SUCCESS ACHIEVED IN LENTICULAR RESERVOIRS THROUGH ENHANCED VISCOSITY, INCREASED SAND VOLUME, AND MINIMIZATION OF ECHELON FRACTURES

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Abstract

A common trend in our industry is to minimize gel concentrations and utilize the lowest viscosity fluid available to place proppant. Barrett Resources Corporation has found, for lenticular microdarcy formations, that one of the keys for success is enhanced proppant transport. This is achieved incorporating stable gels which maintain greater than 1000 cps viscosity at bottomhole static temperature for the duration of the treatment. An extensive case study has been completed, involving over 500 fracture stimulation treatments in more than 175 wells, that illustrates the poor results achieved in the Williams Formation of the Mesaverde Groups using low viscosity fluids. Low viscosity fluids invariable exhibit poor proppant transport. The statistical study shows that larger treatments utilizing "perfect proppant transport" fluids gain superior results. Based upon the case study, 100% economic success has been achieved upon incorporating stable fluids containing delayed breakers, reducing pad volumes to less than 5% of total job size, and minimizing echelon fractures while implementing a limited entry stimulation technique.

Background

Barrett Resources Corporation has drilled and completed over 175 Williams Fork producers across the Grand Valley, Parachute and Rulison Fields within the Piceance Basin of Western Colorado (Figure 1). The Williams Fork Formation lies within the upper portion of the Cretaceous Mesaverde Group and is the primary target for development in the area. Depths range from 5900 to 8300 feet. Each well must be fracture stimulated to yield commercial production through a series of limited entry treatments ranging from one treatment to as many as six fracture stimulations to complete the entire gas saturated section. An interval from 100 to 600 feet in gross thickness may be considered for an individual treatment. Limited entry techniques must be employed to stimulate the numerous and discontinuous lenticular bodies or point bars within a selected interval. Evaluating the success of previous stimulations to optimize future treatments caused Barrett to embark upon a large statistical study of our completion practices. [1] Prior to the study, Barrett essentially perforated most mud log shows in attempting to recover gas from the numerous lenticular sands present in each well. A typical perforating scheme would include 20 to 30 holes distributed between 5 to 10 sand bodies within a zonal treatment. Stimulations ranged from 100,000 lbs. of sand to 350,000 lbs., incorporating through time, virtually every water based fluid available. As a result, a statistical analysis of the previous treatments produced a number of meaningful conclusions enabling Barrett to improve gas recovery while reducing overall well cost.

Geology

The gas saturated portion of the Williams Fork Formation is 1700 to 2400 feet in thickness and encompasses all of the paludal interval (commonly referred to as the Cameo), the coastal, and the majority of the fluvial interval (Figure 2). The formation consists of interbedded silts, shales, and sands with numerous coals interspersed throughout the paludal (lower) section. All of the sands are fluvial in nature and are very heterogeneous and discontinuous. The two main fluvial (river) deposits are distributary channel sands and meanderbelt complex sands. The more prevalent and somewhat larger meanderbelt complex sands are comprised of both vertically and laterally stacked point bar deposits. It is the point bar that is the basic reservoir unit in the Williams Fork. Based upon the tremendous amount of data collected at the Multiwell Experiment Site 2 (MWX) and associated outcrop and aerial photo studies, these point bars are nominally very small in size. Studies conclude, these lenticular sands have an average width of 750 feet on the long axis and are approximately 2 to 14 feet in thickness. The meanderbelt complex sands average 1500 feet in width, indeterminate lengths, and range from 10 to 60 feet in thickness. The single sands commonly identified on logs are meanderbelt complex sands and are comprised of two or more stacked point bars.

Figure 3 illustrates the discontinuous nature of a meanderbelt complex in relationship to wells drilled on a 40 acre well density pattern in a typical 640 acre governmental section. Note the likelihood of missing an entire reservoir (point bar) within one wellbore but encountering a large point bar in a direct 40 acre offset. The chances of draining adjacent or distant point bars are marginal at best since these reservoirs are commonly separated by thin shale drapes and are not connected by natural fractures. Only by means of artificial stimulation could we expect to increase the probability of draining adjacent point bars. Utilizing Figure 3, the reader must visualize numerous meanderbelt complex sands stacked vertically and randomly throughout the section in order to fully understand and appreciate the extremely complex nature of these deposits. The geologist or engineer must realize that open hole logs in a lenticular environment can only identify those reservoirs within reach of the logging tool depth of investigation (i.e., less than 5 feet).

