SPE 90483

Post Frac Evaluation of Multiple Zone Fracture Treatments Using the “Completion Efficiency” Concept

Robert E. Barba, Integrated Energy Services Inc, and Ronald A. Shook, Cimarex Corporation

This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Houston, Texas, U.S.A., 26–29 September 2004.

Abstract

The presence of more than one pay sand in a well can be both a blessing and a curse. The blessing is the presence of additional net pay and potential additional reserves. The curse is that it is often difficult to economically justify selective fracture treatments for each individual sand. Operators often feel compelled to combine more than one sand in a single frac stage to reduce the total number of frac stages. 3D hydraulic fracture simulations suggest that when multiple zones are perforated in a single frac stage multiple fractures of varying lengths may be created, with the target propped frac length not being obtained in each sand. Obtaining verification of frac lengths in all zones completed in multiple zone completions is difficult with traditional post frac pressure transient analysis or rate-transient analyses due to the multiple reservoir layers involved. When production logs are run there is generally only one flow rate at one drawdown pressure for each zone, and not a time vs. pressure series of datapoints required to estimate fracture length, conductivity, and formation permeability. The PLT measurement by itself cannot determine whether low production is a function of low pressure, low kh, or an ineffective fracture treatment. As a result, even with PLT data it is often not clear whether each sand is being effectively stimulated in multiple perforated interval frac stages.

To address these issues the concept of “completion efficiency” has been proposed. The process involves estimating the productivity of a zone with a minimum acceptable frac geometry and comparing it to actual production. Key inputs to the model include permeability from pre-frac flow test data or correlated to flow tests using wireline logs, reservoir pressure from either a wireline formation test measurement or empirical correlation to fracture closure pressures, PLT rate, and PLT drawdown data. This technique was applied in four South Texas reservoir studies on 135 wells in 2002 and 2003. From these studies it was evident that when multiple perforated intervals were stimulated in the same frac stage that the highest flow rate sands had significantly higher completion efficiencies than the other sands in the same stage. In many cases the lesser performing sands in the stage received only skin removal or were not stimulated at all. In 40% of the stages the lower flow rate perforated intervals had higher kh values than the highest flow rate perforated interval. It was also clear that zones that were treated with a single perforated interval had significantly higher completion efficiencies than zones in multiple perforated interval frac stages, and that within that subset shorter perforated intervals had higher completion efficiencies. Another observation was that single perforated interval stages with less than 2 degrees wellbore deviation had higher completion efficiencies than zones with higher deviations. Zones with higher reservoir pressure and higher drawdowns had lower completion efficiencies than lower pressure and drawdown zones. Finally, higher performing zones recovered less load between multiple stages than lower performing zones.

Introduction

Hydraulic fracturing has been accepted for the last 55 years as a viable technique for increasing productivity from oil and gas wells. The industry is in general agreement that in most low permeability wells frac treatments work. All 135 wells evaluated in this study had increases in production over pre-frac rates following hydraulic fracture treatments. While production was increased across the board, it is not always clear whether the post frac production was maximized with the treatment pumped. If the production increase did not meet expectations, it was not always clear whether the lower than expected productivity was the result of a poor reservoir or a poor completion. Various techniques have been presented to evaluate the effectiveness of frac treatments, with the two most widely used techniques being post-frac pressure transient analysis and post-frac production decline analysis.[1,2] Post frac pressure transient analysis provides an estimate of effective propped fracture length, reservoir permeability, and reservoir pressure. Unfortunately, these are run on a relatively small percentage of wells in South Texas. In the 135 well study there was one frac stage analyzed with a post-frac pressure buildup out of the 500-plus stages analyzed. Post frac production decline analysis can also provide an estimate of the same parameters, however the analysis is not unique when multiple stages are involved. In the study area there was an average of five frac stages per well, thus the results would not have been unique for most of the wells studied. To better estimate individual zone performance an alternate method is needed.

Completion Efficiency Concept

To address this issue the concept of "Completion Efficiency" (CE) is proposed. CE is the ratio of actual production rate to the expected rate for a minimum acceptable propped fracture length and conductivity. In the permeability range encountered in the study area (0.02 md median permeability) this target length is typically 90% of the drainage radius for each location. A more rigorous approach using the NPV concept[3] was initially used, however in virtually all cases where the zone was economically viable the NPV analysis was constrained by the 90% limit. This 90% guideline may not apply in higher permeabilities, but in the 0.01 to 0.1 md range it was the case in most of the zones evaluated. In the fields studied a 20 acre minimum drainage area was assumed, and for this a minimum propped length of 420 ft was proposed. It is a minimum target length in that drainage areas in low permeability hydraulically fractured reservoirs are elliptical in nature with the long axis in the direction of the maximum horizontal stress. The 420 ft target assumes a circular drainage pattern. In areas where a 40 acre drainage are is assumed the target length increases to 600 ft. In all cases where 3D models were run there was adequate proppant and fluid volume pumped to obtain this target length if a single bi-wing fracture was created.[4]

Fracture conductivity in the productivity model assumed a 200 md-ft minimum, as conductivities in excess of that had minimal increases in flow rate in the reservoir permeability range involved. Some studies indicate that this value may often be optimistic, and that non-Darcy flow and proppant pack damage can result in reduce the effective conductivity to double or even single digit kfw values.[5] The completion efficiency concept is based strictly on production rate, and does not attempt to separate the length and conductivity parameters. Better resolution of these two parameters may be obtained in single perforated interval wells with pressure transient or rate transient analysis.

