SPE 160206

Hydraulic Fracture Design Optimization in Unconventional Reservoirs – A Case History

Terry T. Palisch, SPE, Mark A. Chapman, SPE, Jonathan Godwin, SPE, CARBO Ceramics Inc

This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, USA, 8-10 October 2012.

Abstract

Multistage hydraulic fracturing is one of the key technologies affording the successful development of unconventional reservoirs. Transverse fracturing of horizontal wells has become the standard for development of these plays, allowing commercial exploitation of what were once considered uneconomic resources.

The primary goal of the completion in these ultra-low permeability formations is to provide a conductive path to as much rock as possible, through the use of multistage hydraulic fractures along a horizontal lateral. This requires two separate, yet complimentary strategies – a wellbore with optimal length and completion hardware, and multiple hydraulic fractures with optimal conductivity. Most completions engineers have a good understanding of their wellbore and completion hardware; however, many do not have the same level of knowledge of their hydraulic fractures. This leads many to incorrectly assume that fracture conductivity is unimportant. However, the fracture provides the critical link between the formation and the wellbore; without a durable fracture, the completion will fail.

This paper will present a technique to assess the realistic conductivity of the fracture at downhole conditions, describe the relationship between conductivity and productivity, and evaluate the impact of treatment optimization on economics. Use of this approach allows engineers to design their fracture stimulation to maximize the economic potential of their well.

Laboratory data are presented which demonstrate the impact of downhole conditions on proppant performance, including fines migration, elevated temperatures and embedment. In addition, fracture modeling and actual field results will be presented to illustrate the optimization process. Case histories showing the successful implementation of this method will be provided in unconventional gas (Haynesville), a liquids rich formation (Eagle Ford) and an unconventional oil reservoir (Bakken).

This paper will serve as a resource to those engineers who wish to gain a better understanding of hydraulic fractures or desire to maximize the economics of their completions in unconventional plays.

Introduction

The successful development of unconventional reservoirs has provided unprecedented opportunities for the oil and gas industry. When operators "cracked the code" in the Barnett in the early 2000's, the rush was on to find other shale gas plays, such as the Haynesville Shale and the Marcellus. As the development/ completion technologies were successfully applied to gas plays, operators then began to take these practices to oil/condensate plays, such as the Bakken and Eagle Ford. The industry continues to expand, and new unconventional plays are being reported every year (**Figure 1**). Additionally, these technologies are being exported to other international arenas. Many describe these plays as "technology plays". One reason is that the success of these plays is not typically hinged on finding or discovering them. The industry has drilled

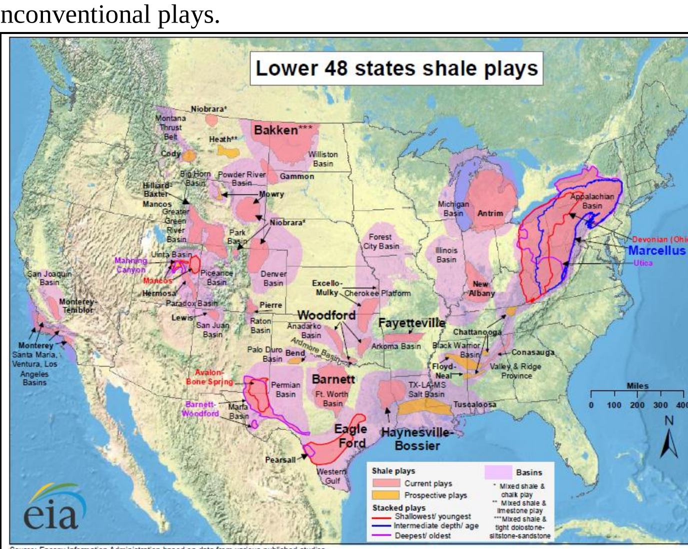

Figure 1 – Unconventional Shale Plays dominate the current activity in the US [courtesy Energy Information Administration].

through most of these reservoirs many times in their quest to develop "conventional" reservoirs, yet they have never been developed due to their ultra-low permeabilities. In most cases they have either been considered hydrocarbon trap barriers or source rocks. Rather, success hinges on whether engineers can effectively and economically adapt the completion technologies used in other plays.

The two primary technologies that have contributed to unconventional reservoir development are the successful combination of multi-stage fracturing and horizontal wells. Both technologies have been around for decades, but our ability to run plugs, perforate, slide sleeves and perform other operations in long, horizontal wellbores has allowed the industry to place multiple, transverse hydraulic fractures. This combination permits the industry to contact large rock volumes from a single wellbore (**Figure 2**), leading to economic production from reservoirs with permeabilities in the nanodarcy range.

Therefore, economically successful wells in unconventional reservoirs are tied to the optimal coupling of proper completion techniques to reservoir deliverability. Simply put, when the drilling and completion rigs and frac equipment leave the wellsite, the industry relies on the fracture treatment and the wellbore to economically deliver the hydrocarbons to the sales meter. Moreover, it is the hydraulic fracture treatment that provides the critical link between the reservoir and the wellbore. While our industry continues to grapple with optimization of wellbore placement, lateral length, frac isolation techniques and fracture spacing, many fail to consider the impact of fracture geometry and fracture conductivity, yet is the fracture conductivity that provides the vital link.

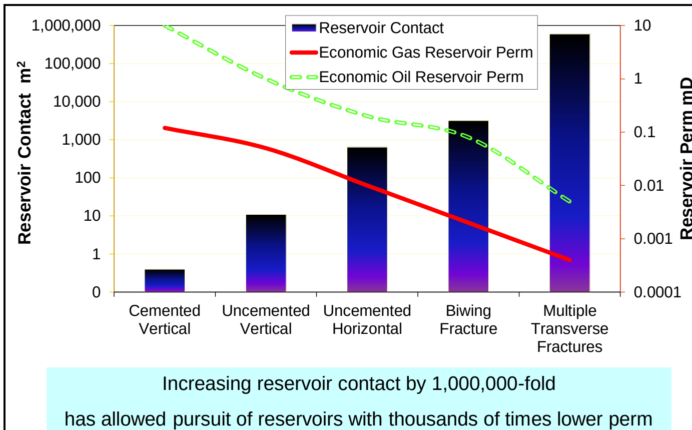

Figure 2 – Multistage fracturing in horizontal wells can provide two orders of magnitude higher reservoir contact than a single biwing fracture [Vincent 2011].

Fracture conductivity is governed by many parameters, including proppant size, proppant type/quality, proppant concentration (fracture width), proppant durability, fluid clean up, embedment/spalling, and fines migration. With few exceptions, the majority of the parameters on this list are tied directly or indirectly to proppant selection. Therefore, proppant selection must be viewed as a critical parameter when designing the completion and hydraulic fracture treatments. The remainder of this paper will present a methodology for optimizing hydraulic fracture designs that have been successfully implemented in many unconventional reservoirs.

Proppant Selection in Unconventional Reservoirs

Proppant selection in unconventional reservoirs has been driven by four parameters – proppant availability, frac fluid selection, conductivity requirements and cost-benefit analysis. Depending on operator and reservoir, each parameter may be more or less significant in any given application. But a good understanding of each is critical to successfully optimizing the completion.

Proppant Availability. Over the past several years, world-wide proppant utilization has increased by almost 15-fold. It is estimated that global proppant use in 2011 was 60-70 billion lbs per year, whereas prior to the development of the Barnett Shale in 2004, annual usage was ~5 billion lbs. In fact, the total proppant being delivered to the Eagle Ford Shale alone exceeds 12 billion lbs per year, more than twice the global consumption of 2004 [estimated from current rig count (250), drilling days and an average proppant volume of 5 million lb/well]. In addition to putting tremendous strain on logistics, this dramatic increase in demand has strained proppant supply (particularly high quality proppant) in all tiers. New sand mines are continually being opened, resin coating operations are being built and expanded, and new ceramic proppant plants are being constructed. However, as is typically the case, when demand increases in such dramatic fashion, quality can suffer. In times of high demand, sand mines may not deliver the same quality and sieve distribution as traditionally expected [Stephenson 84304].

Figure 3 – Note the differences in shape and internal porosity of several internationally manufactured ceramic proppants compared to high quality ceramic (red star). Both factors adversely affect proppant performance [Courtesy CARBO].

Resin coating operations depend on these same sand sources as a substrate for resin coated sand, so demand increases can adversely affect quality of these products as well. Ceramic plants require more capital and lead time, and very few suppliers have the expertise to build quality products from the ground up, leading to a shortage of high quality ceramic proppant and the importation of certain Chinese ceramics that may have been historically rejected due to poor or variable quality. Unfortunately, ceramic proppant quality can be adversely affected by inferior raw material supply, lack of process control, inferior firing methods as well as lack of quality control measures. This can lead to irregular shapes and incomplete sintering (**Figure 3**) and can result in disappointing well productivity. Due to insufficient quantity of quality proppants to meet demand, for many engineers, proppant selection over the past few years has therefore been one of "bring what is available".