To elaborate further, recent open hole logs were obtained on two north Rulison Field wells shown in Figure 4. After drilling and logging the original wellbore on the left, the hole was lost attempting to set casing and was subsequently sidetracked in a path just 142 feet away at bottomhole from the original wellbore. The well on the right is the density/neutron log of the sidetracked hole. Both logs in Figure 4 lie within the paludal section of the Williams Fork and would be considered a "typical" interval to selectively perforate, incorporating a limited entry technique and fracture stimulate. The original wellbore on the left has zero feet of density porosity greater than or equal to 10% compared to the re-drill which contains 53 feet of 10% or greater porosity. Although these wells are less than 0.5 acres apart, the sand quality and quantity changes drastically. Upon inspecting logs in the original wellbore, the operator would naturally be discouraged to complete this interval and may even elect to move uphole without perforating. However, beyond the logging tool depth of investigation may lie numerous point bars within reach of a hydraulic stimulation. Certainly, a stimulation with at least 140 feet of propped fracture length would gain access to additional and more porous sand bodies. The Williams Fork Formation is a complex depositional environment. The lenticular nature masks our ability to qualitatively and quantitatively rely upon open hole logs to determine a well's potential. It is extremely important to effectively stimulate and propagate all sands within reach of a stimulation treatment.

All sands within the Mesaverde Group across the three field areas are naturally fractured to some extent. With matrix permeability ranging from 0.1 to 2.0 microdarcies[3], the rock is incapable of producing commercial quantities of gas without the presence of natural fractures. Considering the natural fractures, the effective permeability ranges from 10 to 50 microdarcies. The dominant natural fracture set consists of vertical extension fractures oriented subparallel to each other. The natural fractures are found solely within the siltstone and sandstone lithologies and terminate at lithologic boundaries. It is important to note that these fractures do not connect reservoirs that are separated by even thin (2-3 inch) mudstone or shale beds. The natural fractures lack the vertical and lateral extent necessary to produce commercially by themselves. The reservoirs must be subjected to artificial stimulation to sustain commercial production.

"Pseudohomogeneity"

The log example shown in Figure 4 tied with our extensive case study in the area, led the authors to arrive at a term called "pseudohomogeneity." Pseudohomogeneity is defined as the wide spread homogeneous appearance of a heterogeneous reservoir. The definition of this term relates to the entire study area which exhibits tremendous heterogeneity from well to well. As many as 60 or more reservoirs or point bars are witnessed upon examining well logs. A very simple illustration is drawn which depicts the likely point bar distribution in three hypothetical wellbores A, B, and C (Figure 5). The open hole logs for well A indicate the presence of a large number of point bars or meanderbelt complexes with the expectation of a very strong well. The operator would consider a relatively large fracture stimulation for Well A. Well B may be typical of a moderate number of point bars present and would receive smaller stimulations than Well A. Through log interpretation, Well C indicates a significant lack of sand, and for lack of knowledge in the area, the operator would not set pipe. However, a successful stimulation of Well C that would include propping all zones within reach of a hydraulic fracture stimulation may yield similar results as Well A. The pseudohomogeneity present throughout the study area establishes the fact that we must effectively stimulate all reservoirs with sufficient job size to communicate the maximum number of reservoirs to the wellbore. In addition, the study area is essentially a statistical play that requires the performance analysis of a large well count or data base in order to derive meaningful conclusions. Conclusions relating the effectiveness of a treatment based on the performance of one or two wells are extremely premature due to pseudohomogeneity.

Quantifying The Success of Previous Fracture Stimulation Treatments

Barrett embarked upon a study of the previous 500 treatments pumped in the Williams Fork Formation in an effort to optimize future stimulations. Since 1984, Barrett has been involved in treating over 175 wells throughout the area while employing virtually every water based treatment fluid available in the industry. Every aspect of our past treatments, such as job size, fluid type, gel loading, breaker type and quantity, perforating scheme, and flowback technique was assembled and documented in an extensive data base. Performance and reservoir characteristics such as estimated ultimate recovery (EUR), first year cumulative production, and net pay based on porosity and gamma ray unit cutoff values were closely examined to eventually arrive at a formula for a more optimized well treatment and commercially successful development program throughout the three-field area. Numerous correlations were attempted in an effort to separate poor performers from better wells. After close examination of log-derived net pay calculations, there does not appear to be a clear cut correlation solely between the amount of net pay exhibited on the open hole logs and EUR. As mentioned earlier, the discontinuity and extreme heterogeneity or "pseudohomogeneity" of the Williams Fork Formation prevents correlating log-derived net pay calculations with performance. Net pay is important only when it is supported with natural fractures and good stimulation practices.