The actual producing rate is observed either at the time the production log was run or 30 days after initial production when no PLT data were available. In the cases where PLT data were available the bottomhole flowing wellbore pressures (pwf) were obtained directly from the PLT log. In cases where no PLT was available the pwf was estimated from flowing tubing pressures using a correlation developed from zones where both PLT and surface flowing pressures were available. The flow rate estimates were done using a single phase analytical simulator (Meyer and Associates MPROD).[6]

Permeability Estimation

The estimation of permeability is the most challenging of all inputs, as there were relatively few pressure transient tests available in any of the fields studied. Fortunately, in order to qualify for the state severance tax exemption each of the producing sands in the fields studied had pre-stimulation stabilized flow rates.[7] From these rates a calculated in-situ permeability was estimated using an assumed skin value.[8] As these tests assume 0 to 0.4 skin damage and the zones have not been stimulated, these permeability estimates may be pessimistic if higher skin values are present. In addition, since the objective of the test is to certify that the zone qualifies for the tight gas credit it is possible that if there were multiple tests only the lowest permeability tests were submitted. These two factors combined should make the permeability estimate conservative with respect to flow rate predictions.

To extrapolate the effective permeability values to offset wells, a log-based model was used. The model that has provided the best results in the study was a modified Coates-Denoo equation using log derived effective porosity and bulk volume water:[9,10]

$$(1)\ kg = ((C*\phi_e{}^2*((\phi_e - BVw)/ BVw)))^2$$

Where

C = Calibration factor
kg = Effective gas permeability
ϕ_e = Effective porosity
BVw = Modified Simandoux ($Sw*\phi_e$)

In the Bob West field a "C" factor of 3.8 provided a median log derived permeability of 0.02 md. The median pre-frac flow test permeability for these same zones was 0.022 md. A distribution by zone is shown in Fig. 1. Similar results were obtained in the other fields studied. The above equation was input to the Petcom log analysis package and a permeability value was calculated for each sample interval (normally 0.5 ft). The arithmetic average permeability was then used as an input to the production simulator.[11]

Reservoir Pressure Estimation

The reservoir pressure inputs used a correlation between wireline formation test data and pre-frac pump-in test closure stress in single perforated interval frac stages.[12] In that study a high correlation coefficient was obtained (over 91%) from the comparison (Figs 2-3). A similar correlation was done by Salz where a 94% correlation coefficient was obtained between fracture gradient and reservoir pressure from pressure transient tests (Fig 4).[13] In all cases the error between measured pressure and pressure estimated from fracture closure data was less than 5% in single perforated interval stages. Since all 500 plus frac stages evaluated had pre-frac pump-in tests this resulted in a reasonable estimate of reservoir pressure for each stage. In stages with multiple perforated intervals the pressure from the fracture closure data was frequently lower than RFT pressures in the zone and static bottomhole gauge pressures.

This was expected, as the fracture should initiate in the lowest pressure sand when there is vertical pressure heterogeneity. The use of this lowest pressure estimate should also result in a conservative estimate of flow rate.

A second method for estimating reservoir pressure is with a linear elastic model. If estimates of closure stress, overburden gradient, Poisson's ratio, and a measured reservoir pressure are available the *Pext* term in Eq. 2 can be solved for. [14]

$$Smin/D = sz/D * (\nu/1- \nu) + Pr/D* (1-(\nu/(1- \nu)) + Pext \qquad (2)$$

Where:
$Smin/D$ = closure stress gradient (psi/ft)
sz/D = overburden gradient (psi/ft)
ν = Poisson's ratio
Pr/D = pore pressure gradient (psi/ft)
$Pext$ = calibration component (psi/ft)

Overburden gradient can be obtained from averaging the density log data above the sand tests (Fig. 5). Poisson's ratio can be estimated from a dipole sonic log or correlated to coherent dipole data with lithology. In cases where the dipole shear and compressional curves were not at least 95% coherent the correlated value was used. Reservoir pressure was obtained from wireline formation testers in all four fields studied. On subsequent zones without reservoir pressure data the *Pext* can be held constant and the equation solved for reservoir pressure. In the fields studied to date this *Pext* term has been reasonably consistent within a local area. In the Bob West study it varied between 0.083 psi/ft and 0.088 psi/ft in zones where RFT tests were obtained.[12]

Other Petrophysical Inputs

Additional model inputs included net pay thickness, average porosity, Sw, gas gravity, and temperature. The MPROD model calculated the gas compressibility and viscosity from the input data. Net pay was defined as porosity greater than 10% and Sw less than 65%. The porosity cutoff was established from a cumulative distribution of core NOB porosity and permeability (Fig. 6), where over 99% of the cumulative kh was from samples over 10% porosity. The Sw cutoff was established from core relative permeability data. Sw was estimated using the modified Simandoux model.

Porosity, Vshale, and Sw were all calibrated to special core analysis and MRI log data for all fields studied. In cases where MRI log data were available it was used to calibrate the basic Sw model for input into Eq. (1).