Frac Fluid Selection. Beginning with the development of the Barnett Shale, there has been a significant shift away from traditional crosslinked fluids, to slickwater and other low viscosity fluids. As lower viscosity fluids are utilized, it has become necessary to specify smaller diameter proppants due to the inability of these low viscosity fluids to transport proppant [Palisch 2008]. Stokes Law dictates that as proppant diameter increases, settling velocity increases exponentially. Development of such shale plays as the Barnett, Haynesville and Marcellus drove a rush to 40/70 or 40/80 Mesh, and in many cases 100 Mesh proppants. In some cases engineers began to tail in with larger diameter proppants (such as 30/50) to overcome near wellbore flow convergence impacts, but in those cases a linear gel was frequently required.

In 2011, as the industry slowed development of the gas reservoirs due to depressed gas prices, and reallocated resources into the unconventional oil and/or condensate reservoirs such as the Bakken and Eagle Ford, the need for larger diameter proppants and elevated proppant concentrations (due to increased conductivity requirements) led to a shift back to higher viscosity fluids. In most cases the fluid systems utilized in these treatments are of a hybrid nature, meaning lower viscosity fluids (such as slickwater or linear gel) are pumped in leading stages, and then as the proppant concentration and/or diameter is increased, crosslinked fluids are used. This move from gas to liquids-rich plays has caused a shift from the small mesh proppants, to more 30/50 and 20/40 mesh. In fact there has even been some experimentation with 16/20 and 12/18 mesh proppants as a tail-in for maximum near wellbore conductivity with encouraging results. In general, smaller mesh proppants are used with low viscosity fluids, and moderate to larger mesh proppants are employed with crosslinked fluids.

Conductivity Requirements. The primary role of proppant is to provide a sufficiently conductive pathway for hydrocarbons to travel to the wellbore. As such, proppant selection is dictated primarily by how much flow capacity is needed in a given fracture. The concept of fracture conductivity is often overlooked as an important stimulation design variable in unconventional reservoirs, as the presence of micro- and nano-Darcy rock may not suggest a critical need for fracture conductivity. However, while the fracture conductivity required to economically produce a horizontal well in an unconventional play varies by reservoir, many engineers fail to recognize the conductivity requirements to optimally accommodate hydrocarbon flow in these transverse fractures.

The conductivity of the fracture is calculated as the product of the permeability of the fracture and the fracture width, and can be represented by the following equation:

$$\text{Conductivity} = k_{frac} * w_{frac} \quad \ldots\ldots(1)$$

The pack conductivity for a given proppant is a function of many physical properties, including proppant particle size, strength and proppant grain shape (roundness and sphericity), and is typically measured in the laboratory at standard conditions. In 2006 the International Organization for Standardization (ISO) set the current standard under ISO-13503-5 [ISO 2006] and in 2008 the API adopted this standard under API-RP-19D. Highlights of the API/ISO conductivity test include the following:

- Proppant is loaded into the conductivity cell at 2 lb/ft2
- Proppant is placed between Ohio Sandstone shims with a Young's Modulus of 5 million psi
- The test is performed at 150º F for sand and 250º F for ceramic proppants
- Stress is increased at a uniform rate, and then held for 50 hours at the target stress
- 2% KCl fluid is circulated at an extremely low rate of 2 ml/min.
- Darcy's Law is used to calculate the permeability and conductivity of the proppant pack

The objective of this test is to provide a consistent methodology for proppant conductivity testing and comparing proppant materials under comparable *laboratory conditions*. Recognizing the standard's limitation given the differing conditions between lab and realistic downhole conditions, API-RP-19D specifically states that this testing "*is not intended for use in obtaining absolute values of proppant pack conductivities under downhole reservoir conditions*" [API 2008]. Although these standard conditions allow for comparable testing between proppants, and account for many parameters such as size, shape, crush, thermal effects and density, they rarely represent the realistic conditions in which proppant is placed in hydraulic fractures [Palisch 2009]. The conductivity is also impacted by many downhole conditions including fluid flow effects (non-Darcy and multi-phase flow), reduced proppant concentrations, fracturing fluid residue, fines migration and cyclic stress on proppant. When accounting for these effects, it is not uncommon for the actual conductivity of the proppant pack to be reduced to double or even single digits compared to the hundreds or thousands of md-ft advertised in literature [Palisch 2007]. Further complicating matters, different proppant types may be affected differentially by each parameter. A brief description of the key effects is given below. The interested reader can refer to SPE 106301 for a full description.

Non-Darcy and Multiphase Flow. The ISO/API test flow rate of 2 ml/min is not representative of actual flow rates in a proppant pack. This rate would equate to ~6 BPD in a fully perforated vertical oil well with a 50 ft tall bi-wing frac achieving 2 lb/ft^2 concentration, or ~15 MSCFD flowing at 1,500 psi and 250°F in a similar dry gas well. The fluid velocities resulting from more prolific wells will cause tremendous amounts of energy to be lost, due to additional pressure losses not described by Darcy's Law. Forchheimer's equation (shown below) includes the non-Darcy pressure drop ($\beta\rho v^2$) component for a single phase fluid and is dominated by the velocity-squared term [Forchheimer 1901].

$$\frac{\Delta P_{frac}}{X_{frac}} = \frac{\mu_{fluid} \cdot v_{fluid}}{k_{frac}} + \beta\rho_{fluid} v^2{}_{fluid} \quad \text{.....(2)}$$

Additionally, the fluid circulated in the ISO/API tests is a solution of silica-saturated, oxygen free 2% KCl water. In reality oil and gas wells rarely produce 100% water, or even a single phase fluid for that matter. Instead, two or three phases are typically present (oil, water and gas), yielding a much more complex flow regime than tested in the lab. Multiphase effects have been described in many ways by various researchers. Lab data consistently demonstrate that pressure losses in the fracture may increase significantly when both liquid and gas phases are mobile within the fracture. This is typically attributed to the highly inefficient flow regime that occurs when gas, oil and water molecules move through the proppant pack, each moving at different velocity. In fact, some tend to consider multiphase flow impacts as a multiplier to non-Darcy effects since the impacts are most pronounced at high velocity flow. Significant pressure losses are documented even when only small percentages of a second phase are mobile within the fracture [Palisch 2007]. Interpreting the extra pressure drop caused by non-Darcy and multiphase flow as a conductivity reduction typically shows a fracture conductivity impairment exceeding 70%.

Proppant Concentration. It is generally accepted that in most slickwater or hybrid frac stimulations, the effective proppant loading achieved in the fracture is much less than 2 lb/ft^2, and in most cases is estimated to be less than 1 lb/ft^2. This means that the fracture is frequently much narrower than in the ISO/API test. In addition to directly impacting conductivity via the conductivity equation (fracture perm * fracture width), the much narrower width sustained by the reduced proppant concentration also increases the fluid velocity through the pack for a given flow rate. This in turn exacerbates the non-Darcy and multiphase flow effects in the fracture. If the fracture width is halved, and hydrocarbon velocity is doubled, then non-Darcy pressure losses are increased by a factor of four.

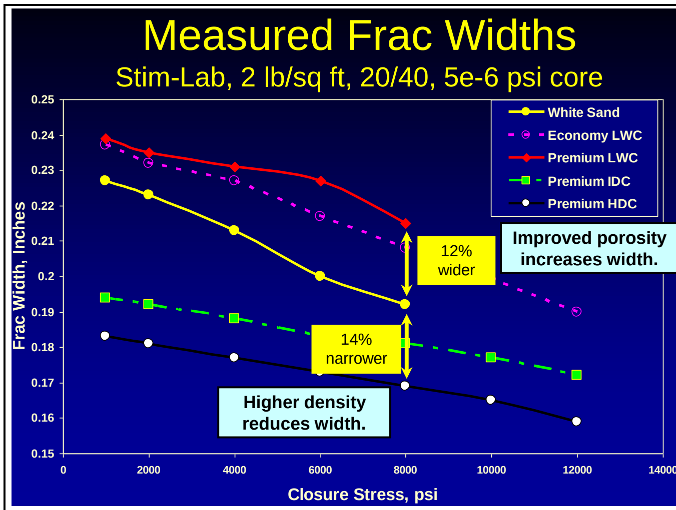

Figure 4 – Proppant selection affects fracture geometry (width or length). A LWC-filled frac will retain more width than an IDC or HDC-filled frac. Higher pack porosity premium proppants will also sustain greater width. [Courtesy StimLab].

In addition, effective fracture width can be affected by gel filter cake, formation embedment/spalling and proppant density. When fluids leak off and gels dehydrate, they form a durable filter cake on the fracture face that reduces the effective fracture width [Palisch 2007, Stim Lab 2002]. Embedment and spalling will be covered later in the paper, so it will not be discussed here. Proppant density impacts were largely ignored by many in the industry when proppant concentrations were well in excess of 1 lb/ft^2. However, with the realization that current designs provide much less than 1 lb/ft^2, the proppant density effect now becomes crucial. Sand, RCS and Lightweight Ceramic (LWC) all have very similar densities. However, with the shortage of proppant, many tend to consider all grades (densities) of ceramic proppant as "interchangeable" except for strength. Yet, an Intermediate Density Ceramic (IDC) is 20% denser than a LWC, and a High Density Ceramic (HDC) is 30% denser. Therefore, under comparable proppant loading, fracture width can change dramatically depending on the type of proppant being placed (**Figure 4**). Unfortunately, our industry designs treatment schedules by mass, not volume, so if one substitutes an IDC for an LWC/RCS/Sand, a narrower or shorter frac will be placed. To illustrate, a pile of 4 million lbs of LWC/RCS/Sand will be 20% larger than a 4 million lb pile of IDC, and 30% larger than a 4 million lb pile of HDC. If similar proppant mass is purchased, an engineer must recognize that the frac geometry will be reduced by 20%-30% with higher density proppants.