Criteria To Classify Well Performance (Grand Valley and Parachute Area)

To correlate well performance with various aspects of a stimulation treatment, one must establish the criteria for ultimate recovery of a poor performer versus a good well. The following is the definition of a "good well," a "marginal well," and a "poor well" based upon a 20 year estimated ultimate recovery (EUR):

Good Well	EUR > 1.2 BCF total or >0.4 BCF/zone
Marginal Well	EUR 1.0 - 1.2 BCF total or > 0.3 BCF/zone
Poor Well	EUR <1.0 BCF total or <0.3 BCF/zone

Barrett completed numerous wells containing only one or two stimulations in the paludal and coastal intervals out of a possible three or four zones in the entire gas saturated section of the Williams Fork Formation. Therefore, performance based on gas recovery per zone allows for additional comparisons to be made against those wells that have the entire gas saturated section completed.

New Generation Fracturing Techniques

Prior to initiating our case study in April, 1994, Barrett was directing a development program in the Grand Valley field that commenced June, 1993, incorporating a completion process designated as "New Generation Fracturing Techniques." This technique included stimulating with 30-35#/1000 gals. borate crosslinked gel loading, encapsulated breakers, delayed crosslinkers, and immediate flowback techniques. Figure 6 illustrates that 29 out of 40 wells (72.5%) in this category are classified as "good wells." Essentially, the correlation gave Barrett some indication that our treatment efforts during this period of field development were very effective as a result of pumping good proppant transport fluids, utilizing proper breaker schedules, and implementing immediate flowback techniques.

Poor Proppant Transport Yields Poorer Wells

Poor proppant transport or low viscosity fluids are defined as containing 30#/1000 gals. crosslinked gel loading or less, foams and energized fracturing fluids, and linear gels. This survey indicated that 83% or 29 out of 35 wells were determined to be "poor wells" (Figure 7) when low viscosity fluids were employed. Barrett firmly believes that proppant transport is one of the most influential and deciding characteristics in determining well performance in the Williams Fork formation.

Large Stimulations Improve Well Performance

Figure 8 depicts the performance results after examining those wells containing large stimulations. Large stimulations are defined as containing at least 350,000 lbs. of sand per treatment interval. Of the 35 wells examined, 27 wells or 77% were classified as "good wells." Large stimulations yield improved fracture conductivity to aid in fluid clean up and improve sand placement across pay intervals to effectively communicate with the wellbore. Figure 9 illustrates the converse effect of small stimulations. The 46 wells that were treated with less than 300,000 lbs. per treatment produced 27 wells or 59% that are considered poor producers. Large stimulations coupled with "perfect proppant transport fluids" are keys to successfully stimulating the Williams Fork Formation.

Upon examining large stimulation treatments, a number of wells were recognized as "outstanding" performers with EUR's exceeding 1.5 BCF/well. (Figure 10) This 25-well data base indicated 18 wells or 72% with more than 1,000,000 lbs. of sand pumped in the entire gas saturated section demonstrated outstanding performance. Again, proppant volume and placement play extremely important roles in the Williams Fork Formation.

Current Stimulation Practices

Numerous improvements of operational procedures, improved fluid designs, and intense quality control guidelines are presently being executed by Barrett as a result of the 175 well case study. Our current stimulation practices are outlined as follows:

1. Utilize Stable Fracturing Fluids - As pointed out earlier, we must effectively propagate all zones within reach of a stimulation treatment. This task requires the fracturing fluids to be stable at static bottomhole

temperature for the duration of the treatment. The first approach aimed at obtaining a stable fluid encompassed pumping 35 and 40 lbs/1000 gals. gel concentration rather than previous 30 and 35 lb. loadings. Fluid stability at static bottomhole temperature improves with increased gel loadings. Unstable gels allow proppant settling which prevents adequately communicating the maximum number of point bars to the wellbore.

Achieving 100% hydration of the polymer gel also enhances fluid stability. Prior to the case study, fracture treatments were pumped without allowing the gel sufficient time to hydrate 100%. The estimated 90% hydration rate was corrected upon employing a holding tank, termed a "CMG Unit." Improved gel stability at 40-50 BPM pump rates were achieved by allowing the extra residence time for 100% hydration.

The crosslink time was accelerated to prevent near wellbore proppant settling. Extending the crosslinking time could contribute to proppant settling in the near wellbore area. The combination of a delayed crosslinker and rapid crosslink system causes the viscosity to increase prior to the fluid entering the perforations thus reducing the potential for settling.

Breaker schedules were examined carefully by conducting laboratory tests at static bottomhole temperatures. Breaker concentrations were altered considerably to prevent proppant settling and thus poor communication of the lenticular reservoirs to the wellbore. Lower concentrations of breaker in the early portions of the treatment ensure fluid stability for the duration of the treatment. Tailoring a more aggressive breaker schedule as the treatment advances ensures a broken gel at surface during flowback while maintaining sufficient viscosity to prevent near wellbore proppant settling.