Comparison to Long Term Performance

An additional evaluation technique was implemented on later wells in the study to incorporate a long-term performance index. As the evaluation process requires a comprehensive petrophysical evaluation, all of the inputs are available to do an estimate of gas in place for each wellbore assuming homogeneous distribution of reservoir properties over the assumed drainage area. Once a decline curve is established and an estimated ultimate recovery established a comparison can be made between the EUR and the volumetric gas in place for the drainage area. The quality of this estimate is certainly related to the quality of the reservoir characterization, and better estimates should be expected when the reservoir architecture is better defined. Nonetheless, when this ratio is compared to completion efficiency the correlation has been excellent to date using the homogeneous reservoir property assumption. This is encouraging, as the result is independent of the permeability and fracture geometry inputs to the basic completion efficiency model.

Analysis results

In all areas studied the completion efficiency was less than 100% in the majority of wells, with a 30% median completion efficiency for all fields studied. Distinct trends were observed (Figs. 7-16):

1. Single perforated interval frac stages had higher median CE's (53%) than multiple perforated interval stages (32%)
2. The zone with the highest PLT gas rate within each multiple perforated interval frac stage had a significantly higher median completion efficiency (53%) than the lower producing zones (17%). The 17% completion efficiency was the equivalent of a 4 ft propped frac length or skin removal
3. In one field in 40% of the cases observed the highest producing rate zone was not the highest permeability-thickness zone.
4. Stages with shorter perforated intervals had higher median CE's than stages with longer perforated intervals
5. Stages with lower wellbore deviations had higher CE's than stages with higher deviations.
6. Stages with higher reservoir pressure and higher drawdowns had lower CE's.
7. Stages with higher load recovery between frac stages (recovered prior to setting the plug to frac the following stage) had lower completion efficiencies.

Why Do Multiple Zone Completions Leave Gas Behind?

A possible cause of the low completion efficiency in multiple zones, long perforated intervals, and deviated wellbores is multiple fractures. When more than one fracture is created the injection rate per fracture is reduced (Fig. 17). This rate reduction can result in narrow frac widths, premature proppant bridging, and short effective frac lengths. Figs 18-20 are taken from the GRI Canyon Sand tight gas research project where a PLT was run during the minifrac.[15] The lower zone had 80% of the kh, yet initially received only 28% of the rate. As the rate increased the rate percentage decreased to 16% of the rate. With this trend, it was highly likely that the rate would not be adequate to create sufficient width to allow any significant proppant concentration to enter. This was supported by the poor production from the zone after the propped fracture treatment. It did not flow enough gas to allow for a post-frac pressure buildup, even though the kh and pressure should have resulted in a 400 to 500 MCFD zone.

A second example was seen in Fig 21 where two different isotopes were run in the ramp and final resin coated stage.[16] The 1 to 4 lb/gal proppant ramp was the red tracer, while the 5 lb/gal resin coated sand was the blue tracer. The 9 separate perforated intervals were stimuated in one frac stage, with treatment rates in the 35 to 40 BPM range. This rate was split among the perforated intervals, resulting in narrower widths than would be expected from a single perforated interval. While it is apparent that fluid entry was achieved in all 9 perforated intervals, 6 of the 9 intervals screened out during the ramp most likely due to restricted width. It is unlikely that even in the zones that accepted the 5 lb/gal stage there was significant propped length extension as a large percentage of the pad was diverted to perforated intervals that screened out prematurely. These last two examples (Figs. 18-21) demonstrate some of the dynamics of attempting to fracture treat multiple perforated intervals in the same frac stage, and should help clarify why these type of completions usually result in low completion efficiencies.

The reservoir pressure statistic was unexpected, as higher reservoir pressures would ideally result in more reservoir energy to provide for fracture fluid cleanup. When it is combined with the drawdown statistic, however, it suggests that the damage may be drawdown related rather than pressure related. It is possible that the drawdown was the result of the lower CE instead of the cause, however when the pressure statistic is introduced the evidence supports the latter.

The statistic regarding load recovery was interesting. It showed that the higher performing stages recovered an average of 14% of their load before moving on to the next frac stage, while lower performing stages recovered an average of 34% of their load before moving on. The work done by Baree offers a possible explanation.[17] This suggested that partial cleanups of load followed by resaturation of the fracture to kill the zone for subsequent stage operations can cause irreversible damage to gas relative permeability. One of the wells in the study area provided a good example of this phenomena. The zone was the second of six stages, and was flowed back after the frac for 2 weeks. The zone was killed with 11 lb/gal CaCl and a composite bridge plug was set above the zone. When the plugs were drilled out and a PLT log run 2 weeks later the zone was making 41% of the pre-kill rate with essentially the same estimated bottomhole flowing pressure. This was a good example of the “50% rule” South Texas operators refer to when describing the effect on pre-kill rates when zones are killed to complete uphole stages. It is not known whether the zone would have performed better if it had not been partially flowed back and then killed, however this example, the CE statistics, and Ref. 14 suggest that the recovery of load between stages may not be beneficial if the zone is to be later re-saturated to complete upper stages.

