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Liquids Rich Organic Shale Recovery Factor Applications

Robert E Barba, Integrated Energy Services Inc

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Abstract

Recovery factor analysis involves the integration of hydrocarbon pore volume from a core calibrated petrophysical analysis with the estimated ultimate recovery from the lateral wellbore. A key benefit is the normalization of performance among wellbores with varying oil in place volumes and establishment of “best practices” for well completions. A secondary benefit is a method to obtain production performance estimates for various landing zone options prior to drilling the lateral. Lastly, a comparison of recovery factors for various assumptions of producing height can provide a “reality check” on how much of the vertical pay column is connected to the wellbore via propped or unpropped conductivity. Initial results from analysis of over 150 Wolfcamp and Cline wells indicated an average recovery factor of 8.2% for 160 acre drainage areas. The performance study suggests that the producing heights in these low modulus formations are limited primarily to the propped height with limited unpropped height. This is a significant finding in that propped height from tracer surveys is limited to 50 to 60 ft regardless of the fluid type pumped with resultant producing heights of 100-150 ft when unpropped height is considered. The unpropped height estimate was made from a correlation to recovery factors. While normally propped heights can be improved in conventional reservoirs with gelled fluids, the higher viscosity fluids are shown to be ineffective at increasing propped heights in organic nanodarcy shales due to the large disconnect between break and closure times. Recommendations are provided to determine “best practices” to economically increase producing height, ideally with generic completion procedures using normal hybrid slickwater/borate systems. One option proposed is the use of coiled tubing to deliver the treatment via the annulus and then clean out the subsequent bridge plug location following a traditional “forced closure” procedure in the lateral to close the fracture prior to excessive proppant settling. Another option being discussed is the use of lightweight proppants, however the unit cost will need to be significantly reduced to make this an economic option due to the large proppant volumes required in shales. With lightweight proppants the volumes are reduced significantly due to the difference in specific gravity, however at the high unit cost this would still increase the stage cost by a factor of three. There are several other recently released products that have the potential to improve propped height and these should be thoroughly evaluated before dismissing them given the significant upside that exists. In many shale plays the gross pay thickness is well in excess of the expected conductive height and the ability to contact more vertical section should translate into significantly better production rates that may help justify the increased investment. The study should encourage additional research to be conducted in this area.

Recovery Factor Process

The recovery factor technique integrates the oil in place or gas in place estimates from the petrophysical and geological analysis with decline curve analysis. The hydrocarbon pore volume at the wellbore is extrapolated to the expected drainage area with the geological characterization. In many cases the lateral homogeneity of the resource plays enables the wellbore estimate to be used alone without a significant loss of accuracy. The basic building block for the process is a calibrated log analysis to estimate clay volume, effective porosity, water saturation, and net pay. Generally a full suite of logs is recommended for the initial pilot holes, with core, a density-neutron-resistivity (Triple Combo or TCOM) suite along with dipole sonic, pulsed neutron mineralogy, and spectral GR. Subsequent pilot holes and offset legacy logs can typically be analyzed using the relationships developed in the pilot "science" hole and just the TCOM suite. For organic shale reservoirs the same properties are estimated with the addition of a kerogen correction. "Calibrated" log analysis involves validating the volume of clay with XRD or FTIR (X ray diffraction or Fourier Transform Infrared), the porosity with core, and the log derived water saturation estimate with core data (Fig. 1).

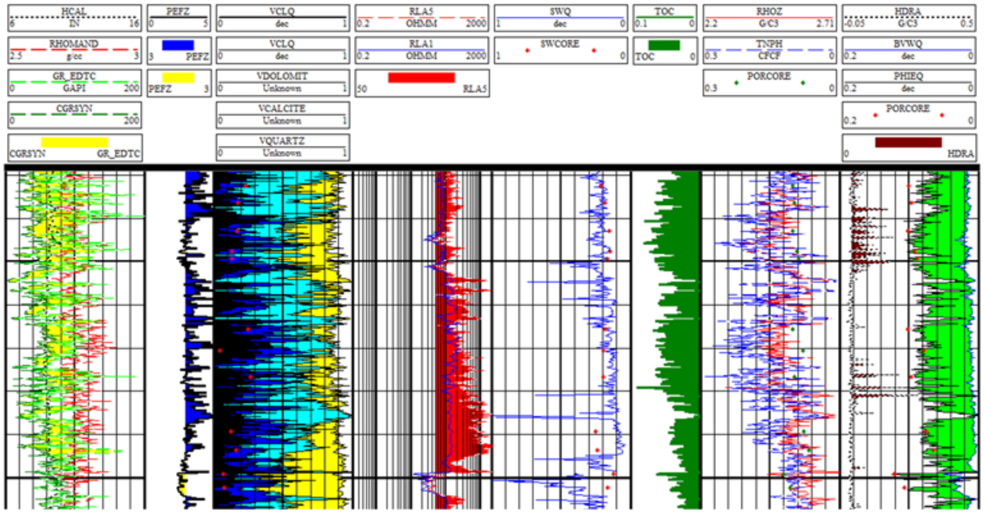

Fig. 1 Example Plot with Key Outputs and Core Calibration

For nanodarcy organic shales the GRI tight rock porosity method using crushed core is typically used. A useful technique for log based Sw validation has been the BVH vs porosity plot (Fig. 2) for reservoirs at irreducible Sw. In many organic shales the bulk volume water irreducible (BVI) is relatively constant. The Marcellus is a good example with a 2.2% BVI in all pay zones) and so is the Eagle Ford (Lower EFS with a 0.038 BVI and the Upper EFS a 0.02 BVI). The bulk volume hydrocarbon (BVH) vs porosity plot can provide an estimate of BVI that can be used to estimate Sw from porosity data alone and as a possible pay cutoff. This can be used to calibrate a conventional Archie based Sw model in the organic zones if there are mixed organic and inorganic zones. If the zone is not at irreducible Sw a traditional Archie model can be run and compared to core Sw, with the log based model typically adjusted downward from the core values to account for sample flushing that appears to happen even though the "as received" nanodarcy samples probably do not get flushed significantly due to the low permeability. Pressure cores are an emerging technology that may help with this process.

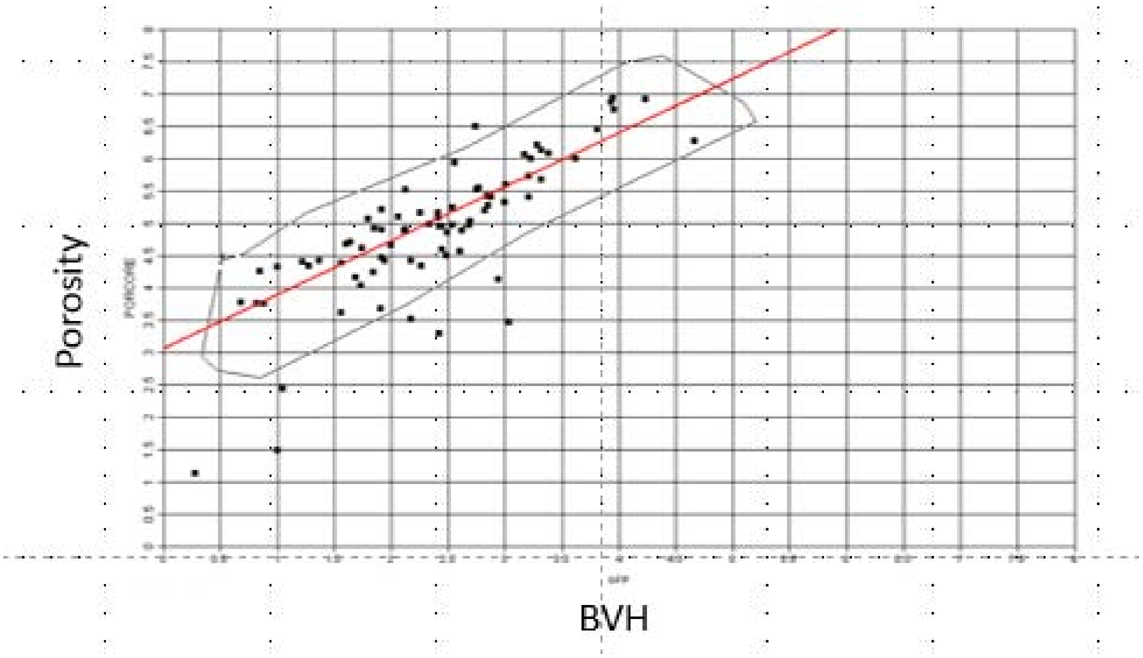

Fig. 2 Bulk Volume Hydrocarbon vs Porosity Plot
Sw = BVI/porosity, BVI shown above 3%

Role of Total Organic Carbon

Many operators devote a lot of attention to the TOC measurement, however in liquids rich organic shales the TOC can be both mobile oil and organic matter and that makes it difficult to separate the kerogen component for analytical modeling. Most of the correlations involving TOC are regressions with bulk density and are only valid in zones with low matrix porosity since the density log cannot differentiate between porosity and kerogen. In gas prone shales (Marcellus and Eagle Ford gas window for example) the TOC measurement can be used to estimate kerogen volume, however the overprint of porosity introduces some uncertainty unless it is accounted for. In one study done in oil shale (containing only Kerogen and water filled porosity) a log based correlation between grain density (from bulk density and NMR porosity) and TOC had a significantly higher correlation coefficient (0.98) than the model from bulk density alone that the majority of the industry uses (generally in the 0.75-0.8 correlation coefficient range.) An empirical local model using both a bulk density and porosity input is recommended at a minimum with a tie to measured TOC (Fig. 3). If the correlation is good the TOC can be used in the analysis to refine the kerogen volume and sorbed gas in gas prone shales. It is also a useful proxy for Sw as the higher volumes of oil wet kerogen in the rock reduce the amount of capillary bound water. Useful empirical relationships have been developed with high correlation coefficients between Sw and TOC, the parameter has value if it is properly calibrated but the error bar from a density only correlation may be unacceptable.