2. Intense Quality Control - Early in our case study, enhanced quality control procedures were initiated.[4,5] The service company is required to conduct on-site pilot testing of the fracturing fluids at bottomhole conditions of shear and temperature to ensure complete gel stability for the duration of the treatment. Fluids are presently tested in the lab and field, utilizing a Brookfield viscometer capable of providing accurate fluid rheology coupled with the convenience of portable table top hardware. All sand storage compartments on location are sieved to check the material quality. Pre- and post-job inventories of all chemicals and water volumes are monitored and reported. Barrett has drafted a quality control checklist form that meets their specific treatment requirements and is filled out before and after job execution. Barrett demands strict adherence to established testing procedures and quality control guidelines to ensure excellent proppant transport is achieved.

3. Immediate Flowback Technique - Barrett has been practicing the "forced closure" or immediate flowback technique[5] during the past 2.5 years. During the cast study, a more aggressive flowback procedure was initiated which accelerated the previous 0.25 - 0.50 bbls/minute flowback rate to 1.0 - 2.0 bbls/minute immediately upon cessation of the treatment. This procedure allows reverse gravel packing to occur external to the perforations and improves communication between the created fracture system and the wellbore. Only minute amounts of frac sand have been produced using this aggressive flowback technique.

4. Non-Essential Chemicals Eliminated - A polymeric clay stabilizer has been eliminated on all wells. This product has application in some formations which contain high percentages of migrating and swelling clays. However, the lithological characteristics of the Williams Fork Formation and its extremely tight matrix permeability does not require this product. In addition, Barrett has just recently eliminated the liquid KCl substitute product for the same reasons. Extensive laboratory work coupled with actual field performance indicates no benefit is being realized with this chemical. Substantial savings approaching $25M per well have been gained by eliminating non-essential chemicals.

5. Initiate Proppant Pumping at Maximum PPG/Reduce Pad Volumes - Screenouts were uncommon in the Williams Fork Formation as previous stimulations were pumped at 3 ppg 20/40 sand concentrations ramping toward 5 ppg. Job design changes have resulted in initiating the fracture treatment at 5 ppg and maintaining this concentration for the duration of the treatment. In addition, pad volumes as a percent of total treatment fluid volumes have been reduced from 32% to the present level of 5% or less without incurring screenouts. When the service company has the desired quality of fracturing fluid ready, sand is added to the blender at 5 ppg concentration and pumped downhole with less than 5% pad volumes. Minimizing pad volume reduces job cost appreciably and minimizes fracture closure times.

It should be mentioned that service companies have been able to pump relatively high concentrations of proppant with low gel loadings compared with our findings that support the use of stable gels through increased loading. Since the treatments did not screen out, it was theorized that low gel loadings were sufficiently stable to adequately place proppant. Indeed, very little fluid stability is necessary in low permeability formations such as the Mesaverde. However, a problem exists in relationship to proppant transport whether or not the operator desires a banking type of fluid or a "perfect proppant transport" fluid. As witnessed in the Williams Fork, either type of fluid can be pumped but will yield very different results. The perfect proppant transport fluid with controlled viscosity will produce a much longer propped hydraulic fracture. Complete proppant coverage across the interval, accompanied with greater length, is required in stimulating low permeability formations. The banking type of fluid will yield a short and highly conductive fracture less beneficial toward adequately draining the lenticular or compartmentalized reservoirs of the Williams Fork.

6. Dead String Pressure Analysis - Early in the case study, Barrett recognized that conducting a series of cased hole stress tests would be time consuming and expensive in identifying lithological barriers. It was decided to conduct a number of stimulations down the annulus of the 5 ½" 17#/ft N-80 casing and the 2 3/8" 4.7#/ft J-55 tubing and monitor bottomhole treating pressures via the "dead string." The tubing or "dead string" was filled with water prior to the treatment to provide accurate bottomhole treating pressure measurements with a known and static hydrostatic column of fluid absent of any pipe friction. The pressures were recorded from the dead string, corrected for hydrostatic, and loaded into a 3D fracture stimulation model. The pressure matches from the modeling work confirmed that virtually no lithologic barriers exist for fracture height containment. The possible exception to this rule is the paludal or Cameo section which contains numerous coal seams. The modeling work indicates radial growth or "penny" shaped fractures appear to be the dominate hydraulic fracture geometry throughout the Williams Fork. Approximately $150,000 in savings was gained by eliminating cased hole stress testing and electing to conduct extensive 3D modeling work of the treatments.