“Best Practices” Recommendations Based on Study Results

The wireline log data is generally available prior to the completion, thus a permeability distribution is usually available to estimate net pay and permeability. If a measured pressure is not available from a wireline formation tester, a range of expected pressures can be used based on offset data. Another option that has been used is to use the kill truck that loads the hole the day prior to the frac treatment to pump into the formation at fracturing rates and obtain a closure pressure to estimate the reservoir pressure. A Hall plot (rate vs surface pressure) should be run to ensure that the zone is indeed being fractured. With this pressure information an estimate of flow rate and a production decline can be obtained. A NPV analysis can be done to incorporate the cost of the fracture treatment using log derived permeability and estimated reservoir pressure from either RFT or expected fracture gradient

A more basic technique can also be implemented based on flow rates alone. This involves estimating expected flow rates with target fracture lengths. An initial rate threshold can be used for each potential stage to determine if the zone can economically support a separate frac stage. In many areas a clear relationship exists between initial stabilized rate and cumulative production. If this is the case the required cumulative production over a specified time frame that would result in an economic fracture treatment can be related to an initial rate, and this rate threshold can then be used to determine if a separate fracture treatment for a given sand provides an acceptable NPV.

The study results strongly suggested that high potential flow rate zones should always receive separate treatments. Lower potential flow rate zones should be accessed through fractures initiated from the high potential zones if possible, however if all of the zones are lower potential the staging decision is not always easy. If more than one zone is to be included in a stage, only one should be expected to receive significant stimulation. The economic decision to complete these zones should be made based on the lowest kh zone. One issue that is clear from the studies is that hydraulic fractures are not permeability seeking devices-they follow the path of least resistance in both stress and net pressure. This path may or may not coincide with the highest kh intervals, and additional risk is introduced into the completion process (Figs. 22-24).

In developing stress profiles to determine the probability of communication with unperforated sands, the pore pressure input to the stress profile can be a critical variable. Numerous service company generated stress logs assume uniform pore pressures in all permeable intervals and rely primarily on contrasts in Poisson’s ratio to estimate fracture height growth. When vertical heterogeneity exists in pore pressure significant stress layers can exist across permeability barriers with minimal Poisson’s ratio contrast. In the event that there are stress layers between the perforations and additional pay, care should be exercised to avoid proppant “squeezing” from higher closure stress layers between the perforations and unperforated pay. This risk can be reduced with proper pad management to avoid excess proppant settling at the end of pumping. This is especially critical if there is economic unperforated pay above the perforated interval. Light “tip screenouts” at the end of the treatment can help minimize the squeezing phenomena, however hard packs should be avoided in low permeability reservoirs to avoid excessive gel dehydration and unnecessary stress on the proppant packs. The propped length stops once the packoff begins, and thus in low permeability it may be advantageous to commence the flush once the packoff begins.

In addition to proppant "squeezing" and settling below upper unperforated zones, there has been some work done in highly laminated zones that suggest that fracture growth may be affected by shear slippage along the lamination surfaces.[18] This phenomena increases the stress contrast between the perforations and the adjoining layers above what the conventional elastic models would predict. If local knowledge suggests that this phenomena exists or if the pore pressure contrast is not known care should be exercised in leaving economic pay unperforated.

The highest probability of success will be obtained with separate treatments for each high potential zone. Vendors have recognized that this often presents difficult economic choices, and technology has been developed that allows for more stages in a shorter period of time. Major advances have been made in recent years in both coiled tubing fracturing and in casing-conveyed perforating (the "Excape" system).[19] These advances have the potential to reduce the cost of multiple stage treatments by allowing for multiple frac stages to be treated in a single day.

Application of Technique Outside of Study Area

While the statistical database for evaluating completion practices was from South Texas, the concept has been applied successfully in a wide range of other sedimentary basins. The original work on calibrating log derived permeability to flow tests was done in East Texas, South Louisiana, and Offshore Gulf of Mexico sandstone fields.[10] Subsequent to that study the technique has been applied successfully in the sandstones in the Alberta Basin, Anadarko Basin, Burgos Basin, Delaware Basin, Midland Basin, Venezuela, and the Vienna Basin. Previous work using a derivative of equation (1) had excellent results in predicting pre-frac flow rates from logs in the Anadarko Basin Morrow and Springer.[20]

The best results have been obtained with calibrations to pressure transient tests, with the second most successful applications from tie-ins to pre-frac flow tests with assumed skin. Carbonate results have been mixed, with reasonable correlations where intergranular porosity is dominant but generally poor results when there are natural fractures or vugular porosity.

Conclusions

The "Completion Efficiency" concept is a useful technique for evaluating the performance of hydraulically fractured wells. It provides a means to determine if sub-optimal production is a function of low pressure, low kh, or an ineffective fracture treatment. The study results strongly suggest that fracture treating more than one perforated interval in a single fracture stage may result in only one of the perforated intervals being effectively stimulated. Long perforated intervals in wells with over 2 degrees deviation should be avoided. Excessive drawdown pressures should be avoided as well. While frac fluid cleanup is important, the study suggests that if the zone is to be killed with fluid prior to fraccing subsequent stages extended flowback periods between stages do not improve completion efficiency. In addition to a post-frac analysis tool to help determine "best practices," the productivity models developed for the process can be useful in determining the optimum perforation and staging strategy for new wells.

