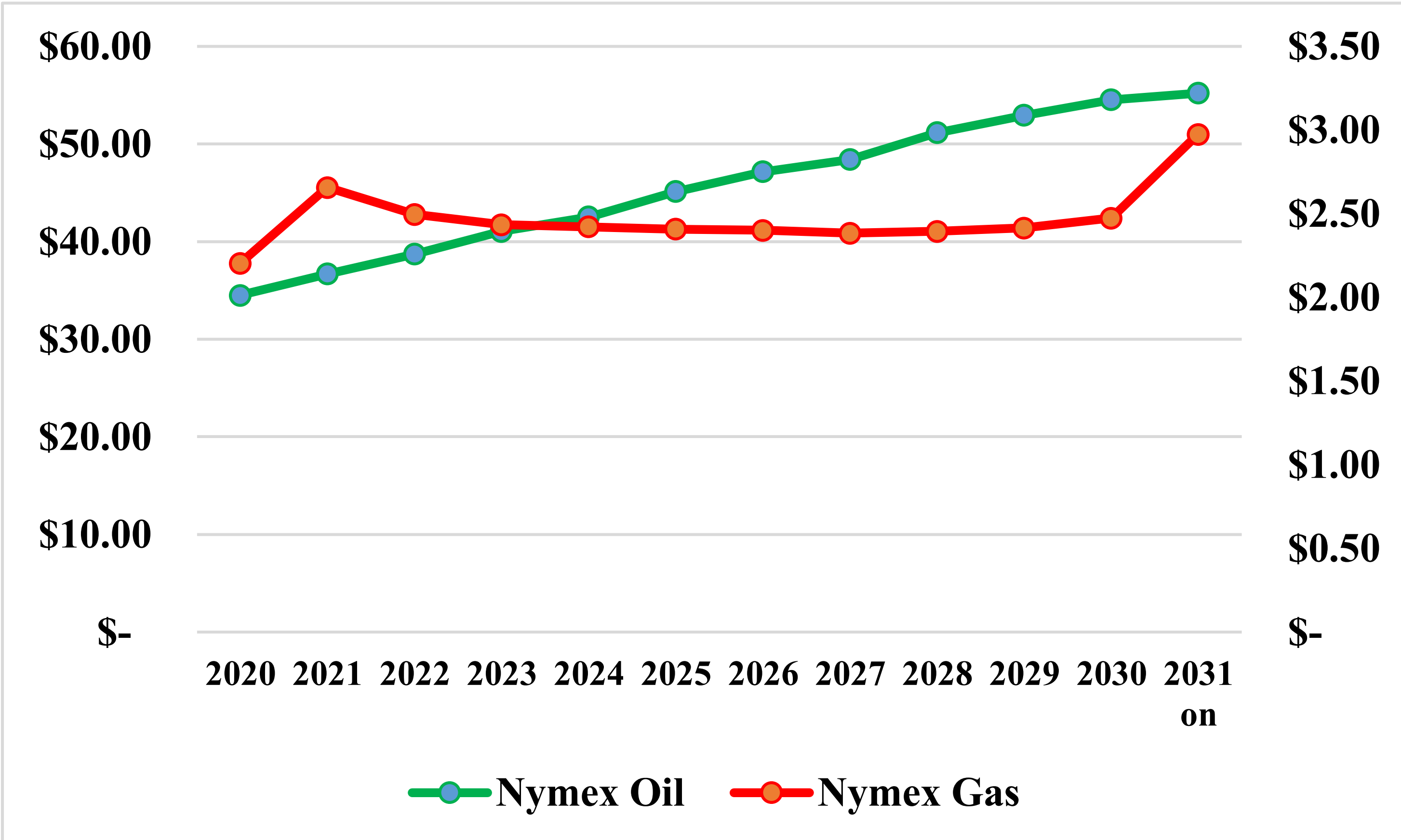
15% savings assumed due to industry conditions

