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Big Data Yields Completion Optimization: Using Drilling Data to Optimize Completion Efficiency in a Low Permeability Formation

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Abstract

Poor production results in the subject area was determined to be caused by poor reservoir contact along the laterals. In a series of wells using multi-stage plug-and-perf completions, poor perforation efficiency was diagnosed. A solution to improve formation contact was employed which made absolute contact with the reservoir by using sliding sleeves and coil tubing technology. However this system demonstrated issues mainly around lower estimated ultimate recovery (EUR) values due to wide fracture spacing limitations and also suffered occasional human related, not tool quality, failures which caused costly penalties in completing wells. Returning back to the original completion scheme re-presented the original problem that very few of the perforation clusters were opening and thus using plug-and-perf and also obtaining better perforation efficiency was re-sought.

This solution step developed in this paper uses drilling data which through the use of neural networks, can generate a synthetic log. The log can yield rock properties which can generate stresses along the wellbore. These stresses are then used to select perforation spacing to better take advantage of 'like' stresses so that perforation opening can improve. Minimum pressure drops between perforations can then be designed. Additional information pertaining to reservoir quality was generated by adding gas chromatograph data to determine the highest permeability sections of the lateral as well as the liquid-rich hydrocarbon bearing sections. This analysis allows for a solution matrix of job and cluster spacing types to optimize fracture spacing (frequency of contact) and conductivity requirements to optimize the completion based on stress and relative or contrasting permeability.

This paper will demonstrate how the problem was determined, the solution was implemented, how some alternatives were explored and how fracture geometry was greatly improved using these workflows.

Introduction

The issue of breaking down each perforation cluster in a frac stage has plagued the Operator for quite some time. As stated in the abstract, the issue was temporarily mitigated by using frac ports that were facilitated by coil tubing. However, for several reasons, that solution was discarded and the completion team returned to plug-and-perforation completion techniques. After some attempts to understand the issue, a better solution

as presented to the completion team and that solution is the basis of this case study. This is a case history which involves two formations. The last example well is in the 3rd Bone Springs and the solution wells are in the deeper Wolfcamp A. As a means of making the reader familiar with both formations, their reservoir characteristics will be explained.

The study area is based in West Texas and South Eastern New Mexico. The main formations are the Bone Springs sands and the Wolfcamp series of the lower Permian age. This area is part of the Delaware Basin, which is located to the west of the Central Basin Platform (CBP) as a structural and topographic low, providing an inlet for marine waters during the majority of the Permian period. The basin has an asymmetrical geometry, and its axis is adjacent and largely parallel to the faulted margins of the CBP[i]. The Delaware Basin is structurally deeper in comparison to the Midland Basin.

Along the border between the Delaware Basin and the CBP there is local reverse faulting and graben development, and minor anticlinal features can be found along the northern slope, in New Mexico. Small scale normal faulting can be found on the western flank of the basin. It is suggested that any major deformation within the basin had ceased by the Wolfcampian-early Leonardian times[ii]. As a result of the Laramide transgression during the Late Cretaceous-early Tertiary, an east-southeastern regional tilt was imposed which flattens out in the basin center (eastern Lea and Winkler Counties).

The Bone Springs group underlies the middle aged Permian and overlays the older Permian age strata, immediately above the Wolfcamp. The Bone Spring formation is Leonardian in age and can be broken down into three packages: 1st, 2nd and 3rd Bone Spring. Each package contains carbonate followed by a thinner sand unit. This cyclical sedimentation is due to changes in sea level that created the juxtaposition of different depositional environments. The carbonate formed when the sea level was at a high, and the sandstones when the sea level was at a low. At the top of the Bone Springs formation is the Avalon Shales and carbonates[iii]. In depth details of the reservoir, stress and completion characteristics of the Bone Springs sands has been covered most recently by the principal author in SPE 176862[iv] and the second author in SPE 170720[v]

The Delaware Wolfcamp (Wolfcampian): Behaves as a reservoir and source rock due to ideal mineralogy and grain size distribution. Industry publications[vi] cite mineralogy at 50-90% quartz and carbonate, with 10% clay. Other stats include a pressure gradient of 0.7 psi/ft., porosity around 5-9%, and TOC about 2-5%. However most of the basin experiences normal reservoir pressures and slightly elevated closure stresses. Near the contact between the Bone Springs and Wolfcamp A, a transitional Bone Springs-Wolfcamp facies (alternating Wolfcamp A and Lower 3rd Bone Springs facies) begins to develop in the northern Pecos area and thickens moving northward into the basin toward western Loving County (our study area) where it is best developed. There are several horizontal wells that target the sandy intervals in the northern area. Immediately south and southeast of Pecos the stratigraphic equivalent of this transitional zone consists almost entirely of resistant organic-rich siltstone interbedded with tight limestone.

In terms of completion potential, the main driver behind the Wolfcamp is reservoir thickness. The Wolfcamp has long been a zone that piqued the interest of many exploration company[vii] and in the late 1990's and early 2000's, the reservoir became a viable entry into the Permian Basin scene. The first well that started the process of unraveling the Wolfcamp was Henry Petroleum Beverly #1 well, located south of the Midland-Odessa airport. This well was fraced with essentially the same technique as that used in the Barnett Shale. Using thin slick water, 100 and 40/70 mesh sands, and the well was successfully completed and sustained its production for a period of time unheard of in 1998.

The Beverly #1 was a vertical well and was highly profitable which lead other operators to explore the Wolfcamp in other parts of the Permian, including the Delaware Basin. The migration to employing a horizontal completion was a natural step in the progress.

The completion process further developed as other completion styles were tried but the better wells appear to come from the simplified completion of this fluids and small proppant. The pervasive theory here is that the Wolfcamp's success is based more on reservoir contact than placement of conductivity.