Fines Migration & Cyclic Stress. Fines can be generated by both the proppant when it crushes, and the formation as proppant embeds into the fracture face. In either case, fines moving through the proppant pack can plug pore throats and decrease flow. The impact of these fines on the proppant pack conductivity can vary by proppant type and size [Palisch 2009, Gidley 1992]. In addition, the impact of fines migration, like other parameters, must be viewed in the context of the test. For example, **Figure 5** shows the results of a high fluid rate fines migration study where a LWC lost 23% permeability due to fines migration, whereas the RCS lost only 10%. However, despite this difference, the LWC still exhibited twice the retained permeability as the RCS after fines migration impacts are included.

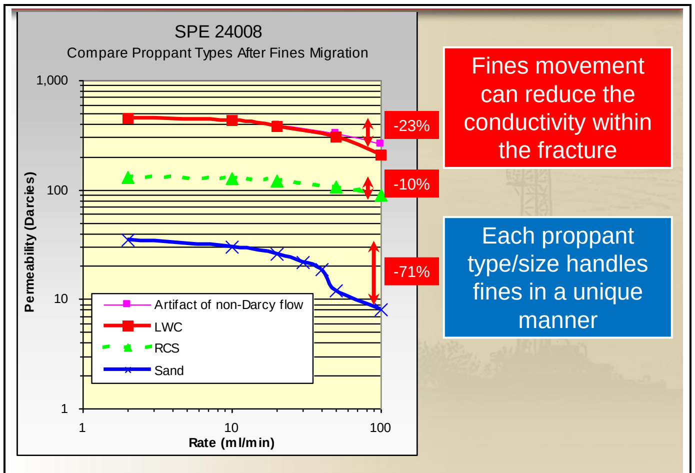

Figure 5 – Fines migration can reduce proppant permeability significantly. Note that the API/ISO test is performed at 2 ml/min, much lower than where fines are mobilized. This data was generated at high rates which mobilized the fines. [Gidley 1992].

Conductivity can also be adversely impacted each time the bottom hole pressure changes. This occurs primarily when the flowing tubing pressure is changed, whether due to well shut in or line pressure fluctuations. It has been demonstrated that every time the bottom hole pressure changes, proppant stress is "cycled" and fracture conductivity is lost [Stim Lab 2000, Palisch 2007]. While difficult to measure for every potential scenario, cyclic stress impacts must be viewed as yet another detrimental impact on fracture conductivity when proppants are placed into realistic conditions. In general, stress cycling is more damaging to low strength proppants, while high quality proppants are more resistant to cyclic stress degradation.

Cumulative Conductivity Impact. When all of these effects are taken together, the overall impact of these damage mechanisms on the conductivity at actual bottom hole flowing conditions can be severe. In fact, laboratory testing under more realistic conditions typically show the overall loss of conductivity to exceed 90% (**Figure 6**). Additionally, while all proppants experience these several orders of magnitude reduction in conductivity, the individual damage mechanisms can have different impacts on the various proppant types [Schubarth 2006]. While the above conductivity damage is already severe, there are additional downhole realities that can further exacerbate the damage, including long term conductivity degradation as well as gel/fluid residue damage and many other mechanisms [Pearson 2001, Barree 2003, Palisch 2007]. Regardless of the exact magnitude of these reductions, the bottom line is that the realistic conductivity in all hydraulic fractures is significantly lower than measured in standard lab testing and reported in industry literature. Further, if these reductions are not accounted for when designing hydraulic fractures and/or selecting the appropriate proppant, significant production may be deferred or in some cases not recovered in the existing completion [Blackwood 2011].

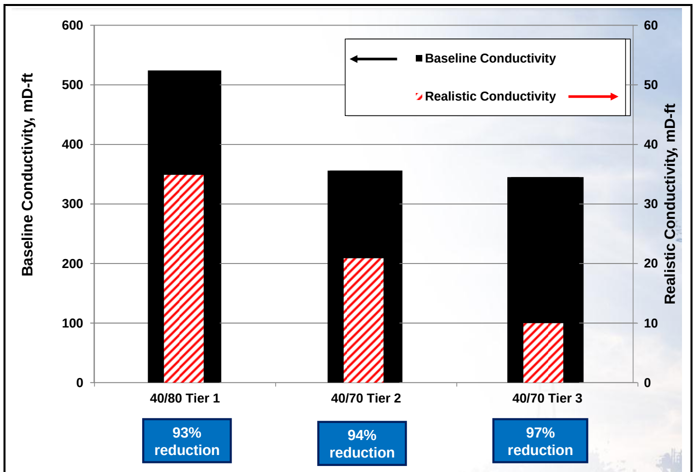

Figure 6 – Comparison between standard ISO/API test conductivities and the realistic conductivities at Eagle Ford Shale conditions for a well in Webb County, TX. Note that while all proppants lose over 90% conductivity, the Tier 1 proppant retains nearly twice the value of a Tier 2 and over 3x that of a Tier 3 proppant [Bazan 2012].

Additional Conductivity Impacts

The damage mechanisms discussed previously will be encountered in virtually all propped fractures, regardless of completions type or reservoir. However, completions in many unconventional reservoirs may also carry additional parameters that adversely impact conductivity, including thermal degradation of proppant, proppant embedment and flow convergence in transverse fractures.

Temperature Effects. As noted earlier, the ISO/API conductivity test is performed at 150°F for sand and 250°F for ceramic proppant. The reason for this difference is detrimental impact of higher temperature on sand and sand-based proppants (i.e. Resin Coated Sand). Specifically, as temperatures exceed 200°F, sand-based products can experience a significant loss in strength and subsequent decrease in conductivity (**Figure 7**). For example, an uncoated sand, when exposed to 250°F at 6,000 psi stress will lose 40% of its conductivity when compared to the 150°F published data, and this loss increases to nearly 80% at 300°F and 8,000 psi. Coating the sand with a resin lessens the damage because the resin can encapsulate the crushed fines. However, even resin coated sand loses 30% of its conductivity at 8,000 psi and 300° F. Ceramic proppants are tested at 250° F due to their thermal stability. These proppants are sintered at ~2,700°F and are engineered for improved sphericity, strength and thermal resistance. Therefore, no correction is required when placing a ceramic proppant into higher temperature formations.

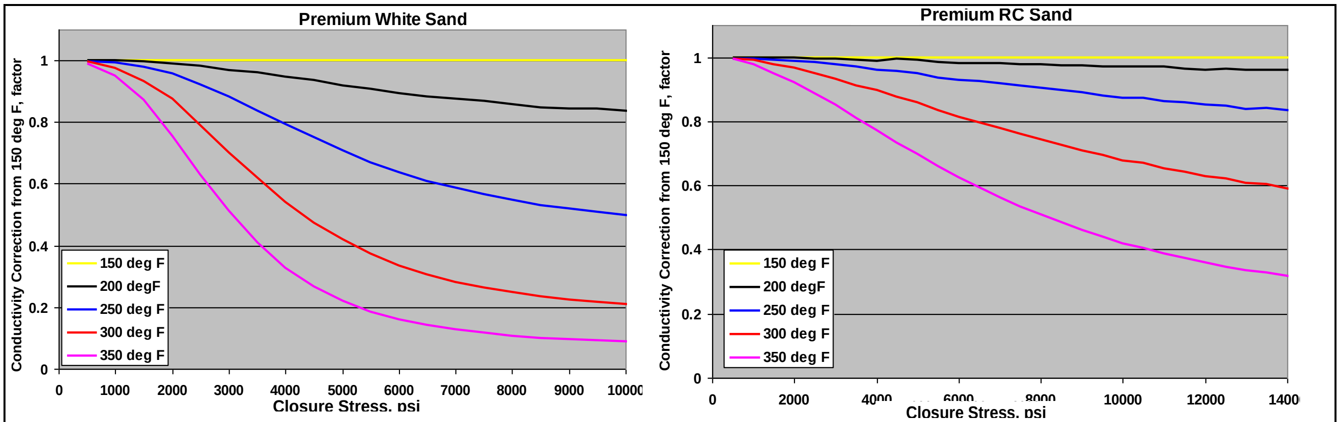

Figure 7 – The effects of temperature on conductivity for Sand-based proppants [Pope 2009].