7. Eliminate Multiple Entry Points - The 3D fracture modeling work simulated and confirmed the presence of multiple echelon fractures when utilizing the limited entry technique. The limited entry technique essentially places perforations over a number of separate sand bodies within a 100 to 400 feet zone and assures each completion of creating multiple fractures. Table 1 illustrates the modeling results comparing various propped fracture lengths of radial growth to the number of multiple fractures created or "entry points." The fracture lengths shown are based upon a fracture conductivity of at least 1000 md-ft and is considered the minimum conductivity necessary to effectively clean up load fluids. It is quite evident from simple volumetrics that multiple fractures dilute fracture width, length, and conductivity. Barrett is presently limiting the number of entry points creating separate hydraulic fractures to a maximum of four. With four entry points, the model predicts a propped length of 172 feet with a minimum conductivity of 1000 md-ft. It should be noted that Barrett has performed stimulations on three wells using a "single point entry technique" where a single point of the hydraulic fracture is used to cover approximately 400 feet of gross vertical interval. Results to date on two of the three wells are encouraging and continue to be monitored.

One of the concerns with this procedure suggests that possible pinch out effects are occurring across the mudstones and siltstones. The stress contrast between various lithologies provide areas of width restriction or "Pinching" when placing proppant. Pinch out effects prohibit adequately placing proppant across the entire fracture which encourages bridging throughout these zones.

8. Flush at Maximum Sand Concentration - Identifying the flush at the maximum sand concentration will maximize the conductivity at the wellbore. Utilizing a high pressure in-line densiometer near the wellhead will eliminate the old practice of under-flushing approximately 2-3 bbls. due to inaccurate flow meters.

9. Rigless Completions - Barrett is presently conducting all completions without a rig for the majority of the operation. After a casing gun perforates the interval, the perforations are broken down and balled out down the 4 ½" or 5 ½" casing at maximum rate. The well pressure is surged to allow the balls to drop and subsequently fracture stimulated down the casing. After sufficient load is recovered to yield burnable gas at surface, a composite bridge plug is set with wireline and lubricator. Thus the entire process is repeated for the remaining zones until the final zone is stimulated. A completion rig is then moved on location to pick up tubing, drill out the composite bridge plugs, and clean out to PBTD. The wellhead replaces the BOP, the tubing is landed, a ball is dropped to pump off the bit into the rathole, and the well is ready for production.

Results of Improved Fracture Stimulation Techniques

After pumping approximately 30 stimulations within the Grand Valley and Parachute Fields, incorporating the practices outlined above, Barrett has achieved notably improved results. Figure 11 illustrates the results of 13 Grand Valley/Parachute wells stimulated from June, 1993 to April, 1994, prior to implementing the revised techniques. Of the 13 wells, 6 wells or 46% proved to be outstanding performers with EUR's exceeding 1.5 BCF per well. Figure 12 indicates the improvement in performance attributed to the revised practices. The 10 wells in this category yielded a 90% success rate in achieving EUR's exceeding 1.5 BCF per well. Figure 13 points out that Barrett has achieved an average 20% increase in EUR as a result of implementing the revised completion techniques compared to our previous 1993-94 efforts.

Ongoing Fracture Stimulations in the Rulison Area

Since completing the extensive study of the Mesaverde fracture treatments in the three field area, Barrett has focused their development drilling efforts in the Rulison Field of the Piceance Basin. Early stimulation work (September - November, 1994) in the Rulison area yielded excellent producers with EUR's ranging from 1.8 BCF to over 3.0 BCF per well incorporating the guidelines set forth in the study.

It became apparent in late 1994, that wells were not satisfactorily performing compared to earlier efforts. Many of the poor performers were predicted to recover less than 1.0 BCF per well which is far below Barrett's economic threshold. Based upon the performance of these wells, a comprehensive study was initiated to determine the cause of failure and perhaps isolate a particular change in fluids, geology, etc. Again, our previous experience in evaluating well performance versus numerous stimulation variables was applied in order to isolate potential problem areas. It should be noted that the Rulison Field economic criteria differs in that three to five stimulations are required within a thicker gas saturated section of the Williams Fork compared to three or four jobs in the Grand Valley/Parachute Fields. The criteria to classify well performance in the Rulison Field was re-defined as follows:

Good Well	EUR > 1.8 BCF total
Marginal Well	EUR 1.2 - 1.8 BCF total
Poor Well	EUR <1.2 BCF total

Upon accumulating the data, it became very apparent there were several critical factors contributing to the lack of success on many of the jobs pumped after November, 1994. The findings conclude:

1. Almost simultaneously with the advent of the poor performing wells, buffering agents were changed due to a lower cost and higher activity level. Coincidentally, with the early use of the new buffer, lower temperature sections of the Williams Fork were being treated. The newer buffer caused slower breaking of the fracturing fluid as noted by higher viscosity flowbacks. Due to the fluid failing to break properly, a tapered buffer loading was initiated. We found a direct correlation between poor well performance and the tapered buffer loading. The tapered buffering yields extremely poor fluid stability and translates into poor proppant transport. In trying to solve the fluid break problem, a fluid stability problem was inadvertently created.