New well comparison $4.5 million operator 2019 AFE no XLE 10 clusters/stage

14 clusters per stage assumed above 15 ft cluster spacing

Normalizes to $3.1 million in current costs with liner

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

Economic Analysis 10 Refrac Candidates

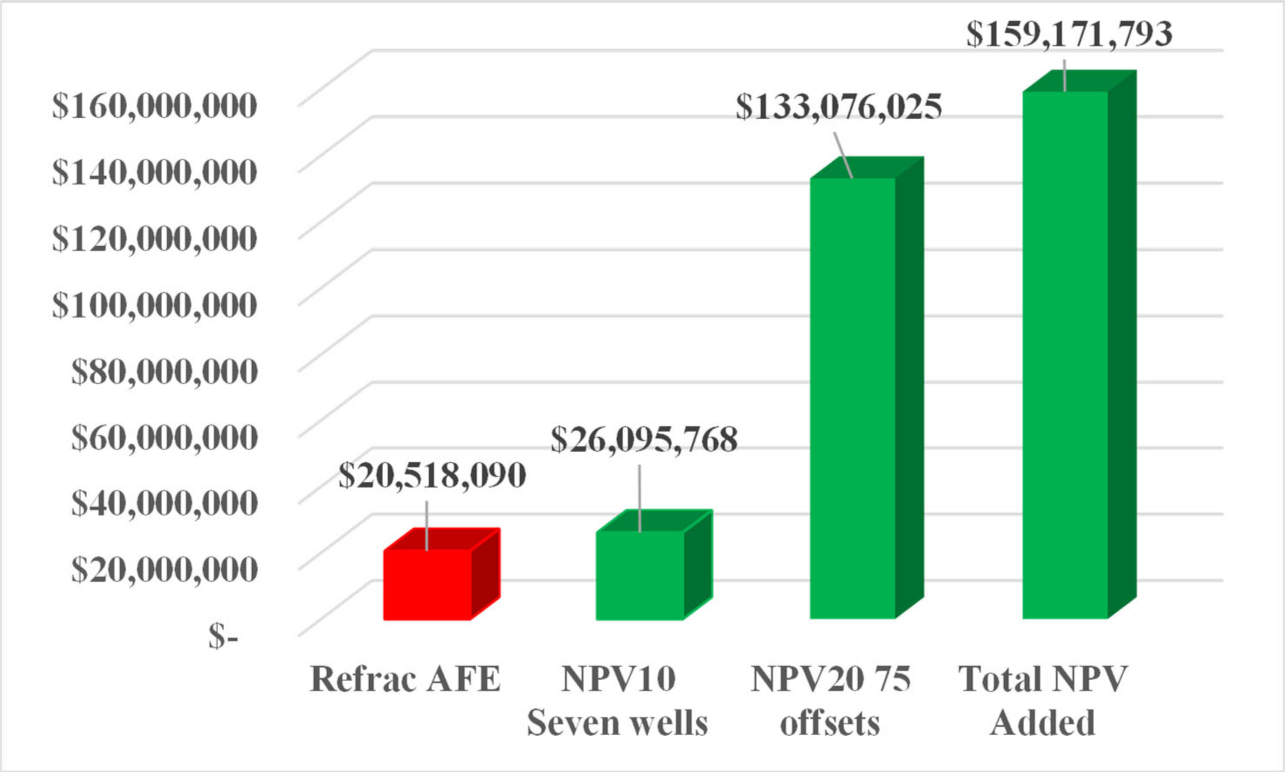
Well No	Original RF	Refrac EUR	AFE Refrac	Refrac IRR	Refrac NPV10	Refrac PUD NPV20	Current BOPD	PV10 PDP	Refrac IP BOPD
1	4.8%	126,805	$2,820,370	12%	$287,447	Negative	7.03	$242,629	153
2	9.3%	157,147	$2,971,410	18%	$964,712	Negative	8.9	$401,288	190
3	3.7%	166,552	$2,918,426	21%	$1,274,443	$61,882	5.21	$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

Bookable Reserves from Refracs

- Should be a clear indication that the reserves added were incremental and not an acceleration of existing production
- Should establish a reasonable certainty that the refrac operation would be successful
- Should generate a large enough number of successful refracs to establish confidence in the process

Holroyd, Samantha "Refrac Integration in the Capital Deployment Plan," Dec 10-11 2015, Houston Energy Forum.

7 Well Refrac Program Economics with Behind Pipe Reserve Booking



7.75 to 1 return on refrac investment

Incremental NPV20 truly "money for nothing" only cost is 3rd party reserve report

Conclusions

- 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
  - The P50 recovery factor of 13.7% is just below the generally accepted value of 15% for conventional matrix permeability reservoirs
- The methodology provides a means to quantify the expected increase in productivity for a refrac provided the operator maximizes cluster efficiency with XLE
- An additional benefit is the normalization of primary-infill comparisons where offset analog wells were completed with low cluster efficiencies and expected performance should be a product of the “best practices” expected recovery factor of 13.7%

Conclusions

- The results from the Southern Midland Basin suggest that refracs can be economic in the current poor pricing environment even on a cash on cash basis
- If a refrac program is successfully implemented and consistent results can be obtained (5 to 6 wells economically completed with no failures) the ability to book behind pipe reserves could be realized
    - The use of mechanical isolation has resulted in much more consistent successful results than earlier diverter based treatments
- To be valid the economic analysis requires the maximum cluster efficiency possible at the lowest possible completion cost and that is within reach using XLE and expandable liners