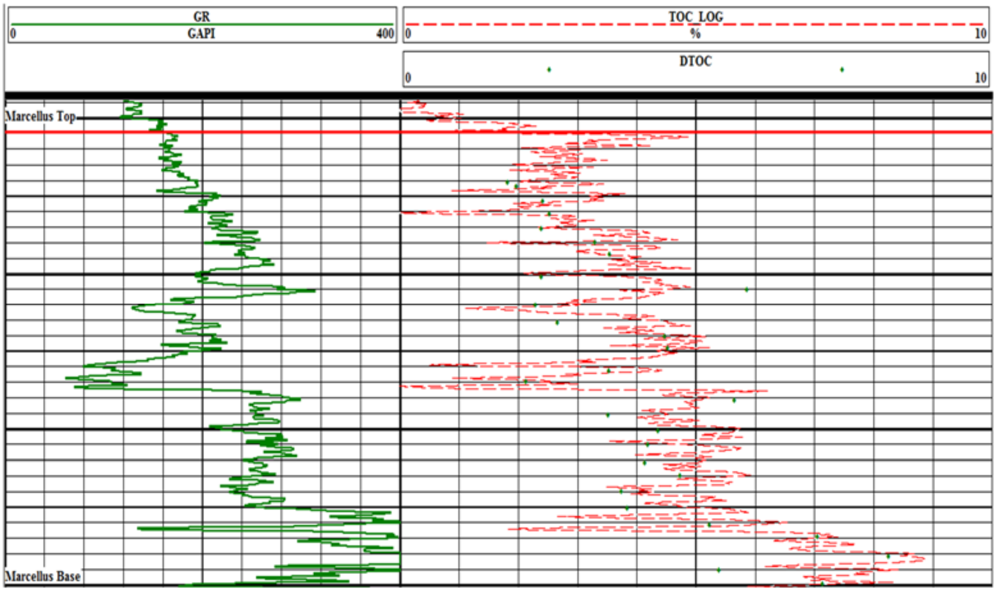

Fig. 3 Core vs Empirical Total Organic Carbon

Organic Zone Delineation and Kerogen Correction

For unconventional organic plays an additional correlation is done between spectral gamma data and conventional TCOM log curves to provide a synthetic spectral GR curve for all wells (Track 1 Fig. 1). This flags the organic zones and indicates where a kerogen correction is appropriate. A TOC curve can be used for this as well subject to the limitations discussed above. A first pass is made using a conventional analysis model with density porosity and a core (XRD or FTIR) or ECS calibrated clay volume to obtain an effective porosity plus kerogen volume. The kerogen correction is normally done using a multivariable regression technique that ties the TCOM log data to core porosity to remove the kerogen effects. In the Wolfcamp and Cline a reasonable empirical correlation between core porosity and log data was obtained using normalized density porosity, the synthetic spectral gamma ray, and conductivity. The theoretical basis for the correlation is based on the work done by Passey et al to quantitatively estimate organic content from porosity and resistivity data.[1] The model was applied to a variety of areas in the Midland Basin and Eastern Shelf and was validated multiple times with core data. Fig. 1 shows this and the other typical curves presented in the hydrocarbon pore volume analysis.

Normalization Process

Once the calibration process is done and prior to the calculation of volumetric reserves the raw data needs to be normalized among the available logs. Many of the shale projects are in areas with legacy open hole log data and all data points should be considered before developing an area. While the correction factors are often not significant, the reduction of the shale corrected effective porosity by the kerogen volume often results in effective porosities within a percentage point or two of the pay cutoff. In several large organic shale projects the normalization process changed wells from sub-economic to economic and vice versa as significant net pay thickness variations occurred when zones fell below or above the cutoff due to un-normalized data.

Net Pay Model Development

Once all of the basic log inputs are calibrated an accurate net pay estimate can be made for most conventional reservoirs based on perm and Sw. A permeability cutoff is difficult to apply in organic shales since the permeability estimates have a much higher error bar than in conventional rocks. An additional complication in organic shales is the disconnect between core matrix permeability and DFIT permeability (Figs. 4 and 5). In the case presented the DFIT permeability (0.027 mD or 27,000 nD) was significantly higher than the core permeability from the GRI method (14 nD “as received” and 180 nD “dry”). If an apparent permeability from the leakoff coefficient (C_t) is estimated from the Leshchyshyn equation the estimate increases to approximately 2000 nD (Eq. 1).[2]

(1) $C_t = 0.005*(k)^{0.5}$

Where:

k= effective permeability from well test

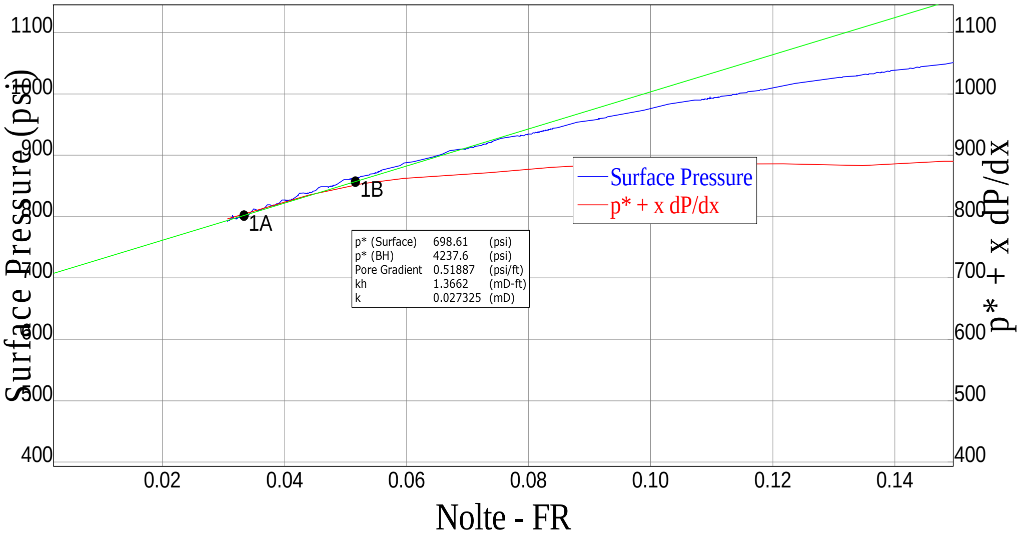

Fig. 4 DFIT analysis with 0.027 md in organic shale

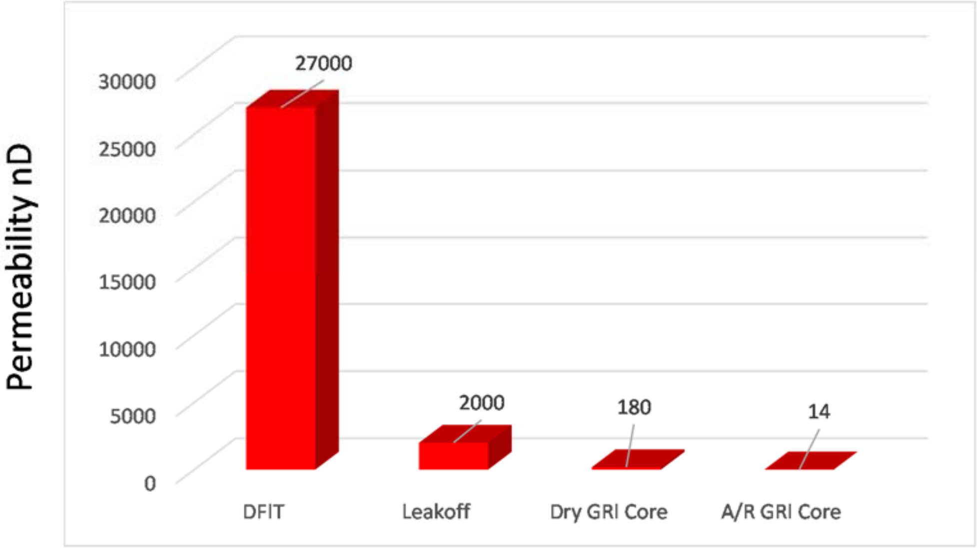

Fig. 5 DFIT vs Leakoff and Core Permeability

While there is probably more of an error bar in this equation than in the DFIT analysis or the core analysis, intuitively a leakoff coefficient of 0.0002 ft/min ^{½} is more characteristic of a 1000 nD reservoir than a 27,000 nD reservoir as a reality check. The fluid efficiency calculated from the DFIT of 96% further supports this. This suggests the fracturing process has opened up natural fractures in the rock to increase fluid mobility and that the frac has actually increased the effective permeability of the system. It also suggests that using core permeability for net pay or performance estimates in shales can be problematic since it is not representative of the flow capacity. This reinforces the use of the recovery factor process since permeability is not a direct input to well performance predictions other than possibly a minor role in establishing pay cutoffs. For that function in organic shales the porosity vs BVH plot can be used to determine the porosity cutoff where BVH = zero (Fig. 2). Porosity values less than that cutoff should not have any matrix perm, and some operators use that value for a porosity cutoff outright although that may be optimistic. In a recent large scale study done in the Midland Basin a 5% porosity cutoff was applied to over 500 organic wells in the organic shale sections and the results appear to be reasonable as the study will show in the subsequent sections of this study. Some operators use a bulk volume hydrocarbon cutoff (such as 3%) instead of a simple porosity and Sw cutoff and that has some merit as well.

Comparison to Production Data

From this process an estimate of volumetric reserves can be calculated. For all reservoirs this “recovery factor” analysis is based on a comparison of original hydrocarbons in place with estimated ultimate recoveries (EURs) from decline curve analysis. EUR estimates are preferred, however for well performance comparisons and “best practices” shorter common production periods (preferably 6 months or longer) can be used to normalize performance without estimating an EUR.

While this is probably obvious, individual well production declines are needed vs lease production values from multiple wells. This complicates the analysis of public data where often only multi-well lease values are reported. In Texas only gas wells have individual well production reports in most cases unless it is a single well lease for an oil well. Oil wells are allowed to commingle production at the surface from multiple wells on the same lease. For oil wells with only public data the only valid candidates are single well leases prior to commingling with other wells. Operators typically measure each well separately internally, though, and can evaluate their wells accurately. For offset wells with only public data the process is more complicated and hopefully the annual tests provided to the regulatory agencies are truly accurate for allocation of the lease production.

For EUR estimation most operators use conventional decline curve analysis with an initial rate of decline in the 70 to 90% range, hyperbolic exponent in the 1.5 range, and a terminal decline rate that is generally single digit. Several attempts have been made to correlate initial rates to ultimate recoveries and the correlations have frequently been problematic. This typically improves with more lengthy production histories but still needs work. Frantz[3] developed a correlation between the top three months performance in the Barnett with five year performance and there was a fairly strong correlation (Fig. 6). There was no attempt to extrapolate the EURs to conduct a similar comparison though. Barba and Shook[4] used an empirical correlation between highest monthly gas rate and EUR from an extensive database of South Texas Wilcox and Vicksburg wells and the results were encouraging there. The jury is still out for unconventionals, though, for doing a simple initial rate to EUR correlation.