Proppant Embedment. The ISO/API test uses a sandstone core with a Young's Modulus (YM) of 5 million psi, which tends to mimic "hard rock" fracturing. However, as YM decreases, proppant will embed into the fracture face, and fines will spall into the proppant pack. Lab data suggests that proppant embedment is a function of both YM and proppant diameter (**Figure 8**). Many shale and unconventional reservoirs are significantly softer than the sandstone cores used in the published tests. Embedment leads to a loss of width and conductivity. Similar to the impact of lower proppant concentrations, the reduced effective width has the double effect of diminishing conductivity (directly proportional), and increasing fluid velocity due to the smaller cross section of the resulting proppant pack (exponential effect). As a consequence of decreased flow area, non-Darcy pressure losses will be increased, as well as multiphase flow impacts.

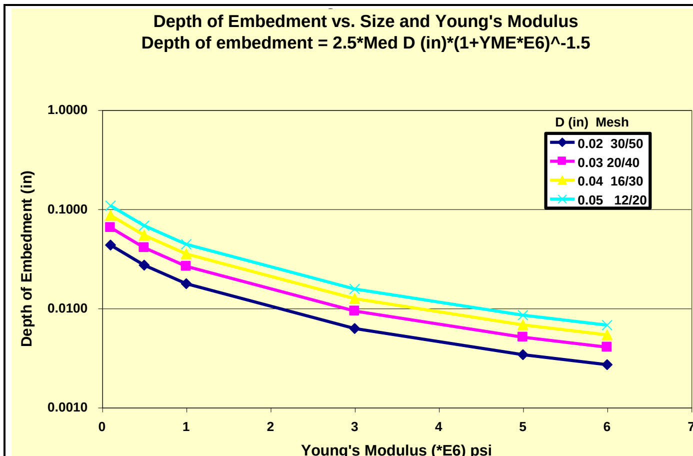

Figure 8 – Embedment is a function of formation Young's Modulus and Proppant Diameter [Stim Lab 2002]. Placing a curable resin on proppant can minimize this embedment, provided it is fully cured at low closure stress, prior to production of the well.

Flow Convergence in Transverse Fracs. Recall that the goal in many unconventional plays is to place numerous transverse fracs along a horizontal lateral, as opposed to conventional plays which may exploit a single, bi-wing frac in a vertical well. Production into a horizontal wellbore from an orthogonal fracture will exhibit linear flow in the far field as it travels down the fracture(s). However, as the fluids converge on the relatively small diameter wellbore (**Figure 9**), the fluid velocities in that near wellbore region increase dramatically. In fact, if one considers a single planar 100 ft tall vertical fracture, and places it fully connected in a vertical well and then transversely in a horizontal 6 inch diameter wellbore, the fluid velocity in the near wellbore region would be 127 times higher in the transverse fracture as compared to the vertical well. Further, recall that velocity is a squared term in the Forchheimer (see previous discussion) pressure drop calculation, therefore, the pressure drop in the transverse frac could be over 16,000 times greater than in a fully connected vertical well. This leads to the conclusion that it is practically impossible to place enough conductivity near the wellbore in a transverse/HZ well to be fully optimized. Completions in unconventional resources will benefit from more conductivity near-wellbore in transverse fracs [Besler 2007, Rankin 2010, Shah 2010, Vincent 2011, Economides 2000].

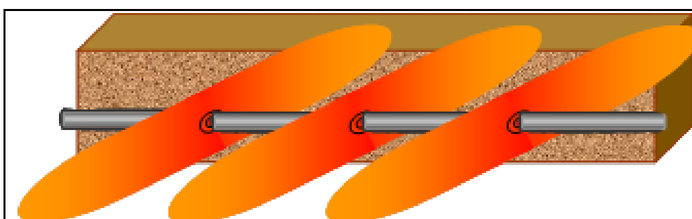

Figure 9 – Fluids flowing within the hydraulic fracture in horizontal wells must converge into an extremely (relatively) small area as they cut transversely with the wellbore [Shah 2010].

Cost-Benefit Analysis

Figure 10 – The Proppant Conductivity pyramid showing the three Tiers of proppant. 99% of all proppant can be placed into one of three Tiers. As one moves up the Triangle, proppant performance (conductivity) improves [Gallagher 2011].

When these additional impacts are considered, the conductivity of hydraulic fractures is significantly reduced from lab measurements. Whether using Agarwal Type Curve analysis in vertical wells in Wamsutter [Palisch 2007], or history matching actual production in the Eagle Ford with a fracture model [Bazan 2010], realistic conductivities in the single digits are not uncommon (i.e. frequently less than 10 md-ft). It is worth noting that while single digit conductivities are dramatically lower than baseline conditions, they are still significantly better than the micro and nano Darcy permeability found in unconventional reservoirs. However, when one understands the realistic conditions within the proppant pack, and their impact on fracture conductivity, it becomes apparent that the fracture flow capacity is not optimized (i.e. the F_{CD} is much lower than anticipated) in horizontal multistage fractures in unconventional reservoirs. Furthermore, anything that can be done to increase the conductivity of the fracture should provide an increase in production. While there are many ways to increase the conductivity of a fracture – increasing proppant concentration, using larger diameter proppants, pumping cleaner fluids – and all should be considered when designing fracture stimulations, one of the easiest and most common is to upgrade the proppant size and/or type. As one moves up the Proppant Conductivity pyramid, fracture conductivity (and production) improves (**Figure 10**). However, moving up the pyramid typically carries with it an increase in completion (proppant) cost. Therefore, the decision to increase conductivity must also involve an economic analysis, and ultimately will become an economic decision. The process for selecting proppant (or the "Economic Conductivity" approach) must involve three steps:

1. Calculate the conductivity of the fracture at realistic conditions and predict the production performance achieved with each proppant
2. Complete a cost-benefit analysis and select the proppant that maximizes the economics of the completion
3. Review the actual field production benefits to ensure validity of the previous evaluations

Step 1 must typically be performed through the use of a fracture propagation model that is coupled to a reservoir simulator/model. The model must account for the realistic conditions of the fracture and the corresponding impact of fracture conductivity. Step 2 can then be performed using the economic hurdles for the given situation; some production simulators automate this function. The third step is often the most overlooked step in the process, due to the significant activity level required of most engineers involved with developing unconventional reservoirs. The following sections will present case histories from three prominent unconventional reservoirs in which proppant was selected using the steps above. These cases illustrate the robustness of the Economic Conductivity methodology and demonstrate the production and economic benefits of placing enhanced conductivity in ultra-low permeability formations.

Case Histories

The importance of fracture conductivity has been documented in a wide variety of reservoir types. A comprehensive review of more than 200 SPE papers demonstrated the production increases achieved when fracture conductivity was increased compared to previous frac designs [Vincent 2009]. In an enormous variety of well conditions, including deep and shallow wells, oil/gas/water wells, wells completed in sandstone/carbonate/coals, and high and low production rate wells, increasing the fracture conductivity yielded much larger production benefits than predicted by typical models. This section will specifically review recent field studies in three unconventional reservoirs which were completed with horizontal wells and multistage fracture treatments. The results serve to illustrate the production increases and economic benefits achieved when placing higher conductivity fracture treatments.

Haynesville Shale. The Haynesville Shale is a Jurassic age, prolific unconventional reservoir that produces primarily dry gas. Unfortunately, activity has slowed due to prolonged low natural gas prices that are ironically caused in part by the success of the play itself. The play extends from East Texas to Northwestern Louisiana encompassing over 20 Texas counties and Louisiana parishes. The play ranges in depths of 11,000 - 13,000 ft TVD, gross thicknesses of 150 – 400 ft., BHST of 300-340°F, BHP gradient of 0.84 – 0.88 psi/ft., closure gradient of 0.95 – 1.05 psi/ft., porosity of 6-12% and permeability of 5-800 nD [Pope 2010]. In this case study, the original goal was to improve production results through optimizing completion designs utilizing modeling and verifying with field results. In the initial modeling phase, it was apparent that the fractures would be conductivity limited using any small mesh proppant, and that upgrading to a higher Tier proppant would increase production (**Figure 11**). Of particular concern was the high temperature (>300º F) and high closure stress environment (>10,000 psi) in the Haynesville Shale wells, and their impact on both short term production and long term durability of the proppant pack if Tier 2 or Tier 3 proppants were utilized.

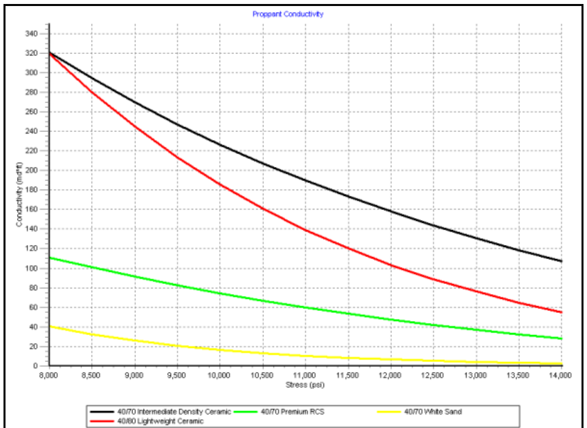

Figure 11 – Tier 1 ceramics (black/red) provide over twice the conductivity as Tier 2 RCS (green) at realistic Haynesville conditions, and nearly 10x that of Tier 3 sand (yellow) [Pope 2009].