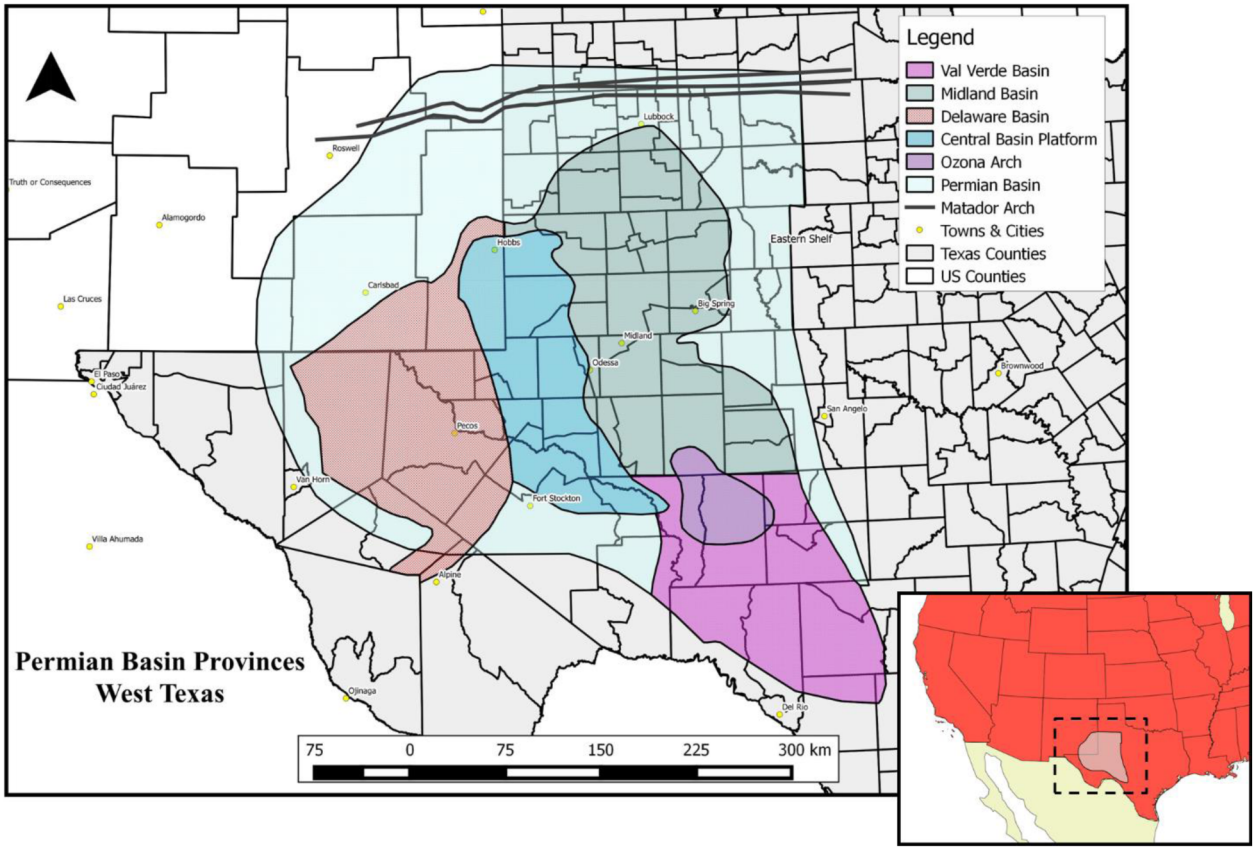


Figure 1—Map of the general area of study.

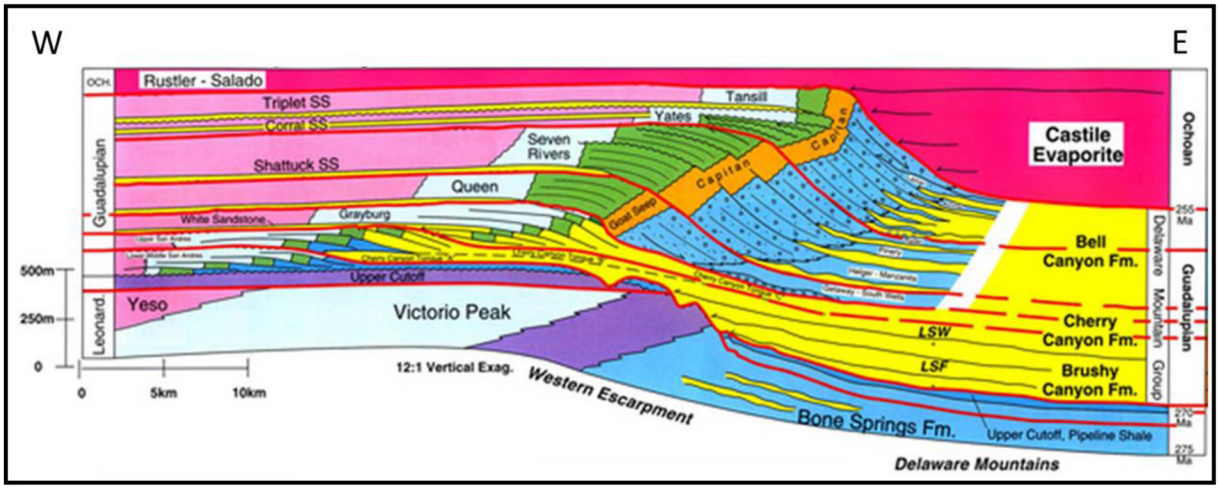


Figure 2—Geologic Column as a cross section of the Delaware basin.

In developing this asset, the operator (Endurance) drilled a vertical pilot well which was later converted to a horizontal well. The pilot well offered much of the data needed to develop the field plan as the Wolfcamp A indicated much more producible hydrocarbons than the B or C benches. As illustrated in figure 3, the Wolfcamp is a very thick pay section and has been the subject of several successful field development

programs. A massive amount of technical work exists on the Wolfcamp. One such study was performed by Parker and Bazan which utilized a discrete fracture network[viii].

