



**Stimulation Technologies for
Deep Well Completions
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Abstract

The Department of Energy (DOE) is sponsoring the Deep Trek Program targeted at improving the economics of drilling and completing deep gas wells. Under the DOE program, Pinnacle Technologies conducted a study to evaluate the stimulation of deep wells. The objective of the project was to review U.S. deep well drilling and stimulation activity, review rock mechanics and fracture growth in deep, high-pressure/temperature wells and evaluate stimulation technology in several key deep plays. This report documents results from this project.

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1. Summary

1.1 Deep Gas Well Drilling Activity

The challenges of drilling and completing deep gas wells are quite significant, and relatively few deep wells are drilled annually. For example, of the estimated 29,000 wells (U.S., oil, gas and dry holes) drilled in 2002, approximately 300 (~1%) were deep wells; however, successful deep gas wells can be significant producers¹ and it is projected that natural gas from deep reservoirs will be essential to meet future domestic supply demand^{2,3}. To help with the development of deep gas reservoirs, the U.S. Department of Energy (DOE) is sponsoring the Deep Trek Program⁴ targeted at improving the economics of drilling and completing deep gas wells. As part of the Deep Trek Program, DOE supported a study to review current deep well stimulation efforts.

Under the Deep Trek Program, this study was conducted to evaluate the stimulation of deep wells onshore U.S. and Gulf of Mexico Shelf. The objective of the project was to assess U.S. deep well drilling and stimulation activity, review rock mechanics and fracture growth in deep, high-pressure/temperature wells and evaluate stimulation technology in several key deep plays.

1.1.1 U.S. Deep Well Drilling and Stimulation Activity

The study included a review of deep gas well drilling activity (historical from 1995) and forecast through 2009. Interviews were conducted with operators, service companies and consultants on deep gas well stimulation practices and technology needs by region. For purposes of the study, DOE defined deep gas wells as greater than 15,000 ft true vertical depth (TVD). Shallower wells were also included provided they were located in high-temperature and pressure (>350°F and >10,000 psi reservoir pressure) environments. Deepwater wells were not included, as DOE is emphasizing onshore and shallow water resources (Gulf of Mexico Shelf) for the program at this time.

Well drilling and completion data was obtained from IHS Group and current and historic drilling rig activity was obtained from Smith International. This data was analyzed along with information from prior research to quantify deep drilling activity and identify and rank active operators. This was supplemented with interviews of active deep drilling operators and service companies to ensure the accuracy of the information and to learn more about activity in various regions. Approximately sixty operators, service companies and other organizations participated in the study, and over 350 interviews were conducted for the study.

1.1.2 When Is a Deep Well Not a Deep Well?

One interesting issue came up during analysis of the data set. For decades it has been assumed that IHS and the American Petroleum Institute (API) have been reporting drilling and producing activity based on well depth since reports are issued under headings like, “*New well drilling by 5,000 ft depth increment.*” Knowing that many wells in the U.S. are directionally drilled and that the DOE’s program focused on wells with true vertical depth of 15,000 ft and greater, a special

database was obtained for wells with TVD greater than 15,000 ft. A database of almost 6,000 wells was delivered, and based on this, operators were contacted with deep drilling activity over the last few years.

Immediately, operators began to identify wells that were not even close to 15,000 ft deep, particularly in the most active region on the list – the Austin Chalk area of Texas. In most cases the wells had TVDs of 9,000 ft with lateral extensions of 6,000 ft. The area of greatest difficulty was offshore, where almost every Gulf of Mexico Shelf (GOM Shelf) well is drilled directionally and measured depth commonly exceeds 15,000 ft. The data set is actually reporting well length, not well depth (see **Figure 1**). The database certainly included all 15,000 ft TVD wells, but it included an even greater number of wells with 15,000 ft measured depth wells. These wells had to be systematically culled out to leave only those wells that fit the DOE criteria.

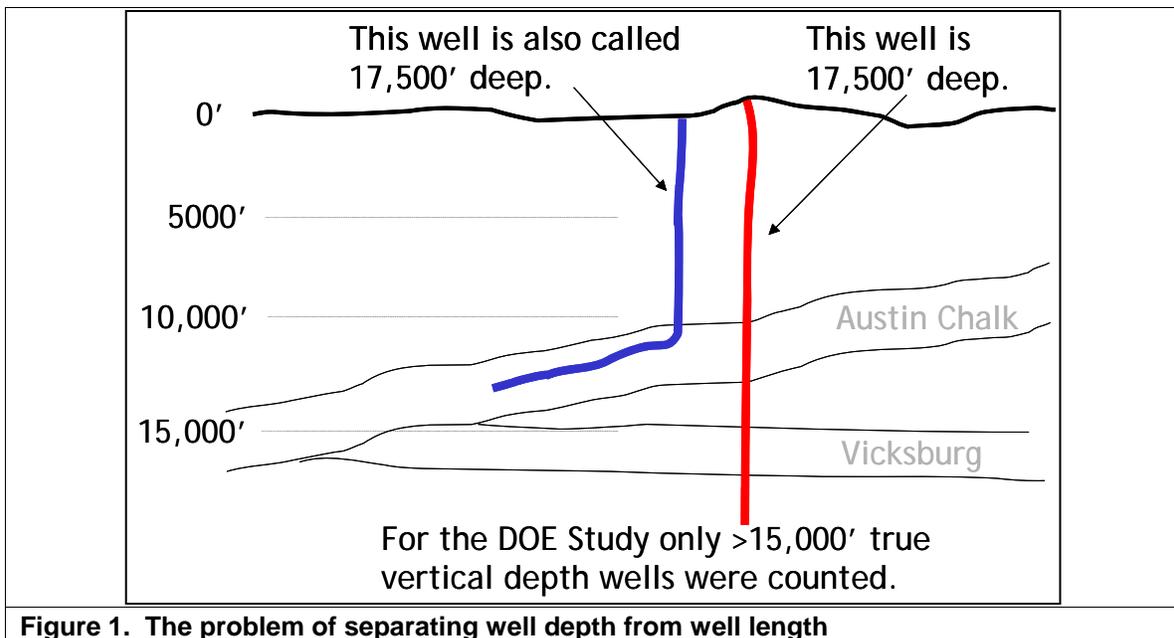


Figure 1. The problem of separating well depth from well length

1.1.3 Deep Gas Well Drilling History and Forecast

Based on historical deep well activity, interviews with operators and forecasts of overall drilling levels, a deep gas well forecast was developed. After a cyclic low in 2002, drilling in the U.S. rose in 2003 and has continued to rise. With this rise there has been an increase in deep gas wells as shown in **Figure 2**. Deep gas well drilling exceeded 600 wells in 2004 and is expected to stay in that range for the near future.

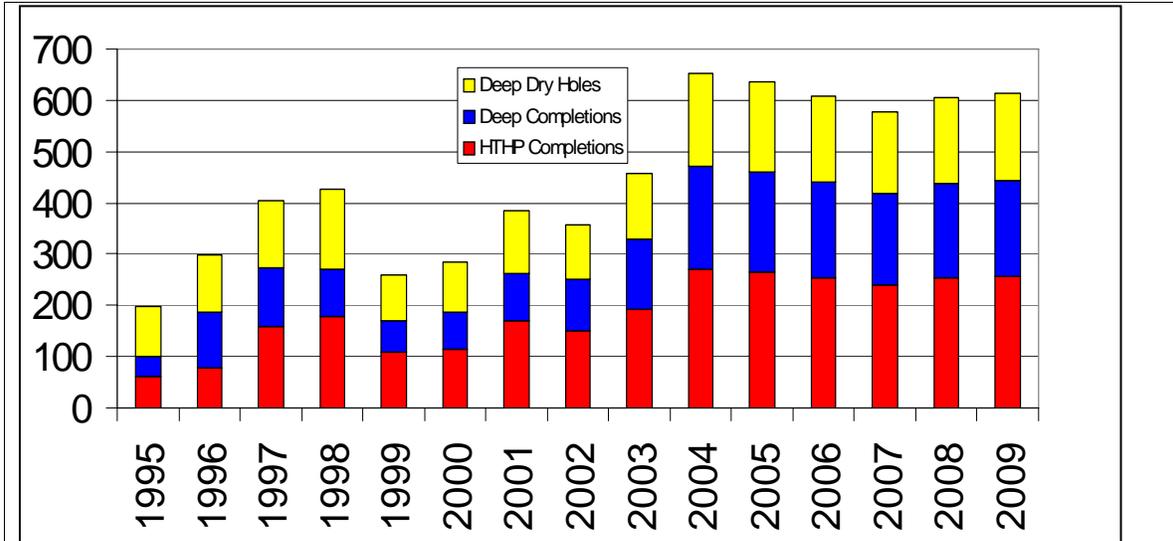


Figure 2. Deep gas well drilling forecast

1.1.4 Deep Gas Resources and Drilling By Region

Deep natural gas⁵ is found in many areas of the U.S. as shown in **Figure 3**. **Table 1** shows deep gas resource estimates (>15,000 ft) by region as estimated by various groups. For the past few years the leading regions for deep gas well drilling have been South Texas with about 30% of these wells, Oklahoma 20%, Gulf of Mexico Shelf 15% and Gulf Coast about 15%. These areas typically account for 60% or more of deep well drilling activity in a given year. The Rockies, despite large deep gas resources, represent only 2% of deep drilling. Of the sixty operators who drill deep and HT/HP wells, the top twenty drill almost 80% of the wells with just a few operators drilling half the U.S. deep wells. Anadarko, BP, Chesapeake, El Paso, EOG Resources and ChevronTexaco are generally among the most active deep drillers.

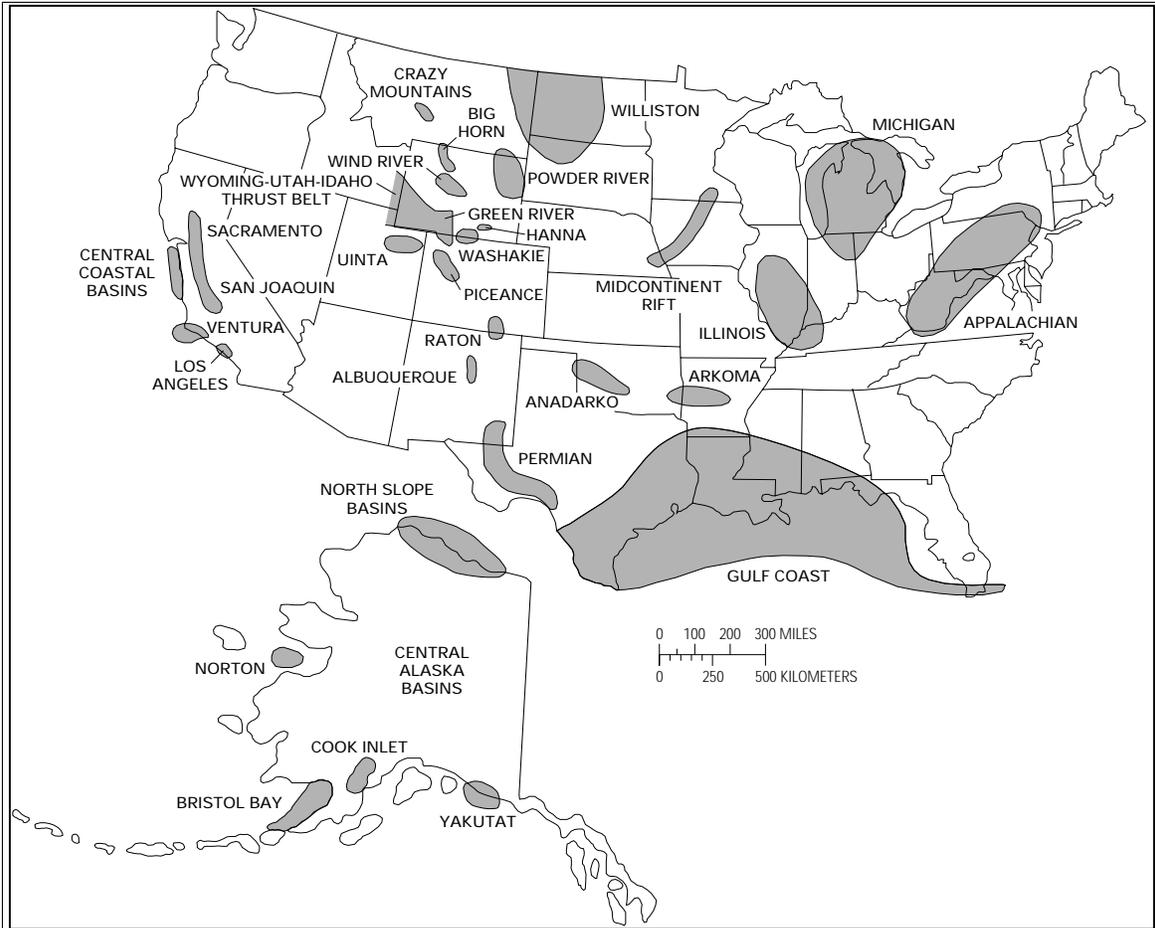


Figure 3. Deep gas basins in the U.S. (USGS Bulletin 2146)

Table 1. Deep Gas Resource Estimates By Region

Region	Resource Estimate (Tcf)
Rockies	21-57
Gulf Coast	26-47
Mid-Continent	2-22
Permian	5-13
Other	5-15
Total	87-133

Resource estimates from National Petroleum Council, United States Geologic Survey, Potential Gas Committee and Gas Technology Institute

South Texas

As noted earlier, South Texas is the leading area for deep well drilling. It is also the primary region in the U.S. where HT/HP wells are less than 15,000 ft deep. Approximately 125 to 175 deep wells are forecast for this region over next few years. This includes both >15,000 ft drilling and the slightly shallower hot, high-pressure wells being drilled in the area. Deep drilling has increased markedly in this region from 15 in 1995. Active operators in the past few years include El Paso, EOG Resources, ExxonMobil, Shell, Total, Dominion and ConocoPhillips.

Oklahoma

Oklahoma can be one of the most active regions for deep drilling in the U.S. Even with the industry's downturn in 2002, >15,000 ft drilling continued to climb. Deep drilling activity approaches levels seen in South Texas. Active operators in recent years include Chesapeake, Apache, Marathon, St. Mary Operating, Sanguine, BP, Ward Petroleum and Cimarex.

East Texas / North Louisiana

East Texas, along with the northern half of Louisiana, has recently had 10 to 20 wells drilled to 15,000 ft each year, significantly less than the 100 drilled annually in the late 1990's. There are a number of wells being drilled in this area that fall just short of the depth/temperature cutoff to count as deep wells with Anadarko, XTO and other operators drilling in the 10,000 to 14,000 ft range for the Bossier Formation. These wells were not counted in the survey since they did not meet the depth or pressure/temperature limits set by DOE for deep wells.

Gulf Coast (Texas and Louisiana)

The Gulf Coast, upper Texas coast and the southern half of Louisiana has 60 to 70 wells drilled to 15,000 ft each year, down from the peak year of over 130 drilled in 1998. The most active operators have been BP and ExxonMobil, and there are several dozen operators who drill a well or two each year.

Rocky Mountains

The Rockies is a large area from Northern New Mexico up to Montana and North Dakota. Most of the deep drilling, however, occurs in Wyoming in pursuit of deep gas. Drilling spiked with high gas prices in late 2000, but high drilling costs, poor gas quality (including CO₂, H₂S and N₂), combined with limited access to gas markets and sometimes marginal finds, has brought deep drilling expectations back down to the five well per year level, with most being exploration holes. North Dakota reports dozens of >15,000 ft wells, but these are all horizontal wells shallower than 15,000 ft. Recent and/or current active operators include ChevronTexaco, Anadarko and Burlington.

Gulf of Mexico Shelf

As noted earlier, determining the exact number of deep wells drilled on the GOM Shelf each year is challenging. Rowan Drilling, whose massive jackup rigs drill over half the deep GOM Shelf wells, says that fewer than 50 holes were punched deeper than 15,000 ft TVD in 2002. On the other hand, the database lists almost 120 in the prior year, 2001. The problem is, 44 of the 118 listed have no vertical depth indicated, just measured depth with the additional notation that the well is directional. While it is certainly possible that some of the 44 are truly deeper than 15,000 ft, it is likely these are not 15,000 ft TVD wells. For example, BP's subsidiary companies, Vastar and Amoco, are listed as drilling 13 holes deeper than 15,000 ft TVD in 2001. But several conversations with BP indicated that none of their wells in recent years hit the 15,000 ft TVD requirement. GOM Shelf drilling may be bolstered by high gas prices and incentives provided by the Department of Interior in March 2003 for deep gas investment. Recent and/or current active operators include ChevronTexaco, El Paso, Anadarko, Dominion and Bois D'Arc.

Please see **Review of Deep Gas Well Drilling Activity (1995 – 2009)** for more information on this segment of the project.

1.2 Rock Mechanics Issues in High-Pressure/High-Temperature (HP/HT) Wells

In HP/HT environments the likelihood of fracture treatment execution problems and production enhancement problems greatly increases. One known major issue, for example, is the temperature limitation of fracturing fluids; however, not much discussion and research have been conducted on rock mechanics in HP/HT environments and how it affects hydraulic fracture growth. For instance, near-wellbore conditions may be poor in HP/HT wells due to drilling problems. Also, over-pressured reservoirs typically have a low effective stress, which may hamper efficient fracture propagation. The nature of deep reservoirs can result in very complex hydraulic fracture growth and production behavior due to the complex stress regimes and the large component of the stress field that is initially supported by the high reservoir pressure.

There are two challenges associated with the use of fracture models in general. First, there is often a lack of direct modulus, permeability and stress measurements, and second, we lack a complete understanding of the physics that govern hydraulic fracture growth. These challenges are even greater in HP/HT wells. In HP/HT applications we can expect a wide range for the Young's modulus. Some tight gas reservoirs are comprised of very stiff rock with moduli as high as $8 - 10 \times 10^6$ psi, whereas other reservoirs may be nearly unconsolidated (owing to the high reservoir pressure that prevents significant compaction and cementation) and have a much lower modulus, possibly as low as $0.1 - 1.0 \times 10^6$ psi.

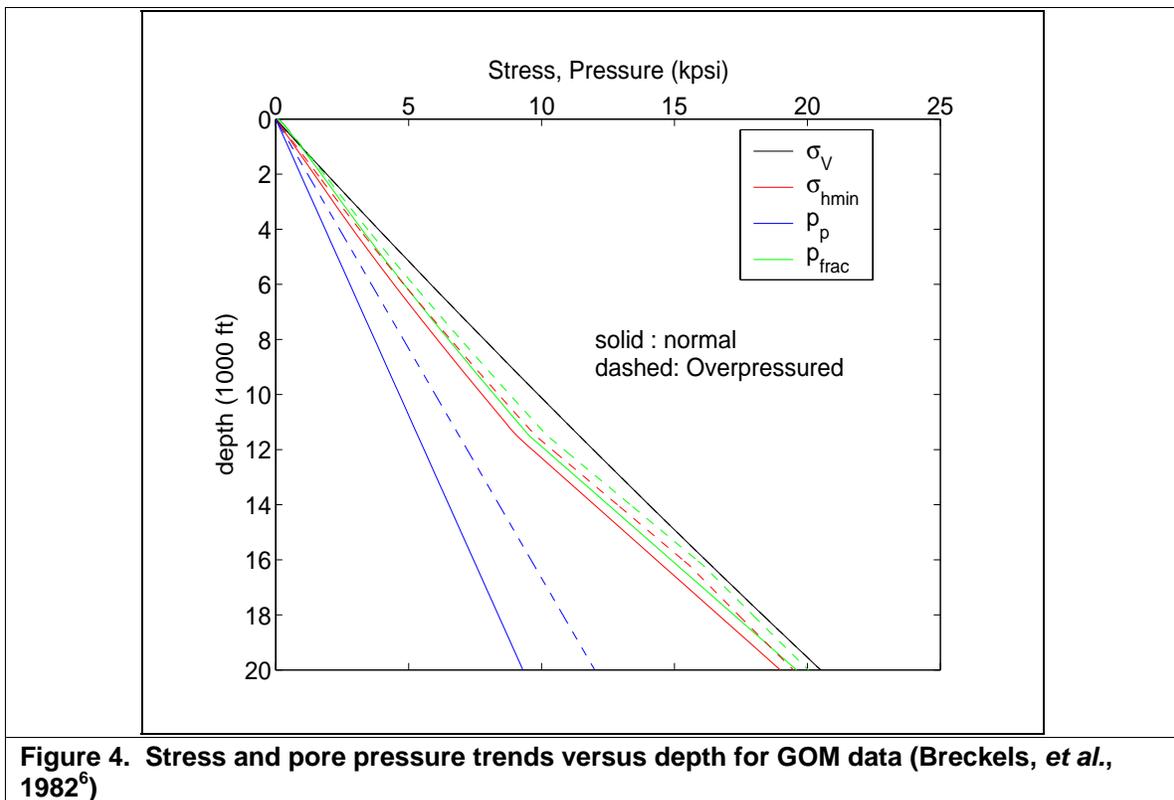
The 3-D stress state and rock discontinuities (heterogeneities) play a dominant role, both for near-wellbore and far-field fractures. These two factors are strongly linked since discontinuities are the natural result of rock deformation, which is governed by the stress regime. Often, it is assumed that formations are in a state of rest because many reservoirs are found in thick sedimentary deposits. However, even in a tectonically quiet region like the Gulf Coast, the rapid sedimentation can lead to bending of the sedimentary package so that the formations are close to failure, as evidenced by faulting; therefore, discontinuities are present in most rock formations, but they are only significant if they accept fluid in a hydraulic fracture treatment and interact with the fracture. This depends on the stresses and the fracturing pressure.

Although fracture propagation does not depend on depth, the character of deep reservoirs will change fracture behavior through the dependence of the stresses on depth. Probably, the tendency of the stress to become isotropic is related to temperature (rock creep), but that is the main influence of temperature on the mechanics of fracture propagation. Rock discontinuities and complexities such as natural fractures can be common in deep tight reservoirs that are targeted for production since in many cases matrix permeability is very low and sufficient production rates require some degree of natural fracturing. The influence of natural fractures on hydraulic fracture propagation will depend on the state of stress and conductivity. For understanding the specific behavior of fractures in HP/HT reservoirs, there are two principles:

- Effective stress controls fracture behavior and interaction with discontinuities

- Stress is determined by incipient failure of rock formations

Data on stress versus depth are available for the GOM⁶ and the North Sea⁷. The conclusions are quite similar on the trends of stress versus depth. This is surprising because these basins have quite a different tectonic setting. The North Sea is an ancient rift system (Rhine graben) and extensional in nature. The GOM is a dormant ocean basin with rapid sediment loading. It appears that the stresses are similar because of lithological similarity, and it may be a coincidence that these basins are predominantly in a regime of normal faulting. **Figure 4** shows stress and pore pressure trends for the GOM versus depth. In the intermediate depth range up to about 11,500 ft, the contrast between vertical σ_v (maximum) and horizontal σ_{hmin} (minimum) stress increases. At greater depth, however, the stress contrast decreases again, and almost disappears (becoming isotropic), especially in over-pressured reservoirs.



Fracture propagation does not depend on depth as such but is impacted by change in stresses and how that impacts failure along natural rock discontinuities. Rock discontinuities, natural fractures and faults are the biggest contributors to complex fracture growth. High net pressures with respect to effective stress can also be expected to contribute to complex fracture growth.

Please see **Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells** for more information on this segment of the project.

1.3 Case Histories

Small case studies on well stimulation, involving three to six wells, were performed in three deep gas regions as part of the project. For each major deep gas region, five to ten of the most active operators were contacted about participating in a study. Case study partners were identified for three areas:

- ConocoPhillips, Jennings Ranch Field in South Texas
- Anadarko and ChevronTexaco, Table Rock Field in Wyoming
- Marathon, several wells in Oklahoma

1.3.1 South Texaco – ConocoPhillips

This study focused on a deep gas productive horizon operated by ConocoPhillips in the Jennings Ranch Field, Zapata County, Texas. The primary targets are the Lobo 6, Lobo 1 and Lobo Stray Sands. This study focused on the deeper Lobo 6 interval at depths of roughly 12,200 to 12,500 ft. The formation is highly over-pressured with pressures of about 10,200 psi (0.81 psi/ft) and fracturing pressures of about 0.93 to 0.96 psi/ft. Porosities are about 16% to 21% with water saturations of 45% to 55%. Net pay can vary from about 20 to over 100 ft. All wells are completed with crosslinked gel fracture treatments using ceramic proppants. Multiple target zones are generally commingled, with a typical well producing about 7 to 8 MMCFD initially, and declining fairly fast to 2 MMCFD or less within one year. The wells are located in 80 to 120 acre fault blocks with three to four wells per fault block (20 acre to 40 acre well spacing). Approximately sixty to seventy wells were drilled over the last five years. The study included a total of six wells drilled and completed from 1999 to 2001.

The main conclusions are that modeled propped fracture lengths are approximately 400 to 660 ft, with fracture heights slightly larger than the perforated interval. Fracture treatments do not show any obvious problems with fracture length generation or proppant placement. Production analysis, although somewhat non-unique, indicates that effective fracture lengths could be as long as the ones calculated with the fracture model.

All wells show fairly rapid production declines, which is normal in highly over-pressured reservoirs with fracture stimulation. Two wells, however, did show higher production declines, which may indicate an impairment of either reservoir or fracture flow capacity since production could not be modeled with constant reservoir/fracture properties. It is not clear, however, if the impairment was caused due to stress-sensitive reservoir permeability (high drawdowns) or a deteriorating hydraulic fracture (reduced proppant conductivity due to higher effective stress, fines migration into proppant pack, multi-phase flow). Flow tests with bottomhole gauges followed by pressure buildup tests could be used to diagnose if the problem is due to a deteriorating hydraulic fracture.

Production data shows reservoir linear flow for about one to two years indicating effective fracture stimulation. This period is followed by the onset of a depletion stem, which could be limited drainage from offset wells, geology and/or liquid loading conditions. Estimated drainage areas highly depend on assumptions of hydrocarbon pore volume (porosity, net pay, water saturation) but, using the numbers provided by the operator, drainage areas were estimated to range from as low as seven acres to about 70 acres.

The biggest opportunity in this drilling program appears to be fracture optimization as a function of actual well spacing. Preliminary generic optimization simulations show the potential for job size reductions as well spacing is reduced. It also indicates that current job sizes may be close to the optimum if well spacing is around 40 acres, but for fault blocks with well spacing smaller than 40 acres, job sizes could potentially be reduced.

Please see **Case History of Hydraulic Fracturing in Jennings Ranch Field, Texas** for more information on this segment of the project.

1.3.2 Wyoming – Anadarko and ChevronTexaco

This study focused on three deep gas productive targets in the Table Rock Field in Wyoming. The primary target is a higher permeability dolomite layer (20 to 30 ft thick) surrounded by thick (150 to 200 ft) low permeability/porosity sandstones (secondary targets) designated as the Lower Weber (below Dolomite), and Upper Weber (above dolomite) at depths of roughly 17,300 to 18,100 ft. While the dolomite provides the majority of the gas flow rate (75% to 90% of total without hydraulic fracturing), it is limited in reserves due to its smaller thickness. The Weber Sands, on the other hand, are very thick and potentially contain vast amounts of gas reserves but are limited in flow rate and require hydraulic fracture stimulation. Natural fractures are believed to play a role in the production of both Weber Sands and Dolomite. One theory is that the dolomite could actually be serving as a high permeability conduit, with the Weber Sands feeding gas through a natural fracture system. Decline curve estimates and gas-in-place calculations indicate that gas reserves are higher than can be attributed to the dolomite alone; however, the current reserve estimates are very uncertain, having a large spread, which is partly due to uncertain delineation of the field and location of a water-contact. Studies are currently being performed to ascertain the reserve base.

The field includes 17 wells drilled in the late 70's and early 80's. All wells are located to the east of a NNE to SSW trending thrust fault. Recently ChevronTexaco and Anadarko have started a new wave of development in this field. Most of the older wells had natural completions in the dolomite (perforated and acidized) and in some cases in the Upper Weber. Five of the older wells had hydraulic fracture completions with varying success. Currently the Upper Weber and sometimes the Lower Weber are stimulated with hydraulic fractures followed by a natural completion in the dolomite (perforate and acidize). The best well in the field was perforated and acidized only, and it has a current cumulative production of about 34 BCF in twelve years. Well performances indicate that reservoir quality can vary significantly across the field, with the challenge being to obtain consistent economic success for every well drilled. Being able to exploit the large Weber gas reserves with effective hydraulic fracture stimulation would be an important "add-on" to the high productivity dolomite.

The general problem with treatments in this area appears to be the creation of complex, multiple fracture systems during hydraulic fracturing. This causes fracture widths to be very small, which is problematic for pumping higher concentrations of proppant and has led to screenouts in the majority of treatments. The propagation of complex fractures and the inability to transport proppant deep into the hydraulic fracture will result in low quality fracture stimulation due to short, low conductivity fractures, which is aggravated by the high stress environment at large depths. This conclusion was supported by a post-frac pressure buildup test, which revealed largely ineffective fracture stimulation. The fracture complexity may also be related to the close proximity of a thrust fault, which can create complex stress fields. In addition, the normal- to even under-pressured pore pressure poses a severe challenge for effective hydraulic fracture stimulation and production.

Three different types of fracture treatments were reviewed in this study. The most frequently pumped design is a CO₂-assisted heavy crosslinked gel treatment with moderate concentrations of bauxite (up to 4 ppg). In January of 2004 one well was completed with a hybrid-frac design, which uses a large slickwater pad followed by a “low gel loading” crosslinked fluid and lower proppant concentrations of bauxite (up to 2 ppg). The hope was that the hybrid design would increase fracture length, which is the most important design parameter in low permeability rock, while also reducing potential polymer damage to the natural fractures. In April 2004, an acid fracture treatment was pumped to target the dolomite reservoir formation.

It is unclear at this point which type of treatment provides the best fracture stimulation. Fracture modeling indicates that the hybrid treatment may have created longer fractures but production was not better than in the other conventional Upper Weber completions. The key to economic development of this field is high-grade drilling locations that ensure a high quality dolomite zone. Completion technology and stimulation of the low permeability Weber Sands provides added value in these wells. The completion and stimulation of these wells are challenging and it appears that every attempt at improved stimulation does not result in a significant enhancement of well production as reservoir quality is the key driver for performance. It is highly recommended to more frequently employ diagnostic technologies such as pressure buildup tests to segregate completion effectiveness from reservoir quality and estimate pore pressure as this will help both in the optimization of well completion and reserves quantification.

Please see **Case History of Hydraulic Fracturing in Table Rock Field, Wyoming** for more information on this segment of the project.

1.3.3 Mid-Continent – Marathon

This study focused on deep gas productive horizons in Stephens and Caddo County, Oklahoma operated by Marathon Oil Company. The primary targets are the Springer and Granite Wash Sands and Arbuckle Carbonate Formations (dolomitized limestone) at depths of roughly 15,000 to 18,700 ft. The Arbuckle is the deepest target and produces gas with a sour gas content of 2% to 4.5%. The study shows treatment examples from all three formations. Less information was available for these wells compared to the other two case studies, so a reduced engineering effort was spent on this area of the project.

The geologic setting of the Arbuckle is an anticline with possible thrust faulting and is believed to contain a fine network of natural fractures. The Springer and Granite Wash Sands are a seismic stratigraphic play removed from structure. Temperatures range from about 240 F to 270 F and pore pressures from about 7,000 psi to 13,000 psi, with most target zones being over-pressured (0.65 to 0.75 psi/ft). The Springer and Granite Wash Sands are usually completed with crosslinked gel fracture treatments and high strength proppants. The carbonates in the Arbuckle are completed with acid fractures (some are hybrid treatments including high-strength proppant).

Fracture treatments in the Springer and Granite Wash Sands show fairly high fracturing net pressures and in some cases high tortuosity (near-wellbore fracture complexity). This indicates a tendency towards fracture complexity (multiple fractures) and higher risk of screenouts. Marathon has been combating some of these challenging issues with specific perforating strategies (such as low-density, zero degree phasing) that can limit the amount of multiple fractures. In addition, large pad sizes with lower proppant concentrations are employed to reduce the risk of early screenouts.

Completions in the deep (17,900 to 18,700 ft) Arbuckle Carbonate Formations face the challenge of achieving economically successful wells in a challenging environment with 2% to 4.5% sour gas production. So far, four wells have been completed with mixed success. Initial production can be fairly high (10 to 12 MMCFD) followed by a rapid decline. From a completion point of view, the biggest challenge is to find the best acid fracture stimulation technique that will maintain enough fracture conductivity at these large depths.

Please see **Case History of Hydraulic Fracturing in the Springer, Granite Wash and Arbuckle Formations in Oklahoma** for more information on this segment of the project.

1.4 Conclusions

As the oil and gas industry moves to ever more challenging environments such as deeper target zones and high-pressure/high-temperature (HP/HT) environments, the likelihood of treatment execution problems and production enhancement problems greatly increases. Although fracture propagation does not depend on depth, the character of deep reservoirs will change fracture behavior through the dependence of the stresses on depth. Rock discontinuities and complexities such as natural fractures can be common in deep tight reservoirs that are targeted for production since, in many cases, matrix permeability is very low and sufficient production rates require some degree of natural fracturing. This situation can produce complex hydraulic fractures, which pose great challenges both for treatment execution and economic well performance. Case studies showed how hydraulic fracture completions achieve economic success (South Texas) and also illustrated challenges and major problems (Rocky Mountain and Mid-Continent). Some challenges cited by operators and service companies that hinder completion of deep gas wells follow.

1.4.1 Stimulation Design and Evaluation

Operators find it difficult to evaluate stimulation success and to compare various completion options. Better techniques are needed to evaluate the benefit/cost of using advanced technology.

Reservoir characterization (evaluating pay zones and reservoir complexity) is necessary to optimize stimulation design and help is needed in understanding formation layers, fracture staging and zonal isolation. These efforts are hindered by the lack of direct fracture diagnostics for deep wells. Current fracture mapping equipment is limited by temperature (300°F) and observation distance (40 acre well spacing or closer in many cases). More research is required to better understand hydraulic fracture propagation in HP/HT environments, and existing HP/HT data should be systematically studied for trends in fracture behavior in different stress regimes and the dependence on depth, pressure and temperature.

1.4.2 Fracturing Fluids and Proppants

HP/HT environments pose great challenges for hydraulic fracturing fluids and proppants. Oil service companies are currently working on new technologies to overcome these hurdles and provide economically attractive options but operators keep pushing into harsher environments. It is difficult to use conventional fracture polymers above 400°F for more than two hours. High-temperature application of conventional fracturing polymers requires the use of O₂ scavengers and gel stabilizers, fracture cool down and high gel loading (50 ppt and higher). Jobs must achieve a balance between crosslink delay and proppant transport and between optimum breaker schedules and final conductivity. The development of unconventional fracturing fluids based on synthetic polymers could be important to stimulating future deep gas wells.

Proppant and conductivity issues are very important to the final productivity of a well. Among the areas of concern are:

Gel damage to the proppant pack. As new fluid systems are developed to address hostile environments, it will be important to investigate the cleanup of these systems from the proppant pack. Inefficient cleanup can greatly reduce the conductivity of the proppant pack. Further, this cleanup efficiency should be examined as a function of the type of proppant and not just as a function of the fluid system alone as it has been shown by other researchers that proppant type can significantly impact gel cleanup.

Long term conductivity at high temperature: Proppant conductivity is typically reported at 50 hours of closure stress and 150°F or 250°F. It is known that, even under these conditions, proppant pack conductivity for all proppant types continues to decay with time beyond 50 hours. Under extreme conditions of temperature (>350°F) this effect may be even more pronounced. Investigation of the longer term conductivity at high temperatures should be investigated as a function of proppant type.

H₂S/CO₂: High concentrations of H₂S and/or CO₂ are often present in the produced fluids from deep gas wells. There is very little information in the literature regarding the effects of these compounds on the long term strength/stability of proppants. Different types of proppants would be expected to behave uniquely in these environments.

High pressures: Very little data exists on the performance of proppants at compressive stresses of greater than 14,000 psi.

1.4.3 Operational Challenges

There are practical operational challenges when hydraulic fracturing deep gas wells. The high surface pressures push the limits of frac iron and pumps and raise well control and safety concerns. The industry does not readily have available multiple strings of 20,000 psi working pressure treating iron and there is considerable lead time for new equipment. Injection rates are limited to reduce erosion of expensive high-pressure iron. Many of the pump trucks used by the industry are limited to 20,000 psi surface treatment pressures with sintered bauxite proppants. The industry will have to research what the next generation high-pressure pump units should look like. Heavy weight fracturing fluids that will improve well safety and reduce surface treating pressure with increased hydrostatic heads are also an option. The industry as a whole will need to address the safety issues related to treating and producing deep gas wells.

While few in number relative to shallower wells, deep gas wells are often prolific producers and have the potential to add significant reserves. Despite recent increases in deep drilling, from interviews and published data it appears that operators have not seen the investment returns they had hoped for on some of these extreme wells. While reserves and production rates are typically much higher for deep gas wells, increased drilling and completion costs and lower success rates can make them poorer economic performers than shallower wells. Increased domestic natural gas demand and depletion of gas from conventional reservoirs will put pressure on operators and service companies to increase the capacity to drill deep wells and to improve the economics of these wells. Research efforts, such as the DOE Deep Trek Program, are necessary to help meet this challenge.

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Please see **Bibliography: Deep Gas Well Stimulation** for a more extensive set of references on deep gas well stimulation.

2. Review of Deep Gas Well Drilling Activity (1995 – 2009)

Pinnacle teamed with Spears & Associates to look at historic and future (1995-2009) deep gas drilling activity. The initial review was performed in late 2002 and was updated in 2004. For purposes of the study, deep gas wells were defined as greater than 15,000 ft true vertical depth (TVD). Shallower wells were also included provided they were located in high temperature and pressure (>350°F and >10,000 psi reservoir) environments. Deep water wells were not included as DOE is emphasizing onshore and shallow water resources (Gulf of Mexico Shelf) for the program at this time.

Well drilling and completion data was obtained from IHS Group and current and historic drilling rig activity was obtained from Smith International. This data was analyzed along with information from Spears' prior research to quantify deep drilling activity and identify and rank active operators. This was supplemented with interviews of active deep drilling operators and service companies to ensure the accuracy of the information and to learn more about activity in various regions. Approximately sixty operators, service companies and other organizations participated in the study and over 350 interviews were conducted for the study.

One interesting issue came up during analysis of the data set. For decades it has been assumed that IHS and the American Petroleum Institute (API), which uses the IHS data set for its own sourced well activity reports, have been reporting drilling and producing activity based on well depth since reports are issued under headings like, "*New well drilling by 5000 ft depth increment.*" Knowing that many wells in the U.S. are directionally drilled and that the DOE's program focused on wells with true vertical depth of 15,000 ft and greater, a special database was obtained for wells with TVD greater than 15,000 ft. A database of almost 6,000 wells was delivered and, based on this, operators were contacted with deep drilling activity over the last few years.

Immediately, operators began to identify wells that were not even close to 15,000 ft deep, particularly in the most active region on the API and IHS list – the Austin Chalk area of Texas. In most cases, the wells had TVDs of 9,000 ft with lateral extensions of 6,000 ft. The area of greatest difficulty has been offshore, where almost every Gulf of Mexico Shelf (GOM Shelf) well is drilled directionally and where measured depth commonly exceeds 15,000 ft. IHS Group and the API are actually reporting well length, not well depth (see **Figure 5**). The database certainly included all 15,000 ft TVD wells, but it included an even greater number of wells with 15,000 ft measured depth wells. These wells had to be systematically culled out to leave only those wells that fit the DOE criteria.

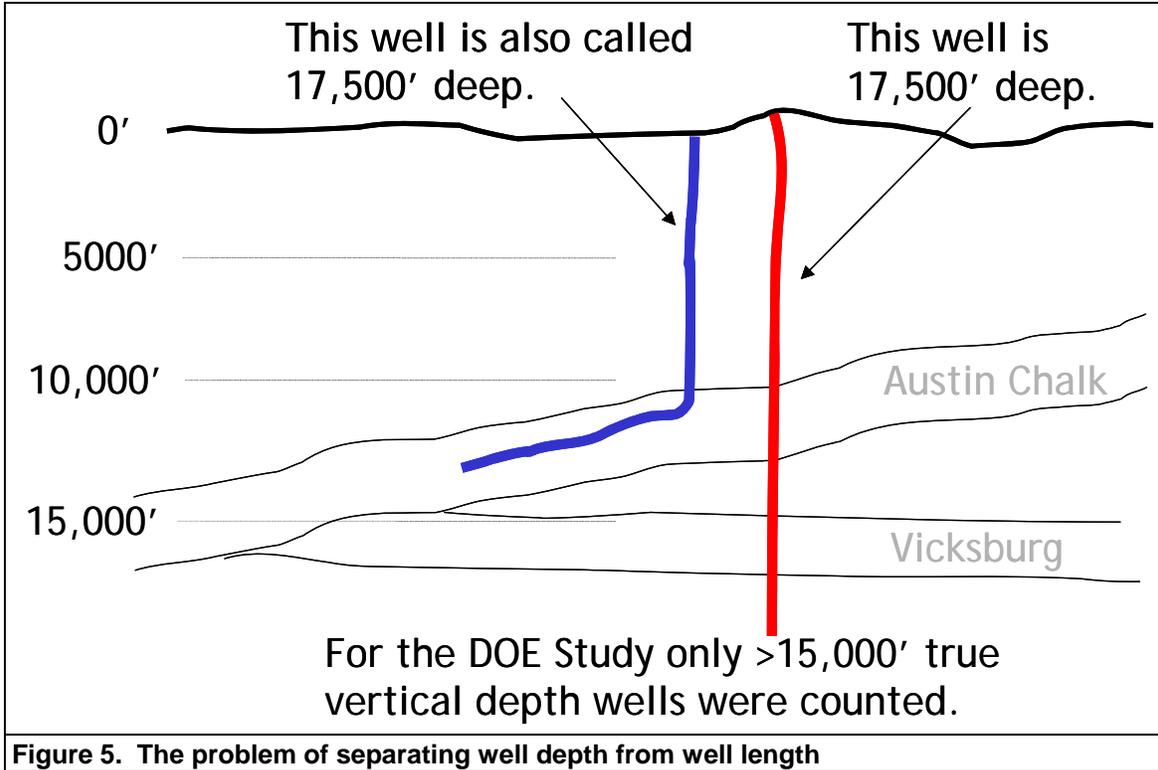


Figure 5. The problem of separating well depth from well length

Another major difficulty came in identifying high-temperature and high-pressure (HT/HP) wells. There exists no easily accessible database whereby depth-related temperature and pressure of wells around the U.S. can be determined. Geologic surveys have some data, disparate well files have other data and wireline logs are yet a third source, but no searchable, geographically sensitive, depth-related database is known to exist for temperature and pressure estimation. Spears used a model developed in-house to study the market for downhole high-temperature electronics.

2.1 Drilling Forecast

After a cyclic low in 2002, drilling in the U.S. rose in 2003 and continues to rise. One interesting change since 1995 has been in the percentage of rigs drilling for gas and rigs drilling for oil. Despite the relatively high oil prices today, gas is the target for 85% of the rigs drilling in the U.S. today versus 55% of the rigs drilling in 1995. This ratio is not expected to change significantly over the next few years. The U.S. is now very much a natural gas province and average well depths are trending deeper and deeper as operators seek new horizons to develop. Total deep gas drilling (U.S. onshore and GOM Shelf) has risen in the past few years as shown in **Figure 6** (this forecast was performed in early 2003).

2. Review of Deep Gas Well Drilling Activity (1995 – 2009)

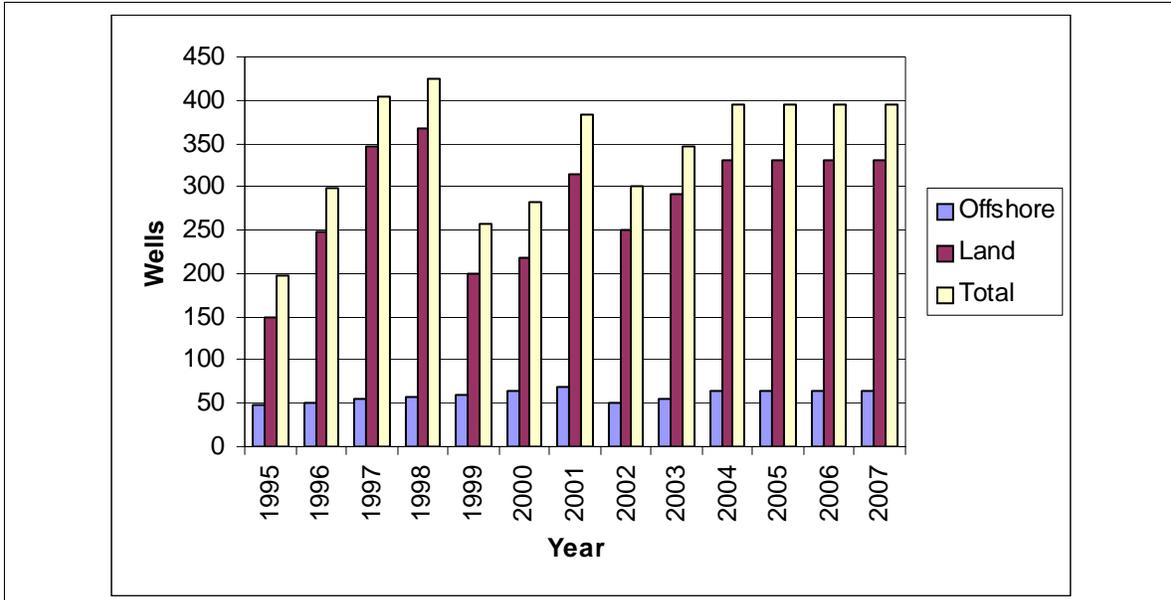


Figure 6. Deep gas drilling in the U.S. (onshore and GOM Shelf), 2003 forecast

Of the 60 operators who drill deep and HT/HP wells, the top twenty drill almost 80% of the wells with six operators drilling half the U.S. deep wells. El Paso has led the pack, drilling 20% of all wells. Other leading deep well drillers include Anadarko, Chesapeake, BP, EOG Resources and ChevronTexaco.