References

1. Crafton, J.W.: "Oil and Gas Well Evaluation Using the Reciprocal Productivity Index Method," paper SPE 37409 presented at the 1997 SPE Production Operations Symposium, Oklahoma City, 9-11 March.
2. Crafton, J.W.: "Well Evaluation Using Early Time Post-Stimulation Flowback Data," paper SPE 49223 presented at the 1998 Annual Technical Conference and Exhibition, New Orleans, La 27-30 Oct.
3. Meng, H.Z. and Brown, K. E.: "Coupling of Production Forecasting Fracture Geometry Requirements, and Treatment Scheduling in the Optimum Hydraulic Fracture Design," paper SPE 16435 presented at the 1987 SPE/DOE Symposium on Low Permeability Reservoirs, Denver, May 18-19.
4. Meyer, B.R.: "MFRAC-III Three Dimensional Hydraulic Fracturing User's Manual," Meyer and Associates, Natrona Heights PA, 2000.
5. Baree, R.D., Cox, S.A., Gilbert, J.V., and Dodson, M: "Closing the Gap:Fracture Half Length from Design, Buildup, and Production Analysis," paper SPE 84491 presented at the 2003 Annual Technical Conference and Exhibition, Denver Oct 5-8.
6. Meyer, B.R.: "MPROD Production Simulator for Fractured and Unfractured Reservoirs User's Manual," Meyer and Associates, Natrona Heights PA, 2000.
7. S.A. Holditch and Associates: "Engineering Evaluation of the Wilcox Formation L-1 and L-2 Sand Intervals, Starr and Zapata Counties, Texas For Application as "Tight" Gas Formation," prepared for Coastal Oil and Gas Corporation, Corpus Christi, Texas February 1996.
8. Lee, W.J., Juo, T.B., Holditch, S.A., and McVay, D.A.: "Estimating Formation Permeability from Single-Point Flow Data," paper SPE 12847 presented at the 1984 SPE/DOE/GRI Unconventional Gas Recovery Symposium, Pittsburgh, May 13-15.
9. Coates, G.R. and Denoo, S.:"The Producibility Answer Product," Schlumberger Technical Review 29, No. 2, June 1981, 55.
10. Barba, R.E. and Darling, H.: "Recent Advances in Log Derived Permeability," presented at the 1991 Schlumberger Gulf Coast Interpretation Symposium, New Orleans, LA.
11. Ahmed, U., Crary, S.F., and Coates, G.R.: "Permeability Estimation: The Various Sources and Their Interrelationship," paper SPE 19604 presented at the 1989

Annual Technical Conference and Exhibition, San Antonio, Texas Oct 8-11.
12. Barba, R.E. and Allen, M.P.: “Development and Validation of an Integrated Reservoir Pressure and Effective Gas Permeability Model Using Wireline Log and Pre-Frac Pump-in Test Data in the Bob West Field, South Texas Wilcox,” SPE Paper 71651 presented at the 2001 Annual Technical Conference and Exhibition, New Orleans, LA 30 Sep- 8 Oct.
13. Salz, L.B.: “Relationship Between Fracture Propagation Pressure and Pore Pressure,” paper SPE 6870 presented at the 1977 SPE Annual Technical Conference and Exhibition, Denver, Colorado, Oct. 9-12
14. Newberry, B.M., Nelson, R.F., and Ahmed, U.:"Prediction of Vertical Hydraulic Fracture Migration Using Compressional and Shear Wave Slowness," paper SPE 13895 presented at the 1985 SPE/DOE Symposium on Low Permeability Reservoirs, Denver, May 19-22.
15. Gas Research Institute:”Well Completion and Hydraulic Fracture Treatment Design and Analysis of the Canyon Sands (Lower Interval),” Topical report May 1991 pp 30-37.
16. Holditch, S.A., Holcomb, D.L., and Rahim, Z.: “Using Tracers To Evaluate Propped Fracture Width,” paper SPE 26922 presented at the 1993 Eastern Regional Conference and Exhibition, Pittsburgh, Pa. 2-4 Nov.
17. Baree, R.D.: “Effects of Partial Clean-up and Well Killing on Post-Frac Production,” personal communication.
18. Miskimins, J.L. and Barree, R.D.: “Modeling of Hydraulic Fracture Height Containment in Laminated Sand and Shale Sequences,” paper SPE 80935 presented at the 2003 Production and Operations Symposium, Oklahoma City, 22-25 March .
19. Eller, J.G., Garner, J.J., Snider, P., and George, K.: “A Case History: Use of a Casing-Conveyed Perforating System to Improve Life of Well Economics in Tight Gas Sands,” paper SPE 76742 presented at the SPE Western Regional/AAPG Pacific Section Joint Meeting, Anchorage, Ak 20-22 May 2002.
20. Denoo, S.A., Hammar, R.F., and Maxwell, J.B.: “Utilizing Log Derived Permeability to Predict Rates of Gas Production,” “Journal of Canadian Petroleum Technology,” Vol. 20, No. 2 April-June 1981.

Nomenclature

D = True vertical depth, ft
kg = gas permeability, md
$k\infty$ = Klinkenberg permeability, md
pw =wellbore pressure, Psi
Po =initial reservoir pressure, psi
Pr/D=reservoir pressure gradient, psi
Sw =water saturation, dimensionless
BVw=bulk volume water, dimensionless
Siw =irreducible water saturation, dimensionless
υ =Poisson's ratio, dimensionless
$smin$ =minimum horizontal stress, psi
$ISIP$ = Instantaneous shut in pressure, psi
sz =overburden stress, psi
ϕ =porosity, dimensionless