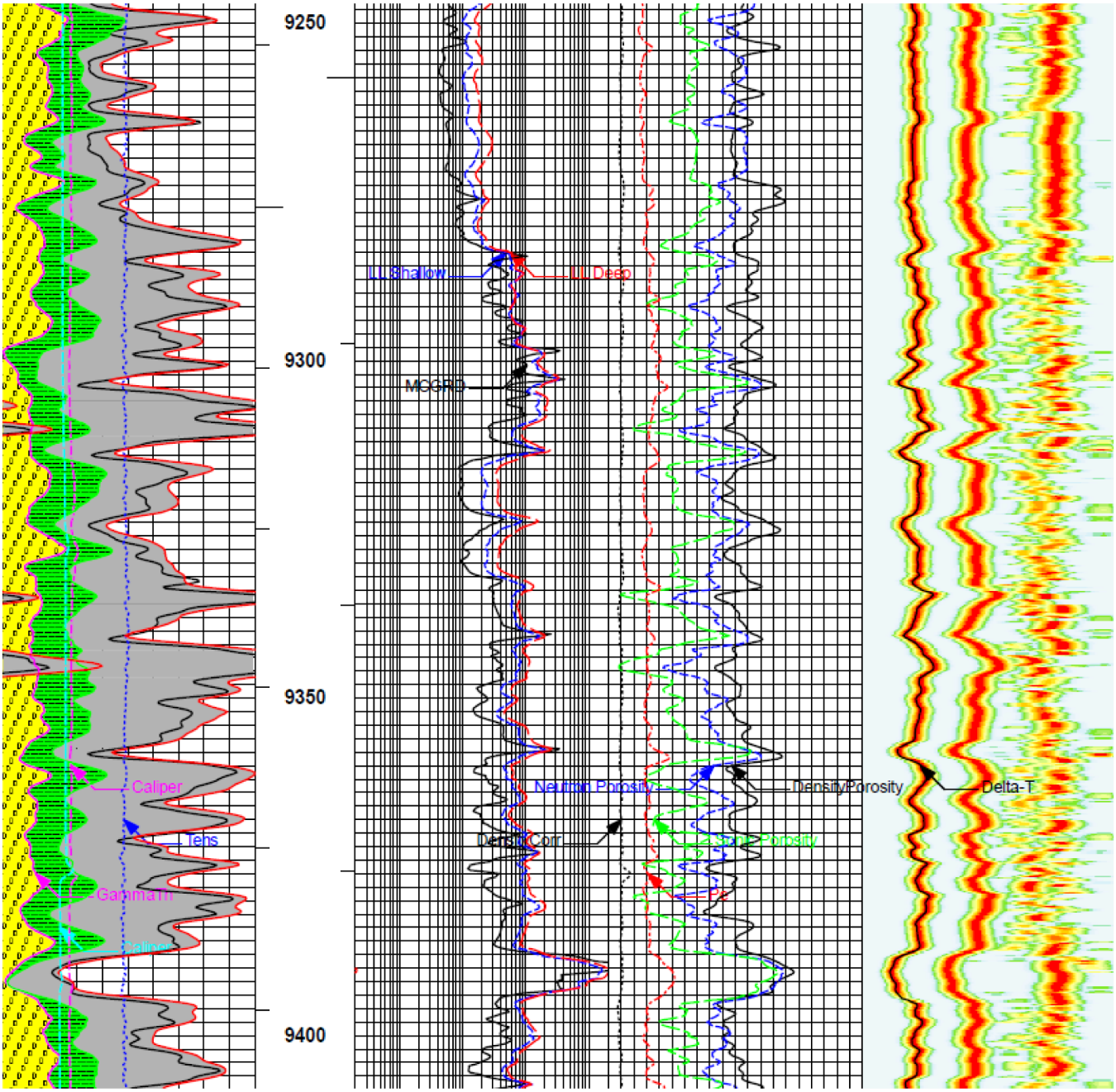


Figure 3—Log of the Pilot well for the Wolfcamp completion.

The Issue of Perforation Inefficiency

The completion team knew that there is an inherent inefficiency with perforating horizontal wells. In these cases, the perforating gun is a decentralized – meaning that it lays on the bottom of the pipe – with 6 jet shots per foot phased at 60°. Figure 4 is a very simplified cartoon illustrating how perforating in a horizontal wellbore has inefficiency built-in. One might argue that this cartoon does not accurately illustrate the perforating environment but the cartoon is merely meant to bring the reader's attention to the issue in a simple way, plus the differences can only be 30° off from this illustration so the illustration is pertinent.

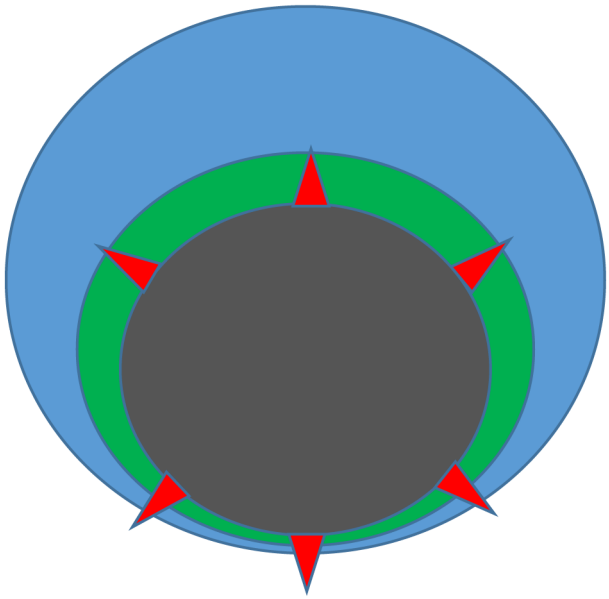


Figure 4—Cartoon depicting perforating in a horizontal wellbore.

The blue circle depicts the lateral or "hole" and probable cement fill with the green casing sitting on the bottom of the hole allowing the cement to fill the void in the annulus above the casing. Likewise, the perforating gun sits on the bottom of the casing. The author's impression is that this issue occurs regardless of the frequency of centralizers used.

This double-decentralization then allows the perforations shooting down to be emitted from the gun into the formation as it lays on the bottom of the casing. Their success is almost assured by the fact that they are laying against their target. The upward facing perforation charges are not located as close to their target and therefore some inefficiency is built-in. A second inefficiency factor occurs, being that the casing is decentralized inside the hole requiring the upward perforations to penetrate the cement filled annulus in order to penetrate into the formation and then being able to 'breakdown' and allow a fracture to initiate.

The clusters were perforated in a limited entry scheme to attempt to apply excessive pressure on the perforations so they will in fact breakdown and take frac fluid. The perforation scheme was to apply 12 – 0.40" holes at the heel contact point in the stage, 14 – 0.40" holes at the mid-point and 16 – 0.40" holes at the toe point. In pressure analyzing the frac treatments, the perforations better suited 0.38" diameter holes rather than 0.40" which is normal considering the depth and stress conditions per standard perforating API tables and best practices[ix].

Figure 5 is a plot of stage 3 of 18 in the 3rd Bone Springs well. All of the stages in this well had comparable data. The arrow marking the pressure drops and increases are where the perforations open. However at this point in time, only 14 of 42 - 0.4" holes are open. The poor perforation efficiency causes 700 psig of additional resistance which, in this case, is added to 3,148 psig of tortuosity. This excess pressure does not allow the frac treatment to be pumped at the design rate of 75 bpm. As the treatment progresses, hydrostatic of the proppant increases and more perforations open but by job end the rate finally reaches 75 bpm however only 19 holes are open at this point. That equates to 45% efficiency.