The deep drilling forecast was updated in late 2004. As shown in Figure 7, the drop from 2001 to 2002 was not as steep as initially forecast. There was an increase in deep drilling in 2003 and 2004 with the largest increase in 2004. The primary increases in activity have been in South Texas and the Mid-Continent.

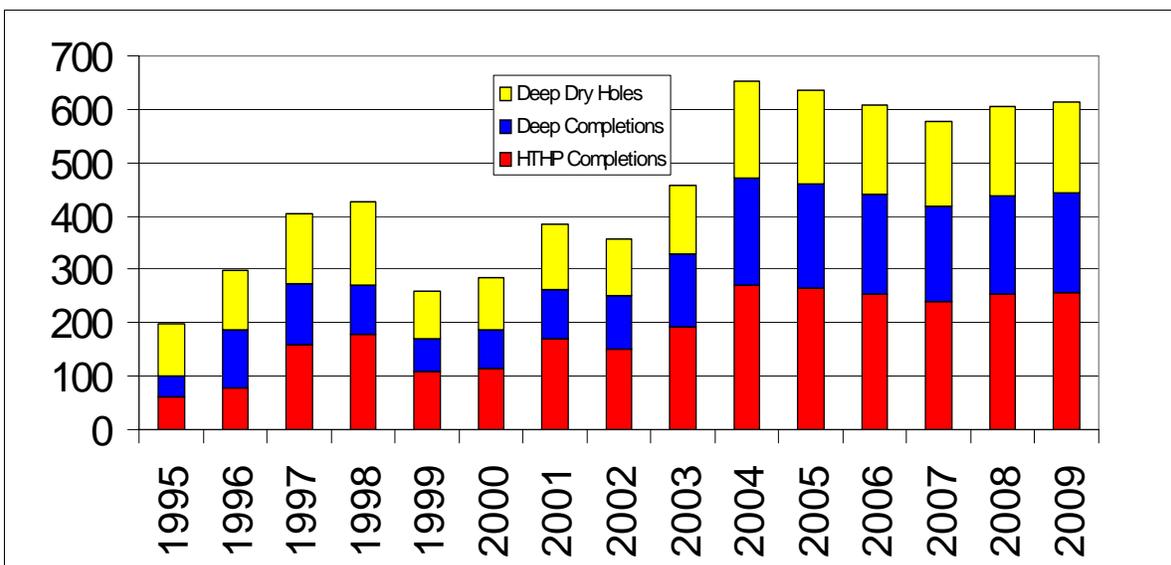


Figure 7. Deep gas drilling in the U.S. (onshore and GOM Shelf), 2004 forecast

2.1.1 South Texas

As noted earlier, South Texas is the leading area for deep well drilling. It is also the primary region in the U.S. where HT/HP wells are less than 15,000 ft deep. This includes both >15,000 ft drilling and the slightly shallower hot, high-pressure wells being drilled in the area. Deep drilling has increased markedly in this region from 15 in 1995. By far the leading driller of deep wells in South Texas has been El Paso. Other active operators have been EOG Resources, ExxonMobil, Shell, Total, Dominion and ConocoPhillips.

2.1.2 Oklahoma

Oklahoma can be one of the most active regions for deep drilling in the U.S. Even with the industry's downturn in 2002, >15,000 ft drilling continued to climb. Chesapeake has been the most active operator in this region; others drilling multiple deep wells annually have been Apache, Marathon, St. Mary Operating, Sanguine, BP, Ward Petroleum and Cimarex.

2.1.3 East Texas / North Louisiana

East Texas, along with the northern half of Louisiana, has recently had 10 to 20 wells drilled to 15,000 ft each year, significantly less than the 100 drilled annually in the late 1990's. There are a number of wells being drilled in this area that fall just short of the depth/temperature cutoff to count as deep wells. Currently a mini boom is going on in Freestone and Leon Counties in Texas as Anadarko and XTO drill in the 10,000 to 14,000 ft range for the Bossier Formation. These wells were not counted in the survey since they did not meet the depth or pressure/temperature limits set by DOE for deep wells.

2.1.4 Gulf Coast (Texas and Louisiana)

The Gulf Coast (upper Texas coast and the southern half of Louisiana) has 60 to 70 wells drilled to 15,000 ft each year, down from the peak year of over 130 drilled in 1998. Drilling spiked with \$10 natural gas in 2001 but is expected to be fairly flat through 2009. The most active operators have been BP and ExxonMobil and there are several dozen operators who drill a well or two each year.

2.1.5 Rocky Mountains

The Rockies is a large area from Northern New Mexico up to Montana and North Dakota. Most of the deep drilling, however, occurs in Wyoming in pursuit of deep gas. Drilling spiked with high gas prices in late 2000, but expensive hard rock drilling, poor gas quality (including CO₂, H₂S and N₂), combined with limited access to gas markets and sometimes marginal finds has brought deep drilling expectations back down to the five-well-per-year level, with most being exploration holes. North Dakota reports dozens of >15,000 ft wells but these are all horizontal. Recent and/or current active operators include ChevronTexaco, Anadarko and Burlington.

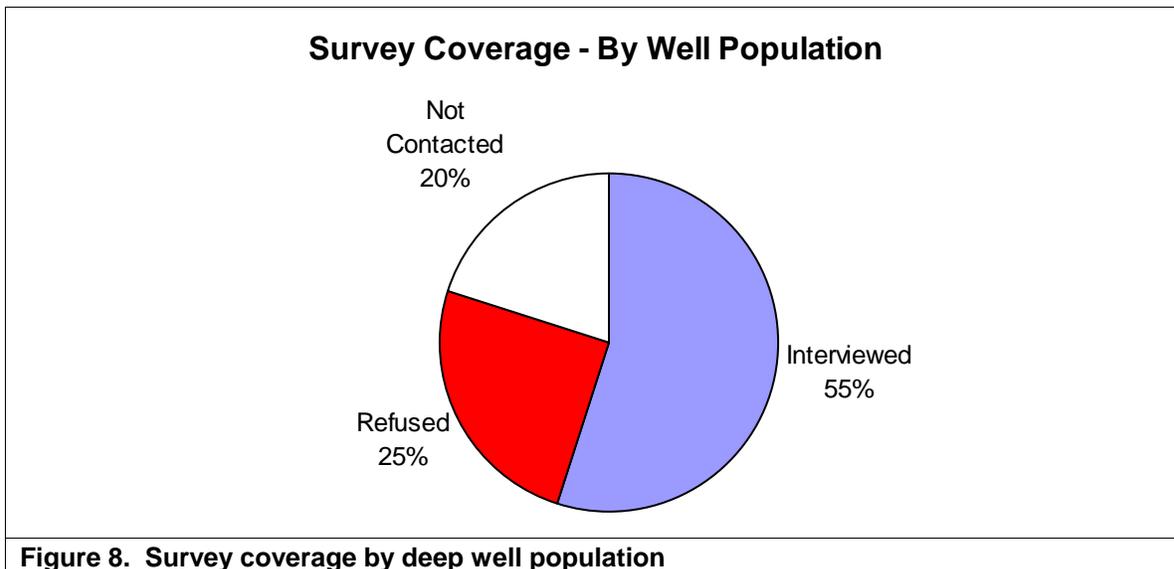
2.1.6 Gulf of Mexico Shelf

Determining the exact number of deep wells drilled on the GOM Shelf each year is challenging. Rowan Drilling, whose massive jackup rigs drill over half the deep GOM Shelf wells, says that fewer than 50 holes were punched deeper than 15,000 ft TVD in 2002. On the other hand, the database lists almost 120 in the prior year, 2001. The problem is that 44 of the 118 listed have no vertical depth indicated, just measured depth with the additional notation that the well is directional. While it is certainly possible that some of the 44 are truly deeper than 15,000 ft, it is likely these are not 15,000 ft TVD wells. For example, BP's subsidiary companies, Vastar and Amoco, are listed as drilling 13 holes deeper than 15,000 ft TVD in 2001. But several conversations with BP indicated that none of their wells in recent years hit the 15,000 ft TVD requirement. GOM Shelf drilling may be bolstered by high gas prices and incentives provided by the Department of Interior in March 2003 for deep gas investment. Recent and/or current active operators include ChevronTexaco, El Paso, Anadarko, Dominion and Bois D'Arc.

2.2 National Survey Results

2.2.1 Survey Coverage

Approximately 60 operators, according to IHS, drilled about 300 deep or HT/HP wells in the U.S. in 2001. SAI managed to interview operators who drilled 55% of these wells as shown in **Figure 8**.



Operators drilling 25% of the deep wells refused to cooperate and operators of the remaining 20% were not contacted because they only drilled one or two deep wells over a two-year period. SAI concentrated on the most active operators. As **Figure 9** indicates, the top one-third of the deep-

2. Review of Deep Gas Well Drilling Activity (1995 – 2009)

drilling operators drilled three-quarters of the deep wells, while the bottom one-third drilled only 6% of the holes.

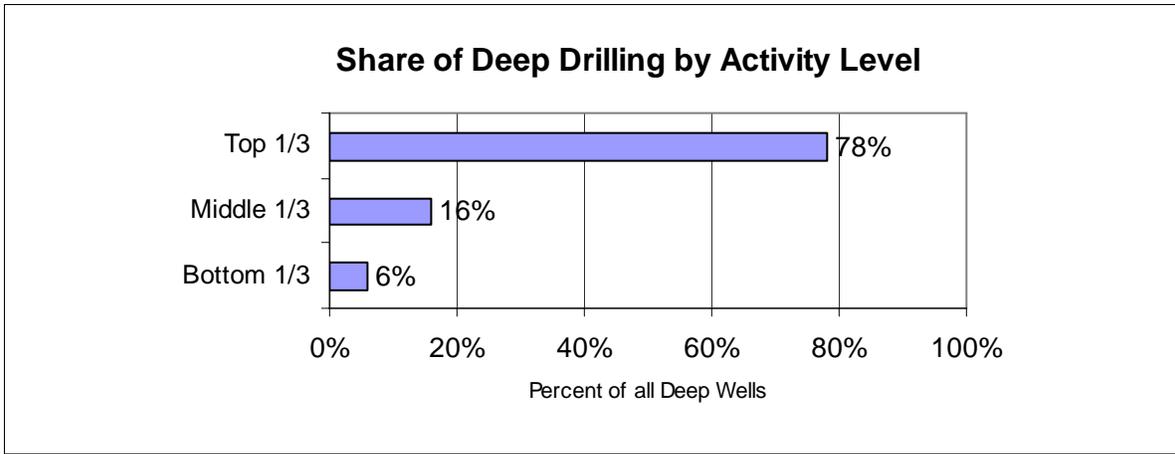


Figure 9. Share of deep well drilling by activity level

Since it requires just as much effort to interview an operator with 50 deep holes as an operator with one, we focused on the larger players; however, we made sure to get a sampling of operators who drilled only one or two wells just to make sure that this part of the activity spectrum was represented. Despite our efforts, we were not able to conduct full-blown, engineering-related interviews with all the most active operators. No survey can accomplish 100% coverage, but we had conversations with all the top 30 to 40 producers. As shown in **Figure 10**, of the top six operators (who drilled half the deep wells) four were willing to provide useful data to our interviewing team.

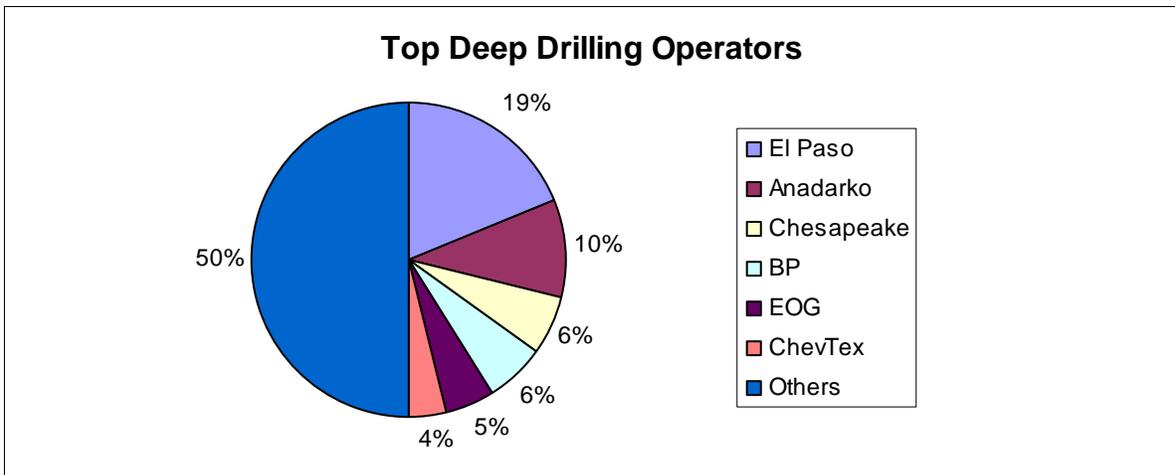
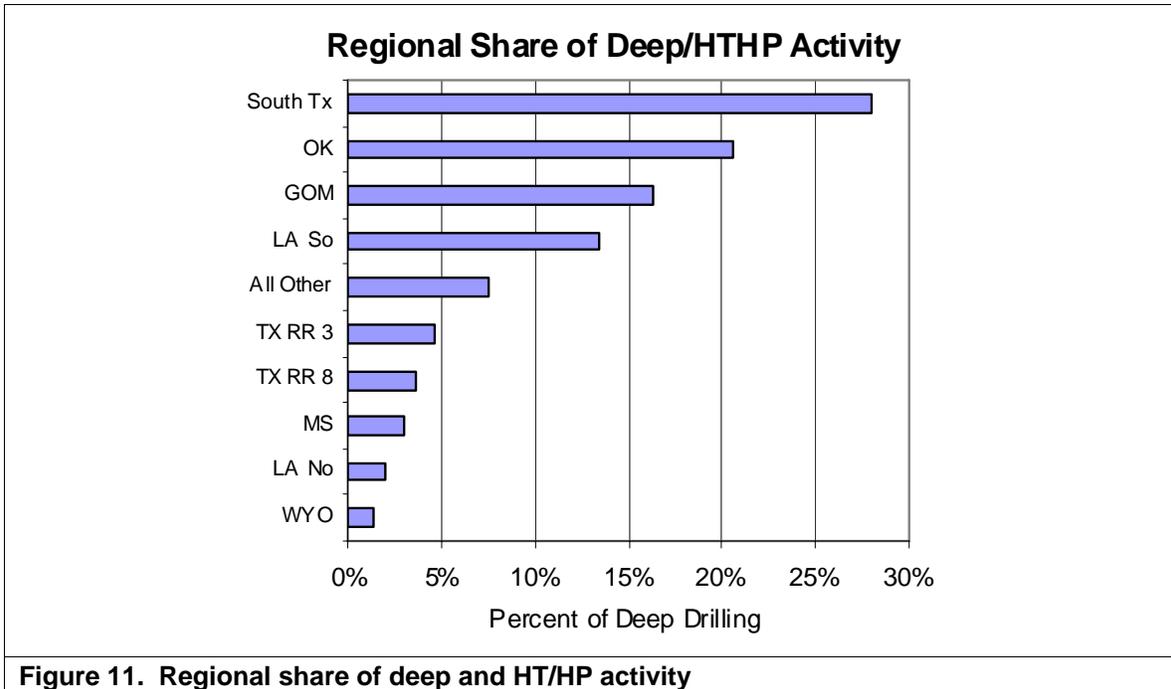


Figure 10. Top deep drilling operators

Figure 11 shows the regional share of deep and high-temperature/pressure well activity. Almost 50% of the nation’s very deep drilling is done in Oklahoma and Texas Railroad Districts 2 and 4 (South Texas). South Texas has almost all the truly HT/HP activity in the country. The Gulf of

Mexico and the southern half of Louisiana contribute another 30% of the deep drilling. Every other part of the U.S. has very little deep or HT/HP activity.



This survey concentrated on the most active operators working in South Texas and Oklahoma, but also covered operators working in every region of the U.S. except for Alaska (which has no extremely deep drilling).

2.2.2 Technologies Employed in Frac Design and Diagnosis

While the following section of this report breaks out regional responses to our survey, it is noteworthy to review how operators employ certain technologies on their deep wells. Operators were presented this question:

I'm going to list for you 11 technologies or tests and I would like you to tell me which ones you use on HP/HT wells that you normally don't use on your "typical" wells?¹

Figure 12 shows the results of this question. Most operators performed injection tests² and flow tests³ on their extreme wells, while very few ran extra logs⁴ and even fewer did fracture mapping.

1 The interviewer read off these tests and, in most cases, the engineer responded with yes or no, or a small descriptive comment. We did not go into great depth.

2 Diagnostic injection tests (step-down tests, mini-fracs, fluid efficiency).

3 Pre-frac and/or post-frac flow tests.

4 Special wireline logs, such as sonic, FMI, and magnetic resonance.

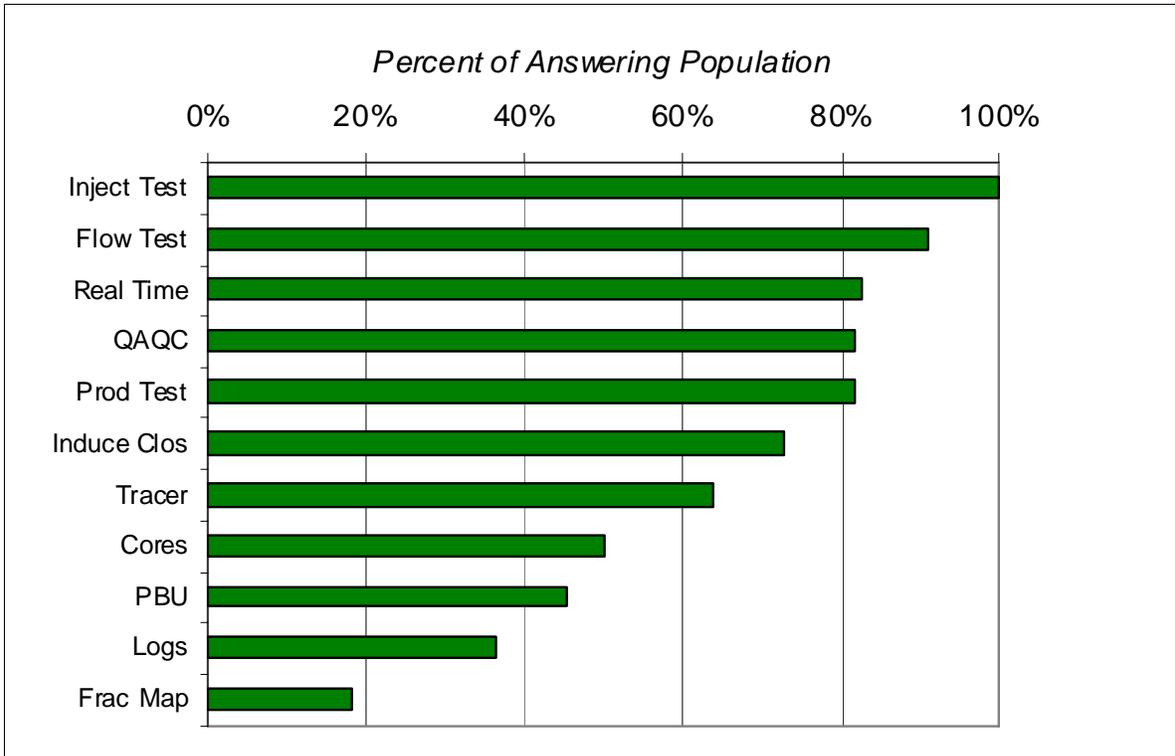


Figure 12. Use of fracture diagnostics on deep wells

2.3 Regional Survey Results

The results presented in the regional survey are based on a deep drilling forecast made in early 2003. To some degree they understate deep gas well drilling especially in South Texas and Oklahoma. An update to the forecast performed in late 2004 showed 50% more deep wells being drilled (600 per year versus 400 per year) than originally forecast.

2.3.1 South Texas

South Texas consists of Railroad Districts 2 and 4, which comprise an area south of Houston to the Mexican border and from the Gulf of Mexico inland about 250 miles. **Figure 13** shows Oil and Gas District Boundaries for the state of Texas. Some companies refer to this as Gulf Coast land and extend the region up to the Louisiana border. We have not used this broader definition.

2. Review of Deep Gas Well Drilling Activity (1995 – 2009)

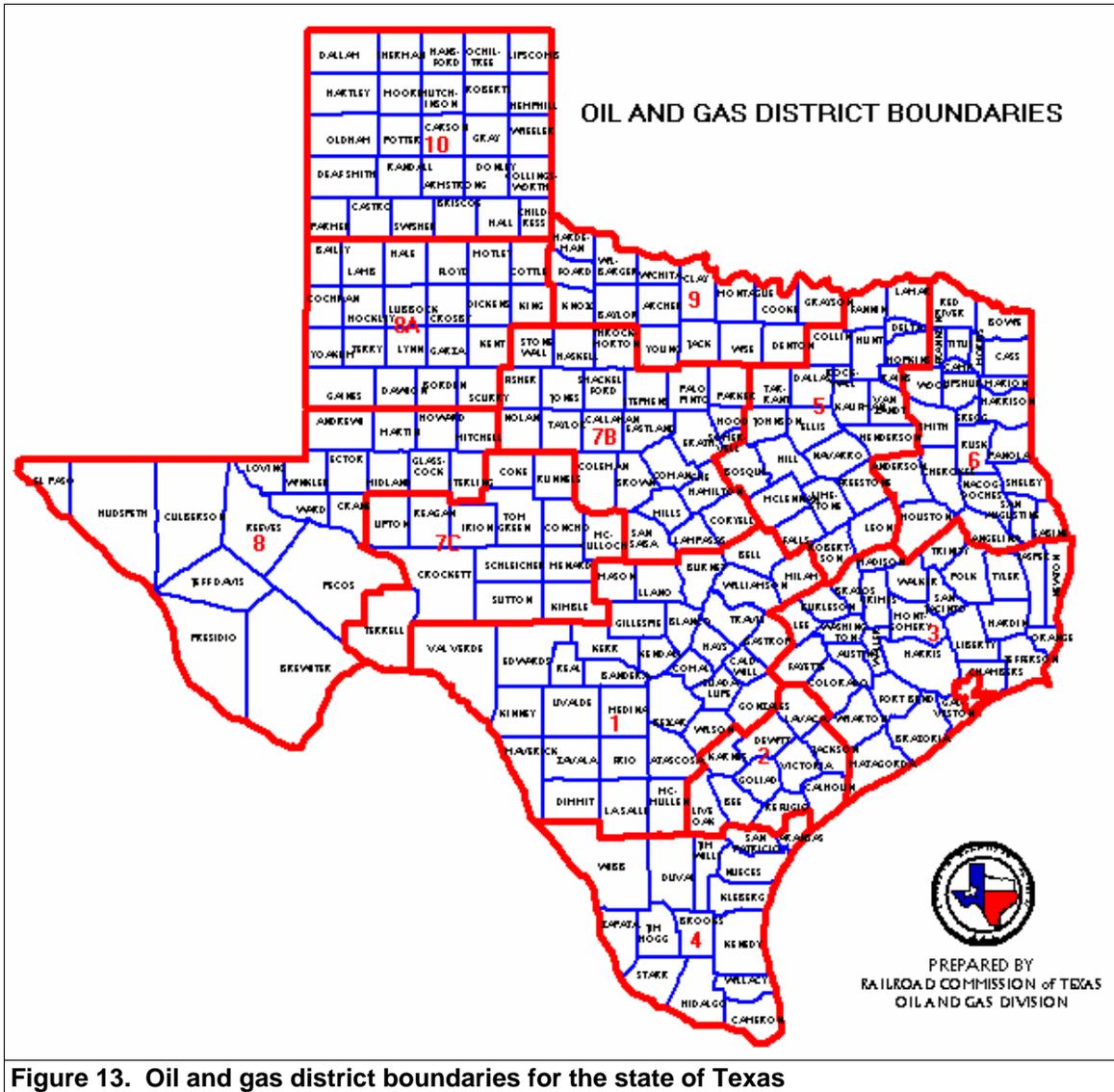


Figure 13. Oil and gas district boundaries for the state of Texas

Drilling Activity and Forecast

South Texas is the primary region in the U.S. where HT/HP wells are less than 15,000 ft deep; therefore, **Figure 14** includes both >15,000 ft drilling and the slightly shallower hot, high-pressure wells being drilled in the area.

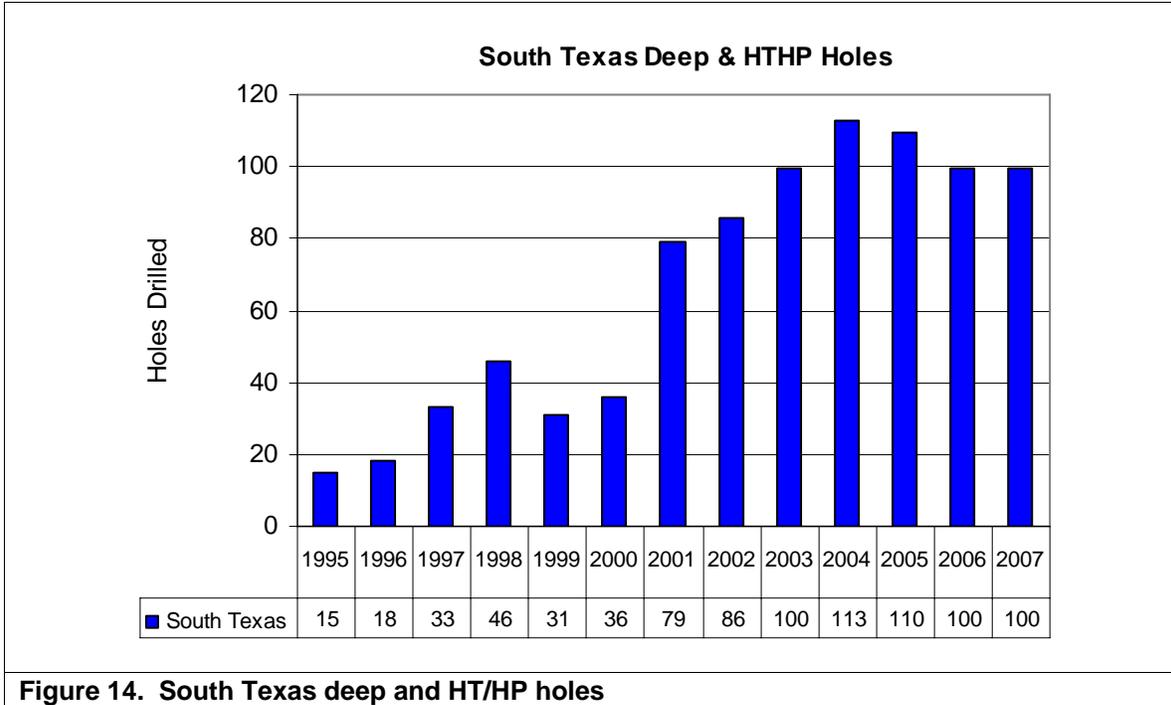


Figure 14. South Texas deep and HT/HP holes

It is possible that South Texas HT/HP drilling could be somewhat greater than we have shown. If wells are drilled to about 12,000 ft in certain areas, the Wilcox, a prolific HT/HP zone, can be tapped. Given the budget constraints of this study, we have investigated as many shallower than 15,000 ft wells as was practical, but it is possible that another 20% could be added to these numbers. Nevertheless, we believe we have identified and tried to contact all operators working in the HT/HP areas of South Texas. Approximately 80% of these wells are completed. Active operators include El Paso, EOG, ExxonMobil, Shell, Dominion, Total, Burlington and ChevronTexaco.

Zones of Interest

13,000 ft	Edwards	235 F
14,000 ft	Wilcox	300 F
15,000 ft	Vicksburg	350 F
16,000 ft	Frio	375 F

Completion Techniques

Operators in South Texas tend to fall into two camps: one large operator believes that gas should be produced as rapidly as possible, blowing down all the zones found in the well, while others tend to complete one zone at a time. As a result, this operator performs frac jobs in South Texas that are many times larger than most other operators in the region. More and more producers are moving toward the rapid production model as other operators recognize the value of producing these wells as quickly as possible, particularly in a high gas price environment.

Rapid Production Completion

- 5-1/2" liner set into Vicksburg and Frio at 15,000 ft
- 5-1/2" production tubing set from top of liner to surface

2. Review of Deep Gas Well Drilling Activity (1995 – 2009)

- Perforate bottom zone
- Pump 500,000# bauxite in 200,000 gallons CMHPG fluid at 30 BPM @ 10k psi
- Set composite bridge plug
- Move uphole to next zone
- Repeat 3 to 5 times
- Drill out composite plugs with coiled tubing drilling unit under pressure
- Commingle zones

Paced Development Completion

- 3-1/2" liner set into Vicksburg and Frio at 15,000 ft
- 3-1/2" production tubing to surface
- Perforate bottom zone
- Pump 200,000# bauxite in 225,000 gallons CMHPG fluid at 30 BPM @ 9k psi
- Produce

Special Tests

Operators in South Texas run quite a few pre- and post-frac tests to gather information about reservoir response (see **Figure 15**). Nevertheless, cores, mapping and special logging runs are not widely used in the region.

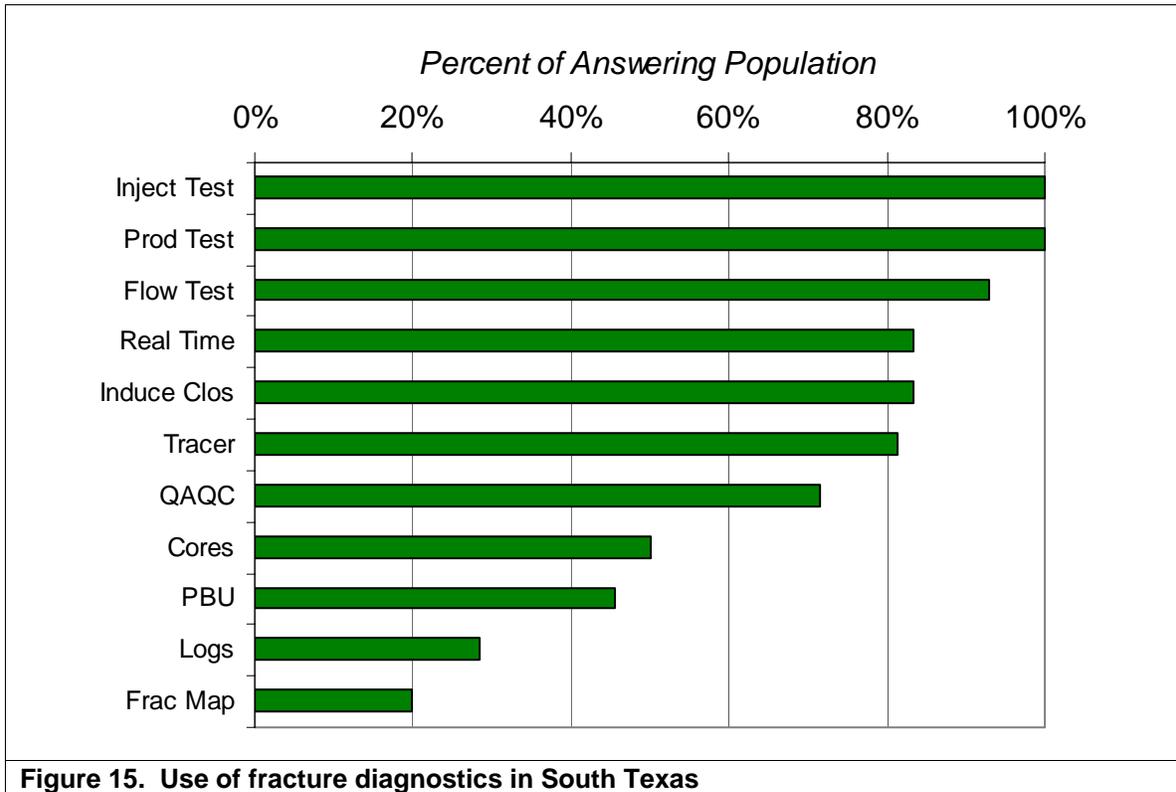


Figure 15. Use of fracture diagnostics in South Texas

Real-Time Monitoring

Based on operator comments, about 75% of all frac jobs use real-time modeling. This is skewed by the most active operator, which performs real-time modeling on most wells. Counter to the industry, one major oil company uses real-time modeling on less than 10% of its frac jobs.

Biggest Challenges

No single “biggest” challenge came out of these conversations, but the following were listed. Interestingly, evaluation of the frac job was not mentioned in this open discussion.

- Evaluating the structure of the formation(s)
- Getting good zonal isolation
- Getting good thermal isolation
- Meeting the limits of tubing
- Controlling the high costs of South Texas development

Best New Completion Techniques (Operator Comments)

The best new completion technologies tended to center on stimulation:

- New frac fluid systems over the last 2 to 3 years
- Step-wise fracs with composite plugs
- Proppants that bind together while in the zone

2.3.2 Oklahoma

Drilling Activity and Forecast

Oklahoma can be one of the most active regions for deep drilling in the U.S. Even with the industry’s downturn in 2002, >15,000 ft drilling continued to climb. We are projecting deep drilling to peak around 85 holes per year in 2004 (see **Figure 16**). Approximately 87% of these wells are completed. Active operators include Chesapeake, Apache, Marathon, St. Mary Operating, Sanguine, BP, Ward Petroleum and Cimarex.

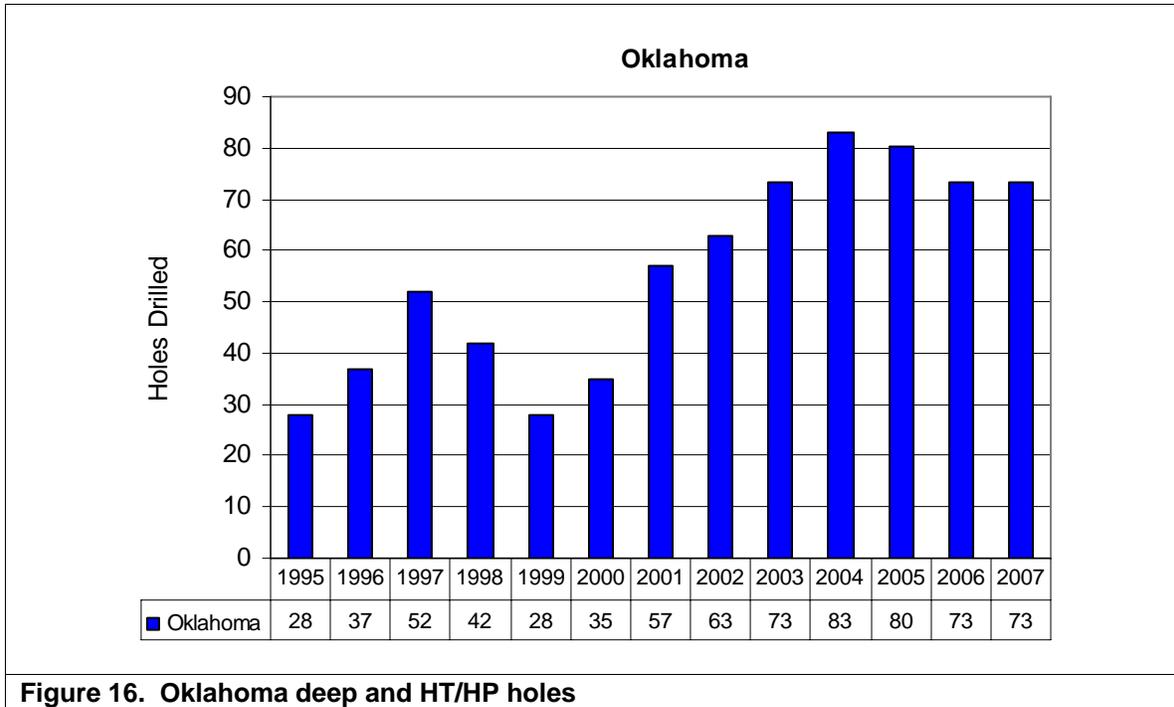


Figure 16. Oklahoma deep and HT/HP holes

Zones of Interest

14,000 ft	Bromide	235 F
15,000 ft	Spiro	300 F
16,000 ft	Springer	300 F
17,000 ft	Morrow	325 F

Completion Techniques

Since operators in Oklahoma tend to work in a variety of zones, no single completion technique is found here. Some of the data gathered included:

Morrow Completion

Pump 120,000# bauxite in 80,000 gallons HPG fluid at 20 BPM @ 13k psi
Produce

Springer Completion

Pump 60,000# bauxite in 30,000 gallons HPG fluid at 30 BPM @ 8k psi
Produce

Special Tests

The main difference between South Texas and Oklahoma is that producers in Oklahoma use radioactive tracers less frequently (see **Figure 17**). Additionally, fewer cores are taken.

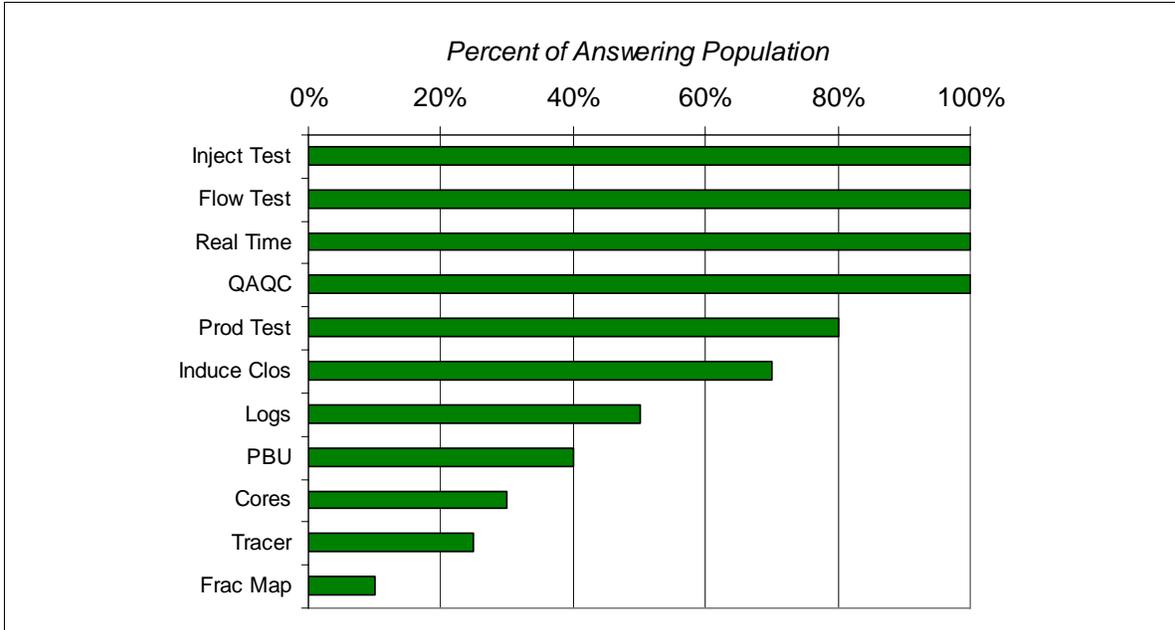


Figure 17. Use of fracture diagnostics in Oklahoma

Real-Time Monitoring

Although 100% of the operators use real-time modeling, this technology is not used on every job. About 80 to 90% of the deep zone frac jobs have real-time frac modeling on location.

Biggest Challenges

The greatest challenge operators say is determining characteristics of the reservoir – pay determination, lithology issues. Formations in Oklahoma appear to be quite tight, with very low permeability. Another challenge is chemistry of the fluids in the reservoir, dealing with compatibility problems.

Best New Completion Techniques

Using composite plugs and fracturing multiple zones holds quite an appeal to operators. Critical to this is completing the well under pressure by using coiled tubing.

2.3.3 Permian Basin

Drilling Activity and Forecast

Permian Basin, which includes Railroad Districts 8, 8A, 7C and 7B (see **Figure 13**), has about a dozen wells drilled to 15,000 ft each year (see **Figure 18**). Many are exploratory, looking for commercial gas in deeper horizons. Active operators include Pure Resources, ExxonMobil, Anadarko and ChevronTexaco.

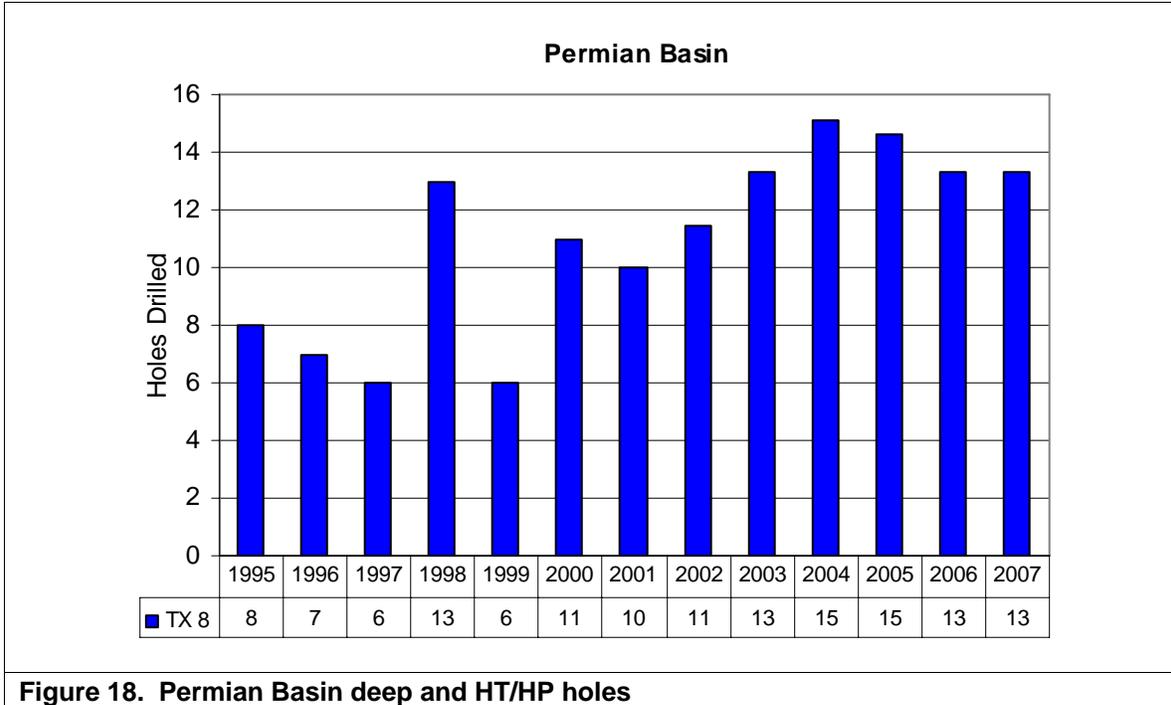


Figure 18. Permian Basin deep and HT/HP holes

Many horizontal wells are drilled in the Permian Basin, so quite a few wells have measured depths greater than 15,000 ft. If we have erred in the chart above, we have erred on the high side, having not culled out all the horizontal drilling in the region.

Approximately 60% of these wells are completed.

Zones of Interest

16,000 ft	Morrow	200 F
17,000 ft	Fusselman	220 F
18,000 ft	Ellenberger	240 F

Completion Techniques

SAI interviewed a variety of producers in the Permian Basin, including frac engineers for the service companies. We found no producers interested in participating in the survey. Additionally, stimulation service companies noted that very few wells are completed below 15,000 ft and that there are no HT/HP wells drilled in the region.

2.3.4 East Texas / North Louisiana

Drilling Activity and Forecast

East Texas, including Railroad Districts 5 and 6 (see **Figure 13**) along with the north half of Louisiana, has 10 to 20 wells drilled to 15,000 ft each year, significantly less than the 100 drilled each year in the late 90's (see **Figure 19**). Currently a mini boom is going on in Freestone and

2. Review of Deep Gas Well Drilling Activity (1995 – 2009)

Leon Counties in Texas as Anadarko and XTO drill in the 10,000 to 14,000 ft range for the Bossier Formation, but deep drilling appears to have fallen out of favor in the area. Active operators include Swift Energy, Anadarko, Clayton Williams, Pioneer and BP.

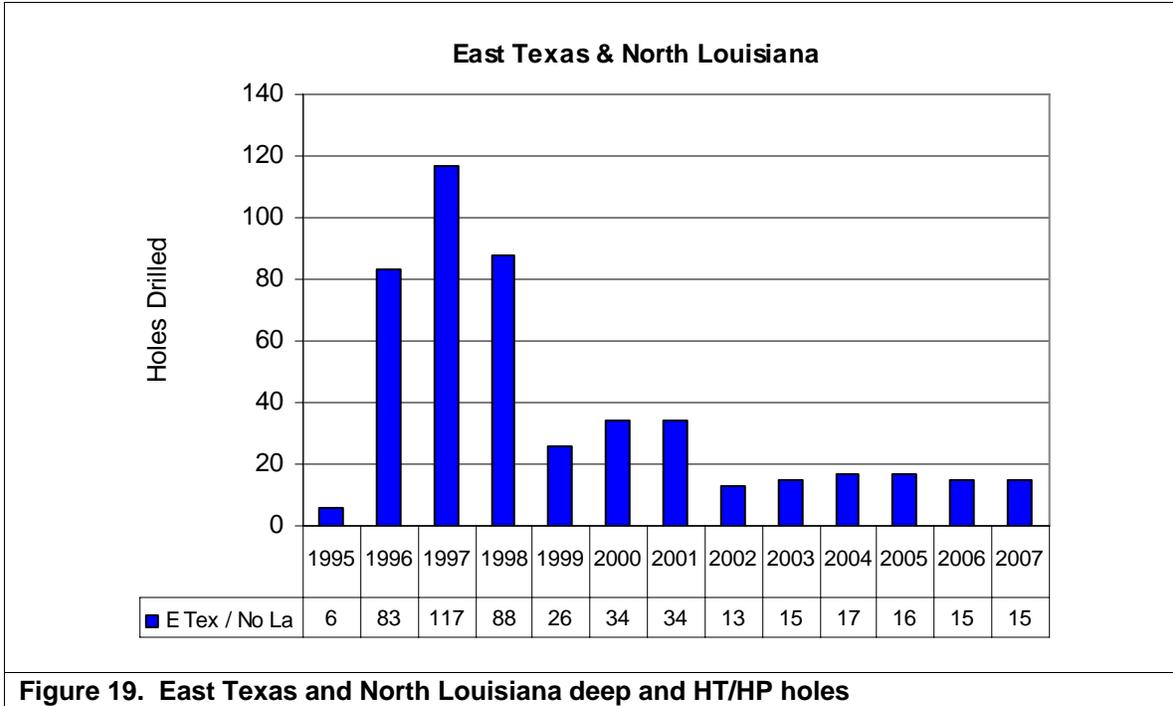


Figure 19. East Texas and North Louisiana deep and HT/HP holes

Approximately 75% of these wells are completed. Swift has been very busy in prior years, but is not drilling deep wells in North Louisiana in 2002; they drilled a couple deep holes in South Texas recently. Number two in the area, Anadarko, also has changed their focus away from deep drilling.