Log Based vs Flow Test Permeability

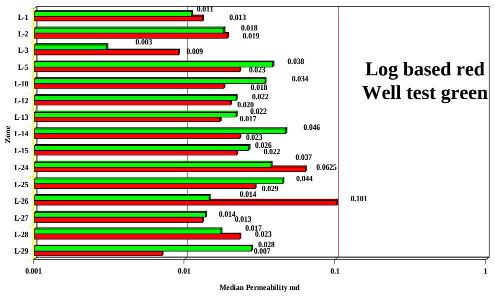


Fig. 1

Closure Stress vs Pore Pressure

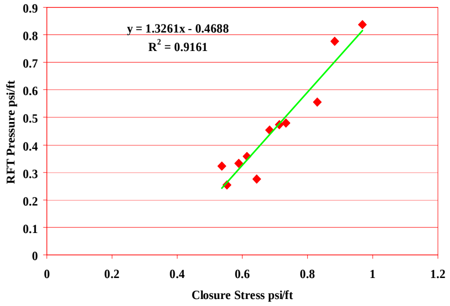


Fig. 2

Frac Gradient vs Pore Pressure

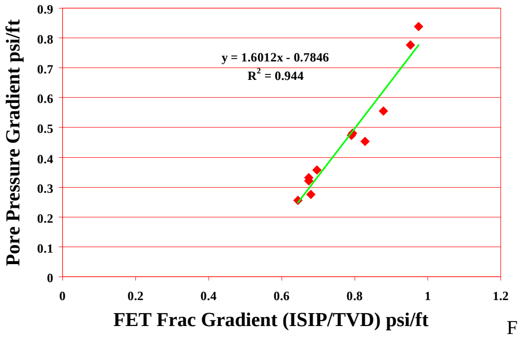


Fig. 3

Salz (SPE 6870) Frac Gradient vs Well Test Pressure Correlation

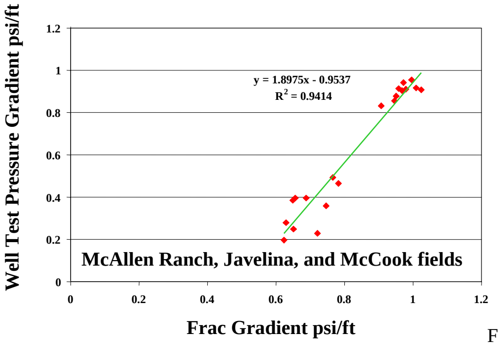


Fig. 4

Bob West Field Overburden Gradient vs Depth

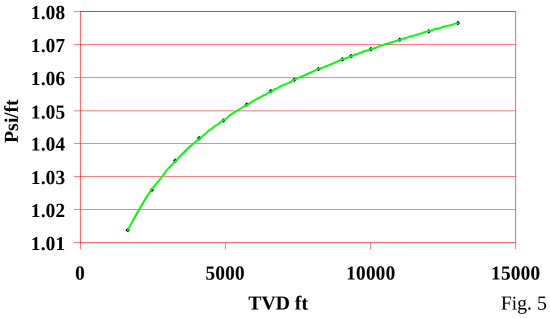
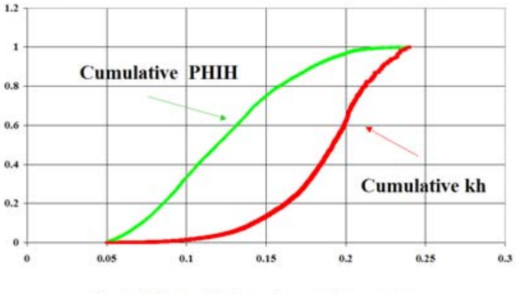


Fig. 5

Cumulative Kh vs Porosity Plot Wilcox Field Study SPE 71651



Insignificant kh less than 10% porosity

Fig. 6

Completion Efficiency Comparison-All Fields Studied

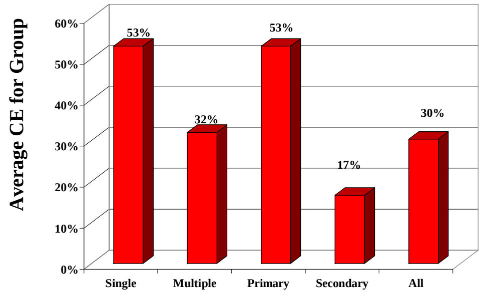
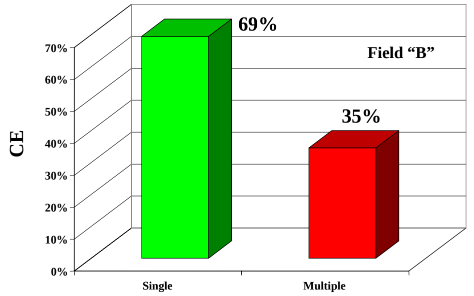


Fig. 7

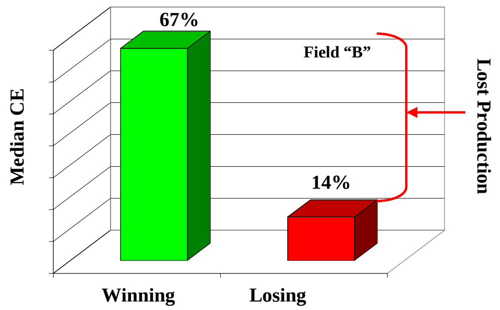
Median CE Single Perforated Intervals vs Multiple



Single=One perforated interval per frac stage
Multiple=2 or more perforated intervals per frac stage-all intervals