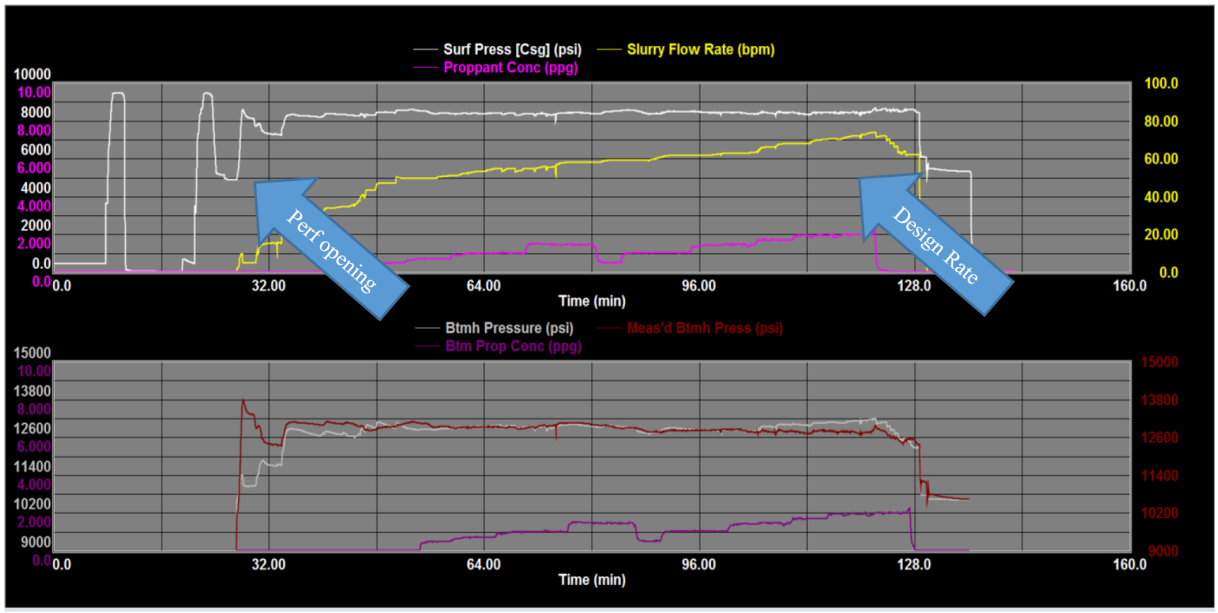


Figure 5—Treating Data for the Bone Springs 3 well with poor perforation efficiency.

Table 1 is a listing of the tortuosity and perforation issues for the 3rd Bone Springs well. The perforation count is after the treatment has been placed and in no case did the efficiency exceed 80%. The overall efficiency was 59.5% as in all stages 42 holes were shot per stage.

Table 1—Listing of Tortuosity and Perforation issues in the example 3rd Bone Springs well.

stage	Tortuosity psig	Final Perfs count
1	2,400	20
2	2,687	26
3	3,148	19
4	886	19
5	3,465	23
6	1,425	21
7	1,765	25
8	132	24
9	1,175	25
10	1,350	27
11	1,938	28
12	143	28
13	1,934	27
14	2,220	22
15	1,388	28
16	1,164	28
17	836	27
18	812	32
Average	1,604	25

Why is this a Problem?

The issue of perforation efficiency draws on the ability to place a treatment as designed versus not being successful in equally stimulating each perforation cluster. In Endurance's case, the challenge is to design the treatment so that each of the three clusters receives the same amount of fluid and proppant. Using limited entry (as previously stated, the clusters were perforated 12, 14 and 16 holes respectfully heel to toe) aids in this process, but limited entry theory *assumes* that the stress at each cluster site is essentially equalized by using limited entry. Thus, the benefit of limited entry is that all of the holes can be *opened* due to limited entry. If the un-opened perforations are evenly distributed along the clusters, then this issue is a "so what". However one does not know the distribution of open and unopened perforations is this case due to the type of treatment data that is commonly collected.

Using the past project results from pressure matching each stage in the Wolfcamp and Bone Springs formations, a matrix of results is displayed in table 3. First a discussion on how the results were established.

- Theoretical design is outlined using 3 clusters, limited entry and assuming all holes are open and maximum rate is achieved. The cluster spacing is 50', therefore 1 frac stage equals 150' of the lateral.
- 70% perforation efficiency is illustrated using past project data which has demonstrated that the maximum rate is achieved 40% through the treatment *at the very poorest overall performance.*
- 40% perforation efficiency is illustrated again using past treatment project data which demonstrated that the initial rate is <60% of design and increases as hydrostatic head aids in surface treating pressure relief as demonstrated in figure 5.

Table 2 is an actual stage design used by Endurance in the completion of the Wolfcamp.

Analyzing the results from table 3 yields averages with gains and (losses):

Table 4 lists the limited entry friction values for the three example rates. The table also demonstrates the averaged frac geometry values from table 3. The general trends are that decreasing the perforation efficiency tends to increase the fluid penetration (frac length) but decrease the propped length, frac height and propped height. The desired Propped length and height values are 400 feet and 170 feet respectfully. Therefore the 70% efficiency solution is acceptable.

Table 2—Treatment Schedule for Example cases – Upper Wolfcamp well

Main frac acid	35.00	0.00	2,500	1.70	156:07	20%HCl	
Main frac pad	80.00	0.00	20,000	5.95	162:04	Slickwater	
Main frac slurry	80.00	0.50	9,000	2.75	164:49	Slickwater	100 mesh
Main frac slurry	80.00	0.75	12,000	3.71	168:32	Slickwater	100 mesh
Main frac slurry	80.00	1.00	15,000	4.70	173:14	Slickwater	100 mesh
Main frac slurry	80.00	1.25	18,000	5.71	178:56	Slickwater	100 mesh
Main frac slurry	80.00	1.50	16,000	5.14	184:04	Slickwater	100 mesh
Main frac pad	80.00	0.00	13,000	3.87	187:56	15# Linear Gel	
Main frac slurry	80.00	0.50	12,000	3.65	191:35	15# Linear Gel	Jordan Sand 40/70
Main frac slurry	80.00	0.75	20,000	6.15	197:45	15# Linear Gel	Jordan Sand 40/70
Main frac slurry	80.00	1.00	20,000	6.22	203:58	15# Linear Gel	Jordan Sand 40/70

(continued on next page.)

Table 2—continued.

Main frac slurry	80.00	1.25	28,800	9.05	213:01	15# Linear Gel	Jordan Sand 40/70
Main frac slurry	80.00	1.50	34,500	10.96	223:58	15# Linear Gel	Jordan Sand 40/70
Main frac slurry	80.00	1.75	18,714	6.01	229:59	15# Linear Gel	Jordan Sand 40/70
Main frac slurry	80.00	2.00	7,875	2.55	232:32	15# Linear Gel	Jordan Sand 40/70
Main frac flush	80.00	0.00	17,645	5.25	237:47	15# Linear Gel	
Shut-in	0.00	0.00	0	45.00	282:47	Shut-in	

Table 3—Results of Model runs for test cases

Geometry Feature	**100% Perf Efficiency (as designed)**			**70% Efficiency - the acceptable goal**			**40% Efficiency - The realized trend**		
	Heel	Mid	Toe	Heel	Mid	Toe	Heel	Mid	Toe
Holes Open	12	14	16	10	11	13	4	5	8
Frac Length (ft.)	511.5	544.1	598.1	536.3	535.8	591.7	586.3	620.8	673.7
Propped Length (ft.)	184.2	243	261.9	190	236	262.8	143.9	204	289.3
Frac Height (ft.)	399.4	429.8	441.2	401.5	433.6	428	357.5	397.4	458.2
Propped Height (ft.)	142.2	189	190.3	140.7	189	187.2	86.2	106.3	227.7