Zones of Interest

15,000 ft	Austin Chalk	250 F
16,000 ft	Pine Island	260 F
17,000 ft	Bossier	275 F

Completion Techniques

Our interviews with operators working in this region turned up very little useful data, other than the opinion that this region’s completions are fairly straightforward. East Texas is home to 10% of the nation’s fracturing horsepower (145,000 HHP), but only 7% of the dollars spent on stimulation (\$170 million). Most frac work is done at shallower depths using lots of horsepower (5,000 to 10,000 HHP) and lots of slickwater and sand (waterfracs and light sands fracs are common in this area). As a result, frac jobs are discounted heavily in this part of the U.S.

2.3.5 Gulf Coast (Texas and Louisiana)

Drilling Activity and Forecast

The Gulf Coast, including Railroad District 3 (see **Figure 13**) and the southern half of Louisiana, has 60 to 70 wells drilled to 15,000 ft each year, down from the peak year of over 130 drilled in 1998 (see **Figure 20**). Drilling spiked with \$10 natural gas in 2001, but we are expecting drilling to be fairly flat through 2009. Approximately 55% of these wells are completed. Active operators include BP, ExxonMobil, Meridian, TransTexas and Murphy. The Gulf Coast region has several dozen operators who drill a well or two each year. The five listed have been the most active in recent years.

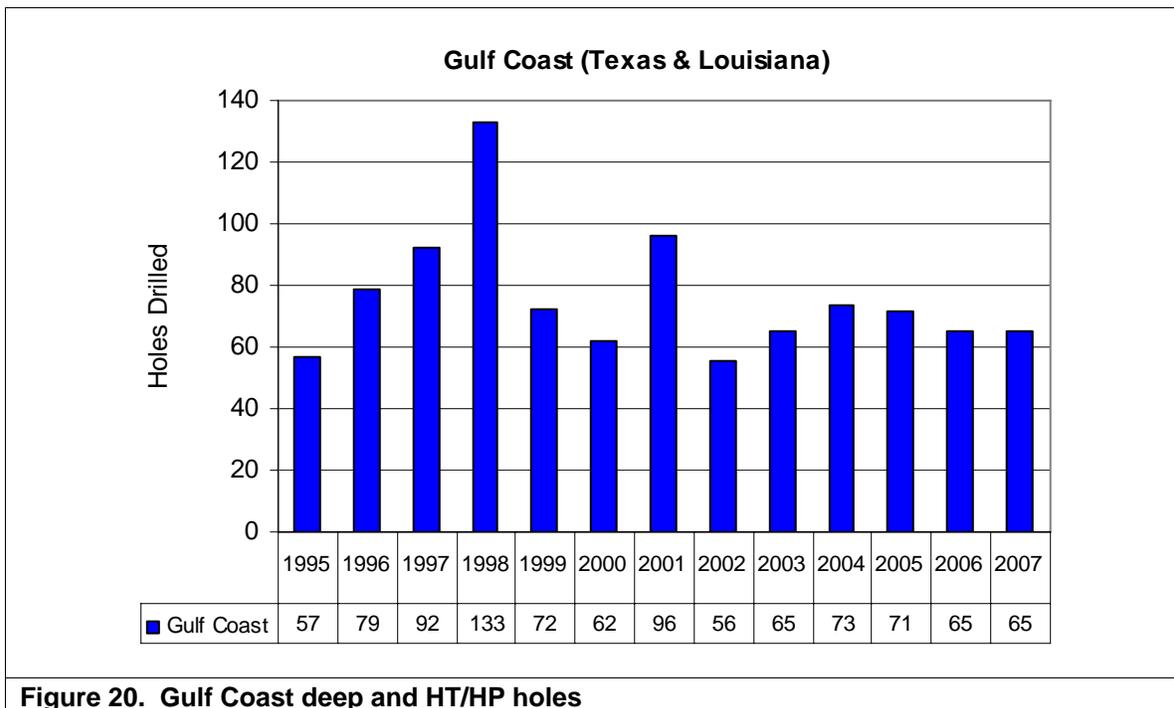


Figure 20. Gulf Coast deep and HT/HP holes

Zones of Interest

15,000 ft	Miocene (LA)	200 F
15,000 ft	Wilcox	300 F
16,000 ft	Vicksburg	325 F
17,000 ft	Frio	350 F

The majority of the South Louisiana wells appear to be in the Miocene, Oligocene and Tuscaloosa zones, while the Texas wells are in the Wilcox and Vicksburg.

Completion Techniques

From our discussions with operators and service companies, we believe that deep completions along the Gulf Coast are among the simplest deep completions in the country. A major operator checked for us regarding neighboring operators' completion methods in South Louisiana and

confirmed that standard completion methods included setting 3½” tubing into the producing zone and running it to the surface. These wells flow naturally. It appears that there is very little uncertainty regarding the proper completion method of deep wells in this region.

2.3.6 Rocky Mountains

Drilling Activity and Forecast

The Rockies is a large area from Northern New Mexico up to North Dakota. Most of the deep drilling, however, occurs in Wyoming in pursuit of deep gas.

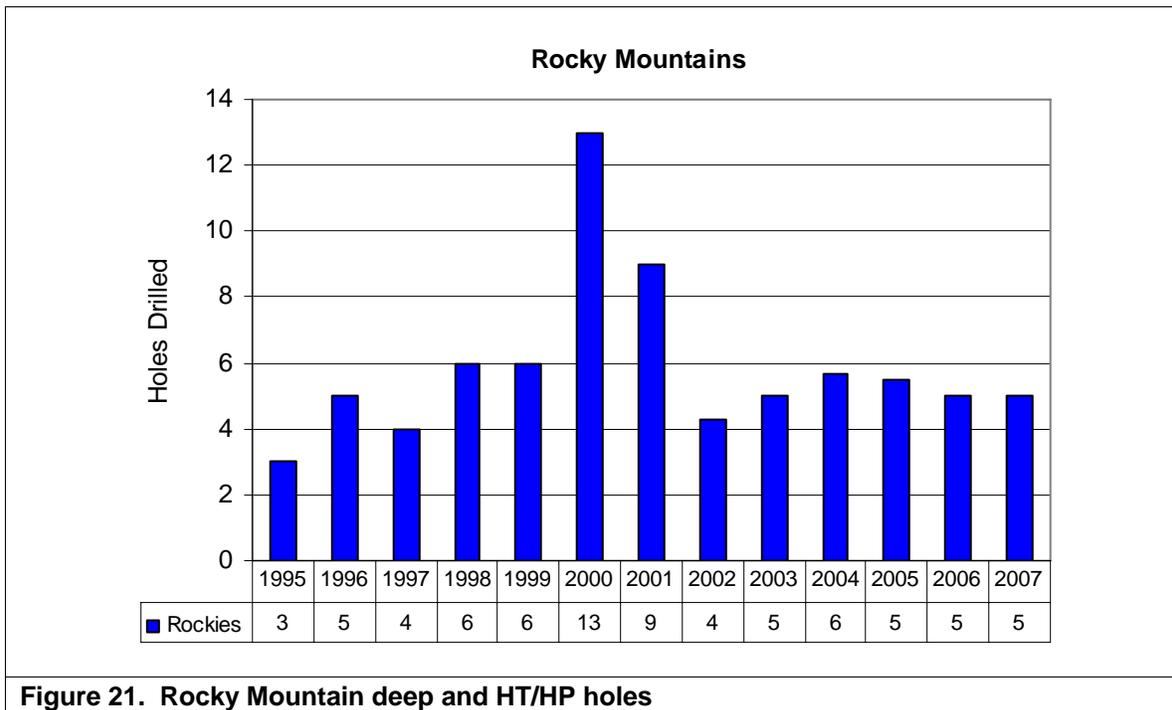


Figure 21. Rocky Mountain deep and HT/HP holes

Drilling spiked with high gas prices in late 2000, but expensive hard rock drilling combined with limited access to gas markets and apparently marginal finds has brought deep drilling expectations back down to the five-well-per-year level, with most being exploration holes (see **Figure 21**). North Dakota reports dozens of >15,000 ft wells, but these are all horizontal. Approximately 50% of these wells are completed. Active operators include ChevronTexaco, Anadarko, Anschutz, Burlington, EOG and BP.

Zones of Interest

14,000 ft	Mission Canyon	200 F
15,000 ft	Nugget	210 F

These wells are reported to be normally pressured and are not considered high-temperature.

Completion Techniques

The completion team leader for a major operator was interviewed about deep completions nationwide. When we addressed the Rocky Mountains, he dismissed the area as not appealing in their eyes for the Deep Trek project citing that the wells were too plain. Other operators we contacted in this area chose not to cooperate.

2.3.7 Gulf of Mexico Shelf

Drilling Activity and Forecast

As noted earlier, determining the exact number of deep wells drilled on the Shelf each year is challenging. Rowan Drilling, whose massive jackup rigs drill over half the deep Gulf Shelf wells, says that fewer than 50 holes were punched deeper than 15,000 ft TVD in 2002. On the other hand, IHS Group lists almost 120 in the prior year, 2001. The problem is that 44 of the 118 they list have no vertical depth indicated, just measured depth with the additional notation that the well is directional. While it is certainly possible that some of the 44 are truly deeper than 15,000 ft, we are more inclined to believe the opinion of the drilling contractor whose business it is to drill these very deep holes. For example, BP’s subsidiary companies, Vastar and Amoco, are listed as drilling 13 holes deeper than 15,000 ft TVD in 2001, but several conversations with BP indicated that none of their wells in recent years hit the 15,000 ft TVD requirement. We are, therefore, using 50 for our 2002 estimated number and have tied deep activity to overall Shelf drilling for our history and forecast. Using this method, drilling in 2001 was almost 70 holes rather than the 74 actually reported by IHS Group (118 – 44 = 74). **Figure 22** shows our estimate of deep well activity in the GOM Shelf.

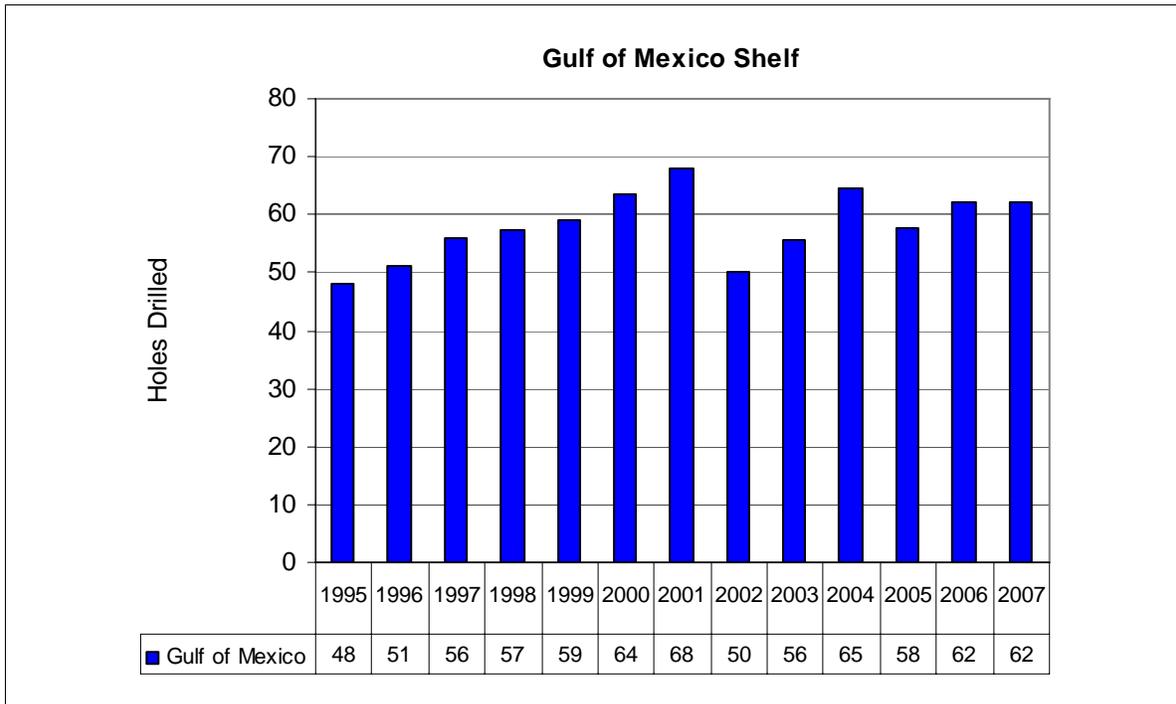


Figure 22. Gulf of Mexico Shelf deep and HT/HP holes

2. Review of Deep Gas Well Drilling Activity (1995 – 2009)

Although drilling in the Gulf remains lackluster, the incentives provided by the Department of Interior on 26 March 2003 for deep gas should bolster investment in drilling, on top of the normal incentives provided by high gas prices. Approximately 60% of these wells are completed. Recent active operators include ChevronTexaco, El Paso, Anadarko/RME, Dominion, Bois D’Arc and Nexen Petroleum Offshore.

Zones of Interest

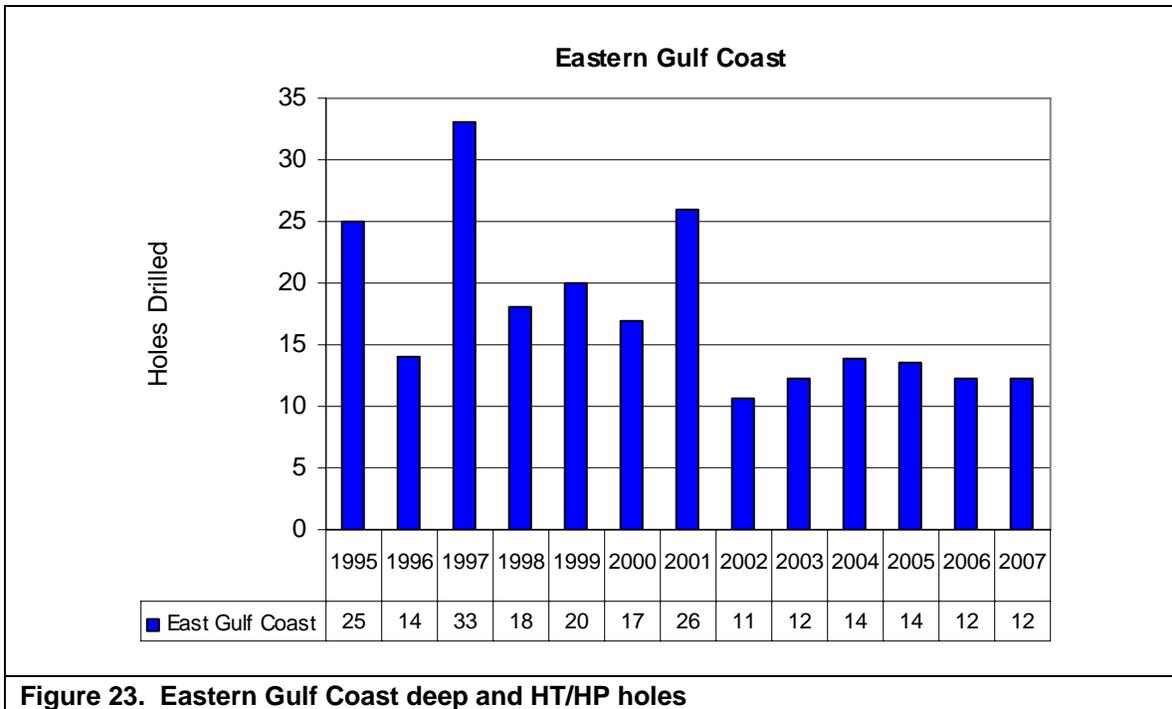
15,000 ft	James	200 F
15,500 ft	Pleistocene	200 F
16,000 ft	Miocene	200 F
21,000 ft	Smackover (AL)	350 F
22,000 ft	Norphlet (AL)	400 F

Since the Gulf of Mexico Shelf is obviously a very large region, the depths shown above are rough averages of where the zones are commonly encountered.

2.3.8 Eastern Gulf Coast

Drilling Activity and Forecast

Mississippi and Alabama have some very hot, high-pressure zones, but very little drilling is being done now (see **Figure 23**).



But for a one-year spike in 2001, the trend in deep drilling has been falling since 1997. Approximately 50% of these wells are completed. About 15 operators have drilled deep land

2. Review of Deep Gas Well Drilling Activity (1995 – 2009)

wells over the last two years, but, most only drill one well per year – and most of these are in Mississippi, not Alabama.

Zones of Interest

14,000 ft	Hosston	200 F
15,000 ft	Cotton Valley	210 F
16,000 ft	Smackover	325 F
18,000 ft	Norphlet	350 F

2.3.9 Other U.S. Land

Drilling Activity and Forecast

About ten deep holes are drilled in other parts of the U.S. each year. In 1998, the Texas Panhandle (RRD 10) saw a spike in drilling when Crescendo, Sonat (El Paso) and Devon were pursuing an Upper Morrow play, but for the most part a little deep exploration goes on all the time.

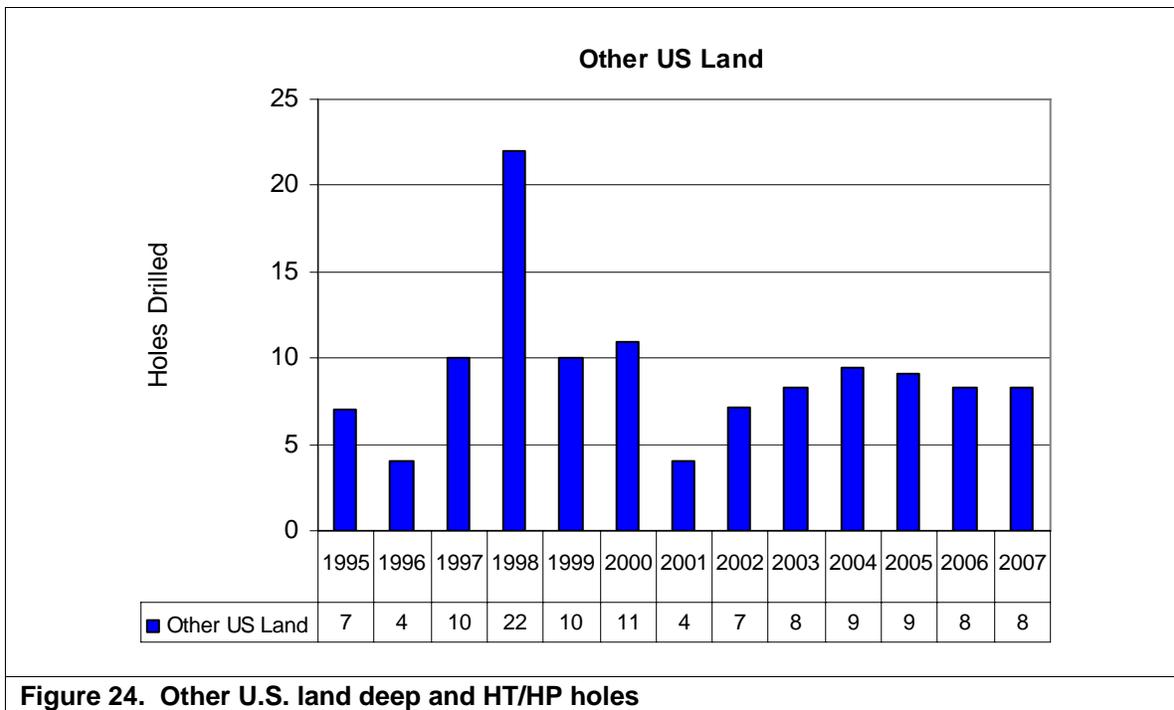


Figure 24. Other U.S. land deep and HT/HP holes

Regions of Interest

California

Since 1995 only one well out of 12 has been completed deeper than 15,000 ft. Berkley Petroleum completed a Kern County well in 2000. Operators will try one or two holes each year in California.

Permian Basin – Southern New Mexico

Several Ellenburger and Morrow gas wells were drilled from 1995 to 1997, but very little since then. We notice that in this portion of the Permian Basin, ten operators drilled 14 holes over eight years. This suggests that prospects of deep production are not very promising.

Utah

There has been no deep drilling in Utah since 1999.

TX RRD 1

Railroad District 1 (see **Figure 13**) is just west of the South Texas region and can be considered part of the basin; however, the region is not prolific in the deeper horizons. In the last eight years, six different operators have each drilled one hole. Only one was completed.

TX RRD 10

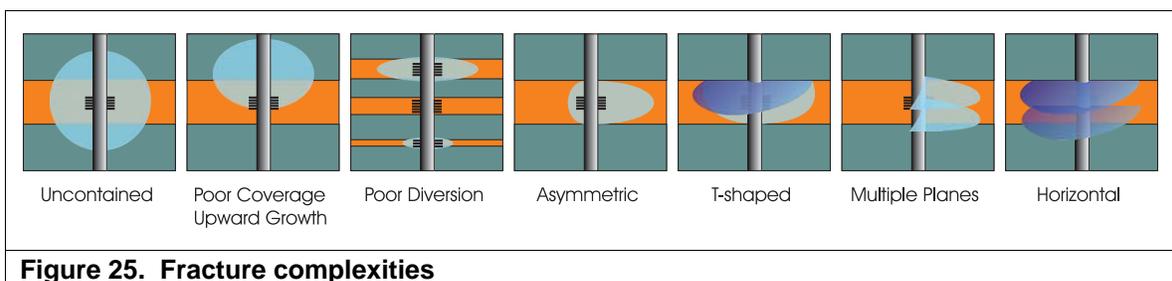
Railroad District 10 (see **Figure 13**) is the top of the Texas Panhandle. Recently, Newton Corporation and EEX each drilled one gas well into the Upper Morrow at about 16,200 ft TVD. As noted above, an earlier spike in drilling was also in the Upper Morrow. Still, very little deep work is being anticipated.

3. Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells

Over the last few decades, hydraulic fracturing has been the stimulation method of choice in a wide range of applications – from ultra-low permeability shales to high-permeability sandstones in shallow and deep reservoirs and in formations ranging from coals to naturally fractured granite. Hydraulic fracture stimulation has become a big business because it is successful in the majority of wells, and in most applications the cost of the fracture treatment is paid back quickly – usually in a matter of weeks or months.

Although hydraulic fracturing is generally quite forgiving, in some fracture treatments we see severe fracture treatment execution problems. Some failures occur due to poor execution practices like poor fluid control, but in many of these cases failures can be linked to complex fracture growth, either in the vicinity of the wellbore (“tortuosity”) or in the far-field (“multiple fractures” or “fracture networks”).

Even if fracture treatment execution is successful, there are many cases where production enhancement from fracturing is significantly lower than what was initially assumed. This can be attributed to fracture growth complexities. As shown in **Figure 25**, we define fracture growth complexities with respect to the ideal goal of a fracture of sufficient length and conductivity that fully covers the target and is properly connected to the well. Common complexities like uncontained growth or partial coverage of the reservoir due to strong containment by a shale layer in the reservoir will lead to sub-optimal stimulation. Of secondary importance are complex fracture growth (multiple fractures) or T-shaped fractures, because these occur less often.



As the oil and gas industry moves to ever more challenging environments and technologies such as deeper target zones and high-pressure/high-temperature (HP/HT) environments (below 16,000 ft), the likelihood of treatment execution problems and production enhancement problems greatly increases. As shown **Figure 26**, many basins in the U.S. host deep gas reservoirs (Dyman, *et al.*, 1997). The review of HP/HT completion applications showed that the most exploited areas are South Texas, Oklahoma, Louisiana, the Gulf of Mexico (GOM) and the Rockies.

For instance, near-wellbore conditions may be poor in HP/HT wells due to drilling problems. Also, over-pressured reservoirs typically have a low effective stress, which may hamper efficient fracture propagation. The nature of deep reservoirs can result in very complex hydraulic fracture

3. Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells

growth and production behavior due to the complex stress regimes and the large component of the stress field that is initially supported by the high reservoir pressure.

To model hydraulic fracture growth, typical industry simulation software uses numerous parameters. The most important rock mechanical parameters are the Young's modulus, the minimum horizontal stress (fracture closure stress), the closure stress contrast with bounding strata, the rock permeability and the reservoir pressure. These parameters are believed to govern fracture geometry – fracture width is almost inversely proportional to modulus, fracture height is determined from the level of net pressure in comparison to the closure stress contrast, and leakoff is determined to some extent by permeability and the difference between fracture fluid pressure and reservoir pressure. There are two challenges associated with the use of fracture models. First, there is often a lack of direct modulus, permeability and stress measurements. Second, we lack a complete understanding of the physics that govern hydraulic fracture growth. These challenges are even greater in HP/HT wells.

In this report we will first define the critical rock properties that affect fracture growth. We will discuss how these parameters can be measured and what assumptions we typically make for the parameters. Then, we discuss how these properties change in a HP/HT environment. Next, we will identify the fracture growth characteristics in deep formations, in particular fracture height growth and confinement mechanisms, and the effects of stress regimes and reservoir pressure on fracture complexity. In this section, we will also discuss a few novel approaches to describe a fracture complexity index and tie that back to fracture growth measurements. We complete this discussion with conclusions and recommendations.

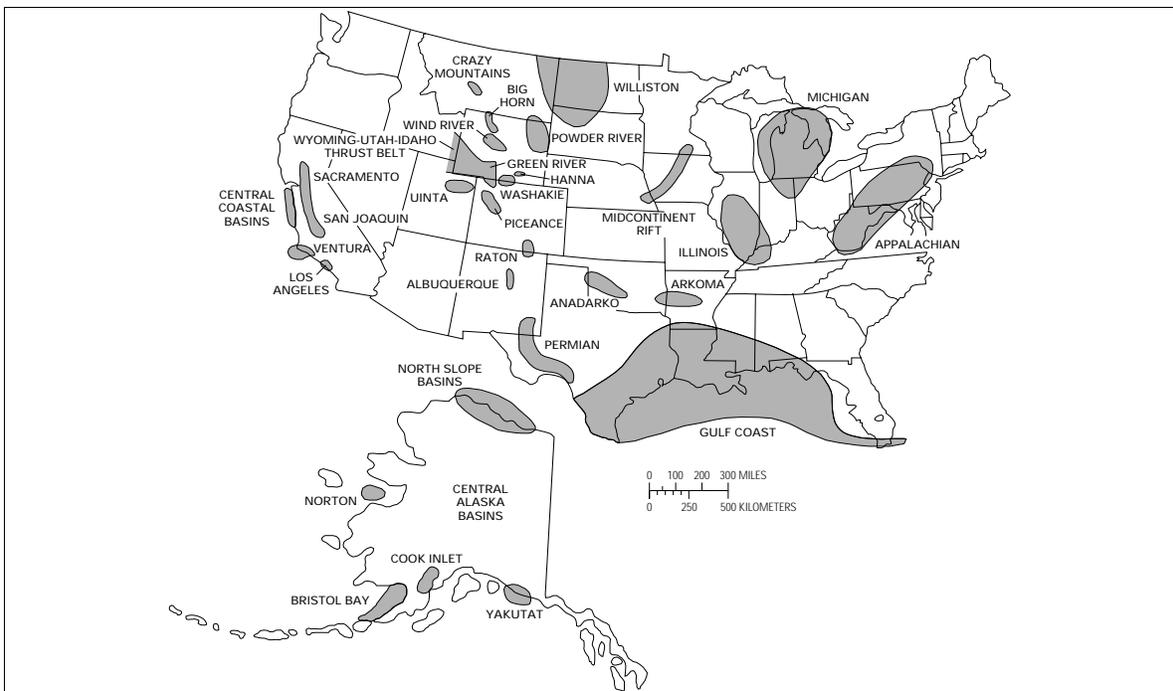


Figure 26. U.S. deep gas basins (Dyman, et al., 1997)

3.1 Rock Mechanical Parameters for Fracture Stimulation

Formation characterization forms the basis of any fracture design – a good review of the subject has been written by Desroches and Bratton (2000). The most important parameters for fracture analysis and design are: stress, Young’s modulus, lithology⁵, reservoir pressure and reservoir fluids, permeability and porosity. Rock strength, friction and fracture toughness are only of secondary importance in hydraulic fracturing.

In the next sections we will briefly describe how each of these parameters impact hydraulic fracture growth, how they can best be measured, how they behave under “normal” conditions, and how we can extrapolate that behavior to HP/HT environments.

3.1.1 *In Situ* Stress

In situ stress is one of the most important parameters in hydraulic fracturing. When we discuss stress, we need to discriminate between a few different aspects:

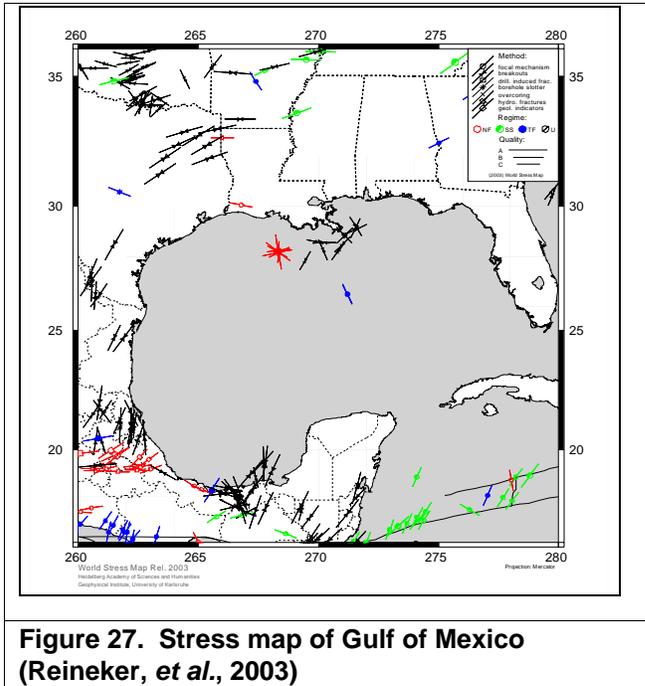
- Fracture closure stress. This is equal to the minimum principle stress in the pay zone. This is the minimum pressure required to open a hydraulic fracture.
- Fracture closure stress profile. This represents the fracture closure stress in the layers above and below the pay zone. The contrast in closure stress between the stress in the pay zone and the neighboring zone is a major driver for fracture confinement.
- 3-D state of stress and horizontal stress contrast. Although the fracture typically grows perpendicular to the least stress component (or fracture closure stress), the intermediate and maximum stress components are important for the near-wellbore fracture geometry - the connection between the wellbore and the far-field fracture system, especially in deviated and horizontal wells.

Prior to an increasing amount of hydraulic fracture treatments, pump-in/shut-ins are performed to measure fracture closure stress in the pay zone of interest. This provides an anchor point for net pressure history matching. If the closure stress in the pay zone is not measured, the level of net pressure during the fracture treatment will be unknown and any modeling effort will be futile.

The closure stress in the zones above and below the pay zone is typically not measured directly. It is sometimes measured indirectly through dipole sonic measurements, but these measurements are not always very reliable, and large discrepancies between dipole sonic inferred closure stresses and directly measured closure stresses have been observed. As closure contrast is a main driver for fracture height growth, the lack of this type of data is a serious shortcoming in most fracture modeling efforts. In tectonically relaxed basins, some of the following assumptions are generally made to “guesstimate” the closure stress in neighboring zones:

⁵ When we talk about lithology, we loosely include lamination, sedimentology and discontinuities.

3. Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells



- Closure stress in shales is typically 0.05 to 0.10 psi/ft higher in shales than in (pay) sands due to higher Poisson's ratio in shales.
- This contrast can become larger due to pore pressure depletion. A rule of thumb is that the closure stress in the pay zone changes by about 2/3 of the change in pore pressure.

The 3-D state of stress has a more indirect impact on fracture growth, and it is not accounted for in any industry fracture simulator. The contrast between the minimum principle stress (fracture closure stress), intermediate and maximum principle stress determines how a fracture system

initiates from a perforated interval and reorients from a (deviated) wellbore toward the preferred fracture plane. The 3-D state of stress can be determined from openhole image logs by studying the orientation of natural fractures and wellbore breakouts.

Figure 27 shows an example of regional stress data for the GOM from the World Stress Map.

Nunn (1985) reviewed the state of stress in the Gulf Coast and he showed that the sediment body is in a state of failure due to the bending of the upper crust. This is related to the faulting in the region, as shown in Figure 28. In general, the flexural model and faulting agree with the World Stress Map data. Onshore, there is a regional fracture orientation with fractures oriented along the coastline, following the major fault systems. Offshore, fracture orientation is more variable.

Most rock mechanics work for HP/HT wells has been done in relation with drilling problems. The first issue was defining a safe pressure window dictated by well control and fracturing. The fracture gradient has mostly been obtained from leakoff tests (LOT). Several studies (Breckels, 1982; Edwards, 1998)

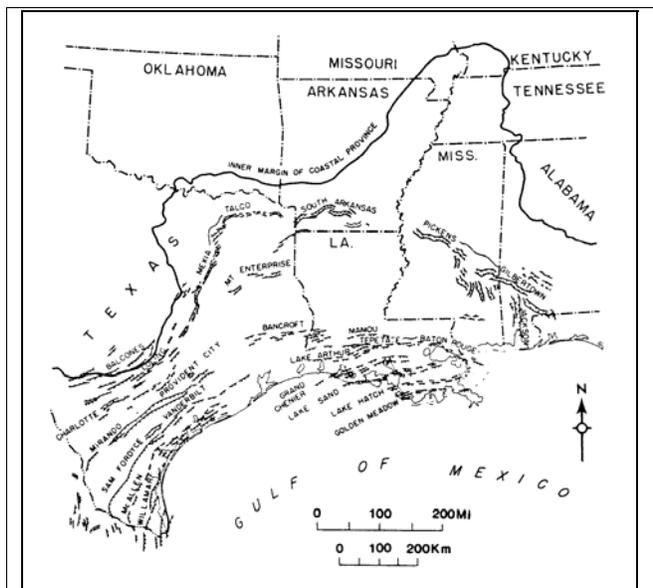


Figure 28. Principal fault systems in Gulf Coast region (Nunn, 1985); The general trend in the coastal province would be extensional onshore and compressional offshore owing to bending of the sediment body

3. Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells

indicated that the LOT data is similar to traditional hydraulic fracturing data. The trend of fracture pressure with depth has been determined for GOM and North Sea wells and has been extrapolated to other environments. The approach has been to define the trend for normally pressured reservoirs and then develop a correction for over-pressured formations.

Data on stress versus depth are available for the GOM (Breckels, 1982) and the North Sea (Edwards, 1998); the conclusions are quite similar on the trends of stress versus depth. This is surprising, because these basins have quite a different tectonic setting. The North Sea is an ancient rift system (Rhine graben) and extensional in nature. The GOM is a dormant ocean basin, with rapid sediment loading. It appears that the stresses are similar because of lithological similarity and it may be a coincidence that these basins are predominantly in a regime of normal faulting. We use the following relations for the stress versus depth:

$$\begin{aligned} \sigma_{h,min} &= 0.197D^{1.145} && \text{for } D \leq 11,500\text{ft} \\ \sigma_{h,min} &= 1.167D && \text{for } D > 11,500\text{ft} \end{aligned} \quad (1)$$

The effect of over-pressure was found to correlate as:

$$\Delta\sigma_{h,min} = 0.46(p_p - p_{p,normal}) \quad (2)$$

Figure 29 shows the stress data of the GOM versus depth. **Figure 30** shows the effective stress versus depth. In the intermediate depth range up to 11,500 ft, the contrast between vertical (maximum) and horizontal (minimum) stress increases. At greater depth, however, the stress contrast decreases again, and almost disappears, especially in over-pressured reservoirs. An interesting observation is also that the effect of over-pressure on geological time scale is similar to the effect of man-made pore pressure changes due to production or injection. Apparently, the stress change by over-pressure is approximately elastic.

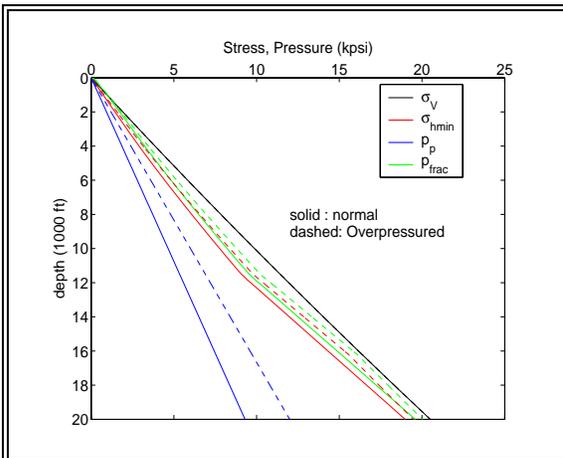


Figure 29. Stress and pore pressure versus depth for GOM data (Breckels, et al., 1982)

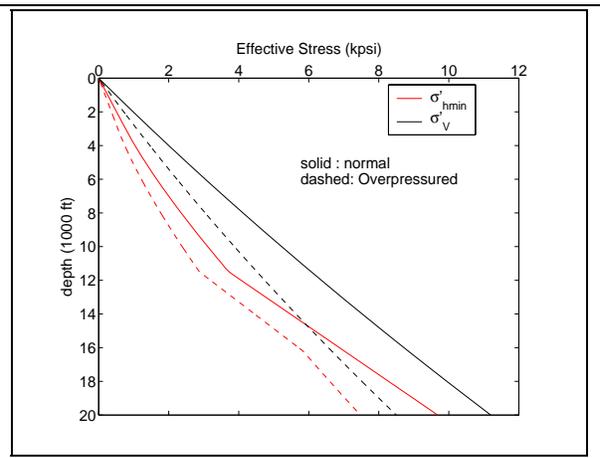


Figure 30. Effective stress versus depth for GOM data (Breckels, 1982)

3.1.2 Young's Modulus

In addition to stress, the Young's modulus is another important parameter for fracture design. The Young's modulus' main impact is on the hydraulic fracture width. For a given net pressure inside the fracture, the fracture width is larger if the modulus of the rock is low, or if the rock is relatively "soft" and easily deformable.

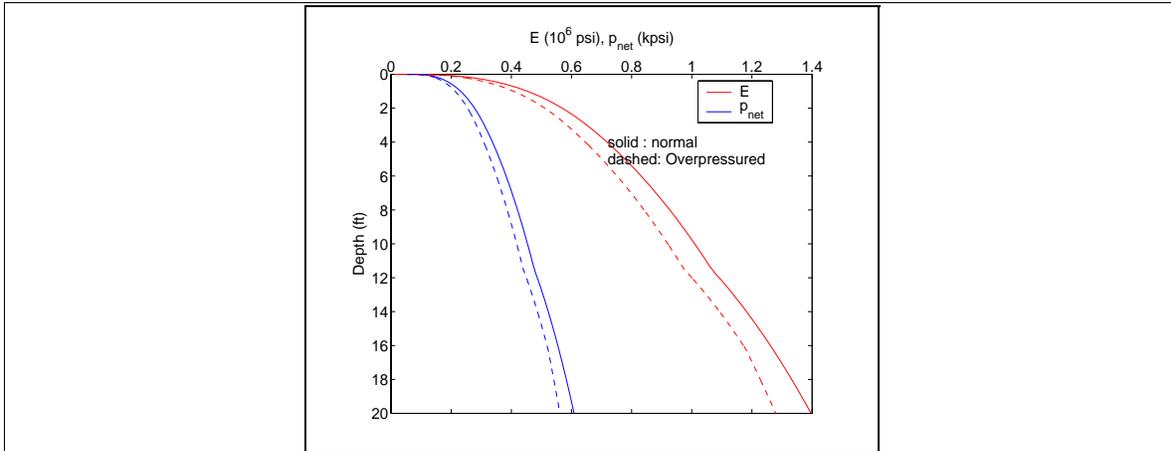


Figure 31. Net pressure and modulus versus depth; the modulus is assumed to depend on the effective stress only

Preferably, a measurement of the modulus is obtained during the unloading cycle in a uniaxial or triaxial compression test on a core sample. A secondary source of modulus data is sonic log interpretation, which provides a "dynamic" modulus. This "dynamic" modulus is typically a factor of two or greater than the "static" Young's modulus that applies to the fracturing process.

Since hydraulic fractures open against the least stress and thus increase the least principle stress, the stress contrast between minimum and maximum principle stress becomes smaller upon fracture opening, therefore, the surrounding rock mass experiences a lower shear stress. For this reason, the relevant modulus for hydraulic fracture modeling should be the "unloading" modulus. The unloading modulus is often close to the dynamic modulus from sonic logs, although the dynamic modulus could be a factor of two (Warpinski, 1998) higher than the static modulus for hard rock and even larger than that for soft rock.

In HP/HT applications we can expect a wide range for the modulus. Some tight gas reservoirs are comprised of very stiff rock with moduli as high as $8 - 10 \times 10^6$ psi, whereas other reservoirs may be nearly unconsolidated (owing to the high reservoir pressure that prevent significant compaction and cementation) and have a much lower modulus, possibly as low as $0.1 - 1.0 \times 10^6$ psi.

The Young's modulus depends weakly on effective confining stress (see **Figure 31**), so we can typically expect a higher modulus at great depth. For the same reason, over-pressured reservoirs typically have a lower modulus, because the effective stress is low.

3.1.3 Permeability

The reservoir permeability is one of the main parameters to affect fluid leakoff from the fracture into the reservoir. Permeability of the zone of interest can best be measured using a pre-frac pressure buildup test. Another recently developed method is to determine permeability from the pre- and/or post-closure pressure decline following a slickwater injection prior to the propped fracture treatment.

Permeability is the most critical parameter when setting up a fracture treatment design. The permeability of the reservoir enters directly in the dimensionless fracture conductivity (F_{CD}). To get the F_{CD} to a certain desirable level and to determine how high the fracture conductivity is required to be, a good estimate of formation permeability is critical.

Formation permeability is a parameter that varies over more than ten orders of magnitude in various applications, from Darcies of permeability in the GOM, and nano- to micro-Darcy permeability in formations like the C-Shale in North Texas.

The permeability generally depends on the level of stress and the reservoir depth. In many deeper applications, the main source of permeability is natural fractures, as opposed to matrix permeability that is more important in shallower reservoirs.

3.1.4 Geological Discontinuities

Outcrops of rock formations can give a good idea what type of geological discontinuities can be found at great depth. **Figure 32** shows the basic types of discontinuities (or “natural fractures”) found in petroleum reservoirs – faults with a shear displacement and joints with mostly opening displacement. The natural fracture systems are often found in outcrops that are representative of reservoir formations. Propagating a hydrofrac through such a naturally fractured rock mass can easily produce a complex fracture geometry when the discontinuities accept fluid or start slipping. Although simplified fracture models have been validated in many cases, there is at least evidence for a complex region at the tip, which is largely controlled by the interaction of the hydro-fracture with geological discontinuities. Although, the main fracture will be shielded from the complex tip region, the overall fracture roughness could be increased by offsets at the tip if the offsets are larger than the fracture width.