Fig. 8

"Winning" vs "Losing" Zone CE



Winning =Zone with top PLT gas rate within multiple perforated interval stage
Losing=Remaining zones in stages

Fig. 9

Frac Length vs Completion Type

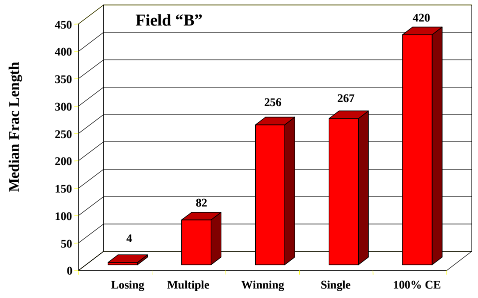


Fig. 10

Production Rate vs Completion Type

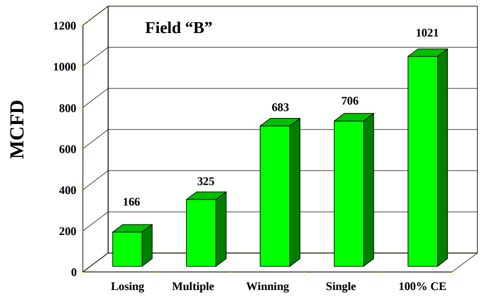
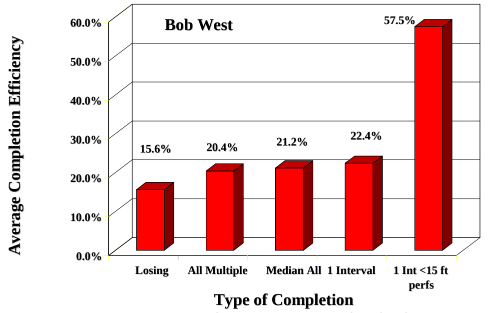


Fig. 11

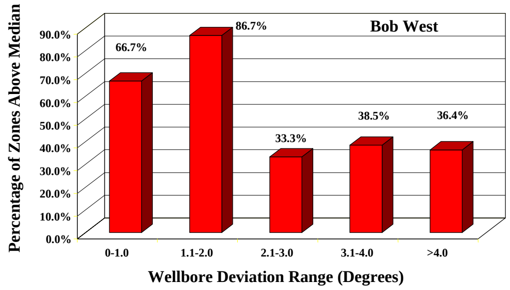
Avg Completion Efficiency vs Number of Intervals Perforated



Median perforated interval 31 feet for field

Fig. 12

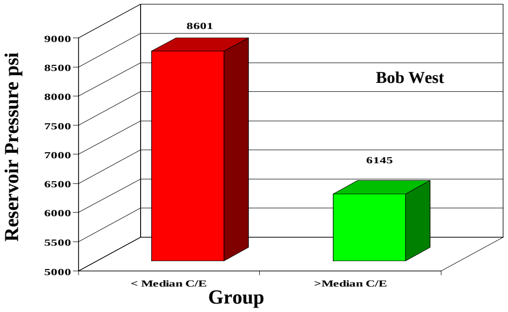
Deviation Range vs % of Zones above Median CE



Efficiency drops significantly above 2 degree deviation
Median perforated interval 31 feet for field

Fig. 13

Reservoir Pressure vs Completion Efficiency



C/E = Completion Efficiency

Fig. 14

Drawdown Pressure Range vs Percent of Samples >Median C/E

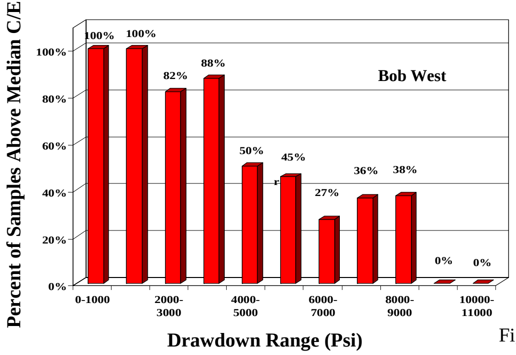
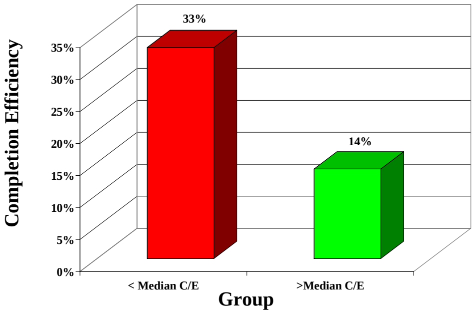


Fig. 15

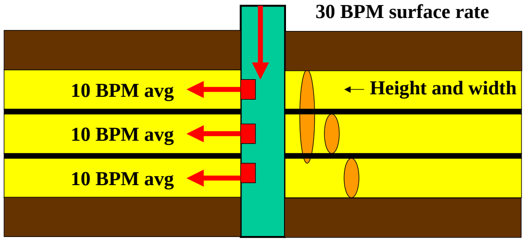
Initial Load Recovery vs Completion Efficiency