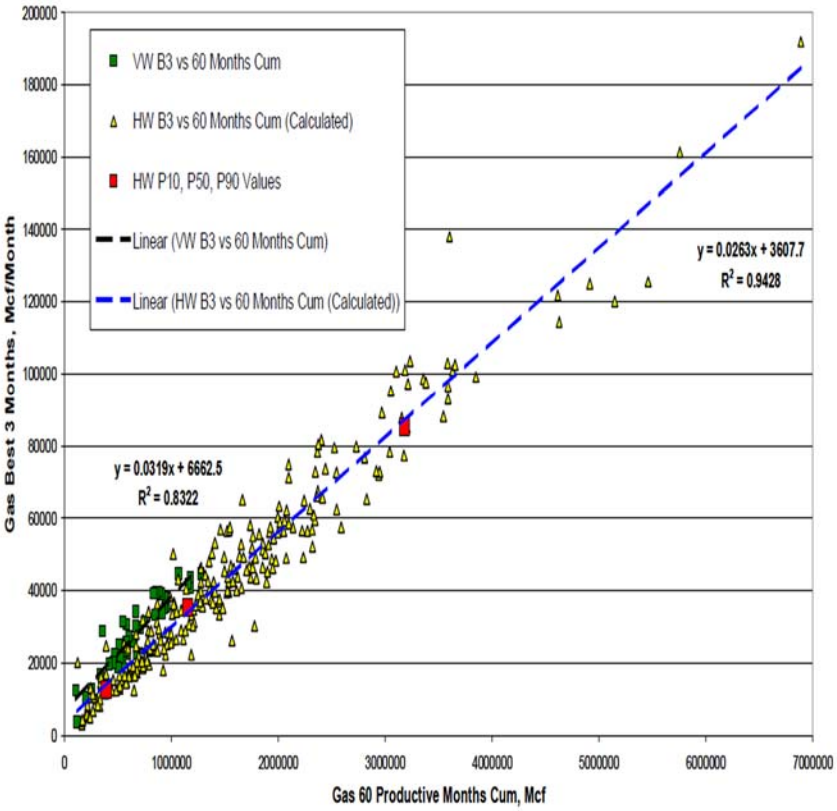

Fig. 6 Barnett 3 month oil vs 5 year oil

As noted above, the absence of a clear EUR for a wellbore does not preclude the process from normalizing well performance results among wells with varying oil in place values (either laterally or vertically depending on where the lateral is landed). Once a finite block of reservoir is identified from the location of the lateral and the expected conductive height for each stage a recovery factor can still be estimated using whatever production data are available. Shorter terms of production can be used, however 6 months or more is recommended if possible. For the second objective of forward modeling the production as a function of lateral placement the process can still be used, although the output of this analysis is a forecast of the production only over the same common time period. For the third application of providing a range of reasonable conductive heights this shorter time period may not be adequate, though, as the only "rules of thumb" for recovery factors involve a percentage of the original hydrocarbons in place as a function of the drive mechanism. For tight gas reservoirs the values are in the 70 to 80% range, with the expected recovery from nanodarcy rock toward the low end. For solution gas drive oil reservoirs the expected recovery is less than 10% since that value is typical for tight conventional reservoirs and again for nanodarcy rock the numbers should be lower than conventional rock.

Determination of Drainage Area

Once the reservoir properties are estimated from the process above a determination needs to be made for a drainage area. This is a function of the expected future lateral patterns within a development area and that depends on lateral length and spacing. This is one area of the analysis that is truly "work in progress" since the issue of lateral spacing is a trial and error process that requires testing of various spacings to optimize the process. Several published studies have outlined pilot projects where more aggressive spacing is tested but those are not routinely done. In many cases operators will follow the lead of the offset operators in a play without directly testing any spacing hypotheses.

For the Midland Basin Wolfcamp and Cline a common configuration for recent wells is six wells per 1.5

sections, with twelve 7920 ft laterals going N-S in the 3 section block (six in the North and six in the South) (Fig.7). For this configuration it is proposed that a 160 acre drainage area be allocated to each lateral if they extend the full 7920 ft and have stages placed as close together as mechanically possible (200 to 250 ft). This should be a function of Young's modulus since the strain imparted by the previous frac converts to stress as a function of Young's modulus. In higher modulus rock more of the imparted strain is converted to stress in the subsequent stages and vice versa for lower modulus rock, implying that stage spacing can be shorter in low modulus rock and longer in high modulus rock due to stress shadowing.

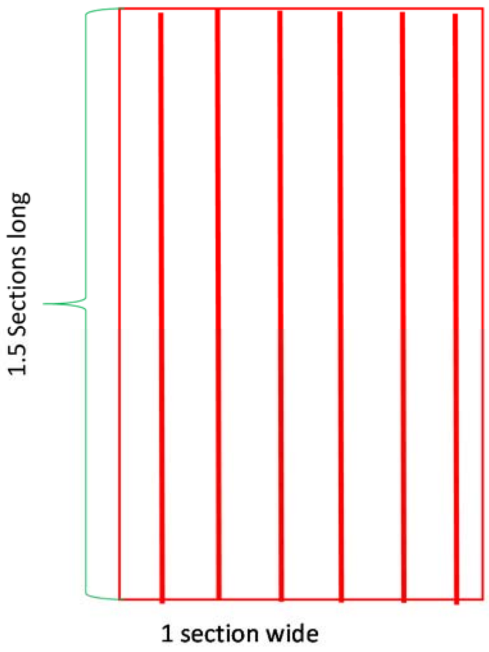

Fig. 7 Typical Midland Basin Wolfcamp lateral configuration

Assuming that the spacing is as close as possible to avoid significant inter-stage stress shadowing the next consideration is the number of effective stages with the pay and wellbore connected via either propped or unpropped fractures. Within the lateral adjustments need to be made for the percentage of successful stages to adjust the overall drainage area. This involves a review of the vertical location of the laterals within the pay column. From all of this Eq. 2 is proposed to calculate the appropriate acreage allocation to the oil in place estimate:

(2) Drainage area = (Gross perforated interval/7920)*160*% of effective stages

In-situ Stress Profile Development

A key part of the process is the estimation of vertical frac extent, with the initial emphasis on the conductive height. This involves the development of a mechanical properties profile to help characterize the vertical in-situ stress and Young's modulus distribution to model the propped frac height above and below the lateral. With regard to vertical stress characterization, quality control of the dipole sonic data is an important step. The primary QC technique is the coherence flag, where a value of 1 is 100% coherent and 0 is totally incoherent. Development of a synthetic Poisson's ratio from the triple combo data and coherent dipole data is needed for both quality control of the data in the wellbore logged with the dipole and for offset well rock property estimates where no dipole data is available.[5] In the majority of studies done to date (several hundred so far) a 90 to 95% coherency (0.9 to 0.95) cutoff is needed to obtain the highest possible correlation between the empirical synthetic dipole data and the coherent data. The dipole tools in use today cannot acquire 100% coherent data due to the lack of borehole compensation and the length of the receiver array. The coherence measurement looks at the transit time differences between receivers and if there are variations in velocity within the array the data will be flagged as incoherent. This is why you frequently see incoherent data at bed boundaries between faster and slower transit time rocks. With the quality dipole data and synthetic model in hand, an in-situ stress profile can be generated from Eq. 3:[6]

(3) Closure Stress Gradient = $(OBG*(\nu/1-\nu))+(1-(\nu/1-\nu))*PPG + Pext$

Where :

ν = Poisson's ratio
OBG = Overburden gradient psi/ft
PPG = Pore pressure gradient psi/ft
Pext = Calibration factor psi/ft

Alternate equations to the above have been proposed to incorporate Youngs modulus vs tectonic strain and vertical anisotropy, however in most areas the above equation is adequate to identify the location of the stress "benches" which is the critical input vs the exact magnitude of the stress contrast unless detailed modeling is done. For detailed 3D frac modeling of a shale fracture treatment there are several models available, however the principal unknown is what the injection rate per cluster is when there are multiple clusters. In most cases where production logs or fiber optic temperature arrays are in place there is typically one dominant cluster and sometimes a second cluster with some contribution. None of the studies have ever suggested that all clusters are producing at all vs. producing equal quantities of hydrocarbons as the "limited entry" technique intends to accomplish.[7,8] A "rule of thumb" that has been used with reasonable results is 50% of the stage rate and volume will be focused on one of the multiple clusters. This estimate can be refined with fiber optic temperature arrays and it will change once more hard data are published. For wells without shear sonic data the "benches" should correlate to layers with either high shale content or high carbonate content with low porosity. Once the in-situ stress profile is complete the lateral landing interval for each stage can be superimposed on the profile. From that the location of the stress "benches" can be determined below the lateral and an estimate of propped height can be made either using a 3D model or following the guidelines in the later section on conductive height (50 to 60 ft expected height regardless of fluid type) (Fig. 8). A comparison can be made to the lithology layers that provide the "benches" to estimate conductive height bases in offset wells without the dipole sonic information.

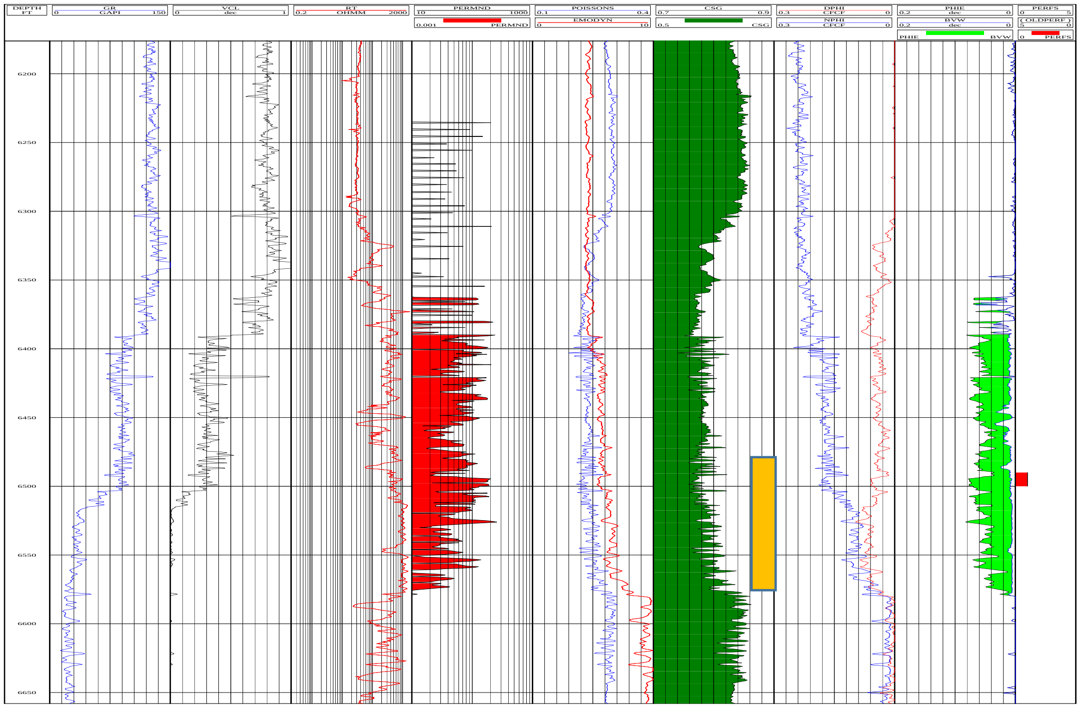

Fig. 8 Utica stress "bench" vs expected proppant distribution

Young's Modulus Estimation

The second major output from the dipole/triple combo suite is Young's modulus, a key input to frac modeling and the brittleness equation that will be discussed in the next section. It can be estimated from Eq. 4:

(4) Edynamic = 2*(13400*(RHOB/^DTSM^2))*(1+ν)

Where:

RHOB = bulk density
DTSM = shear transit time

The dynamic measurement needs to be converted to static, with a conversion factor of 50% for low modulus rocks (2 to 3 e6 psi). For higher modulus rocks the conversion can be done with Eq. 5:[5,9]

(5) Estatic = Edynamic * 0.85 -0.424

Brittleness Estimation

A lot of operators used the "brittleness" estimate to optimize the landing zones in organic shales. It is calculated from Poisson's ratio and Young's modulus with Eqs. 6-8:[10]

(6) Young's Brittleness = (Estatic-1)/7
(7) Poisson's Brittleness = (ν-0.4)/(0.15-0.4)
(8) Average Brittleness = (Young's Brittleness+Poisson's Brittleness)/2

Operators routinely comment on the need to land laterals in brittle rock, however that goal alone may not be adequate to ensure optimum results particularly where the organic shale has a high carbonate content and correspondingly higher Poisson's ratio (and sends the above equation in the less brittle direction). It is well known that ductile shales are not conducive to fracturing as less ductile shales, and generally this is reflected in the clay content. It is recommended that clay volume, hydrocarbon pore volume, and the in-situ stress profile be used to optimize landing zones in these cases rather than just "brittleness" as the technique has some shortcomings. In one case an operator landed multiple wells in a relatively ductile zone when offset operators were targeting more brittle zones above in the pay column. Well performance lagged the offset well results even though the log analysis indicated economic volumes were present. The higher clay content could have reduced the "brittleness" enough to limit the conductive height after the frac or the generation of secondary fractures that are needed to enhance the poor matrix permeability in organic shales. The fracs were typically well executed using industry accepted "best practices" and the poor performance of the wells is most likely related to the reservoir conditions.