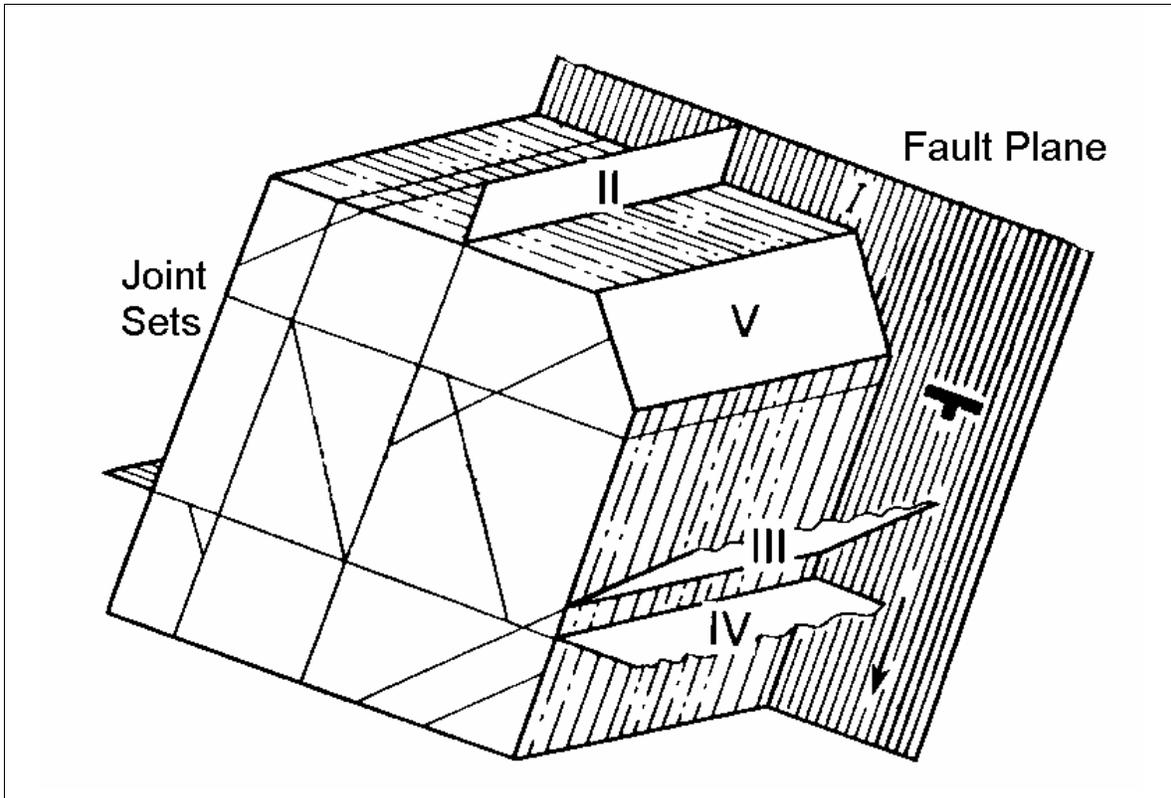
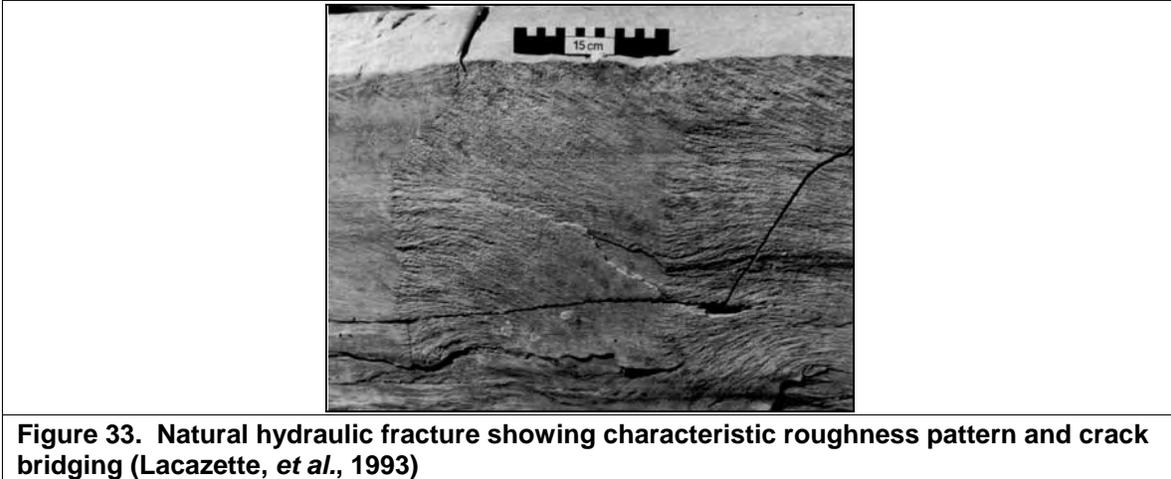


Figure 32. Fault plane and joint sets; I: fault, II-V: vertical, horizontal and oblique joint sets (taken from Chernyshev, 1991)

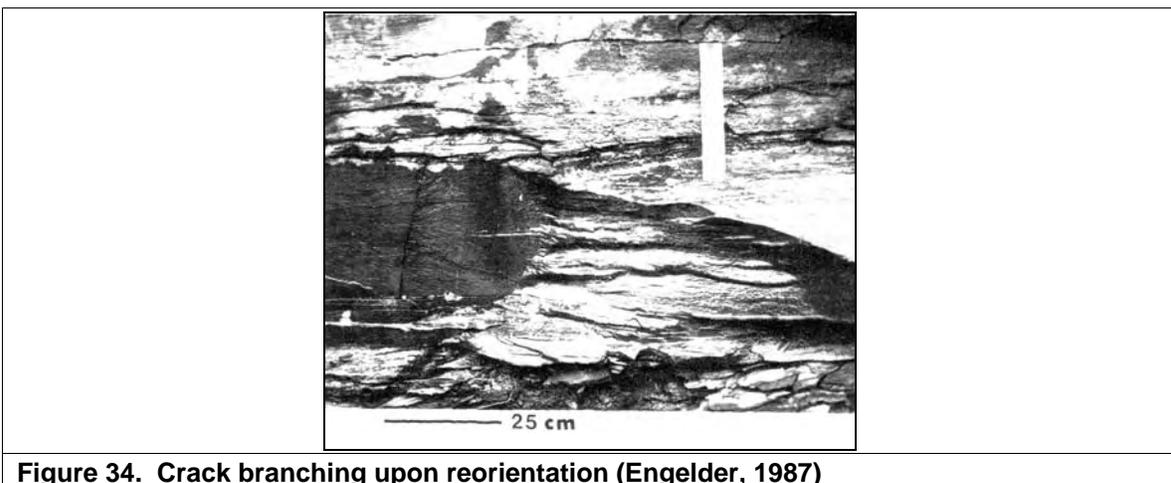
For a long time petroleum engineers believed that discontinuities may be important in shallow rock masses, but that they become insignificant at great depth. Also, it was thought that shallow rock formations show much more jointing because the joints would form by thermal-elastic contraction during uplift. Fractured reservoirs have been known for a long time but they were regarded as a separate class (and rarely needed stimulation). It was believed that joints and fissures are the only conductive discontinuities at depth and that in tight reservoirs at great depth natural fractures could determine the production mechanism, but they would not play a significant role in hydrofrac propagation. The reasoning was that rupture of the rock at the tip could be quite complex and open micro-fractures, but that the opening of the fracture would be shielded from the complex tip region. Even though a common picture of a natural fracture in rock is a branched and rough discontinuity, hydrofrac models assume a planar and smooth fracture in a uniform elastic medium. All industry fracture models currently assume that the fracture is perfectly coupled over the fracture height, through layer interfaces. For engineering work such a simplified picture is often necessary and sufficient, but important aspects of the fracturing process are neglected by doing so.

In recent decades this simplified approach has been modified by insights in geology, fracture mechanics and direct observations of hydraulic fracture growth. Geologists concluded that different mechanisms cause fracturing and that deep formations contain natural fractures caused by tectonic processes and high pore pressure. Interaction of hydrofracs with discontinuities has been directly observed in mine-backs and core-throughs, and is very likely the cause of complex growth with multiple fractures (Warpinski, *et al.*, 1982, 1987, 1993).

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In sedimentary basins, it is often found that significant over-pressure occurs at great depth. The cause of over-pressure can be the relatively low weight of the hydrocarbon column, lack of fluid escape during compaction and the continuous upward flow of fluid from deep, compacting sediments. The low effective stress in over-pressured formations is a key parameter for the importance of discontinuities. Geologically, tensile fracturing can also be explained by over-pressure. Geologists designate these fractures as hydraulic fractures because they are driven by high pore pressure. Although some claim that these fractures really propagate due to a source of high water pressure, it is more likely that these fractures form under the influence of compressive stress when the other stress components are relieved by the pore pressure. Under these conditions, the rock formation fractures in a cleavage mode, meaning that all stress components are still compressive but that the maximum stress is much higher than the minimum stress, leading to failure in extension. **Figure 33** shows an example of such a fracture, with typical surface roughness and crack plane offsets. In over-pressured reservoirs, the hydraulic fracture propagates in a medium that is close to natural fracturing and we can expect interaction of hydraulic fractures at discontinuities, leading to fracture roughness and offsets.



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It is probable that discontinuities become important in the hydraulic fracturing process once they accept fluid. It has been shown that in some hard rock formations, the most conductive faults are critically stressed in view of their orientation with respect to the principal stresses (Barton, *et al.*, 1995). For a normal faulting regime, this would imply that the dominant interaction with the hydraulic fracture should come from inclined faults. In petroleum reservoirs, this observation may be modified in two ways. First, in soft rocks the critically stressed faults might be less conductive because sliding of soft rock surfaces may form gouges that prevents fluid flow through faults. The opposite can also happen, and there are cases where active faults have enhanced reservoir transmissibility. Second, we often observe that a normal faulting system is accompanied by joint sets. Ideally, one expects that the joint plane coincides with the maximum principle stress; however, stress rotations are common over geological time and the current stress may easily deviate from the orientation of the joint set. If the joint planes deviate from the preferred fracture plane, the interaction could still be quite strong and yield fracture offsets that increase friction and obstruct proppant transport. To assess this we would need accurate stress measurements and information about the orientation of the joints.



Figure 35. Fracture front splitting observed in a laboratory model test on hydrostone, with a large stress difference between the in-plane and out-of-plane stresses (Van Dam, 1999)

Lithology changes and local stress rotations (related to lithology or faults) can yield complex fracturing. In this respect, we can learn from geologists who studied fracture morphology in detail. **Figure 34** is a picture of a natural fracture that propagated in a single plane and then branched into several planes. Hydraulic fractures may behave in a similar fashion in the presence of stress heterogeneity, *e.g.*, near a fault or near a lithology change. Although tensile fractures in uniform media tend to propagate with a razor sharp plane, it is well known that shear fractures tend to be complex because they interact with their own stress field, which tends to rotate the fracture edge (Scholz, 2002). This leads to quite complex shear fracture geometries. Similarly, if tensile fractures reorient there exists a significant shear component, and the resulting fracture plane becomes more complex with fracture offsets. **Figure 35** shows splitting of the fracture in a lab test under high stress difference, where the fracture tended to twist from the preferred fracture plane (Van Dam, 1999). Finally, it is possible that a hydrofrac interacts with bedding planes if the fracture pressure is sufficiently high. **Figure 36** is an example of fracture interaction with bedding planes, seen in a mineback test (Warpinski, 1982).

We conclude that even at great depth discontinuities (or natural fractures) are common and that the effective stress is the decisive factor in the influence of discontinuities on hydraulic fracture propagation.

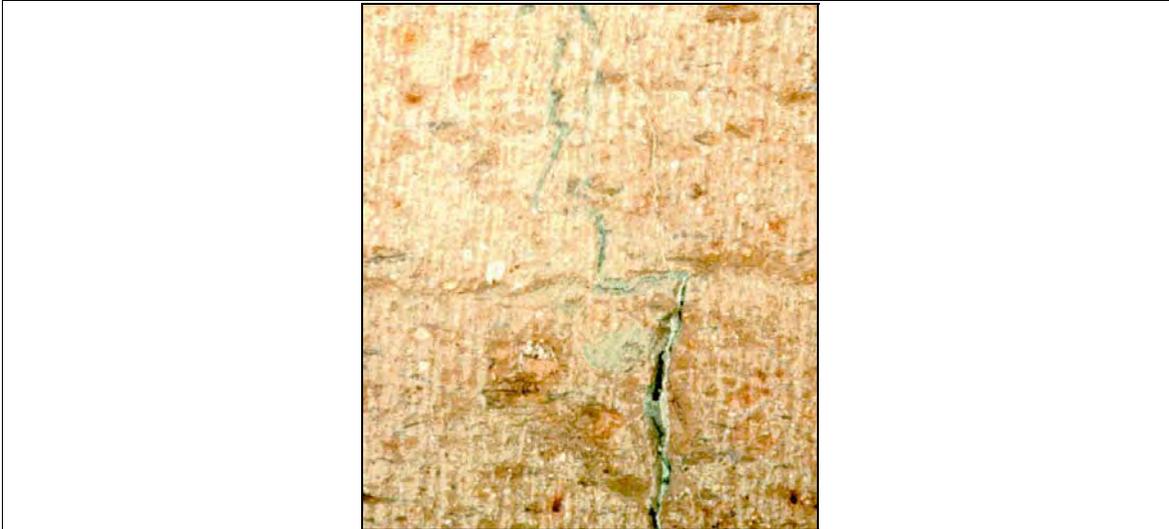


Figure 36. Hydraulic fracture trace seen in mineback; the fracture offsets at a joint (Warpinski, 1982)

3.2 Hydraulic Fracture Growth and Geometry

3.2.1 Fracture Height Growth

It has been established that stress controls fracture height in most cases, but there is evidence that fractures may be more contained than predicted by current industry models. It is uncertain whether this is just due to deficiencies in the models (*e.g.*, the equilibrium height modeling) or that lithological contrasts play a bigger role than assumed.

The available stress data indicates that the difference between vertical and horizontal stress increases until a depth of some 12,000 ft and then decreases. This seems to imply that the same behavior can be expected for the vertical stress contrast between sands and shales if the stress becomes more isotropic. Higher temperature at depth causes a more isotropic stress due to creep of the rock (Nolte, 2000c). Moreover, over-pressured formations will have a higher horizontal stress. Assuming that the minimum horizontal stress is less than the vertical stress, the upper bound to the vertical stress difference will decrease and finally vanish. This would result in less fracture containment at great depth. The only effect that would yield more containment is opening of layer interfaces at low effective stress and high fracture pressure.

Another effect that may play a role is poro-elasticity. Even in gas reservoirs poro-elastic stress may be important because of the low compressibility of the fluid at high pressure (Nolte, 2000e). Poro-elastic backstress will appear as a high net pressure since the closure stress increases during fracture propagation and then decreases again during pressure decline. Another effect of the

increase in closure stress is that the reservoir stress will approach the stress of the bounding strata. Containment may then be lost if the original stress contrast was small.

3.2.2 Fracture Networks/Complex Fracture Growth

Direct observations of hydraulic fractures in mine-backs and intersection wells also revealed a complex fracture system with multiple fractures and branched system in many cases. The seminal work in this area has been done by Warpinski, Branagan and co-workers (Warpinski, 1991) in the MWX and M-Site field experiments. **Figure 37** shows the typical fracture system found in cores taken through a hydraulic fracture. Although it was a surprise to find such a complex fracture, one should keep in mind that the final fracture geometry was fairly well contained in the formation and that a relatively long fracture (compared to its height) was propagated that is needed in tight gas stimulation. The most detrimental effect was the conductivity damage of 70%, but this would only have a marginal effect on the well performance (which was never tested because the reservoir was uneconomic). For the present discussion it is of interest to note that the MWX experiment was conducted in some over-pressured reservoir layers.

Hydraulic fracture propagation in uniform media produces a simple geometry because of the weakness of rocks in tension and the role of fluid friction in the driving force. Since rocks fail so easily in tension (while they are much stronger in shear), the fracture always tries to propagate along a straight plane and in view of the fluid friction and elastic interaction of possible fracture branches the stable mode will be a single fracture. This picture has to be modified in heterogeneous media, because the fracture will necessarily reorient by stress changes and lithology changes. Moreover, at discontinuities the hydrofrac has a choice of cutting straight through it or opening the discontinuity and following it for some time and then branching off, possibly with several branches. Apart from that, in the near-wellbore region there will always be stress gradients, rock damage and a complex geometry that promote a fracture network.

We distinguish two kinds of fracture networks: near-wellbore and far-field. It is common (though not general) experience that fractures from perforated completions yield a large friction pressure drop near the well (*i.e.*, the pressure drop vanishes rapidly upon flow rate decrease), which can only be understood when the fracture is branched. The most probable picture is that each fracture branch is connected only to a few perforations. This problem is worst when the horizontal stress difference is large (for vertical wells and vertical fractures). It is exacerbated by well deviation. Natural fractures appear also to make this tortuosity problem worse. Some argue that far-field multiple branches are just a result of multiple fractures initiating at the well, but it appears that these two problems are not completely related. Possible mechanisms for splitting of fractures may be the influence of discontinuities, but even homogeneous rock may yield splitting, as shown in lab studies, when the shear stress is large. In deep formations we can expect more tortuosity problems, because drilling and cementing will likely do more damage to the well.

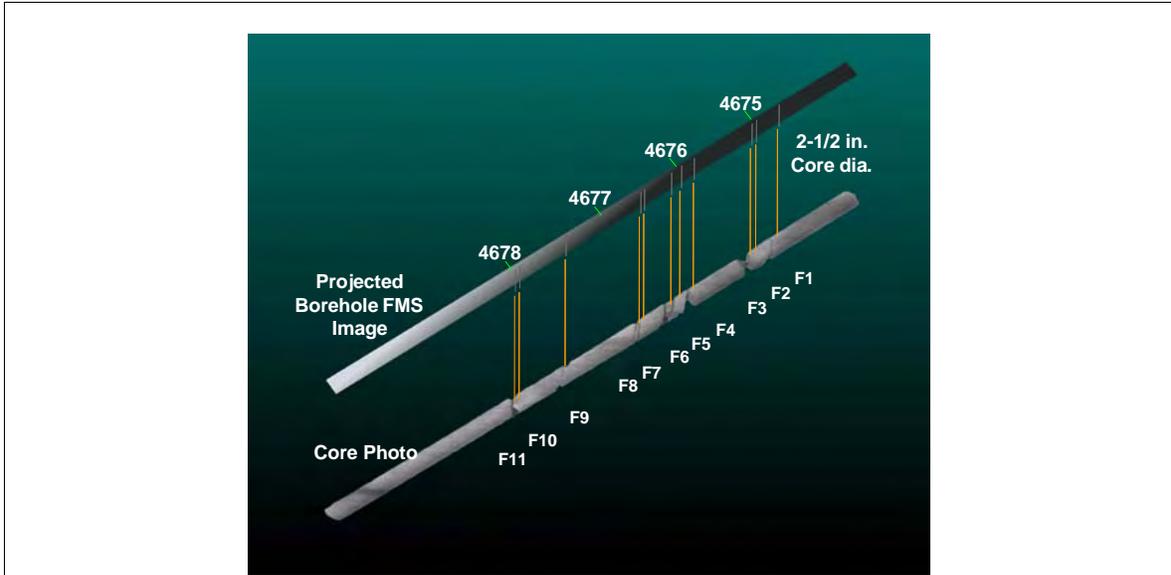


Figure 37. Multiple fractures found in core, fracture F2 ended in the core, indicating that the branches were not very long (Branagan, et al., 1998)

Intuitively, one would assume that multiple fracture problems are worst in isotropic stress, since the fracture can then grow in any direction; however, there is evidence that the reverse effect happens – fracture complexity is worst in tectonically stressed formations. A case of fracture treatments in a deep reservoir in Oman (over-pressured and embedded in salt) showed hardly any problems with the treatments (both with respect to tortuosity or multiple fractures) while the minimum stress was equal to the overburden and the bottomhole pressure exceeded even the overburden stress. In our experience, many problem areas are tectonically stressed: Japan, Colombia, Oman mountain area, some German onshore, Italy onshore, Rockies, East Texas, and Northern China.

It is uncertain whether the fracture complexity seen in strike-slip or overthrust areas is purely caused by near-wellbore phenomena or that far-field multiple fractures are the main cause. With regard to near-wellbore complexity, the effect of tectonics may be easily explained since fracture link-up is unlikely with a large stress difference, so that every perforation may generate a fracture. It is, however, unlikely that far-field fracture complexity (multiple fractures) is caused by generation of multiples at the well. It appears that a large stress contrast induces more multiples. Evidence for this effect comes from laboratory tests (van Dam, 1999) that showed that a hydraulic fracture might split under a large differential stress, see **Figure 9**. An effect that may play a role in formations with high tectonic stress is the heterogeneity of the stress field. Geologic observations of fractures often show splitting of the fractures which may be caused by reorientation due to lithologic and stress heterogeneity, as shown in **Figure 8**.

3.2.3 Modeling Fracture Networks

In view of field observations of hydraulic fractures that looked more like a network than a single fracture (Mahrer, 1996), several authors have modified the fracture propagation models for the effect of multiple fractures. The first attempt (Nolte, 1987) simply proposed to replace the

3. Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells

modulus by an effective stiffness of NE (where N is the number of effective multiples) and reduce the flow rate by the number of multiples. Nolte neglected the change in fluid friction due to a change in the fracture geometry with respect to smooth parallel plates, so the ratio of viscosity over channel flow coefficient was taken constant. With some generalization, this model was implemented in several industry simulators and the most important result is that it leads to high net pressure and short fractures.

A shortcoming of the current modeling of multiple fractures is that any fracture simulations of multiple fracture growth, and also physical model tests on laboratory samples, show that in a short while a single dominant fracture survives. Field observation of two fracture strands separated by a few inches do not make sense if we assume that the fracture minimizes the free energy – the plate of a few inches between the fracture strands should be sufficiently flexible to move sideways and thereby reduce the frictional dissipation in the fluid by an order of magnitude. If we observe that this does not happen in the field, it implies that over the time of a fracture treatment the system is far from equilibrium. In geologic formations, the interaction of the hydraulic fracture with bedding and discontinuities might indeed lead to a fracture geometry that is far from the most favorable configuration with a single dominant fracture plane. In some cases, a single dominant fracture will be unlikely, because there is no full elastic interaction in a fracture network, due to ligaments and bridging across the fracture faces. The limitation of the current fracture simulators is that they are all based on minimizing the free energy (for instance, for solving the elasticity problem), while they then add the effect of a fracture network. For instance, the level of interaction of fracture strands is now an adjustable parameter as well as the global fluid leakoff and the fluid friction. Probably these parameters are somehow linked, but it is impossible to predict the relation at present.

Fluid viscosity influences the interaction of hydraulic fractures with discontinuities, because low viscosity fluid will penetrate a discontinuity easier than a viscous fluid. In this respect it is interesting to look at the experience with so-called waterfracs in tight gas. Many people have scratched their heads over the tendency of fracture pressure in tight gas formations to rise significantly during the job. Even with a fixed height this was difficult to explain; however, this happens only with gel fracs and high proppant loading. Experience with water and low proppant concentration showed a low net pressure and much longer effective fracture length. Microseismic mapping of such treatments, as shown in **Figure 38**, reveals a fracture network at the end of the treatment. Moreover, the fracture network becomes progressively more complex at the end of the job. Still, the net pressure of some 300 psi was flat and the fracture very well contained. If the stiffness of the network would have increased significantly, the net pressure would have risen. We can conclude that fluid rheology has an important influence on fracture behavior, but the relation between net pressure and fracture complexity remains unclear. Very often we find that the effect of fluid viscosity on fracture pressure is even lower than predicted by elastic fracture models. If different fluids produce a different level of fracture network, this may have a mitigating effect on the rheology dependence of the fracture pressure.

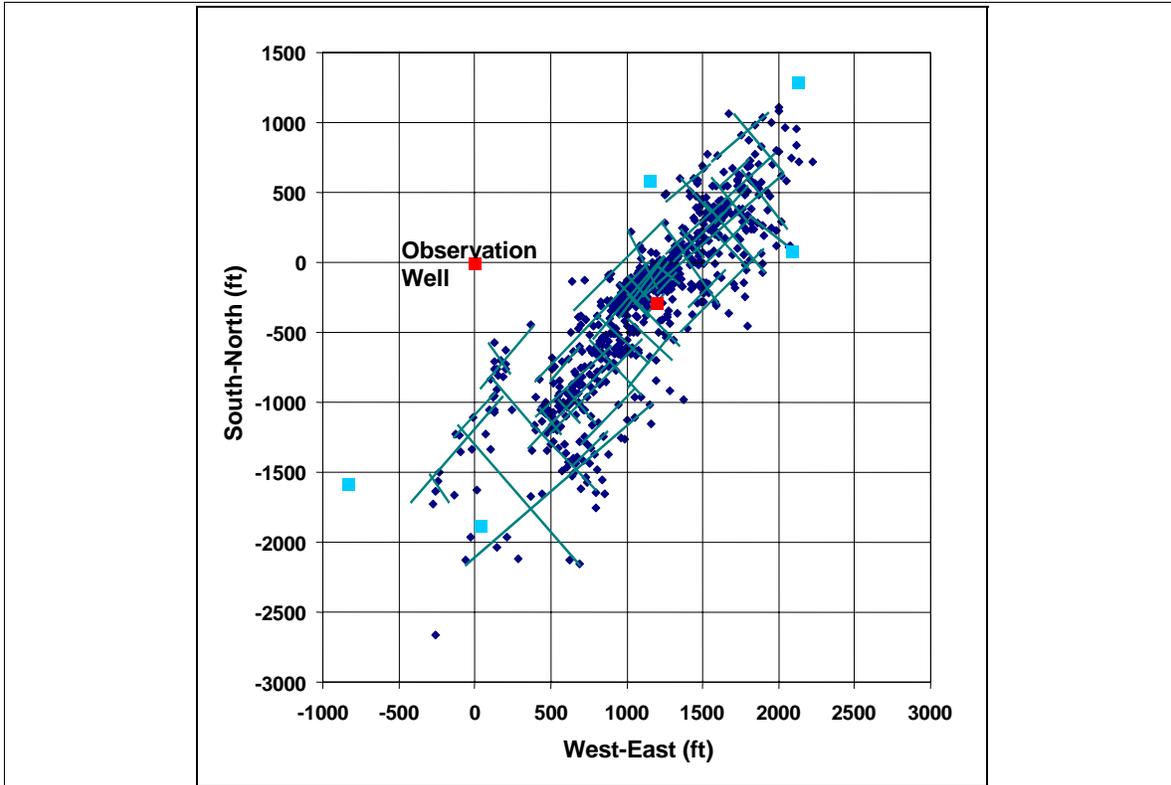


Figure 38. Plan view of microseismic events of waterfrac treatment in tight gas formation with extreme multiple fracture network. The width of the event cloud is much larger than the location uncertainty, so the width of the cloud could not be explained by a single fracture plane. During this treatment the net pressure was flat and relatively low with direct observations of near-perfect containment.

3.2.4 Indices of Fracture Complexity

In some cases, natural fractures are invoked to explain fracture treatment failures; however, that is hardly ever confirmed by independent data. What we need is a way to predict when problems are to be expected. This would be especially relevant in deep or over-pressured formations. Let's now try to link the stress and discontinuity behavior by quantifying the conditions for which discontinuities and fracture complexity become important. We define a complexity index that indicates when we can expect problems, in a simplest form this depends on stress difference and average stress:

$$R_{c,dev} = \frac{\sigma_V - \sigma_{h,min}}{\sigma_V + \sigma_{h,min} - 2p_p} \quad (3)$$

When the fracture pressure exceeds the intermediate stress, we can expect that the fluid enters off-plane joints and yield some complexity. When the fracture pressure exceeds the greatest stress, then any and all complexities could occur. Nolte (1993) defined a complexity index based on net pressure and effective vertical stress, postulating that complexity increases when this ratio is large:

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$$R_{c,hf} = \frac{P_{net}}{\sigma_V - P_{pore}}, \quad \sigma_V - P_{pore} \geq \sigma_V - \sigma_{h,min} \quad (4)$$

The virtue of this indicator is that we can use it after drilling and logging of the well, when we have an estimate of net pressure for the frac design. Note that we assume that the effective vertical stress is always larger than the difference between vertical and minimum horizontal stress; thereby the effective vertical stress provides a boundary to the net pressure level above which complex fracturing is possible. Complexity is in this view due to the opening of horizontal fractures by delamination of the layer interfaces.

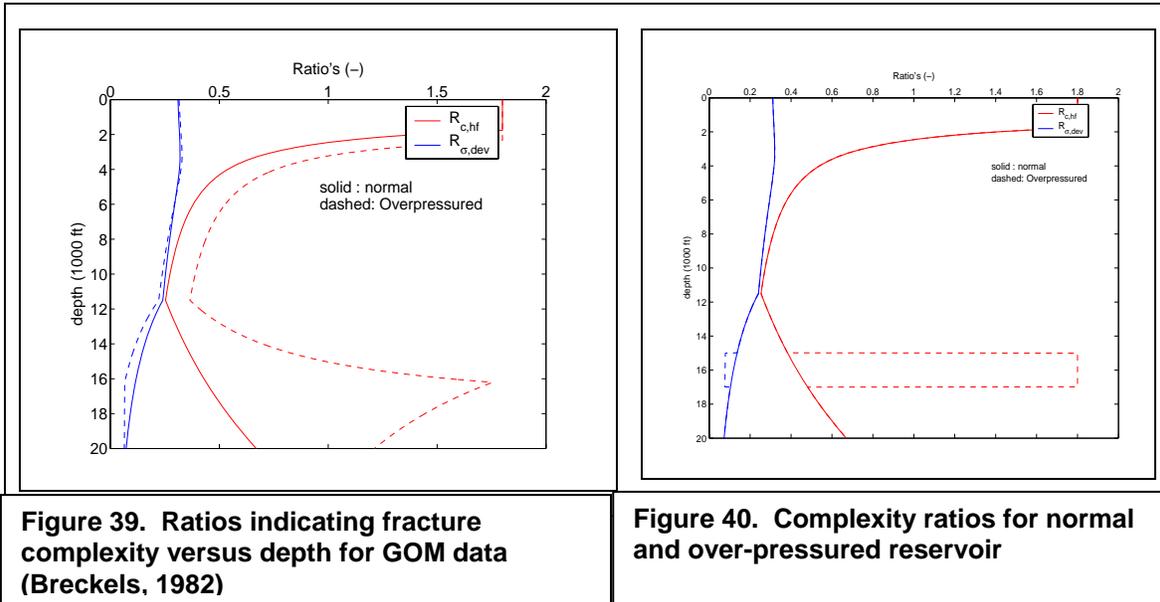


Figure 39. Ratios indicating fracture complexity versus depth for GOM data (Breckels, 1982)

Figure 40. Complexity ratios for normal and over-pressured reservoir

Figure 39 and **Figure 40** show fracture complexity ratios. If we look at the effect of depth we see that the stress deviator ratio decreases with depth. The horizontal frac indicator increases since the horizontal stress tends towards the vertical stress. The effect of over-pressure is to decrease the stress deviator ratio. There is an increase in the horizontal fracture ratio, since the effect of pore pressure is to bring the vertical and minimum stress closer together.

The trends of the complexity indicators agree with the finding that fracture complexity is high for shallow formations and decreases for deep formations; however, the tendency for horizontal fractures appears to show an increase at great depth.

3.2.5 Net Pressure Index

The net pressure for radial fractures can be computed straightforwardly for a conventional approach, on the basis of elasticity and fluid friction (Cleary, *et al.*, 1980). Such an estimate can serve as the basis for evaluating measured net pressure. Alternatively, we can estimate the fracture radius from the observed fluid efficiency and the observed net pressure. We will show

some examples of such a comparison, assuming either penny-shaped fractures or long fracture with fixed height – PKN geometry.

Based on elasticity and Newtonian fluid friction for PKN, the mass balance and elastic opening relation yield a relation for the fracture length and pressure:

$$L = 0.34 \left(\frac{E}{\mu q (1 - \nu^2)} \right)^{\frac{1}{5}} \left(\frac{\eta V_i}{h} \right)^{\frac{4}{5}}, \quad (5a)$$

$$p_{net} = \frac{wE}{2(1 - \nu^2)h} = 1.5 \left(\frac{q\mu E^3 L}{h^4 (1 - \nu^2)^3} \right)^{1/4} \quad (5b)$$

For radial fractures we obtain analogous relations for radius and pressure:

$$R^9 = \frac{E}{\mu q (1 - \nu^2)} (\eta V_i)^4, \quad (6a)$$

$$p_{net} = \frac{\pi w E}{8(1 - \nu^2)R} = 0.31 \left(\frac{q\mu E^3}{(1 - \nu^2)^3 R^3} \right)^{1/4} \quad (6b)$$

These expressions can be used to define a “net pressure index” that tells us how much the observed net pressure deviates from an elastic model prediction. Of course, a deviation could be due to underestimating the closure pressure, the modulus, fluid friction, poro-elastic backstress or assuming the wrong geometry. Alternatively, a high index could indicate deviation from elastic, single fracture behavior. Closure pressure is sometimes especially difficult to obtain from routine field data. Pressure decline often shows multiple slope changes and one can easily mistake the transition from linear to radial flow for the fracture closure. Additional methods like step-rate tests, flow-back tests and pulse tests can be used to obtain bounds for the closure pressure (Nolte, 2000b; Wright, *et al.*, 1995).

3.3 Field Examples

Table 1 lists a few cases of fracture treatments with a comparison of the expected and observed net pressure. In these cases there was strong evidence for a penny-shaped fracture geometry. The observation that fractures are often more contained than predicted by standard industry models could also imply that in some cases with a radial fracture geometry one invokes multiple fractures or tip effects to model high net pressure while in reality the fracture is contained. In cases where one suspects containment, it should be considered to determine fracture height independently using microseismic or tiltmeter monitoring.

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A clear case of fracture network complexity is the Minami-Nagaoka Field where very high net pressures were observed (Weijers, *et al.*, 2002), which probably indicate opening a fracture network, rather than creating a dominant hydraulic fracture. Here, the net pressure was ten times bigger than expected and it would be hard to explain this away with a wrong closure pick.

The Oman-Athel case was a deep, over-pressured reservoir that showed a fairly low observed net pressure. When the observed net pressure is much higher than the model net pressure (low values of $p_{n,mod}/p_{n,obs}$), the actual fracture length and height could be a factor of 2 or 3 smaller than the model geometry.

Table 2. Several cases of fracture treatments with a comparison of observed and expected net pressure; Fracture growth was near radial in these cases

Case	Depth ft	Input Parameters				Observed			Conventional Model		$P_{n,mod}/P_{n,obs}$ -
		V_{inj} bbl	Q Bpm	μ cp	E 10^6 psi	η -	$P_{n,obs}$ psi	$R_{f,obs}$ ft	$P_{n,mod}$ psi	R_f ft	
HP/HT	19685	600	18	529	3.6	0.34	725	117	68	257	0.09
Athel	14068	720	42	1200	1.5	0.32	232	131	112	167	0.48
Minami-Nagaoka	13780	1920	24	1920	4.4	0.3	3000	109	167	287	0.06

Table 2 lists cases with a contained height and a long fracture (PKN geometry). It is evident that a strong containment can lead to much higher pressure. Actually the Oman deep gas case was initially analyzed with a penny-shaped fracture, but it turned out later that in this case small shale layers could contain the fracture. This explains to a large extent the high net pressure observed in this case.

For some of the PKN geometry cases, the fracture length was measured with independent diagnostics (tiltmeters or microseismic). We see that the observed fracture length was in some cases much larger than the one inferred from the net pressure. This may indicate that the observed net pressure was much overestimated.

The Oman deep gas case showed very high net pressure, which could be related to a high tip resistance or multiple fracture growth. The M-Site data could be reconciled by changing closure, increased fluid friction or multiple fractures.

Table 3. Several cases of fracture treatments with a comparison of observed and expected net pressure; Fracture geometry was close to a perfectly confined PKN-type geometry

Case	Depth ft	Input Parameters				Observed					Conventional Model		$P_{n,mod}/P_{n,obs}$ -
		V_{inj} bbl	q bpm	μ cP	E 10^6 psi	$L_{f,diag}$	$H_{f,diag}$	η	$P_{n,obs}$	$L_{f,obs}$	$L_{f,mod}$	$P_{n,mod}$	
						ft	-	psi	ft	ft	psi		
HP/HT	19685	600	18	529	3.6	-	98	0.34	725	275	314	603	0.83
SR	14764	300	48	132	3.6	-	98	0.4	1088	108	223	500	0.46
M-Site-B	4495	417	22	40	4.5	375	82	0.4	1200	243	520	531	0.44
Bossier-A	13300	8348	78	1	4.4	400	190	0.07	600	307	1166	150	0.25

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Bossier-B	12700	6229	63	1	4.4	683	450	0.27	500	189	1424	63	0.13
Bossier-C	13100	3490	23	15	4.4	295	130	0.25	2300	255	1610	346	0.15

For assessing the relation between net pressure and fracture complexity, the M-Site and MWX field experiments provide the most complete data sets. The fracture network was apparent in cored intersection wells and the fracture geometry was measured with fracture mapping. Even in this case, however, different analysts reached quite different conclusions when interpreting the data of the B-Sand injections. The biggest disagreements were on the closure pressure (and stress) and the fluid efficiency. Warpinski (1996) used the micro-frac measurements, whereas Gulrajani (1998) used a closure stress which was 500 psi higher, supported by the step-rate test, tiltmeter response and the pressure decline. Also, the bounding stresses were assumed to be higher. Perhaps even more important was the disagreement on fluid efficiency of the mini-fracs – this varied between 40% (Gulrajani, 1998), 55% (Warpinski, 1996) and 80% (Wright, 1998). Since the fracture area was measured with microseismic data and the fracture width was obtained from the tilt data, the fracture volume could be estimated and appeared to agree with the lower efficiency. However, the width from tilt was modeled with a net pressure of 1,200 psi, which is in contrast with the lower net pressure estimated by Gulrajani (1998) of some 750 psi. The latter value of the net pressure is much higher than predicted by a conventional model, but it can be matched by a model that correctly describes the effect of the fluid lag. Note that this model gives a tip pressure equivalent to a toughness that is ten times higher than lab measured fracture toughness of rock. If we believe in the higher estimate of the net pressure, the discrepancy would be larger, which could be explained by increased tip effect, increased fluid friction or stiffness owing to the fracture network observed in the intersection core.

Major contributors to fracture complexity are rock discontinuities, natural fractures and faults. A clear example of this is seen in a well completed in the Bossier Sand in East Texas (Sharma, 2004). Microseismic hydraulic fracture mapping was performed on two stages in one well. The mapping results, shown in **Figure 41**, indicated that the hydraulic fracture was fairly well contained near the wellbore; however, a previously unmapped fault encountered not far from the wellbore allowed the frac to move upwards into another zone and actually back toward the wellbore.

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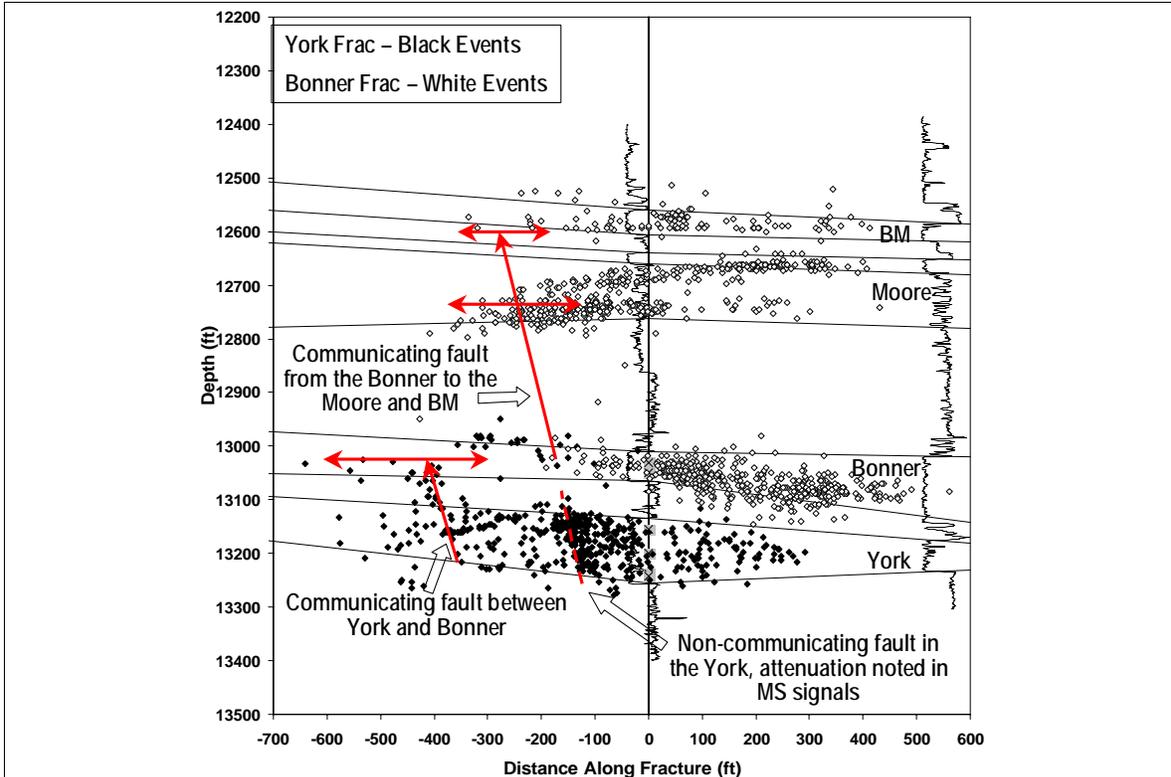


Figure 41. Side view showing microseismic results for the treatment stages 1 and 2 in the APC Anderson No. 2 well

Given the approach that one should find a match between model and observed net pressure, it is still a disturbing fact that in many cases ad-hoc phenomena have to be invoked to make the model match the observed pressure. This erodes the confidence one can put in the simulation models. On the other hand, matching the model to the observed net pressure to obtain the fracture size is equivalent to pressure decline analysis (Nolte, *et al.*, 1979), although pressure analysis does not assume any theoretical fracture propagation model. The only assumption behind pressure analysis is the mass balance (hardly challenged) and elastic fracture opening on a large scale. The latter assumption may be challenged because rock formations are far from isotropic, uniform elastic bodies. We know, however, from thousands of tiltmeter observations that there is a global agreement between fracture volume from pressure decline analysis and earth surface tilt. Also, downhole tilt measurements generally agree with the width obtained from pressure analysis. If there is any discrepancy between these observations, it would point to a larger volume from tilt, rather than the other way around which one would expect from inelastic behavior.

3.4 Discussion and Conclusions

Although there is some consensus that discontinuities are common, that they are important at low effective stress and that deep rock formations are in a state of incipient failure, there is much less consensus on the implications for fracture applications. Let us start with the commonly accepted conclusions and then discuss the more controversial issues.

3. Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells

- Increased leakoff due to fissure opening at high treating pressure is commonly observed and hardly contested in the industry. The mechanism has been analyzed by Nolte and Smith (1979). For HP/HT completions this is not much of a problem initially, since the reservoir pressure is high, reducing leakoff; however, the fracture pressure may easily exceed the stress threshold for fissure opening.
- Problems with well-to-frac communication can be caused by natural fractures, especially in strike-slip or overthrust stress regimes. In HP/HT completions these problems may be less severe, since the stress will be more isotropic.
- Complex fractures can obstruct proppant transport. Reduced leakoff can aid in these cases; fluid quality control is then very important.
- Delamination of bedding interfaces could arrest height growth of fractures. There is evidence for more containment than predicted by standard industry simulators, which could be explained by such a mechanism (Warpinski, *et al.*, 1996; Miskimmins, *et al.*, 2003). Alternative explanations exist because modulus contrasts could yield more containment than currently accounted for in equilibrium height models and large pressure drops in fractures could also explain less tendency to grow into stress barriers.
- Discontinuities can lead to splitting of hydrofracs and it has been proposed that this can raise the net pressure because the fracture branches interact elastically. On this topic the industry has not reached any consensus. Some claim that the observations in the M-Site experiment, which triggered the attention for multiple fractures, can be easily explained with an elastic fracture model (Gulrajani, 1998), while others see significant deviations from the elastic fracture models (Warpinski, *et al.*, 1996).

Discontinuities can modify the deformation behavior of rock masses. One of the main assumptions of fracture models is elastic opening of the fracture (*i.e.*, a linear relation between pressure and width for given size). If sliding along discontinuities (or opening) plays a role we can expect non-linearity and hysteresis (plasticity) in the opening relation. We know that global elasticity is confirmed by tiltmeter observations of fractures. Otherwise the observation of surface tilt would not agree with the volume of fractures from mass conservation and downhole tilt would not agree on the fracture width with pressure analysis. The proposed deviation from elastic behavior (Barree, 1998) may be appealing to explain some fracture pressure behavior, but it is not generally accepted.

Treatment execution problems in propped fracture treatments can generally be separated into two main groups:

- **Fracture initiation – tortuosity:** Initiating fractures from a perforated completion is likely to result in a complex fracture close to the wellbore. Ideally, the fractures propagate from the perforation tunnels and then zip up to a single fracture within a few borehole radii away from the wellbore. When the preferred plane deviates from the perforations the fracture initiates directly from the annulus, creating a pinch point between cement and formation. When the preferred plane is misaligned from the wellbore by more than 10°, multiple fractures may start that do not link if the horizontal stress contrast is large. Fractures induced by drilling

3. Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells

and perforating can exacerbate this multiple fracture problem, but natural fractures are also a source of fracture complexity.

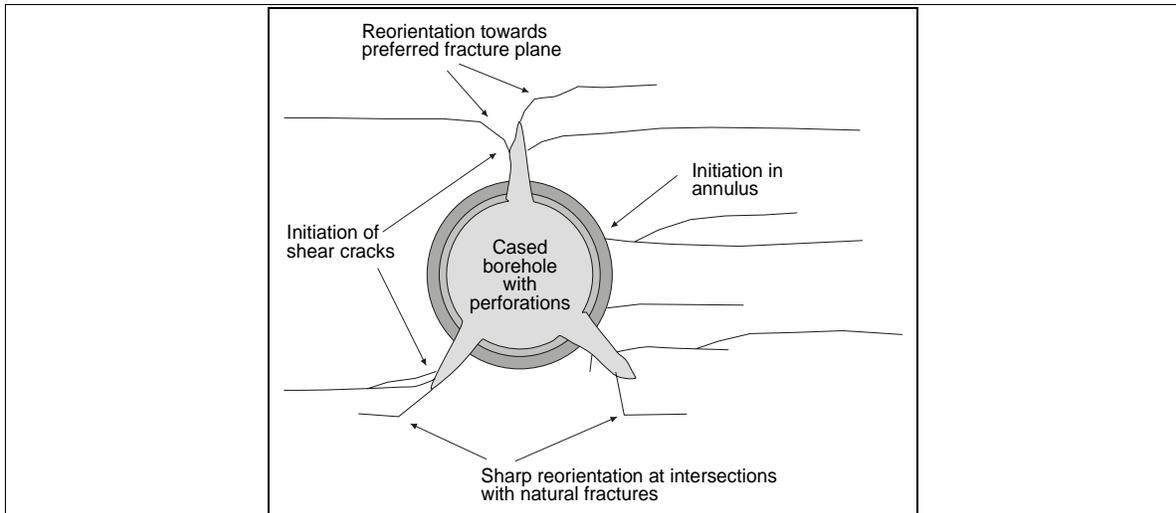


Figure 42. Several initiation sites near a cased, perforated completion

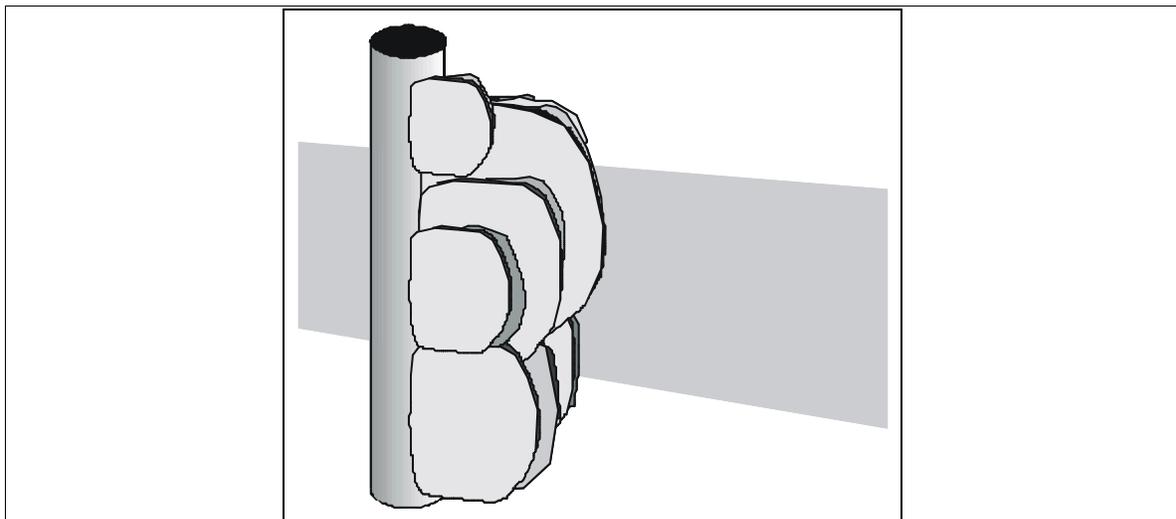


Figure 43. Multiple fracture network that extends far from the well

- **Fracture propagation:** For assessing the probability of fracture complexities, Nolte (1979, 2000a) introduced the concept of “formation pressure capacity” analogous to pressure capacity of pressure vessels. Complexities can be expected when:
 1. Net pressure exceeds stress barriers, with uncontained fracture growth,

3. Discussion of Rock Mechanics in High-Pressure/High-Temperature Wells

2. Fracture pressure exceeds maximum horizontal stress yielding a tortuous path and opening of fissures cutting through the fracture plane or fracture pressure exceeds the vertical stress, giving horizontal fracs, or
3. Net pressure approaches vertical effective stress, leading to fracture network.