In 2010 the actual production and completion data from an existing Haynesville Shale well was history matched using a reservoir simulator [Pope 2010]. Sensitivities to several completion parameters were performed, including an evaluation of the benefits of increasing conductivity which showed a positive impact of conductivity. At the same time the authors also performed a production analysis on a set of wells from another operator containing 55 wells within a 5 mile radius in Caddo & DeSoto Parishes (**Figure 12**). The well set included 55 wells with at least six months of production, 20 of which contained Tier 1 (primarily 40/80 LWC) proppants. The remaining 35 offset wells contained Tier 2 (RCS) proppants. The authors further noted that all the wells in the study exhibited similar completion designs (apart from the noted proppant substitutions) and were completed in roughly the same timeframe.

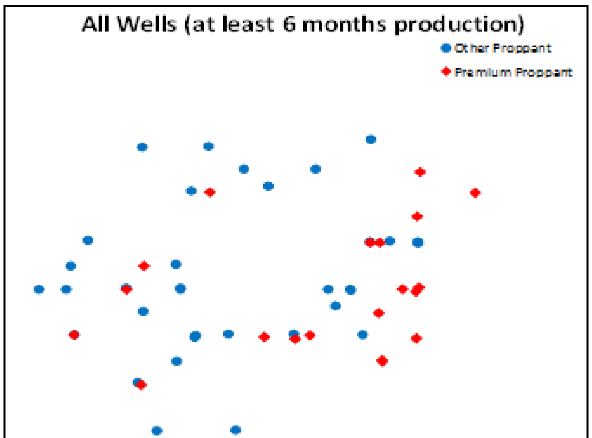

Figure 12 – Wells in the study all completed by the same operator and well distributed throughout Caddo/DeSoto Parish [Pope 2009].

The authors of this paper have taken those same study wells and updated the results such that the wells have now been on production for nearly three years, with all wells having at least 32 months of production. In this time, the higher conductivity Tier 1 proppant group has an average cumulative gas production of ~2.3 BCF while the offset Tier 2 group has produced an average of ~1.8 BCF per well (**Figure 13**) or an increase of 0.5 BCF. Utilizing hyperbolic decline curve analysis the authors project the Tier 1 LWC wells will produce nearly 1 BCF more, *per well*, after a 20 year producing span compared to the Tier 2 RCS wells, representing a 35% increase in ultimate recovery (**Figure 14**). It is also interesting to note that the incremental percent increase in production is growing. After 32 months, the Tier 1 wells have produced an average of 30% more gas, while the 20 year projection indicates this will increase to 35%. This is likely due to the expected increased durability of the Tier 1 ceramic over Tier 2 RCS.

The original studies were performed at a time when gas prices were >$5/MCF. However, the authors of this paper updated the economics at a gas price of $3.50/MCF, to better represent more recent natural gas prices. Since the completion designs in these wells called for a "tail in" of 40% of the treatment utilizing either the Tier 1 or Tier 2 proppants (with the remainder white sand) the incremental cost per well to upgrade from Tier 2 to Tier 1 was ~$250,000 per well. Even with this low gas price, the incremental production paid out the cost difference in less than three months. With a 10% discount rate, the Tier 1 wells have created an *incremental* $1.8 million in present value *per well*

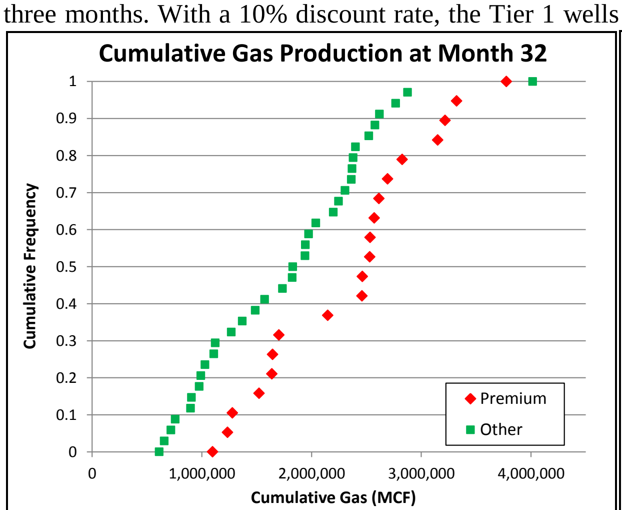

Figure 13 – After 32 months of production, the Tier 1 ceramic wells have produced an average of 0.5 BCF *per well* more than offset wells containing Tier 2 RCS.

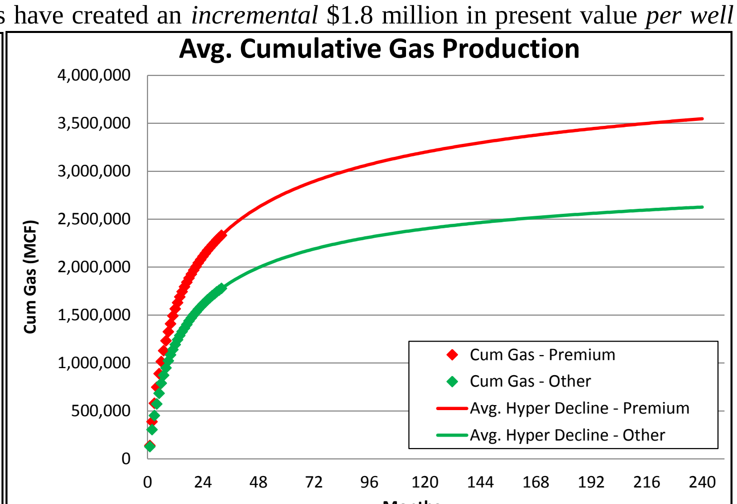

Figure 14 – When projecting to 20 years using hyperbolic decline, it is projected that the Tier 1 wells will produce an incremental 35% more gas than the Tier 2 offset wells.

over the Tier 2 wells at 32 months. Utilizing the hyperbolic decline projections, after 20 years of production the Tier 1 wells are projected to create an incremental $2.4 million in value, *per well*, over the Tier 2 wells. The incremental $250,000 cost of upgrading from Tier 2 RCS to Tier 1 LWC resulted in nearly a 10-fold return on investment. Therefore, even at $3.50/MCF gas prices, Tier 1 proppant designs provide a higher return on investment than Tier 2 designs.

Eagle Ford Shale. The Eagle Ford Shale is a liquids rich play found in South and Central Texas and extending into Mexico. This high growth play has productive areas of dry gas, wet gas, condensate and oil across more than 20 Texas counties (**Figure 15**). Within the productive window, the play ranges from 5,000 ft. to 14,000 ft. in depth with thicknesses between 50 ft and 400 ft [Pope 2012]. The Eagle Ford Shale has long been recognized as the primary source rock for the Austin Chalk in major fields such as the Giddings and Pearsall and overlays the Buda Lime. As such, permeabilities span 50 to 1500 nanodarcies with porosities ranging from 4 to 11 percent and a bottomhole temperature in excess of 275°F.

Over 3,000 wells have been drilled since activity first began in 2009, due in large part to the increased value of the oil and condensate production in these wells. The focus of this study is an area found in the condensate widow of Webb and Dimmit Counties. In this area, the wells are 7,000 – 8,000 ft TVD, with a 150 - 200 ft productive Upper Eagle Ford and 100-150 ft thick Lower Eagle Ford [Bazan 2012]. The study focuses on the production (and corresponding economic) improvement in wells containing multistage hydraulic fracture treatments. A primary improvement was the evolution from traditionally low conductivity slickwater fracture treatments initially used in the play, to the use of higher conductivity hybrid fracture designs. In the early stages of development, models were utilized to run sensitivities on parameters such as perforation strategy, stage interval, fracture fluid type/volume/combinations, as well as proppant type. From this modeling, it became evident that fracture treatments were conductivity limited (see **Figure 6** on page 5). The primary causes of this reduction include multiphase flow, flow convergence near the wellbore in the transverse fractures and the thermal impact on natural proppant due to elevated temperatures. Production forecasting using history matched production on an actual well concluded that upgrading from a Tier 3 Sand or a Tier 2 RCS to a Tier 1 LWC could yield up to a 150% production increase after just three years (**Figure 16**).

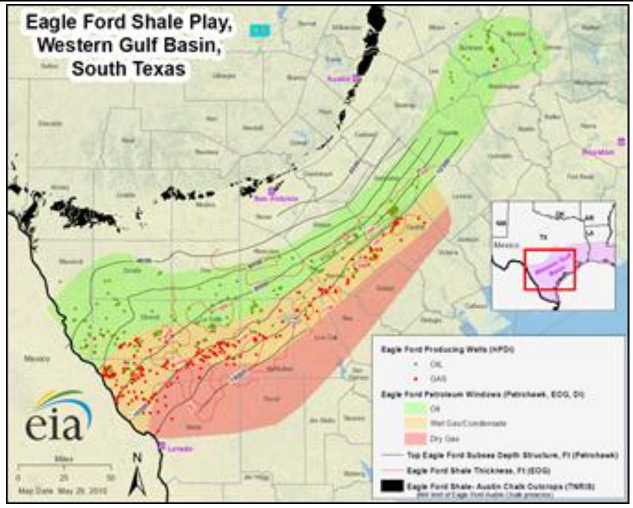

Figure 15 – The Eagle Ford Shale play is located in the Western Gulf Basin of South Texas, and is characterized by an oil, condensate and gas window. [Courtesy EIA].