2. A correlation was made between fluid quality and well performance. Figure 14 indicates that 12 of the 18 wells or 70% with poor proppant transport fluid characteristics yielded marginal or poor wells. Many of the fluids pumped were below Barrett's specifications that require stable fluids for the duration of the treatment.

3. Figure 15 illustrates that 10 out of 11 wells were marginal or poor producers when stimulated with a total of three fracs in the entire gas saturated section of the Williams Fork. Conversely, Figure 16 indicates that 71% or five out of seven wells stimulated with four treatments were classified as good wells. Notice there were no poor wells found in this survey. Many of the wells with four stimulations were pumped with fluids that exhibited poor fluid stability due to the tapered buffer schedules. We conclude that poor proppant transport can be somewhat overcome with better zonal treatment. The wells containing four stimulations received over two million pounds of sand and were better performers regardless of fluid quality. Large sand volumes increase the number of point bars in communication with the wellbore. If all seven wells stimulated with four fracs contained excellent fluids, EUR's would have undoubtedly increased. Again, more proppant across the entire gas saturated section, coupled with good fluid stability, are keys to stimulating the Williams Fork Formation.

4. Our development efforts in the Rulison Field have been outstanding compared to previous attempts in the area. Figure 17 indicates the revised stimulation techniques incorporated in 23 wells (18 of these wells with poor fluid quality) has provided a 225% increase in EUR's above pre-1994 completion efforts in the field. Obviously, completion technology in our industry has markedly improved during the last 15 years allowing operators such as Barrett to economically recover gas in these ultra tight and highly compartmentalized reservoirs.

Conclusions and Recommendations

The very large completion study conducted in the Grand Valley and Parachute areas, as well as the much smaller study conducted in the Rulison Field illustrates the important considerations when fracture stimulating ultra-tight lenticular reservoirs. The resulting conclusions are listed as follows:

1. A strong correlation exists between the size of treatments, fracturing fluid type, and economic success in the study area. Larger sand volumes, improved sand transport fluids, and Intense Quality Control

efforts outlined in this report are key to successfully stimulating the Williams Fork Formation in the Piceance Basin.

2. The use of a 3D fracture stimulation model aided in determining fracture geometry, illustrated the effects of multiple echelon fractures, and eliminated the need for cased hole stress tests. Virtually no lithological barriers exist within the Williams Fork, with the exception of the paludal or Cameo coal section.

3. Since initiating the study and implementing the procedures herein, Barrett Resources Corporation has been able to achieve a 100% success rate in completing wells in the Grand Valley and Parachute area that will ultimately yield 1.5 BCF or greater reserves. Rulison Field wells incorporating the revised completion techniques will ultimately recover greater than 1.8 BCF of reserves per well. These recoveries meet Barrett's economic threshold. In every case where we have not achieved anticipated results, we have been able to isolate the problems that incurred due to poor proppant transport and lack of complete coverage of the intervals.

4. As economic conditions permit, further reduction of the number of fracture initiation points and increased sand volumes must be implemented. After increasing job size by a factor of two (a factor of three on select wells) and reducing pad size to 5% of the total stimulation volume, complete packing of the fracture is not evident. Hydraulic fractures must be adequately propped to drain areas within reach of a stimulation.

5. Total well costs have been reduced 12-15% since initiating the revised procedures contained in this report. This effort is complemented further by the fact that approximately twice the amount of sand is being pumped compared to previous stimulations.

Acknowledgments

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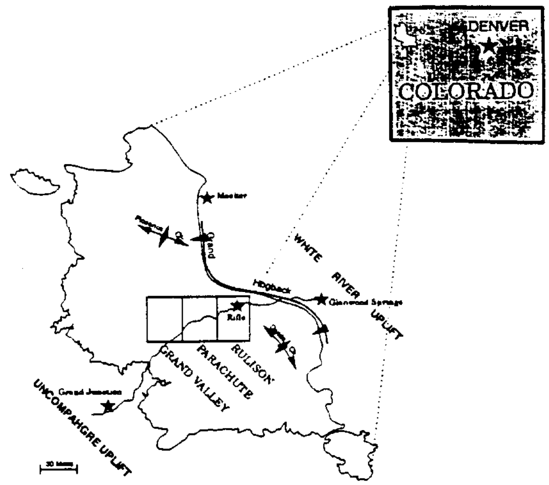
Table 1
Effect of multiple fractures
on effective conductivity

Number of Fractures	650,000# Treatments	300,000# Treatments
1	307 feet	190 feet
2	226 feet	143 feet
3	195 feet	124 feet
4	172 feet	0 feet
5	121 feet	0 feet
6	110 feet	0 feet
7	101 feet	0 feet

* Effective propped length is defined as propped fracture conductivity greater than 100 millidarcyfeet.