Both for near-wellbore and far-field fracture networks, the stress state and rock discontinuities play a dominant role. These two factors are strongly linked, since discontinuities are the natural result of rock deformation, which is governed by the stress regime. Often, petroleum engineers assume that formations are in a state of rest, because many reservoirs are found in thick sedimentary deposits; however, even in a tectonically quiet region like the Gulf Coast, the rapid sedimentation leads to bending of the sedimentary package so that the formations are close to failure, as evidenced by faulting. Therefore, discontinuities are present in most rock formations, but they are only significant if they accept fluid in a hydraulic fracture treatment and interact with the fracture. This depends on the stresses and the fracturing pressure.

Although fracture propagation does not depend on depth, the character of deep reservoirs will change fracture behavior through the dependence of the stresses on depth. Probably, the tendency of the stress to become isotropic is related to temperature, but that is the main influence of temperature on the mechanics of fracture propagation. We have argued that rock discontinuities are common in deep reservoirs and that their influence will depend on the stress. For understanding the specific behavior of fractures in HP/HT reservoirs, we have distinguished two principles:

- Effective stress controls fracture behavior and interaction with discontinuities
- Stress is determined by incipient failure of rock formations

After drilling and logging a well, one should have an estimate of the effective overburden stress, which can be used as a rough indicator of fracture complexity. The full stress tensor would be needed to assess problems with fracture stimulation, since the stress differences govern most fracture complexities. Apart from stress measurements, rock stiffness and lithology control fracture behavior; these parameters can be evaluated from core, sonic logs and borehole image logs.

For optimizing fracture treatments with regard to fracture geometry, we have classified various deviations from an ideal fracture shape. Problems with containment (either lack of containment or poor coverage due to barriers in the target) are the most common, but also complications like T-shaped fractures or fracture networks may prevent efficient fracture propagation and proppant placement. The latter types of complexity are not considered by standard industry fracture simulators, but need to be assessed for design optimization. We have shown that stress and discontinuities control the fracture complexity. The importance of stress regime (*i.e.*, all stress components), discontinuities and heterogeneity explain why fracture modelers have paid little attention to complex fractures apart from height growth. As yet, fracture complexity is not very amenable to simulation or prediction although some progress has been made in developing analysis methods. Much development is still needed to link formation characterization to fracture modeling. At least we can give some guidelines for the prediction of fracture complexity, but

much engineering judgment will be required for applications. A development program would be needed to improve this lack of prediction capability. First, the existing data should be systematically studied for trends of fracture behavior in different stress regimes and the dependence on depth, pressure and temperature.

3.5 Recommendations

Optimization of stimulation designs for HP/HT wells requires first of all comprehensive data collection:

- The 3-D state-of-stress can be obtained from geological information like faulting general trends have been established for the GOM region and in the publication of the World Stress Map; however, local stress in a reservoir may deviate from the regional trend. We know that stress is important but in many cases stress measurements are lacking or incomplete.
- The most reliable closure stress measurements are from diagnostic injections followed by a pressure decline. Image log interpretation can also aid in evaluation of the 3-D state-of-stress.
- Classification of fracture experience in different environments has received little attention to date. It is apparent that stress regime and lithology are important for fracture behavior, but fracturing data has never been systematically analyzed in this context. A global assessment of occurrence of near-wellbore tortuosity, high net pressures or complex fracture geometry would be useful for determining the relation between fracture growth and lithology.
- Fracture containment must be measured with independent diagnostics, like microseismic or tiltmeter mapping, because lithology may control fracture containment rather than pay-barrier closure stress contrast. The development of calibrated models that captures the growth characteristics observed in direct measurements provides an important way to learn more about fracture growth in HP/HT environments and to improve fracture designs for this application.
- For fracturing, the elastic (unloading) modulus obtained from cores is most relevant, but the dynamic modulus can also be used with a correction factor.
- Proper net pressure evaluation can only be made from bottomhole pressure measurements. Furthermore, proper diagnostic injection procedures are required to measure the fracture closure pressure in the pay zone.
- High net pressure with respect to effective stress is an indicator of fracture complexity. High net pressure can be caused by containment, poro-elastic back stress (oil and high-pressure gas) and multiple fracture growth.
- Many problems with HP/HT stimulation can be related to the low effective stress. A possible approach to successfully stimulate a well in this environment could be to first conduct a

minimal stimulation. The well should initially produce with sufficient rate due to the high pore pressure at great depth. After some depletion, the horizontal stress will reduce and it will be easier to perform an effective stimulation treatment. In relatively thin gas reservoirs this will allow longer fractures since containment will improve in depleted layers.

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4. Case History of Hydraulic Fracturing in Jennings Ranch Field, Texas

This study focused on a deep gas productive horizon operated by ConocoPhillips in the Jennings Ranch Field, Zapata County, Texas. The primary targets are the Lobo 6, Lobo 1 and Lobo Stray Sands. This study focused on the deeper Lobo 6 interval at depths of roughly 12,200 to 12,500 ft. The formation is highly over-pressured with pressures of about 10,200 psi (0.81 psi/ft) and fracturing pressures of about 0.93 to 0.96 psi/ft. Porosities are about 16 to 21% with water saturations of 45 to 55%. Net pay can vary from about 20 ft to over 100 ft. All wells are completed with crosslinked gel fracture treatments using ceramic proppants. Multiple target zones are generally commingled, with a typical well producing about 7 to 8 MMCFD initially, and declining fairly fast to 2 MMCFD or less within one year. The wells are located in 80 to 120 acre fault blocks with three to four wells per fault block (20 to 40 acre well spacing). Approximately 60 to 70 wells were drilled over the last five years. The study included a total of six wells drilled and completed from 1999 to 2001.

The main conclusions are that modeled propped fracture lengths are approximately 400 to 660 ft, with fracture heights slightly larger than the perforated interval. Fracture treatments do not show any obvious problems with fracture length generation or proppant placement. Production analysis, although somewhat non-unique, indicates that effective fracture lengths could be as long as the ones calculated with the fracture model.

All wells show fairly rapid production declines, which is normal in highly over-pressured reservoirs with fracture stimulation; however, two wells showed higher production declines, which may indicate an impairment of either reservoir or fracture flow capacity since production could not be modeled with constant reservoir/fracture properties. It is not clear if the impairment was caused due to stress-sensitive reservoir permeability (high drawdowns) or a deteriorating hydraulic fracture (reduced proppant conductivity due to higher effective stress, fines migration into proppant pack, multi-phase flow). Flow tests with bottomhole gauges followed by pressure buildup tests could be used to diagnose if the problem is due to a deteriorating hydraulic fracture.

Production data shows reservoir linear flow for about one to two years indicating effective fracture stimulation. This period is followed by the onset of a depletion stem, which could be limited drainage from offset wells, geology and/or liquid loading conditions. Estimated drainage areas highly depend on assumptions of hydrocarbon pore volume (porosity, net pay, water saturation), but using the numbers provided by the operator, drainage areas were estimated to range from as low as seven acres to about 70 acres.

The biggest opportunity in this drilling program appears to be fracture optimization as a function of actual well spacing. Preliminary generic optimization simulations show the potential for job size reductions as well spacing is reduced. It also indicates that current job sizes may be close to the optimum if well spacing is around 40 acres but for fault blocks with well spacing smaller than 40 acres job sizes could potentially be reduced.

4.1 Conclusions and Recommendations

1. Propped fracture lengths are modeled to be approximately 400 to 660 ft, with fracture heights slightly larger than the perforated interval. Fracture treatments did not encounter any problems, and do not show any obvious problems with fracture length generation or proppant placement. These model geometries have not been confirmed with actual fracture geometry measurements such as microseismic and tiltmeter fracture mapping. Production analysis, although somewhat non-unique, indicates that effective fracture lengths could be as long as the ones calculated with the fracture model.
2. Moderate fracture complexity was observed on most treatments but does not seem to play a major role in proppant placement or severe reduction of fracture length. Estimates of actual fracture conductivities are difficult and limited by both fracture complexity issues and actual effective conductivities under flowing conditions. However, based on initial production and its decline, four out of six wells show no evidence that fracture conductivities have been severely impaired in the first year of production.
3. All wells show fairly rapid production declines, which is normal in highly over-pressured reservoirs with fracture stimulation; however, in two wells (C-10 and C-12) production declines were too high, which may indicate an impairment of either reservoir or fracture flow capacity since production could not be modeled with constant reservoir/fracture properties. It is not clear if the impairment was caused due to stress-sensitive reservoir permeability (high drawdowns) or a deteriorating hydraulic fracture (reduced proppant conductivity due to higher effective stress, fines migration into proppant pack, or multi-phase flow – note these two wells were stimulated with Econoprop). If possible, single-zone flow tests followed by a pressure buildup test could be used to diagnose if the problem is in fact due to a deteriorating hydraulic fracture or is simply a stress-sensitive reservoir permeability issue.
4. Production analysis indicates that all wells have some degree of reservoir linear flow behavior once cleanup effects have subsided and wells are flowed at fairly constant flowing pressures. The linear flow regime lasts about one to two years in most wells, indicating effective fracture stimulation. This period is followed by the onset of a depletion stem, which could be limited drainage from offset wells, geology and/or liquid loading conditions. Estimated drainage areas highly depend on assumptions of hydrocarbon pore volume (porosity, net pay, water saturation) but, using the numbers provided by the operator, were estimated to range from as low as 7 to 70 acres with flow capacity (kh) ranging from about 0.1 to 4 md-ft.
5. Fracture optimization depends heavily on well spacing and reservoir properties such as permeability. Generic fracture optimization simulations show that the 80-acre spacing optimum frac size is about 420 klb, for 40 acre spacing the optimum size decreases to about 240 klb (which is close to current designs - **Figure 44**), and for continued infill drilling to 20 acre spacing, optimum size would decrease to about

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

130 klb (**Figure 45**). These simulations were performed for a representative set of reservoir properties and economic assumptions that may require some fine-tuning but were done to demonstrate the importance of fracture optimization for infill drilling.

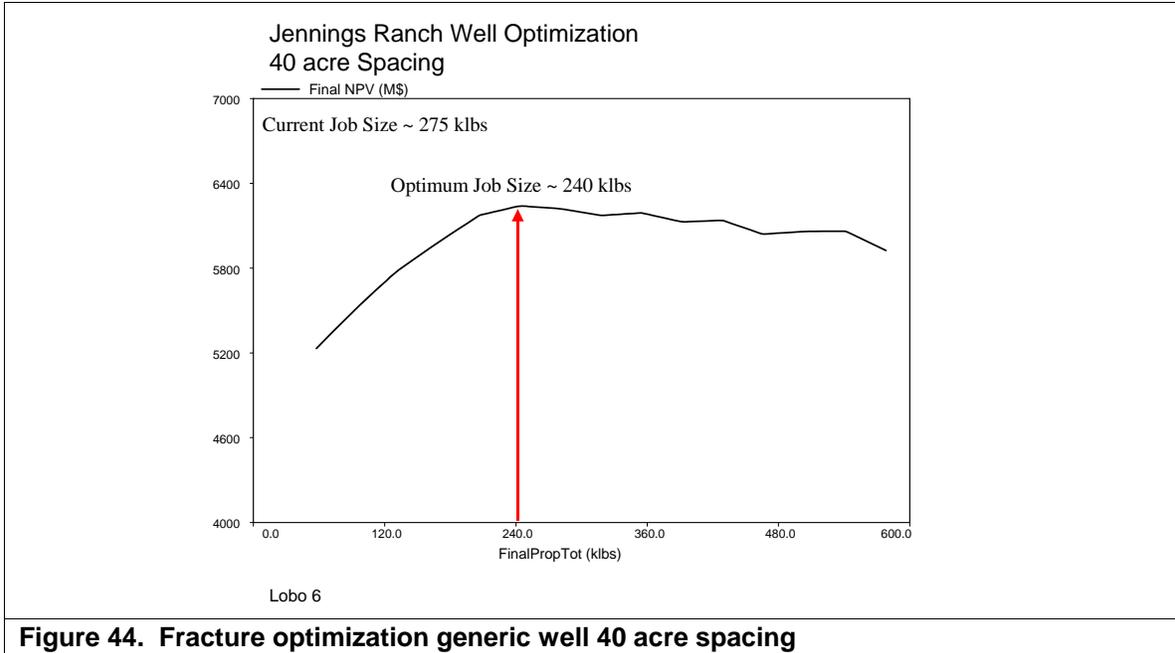


Figure 44. Fracture optimization generic well 40 acre spacing

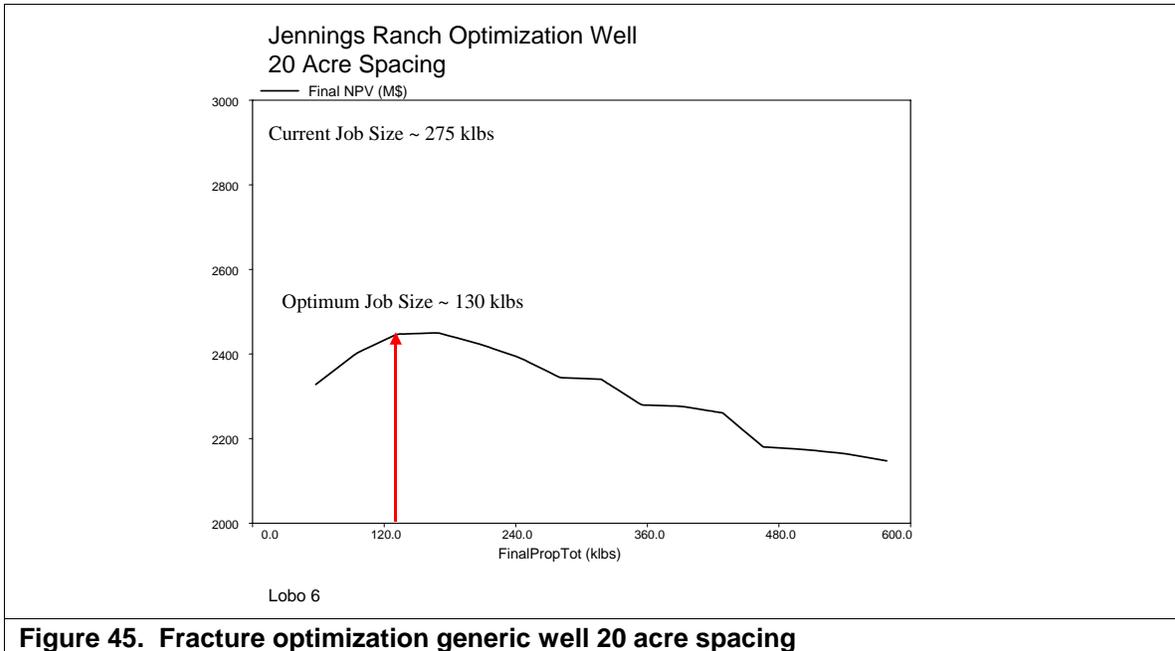


Figure 45. Fracture optimization generic well 20 acre spacing

4.2 Discussion

4.2.1 Introduction

This study focused on a deep gas productive horizon operated by ConocoPhillips in the Jennings Ranch Field, Zapata County, South Texas. The primary targets are the Lobo 6, Lobo 1 and Stray Sands. This study focused on just the deeper Lobo 6 interval at depths of roughly 12,200 to 12,500 ft. The formation is highly over-pressured with pressures of about 10,200 psi (0.82 psi/ft). Porosities are about 16% to 21% with water saturations of 45% to 55%. Net pay can vary from about 20 ft to over 100 ft. All wells are completed with crosslinked gel fracture treatments using ceramic proppants. Multiple target zones are generally commingled, with a typical well producing about 7 to 8 MMCFD initially, and declining fairly fast to 2 MMCFD or less within one year. The wells are located in 80 to 120 acre fault blocks with three to four wells per fault block. Approximately sixty to seventy wells were drilled over the last five years.

The study included a total of six wells drilled and completed from 1999 to 2001. **Figure 46** shows a typical log section of the Lobo 6 interval and **Figure 47** a field map showing the study wells (designated by red arrows).

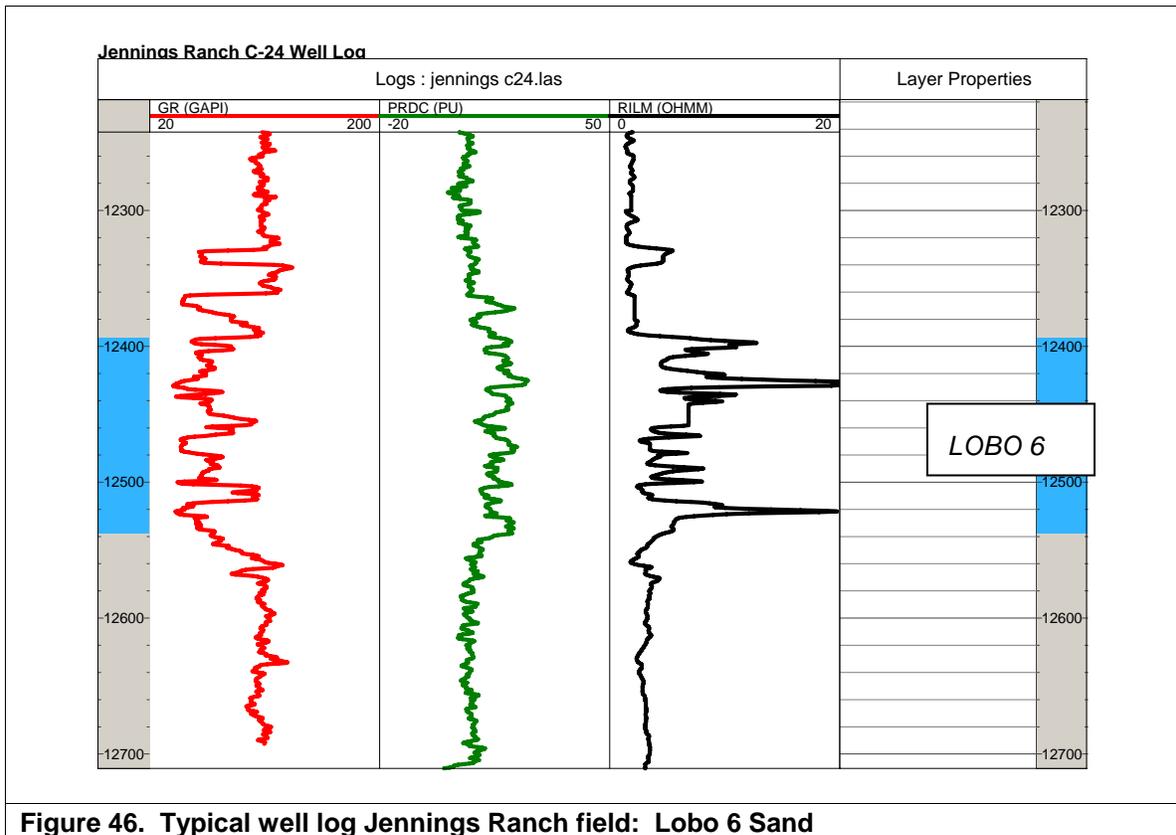


Figure 46. Typical well log Jennings Ranch field: Lobo 6 Sand

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

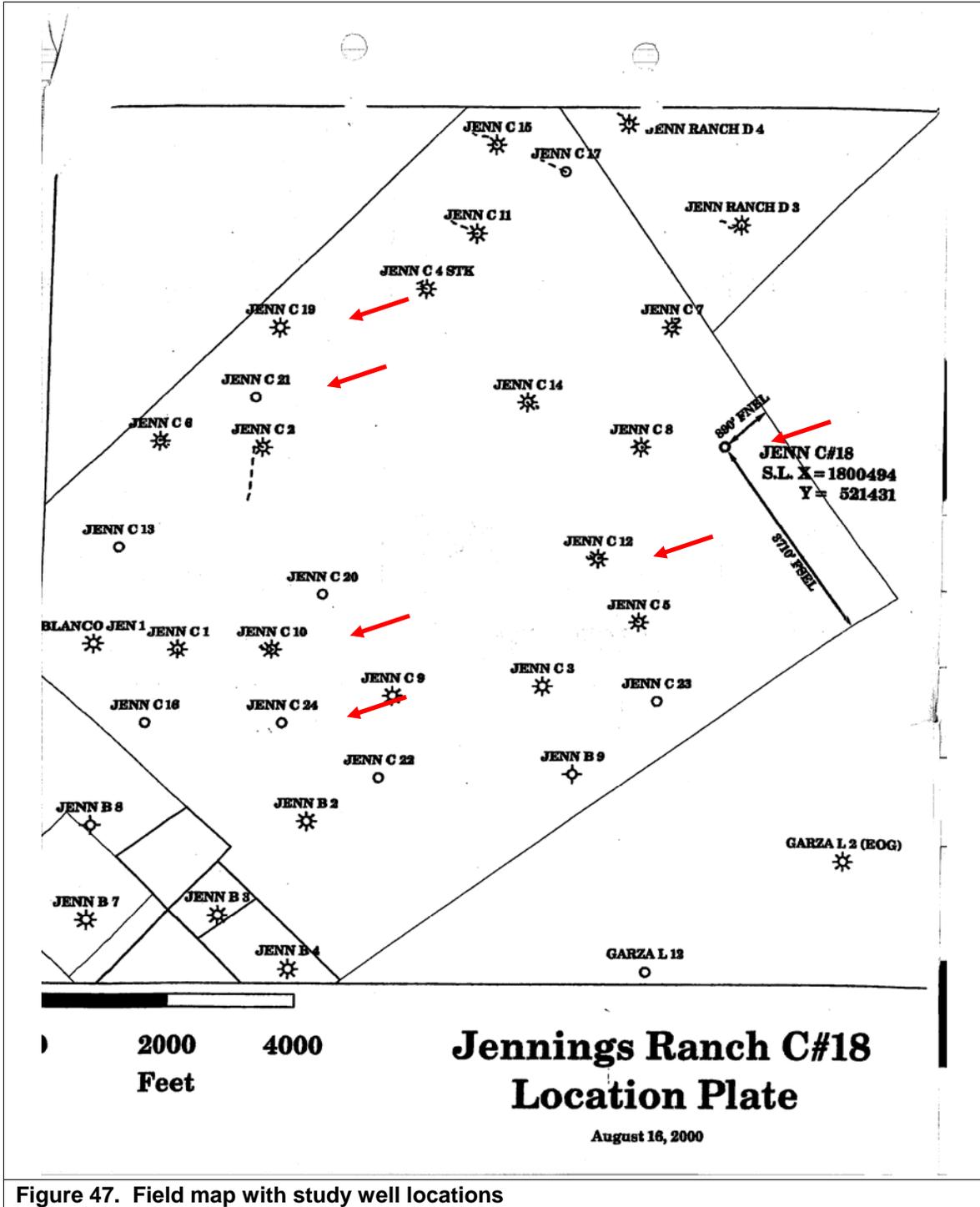


Figure 47. Field map with study well locations

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

4.2.2 Fracture Engineering and Production Analysis

Fracture Engineering

A total of six Lobo 6 treatments in six wells were analyzed in this study. **Table 4** and **Table 5** summarize the most important fracturing treatment information from all study wells. Fracture closure pressure was only measured in the Jennings Ranch C-10 (0.87 psi/ft). ISIPs generally fall between 0.93 to 0.96 psi/ft for both the mini-fracs and main treatments. Assuming 0.87 psi/ft closure stress in all other wells, fracturing net pressures are between 750 to 1,000 psi for the mini-fracs with a fairly low increase of 10 to 300 psi during the main treatment. This indicates that current fracture treatment designs and completion methodologies are successful in placing jobs without any major pressure increases.

Four treatments were pumped using 20/40 Econoprop (lowest strength ceramic proppant) and two with a higher strength 20/40 Carboprop (C-21 and C-24). Fracturing fluids were 50 to 60 lb/Mgal crosslinked gels, tapered off to a 35-lb/Mgal system at the end of the treatment. Maximum proppant concentrations were 5 to 6 ppg with total job sizes being about 270 to 430 klb of proppant depending on gross zone thickness. Pump rate was about 40 bbl/min and total slurry volume about 2,400 to 3,500 bbl with pad sizes of 25 to 30%.

Table 4. Summary of Fracture Treatments: Diagnostic Injections

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Diagnostic Injection-Frac Summary					
				Cls P psi	Eff (%)	Cls Grd psi/ft	ISIP(BH) psi	ISIP Grd psi/ft	Net P psi
C-10	L6	12201.0	12350.0	10709	30%	0.87	11451	0.93	742
C-12	L6	12494.0	12617.0	n.a.	n.a.	n.a.	11829	0.94	798
C-18	L6	12220.0	12360.0	n.a.	n.a.	n.a.	11565	0.94	851
C-19	L6	12253.0	12431.0	n.a.	n.a.	n.a.	11786	0.95	1009
C-21	L6	12496.0	12744.0	n.a.	n.a.	n.a.	11728	0.93	748
C-24	L6	12394.0	12538.0	n.a.	n.a.	n.a.	11855	0.95	961

Table 5. Summary of Fracture Treatments: Propped Treatment

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Propped Treatment Summary								Comments
				Vol bbls	Rate bbls/min	Prop klbs	ISIP(BH) psi	ISIP Grad psi	Net P psi	Screen Out?	Net P Increase psi	
C-10	L6	12201.0	12350.0	3425.0	40.0	426	11746	0.96	1037	n	295	Econoprop 20/40; YF850-835
C-12	L6	12494.0	12617.0	2527.0	36.0	276	11852	0.94	821	n	23	Econoprop 20/40; Med 60# to Med 40#
C-18	L6	12220.0	12360.0	2464.0	40.0	283	11575	0.94	861	n	10	Econoprop 20/40; Med 45# to Med 35#
C-19	L6	12253.0	12431.0	3197.0	40.0	350	11852	0.96	1075	n	66	Econoprop 20/40; Med 50# to Med 35#
C-21	L6	12496.0	12744.0	3220.0	45.0	400	11896	0.94	916	n	168	Carboprop 20/40; Med 50# to Med 35#
C-24	L6	12394.0	12538.0	3039.0	43.0	365	11911	0.96	1017	n	56	Carboprop 20/40; Med 50# to Med 35#

Table 6 shows a summary of the fracture modeling results. All fracture modeling was performed using the 3-dimensional hydraulic frac simulator FracproPT™. Fracturing net pressures were fairly high, indicating some degree of far-field fracture complexity (multiple fractures), which could limit fracture extent (**Figure 49**). The last column of **Table 6** summarizes the fracture complexity settings. These numbers are not meant to be exact representations of the number of multiple fracture branches but indicate that the degree of complexity is moderate in four wells and two wells had no meaningful complexity (C-12 and C-18). Near-wellbore fracture

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

complexity (tortuosity) was fairly low on all treatments, indicating no fracture width problems for proppant as it enters the fracture.

Table 6. Summary of Fracture Analysis Results

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Prop Length ft	Prop Height ft	Conductivity (frac system) md-ft	Multiple Fracture Settings Volume-Leakoff-Opening
C-10	L6	12201.0	12350.0	405	178	2115	3-3-3
C-12	L6	12494.0	12617.0	603	221	451	1-1-1
C-18	L6	12220.0	12360.0	663	204	353	1-1-1
C-19	L6	12253.0	12431.0	419	223	820	5-4-5
C-21	L6	12496.0	12744.0	510	235	1568	2-3-2
C-24	L6	12394.0	12538.0	431	207	1752	4-4-4

Modeled propped fracture lengths are estimated to be about 400 to 660 ft with propped fracture heights between 175 and 235 ft showing some limited growth above and below the target interval but all-in-all fairly contained. Conductivities in **Table 6** are ideal values and do not account for non-darcy and multi-phase flow corrections and assume that multiple fracture branch conductivity is additive. Fracture model results have not been verified with independent far-field fracture diagnostics such as microseismic or tiltmeter fracture mapping since it has not yet been done in deeper, hotter South Texas environments.

Production Analysis

Table 7 summarizes the production analysis results for all six wells. The C-10 was the only well that produced the Lobo 6 by itself for three years. All other wells were immediately commingled with Lobo 1 Sand above. The allocation of production to the Lobo 6 Sand used in the analysis was provided by ConocoPhillips using production logs where available and bulk volume of hydrocarbons. All wells except the C-12 (only 17%), have a Lobo 6 contribution of over 50% (56 to 72%). Net pay, porosity and water saturation estimates were provided by ConocoPhillips. The production analysis was performed using a single-phase, single-layer numerical reservoir simulator in FracproPT™. Non-darcy and multi-phase flow effects (assuming 10 bbl/MMCF liquid yield), and proppant embedment, were included in the simulation. Drainage area shape was assumed to be rectangular with the extent in the frac direction being slightly longer than the fracture length.

Graphs of the production analysis are presented in the following section under each individual well. It includes a log-log diagnostic plot of production versus time and a match of flowing pressures (production rates were used as input constraint in simulations). The plots indicate that all wells have some degree of reservoir linear flow behavior once cleanup effects have subsided and wells are flowed at fairly constant flowing pressures. The linear flow regime appears to last about one year to two years in most wells, followed by the onset of a depletion stem, which could be limited drainage from offset wells, geology and/or liquid loading conditions (**Figure 48**). Production analysis can be non-unique to some extent, but in this case the use of the fracture model lengths appears to result in reasonable matches. Production declines are fairly rapid, which is common in tight over-pressured reservoirs and is also an indication of reasonable fracture stimulation, but in some cases (the C-10 and C-12 wells) the decline was more than can be modeled with constant reservoir or fracture properties (**Figure 56** and **Figure 57**). In those cases, the simulations were performed by reducing reservoir permeability by 75% as a function of

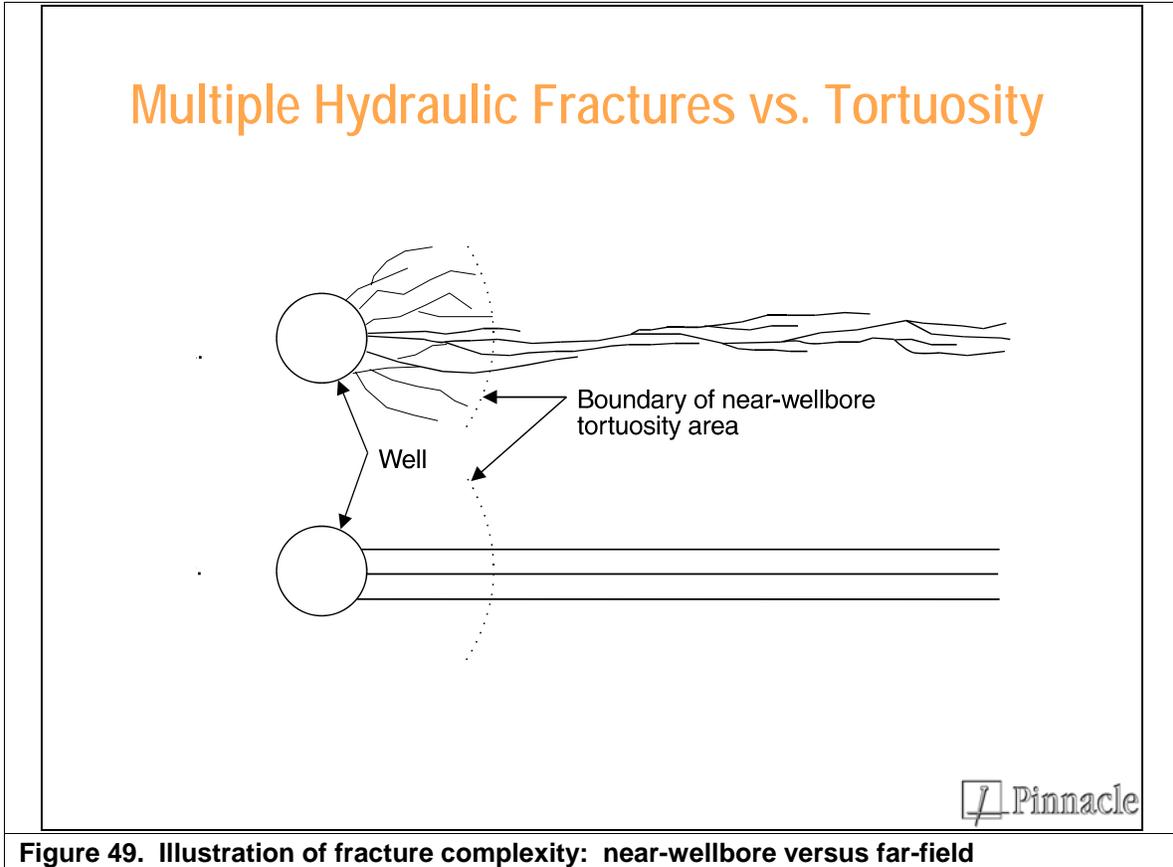


Figure 49. Illustration of fracture complexity: near-wellbore versus far-field

The following section details all the individual fracture treatments with graphs of treatment data, fracture closure analysis, net pressure matches and resulting fracture geometry along with the production analysis plots.

4.2.3 Jennings Ranch C-10

The C-10 treatment was the only treatment where the mini-frac reached closure pressure. It was estimated to be about 0.87 psi/ft (**Figure 51**). **Figure 52** shows that near-wellbore tortuosity and perforation friction are fairly low (190 psi near-wellbore and 100 psi perforation friction at 25 bpm). The net pressure match is shown in **Figure 53**. Fracture length is estimated to be about 450 ft with fracture height slightly more than the perforated interval. The production match in **Figure 56** and **Figure 57** shows how stress-sensitive permeability improves the quality of the flowing pressure match.

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

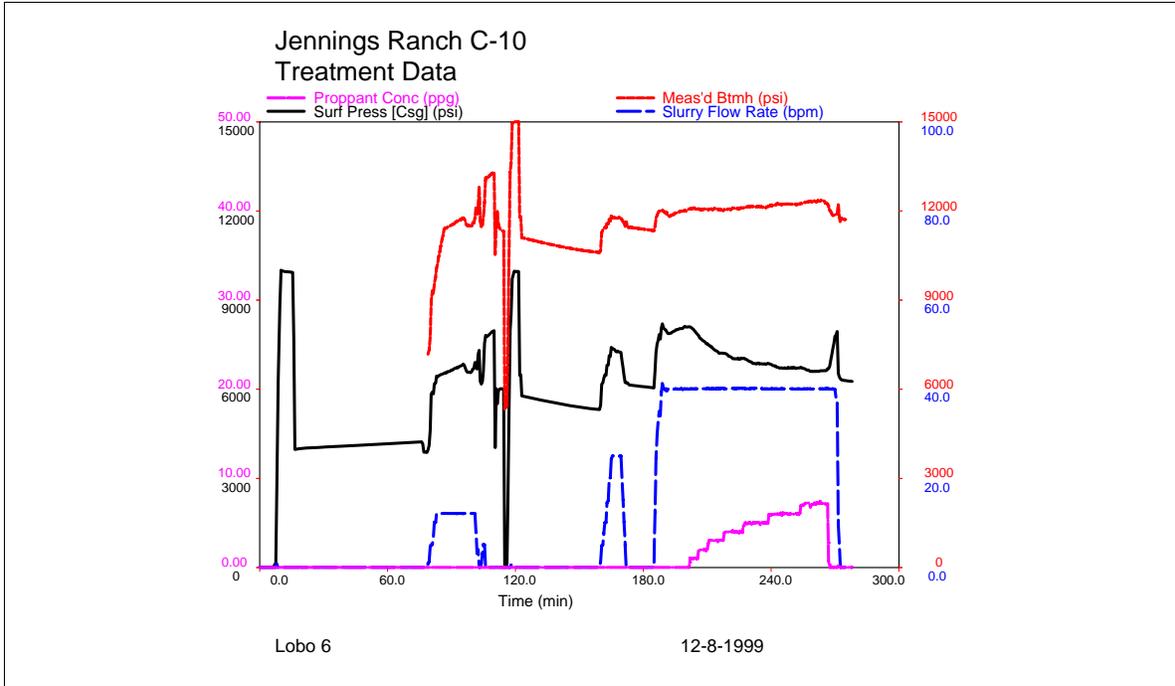


Figure 50. Treatment data: Jennings Ranch C-10 Lobo 6

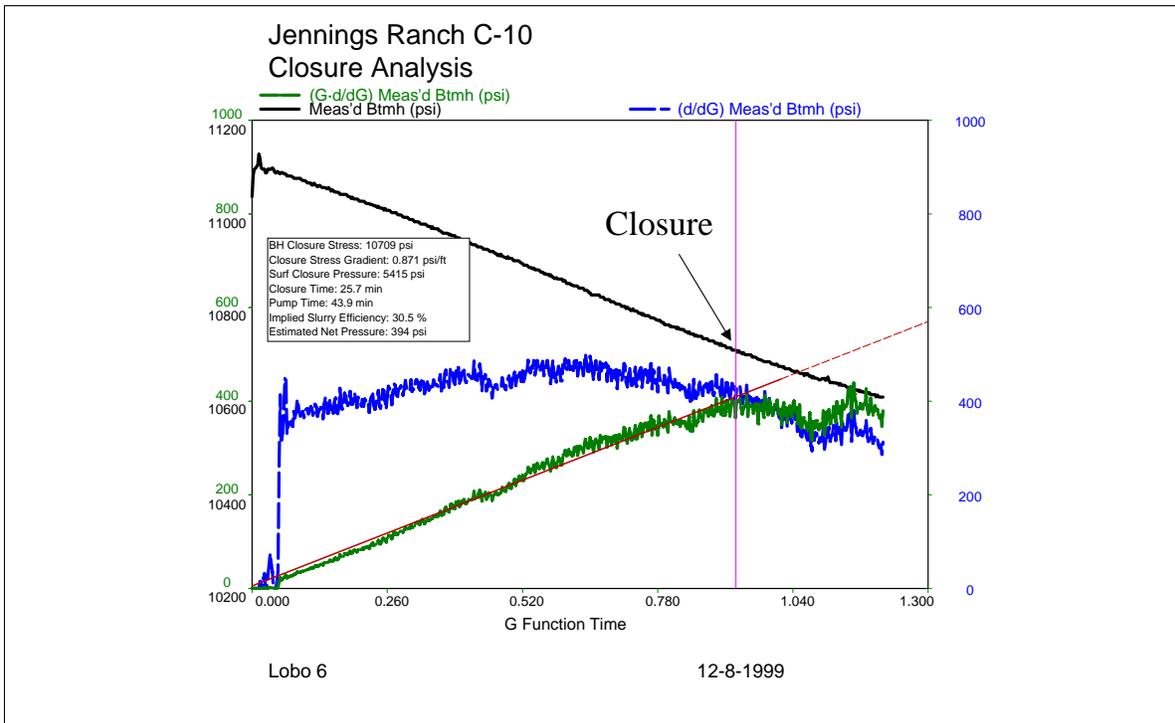


Figure 51. Closure analysis: Jennings Ranch C-10 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

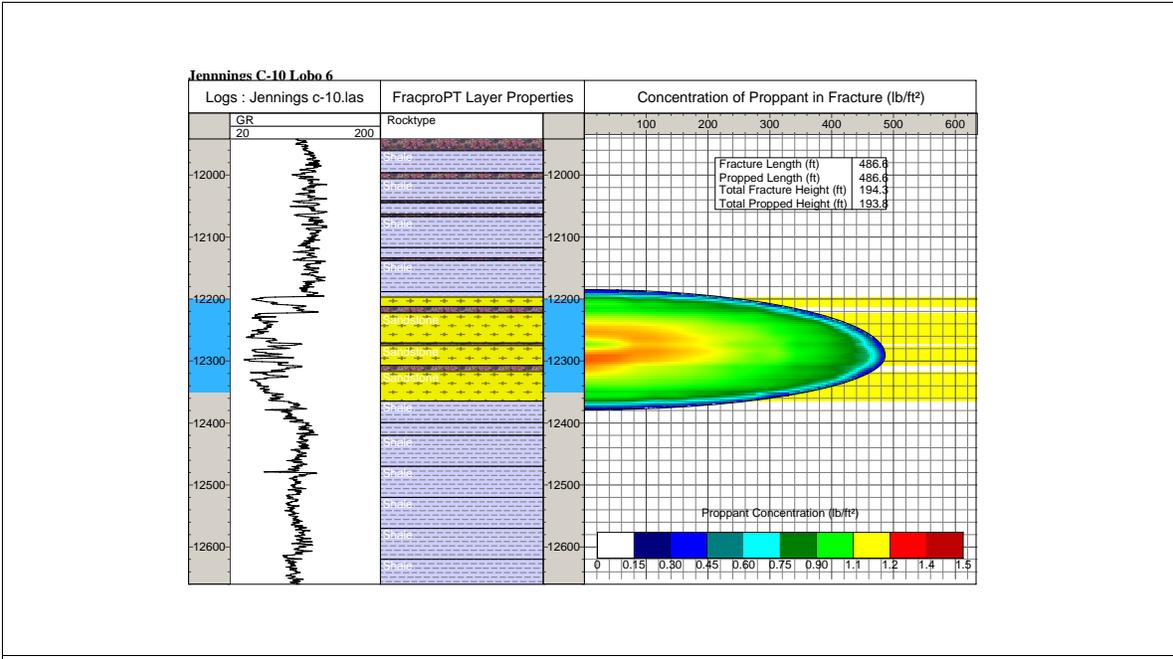


Figure 54. Model fracture geometry: Jennings Ranch C-10 Lobo 6

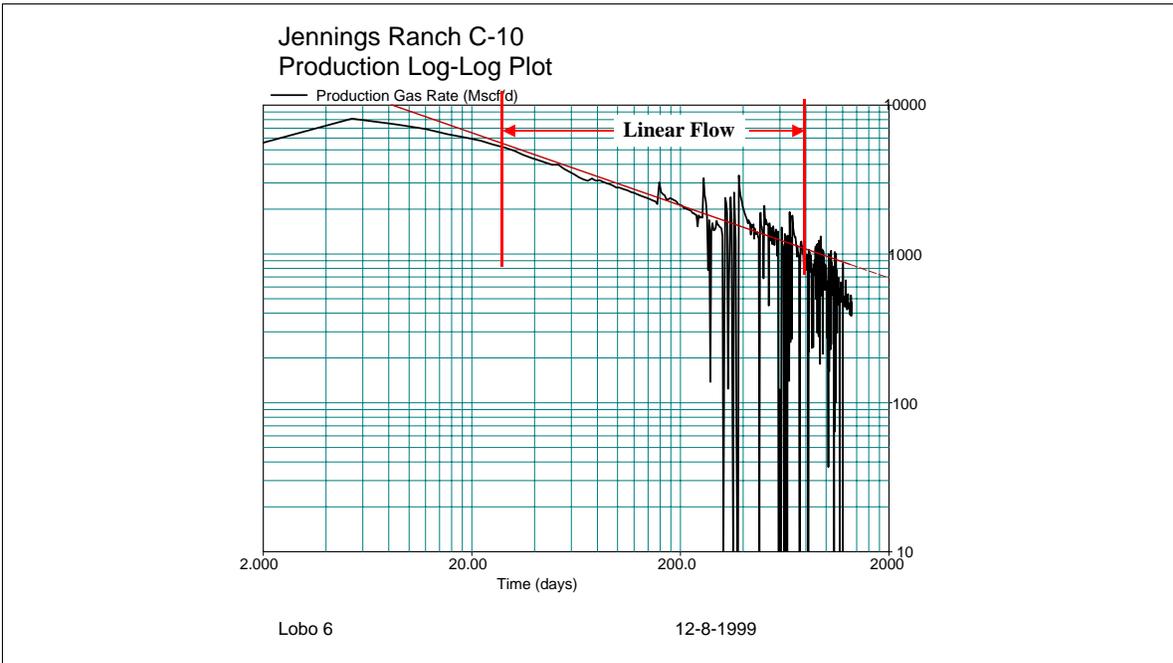


Figure 55. Log-log diagnostic plot of well production: Jennings Ranch C-10 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

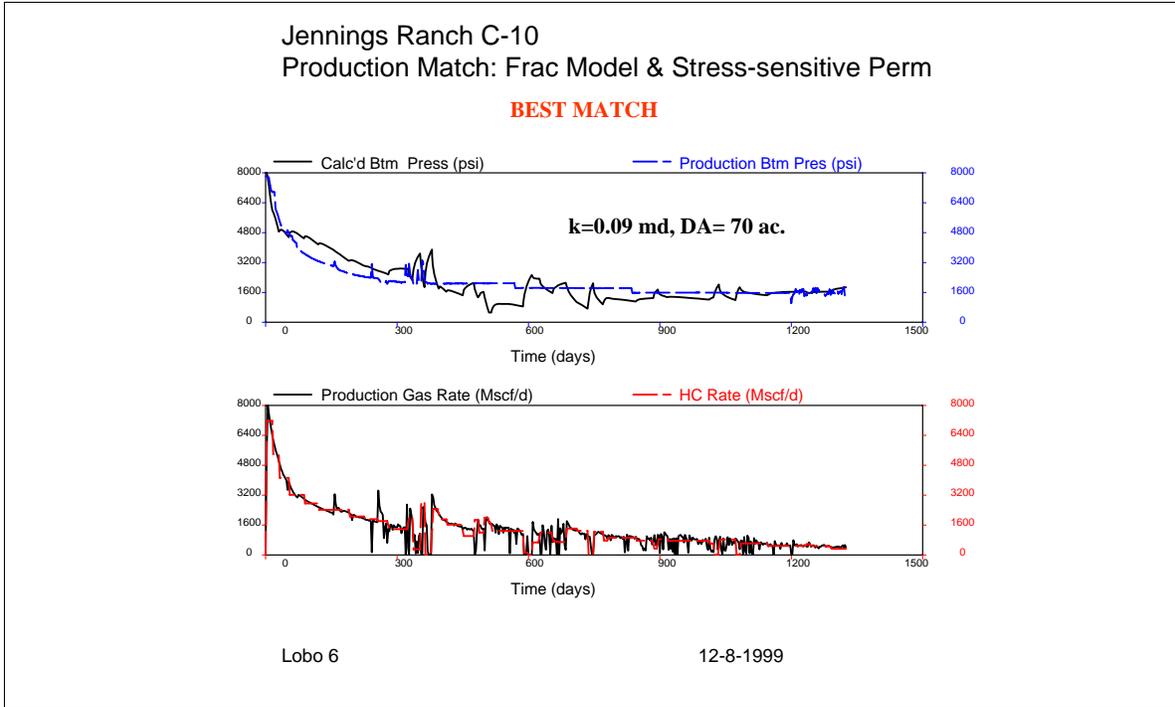


Figure 56. Best production match using frac model length and stress-sensitive permeability: Jennings Ranch C-10 Lobo 6

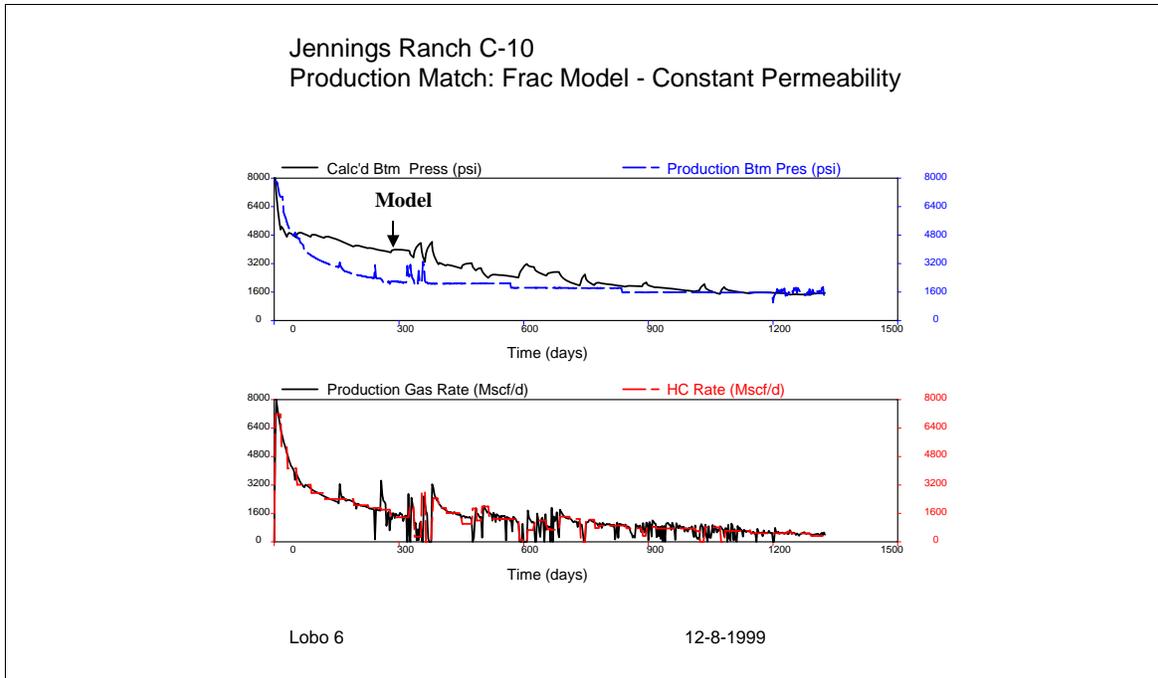


Figure 57. Production match using model frac length and constant permeability: Jennings Ranch C-10 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

4.2.4 Jennings Ranch C-12

The net pressure match is shown in **Figure 60**. Fracture length is estimated to be about 600 ft with some downward growth below the perforated interval. Stress-sensitive permeability was also used in this case to improve the quality of the flowing pressure match.