Table 4—Averaged results and differences

Average Values	**100%**	**70%**	**40%**	**Delta 70**	**Delta 40**
Limited Entry Friction @ 80 BPM	531 psig	1115 psig	3239 psig	584 psig	2708 psig
Frac Length (ft.)	551.23	554.60	626.93	*0.61*	*13.04*
Propped Length (ft.)	229.70	229.60	212.40	*(0.04)*	*(7.49)*
Frac Height (ft.)	423.47	421.03	404.37	(0.57)	(3.96)
Propped Height (ft.)	173.83	172.30	140.07	(0.88)	(18.71)

Options to solve the Problem

As previously stated, the coil tubing conveyed selective sleeve system was originally used to solve this issue but due to several factors was not practical in each and every case. That solution remains viable for certain specific cases. Thus the other possibilities and their strengths and weaknesses are:

Note: TCP guns are used on the toe stage in every case and their efficiency % are no better than the remaining stages.

From Table 5, the options using a more conventional approach are narrow with costs and other issues clouding or impacting their benefits.

Table 5—options for solution

Solution process	Argument For	Argument Against
Return to Coil Tubing Conveyed Solution	Positive placement of frac treatments with minimal failure rate	Human errors when running completion string. Secondly, the Bone Springs and Wolfcamp require tighter fracture spacing than these tools allow from an economic standpoint – see next topic on production comparison between plug-and-perf and coil tubing conveyed completions.
Use More perforations	If the solution is a net % of perforations become open, then shooting more perfs should net more open	First, the process of perforating more holes offers more opportunities for fracture initiation and complexity. Second going to 30^0 phasing (12 spf) requires less powerful charges in standard guns and severely impacts costs
Use TCP guns on every stage	Bigger charges = Higher degree of success?	Costs including time and the guns, remember we are completing 20 – 42 stages per well.
Use Biodiverter intra-stage	Excess pressure when plugging perforations should open new perfs	Not well understood and the "art" of design is not well known – but keep this in mind – developed further in the paper.

Production Comparison between Coil Tubing Conveyed completions and Plug-and-perf or tighter fracture spacing

Figure 6 is a comparison of the plug-and-perf technique vs the zonal isolation method using coil tubing conveyed selective sleeve system. Both wells were fraced in the 2nd Bone Spring Sand and are direct 160 acre offsets. Well #1 was fraced in 13 plug-and-perf stages using 3 clusters per stage at 100 ft. spacing. Well #2 was fraced in 40 stages having each sliding sleeve placed at 97 ft. spacing. These side by side comparison wells were designed to be exact replicas of themselves on proppant type and proppant volume. The only difference was Well #1 was treated at a max rate of 70 BPM while Well #2 was treated at a max rate of 35 BPM. Similar to that as was outlined by the principal author in 2011[x]. Both wells were flowed backed (opened up) in identical fashion flowing up 5.5" casing. While there is a brief distinction between Well #1 and Well #2 flowing casing pressures, production and time until liquid loading remained comparable. Figure 6 demonstrates that while each port was effectively treated using the zonal isolation method, the inefficiencies thought to have come with the plug-and-perf technique are negligible and not apparent when looking at raw production numbers[xi].

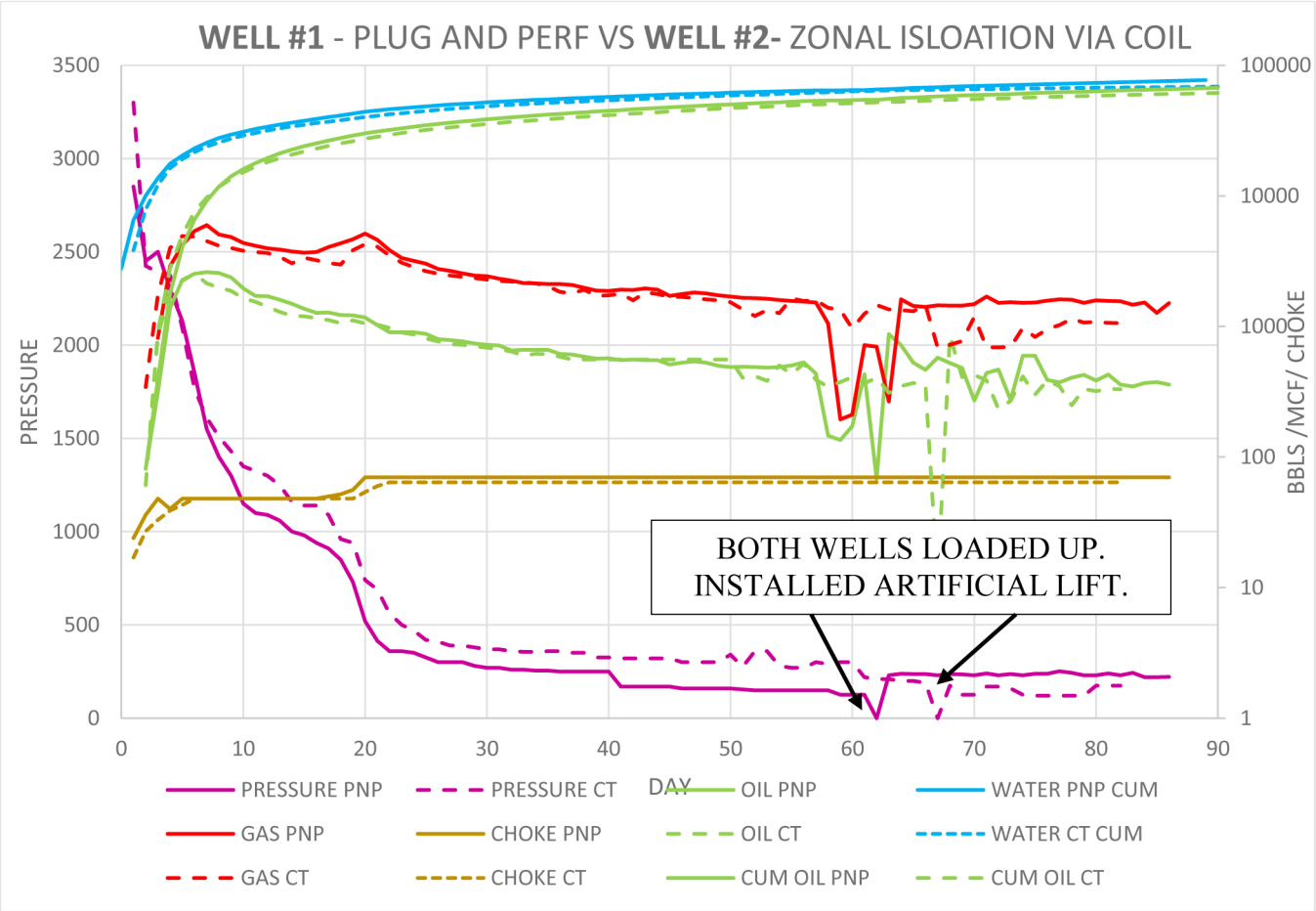


Figure 6—Comparison of Production between Coil-style sleeve completion and Plug and Perf using the Described process