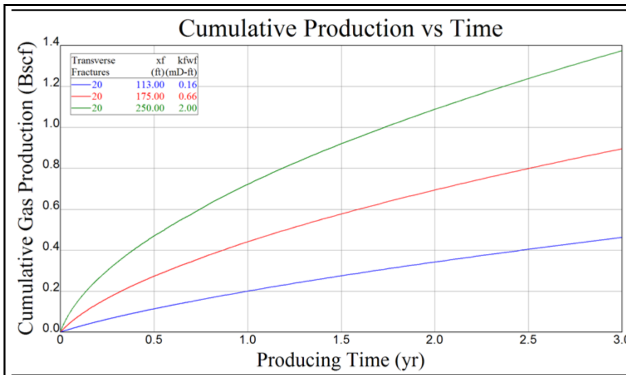

Figure 16 – Using history matched data from an actual Eagle Ford well and projecting 3 years, upgrading from a Tier 3 Sand (blue) to a Tier 2 RCS (red) yields a 100% increase in production. This increase rises an *additional* 50% when upgrading to a Tier 1 LWC [Bazan, 2010].

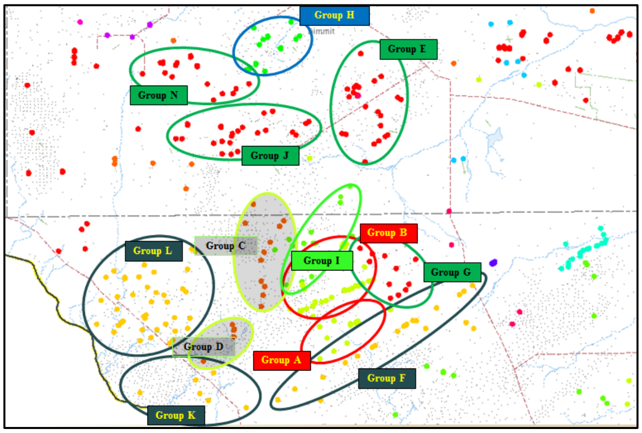

Figure 17 – Well groupings by operator in Webb/Dimmitt Counties. The red areas (Groups A & B) represent Tier 1 LW ceramic wells, with the remainder containing primarily Tier 3 Sand wells.

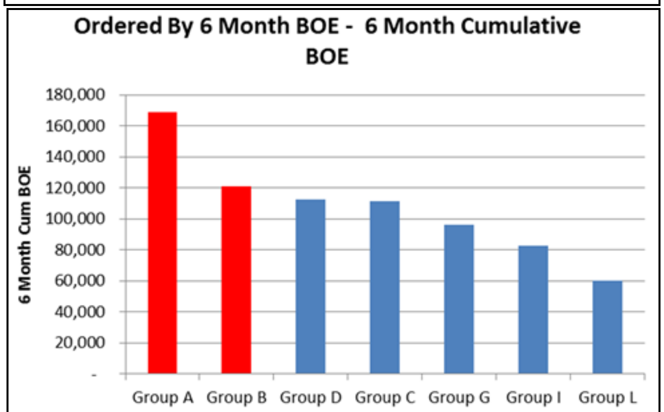

Figure 18 – Cumulative BOE comparison between single operator well groups (see Fig. 17). Tier 1 LWC groupings (red) outperform Tier 2/3 RCS/Sand groupings (blue). Note that groups E, F, H, J, K, & N were eliminated due to differences in reservoir (E, F, J, K & N) and low well count (H, K).

Since modeling suggested that production and economic gains will be achieved by utilizing a higher conductivity Tier 1 LWC proppant, the third step was to verify the modeling through actual field implementation. The operator has completed numerous wells in the Gates Ranch of Webb and Dimmit Counties (**Figure 17**), and observed positive results when compared to immediate offset operators as well as internal studies [Bazan 2012]. The authors of this paper used public production databases to make further comparisons between the Tier 1 operator and offsets using 6 month cumulative production. Offset wells in close proximity were separated into 12 groups, breaking them out first by operator, and then by area (**Figure 17**). In order to use the public data to compare the two proppant types, two assumptions had to be made – 1) the reservoir characteristics were similar, and 2) the completion techniques were similar (except proppant type). One method the authors employed to account for significant reservoir differences was to observe the oil/gas cut for an area. Several groups were eliminated from the study where the oil cut was significantly different from the Tier 1 operator (Groups E, H, J & N) and two groups were eliminated since they were nearly 100% gas (Groups F & K). In addition, all groupings had at least five wells except Groups H & K, which were already eliminated due to reservoir differences. Completion differences (such as lateral length, stage count, proppant volumes, etc) were unknown, and therefore the authors would assume statistics (large well sets and numbers of groupings) would take care of those differences. Five offset groups remained (in addition to the two Tier 1 groups) that had ample well counts and similar liquid cuts. Of these seven, the well groups containing Tier 1 proppant consistently exhibited higher average BOE production after 6 months over the offset groups containing Tier 2 and 3 proppant (**Figure 18**). This corroborated the original analysis performed by the operator [Bazan 2012].

To eliminate completion differences from the above analysis, the same operator also looked at internal comparisons to further verify the modeling. In this case, the operator completed several wells with Tier 3 Sand in addition to the completions with Tier 1 LWC. It was observed that after 6 months cumulative production (normalized for number of stages), the Tier 1 wells were modestly outperforming the Tier 3 offsets (**Figure 19 – left**). Note that higher quality proppant

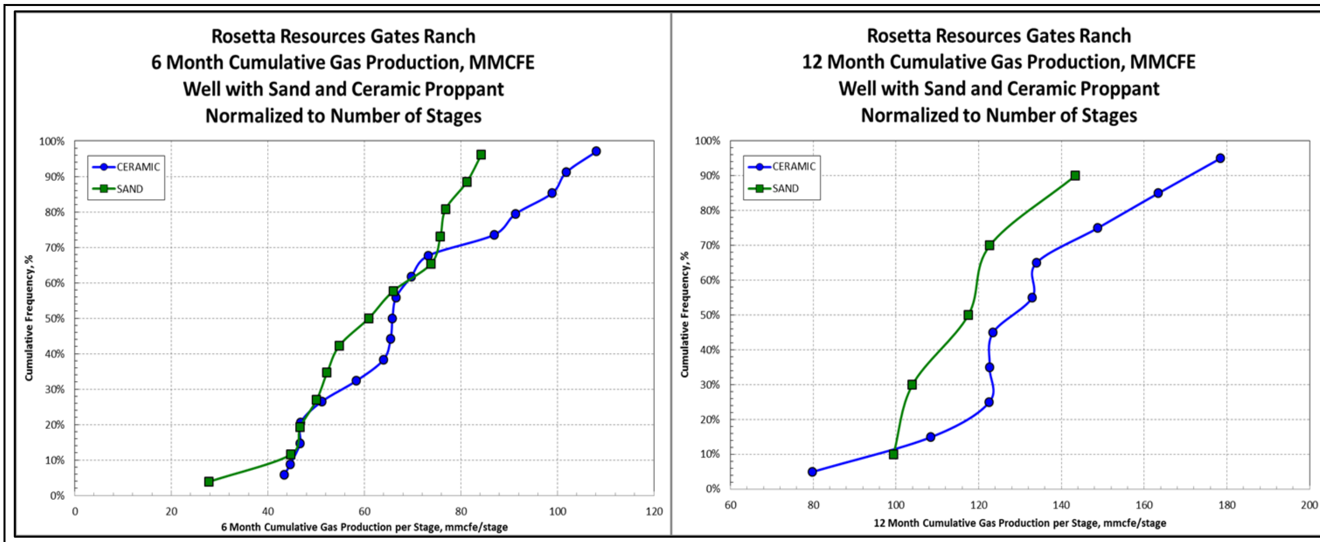

Figure 19 – After 6 months production, wells containing Tier 1 ceramic only modestly outperform Tier 3 sand wells, primarily at higher production (left plot). However, after 12 months, the Tier 1 wells begin to significantly outperform the Tier 3 wells (right) as the stress increases on proppant and the durability of Tier 1 proppants is magnified. [Bazan 2012].

may not always provide immediate increases in production since early time production is dominated by reservoir contact and high flowing pressures (low proppant stress). Improved well performance for higher quality proppants is typically emphasized with long-term production. Wells with 12 months production were also analyzed, and appeared to exhibit this phenomenon. Wells containing Tier 1 proppant are significantly outperforming the Tier 3 wells after 12 months cumulative normalized production. This trend is expected to continue because as flowing pressures are reduced, the stress on proppant increases, and proppant durability differences are magnified.

