ProTechnics

Expert's Corner

BARNETT SHALE TECHNICAL DISCUSSION

APPLIED TECHNOLOGY IS UNLOCKING THE SECRETS OF SHALE GAS DEVELOPMENT

Interview with Lee Matthews, Cornerstone N.G. Engineering, LP

Interviewed by Dick Leonard

In this *Expert's Corner* we're proud to present the views of Lee Matthews, President of Cornerstone N. G. Engineering, LP, who shares his vast knowledge and experience about the development of the Barnett Shale.

Lee worked for several majors and large independents in the 20 years following his graduation from the University of Texas with a BS in Petroleum Engineering and a Masters in Business. His experience with the Barnett Shale began when he joined Mitchell Energy in Fort Worth, Texas, as a senior operations engineer. Over the last few years he has distinguished himself as a true pioneer in developing and applying technologies that have helped unlock the secrets of shale gas development.

Q: ProTechnics

There has been a great deal of interest and effort expended, mainly by large-to-medium independents, on the development of unconventional reservoirs. Certainly, the tight gas shales, led by Barnett Shale exploitation, are some of the hottest gas plays in the domestic US. Would you briefly describe the history of gas shale production with an emphasis on the evolution of the completions and stimulations in the Barnett?

A: Lee Matthews

The Barnett Shale in the Fort Worth Basin has served as an unconventional, shale gas laboratory since Mitchell Energy began its quest in 1981 with the first well, the C.W. Slay No. 1. Since that time, many stimulation technologies have come and gone. George Mitchell's strong convictions that the Barnett would someday be an economic source of natural gas reserves has come true primarily due to three major events: (1) Mitchell's above market gas contract in the 80s and early 90s afforded continuous R&D spending to define the optimum completion technology; (2) "water frac" stimulation technology proved successful in meeting both gas-productivity targets as well as cost-reduction goals when Mitchell's long-term gas contract was bought out; and (3) horizontal completion technology expanded the play beyond the limits of strong frac barriers above and below the Barnett interval. The original core area of the play was defined by the limits of the underlying Viola Limestone which served as a barrier between the Barnett and the Ellenberger, commonly thought to be water-bearing dolomite and a severe risk to frac stimulations. The success of the water frac encouraged many new players to enter North Texas and the success of horizontal drilling has brought the Barnett to a place of prominence in the local press, the nation's largest gas fields, large independents' SEC filings and major integrated companies' acquisition programs.

My shale experience has been confined to the Barnett in North Texas since 1993 until recently when other shale plays have begun to gain momentum. I believe that shale gas will become the next large resource base of energy for our country and that the completion lessons we have learned here will accelerate our understanding of optimum shale completion design in other developing areas.

Q: ProTechnics

Horizontal wells have replaced vertical wells as the standard in almost all areas of the Barnett Shale. Currently over 80% of the wells are horizontals. What are the key design parameters for these horizontal completions and what are the main challenges? What will the role of vertical wellbores be in future development of the Barnett Shale?

A: Lee Matthews

The first question is, "why go horizontal?" There are two main reasons: (1) to increase the probability of staying within the Barnett interval with the fracture stimulation; and (2) to increase reservoir contact. The geometry of fracture propagation is much different in a horizontal completion than in a vertical wellbore and it provides for better control of height growth. The productivity of a wellbore in the Barnett is directly proportional to the amount of Barnett rock that is in communication. Therefore, greater contact area brings about greater initial rates and greater ultimate reserves. These two attributes have opened up the play from a three county area to over 16 counties and growing.

A horizontal well design should start with a reservoir description of the specific area to be drilled. This has driven many operators to acquire 3D seismic prior to beginning a drilling program. Placement of the lateral should respect subsurface geologic control and structural features such as faults or karsts. Strategraphic placement of the lateral is important and should reflect a relationship to other key factors such as the gross thickness, frac barrier types and thickness, the lithology of the Barnett, frac design parameters and offset well locations. Some think that once you have made a good Barnett well, you can duplicate the same completion design on the next well. Unfortunately, the reservoir description does not remain consistent over a very large area.

Q: ProTechnics

Completion diagnostics, radioactive isotope tracers, and chemical tracers have played a key role in the evolution of Barnett Shale completions. Where have you found this technology to be the most beneficial? Can you elaborate on some spe-

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cific examples where these direct measurements have provided valuable data that was used to optimize the completion process?

A: Lee Matthews
The application of RA isotopes was very helpful in the development of horizontal completion designs as we tested the effects of cemented vs. uncemented casing in the lateral. Additionally, it helped us understand multi-staged uncemented completions by tracing the fluid movements. In cemented laterals, I have used RA tracers to confirm fluid entry in each stage and perf cluster as a function of time. They have also been useful in diagnostic work when there is a question of casing integrity. Chemical tracers have provided assistance in learning about well interference. It is one thing to know that a frac hit an offset well due to a loss of production, but it is much more helpful to know which stage it was and whether it was early, middle or late time. Flowback results with chemical tracers also help diagnose the effectiveness of each stage in a multistage completion. Keeping in mind that we are after reservoir contact, these diagnostic tools help us understand the effectiveness of a specific completion technique as well as the deficiencies.