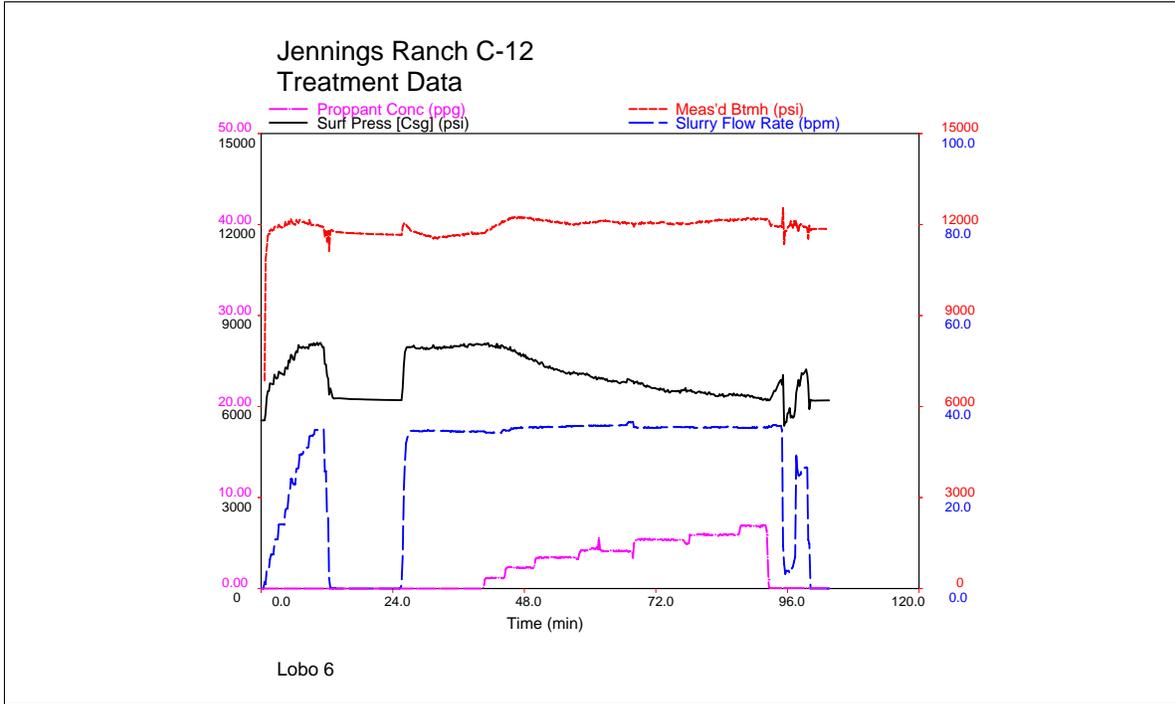


Figure 58. Treatment data: Jennings Ranch C-12 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

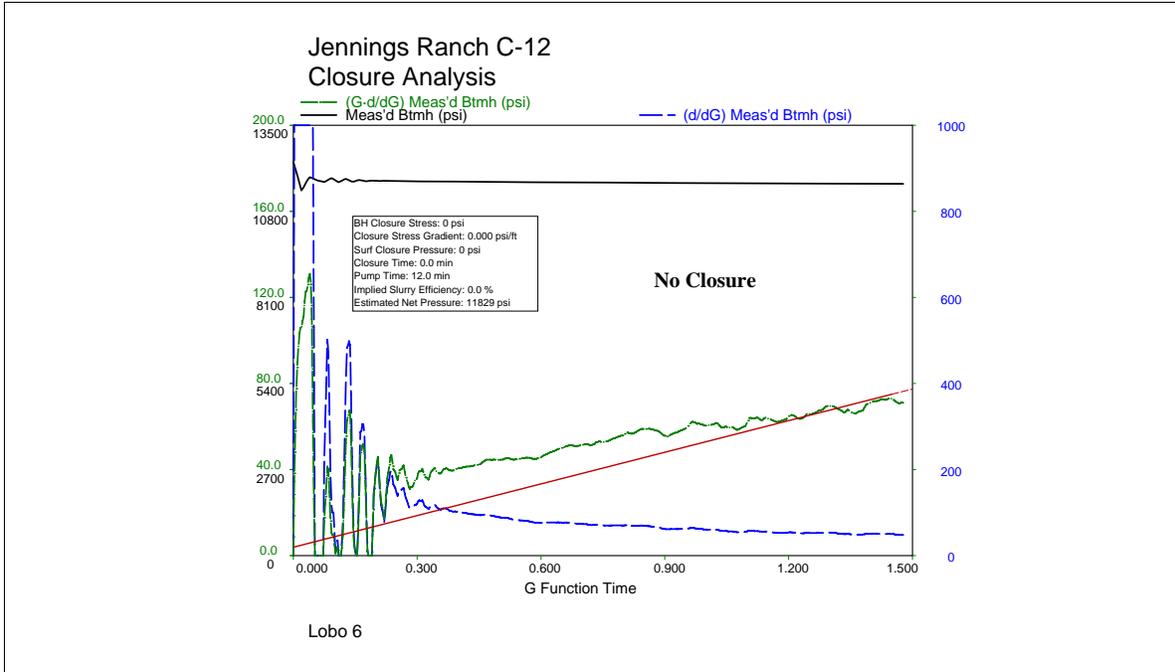


Figure 59. Closure analysis: Jennings Ranch C-12 Lobo 6

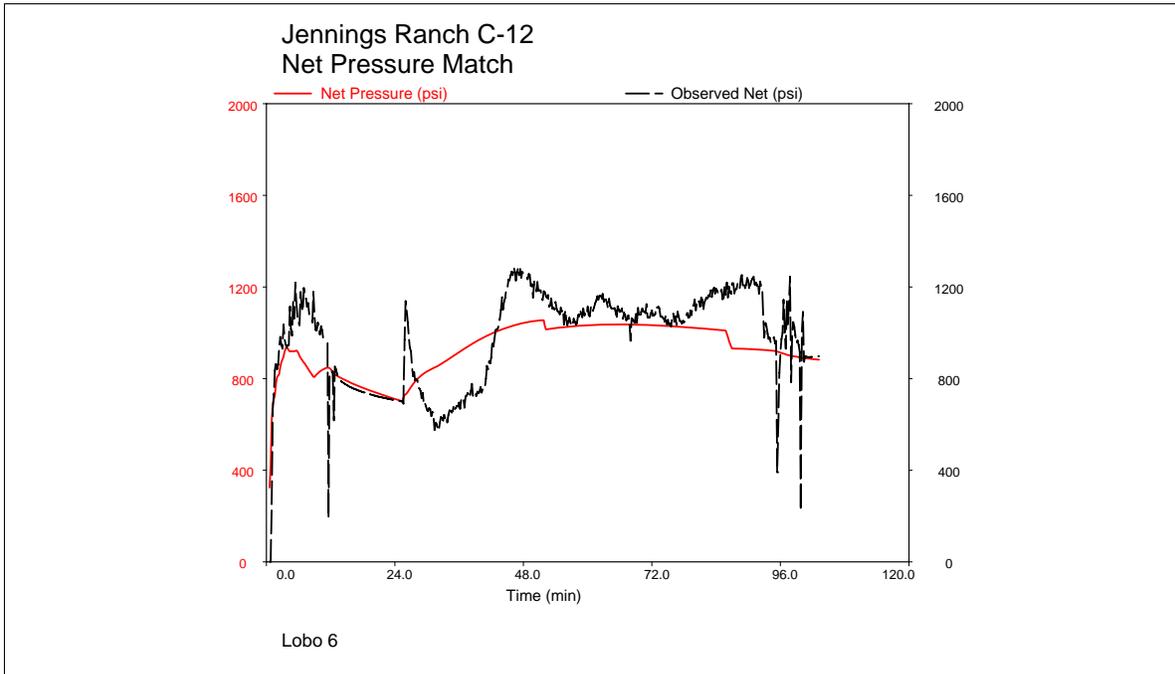


Figure 60. Net pressure match: Jennings Ranch C-12 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

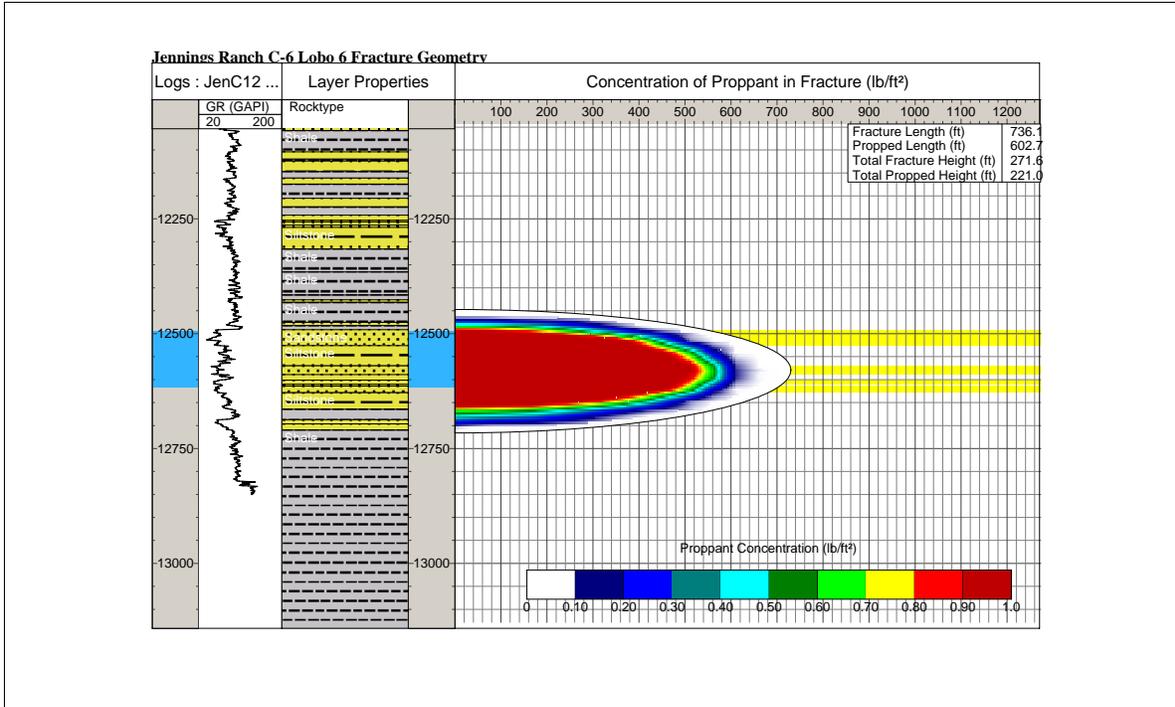


Figure 61. Model fracture geometry: Jennings Ranch C-12 Lobo 6

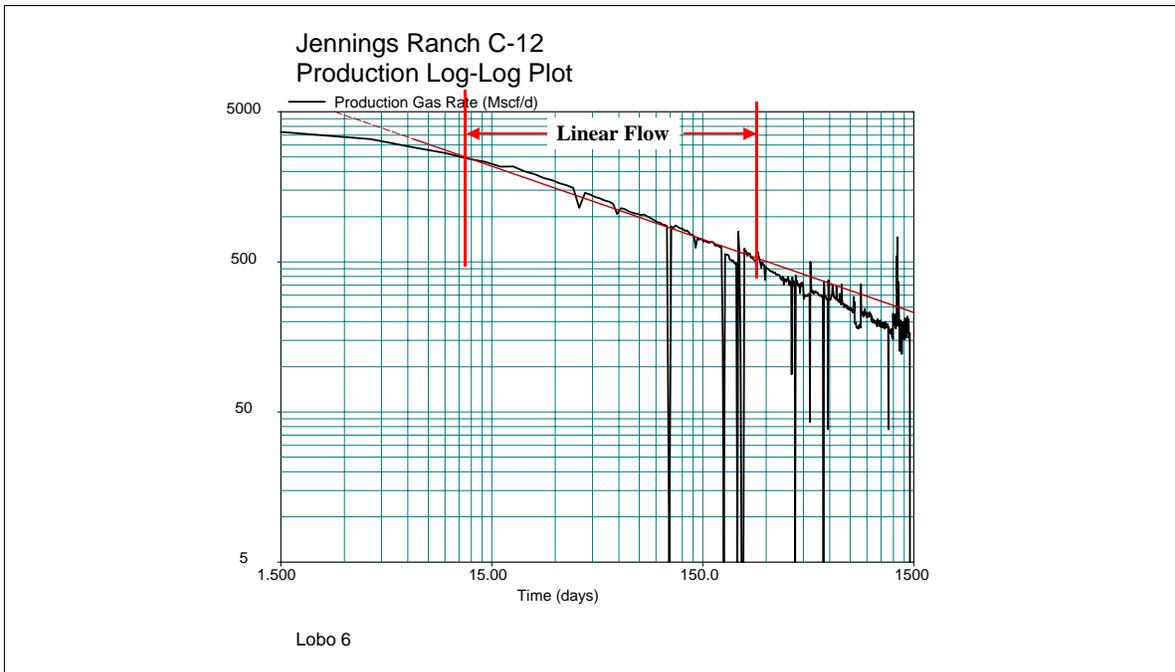
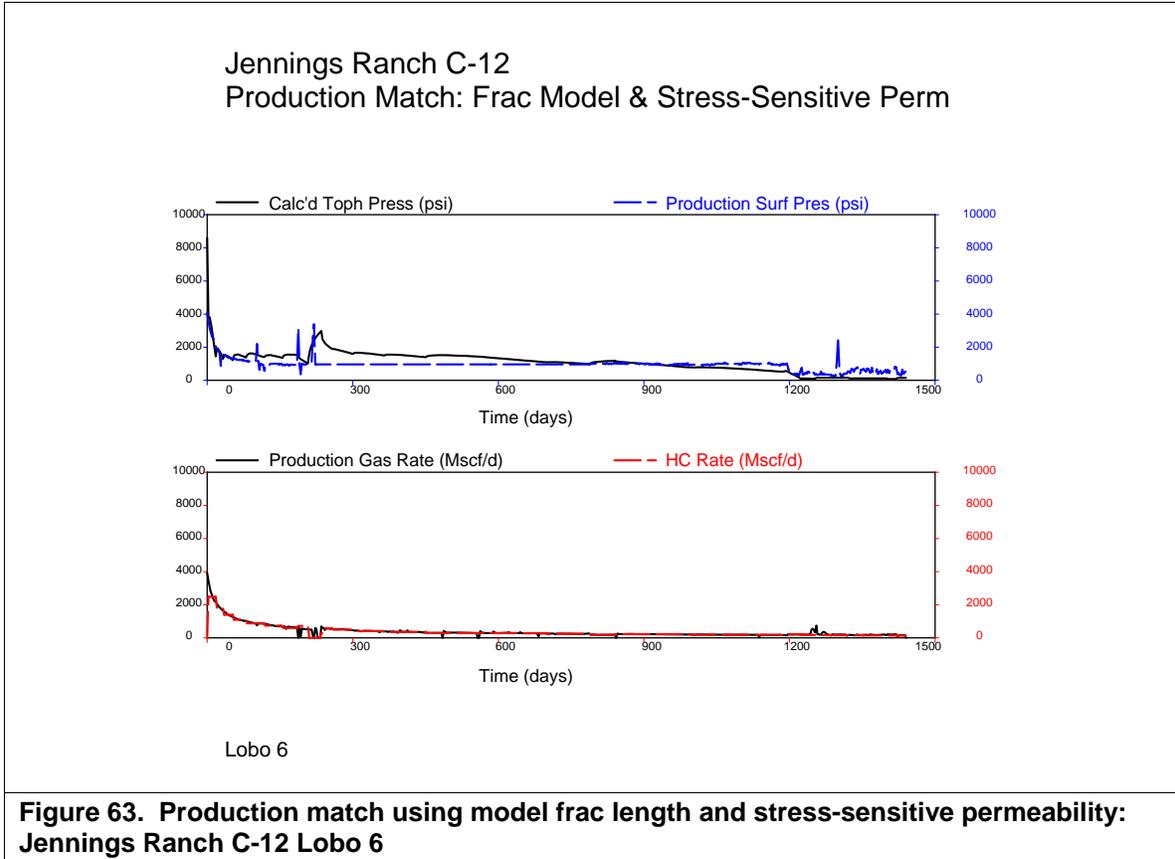


Figure 62. Log-log diagnostic plot of well production: Jennings Ranch C-12 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX



4.2.5 Jennings Ranch C-18

The net pressure match is shown in **Figure 66**. Fracture length is estimated to be about 660 ft with slight height growth around the perforated interval. In this case, it was not necessary to model production with stress-sensitive permeability.

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

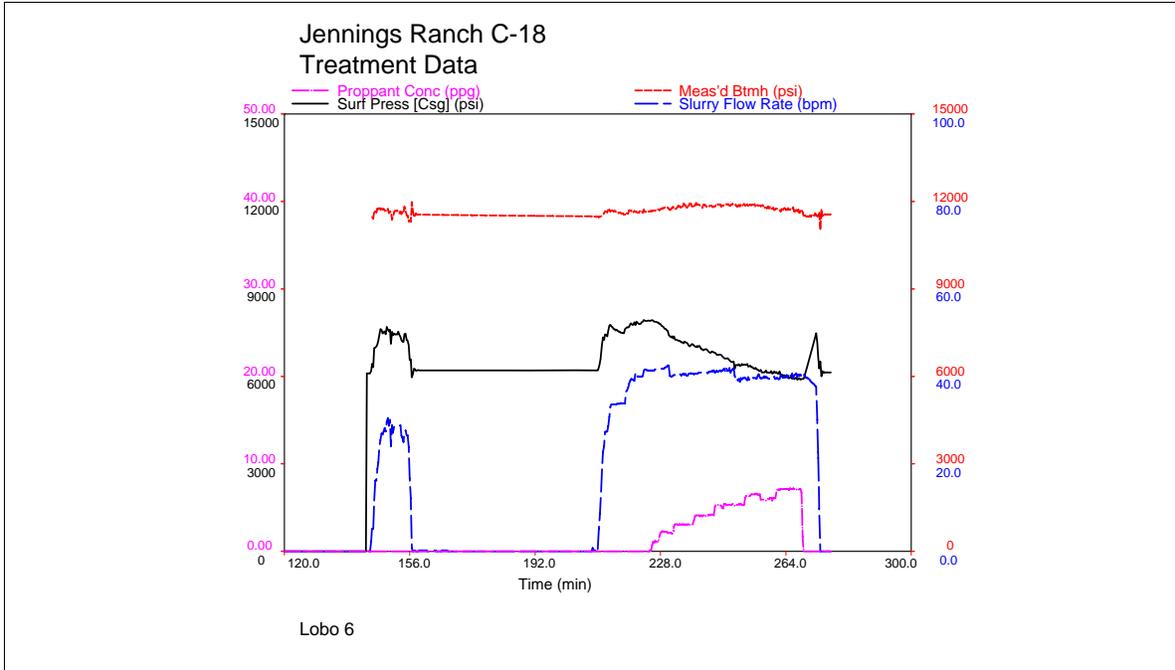


Figure 64. Treatment data: Jennings Ranch C-18 Lobo 6

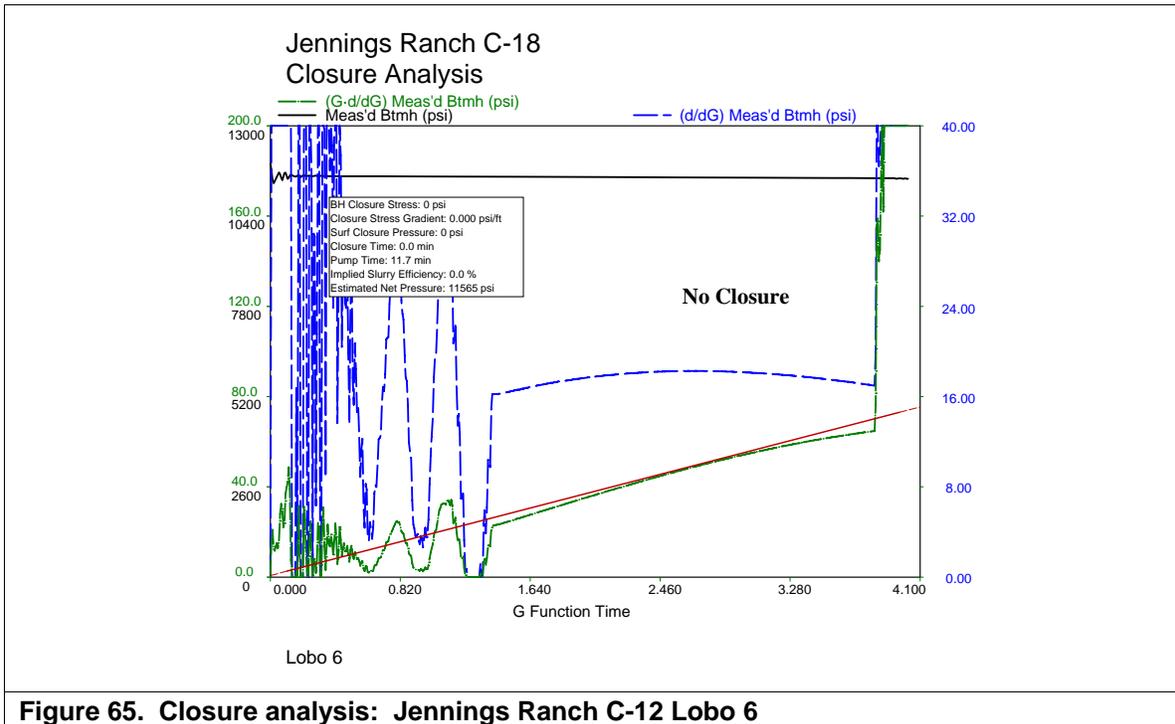


Figure 65. Closure analysis: Jennings Ranch C-12 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

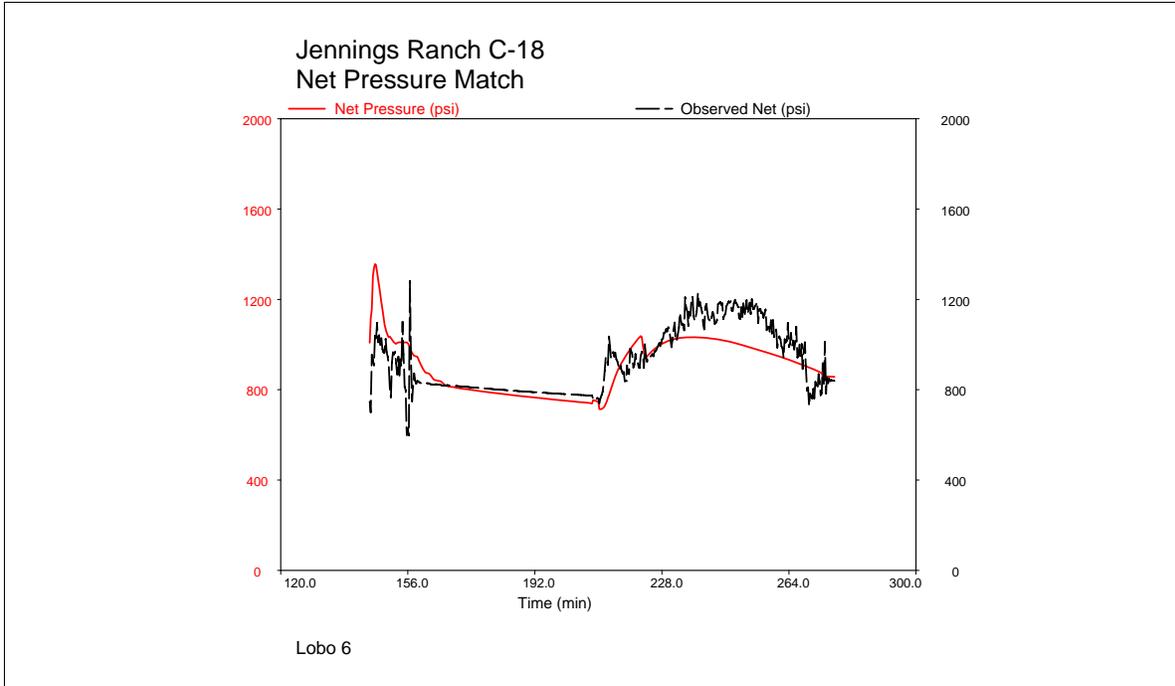


Figure 66. Net pressure match: Jennings Ranch C-18 Lobo 6

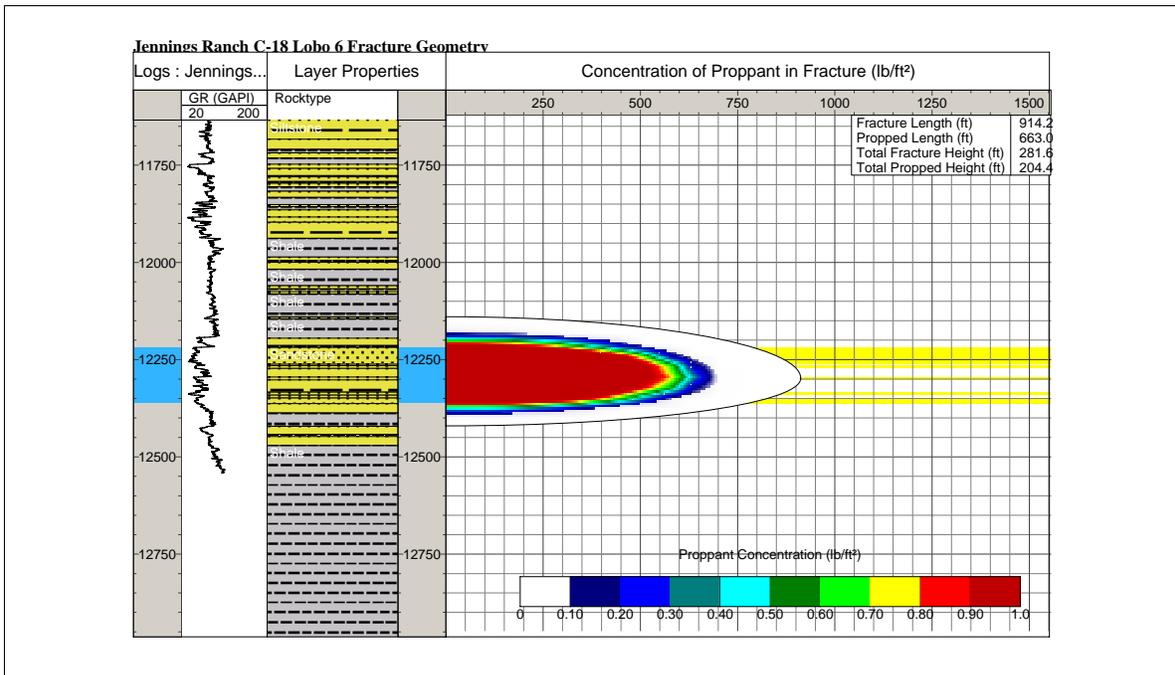


Figure 67. Model fracture geometry: Jennings Ranch C-18 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

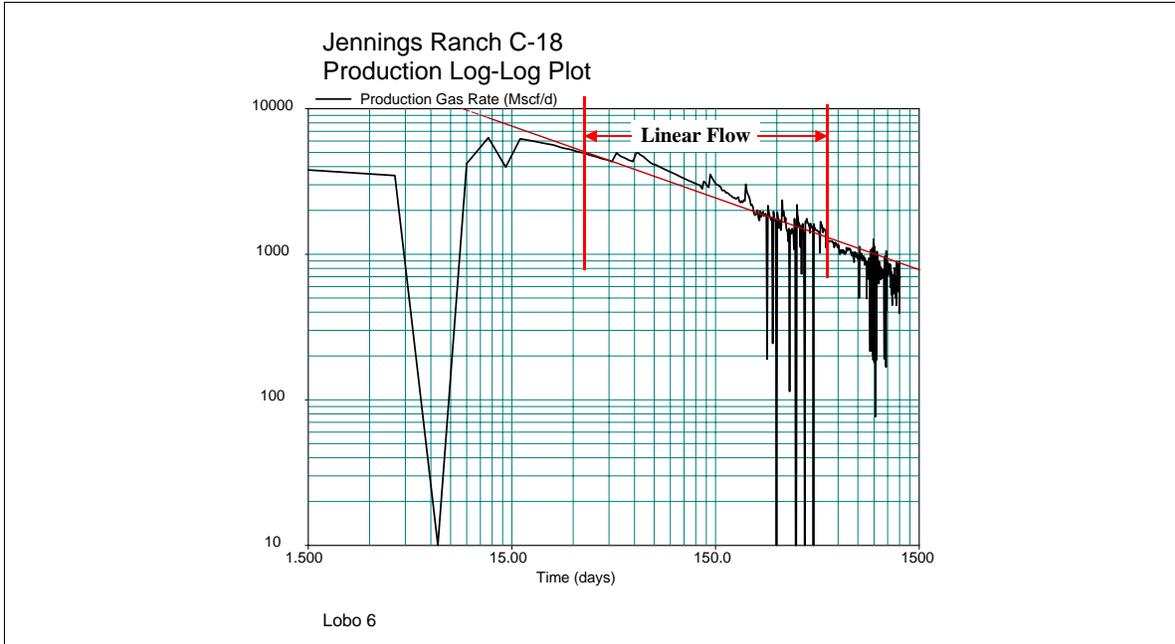


Figure 68. Log-log diagnostic plot of well production: Jennings Ranch C-18 Lobo 6

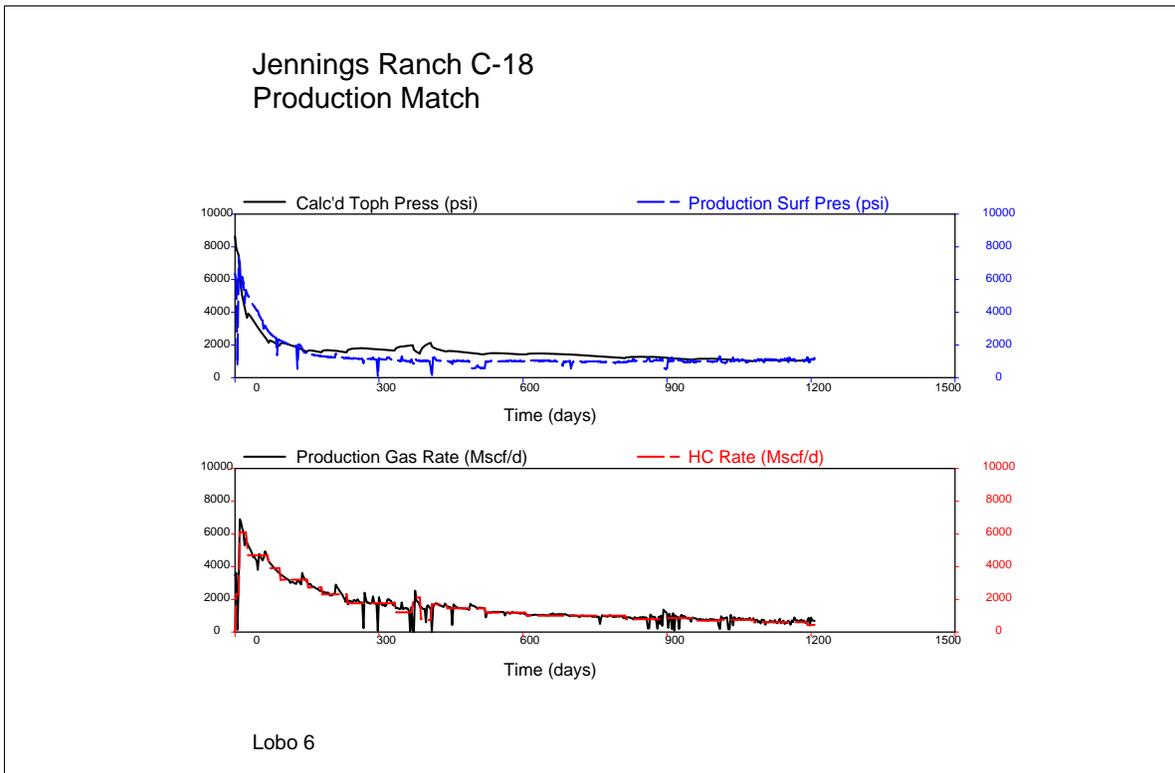


Figure 69. Production match using model frac length and constant permeability: Jennings Ranch C-18 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

4.2.6 Jennings Ranch C-19

The net pressure match is shown in **Figure 72**. Fracture length is estimated to be about 400 ft with slight height growth around the perforated interval. In this case, it was not necessary to model production with stress-sensitive permeability.

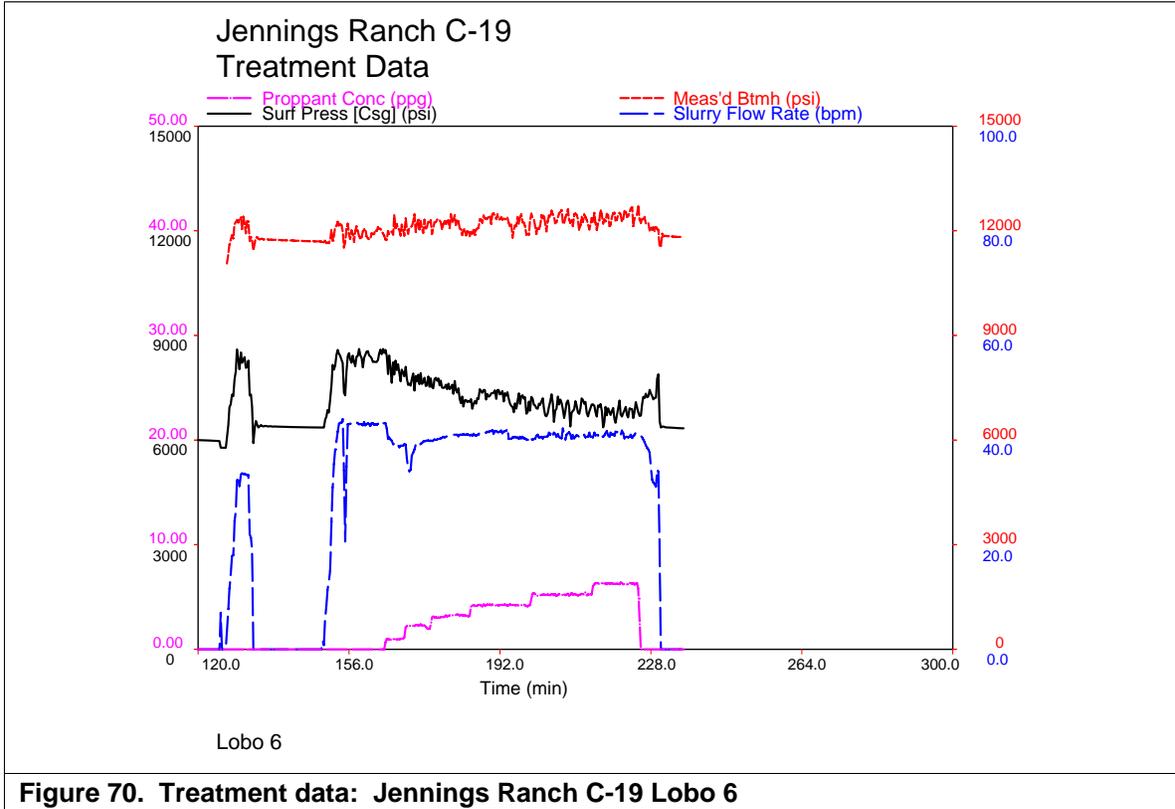


Figure 70. Treatment data: Jennings Ranch C-19 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

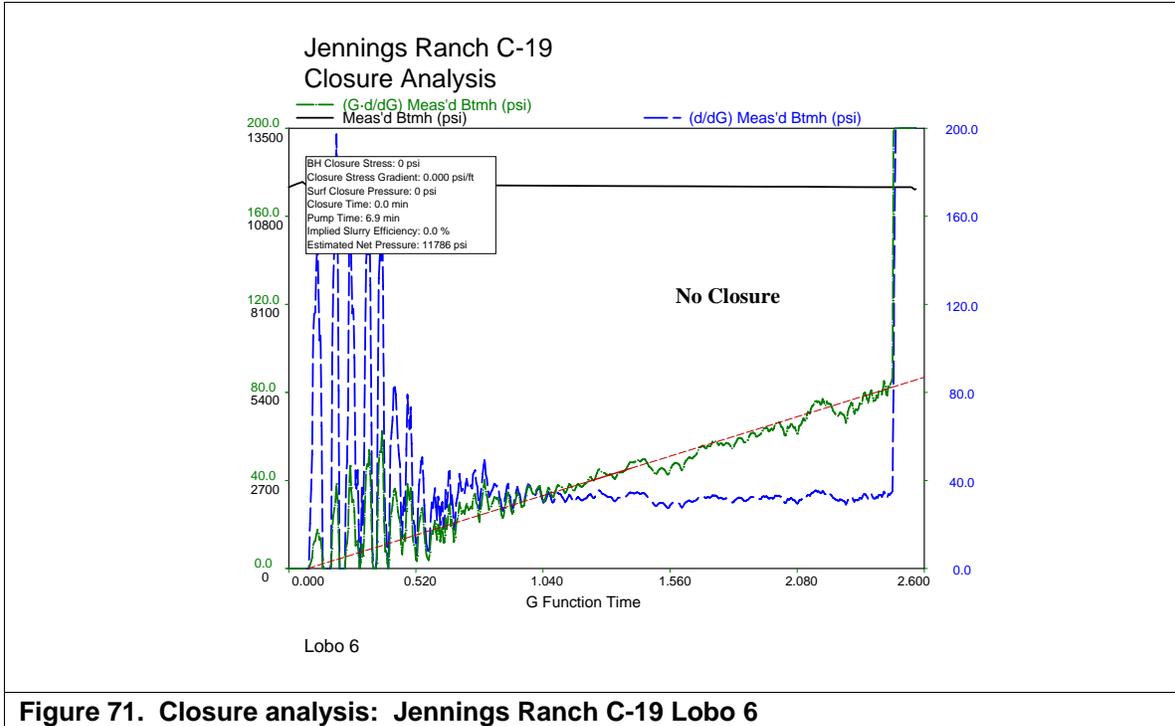


Figure 71. Closure analysis: Jennings Ranch C-19 Lobo 6

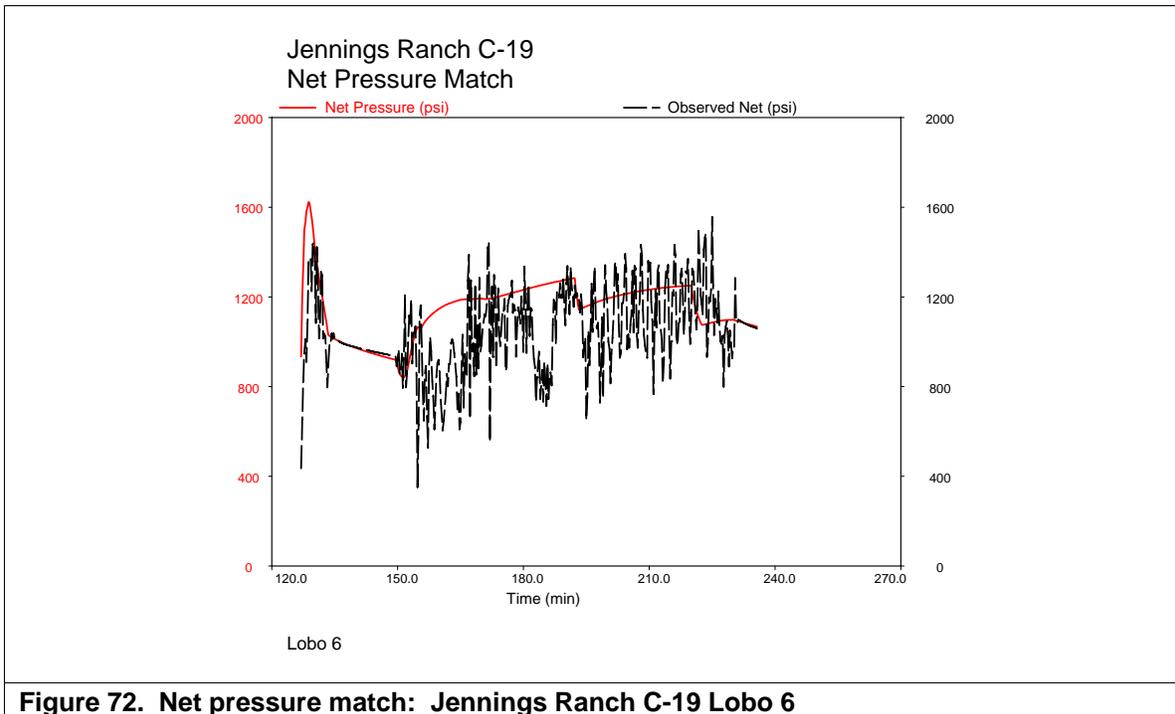


Figure 72. Net pressure match: Jennings Ranch C-19 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