This work confirms that using a higher conductivity proppant will improve Eagle Ford well performance. Therefore, the the economic implications of the increased investment for superior conductivity must be reviewed. Using the well set of 15 study wells (**Figure 19**) a comparison was made between the wells that were identified as either using Tier 1 LWC or Tier 3 Sand. After 12 months, the Tier 1 wells had produced an average incremental of 15 MMcfe per stage when compared to the wells containing Tier 3 proppants. Assuming net pricing of \$3.75/mcf gas and \$75/bbl oil, the Tier 1 wells are generating approximately \$1.5 million in additional value per well after just 12 months, and pay out the increased proppant investment in ~9 months. A similar study was recently completed for the Eagle Ford shale by another author [Pope 2012] using 254 wells with at least 12 months of production of either Tier 1 or Tier 3 proppants and concluded that Tier 1 wells produced 43,000 BOE more than Tier 3 wells, also generating approximately \$1.5 million in additional value. These two studies corroborate the premise that the increase in cost to generate higher conductivity fractures in these Eagle Ford completions is economically justified by the resulting increase in production.

Bakken. The Bakken is a Mississippian/Devonian age oil play found in North Dakota, Montana, Saskatchewan and Manitoba. Spanning more than 200,000 square miles, development has been frenetic, with more than 200 rigs working in the play. Most wells target the Middle Bakken between 9,000 and 11,500 ft true vertical depth throughout much of North Dakota and Montana, although other intervals can be productive. Thicknesses as great as 80 ft, average porosity of ~5% and permeability of 0.04 mD are typical of the Middle Bakken member. The carbonate/clastic sequence contains interbedded siltstones and sandstones, and is oil bearing across an enormous areal extent [Rankin 2010].

Most operators have recognized the need for higher conductivity fractures in this oil reservoir to accommodate multiphase flow in the narrow transverse fractures. Therefore it has generally been targeted for Tier 1 ceramic proppants. However, during the past 2-4 years, the Bakken has also been a victim of the shortage of quality ceramic proppant. As such, many operators have been forced to use whatever they can source, starting with high quality ceramics, and moving through inferior ceramics and down to resin coated sand. In many instances, operators have also used sand to further reduce costs and accelerate completions.

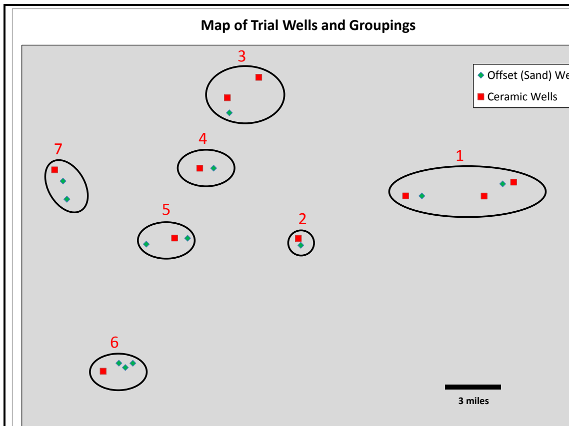

Figure 20 – Location of a previously unpublished 22 well field trial located primarily in Mountrail County, comparing 10 wells containing Tier 1 20/40 LW ceramic proppant (red squares) and 12 wells containing Tier 3 Sand (green diamonds).

During the initial evaluation of completion practices, one operator performed a field test to determine the benefits of increasing conductivity. The initial modeling indicated realistic conductivity values of 10 md-ft, 40 md-ft and 80 md-ft for 20/40 sand, resin coated sand and lightweight ceramic, respectively. Production modeling also suggested that the fractures were conductivity limited, meaning that an increase in conductivity should lead to an increase in production. Therefore, a field trial was designed to complete and stimulate 10 wells with Tier 1 lightweight ceramic, that were offset to 12 wells with similar completion/frac designs, but containing 20/40 Tier 3 sand (**Figure 20**). Production was tracked over time, and the wells were recently revisited. After 22 months production, the wells containing Tier 1 proppant had produced an average of 34% more hydrocarbons than the offsets, and exhibited clear increases in six of the seven study areas in Mountrail County (**Figure 21**). Assuming prices of \$75 per barrel of oil and \$3.50 per MCF of gas, this translates into an incremental \$1.5 million in value created *per well* during the first 22 months alone. This quickly pays out the incremental ~\$300k investment to upgrade the conductivity (**Figure 22**).

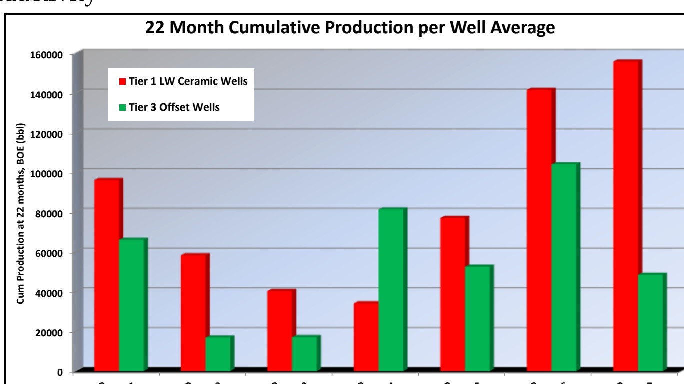

Figure 21 – After 22 months production, the Tier 1 LW Ceramic wells have produced an average of 34% more BOE than the offset Tier 3 Sand wells, including increases in six out of the seven areas.

This corroborates the evidence presented by another Bakken operator that evaluated the benefits of increasing the conductivity while at the same time increasing the number of stages in the horizontal, utilizing a plug and perf methodology in uncemented liners. Initial publications were based on a relatively small well count [Rankin 2010], and indicated a tremendous increase in well productivity when comparing their completions to offset wells. This data set was updated with a larger well population and extended production history. After nearly 2 years of production, completions utilizing Tier 1 ceramic and more stages are sustaining twice the production rates of Tier 3 sand completions with fewer stages [Vincent 2011], generating ~$4 million in incremental value *per well* after just one year, at an incremental cost of approximately $800,000 per well. Significant increases in cumulative production and EUR are apparent for the wells with improved completions designs using Tier 1 proppants.

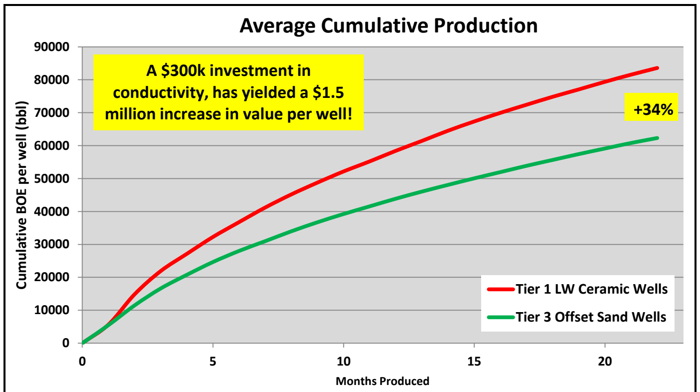

Figure 22 – After 22 months production, the Tier 1 LW Ceramic wells have created $1.5 million in incremental value, *per well* (assuming $75/BO & $3.50/MCF).

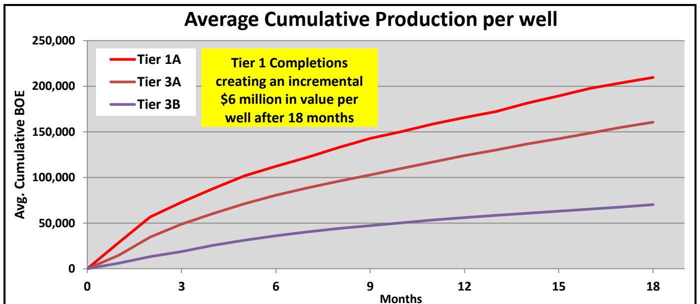

Figure 23 – A comparison of three operators and more recent completions in Mountrail County containing larger volumes of proppant and more stages. The operator utilizing Tier 1 proppant (Tier 1A) is creating an incremental $6 million in value, *per well,* compared to Operators using Tier 3 proppant (Tier 3A, Tier 3B*)* after 18 months of production (assuming $75/BO & $3.50/MCF).

The authors of this paper have recently conducted a more broad analysis of wells specific to Mountrail County in North Dakota to compare productivity of Bakken wells completed by different operators. It is clear that the Tier 1 completions are outperforming the Tier 3 completions by a substantial margin (**Figure 23**). An average incremental value of $6 million per well are apparent in wells using high quality, domestically produced lightweight ceramic proppant (Tier 1A) compared to offset wells completed by two different operators using white sand (Tier 3A and Tier 3B). While there is variability in the performance based on well location, number of stages and other completion parameters, it is very clear that the proppant quality is significantly affecting both initial production rates and sustained productivity.