C/E = Completion Efficiency

Fig. 16

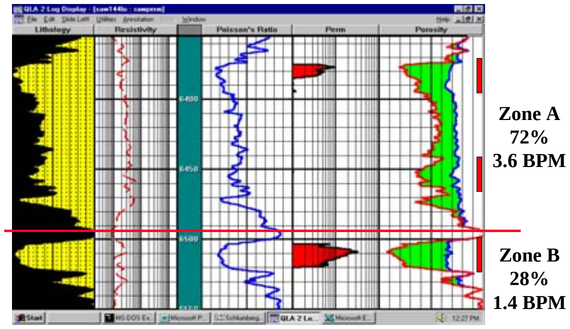
Rate Distribution-Multiple Perforated Intervals



High probability of multiple low conductivity fractures
Statistics suggest one zone usually dominant
“Multiple firecracker” or “multiple horse race” analogy

Fig. 17

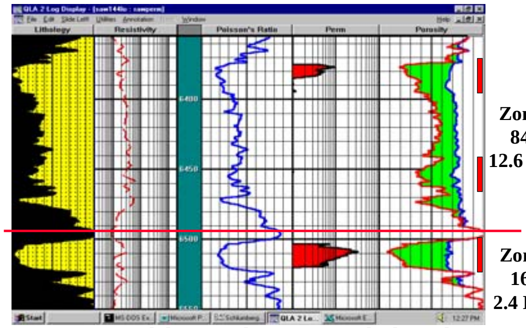
FET PLT 5 BPM Rate Step



Zone B 80% of total kh-West Texas Canyon Sand

Fig. 18

15 BPM Rate Step



Zone A
84%
12.6 BPM

Zone B
16%
2.4 BPM

Stage did not produce economic hydrocarbons
Zone B did not get stimulated-zone abandoned

Fig. 19

Net Pressure Profiles

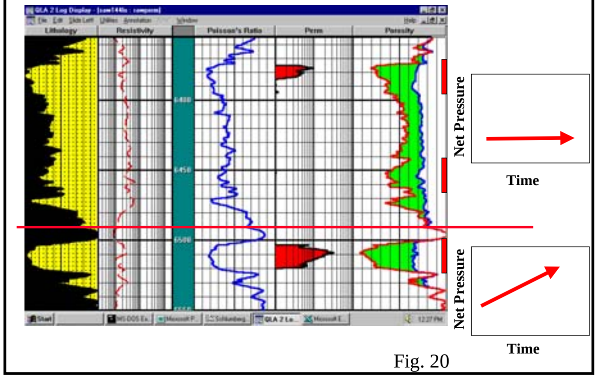
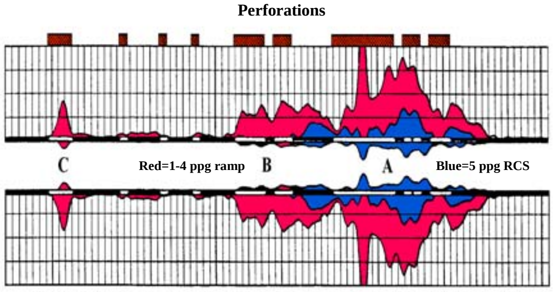


Fig. 20

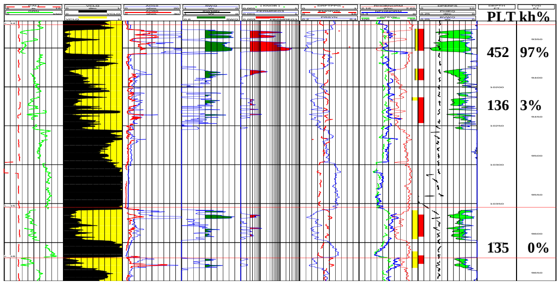
Blanket Perforating and Multiple Isotope Tracer-Tubb Dolomite



Red with no blue=pump rate/perf too low to create adequate width

Fig. 21

Best kh Received Poorest Stimulation

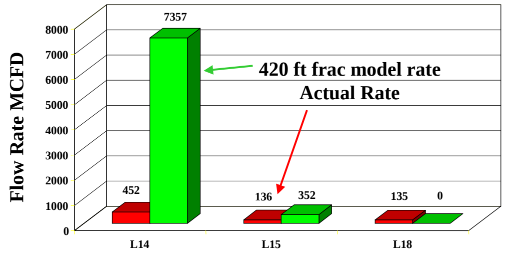


Stg	L	Top	Base	H	PHI	K Reg	K SPE	Sw	kh	kh %
6	14	10128	10236	36.5	0.144	0.071	0.108	0.295	3.942	97%
6	15	10364.5	10391.5	8.5	0.11	0.005	0.016	0.394	0.136	3%
6	18	No pay	0	0	0	0	0	0		0%

SPE 71651

Fig. 22

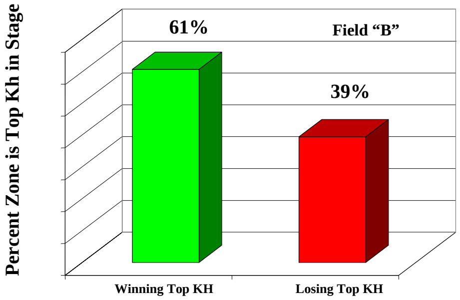
Best kh Received Poorest Stimulation



6% CE 39% CE 100% CE
20 acre offset drilled later-virgin pressure in L14

Fig. 23

Winning and Losing Zone KH Ranking



39% of the time the frac did not find the best pay when multiple zones fracced
Hydraulic fractures are not "permeability seeking devices"

Fig. 24