Using post frac modeling on this case study, the production comparison came down to the difference between the two wells in the area of the port equates to 6 circles each with a radius of 0.803" per sliding sleeve. Equivalent ports open on the zonal isolation method had an average of 3.5 for this well comparison or 58%. Using the plug-and-perf method, 21.8 holes out of 42 were open or 52%. These close percentages in the number of effective perfs open paint a better picture why production from the two wells resulted in similar results.

The Solution – Big Data

As stated in SPE 176862, usage of a coil tubing conveyed selective sleeve system was used to overcome the perforation efficiency issue. However the experience with tool running and other issues clearly not related to the tools themselves suggested that a different solution should be sought. The principal and second author discussed using a new approach which utilizes what is called "Big Data". The process has been outlined by Logan[xii] in SPE 174839 and updated by several providers including the third author.

Petrophysical Data from Drilling Data

Proprietary software models that generate horizontal compressional and shear wave sonic data and bulk density data in well log format by using the conventional drilling data archived in the well construction process[xiii]. (Parshall, JPT August 2015) were developed. Several blind tests conducted by major oil companies have demonstrated that the system is similar in accuracy and reliability as conventional open hole logging tools.

The software has been developed by industry specialists in neural networks and open-hole logging tool design. The neural network models are trained with horizontal wells that possess both drilling and logging data. Rigorous quality control and calibration measures are applied to ensure the integrity of the training data and to reflect local differences in geology. Once trained and calibrated, the neural network models can subsequently utilize a collection of drilling dynamics, gamma ray and survey data to simulate compressional, shear, and density logs. From these three primary logs, geomechnical and reservoir quality properties can be derived such as Young's Modulus, Poisson's Ratio, horizontal stress, brittleness, density-porosity and total organic content. This information allows an engineered or optimized stage and perforation cluster selection in horizontal wells to be completed, or in a look back review of existing geometric completions, when petrophysical data was not obtained during well construction.

Understanding stress along the lateral allowed the authors to adjust the planned perforating scheme to better utilize lower stress differences between clusters in a given stage. Adjustments could be made to ‘move’ clusters a few feet to accommodate the lower threshold to improve perforation efficiency. An obvious benefit of using this process is the fact that the data collection already exists as part of the normal drilling process. No "extra" data or tool expense need be employed to obtain the data needed to input the model.

A geometric plan completion was submitted to the third author who analyzed the drilling data per the process described above and then offered a solution to improve perforation efficiency. Overall, the solution could be achieved by moving the heel or toe perforations a few feet. Again the theme is to utilize limited entry by respecting the assumptions that are attributed to limited entry theory but sometimes forgotten.

Figure 7 is an example of the results of the study. Maximum values for the original geometric design were 424 psig. The solution yielded 170 psig as the maximum stress inside the stage.

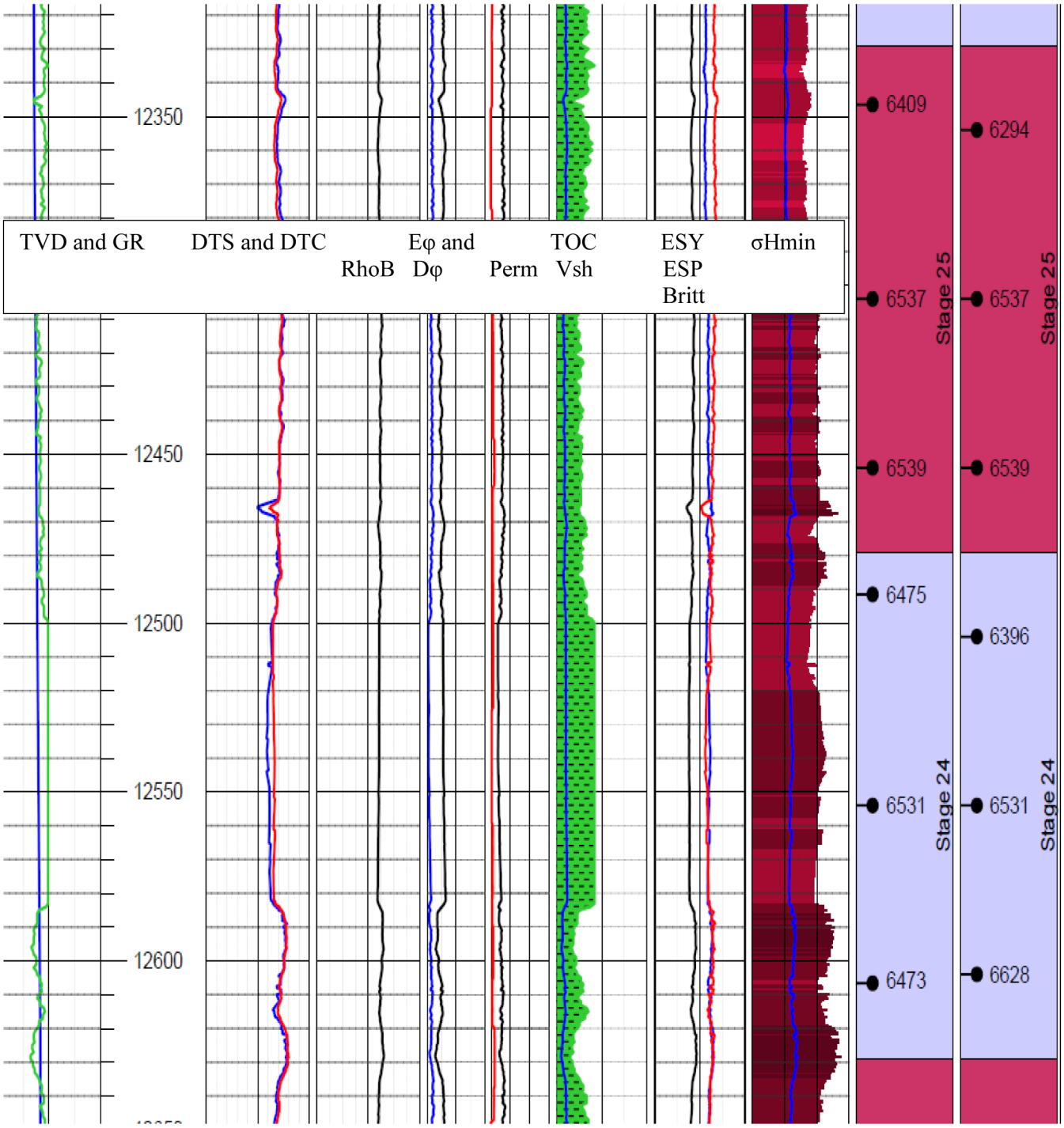


Figure 7—Example of the variation in perforation cluster spacing results by moving the clusters to lower the delta pressure to improve perforation opening efficiency. This chart is for the mid-to-toe region of the well.