Well Performance Comparisons

Numerous methods have been proposed to date to normalize the performance analysis of frac treatments in organic shale reservoirs. Without this normalization process any comparisons of well performance based on production alone are clouded by the uncertainty of whether the results are a function of the reservoir properties or the completion process. A review of numerous studies on the "optimum" completion techniques for various areas indicated that well production alone was the primary criteria with no consideration for the reservoir properties. In a particularly notable group of eight SPE papers done in the Pennsylvanian Red Fork four of the studies recommended crosslinked gels, one recommended linear gel, and three studies recommended CO2 foams. A subsequent recovery factor study done on 135 wells showed clearly that the well fracced with CO2 based systems (assists and stable foams) outperformed the crosslinked gels (XLG) and viscoelastic surfactant (VES) wells by a factor of three (Fig. 9). The other eight SPE paper studies used only production rates to determine the "optimum" treatment fluid. In this study the VES systems were not energized, subsequent to this studies have shown improved performance from foamed VES systems and the comparison is not intended to diminish those findings. In one notable study the authors used effective frac length from rate transient analysis to normalize the production results vs simple production comparisons. While it is probably not as robust a technique as the process described in this paper, it is significantly more credible than the great majority of studies on "best practices" based on production comparisons alone.[11]

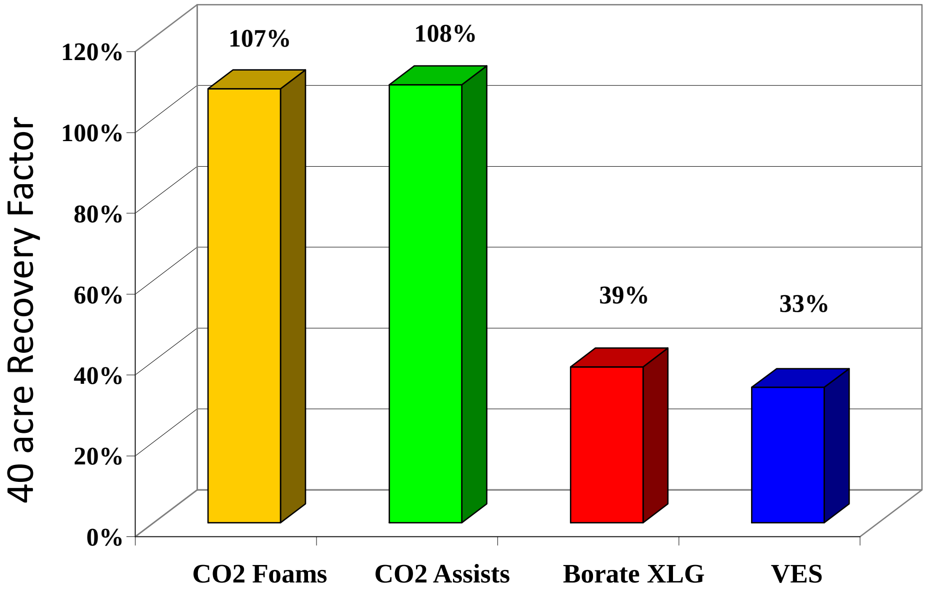

Fig. 9 Recovery Factor Comparison Red Fork
5 of 8 SPE paper studies did not recommend CO2

Conductive Height in Unconventional Laterals

A key "best practice" in shales is to connect the wellbore to the pay via either propped or unpropped conductivity. In several production logging case studies there were totally unproductive stages where the laterals were apparently in the target zone (Fig. 10).[12] This is important in that individual clusters are frequently not effectively stimulated in every stage with more than one cluster and that is to be expected. It is unlikely that the wellbore entered a portion of the reservoir that had no pay, though, due to the relatively consistent stratigraphy present in the shales. Within a stage, however, at least one cluster should be producing and that was not the case in these studies. One of the key selling points for unconventionals to the investment community is the repeatability of results in the shales due to this relative homogeneity. This significantly reduces the probability of a stage encountering a non-productive interval in the lateral provided it is in zone. In all microseismic studies observed to date the frac events are typically 100 to 300 ft high and rarely are out of contact with the lateral. In most cases now operators are pumping from 1500 to 2000 lb of proppant per foot of lateral or 400,000 to 500,000 lb per stage. With this in mind how can a stage produce no hydrocarbons in a relatively homogeneous pay interval? When these plots are shown to operators a common explanation is that the zones that are not currently producing may eventually come on line as wellbore flowing pressure draws down. While this is conceptually possible, there are indications from permanent temperature sensors that suggest otherwise and that non-producing zones rarely start producing significant fluids over time. The problem is more likely a poor connection between the wellbore and the conductive height created by the frac treatment.

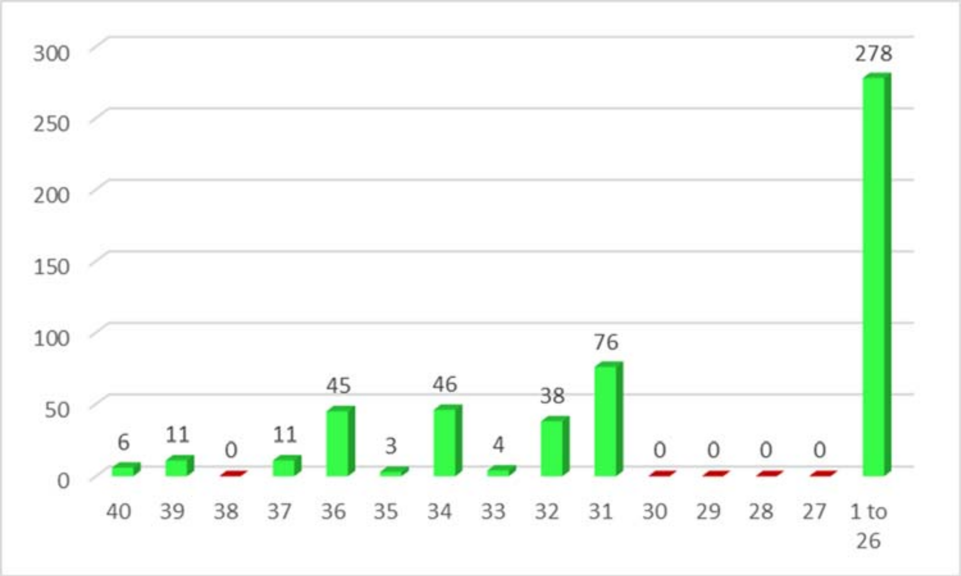

Fig. 10 Bakken PLT results by stage (SPE 160160)
5 of 14 stages with PLT data 0 production rate

Fig. 11 Tracer Height vs Net Pay Thickness
Microseismic frac heights 300 ft +/-

Propped Height vs Conductive Height

In one study with five post frac tracers in a vertical pilot hole the propped height ranged from 50 to 55 feet in pay zones that ranged from 90 to 115 ft thick and in an area where microseismic height typically ranges from 250 to 350 ft (Fig. 11). There was a good stress barrier below the pay to discourage downward settling. Studies have shown that laterals that are either in or in close proximity to the proppant bank perform significantly better than those with higher trajectories (Fig. 12).[13] In high modulus shales (Barnett in particular) well trajectories are frequently above the main pay. In the Barnett high landing targets are frequently chosen to help avoid fraccing into the Ellenberger water zone below. Operators have been successful there, however, in spite of not having a solid connection to the proppant bank. The formation where the tracer were run was relatively low modulus (2E6 psi), and this probably plays a role. If it is Young's modulus dependent the problem may extend to other shales. The figure below shows the distribution of Young's modulus among the major shales. The Barnett, Bakken, and Montney all have high moduli, all of the other shales are low modulus (Fig. 13).

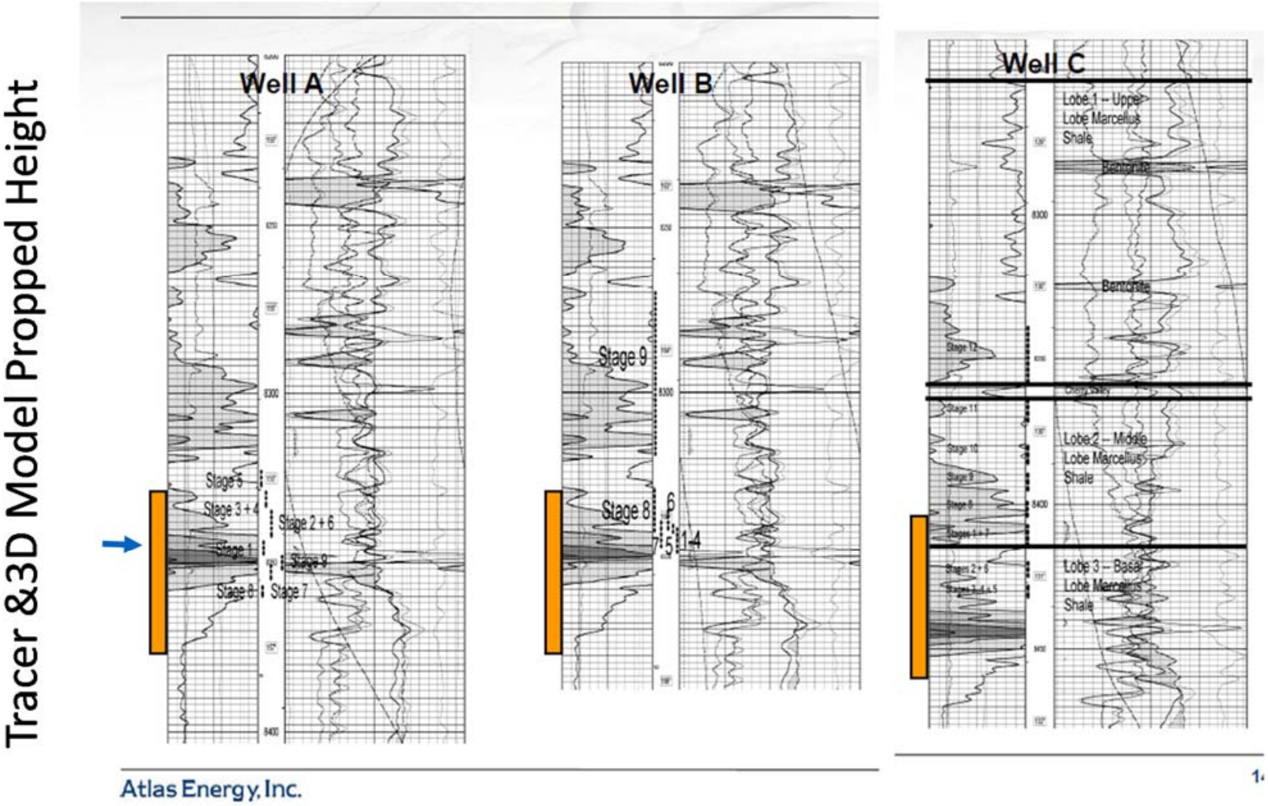

Fig. 12 Marcellus trajectory comparison
Wells A&B (in zone) 5-6 MMCFD, Well C out and 1.5 MMCFD