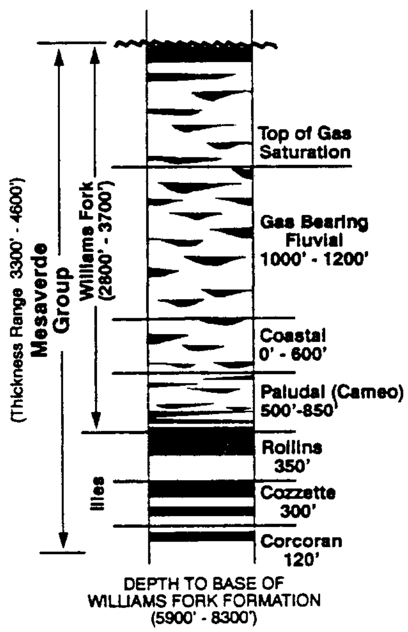


Figure 2 - Generalized Mesaverde Section
Piceance Basin

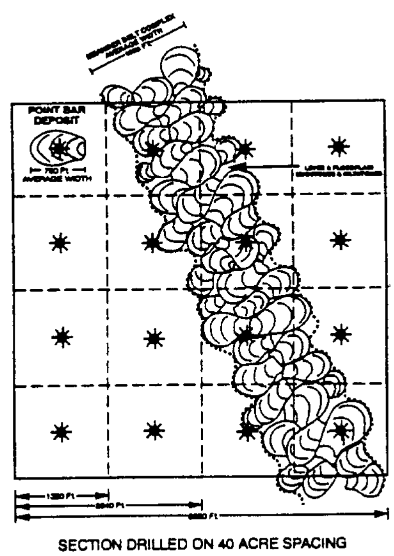


Figure 3 - Reservoir Compartmentalization
Standard Governmental Section

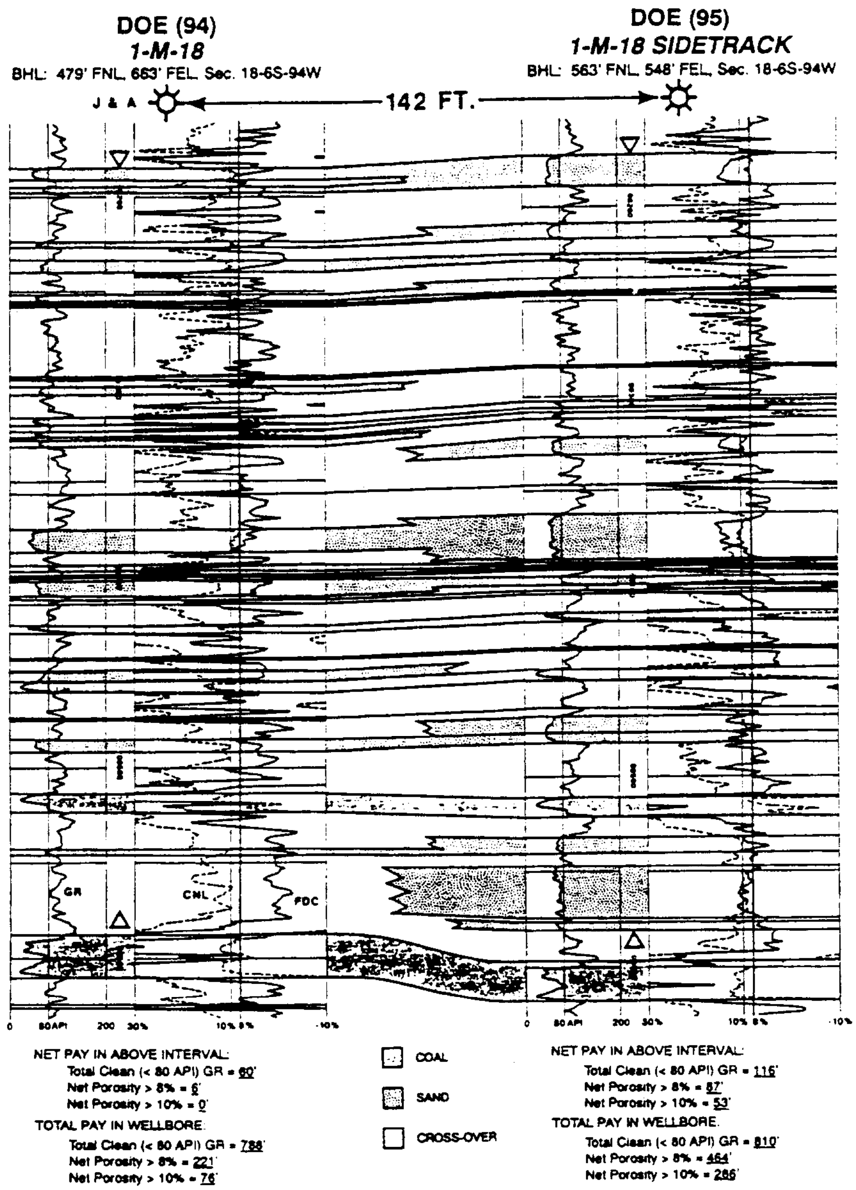


Figure 4 - Discontinuity and variability of reservoirs
Upper paludal interval -North Rulison