Figure 8 is the frac treatment on stage 43 of Wolfcamp #1 well in the study, Upper Wolfcamp (Wolfcamp A zone) well which used the solution outlined in this paper. Detail pertaining to perforation breakdown is outlined in the next figure.

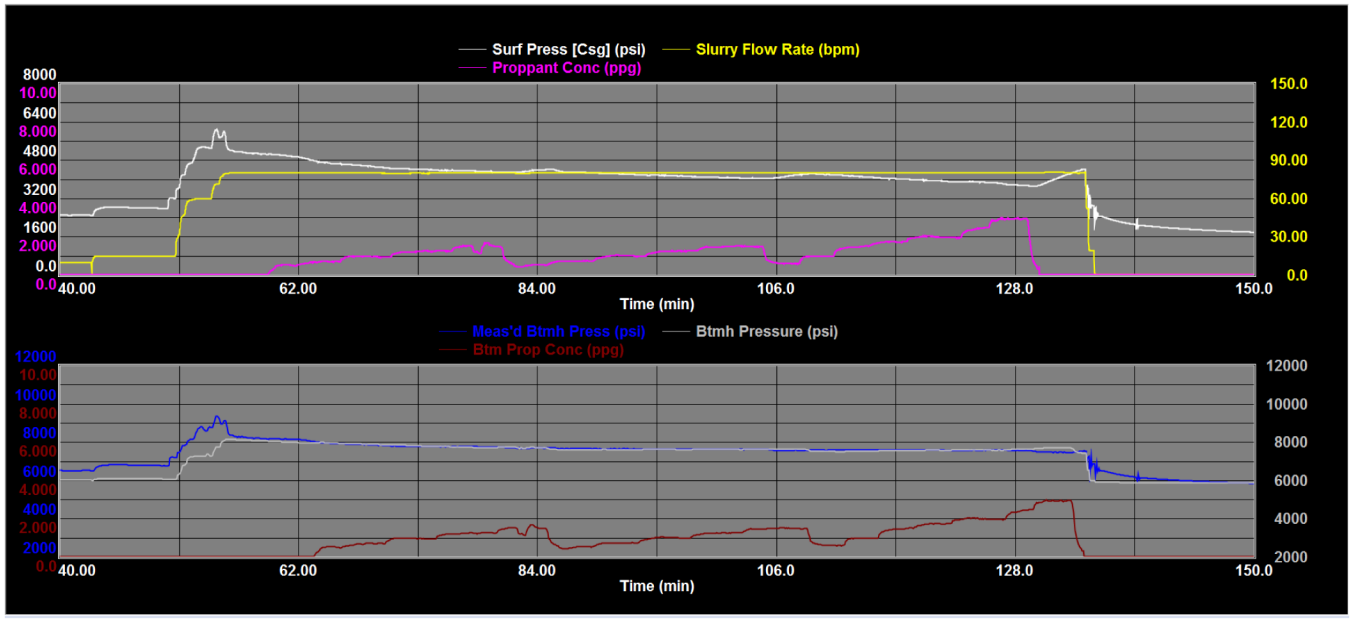
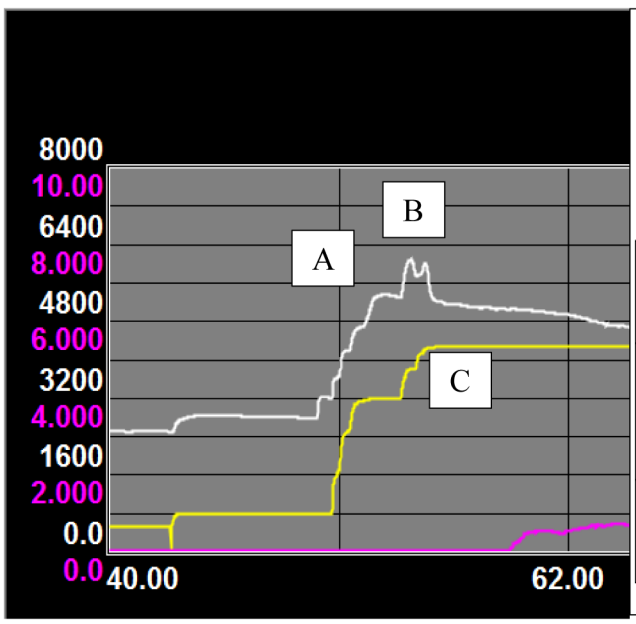


Figure 8—Stage 43 of the Gateway well which used the "Big Data" Solution.



Detail of the Perforation Breakdown events:
A - Isolation ball seats as rate increases

B - Perfs Breakdown

C - Design Rate Achieved

Frac Length (ft.)	608.1	Propped Height (ft.)	268.2
Frac Height (ft.)	453.0	Stages Placed at Design Rate	43
Propped Length (ft.)	393.4	Average Perf Efficiency	50.89%

Figure 9—Exploded view of the early time data for stage 25.

Stage 25 yielded 25 of 42 perforations open or ~59.5% efficiency. The treatment was placed at design rate. Overall, the Wolfcamp #1 well treatment was very successful in placing the treatments as designed. Surface treating pressures were lower and the total treatment times were shorter which saved Endurance on horsepower and time related fees.

Frac Length	608.1	ft.	Propped Height	268.2	ft.
Frac Height	453.0	ft.	Stages	42.0	
Propped Length	393.4	ft.	Perf Efficiency	50.89	%

Using the Solution on Other wells and including the use of Bio diversion

As of this writing, the solution was used on two other wells. Both of these wells used Bio diversion for several reasons including to determine if more perforations could be opened – per the possible solution from table 5. Results were mixed, but one other potential solution was explored – inductively. The team decided to use *fewer* perforations to generate more limited entry friction.

Figure 10 is the second stage of the second Wolfcamp well in the study. Two changes were made in this well. First the number of perforations was lowered from 42 to 36 holes. Second, bio diversion was run with the stage being partitioned to 2/3rds of the treatment prior and 1/3 of the treatment after the bio diversion. The exploded view illustrates the effect of the bio diversion.