Q: ProTechnics
We have heard a lot about natural fractures or fracture swarms in the Barnett Shale. Could you expand on how these fractures affect the completion success and the ultimate production outcome? Typically, do most operators try to perforate these fracture swarms or are their stimulations designed to initiate in other areas of the wellbore?

A: Lee Matthews
Fractures or fracture swarms are typically identified by formation micro-imaging tools conveyed by drill pipe or coiled tubing in the lateral. These tools are relatively expensive and not commonly used in a standard logging suite. Therefore, the completion engineer does not have that information on a regular basis and must rely on other sources of data such as MWD gamma ray logs and mud logs. Fractures and swarms are hard to detect or quantify with these tools. In those cases where the FMI data was available, the lateral did possess a variation in fracture density and after-frac RA tracer logs indicated a correlation to the fracture patterns. I have observed a relationship between high fracture initiation pressure and high fracture density. Where there are many fractures in a localized area, fracture width is difficult to attain as the fractures fight against one another and sand slugs are required to eliminate a large percentage of them so that the remaining few have lower stress to overcome in gaining width. I have seen this phenomena particularly in un cemented laterals. It doesn't make much sense to perforate swarms of fractures if you cannot consistently extend a significant stimulation treatment through them.

Natural fractures do, however, affect well productivity by connecting the wellbore to a greater amount of rock face. FMI logs have shown that many natural fractures are oriented orthogonally to the induced fractures. This is another component of the reservoir description which influences a specific completion design.

Q: ProTechnics
I understand, that operators in most areas are utilizing 3-D seismic to define Barnett Shale geologic features and plan drilling locations and well paths. Typically, most operators do not develop areas that show significant faulting or large karsts. What is your view of the viability of these areas? What are the main challenges in developing heavily faulted areas?

A: Lee Matthews
This is an area where much is yet to be understood. There are instances where faults have channeled the hydraulic energy of a frac job away from breaking Barnett rock and into a wet, porous Ellenberger interval resulting in an economic failure. In other situations, I am convinced that a fault, or a series of faults, were cut with the lateral and a cemented completion design was successful in producing economic wells. The key question is whether the fault encountered is still open and conductive or cemented closed with a mineral deposition. This is very hard to predict and elevates the risk of those locations with known faults. Due to the widespread presence of these features, many are forced to deal with them or allow the acreage to expire. Lateral placement and completion design can reduce the risk, however, and this will continue to be an area of much interest for years to come.

Q: ProTechnics
Parts of the core area of Newark East field in Wise and Tarrant counties have been developed down to 27-acre spacing. How does interwell communication during fracturing affect completion and stimulation design, and what importance does this interference play in a successful or unsuccessful completion?

A: Lee Matthews
The location of offset wells and the completion design of each of them should be considered when developing the plan for the new well. What are the drainage patterns already established in the area surrounding the proposed well? Clearly, interference has been well documented with both positive and negative results. Generally, early completions in the core area were cross-linked gel systems which responded favorably to interference with a water-frac offset completion. The results became more mixed when comparing water-frac interference with another water-frac offset; some were positive and some were negative. When evaluating a horizontal completion in the presence of an offset vertical well, each time the hydraulic fractures in the new well were influenced by the preexisting fractures of the offset, reducing the extent of fracture propagation. It makes sense that fluid will continue to break rock until it finds an easier route. This could be a natural fracture which leads to greater productivity or an offset hydraulic frac system which serves to reduce the fluid efficiency of the current treatment. Once an area of the reservoir has been fractured, secondary fracturing will require a greater amount of energy, fluid loss control or larger volumes pumped. Depletion is also a concern and in highly developed areas, a nitrogen or carbon dioxide assist will be helpful to get the fluid moving to the wellbore and improve load recovery.

Q: ProTechnics
What techniques might be considered to alter horizontal drainage patterns in the more densely developed areas? Is this important in the overall development of the field?

A: Lee Matthews
The most obvious step is to shut in offset wells to allow formation gas to repressurize the fracture system connected to that wellbore. This probably helps more in unloading the fluid that connects to the existing fractures than preventing it from occurring. Another option is to coordinate refrac(s) in the offset well(s) with the new well completion. This will create a greater unloading challenge but could be helpful in increasing the efficiency of the stimulation treatments and would be a good case for the energized systems.

Q: ProTechnics
What do you think the ultimate spacing will be in the expansion acreage of the Barnett Shale?