Summary

1) Proppant selection in unconventional reservoirs is dictated by four primary drivers – proppant availability, fracture fluid selection, conductivity requirements and cost-benefit analysis.
2) Tremendous demand for proppants has caused a shortage of high quality proppants, and has driven many engineers to "settle" for inferior substitutes.
3) Slickwater fracturing tends to drive selection to 40/70 and 40/80 mesh proppants, while liquids rich plays tend to drive the need for gel and crosslinked fluids, due to the desire to place 30/50 and 20/40 mesh proppants.
4) The API/ISO Conductivity test is a great way to account for many physical properties, including size variations, strength/crush, shape, density, hot/wet conditions, and compare proppants for qualification.
5) When selecting proppant, the Conductivity test results must be "corrected" for downhole conditions through the use of a frac model that accounts for damage mechanisms such as non-Darcy & multiphase flow, reduced proppant concentrations, embedment, thermal effects, gel/fluid damage, cyclic stress and fines migration.
6) When correcting for downhole conditions, it is apparent that most hydraulic fractures are conductivity limited; therefore increasing the conductivity will increase production.
7) There are numerous papers documenting the production benefits of conductivity in many different reservoirs.
8) Increasing conductivity generally increases investment; therefore proppant selection becomes a cost vs benefit decision.
9) Completions in the Bakken, Eagle Ford and Haynesville Shale all benefit from increasing the fracture conductivity, and in most cases the uplift in production will pay out the incremental cost in less than a year—ultimately increasing the return on investment in the development.

Conclusion

The development of unconventional reservoirs has been a tremendous success story for the oil and gas industry. Two existing technologies were merged and now the industry is able to profitably develop hydrocarbon resources that were once thought to be uneconomic. Engineers are successfully drilling and completing long horizontal wells and placing multistage fracs in shale oil and gas wells. Science is just now beginning to catch up with the drill bit, and the industry is currently looking for ways to optimize their completions and thereby maximize their returns. To do so, it is critical that engineers take a thoughtful look at understanding their hydraulic fractures. These fracs provide reservoir contact and a conductive pathway from the reservoir to the wellbore. Both parameters are critical to the success of the well, and they must be carefully evaluated. Estimating the conductivity of the fracture at realistic downhole conditions is imperative. When done correctly, it explains many of the observations being seen in the field every day, including 1) short effective fracture half lengths, 2) higher production when fracture conductivity is increased in nano-darcy formations and 3) LWC wells outperforming IDC wells in some areas. Additionally, it is imperative that reservoir engineers use realistic estimates of conductivity in their reservoir models, when attempting to simulate and history match production. These reservoirs present tremendous opportunities for engineers to apply science and technology to create value for their companies. A thorough understanding of the fracture is a critical part of this work.

Nomenclature

API	*American Petroleum Institute*
Bbl	*Barrel*
β	*Beta Factor (non-Darcy pressure drop component)*
BCF	*Billion Standard Cubic Feet*
BHP	*Bottomhole Static Pressure, psi*
BHST	*Bottomhole Static Temperature, ° F*
BO	*Barrel(s) Oil*
BOE	*Barrel(s) Oil Equivalent*
BPD	*Barrel(s) Per Day*
°F	*degrees Fahrenheit*
ΔP_{frac}	*Change in pressure in the fracture, psi*
EUR	*Estimated Ultimate Recovery*
F_{CD}	*dimensionless fracture conductivity*
ft	*feet or foot*
HDC	*High Density Ceramic proppant*
IDC	*Intermediate Density Ceramic proppant*
ISO	*International Organization for Standardization*
IRR	*Internal Rate of Return*
KCl	*Potassium Chloride*
k_{frac}	*Permeability of the fracture*
lbs, lbm	*pounds, mass*
lb/ft^2	*pound(s) per square foot*
LWC	*Light Weight Ceramic proppant*
mD, md	*milliDarcies*
MCF	*Thousand Standard Cubic Feet*
ml/min	*milliliter per minute*
MMCFE	*Million Standard Cubic Feet Equivalent*
μ_{fluid}	*Fluid viscosity, centipoise*
nD	*nanoDarcies*
psi	*pounds per square inch*
psi/ft	*pounds per square inch per foot*
RCS	*Resin Coated Sand*
ρ_{fluid}	*fluid density*
Tier 1	*high conductivity ceramic proppant*
Tier 2	*medium conductivity resin coated sand proppant*
Tier 3	*low conductivity natural sand proppant*
TVD	*True Vertical Depth*
v_{fluid}	*fluid velocity*
w_{frac}	*Width of the fracture, ft*
X_{frac}	*fracture half-length, ft*
YM	*Young's Modulus, psi*

References

API-RP-19D, “Recommended Practice for Measuring the Long-term Conductivity of Proppants”, First Edition, May 2008 API Publishing Services, 1220 L Street, N.W., Washington, D.C. 20005.

Barree, R.D., *et al*. 2003: “Realistic Assessment of Proppant Pack Conductivity for Material Selection”, paper SPE-84306, presented at the SPE Annual Technical Conference, Denver, CO, 5-8 October.

Bazan, L.W., *et al*. 2010: “Improving Production in the Eagle Ford Shale with Fracture Modeling, Increased Conductivity and Optimized Stage and Cluster Spacing Along the Horizontal Wellbore”, paper SPE-138425, presented at the SPE Tight Gas Completions Conference, San Antonio, TX, 2-3 November.

Bazan, L.W., *et al*. 2012: “Hydraulic Fracture Design and Well Production Results in the Eagle Ford Shale: One Operator’s Perspective”, paper SPE-155779, presented at the SPE Americas Unconventional Resources Conference, Pittsburgh, PA, 5-7 June.

Besler, M.R.., *et al*. 2007: “Improving Well Productivity and Profitability in the Bakken – A Summary of Our Experiences Drilling, Stimulating and Operating Horizontal Wells”, paper SPE-110769, presented at the SPE Annual Technical Conference and Exhibition, Anaheim, CA, 11-14 November.

Blackwood, K.W., *et al*. 2011: “Evaluating the Long Term Benefits of Improved Fracture Treatments”, paper SPE-147436, presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, 31 October – 2 November.

Economides, M. and Nolte, K.: “Reservoir Stimulation” Third Edition, published by John Wiley & Sons, 2000.

Forchheimer, P.: “Wasserbewegung durch Boden,” ZVDI (1901) 45, 1781

Gallagher, D. 2011. The Hierarchy of Oily Conductivity. Guest Editorial, p 18, Journal of Petroleum Technology, April.

Gidley, J.L. et al. 1992: “Effect of Proppant Failure and Fines Migration on Conductivity of Propped Fractures”, paper SPE 24008, presented at the 1992 Permian Basin Oil and Gas Recovery Conference, Midland, Texas, 18-20 March.

International Organization for Standardization: “Procedures for measuring the long-term conductivity of proppants”, ISO 13503-5, July, 2006.

Palisch T. *et al*. 2007: “Determining Realistic Fracture Conductivity and Understanding its Impact on Well Performance – Theory and Field Examples”, paper SPE-10630, presented at the SPE Hydraulic Fracturing Technology Conference, College Station, Texas, 29-31 January.

Palisch, T. *et al.* 2008: “Slickwater Fracturing – Food for Thought”, paper SPE-115766 presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, 21-24 September.

Palisch, T. *et al.* 2009: “How to Use and Misuse Proppant Crush Tests - Exposing the Top 10 Myths”, paper SPE-119242, presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, 19-21 January.

Pearson, C.M.: “Dimensionless Fracture Conductivity: Better Input Values Make Better Wells”, paper SPE-60184, Journal of Petroleum Technology (January 2001).

Pope, C. *et al*. 2009. “Haynesville Shale – One Operator’s Approach to Well Completions in this Evolving Play”, paper SPE 125079 presented at the SPE Annual Technical Conference and Exhibition, New Orleans, LA, 4-7 October.

Pope, C. *et al*. 2010. “Improving Stimulation Effectiveness – Field Results in the Haynesville Shale,” paper SPE 134165 presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, 19-22 September.

Pope, C. *et al*. 2012. “Improving Completion and Stimulation Effectiveness in Unconventional Reservoirs – Field Results in the Eagle Ford Shale of North America,” paper SPE 152839 presented at the SPE/EAGE European Unconventional Resources Conference and Exhibition, Vienna, Austria, 20-22 March.

Rankin, R. *et al*. 2010: “Improved Production and Profitability Achieved With Superior Completions in Horizontal Wells: A Bakken/Three Forks Case History”, paper SPE-134595 presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, 19-22 September.

Shah, S. *et al*. 2010: “Fracture Orientation and Proppant Selection for Optimizing Production in Horizontal Wells”, paper SPE-128612 presented at the SPE Oil and Gas India Conference and Exhibition, Mumbai, India, 20-22 January.

Schubarth, S.K. *et al*. 2006: “Using Reservoir Modeling To Evaluate Stimulation Effectiveness in Multilayered ‘Tight’ Gas Reservoirs: A Case History in the Pinedale Anticline Area”, paper SPE-100574 presented at the Gas Technology Symposium, Calgary, Alberta, Canada, 15-17 May.

Stephenson, C.J. *et al.* 2003: “Is Ottawa Still Evolving? API Specificaitons and Conductivity in 2003”, paper SPE-84304, presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, 5-8 October.

StimLab Proppant Consortium Notes from 2002-2010.

Vincent, M.C. 2009: “Examining Our Assumptions – Have Oversimplifications Jeopardized Our Ability to Design Optimal Fracture Treatments?”, paper SPE-119143, presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, 19-21 January.

Vincent, M.C. 2011: “Optimizing Transverse Fractures in Liquid-Rich Formations”, paper SPE-146376 presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, 31 October – 2 November.