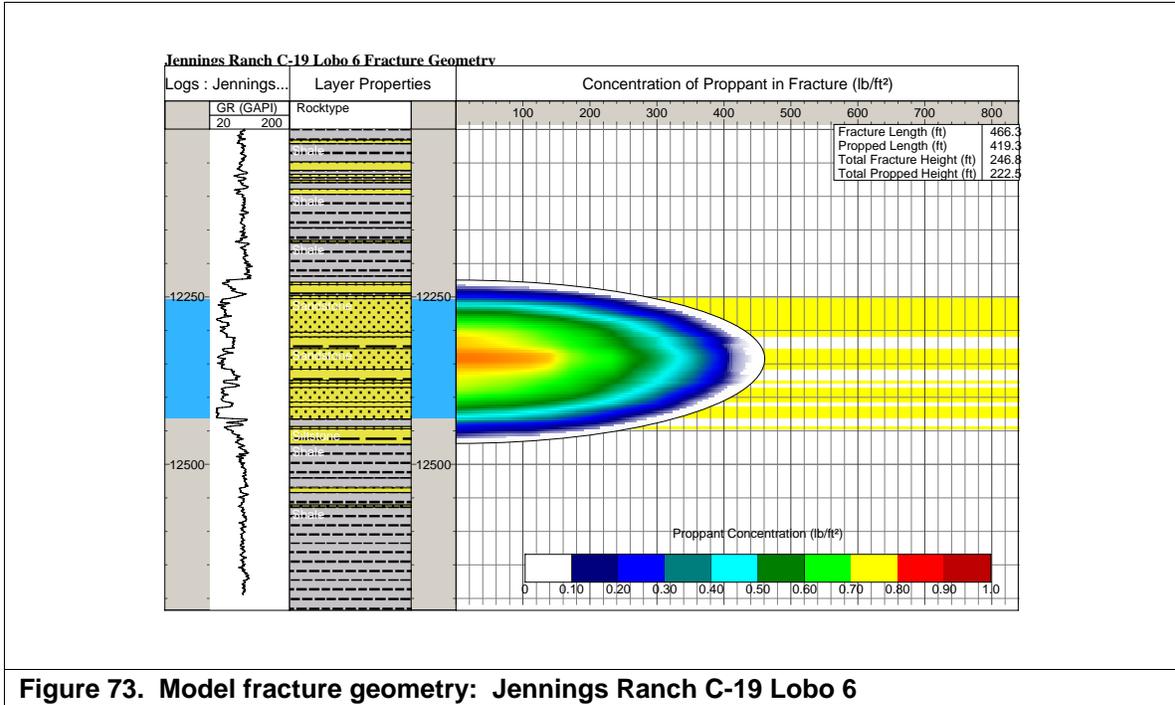


Figure 73. Model fracture geometry: Jennings Ranch C-19 Lobo 6

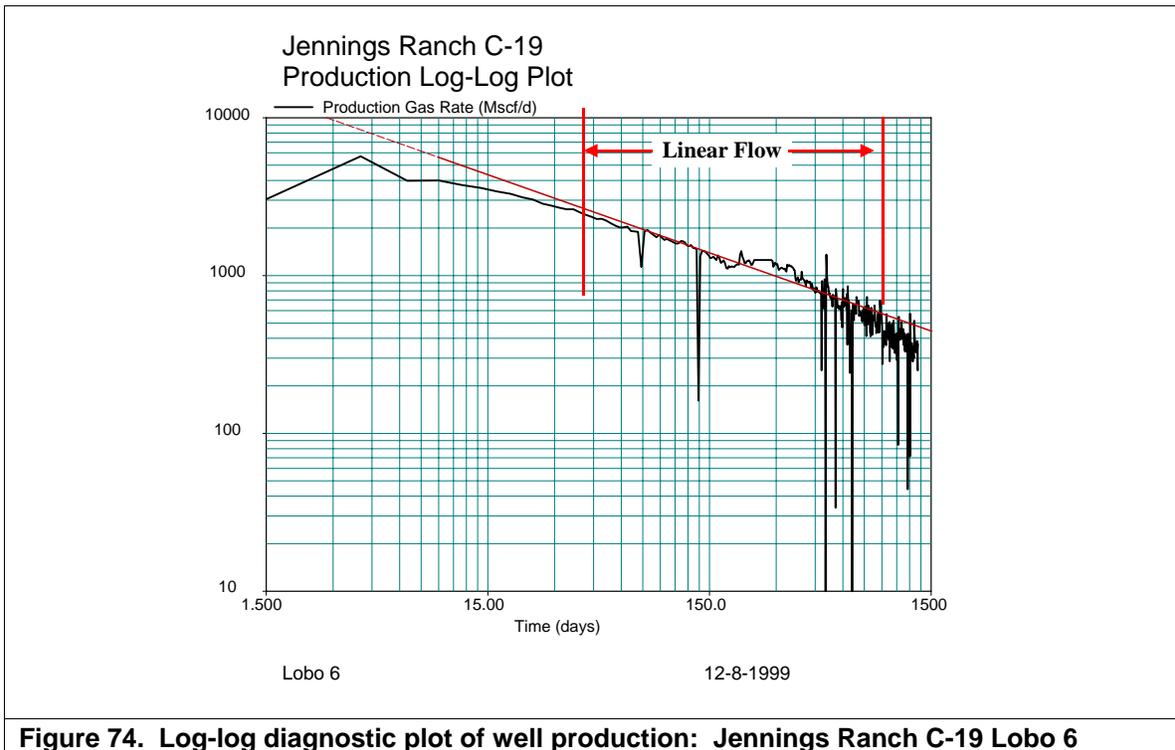
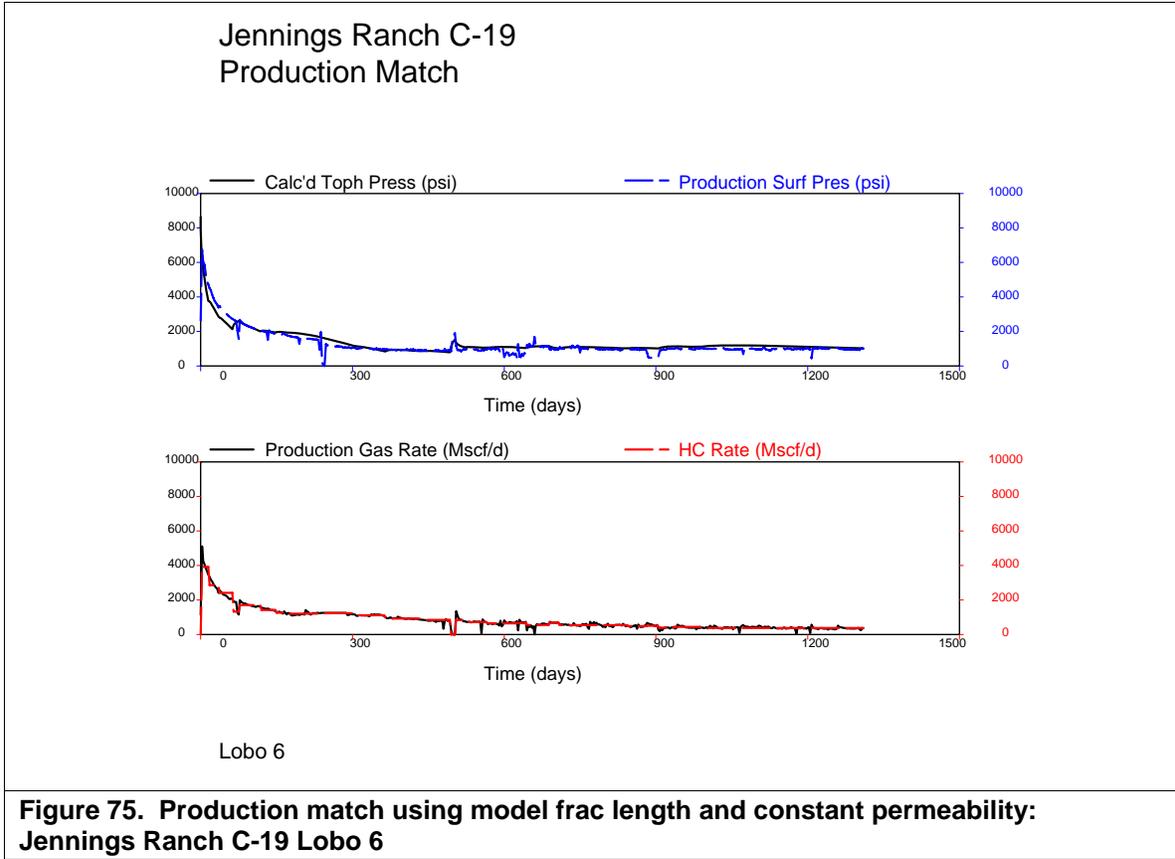


Figure 74. Log-log diagnostic plot of well production: Jennings Ranch C-19 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX



4.2.7 Jennings Ranch C-21

The net pressure match is shown in **Figure 78**. Fracture length is estimated to be about 500 ft with the fracture roughly covering the perforated interval. In this case, it was not necessary to model production with stress-sensitive permeability.

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

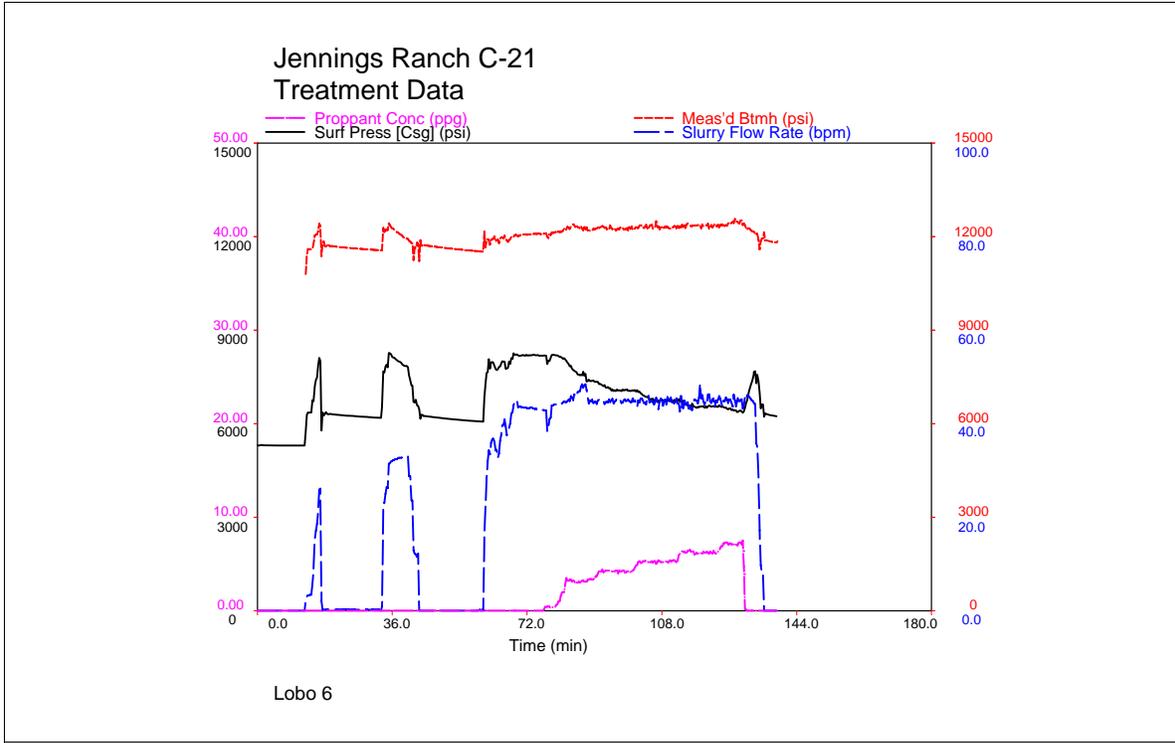


Figure 76. Treatment data: Jennings Ranch C-21 Lobo 6

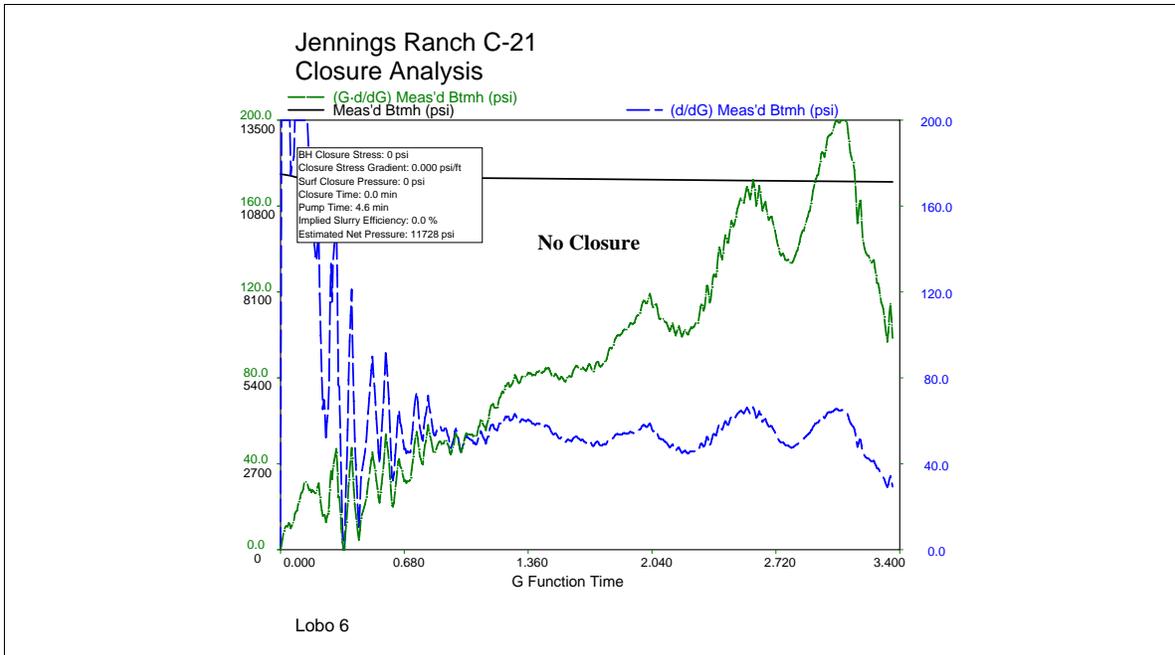


Figure 77. Closure analysis: Jennings Ranch C-21 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

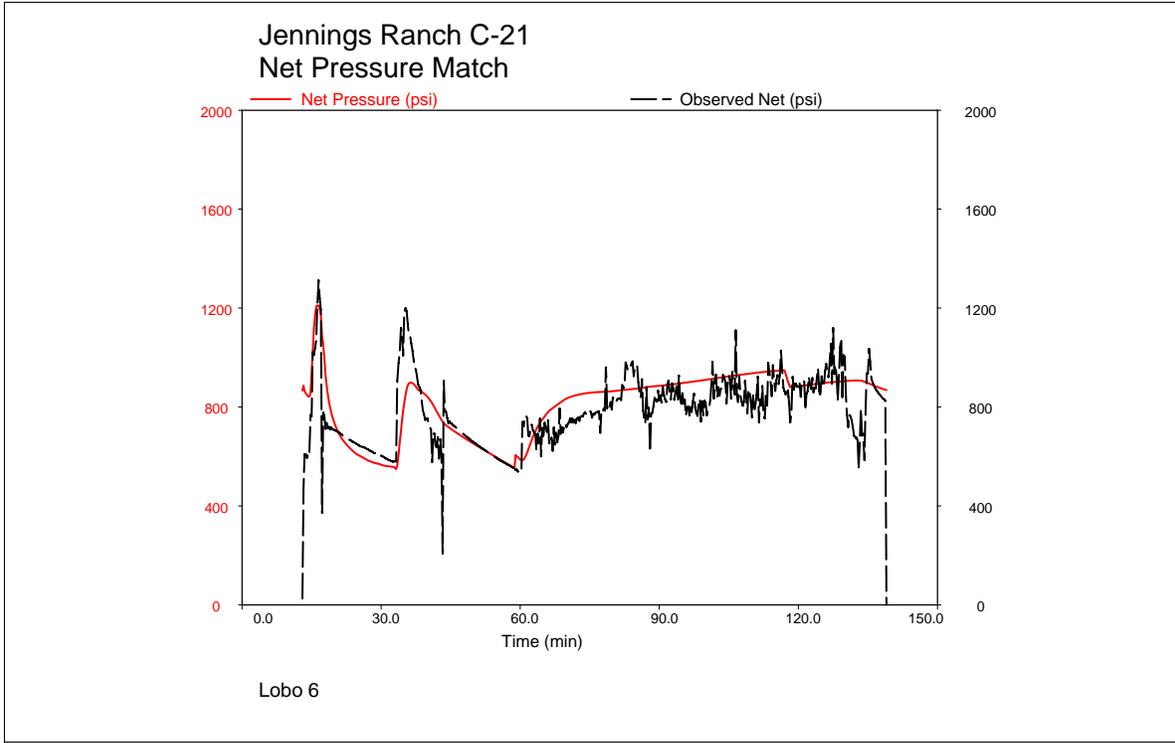


Figure 78. Net pressure match: Jennings Ranch C-21 Lobo 6

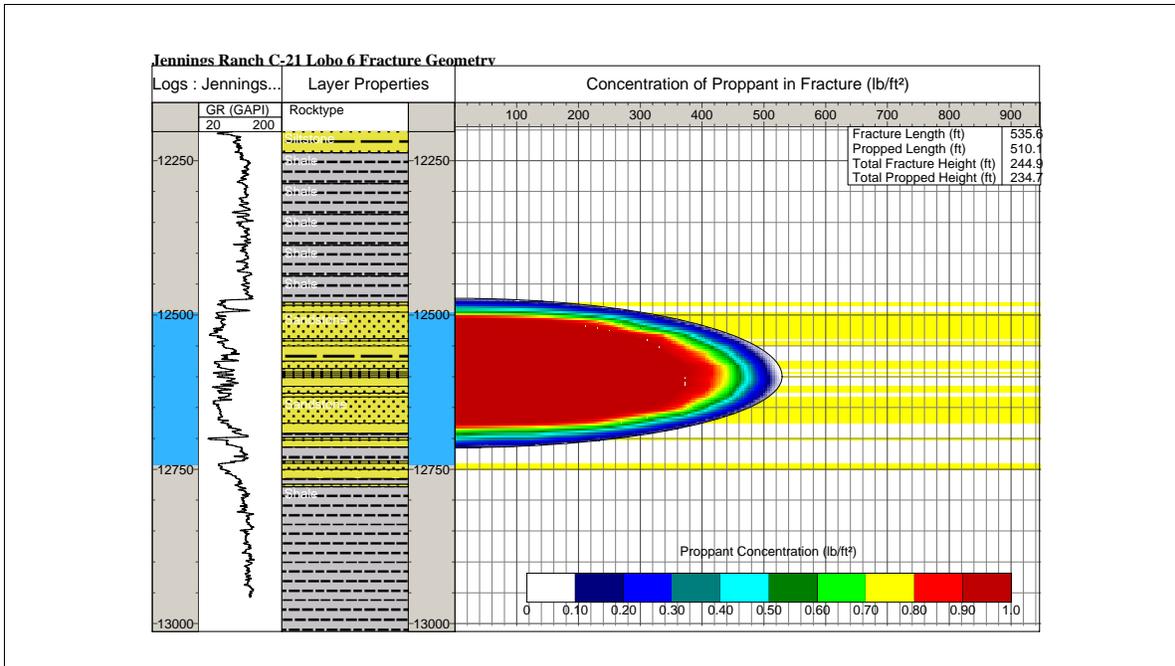


Figure 79. Model fracture geometry: Jennings Ranch C-21 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

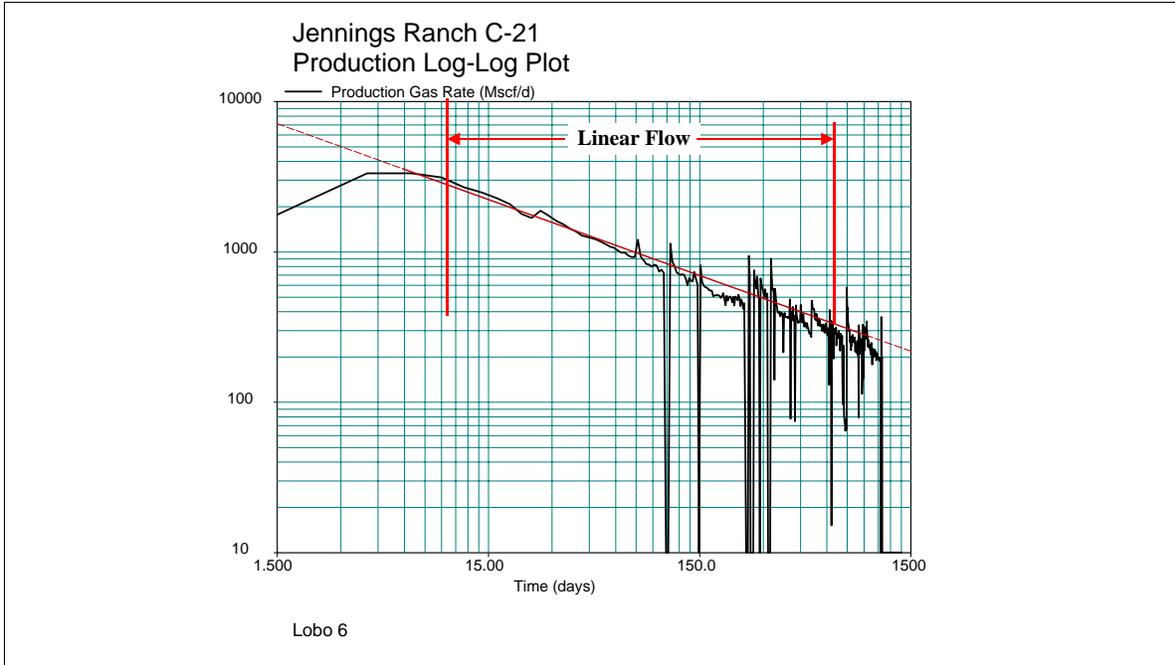


Figure 80. Log-log diagnostic plot of well production: Jennings Ranch C-21 Lobo 6

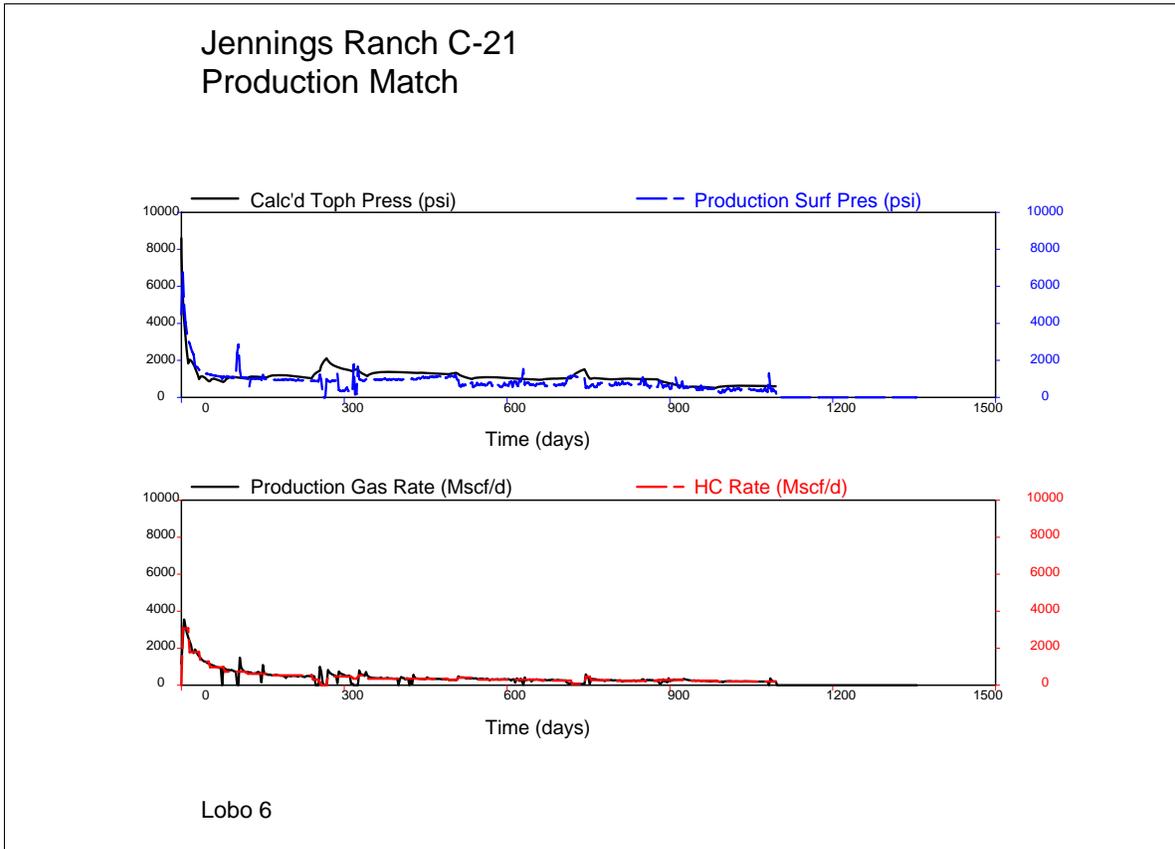


Figure 81. Production match using model frac length and constant permeability: Jennings Ranch C-21 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

4.2.8 Jennings Ranch C-24

The net pressure match is shown in **Figure 84**. Fracture length is estimated to be about 400 ft with the fracture height slightly more than the perforated interval. In this case, it was not necessary to model production with stress-sensitive permeability.

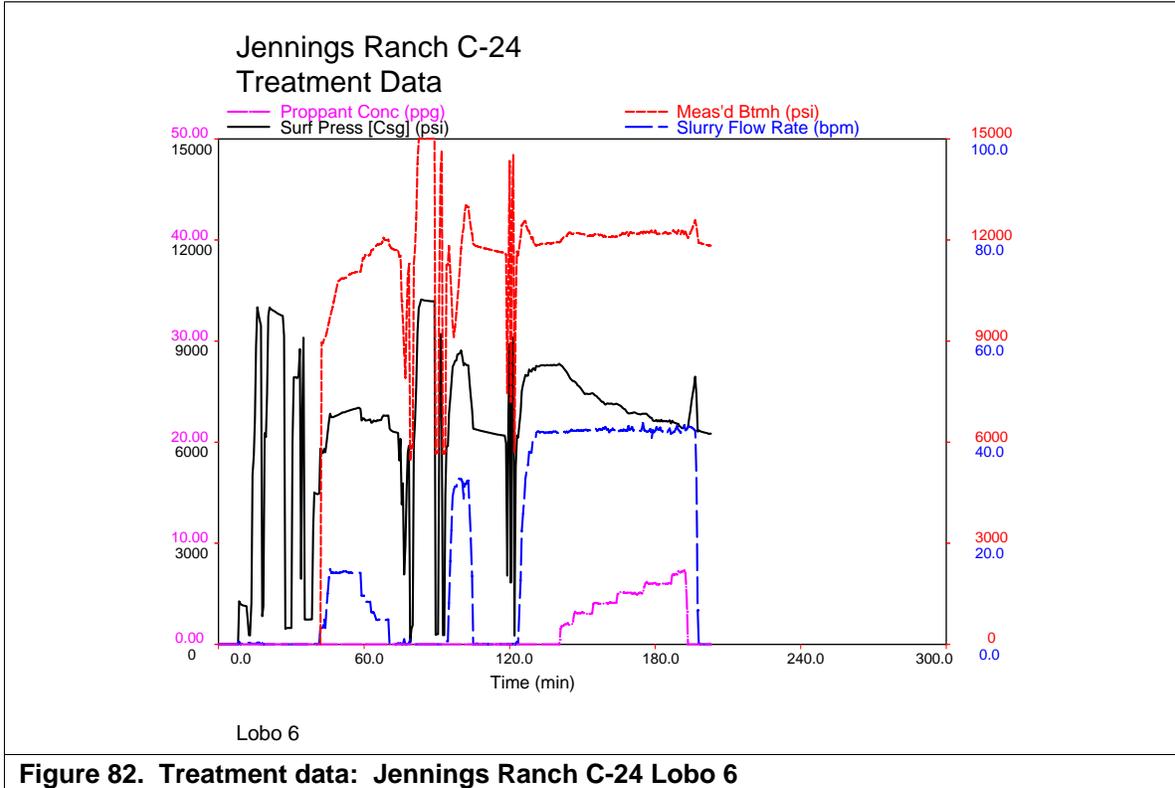


Figure 82. Treatment data: Jennings Ranch C-24 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

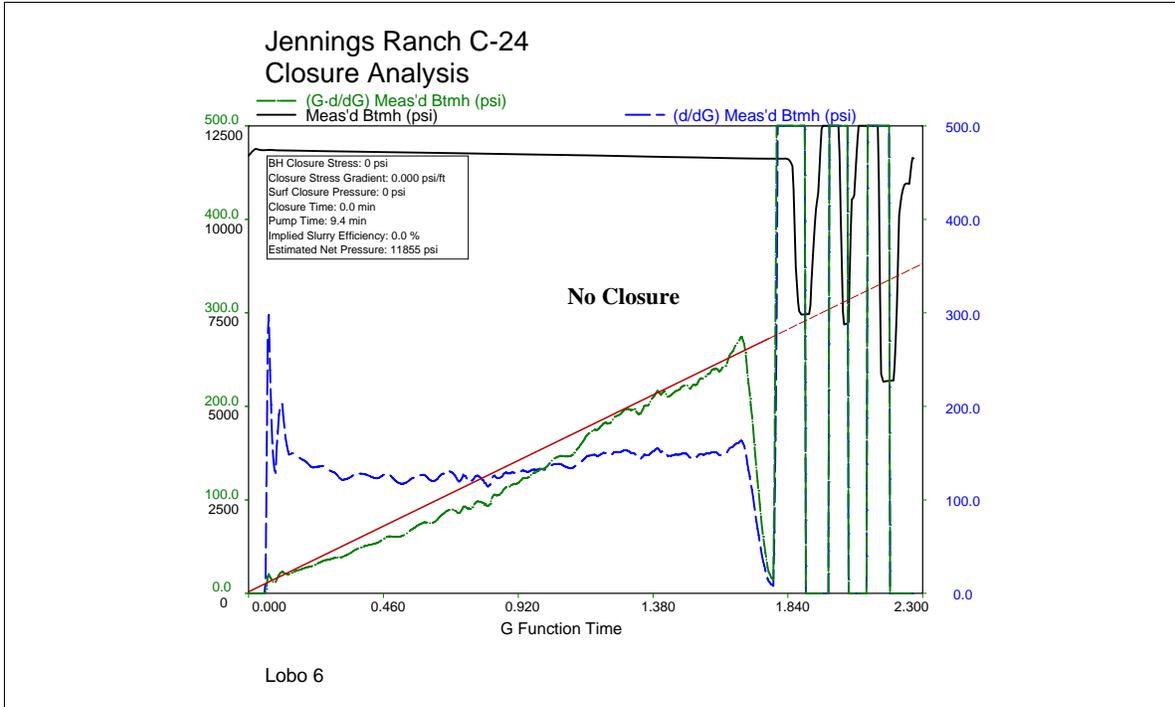


Figure 83. Closure analysis: Jennings Ranch C-24 Lobo 6

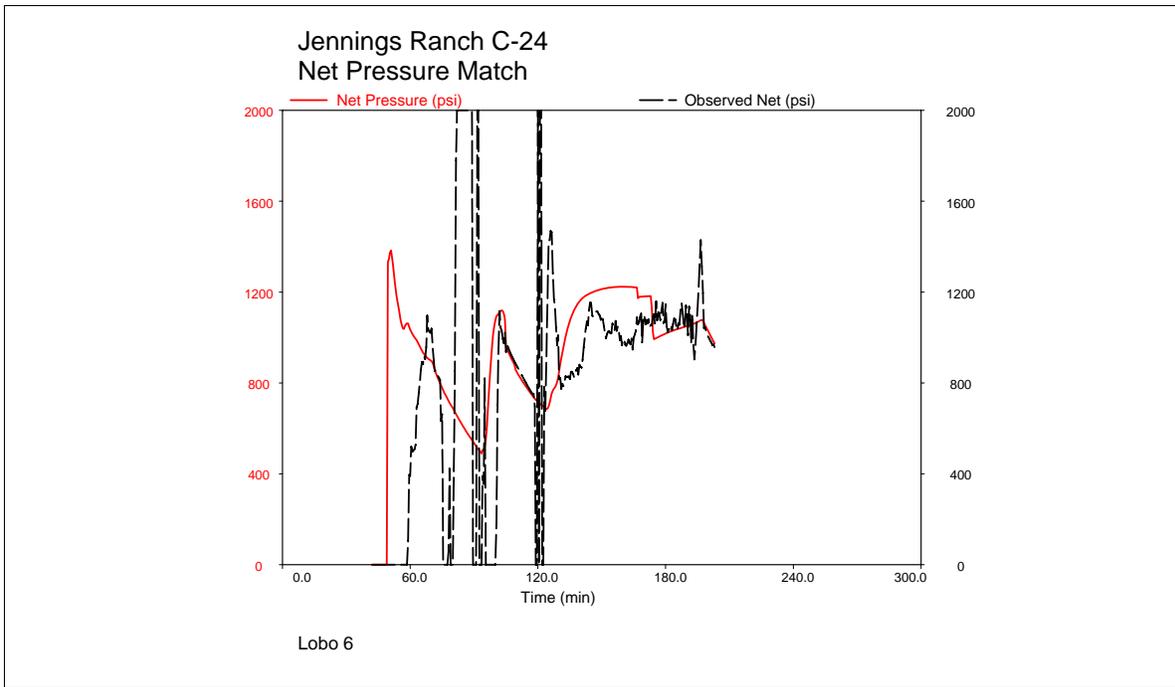


Figure 84. Net pressure match: Jennings Ranch C-24 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

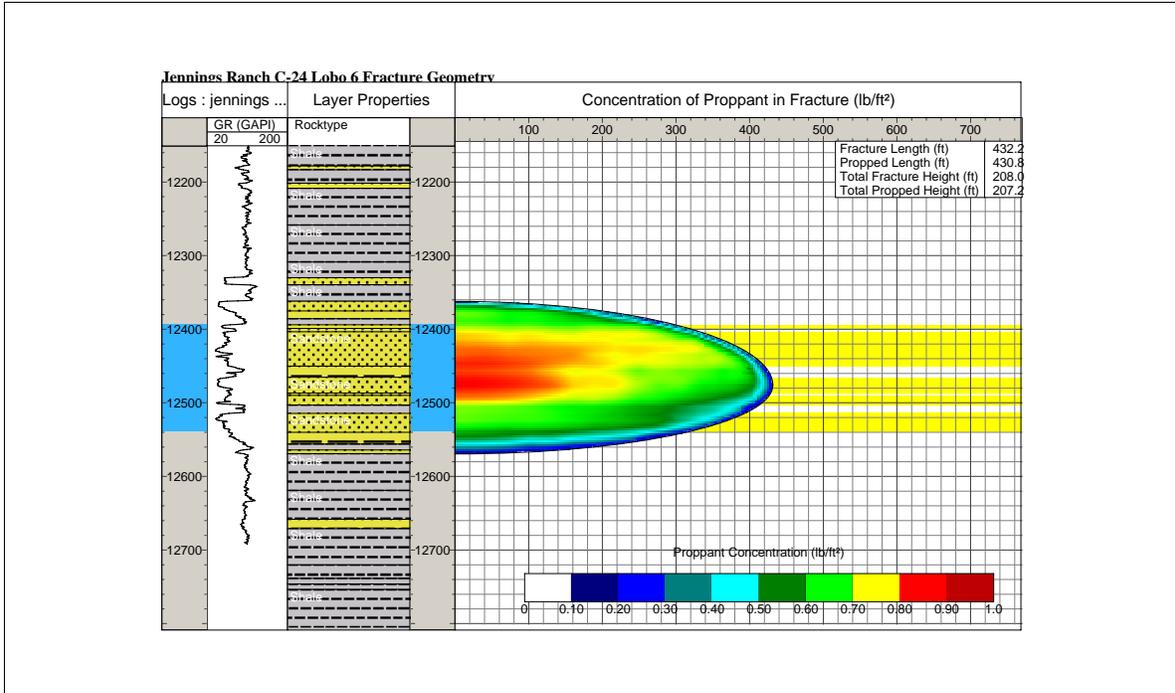


Figure 85. Model fracture geometry: Jennings Ranch C-24 Lobo 6

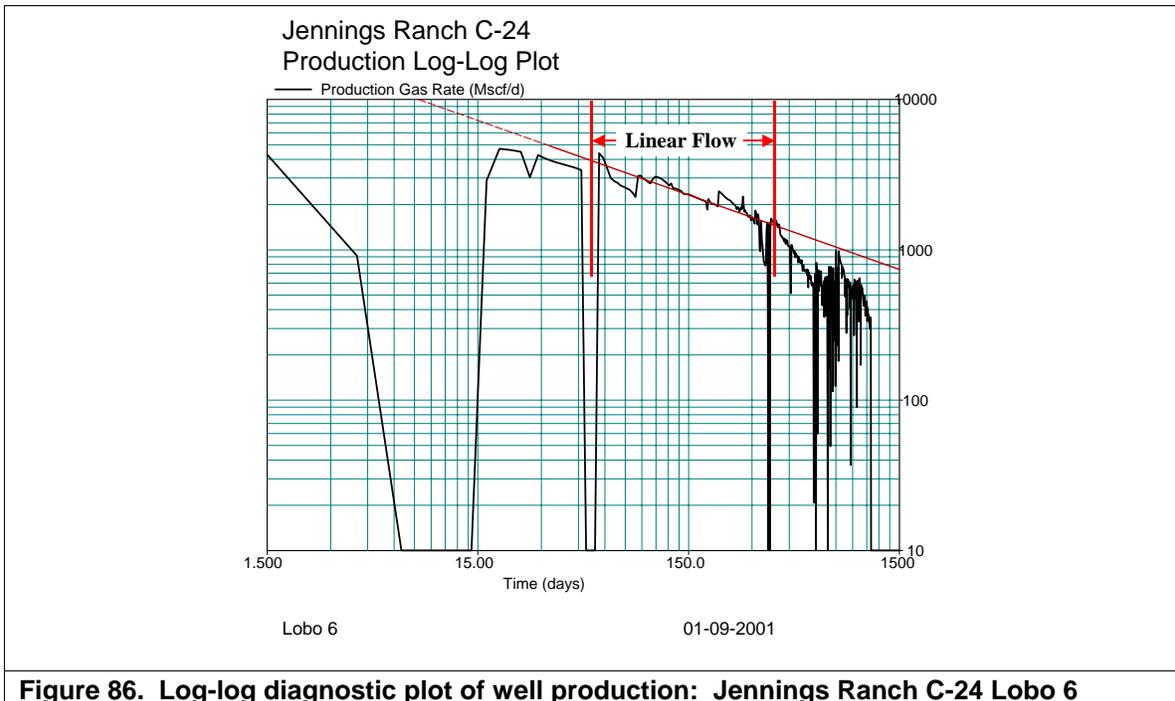
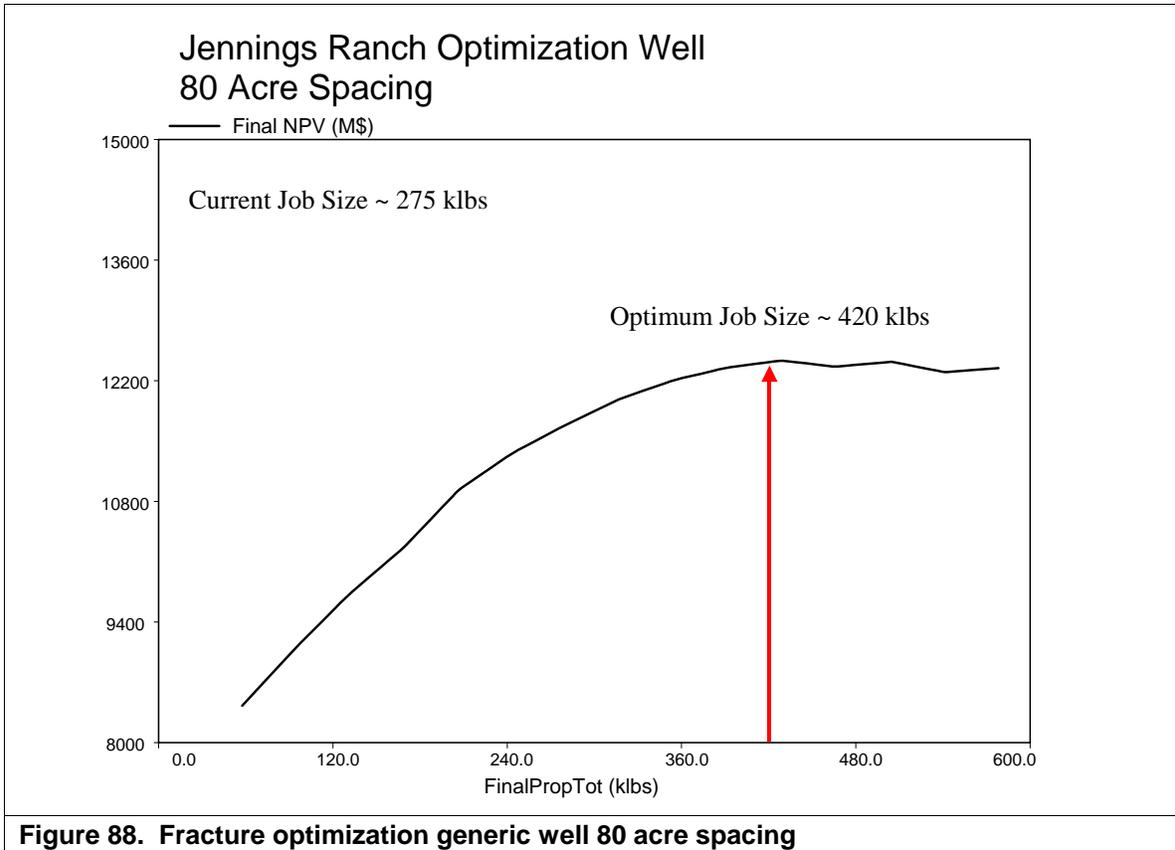
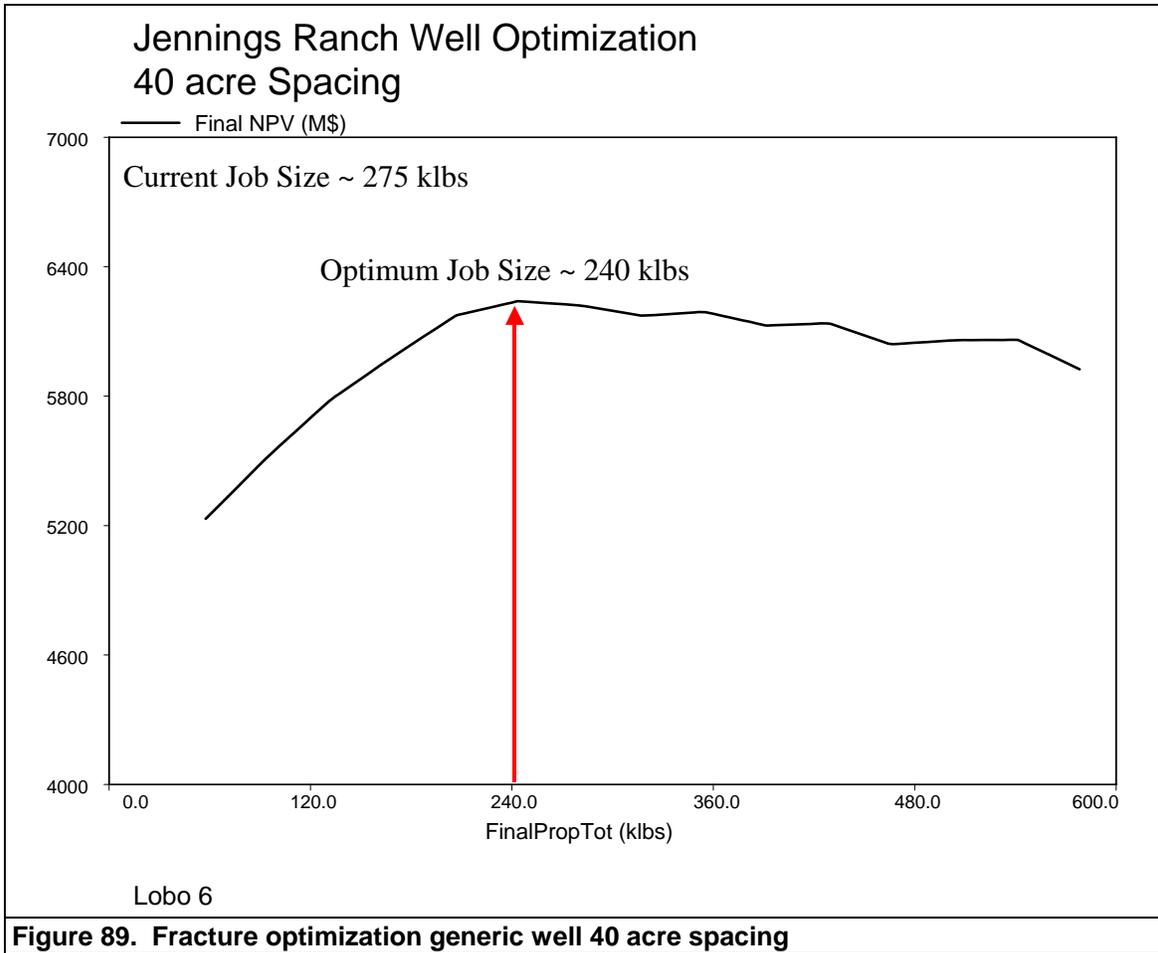


Figure 86. Log-log diagnostic plot of well production: Jennings Ranch C-24 Lobo 6

4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX



4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX



4. Case History of Hydraulic Fracturing in Jennings Ranch Field, TX

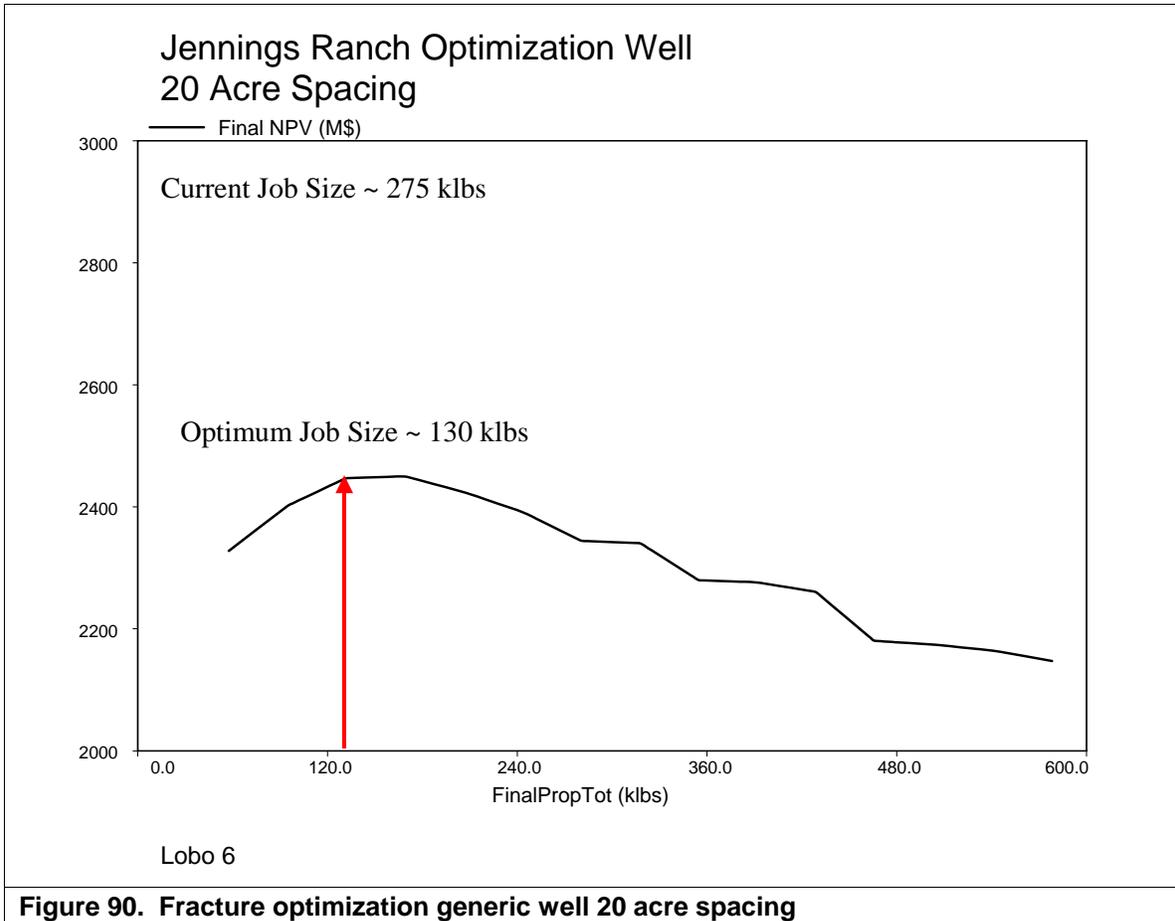


Figure 90. Fracture optimization generic well 20 acre spacing

5. Case History of Hydraulic Fracturing in Table Rock Field, Wyoming

This study focused on three deep gas productive targets in the Table Rock Field in Wyoming. The primary target is a higher permeability dolomite layer (20 to 30 ft thick) surrounded by thick (150 to 200 ft) low permeability/porosity sandstones (secondary targets) designated as the Lower Weber (below dolomite), and Upper Weber (above dolomite) at depths of roughly 17,300 to 18,100 ft. While the dolomite provides the majority of the gas flow rate (75 to 90% of total without hydraulic fracturing), it is limited in reserves due to its smaller thickness. The Weber Sands, on the other hand, are very thick and potentially contain vast amounts of gas reserves but are limited in flow rate and require hydraulic fracture stimulation. Natural fractures are believed to play a role in the production of both Weber Sands and Dolomite. One theory is that the dolomite could actually be serving as a high permeability conduit, with the Weber Sands feeding gas through a natural fracture system. Decline curve estimates and gas-in-place calculations indicate that gas reserves are higher than can be attributed to the dolomite alone; however, the current reserve estimates are very uncertain, having a large spread, which is partly due to uncertain delineation of the field and location of a water-contact. Studies are currently being performed to ascertain the reserve base.