A: Lee Matthews
Generally, the optimal spacing will be closer in the thicker and deeper areas of the Barnett (i.e. Denton County) and more spread out in the shallower and thinner areas. For comparable shale quality, there are more reserves per cubic foot of shale in the deeper regions and that will afford tighter spacing. Additionally, compartmentalized sections (due to limestone stringers) of the Barnett will require greater well density to unlock those reserves. The optimal spacing will vary across the field. Economics may also play into the decision as tighter spacing may increase ultimate recovery but reduce initial production rates and lower metrics such as rate-of-return and NPV.

Q: ProTechnics
Chemical tracers have become a key tool for evaluating interwell communication and treatment well lateral cleanup. What is your view of this technology and what do you think the primary application of chemical tracers will be in the Barnett Shale? Have you been surprised by any of the early results that showed early stages not cleaning up effectively? Are you concerned about cleanup of all stages in these long laterals with 6 to 8 different frac stages?

A: Lee Matthews
Being able to determine that each stage is cleaning up and contributing fluid recovery on flowback is a very clear indicator that the lateral is performing as designed. The use of chemical tracers will also be beneficial in providing data to understand interference between wells and thereby reach the optimal spacing answer for a given area. I have been fortunate, I guess, in seeing good overall cleanup even on early stages. I would be very concerned if some stages were not flowing back and thereby cleaning up. The obvious question is, "why are they behaving this way?" Could they have encountered a fault? How much time elapsed between the frac and the point of flowback? Was the well assisted in recovering the fluid, such as gas lift?

Q: ProTechnics
During the last few years, there has been an ongoing debate on whether to cement the laterals or not. Have you seen or developed any conclusive production evidence in the Barnett Shale that supports cemented or uncemented laterals?

A: Lee Matthews
The decision on cementing deals with the ability to control where the frac fluids go. If the section of Barnett you are completing is perfectly homogeneous and uniform in frac gradient, the hydraulic fractures in an uncemented lateral would initiate adjacent to the perforations and continue to propagate until proppant transport or induced stress caused a bridge near the wellbore. While uncemented laterals provide the greatest exposure at the wellbore, they do not necessarily provide the greatest reservoir contact at the conclusion of the frac. Uncemented laterals are much easier to pump operationally but are less predictable and do not provide lateral isolation for future refrac options. There are good production examples of both systems and the choice for a specific location should be based on its own reservoir description.

Q: ProTechnics
In cemented horizontals, how important is it to get excellent cement integrity throughout the entire lateral? Are you concerned about our ability to get good cement jobs in longer laterals? What production or stimulation problems have you noticed on cemented laterals?

A: Lee Matthews
A good cement job is a critical aspect of the completion performance. We once thought that just a restriction to fluid movement was satisfactory, but now it is much clearer that we need hydraulic isolation to reliably provide for fracture initiation and propagation throughout the job. Good hole cleaning practices prior to running casing are very important along with centralization and proper cement slurry design. Poor production performance on cemented laterals can be correlated to the characterization seen on the after-frac RA tracer log. A poor cement job which caused a section of the lateral to be ineffectively stimulated is one example.

Q: ProTechnics
It seems like every operator has a different idea on how to flow back these Barnett Shale wells. What is your recommended best-practices procedure to maximize well performance?

A: Lee Matthews
In the case of a cemented horizontal completion with slick water fracs, the proppant is usually well distributed and placed in the formation and therefore proppant flowback is minimal. Flowback rates should reflect the number of stages and the total fluid pumped. Higher flowback rates should be used for larger total fluid volumes and higher stage counts. Flowback rates ranging between 200-300 bph are common. Generally, the higher rates are preferable in an attempt to increase load recovery. In the case of uncemented completions, proppant flow back is a limiting factor. Washing out chokes and other surface equipment is more common due to sand unloading in the annular space between the borehole and the casing. Gradually increasing the rate of flowback has been helpful but in some cases only time and fluid recovery is the ultimate solution.

Q: ProTechnics
In some areas, liquid loading is a major issue. What techniques do you use to minimize loading problems during cleanup and later in the life of the well?

A: Lee Matthews
In those areas where the wells die on flowback and require artificial lift to establish production, gas lift has proven to be very effective. After drilling out the frac plugs and circulating the lateral clean, gas lift valves are installed in the production tubing when landed. A portable compressor is used to operate the gas lift system and the well is typically unloaded at rates of 1200-1500 bpd. Swabbing was only capable of recovering 150 bpd and most service companies will not operate at night. An additional benefit of gas lift is the continuous draw that is placed on the formation and the momentum component that is generated as a result. In most cases, the operation is only required for a matter of days before the well kicks off and is capable of unloading the remaining fluid.

Q: ProTechnics
Completion designs vary throughout the field. What is your formula to optimize horizontal lateral length? What is the optimal number of stages per completion?