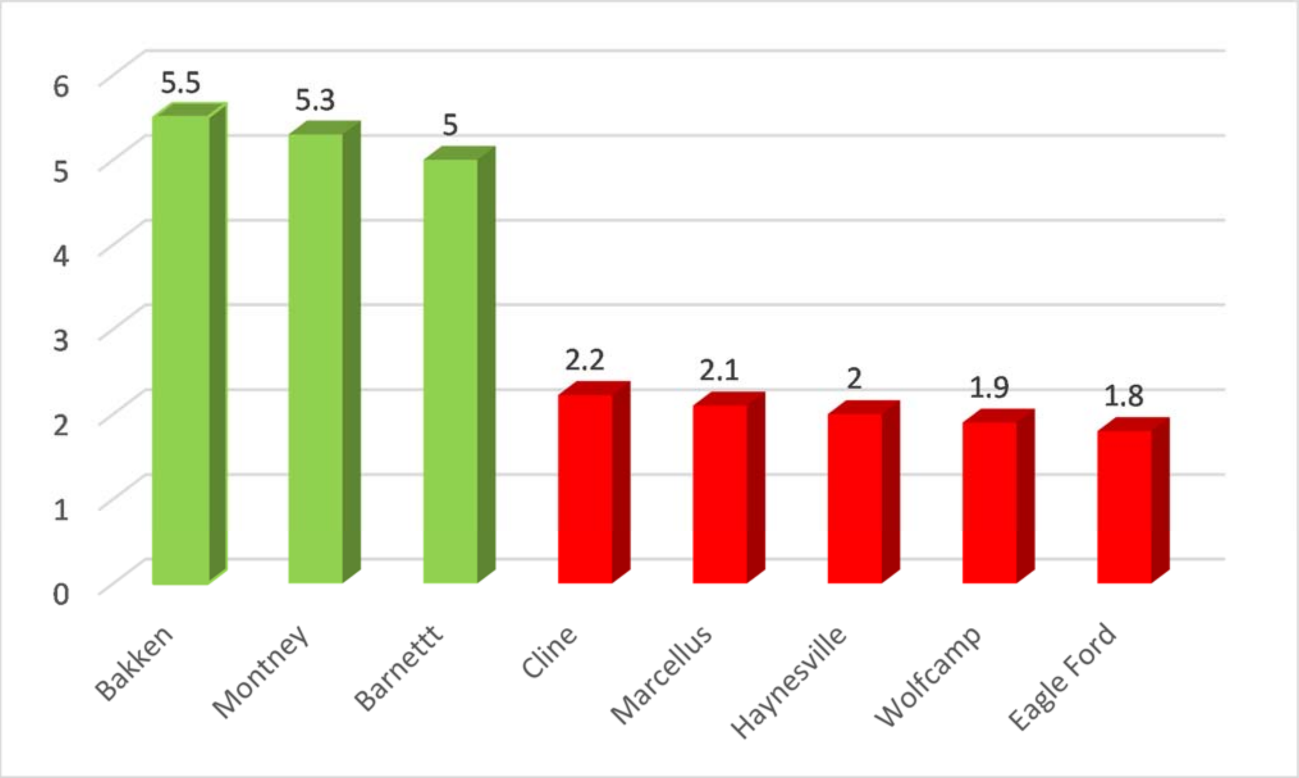

Fig. 13 Static Young's Modulus by Formation

Improving Conductive Height

The key issue driving the limited propped height in nanodarcy shales is the disconnect between gel break time and fracture closure time. In the DFIT presented in Figs. 4 and 5 and again in Fig. 14 the closure time was 60 hours, and the maximum break time with current technology is 2 to 3 hours. In one misguided attempt to lengthen the break time side of the borate system by lowering the breaker loading from 1.0 gpt to 0.5 gpt the load recovery profile was significantly different from previous jobs with the higher loading and that is not recommended. With slickwater fracs this is well understood as proppant transport is generally a banking phenomena where proppant is "dumped" into the formation and it stacks up from the stress barrier below the lateral. What is not as well understood is when gelled fluids are used the initial modeled proppant distribution is close to the created heights (200-300 ft in most cases) yet after closure the propped height is identical to the slickwater propped height. Fig. 15 has a vertical pilot well tracer log where a hybrid slickwater and borate treatment was pumped with identical propped height profiles. Of interest here is the use of a 3D frac model to forecast the propped height with the slickwater frac (Fig. 16). While modeling the created geometry in organic shales can be a complex exercise, 3D model propped height typically agree well with tracer surveys. This is reasonable as the rheological properties of slickwater are relatively consistent and the proppant banking mechanism is fairly predictable (see Fig. 11 with the relatively consistent tracer heights with slickwater regardless of proppant volumes).

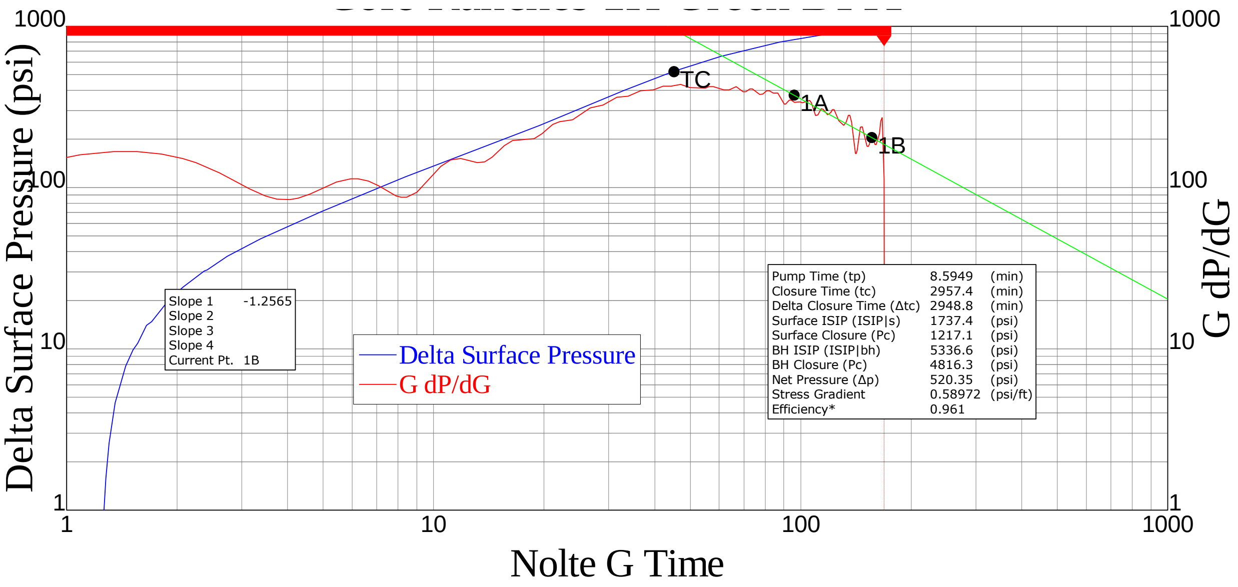

Fig.14 Closure analysis indicating 60 hour closure time

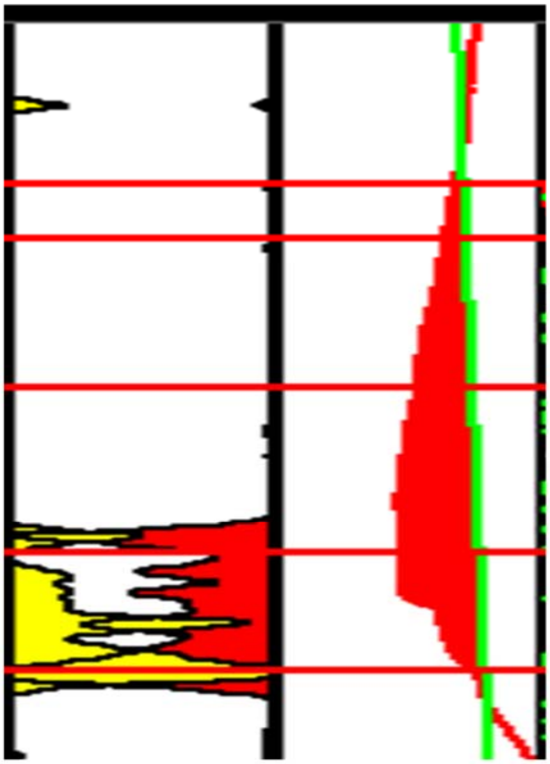

Fig. 15 Tracer Height Slickwater (yellow) vs Borate (red) Temperature survey on right for created height

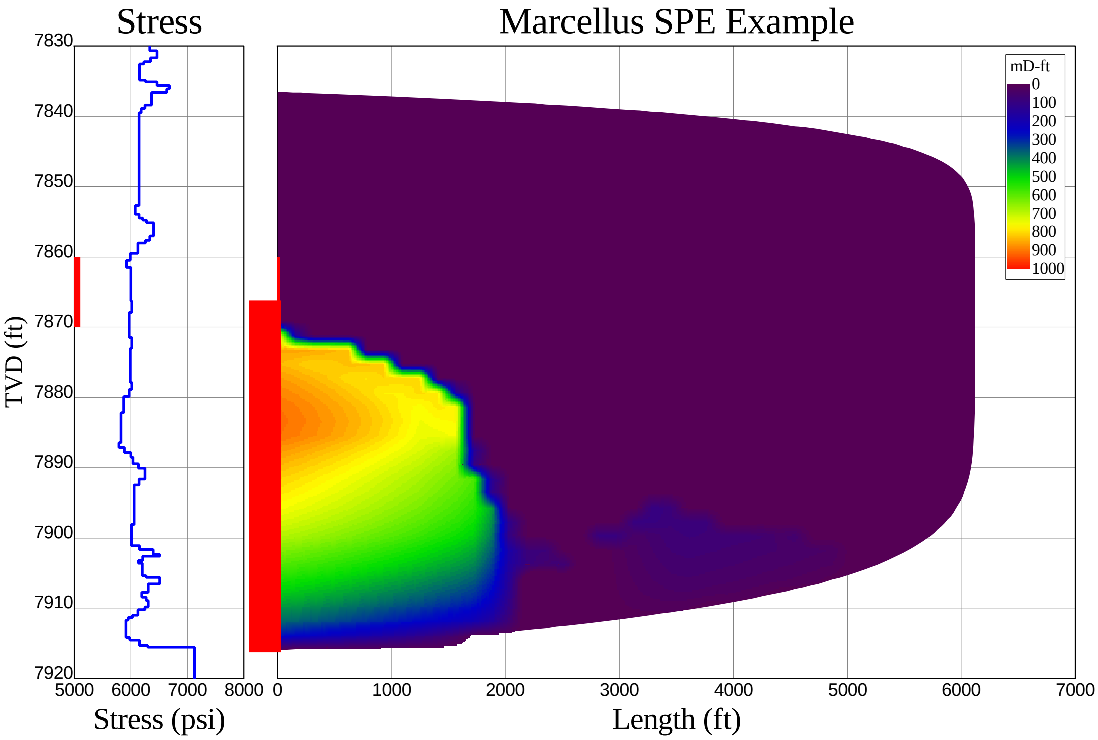

Fig. 16 Slickwater 3D Model Propped Height vs Tracer (in red)

While the problem with conductive height is clear, what is not clear at this point is the optimum solution. It is not recommended that the fluid viscosity be increased as whatever the initial values are they will eventually be broken by the time the frac closes. One possible option is to conduct “forced closure” after each stage to reduce the closure time. It is not known if that will expedite the closure in nanodarcy rock, however, and a vertical pilot rest is recommended prior to executing it in the lateral. The mechanical setup for this operation in the lateral should involve fraccing down the annulus with coiled tubing in the hole and using either coil actuated sleeves or hydrajet slots for perforations. This configuration should also minimize the overflushing process that is utilized in the conventional “plug and perf” technique. In one study done in the Bakken[12] the stage performance improved with lower flush volumes. The primary moving part that causes the “plug and perf” operation to depart from traditional vertical well “best practices” is the overflush and that would be the first area to look for improvement.