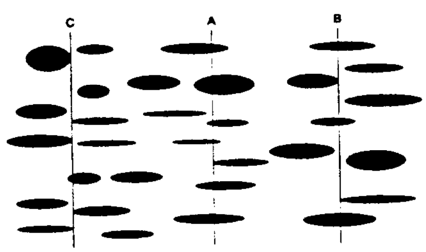


Figure 5 - Pseudo-Homogeneous

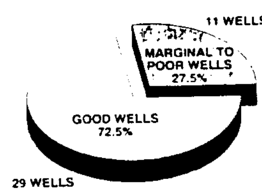


Figure 6 - 'New Generation' Fracture Stimulation Techniques
Total of 40 Wells

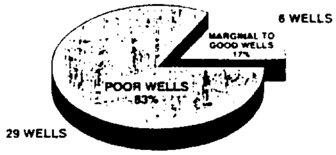


Figure 7 - Low Viscosity Fluids
In Fracture Stimulation Treatment
Total of 35 Wells

Figure 8 - Large Fracture Stimulation Treatments
Containing at Least 350,000 Lbs. of Sand Per Treatment
Total of 35 Wells

Figure 9 - Small Fracture Stimulation Treatments
Containing Less Than 300,000 Lbs. of Sand Per Treatment
Total of 46 Wells

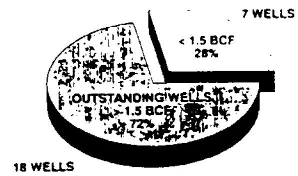


Figure 10 - Wells Containing +1,000,000 Lbs. of Sand
Total of 25 Wells

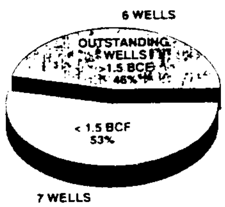


Figure 11 - Results of 6/93 - 4/94 Completion Techniques
Grand Valley/Parachute Fields
Total of 13 Wells

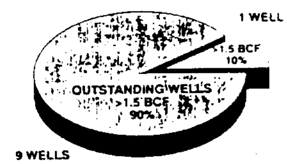


Figure 12 - Revised Completion Techniques Yield Improved EUR'S
Grand Valley/Parachute Fields
Total of 10 Wells

Relationship Between
Completion Techniques and EUR
Grand Valley/Parachute Fields

REVISED COMPLETION TECHNIQUES	10 WELL AVERAGE	1756 MMCF/WELL
6/93 - 4/94 COMPLETION TECHNIQUES	13 WELL AVERAGE	1468 MMCF/WELL

REVISED COMPLETION TECHNIQUES = 20% INCREASE IN EUR

Figure 13

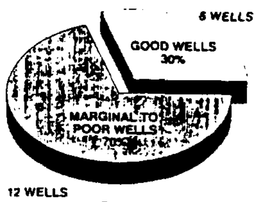


Figure 14 - Poor Proppant Transport Fluids
Rulison Field
Revised Stimulation Techniques - Total 18 Wells

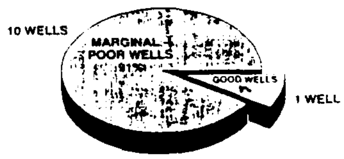


Figure 15 - Wells Stimulated With 3 Fracs
Rulison Field
Revised Stimulation Techniques - Total 11 Wells

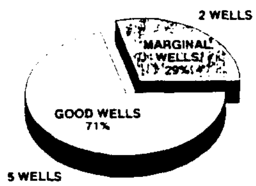


Figure 16 - Wells Stimulated With 4 Fracs
Rulison Field
Revised Stimulation Techniques - Total 7 Wells

Relationship Between Completion Techniques and EUR Rulison Field

REVISED COMPLETION TECHNIQUES	23 WELL AVERAGE	1902 MMCF/WELL
PRE 1994 COMPLETION TECHNIQUES	34 WELL AVERAGE	848 MMCF/WELL

REVISED COMPLETION TECHNIQUES = 225% INCREASE IN EUR

Figure 17