A: Lee Matthews
There are many factors that enter into the choice of lateral length such as lease configurations, subsurface geology, rig

capability and availability of frac dates, to name a few. From a cost standpoint, the cheapest portion of the well is the incremental length of the lateral. Once the bit has been placed in the target interval of the Barnett, penetration rates are frequently seen in access of 100 fph. I prefer longer laterals due to the incremental cost incentive, however I also say "Don't bother drilling it if you're not going to frac it!" The optimal lateral length and number of stages are location specific, but I generally reccomend around 1000 ft per stage and between 3000 and 5000 ft in lateral length.

Q: ProTechnics
Most of the horizontal drilling in tight gas and shales has been drilled perpendicular (transverse) to the frac orientation. What is your view of drilling parallel (longitudinal) to the frac orientation? Are there any areas that longitudinal laterals make sense?

A: Lee Matthews
Everything else being equal, I prefer transverse orientation due to its superior ability to contact a greater surface area of the shale. If the land position or surface use requirements prevent that orientation, today's price environment will support longitudinal well performance and there are cases where it has been successful. In areas where a poor lower barrier is a concern and a wet Ellenberger looms, caution must be taken to place the lateral and size the frac job appropriately.

Q: ProTechnics
There seems to be a wide variety of different perforating strategies in the Barnett Shale. How important is the perforation design in determining the ultimate success of a horizontal well in the Barnett? What do you think is the best technique for perforation selection (gun type, location, orientation, number of clusters)?

A: Lee Matthews
The perforation design is an influential part of the completion and the goal of the completion will affect the optimal choice. If the goal is to avoid a fault, the design would be different than one targeting tight well spacing. The thing to keep in mind is that the perforations are the conduit to the reservoir and their placement, size, spacing, gun choice, et cetera, can be used to custom-fit the completion to the project's specific conditions. Pump rates and proppant scheduling are other factors that will influence the perforation design. It is impossible to provide a standardized plan that will cover all scenarios.

Q: ProTechnics
What is the biggest mistake that has been made in developing the Barnett Shale?

A: Lee Matthews
This question falls right into my response on the last one. The biggest mistake is looking at the Barnett Shale as a manufacturing process where you line up the services and "crank them out." It is true that the Barnett is a blanket reservoir and it is also true that in localized areas, well plans can be fine-tuned into a repeatable approach. However, as we have seen over the last twenty-four years, completion technology continues to evolve and what works in one area of the play could spell disaster in another.

Q: ProTechnics
What is the single biggest factor affecting well performance in the Barnett Shale?

A: Lee Matthews
Optimized fracture stimulation treatments (for those of you looking for a short answer!)

Q: ProTechnics
I know there have been quite a few refracs of vertical wells and that the water refracs of original gel jobs were very successful. Ultimately, how successful do you think refracs of horizontals will be? What are the best criteria for determining refrac candidates? How many times will any one well be refraced?

A: Lee Matthews
Due to the large cross-section of rock available in a horizontal as compared to a vertical wellbore, I believe the potential for refracs in horizontals is tremendous. The challenge will be how to economically isolate existing perfs to provide for a second round of multi-stage fracs. The first candidates will be the ones that are at the lowest current producing rate which means they were probably not the best to begin with. Usually, the best refracs are the wells that were the best original wells meaning they have the best quality reservoir. Mechanical problems or other issues which occurred during a completion may be cause for exceptions.

Q: ProTechnics
Thank you for your candid and insightful answers to this *Expert's Corner* interview. In closing this interview, would you share your opinion on where you think the next technology advances will come in optimizing Barnett Shale completions? What should be the industry's focus as we move forward in the development of other unconventional gas shales throughout the country?

A: Lee Matthews
As the shale play expands into deeper areas, I see significant potential for multilateral completions. The costs associated with wellbore junctions that are designed to withstand high stimulation treating pressures have been a barrier to this point. It has been cheaper to drill a second grassroots wellbore. As the cost increases with depth, this opportunity becomes more realistic. Once the application shifts into large manufacturing production volumes, the unit costs will come down and it will be more widely available.

New shale plays around the country will share some similarities with the Barnett of the Fort Worth Basin but will also have unique reservoir properties and require adaptation to meet those new challenges. We must not force-fit a completion technique where it does not make sense, and we can only know that if we go into the area with an open mind. Acquire the reservoir description information early in the project, you will be glad you did!

Thank you for the opportunity to share a few thoughts and ideas. I wish to thank those who have shared their ideas and experience with me over the last twelve years of my career here in the Fort Worth Basin.

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This interview was previewed in the summer 2005 / September issue of the ProTechnology newsletter. To download a complete version of this and other interviews, as well as other information on completion diagnostics, please visit our website at **www.corelab.com/protechnics**