Another option that is available is the use of lightweight proppants. On the positive side the specific gravity of the proppant is 1.06 and the volume needed to create an equivalent propped volume to conventional sand proppant is reduced by 40%. On the negative side the wholesale cost per pound is in excess of $2 a pound and for a 250 ft stage with 2000 lb of sand per foot of lateral the 500,000 lb sand job becomes a 200,000 lb lightweight proppant job. At a wholesale cost of $2 a lb this is $400,000 per stage and for a 30 stage operation the total proppant cost would be $4.5 million more than a 30 stage treatment with 500,000 lb of sand per stage. The increased production will need to cover that increase and at this time operators are reluctant to drive well costs that much higher for an unproven hypothesis. The hypothesis should be tested, though, as many shale plays have net pay thicknesses well in excess of the expected conductive heights and multilaterals are not always an option. With sufficient interest in the technology from operators service companies may very well rise to the occasion and find methods to drive the cost down to a more palatable level.

Additional options are available but published results with tracer confirmation have not been observed to date. These include self suspending proppant, [14, 15] in-situ chemical proppant generation[16], and fiber. The first two are relatively new technologies, however fiber has been in use for a number of years and is a key component of the "Hiway" frac system from Schlumberger. There have been several documented cases where Hiway has resulted in improved production[17,18], and a possible explanation exists in improved proppant transport. The promotional literature suggests that the primary driver for improved production is the creation of proppant "pillars" with infinite conductivity between the pillars. This explanation of the process is not universally accepted by the fracturing community, though, particularly in low modulus formations. Fig. 17 is a post frac buildup from a 2E6 psi Young's modulus formation that was flushed to the top perforation with ball sealers. The result of the overflush was the creation of an unpropped "gap" between the wellbore and the propped fracture much like the unpropped "gap" between the Hiway system pillars. The pressure transient analysis clearly indicates there is no propped fracture in communication with the wellbore even though 80,000 lb of 20/40 ceramic proppant was placed in the fracture. While this appears to be a negative for the process, the success of the process may very well be due to improved propped heights from the fiber. Confirmation of the improved propped height is needed, however, for all of the proposed remedies and operators are reluctant to invest in disposable vertical completions when the economics of horizontal completions are typically superior.

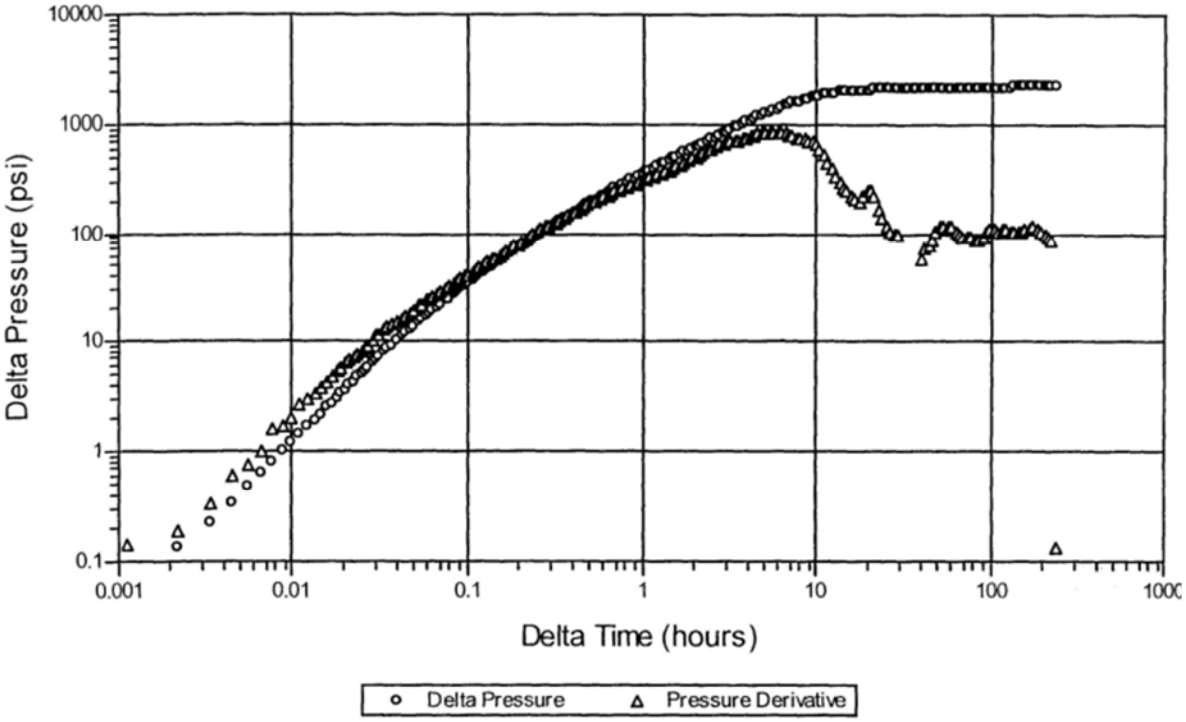

Fig. 17 Post frac pressure transient analysis after ball sealers
Low modulus rock-must prop to be conductive, "pillars" unlikely

An area where this is critical is in the Cline in the Midland Basin, with three separate pay "benches" over a 250 to 300 foot gross interval (Fig. 18). In many areas of the Cline there are adequate volumetric reserves in the aggregate for all three benches but with the 100 to 125 ft of conductive height the recoverable reserves are usually from one of the benches and possibly two. Fig. 19 is a plot of recovery factor vs both gross pay height and the percentage of the wellbore in the target interval. The lowest recovery factors are in thick pays with the lowest percentage of the lateral length in zone. The highest recoveries are in zones with less gross interval (100 to 200 ft) vs the wells with 300 ft of gross interval. Wells with only one productive bench had twice the recovery factors of the wells with 3 benches, suggesting the propped height covered a larger percentage of the total pay when the total pay was limited. It suggests that we are not effectively stimulating the entire pay column when gross thicknesses exceed 100 ft or so. What was not shown was an offset far to the east that had 65 ft of gross pay and the proppant bank should have covered most of the pay height. The recovery factor for that well was 11.8%.

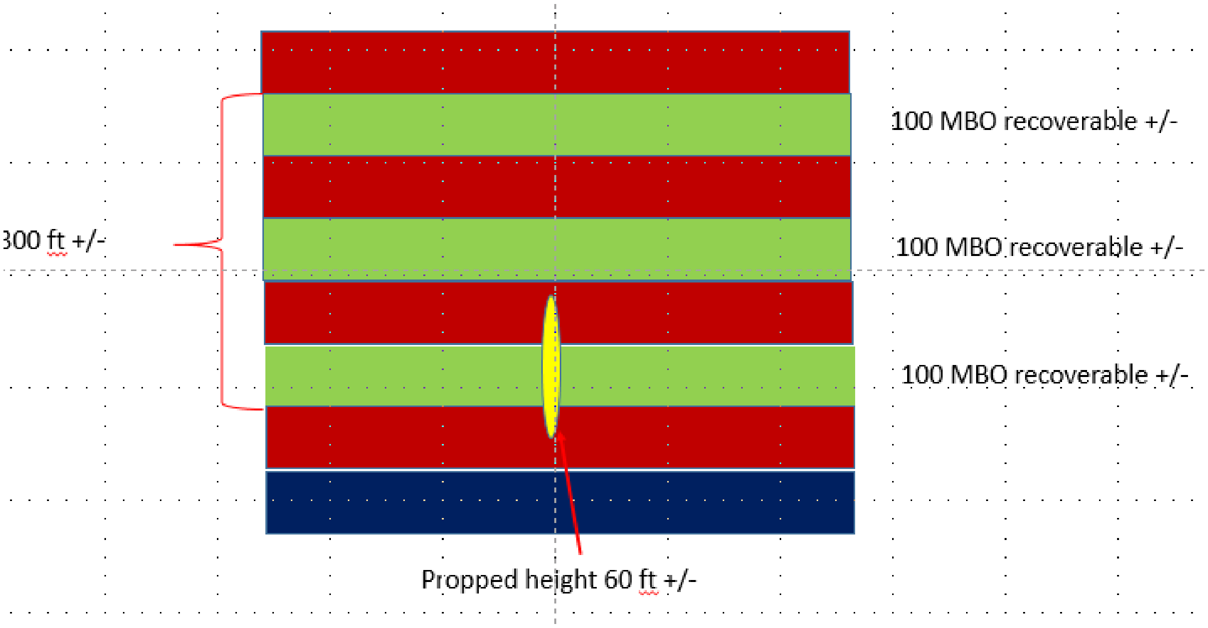

Fig. 18 Cline pay distribution

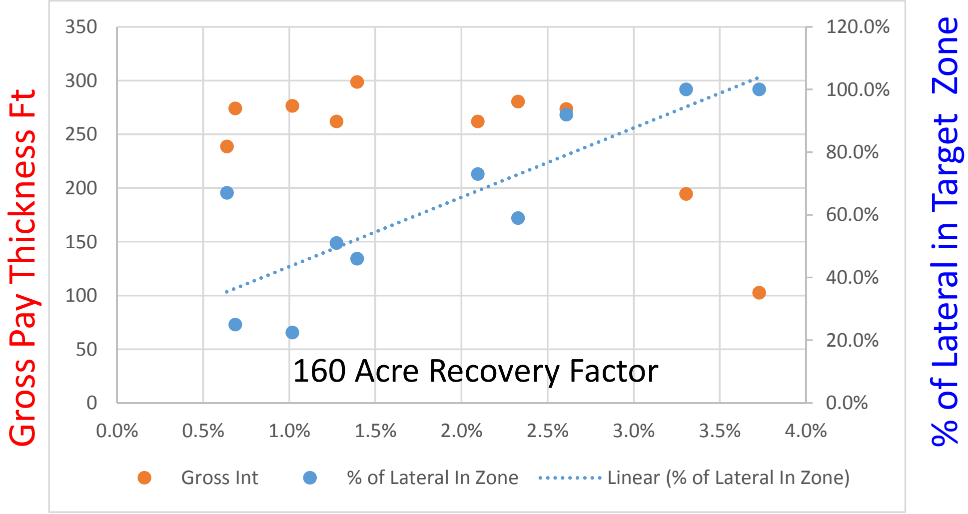

Fig. 19 Recovery Factor vs Gross Pay Height

Conductive Height vs Propped Height

A hypothesis can be made that the propped height is the conductive height, and a test of this can be done with recovery factor analysis. If only the propped height is contributing vs the entire pay height this may be apparent in a comparison of recovery factors for various heights. The analysis assumes that the frac will “bench” on the closest stress layer below the lateral and that all of the production is coming from the proppant bank and above. In a 123 well organic shale study this was done, and if only the propped heights were producing the recovery factors are unusually high (in excess of 10%). If the assumed conductive height was increased to 100 ft (60 ft proppant bank plus 40 ft of unpropped pay) the recovery factors become more believable, with the study average being 8.2% (Fig. 20). The standard deviation for this first pass attempt was on the high side (5.4%), however a lot of the data was based on limited producing times. The analysis should be revisited with longer times at a later date to help determine if the variability is being driven by the EUR analysis error bar or the petrophysical analysis uncertainty.