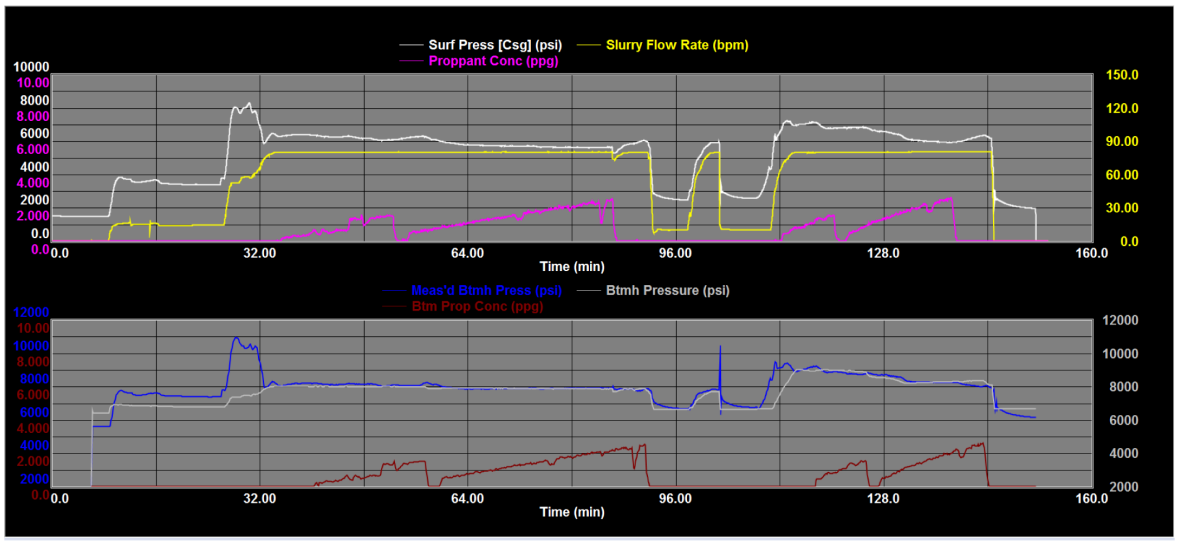


Figure 10—Stage 2 of the Second Wolfcamp well in the study. Bio Diversion was used in this stage.

Figure 11 illustrates the effect of the bio diversion hitting the perforation. Unfortunately the entry solution in the pressure match yielded the same condition prior to and after the bio diversion hit the perforations meaning that the number of perforations did not increase. In fact the detail of perfs matched to the following solution:

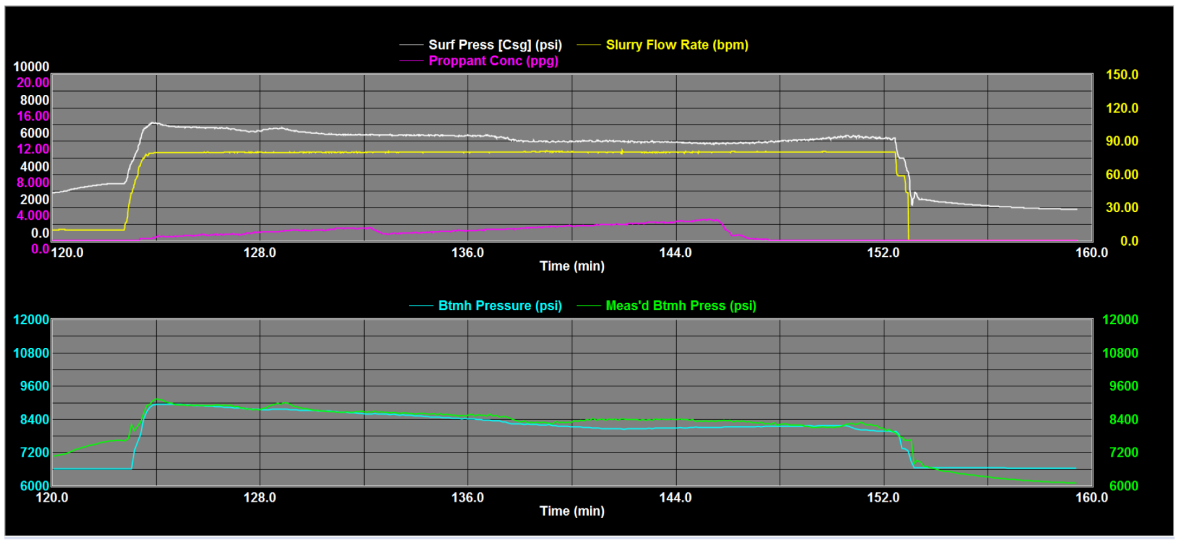


Figure 11—Exploded view of bio diversion hitting the perforations.

Table 6—Time related details of figures 9 and 10

Pump Time (minutes)	Perfs Open	Remarks
51.53	26	36 holes perforated
76.10	28	Rate Increase improved perforation conditions
110.33	29	More Improvement
119.17	20	Bio Diverter hit
141.32	27	Bio Diverter washed way with net loss of 1 less perforation

The third Wolfcamp well returned to 42 hole limited entry perforating scheme with bio diverter and the results were in line with Wolfcamp #1. Table 7 is a final listing of perforation efficiencies per treatment type.

Table 7—Summary of Results

Well/Project	Perforations Shot per stage	Range of Perforations Measured	Biodiverter Used	Comments
Prior Projects Summary	42	16 - 25	No	Typically 38% Efficiency with some improvement as treatments progressed toward the heel.
Wolfcamp #1	42	19 - 25	No	Up to 59.5% Success
Wolfcamp #2	36	22 - 34	Yes	Up to 94.4% Success. Biodiverter values were lower, 15 to 28 holes open after bio diversion
Wolfcamp #3	42	12 – 23	Yes	Return to average of 54% success with Bio Diversion values about equal at 17 to 23 holes/stage

Results and Conclusions

1. A step-change process to solve the problem of perforation efficiency was developed.
2. The apparent solution involves using the described technique to adjust perforation placement to achieve the lowest pressure required to open as many perforations as possible.
3. Bio Diversion does not work effectively when using the described process. This in no way discounts bio diversion, but in our conclusions, with the goal of opening as many perforations as possible, one should either perform one process or the other – not both.
4. Fracture spacing in the Bone Springs requires more frequency than is economically possible (at current prices and costs) than using coil tubing conveyed frac initiation.
5. The 70% solution for perforation opening is adequate in terms of fracture geometry – but not evaluated here in terms of production. No 100% perforation case, using short-spacing fracture entry points (or points of contact) have been admitted into the data set for comparison.

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