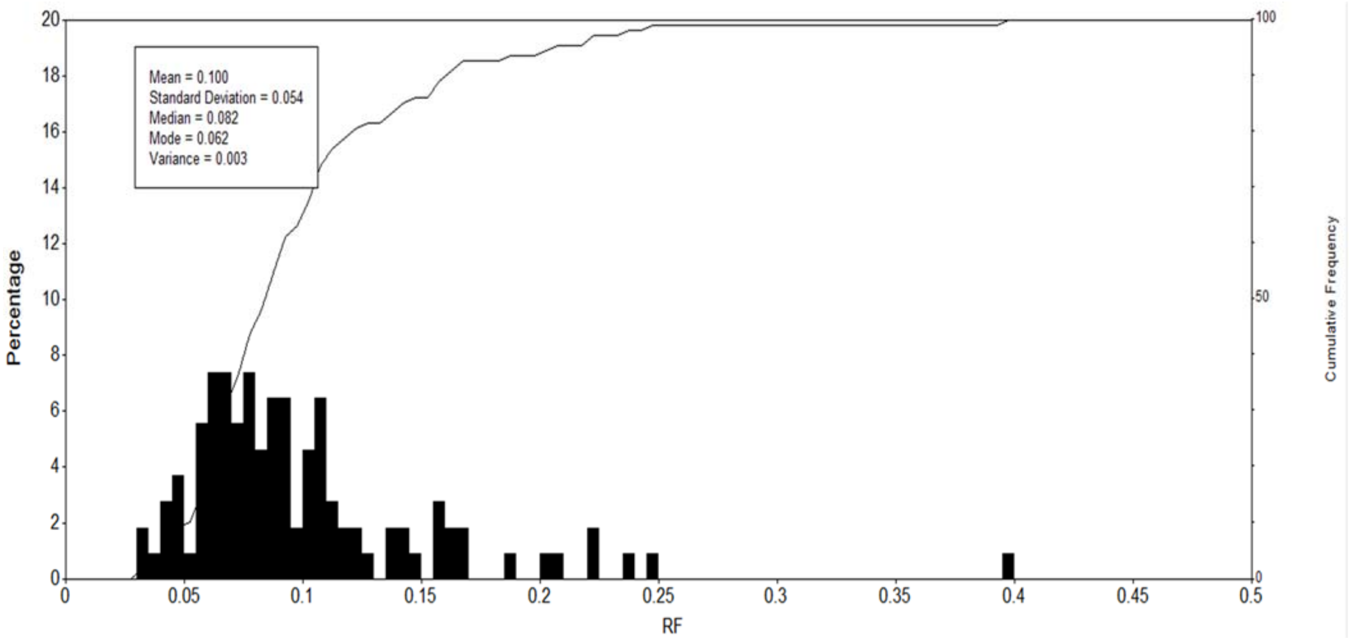

Fig. 20 Recovery Factor Distribution Midland Basin Wolfcamp

Predicting Performance vs Lateral Vertical Placement

When a recovery factor range is determined for an area, an estimate can be made from the hydrocarbon pore volume and in-situ stress profiles. The appropriate stress “bench” should be located from the in-situ stress profile and the expected propped height superimposed on the plot. An estimate of unpropped height above the propped interval is applied (50 to 100 ft additional appears to be the reasonable range). The recovery factor can then be applied to the original hydrocarbons in place within the conductive height to forecast the productivity of the lateral. To be fair to the data there should be an error bar incorporated using the average and then values out to one standard deviation, even though the average is the expected value.

Fig. 21 demonstrates the integration of the propped height estimate with the net pay plot. The stress “benches” are flagged on the right to indicate the most likely base of the proppant pack. The reservoir properties above the benches are calculated and an estimate is made of expected recovery using the average for the study (8.2% of the OOIP). A plot of expected recovery that clearly shows the “sweet spots” within the pay column is shown in Fig. 22. The stress profile in dark green has a distinct decrease at the top of the pay at the interface between the slightly overpressured Wolfcamp interval and the pressure depleted Dean sand. If the frac grows up into the Dean the length generation in the Wolfcamp is limited, with little or no length generated in the Wolfcamp. A Wolfberry microseismic study published in 2010 indicated that completions in the upper portion of the Wolfcamp can grow out of zone through the Dean and up in to the Lower Spraberry with no microseismic events recorded in the Wolfcamp (Fig. 23).[19] With that caveat in place, the combination for Figs. 21 and 22 clearly shows the “sweet spot” for landing the lateral and can be used to estimate the optimum number of laterals needed to drain the 1000 ft thick pay section.

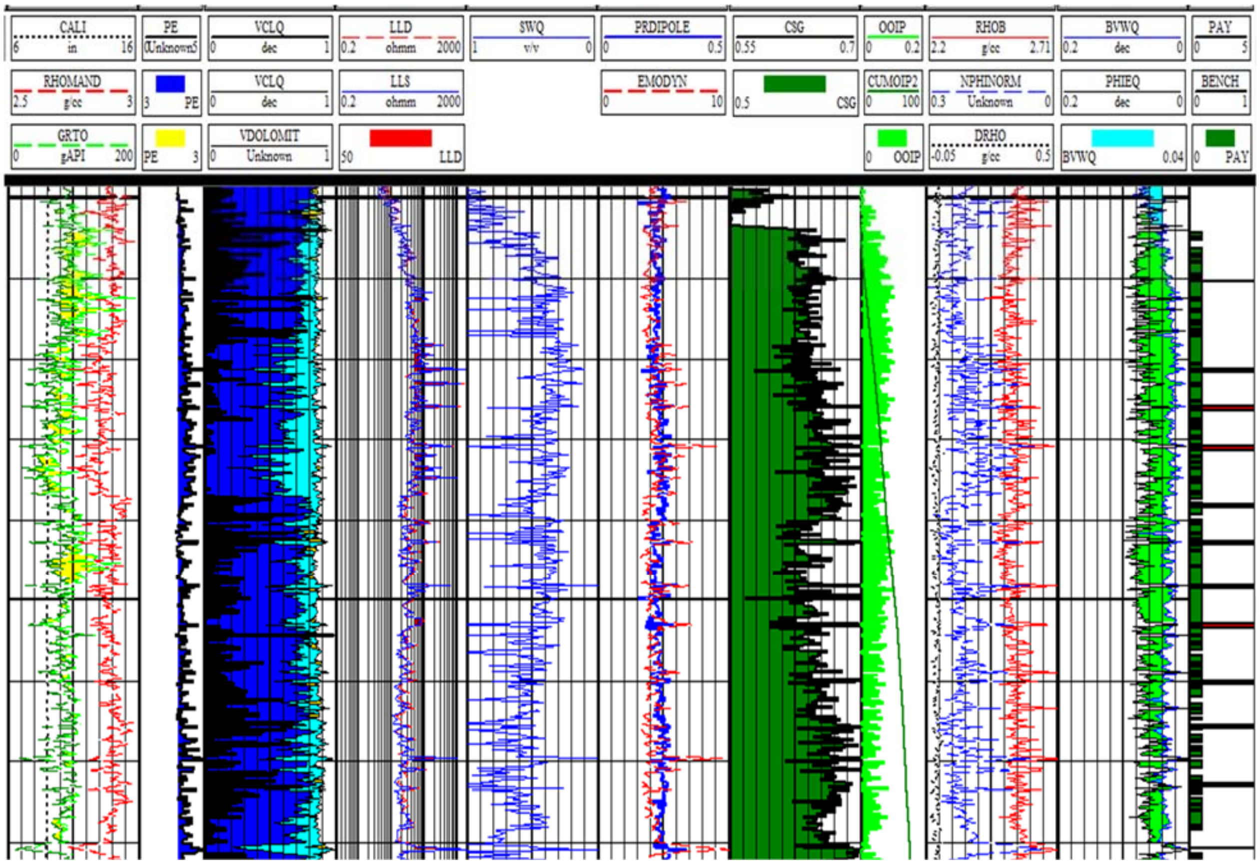

Fig. 21 Wolfcamp with Stress “Benches

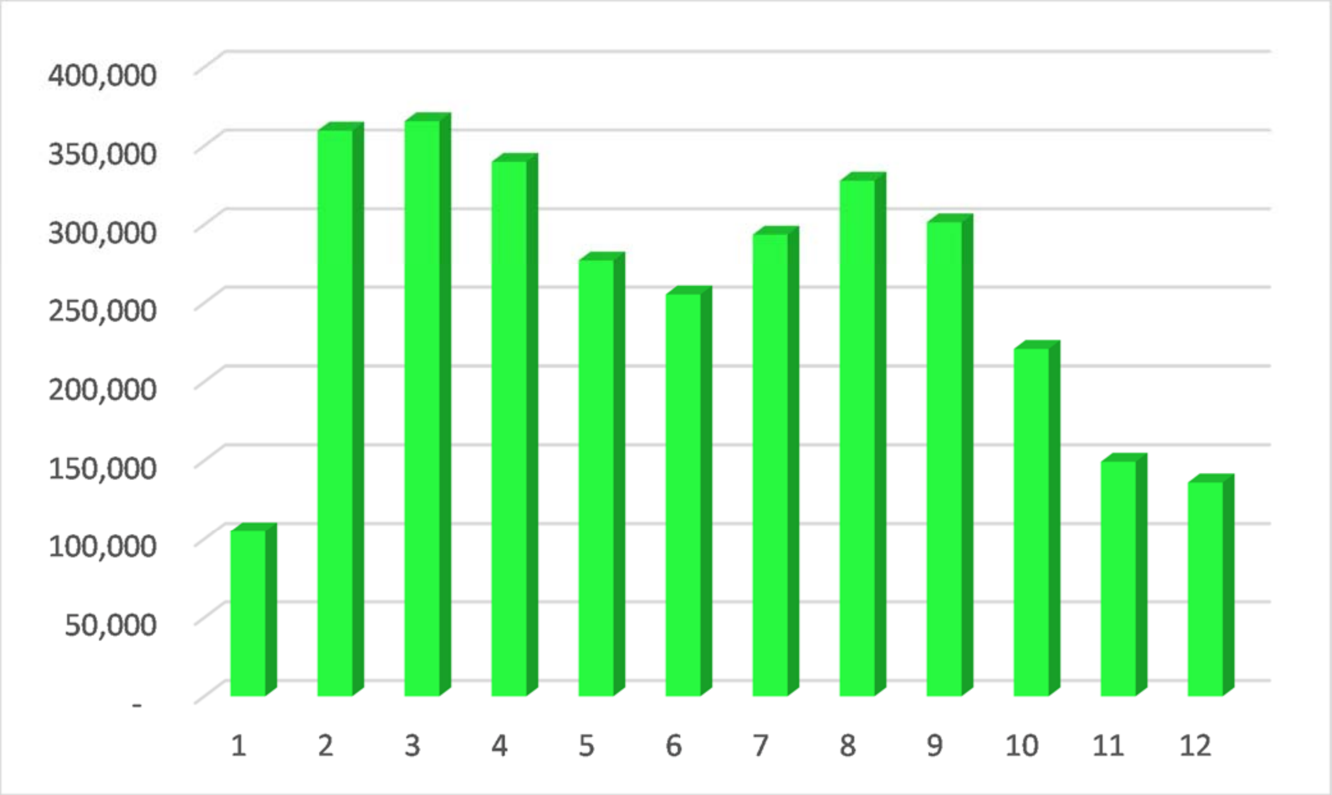

Fig 22 Expected recovery 150 ft above stress benches

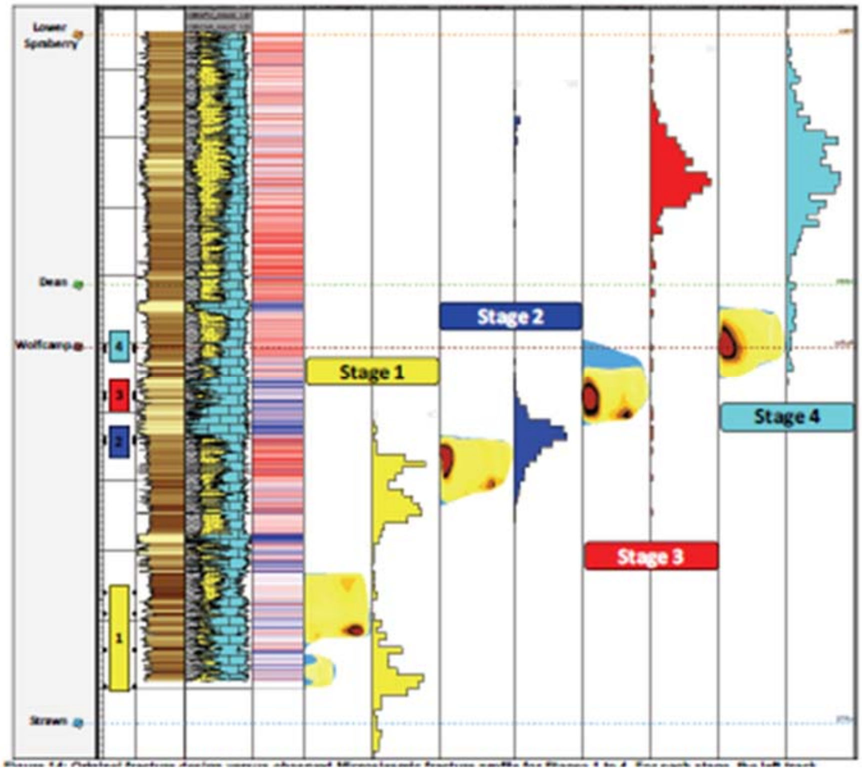

Fig. 23 Wolfcamp Microseismic with events in Lower Spraberry Source: SPE 137996

Implications of Limited Conductive Height

In some organic shales there is significantly more pay than the conductive height can drain. In the Midland Basin Wolfcamp the gross interval between the top of the Lower Spraberry shale and the base of the Cline/Wolfcamp D can be over 1800 ft with only the 150 ft +/- thick Dean formation non-productive within that interval. The Midland Basin Cline is discussed above with its issues. In the Delaware Basin the Bone Springs and Wolfcamp pay have the same issues, large vertical pay intervals that are significantly thicker than the conductive heights discussed above. One of the biggest challenges and perhaps the greatest opportunity that ensues from this is the possibility of highly productive multiple laterals in these plays. Many operators are becoming aware of this now, and it is likely that tests will be run to prove the hypothesis that the production is coming from a much more limited height than some of the initial work suggests. In the case of the Southern Midland Basin Wolfcamp one operator published their schematic for three stacked laterals in the 1000 ft gross interval based apparently on microseismic survey data (Fig. 24). It is unlikely that this model of three stacked laterals will hold based on the limited conductive heights (50 to 100 ft) that are likely above the 50 to 60 ft propped heights.

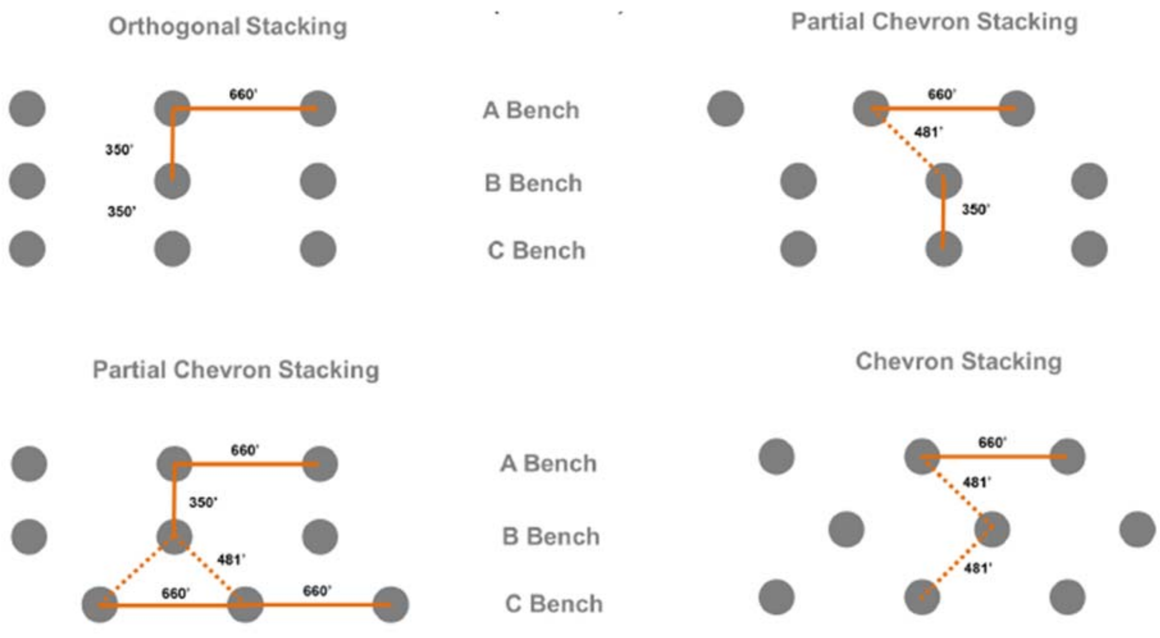

Fig. 24 Proposed Lateral Stacking Based on Microseismic
Over 1000 ft of gross pay (from Approach Resources)
Significant upside based on 150 ft likely conductive heights

Conclusions

The recovery factor technique is a useful tool to help normalize performance among wells with varying hydrocarbon pore volumes and lateral coverage. As a stand alone tool it can be used to compare production results for "best practices" determination and to predict future performance of varying lateral placement options. A third useful exercise with the technique is to compare the recovery factors among wells with varying assumptions of conductive height. While this is not inherently a unique solution the data suggests that there is limited unpropped height created above the 50 to 60 ft high proppant bed, with an additional 50 to 100 feet probably the most likely. The study should encourage operators and service companies to investigate solutions for improving propped and conductive height which could have a substantial impact on recoveries if the efforts are successful. The ideal lateral has a strong connection to the conductive fracture and the pay interval. Fig. 25 is a good depiction of the need to connect all three to optimize completions and the recovery factor process is a promising technique to facilitate this connection.

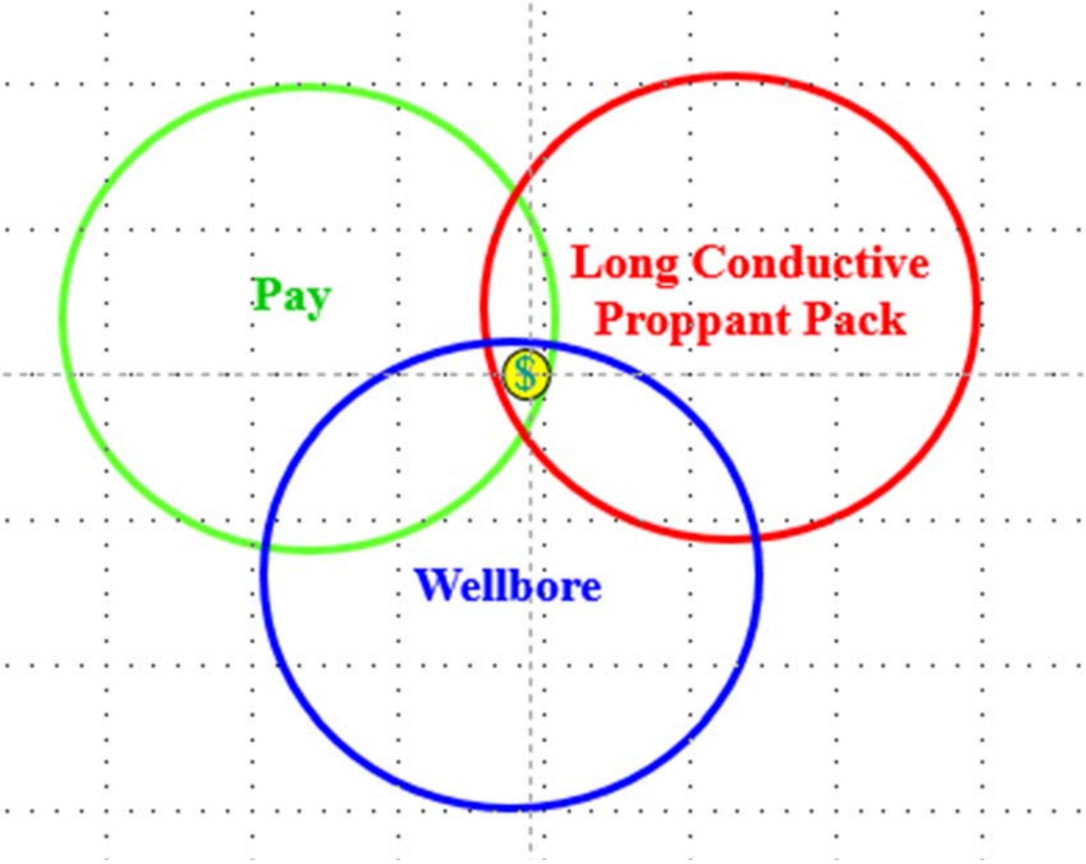

Fig. 25 “Best Practices” Objective

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