The field includes 17 wells drilled in the late 70's and early 80's. All wells are located to the east of a NNE to SSW trending thrust fault. Recently ChevronTexaco and Anadarko have started a new wave of development in this field. Most of the older wells had natural completions in the dolomite (perforated and acidized) and in some cases in the Upper Weber. Five of the older wells had hydraulic fracture completions with varying success. Currently the Upper Weber and sometimes the Lower Weber are stimulated with hydraulic fractures followed by a natural completion in the dolomite (perforate and acidize). The best well in the field was perforated and acidized only, and has a current cumulative production of about 34 BCF in twelve years. Well performances indicate that reservoir quality can vary significantly across the field, with the challenge being to obtain consistent economic success for every well drilled. Being able to exploit the large Weber gas reserves with effective hydraulic fracture stimulation would be an important "add-on" to the high productivity dolomite.

The general problem with treatments in this area appears to be the creation of complex, multiple fracture systems during hydraulic fracturing. This causes fracture widths to be very small, which is problematic for pumping higher concentrations of proppant and has led to screenouts in the majority of treatments. The propagation of complex fractures and the inability to transport proppant deep into the hydraulic fracture will result in low quality fracture stimulation due to short, low conductivity fractures, which is aggravated by the high stress environment at large depths. This conclusion was supported by a post-frac pressure buildup test, which revealed largely ineffective fracture stimulation. The fracture complexity may also be related to the close proximity of a thrust fault, which can create complex stress fields. In addition, the normal- to even under-pressured pore pressure poses a severe challenge for effective hydraulic fracture stimulation and production.

Three different types of fracture treatments were reviewed in this study. The most frequently pumped design is a CO₂-assisted heavy crosslinked gel treatment with moderate concentrations of

bauxite (up to 4 ppg). In January of 2004, one well was completed with a hybrid-frac design, which uses a large slickwater pad followed by a “low gel loading” crosslinked fluid and lower proppant concentrations of bauxite (up to 2 ppg). The hope was that the hybrid design would increase fracture length, which is the most important design parameter in low permeability rock, while also reducing potential polymer damage to the natural fractures. In April 2004, an acid fracture treatment was pumped to target the dolomite reservoir formation.

It is unclear at this point which type of treatment provides the best fracture stimulation. Fracture modeling indicates that the hybrid treatment may have created longer fractures but production was not better than in the other conventional Upper Weber completions. The key to economic development of this field is high-grade drilling locations that ensure a high quality dolomite zone. Completion technology and stimulation of the low permeability Weber Sands provides added value in these wells. The completion and stimulation of these wells are challenging and it appears that every attempt at improved stimulation does not result in a significant enhancement of well production as reservoir quality is the key driver for performance. It is highly recommended to more frequently employ diagnostic technologies such as pressure buildup tests to segregate completion effectiveness from reservoir quality and estimate pore pressure as this will help both in the optimization of well completion and reserves quantification.

5.1 Conclusions

1. There is strong evidence that created hydraulic fractures are very complex multiple fracture systems. The fracture complexity causes created fracture widths to be very small, which is problematic for pumping higher concentrations of proppant. The majority of treatments in this study had problems with severe increases of treating pressures during the proppant stages leading to screenouts in some cases. The fracture complexity may also be related to the close proximity of a thrust fault, which can create complex stress fields.
2. The propagation of a complex fracture system and the inability to transport proppant deeply into the fractures will result in low quality fracture stimulation due to short, low conductivity fractures. The post-frac pressure buildup in the Table Rock #124 (Lower Weber and Dolomite) supports this conclusion as it revealed largely ineffective fracture stimulation along with a permeability of about 0.63 md and formation flow capacity of 19 md-ft (mainly from dolomite).
3. Fracture complexity was modeled both as multiple branches and increasing leakoff due to opening of natural fissures as injection pressures rise above initiation pressures of oblique oriented natural fractures. The hydraulic fracturing process at this point may actually be a mixed mode of shear and tensile fracturing. The opening of natural fissures is confirmed by pressure-dependent leakoff during the mini-frac falloffs. In addition, radioactive tracer logs also indicate separate fractures at each set of perforations.
4. There is no evidence that any of the Weber fracture treatments (except for the Table Rock #124 where the dolomite was intentionally perforated with the Lower Weber) physically fractured into the dolomite; however, it is unclear at this point if the

Weber Sands will eventually feed into the dolomite through natural fractures as the dolomite is depleted.

5. Three different types of fracture treatments were performed:
 - a. 25% CO₂-assisted 50 to 60 lb/Mgal low-pH crosslinked gel with 30/50 bauxite and a 20/40 bauxite tail-in
 - b. Hybrid job with a large slickwater pad followed by a crosslinked 32 lb/Mgal gel and lower proppant concentrations of 0.25 to 2 ppg 30/60 bauxite and 20/40 bauxite
 - c. Acid fracturing using a pad (linear or crosslinked gel) followed by 15% HCl gelled acid

It is unclear at this point which type of treatment provides the best fracture stimulation as only one hybrid treatment was successfully placed so far and initial flow back data indicators are uncertain due to reservoir quality issues; however, the successful hybrid treatment provided a production response that was on the lower end of comparable Upper Weber completions, showing that the desired goal of achieving a clearly better stimulation and flow response was not achieved. The other hybrid fracture attempt was unsuccessful as very high treating pressures precluded any type of propped stimulation. From a treating pressure perspective, it appears that the hybrid fracture was able to avoid proppant transport related pressure increases and place larger amounts of fluid and proppant. Modeling also indicated that a longer fracture was created, which could be a key issue in very low permeability rock.

6. In the study wells, the majority of the production is coming from the permeable dolomite, with some limited contribution (0.8 to 2.0 MMCFD) from the Weber Sands. In one case (Table Rock #125) perforating and acidizing the dolomite lifted production from about 1.5 to 17 MMCFD. It is common procedure to complete the dolomite after the Upper Weber has been fractured (exception is Table Rock #124, where dolomite was fractured with Lower Weber). The high gas flow rates from the dolomite will serve as a natural gas lift for the continued frac water cleanup from the Weber Sands.
7. The most important issue in developing this field is to identify well locations that will ensure a high quality dolomite zone as this is the key to economic well production. The completion and stimulation of these wells are challenging and it appears that every attempt at improved stimulation does not result in a significant enhancement of well production as reservoir quality is the key driver for performance.
8. The goal to stimulate the dolomite pay zone in the Higgins #17 was achieved, though the near-wellbore conductivity could have been improved by a Closed Fracture Acidizing (CFA) stage.

9. The short-term production forecast in the Higgins #17 is consistent with actual post-treatment production data of 2 MMscfd. The reservoir permeability has dramatic impacts on gas production, and the dolomite zone seems to have a permeability of 0.5 mD based on early post-treatment production match.
10. Significant fracture upward growth in the Higgins #17 was observed and caused by a poor cement job in the upper intervals. The reservoir pressure was lower than expected as the wellbore was only filled with one- third of the completion fluid prior to the acid fracture treatment.
11. It is highly recommended to more frequently employ diagnostic technologies such as pressure buildup tests to segregate completion effectiveness from reservoir quality and estimate pore pressure, as this will help both in the optimization of well completion and reserves quantification.
12. The study did not evaluate reservoir characterization and well location strategies but understanding reservoir quality, especially natural fracturing, is important in this field.
13. Hydraulic fracture mapping would assist in optimizing treatments in this field and assist in answering the following questions:
 - a. How does fracture azimuth vary with proximity to the thrust fault?
 - b. What complexities are evident with fracture mapping and how do they relate to screenout problems?
 - c. What is the overall fracture height growth and how effective is pay zone coverage using various treatment types?
 - d. What is the created fracture length and how does it compare to estimates for effective fracture length from production?

5.2 Discussion

5.2.1 Introduction

This study focused on three deep gas productive targets in the Table Rock Field. The primary target is a higher permeability dolomite layer (20 ft thick) surrounded by low permeability sandstones (secondary targets) designated as the Lower Weber (below dolomite), and Upper Weber (above dolomite) at depths of roughly 17,300 to 18,100 ft (**Figure 91**). A field structure map is shown in **Figure 92**. The most significant feature is a NNE to SSW trending thrust fault. All wells are located on the east side of this fault. Some of the issues outlined in this study, such

as hydraulic fracture complexity, could be associated with a complex stress field created by the thrust fault.

The history of the field includes about 17 wells drilled in the late 70's and early 80's. Recently ChevronTexaco and Anadarko have started a new wave of development in this field. Most of the older wells had natural completions (perforated and acidized) in the dolomite and in some cases in the Upper Weber. Five wells had hydraulic fracture completions with varying success. The best well in the field was perforated and acidized only and has a current cumulative production of about 34 BCF. Well performances indicate that reservoir quality can vary significantly across the field with the challenge being to obtain consistent economic success for every well drilled.

Both the Lower Weber and Upper Weber section are gas-filled low porosity sandstones (3%) with limited amounts of natural fractures. The Upper Weber section is generally considered to be higher reservoir quality than the Lower Weber. It is uncertain at this point how the two sandstone sections interact with the higher permeability, higher porosity dolomite. One theory is that the dolomite is connected by natural fractures to the neighboring sandstones and serves as a "conduit" for additional drainage and reserves from these fairly thick sections. RFTs generally indicate that pore pressures are currently below hydrostatic pressure, in the range of 5,000 to 6,000 psi at about 17,500 ft (0.29 to 0.34 psi/ft). These conditions pose quite a challenge for hydraulic fracturing given the 18,000 ft well depth and fracture treating pressures.

The main type of fracture design used for most wells includes pumping 25% CO₂-assisted 50 to 60 lb/Mgal low-pH crosslinked gel with 30/50 sintered bauxite and a 20/40 sintered bauxite tail-in at the end of the treatment. Bottomhole slurry rates are about 30 bpm and proppant ramps are generally 1 to 4 ppg with about 150 klb of total proppant and 3,500 bbl of total slurry volume. A small proppant slug of 30/60 proppant (0.25 ppg) is usually pumped during the pad. Pad sizes are about 50%. Most treatments showed significant increases of treating pressures after 1 ppg proppant concentrations entered the hydraulic fracture, with some treatments resulting in premature screenouts (**Figure 93**).

On a recently drilled well (Higgins #19, January 2004) a new type of hybrid-style waterfrac treatment was attempted. A hybrid treatment consists of a large slickwater pad, employed to create long fractures using thin fluids, followed by crosslinked gel and proppant with the hope that the thicker fluid will transport proppant far down the fracture length thus providing improved propped fracture lengths. A true waterfrac treatment using only slickwater may have been adequate given the very low reservoir permeabilities and its advantage of eliminating gel damage to natural fractures; however, it was not possible to pump this type of treatment given the use of high-density bauxite, which will cause substantial settling and proppant transport problems when pumped with slickwater.

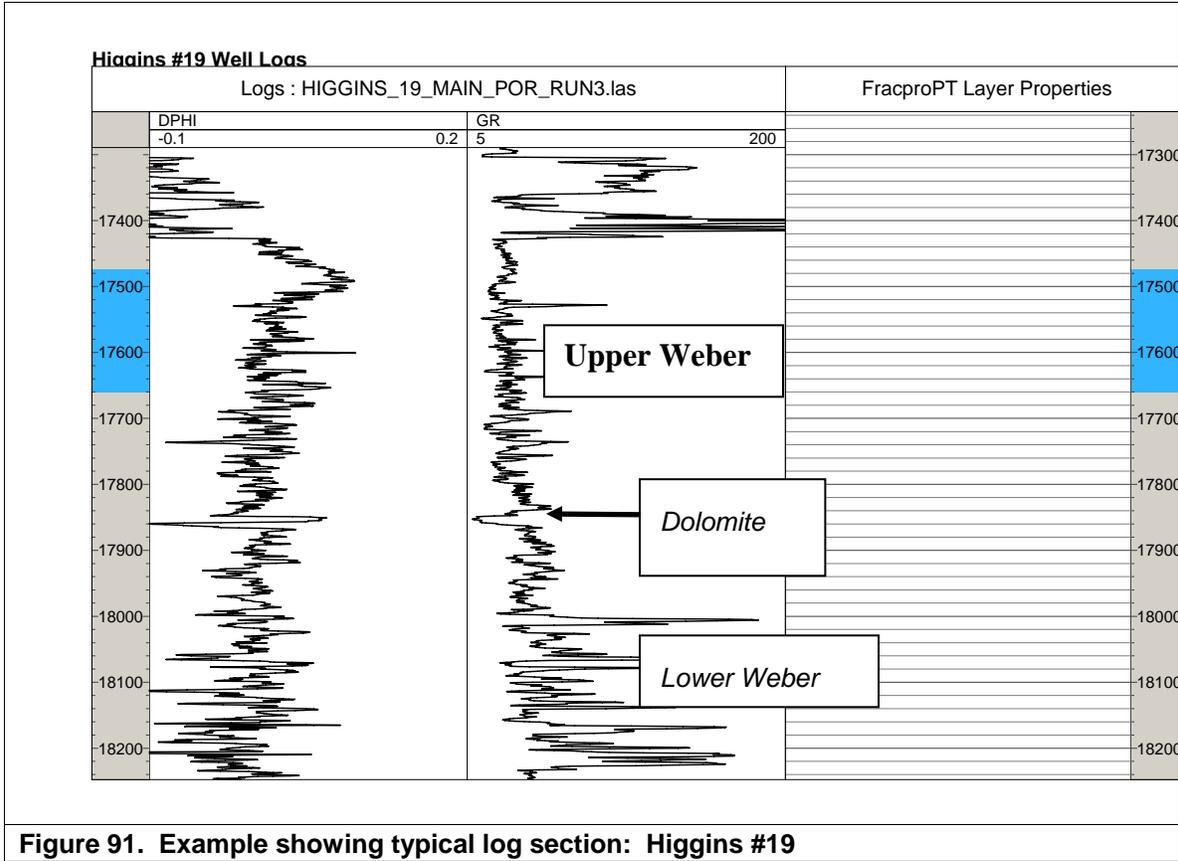
The general goal of the hybrid treatment was to achieve longer fractures by pumping larger treatments (8,000 bbl of fluid with more than 200 klb of proppant) while maintaining adequate conductivity and minimizing gel damage to the natural fracture system. A less aggressive proppant ramp starting at 0.25 ppg to a maximum of 2 ppg was used to minimize proppant entry problems, which enhances the chances of creating a longer fracture. Also, the use of a large slickwater pad (40%) and low polymer concentration crosslinked gel (32# Vistar system) was used to help minimize gel damage (compared to 50 and 60 lb/Mgal gels) while still providing adequate proppant transport capabilities. CO₂ was not added in this type of treatment. It is not

clear at this point if this new type of treatment resulted in better hydraulic fracture performance although it did appear to facilitate placing a larger fracture treatment with reduced risk of screenout.

In most wells, the perforations were placed opposite of natural fractures in the Weber sections (from FMI logs). This perforation strategy will usually result in six to nine clusters of perforations for the Upper Weber and Lower Weber each (if completed). The Higgins #19 was perforated differently with only two clusters of 20 ft perforated intervals in the higher porosity sections of the Weber Sands. At this point it appears that different perforation strategies have little impact on the degree of fracture complexity as all wells show high fracturing net pressures. In all cases, the dolomite (if not included with the fracture treatment of the Lower Weber, *i.e.*, Table Rock #124) is perforated and matrix acidized after the fracture treatment in the Upper Weber has been completed. The available short-term gas flow rates from the Upper Weber (all zones are usually commingled) are in the range of 800 to 2,000 MCFD at 400 to 500 psi surface flowing pressures. The dolomite contributes to most of the gas flow rate, lifting the well production to rates as high as 18 MMCFD in some wells.

The Higgins #17 well was acid fracture treated to target the dolomite pay zone on April 21, 2004. Fracture growth behavior in the region is found very complex – fracture modeling analysis for the Higgins #17 acid treatment indicated a high net pressure of 2,300 psi and complex fracture growth of six multiple fractures. Unlike propped fracture treatments, acid fracture treatments do not run into any risk of screenout. The Higgins #17 acid fracture treatment was executed to completion with a treatment schedule consisting of 1,197 bbl of linear and crosslinked pad and 1,495 bbl of 15% HCl gelled acid. There was no wellhead pressure during the first nine minutes of pumping, which indicated that the wellbore was partially filled prior to the treatment and that the reservoir pressure was lower than expected.

5. Case History of Hydraulic Fracturing in Table Rock Field, WY



5. Case History of Hydraulic Fracturing in Table Rock Field, WY

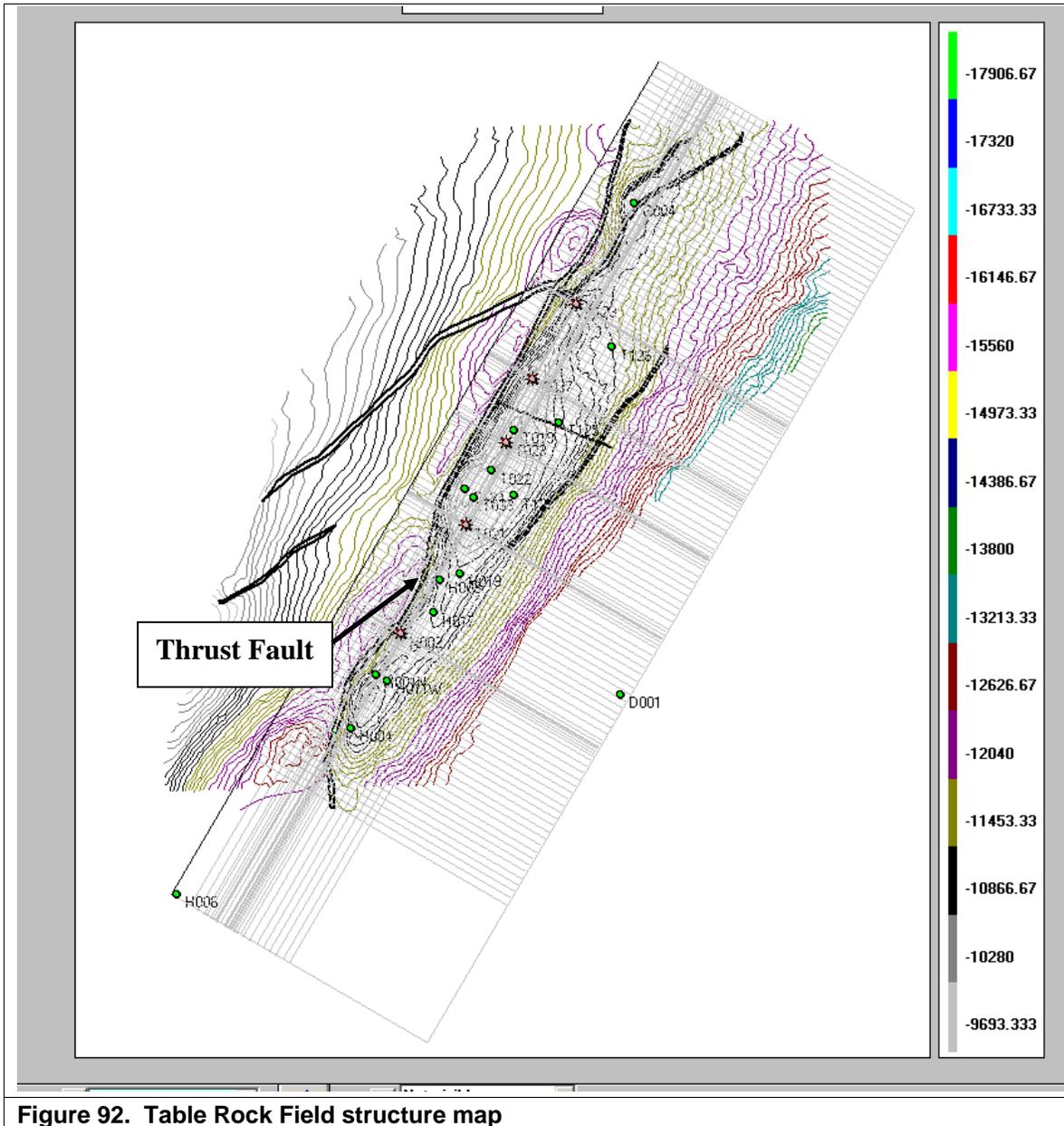


Figure 92. Table Rock Field structure map

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

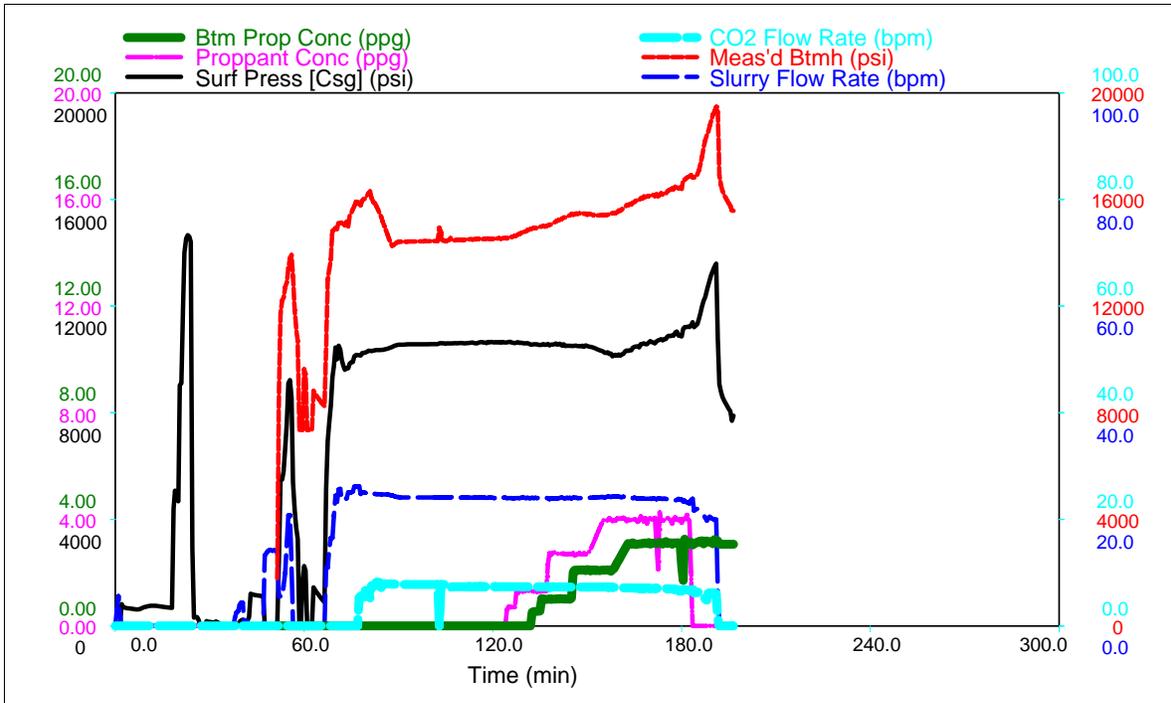


Figure 93. Typical fracture treatment data for conventional CO₂ frac: Table Rock #124 Upper Weber

5.2.2 Fracture Engineering

A total of seven treatments in five wells were analyzed in this study. **Table 4** to **Table 11** summarize the most important fracturing treatment information from all study wells. Fracture closure pressure is generally about 0.66 to 0.69 psi/ft in the Upper Weber (with the exception of 0.8 psi/ft in the Table Rock #123). The “combination” frac treatment of Upper Weber and Dolomite in the Table Rock #124 showed a slightly lower closure of 0.62 psi/ft, which is probably more representative of the dolomite since its perforations were the uppermost set. Closure pressure could not be determined in the Higgins #19 Lower Weber frac attempt since leakoff was slow and fracturing pressures were 1.11 psi/ft. To model the frac upward growth in Higgins #17, the following stress data were used: 0.623 psi/ft for dolomite, 0.75 psi/ft for shale, 0.80 psi/ft for sandstone below dolomite, and 0.70 psi/ft for all other sandstone formations.

Fracturing net pressures are generally very high, ranging from about 500 to 3,500 psi in the mini-fracs and up to 5,000 psi in the main treatment (the screenout in the Table Rock #124 Lower Weber and Dolomite may not reflect the “true” net pressure in the main frac body). ISIP gradients can vary substantially up to 1.1 psi/ft after the mini-frac. The two treatments with the highest ISIP (Table Rock #123 Upper Weber and Higgins #19 Lower Weber) could not be successfully pumped due to pressure limitations. “Successful” treatments have mini-frac ISIPs in the range of 0.69 to 0.82 psi/ft. ISIPs at the end of the treatments ranges from about 0.86 psi/ft to as high as 1.33 psi/ft.

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

Except the acid frac treatment on Higgins #17, all other jobs had substantial net pressure increases throughout the treatment ranging from about 2,300 psi to over 3,400 psi (not counting the 9,000 psi increase for the screenout in the Table Rock #124 LW and dolomite). High fracturing pressures and net pressures are usually a guarantee for very complex hydraulic fracturing. In this field, these circumstances have frequently resulted in either:

- Inability to pump the treatments below the pressure limitations
- Substantial pressure increases during the job due to small fracture widths as proppant is entering the fracture, eventually leading to screenouts

Table 8. Summary of Fracture Treatments: Diagnostic Injections

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Diagnostic Injection-Frac Summary					
				Cls P	Eff	Cls Grd	ISIP(BH)	ISIP Grd	Net P
				psi	(%)	psi/ft	psi	psi/ft	psi
TR 123	UW	17350.0	17480.0	13999	35%	0.80	15963	0.92	1964
TR 124	LW +DOL	17484.0	17726.0	10842	30%	0.62	14426	0.82	3584
TR 124	UW	17114.0	17340.0	11899	11%	0.69	13435	0.78	1536
TR 125	UW	17448.0	17750.0	11556	32%	0.66	13668	0.78	2112
Higgins 19	LW	18068.0	18144.0	n.a.	n.a.	n.a.	20024	1.11	n.a.
Higgins 19	UW	17474.0	17660.0	11511	40%	0.66	12044	0.69	533
Higgins 17	DOL	17967.0	17975.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

Table 9. Summary of Fracture Treatments: Propped and Acid Frac Treatment

Well	Zone	Propped/Acid Frac Treatment Summary							
		Vol bbls	Rate bbls/min	Prop klbs	ISIP(BH) psi	ISIP Grad psi	Net P psi	Screen Out?	Net P Increase psi
TR 123	UW	1038.0	30 to 40	2	18309	1.05	4310	y	2346
TR 124	LW +DOL	3414.0	30.0	101	23391	1.33	12549	y	8965
TR 124	UW	3735.0	30.0	157	16812	0.98	4913	y	3377
TR 125	UW	3700.0	30.0	153	16182	0.92	4626	n	2514
Higgins 19	LW	5014.0	30 to 6	3	20228	1.12	n.a.	y	n.a.
Higgins 19	UW	7966.0	44.0	221	15091	0.86	3580	n	3047
Higgins 17	DOL	2692.0	26.0	0	13491	0.75	2300	n	n.a.

Table 10. Summary of Fracture Treatments: Comments

Well	Zone	Prop/Etech	Prop/Frac	Conductivity (frac system)	Multiple Fracture Settings
		Length (ft)	Height (ft)	(mD-ft)	Volume-Leakoff-Opening
TR 123	UW	0	0	0	14-8-14
TR 124	LW +DOL	85	164	880	16-14-16
TR 124	UW	119	231	715	7-9-7
TR 125	UW	150	302	1120	10-5-10
Higgins 19	LW	79	104	0	60-5-60
Higgins 19	UW	292	272	770	5-9-5
Higgins 17	DOL	223	360	384	6-1-2-6

Table 11. Summary of Fracture Analysis Results

Well	Zone	Top Perf MD	Btm Perf MD	Comments
		(ft)	(ft)	
TR 123	UW	17350.0	17480.0	Borate x-link Gel; could not pump due to pressure limit
TR 124	LW +DOL	17484.0	17726.0	25% CO2 low PH 50-60# x-link; Screen-out
TR 124	UW	17114.0	17340.0	25% CO2 low PH 50-60# x-link; Pressure rise as proppant enters frac
TR 125	UW	17448.0	17750.0	25% CO2 low PH 50-60# x-link; Pressure rise not as extreme
Higgins 19	LW	18068.0	18144.0	Hybrid Frac- Slickwater/Vistar 3200; could not pump due to pressure limit
Higgins 19	UW	17474.0	17660.0	Hybrid Frac- Slickwater/Vistar 3200
Higgins 17	DOL	17967.0	17975.0	Acid Frac of alternating 15%HCl Gelled acid & 30#Pur-Gel III pad stages

Table 4 shows a summary of the fracture modeling results. All fracture modeling was performed using the 3-dimensional hydraulic frac simulator FracproPT™. Pressure-dependent leakoff (cross-cutting fissures opening at high injection pressures) is present in most of the falloffs, which is consistent with the presence of natural fractures leading to multiple complex fracturing. In conjunction with high net pressures, this is an indication of far-field fracture complexity (multiple fractures) which can severely limit fracture extent (Figure 94). Near-wellbore fracture complexity (tortuosity), which manifests itself as friction pressure, was moderate in most cases and does not appear to be the main problem for treatment execution. Every treatment had to be modeled with a large degree of fracture complexity, which included both multiple competing fractures and increasing leakoff throughout the job as fissures open.

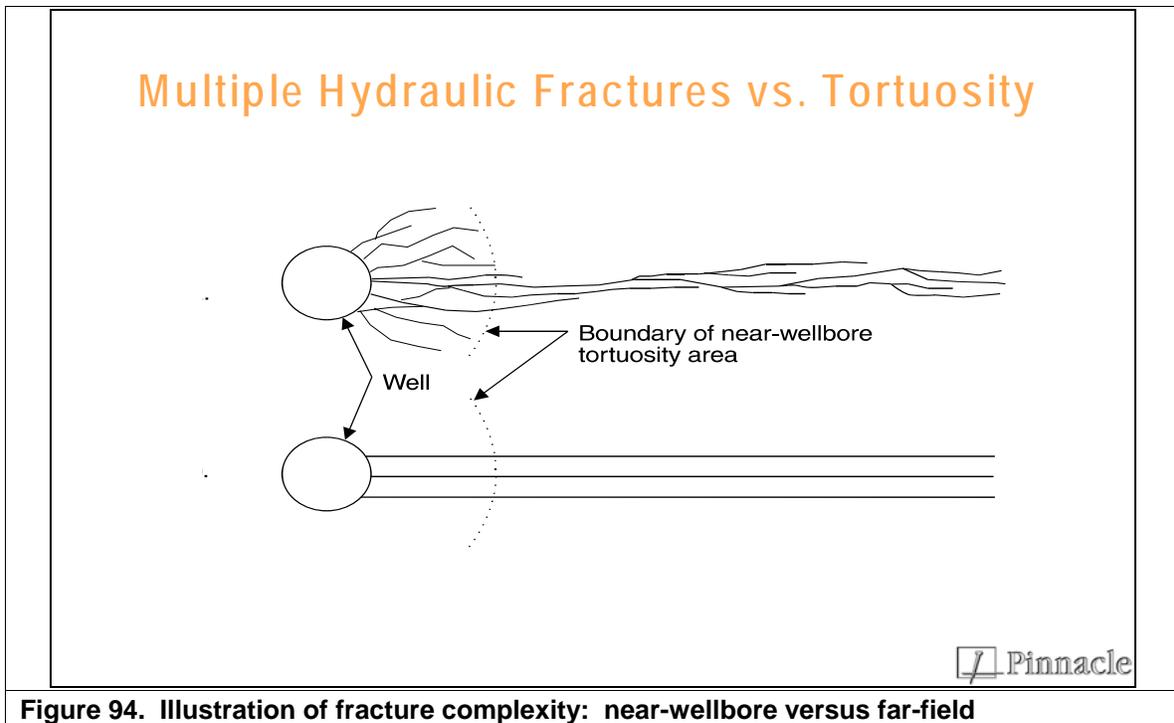
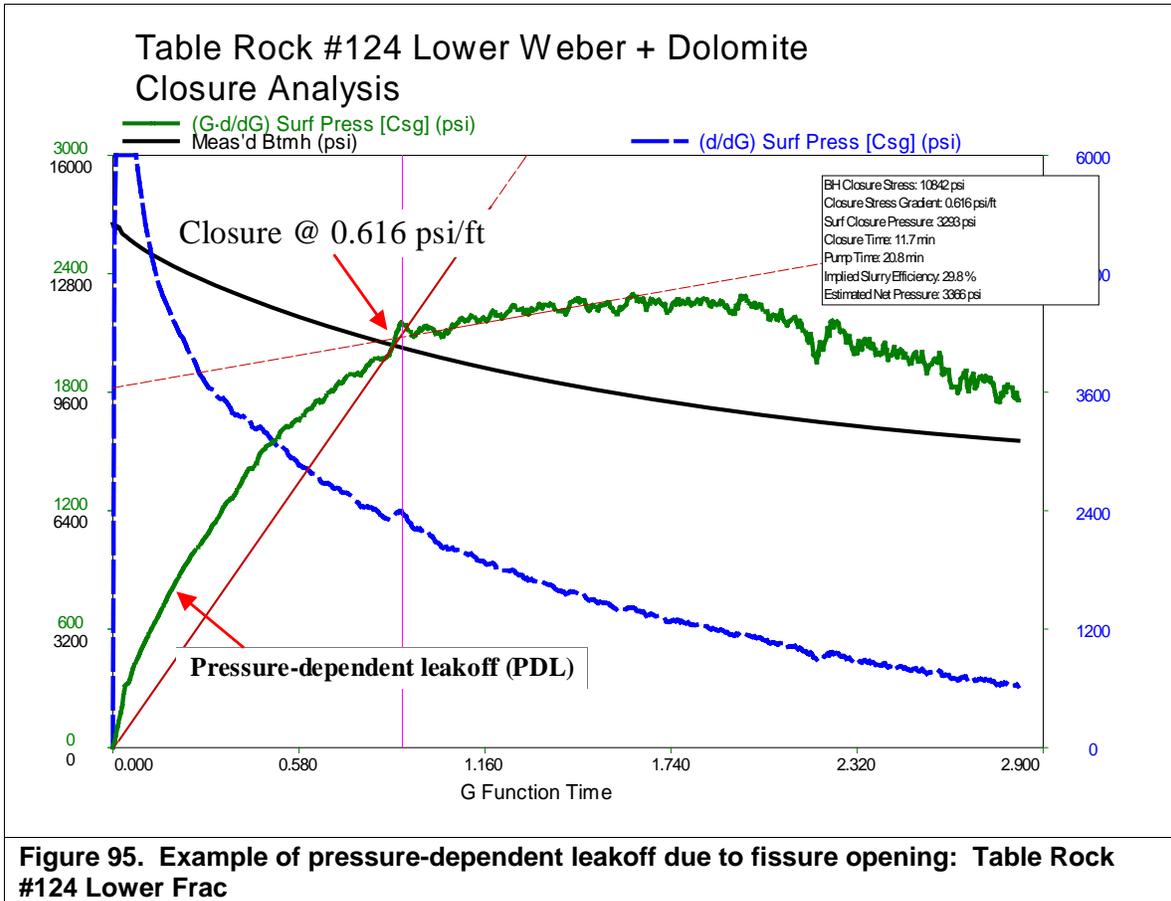


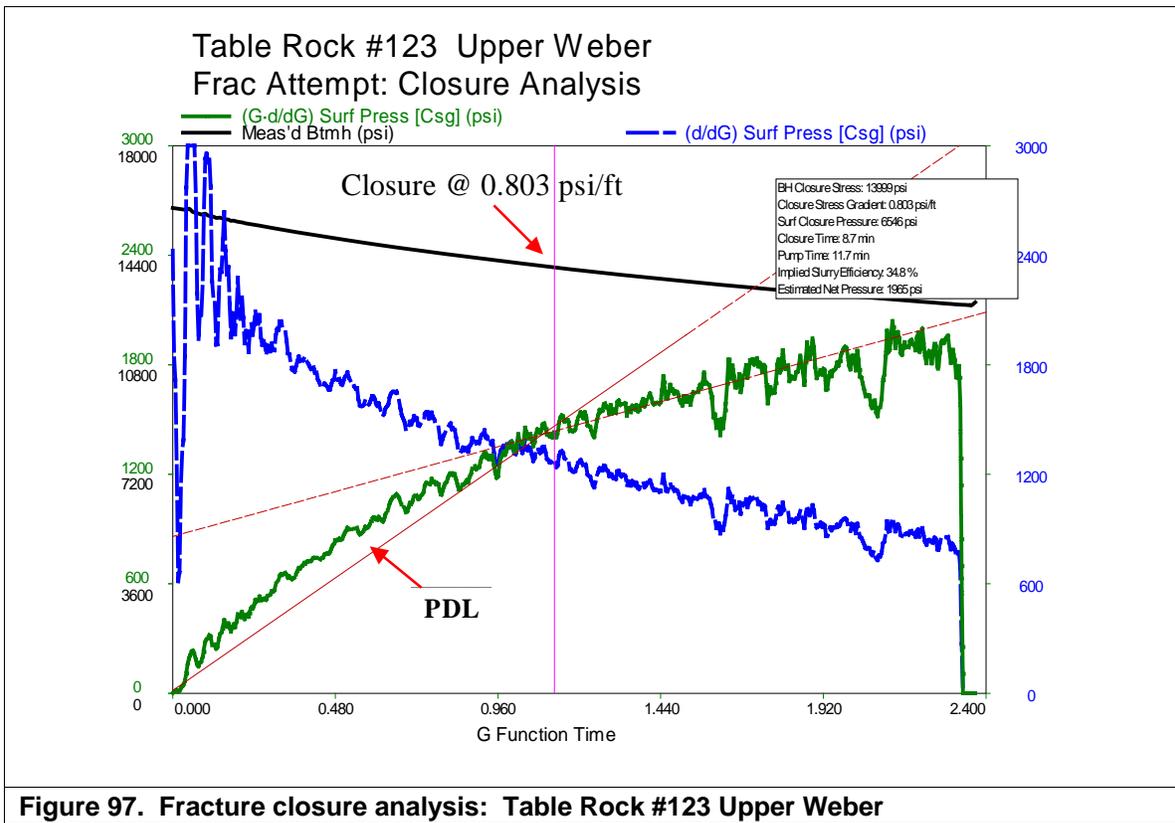
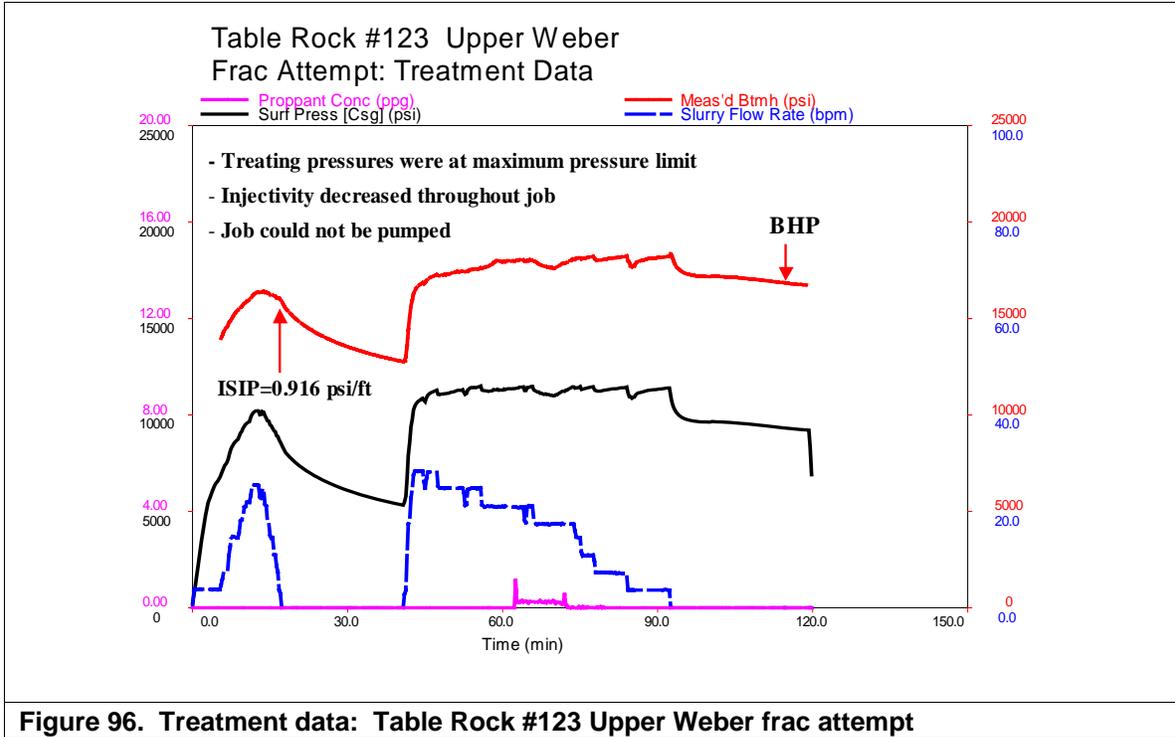
Figure 95 shows an example of a G-function analysis plot (from Table Rock #124 Lower Weber/Dolomite) indicating significant pressure-dependent leakoff (PDL, where oblique-oriented natural fissures open during the fracturing process). Such a behavior in conjunction with high net pressures is strong evidence for very complex fracture growth.



The following section details all the individual fracture treatments with graphs of treatment data, fracture closure analysis, net pressure matches and resulting fracture geometry.

5.2.3 Table Rock #123 Upper Weber Frac Attempt

In this well it was not possible to successfully fracture treat the Upper Weber as meaningful injection rate could not be established due to surface pressure limitations of 12,000 psi. **Figure 96** clearly shows decreasing injectivity through the course of the pad resulting in a premature termination of the treatment without any meaningful amounts of proppant being pumped. **Figure 97** shows that near-wellbore tortuosity and perforation friction are moderate and not the root cause of high injection pressures. The net pressure match shows high frac complexity (**Figure 99**) resulting in a very short, 50-ft un-propped fracture (**Figure 100**). Following this failed fracture attempt, the dolomite was perforated and acidized resulting in initial flow rates of almost 6 MMCFD.



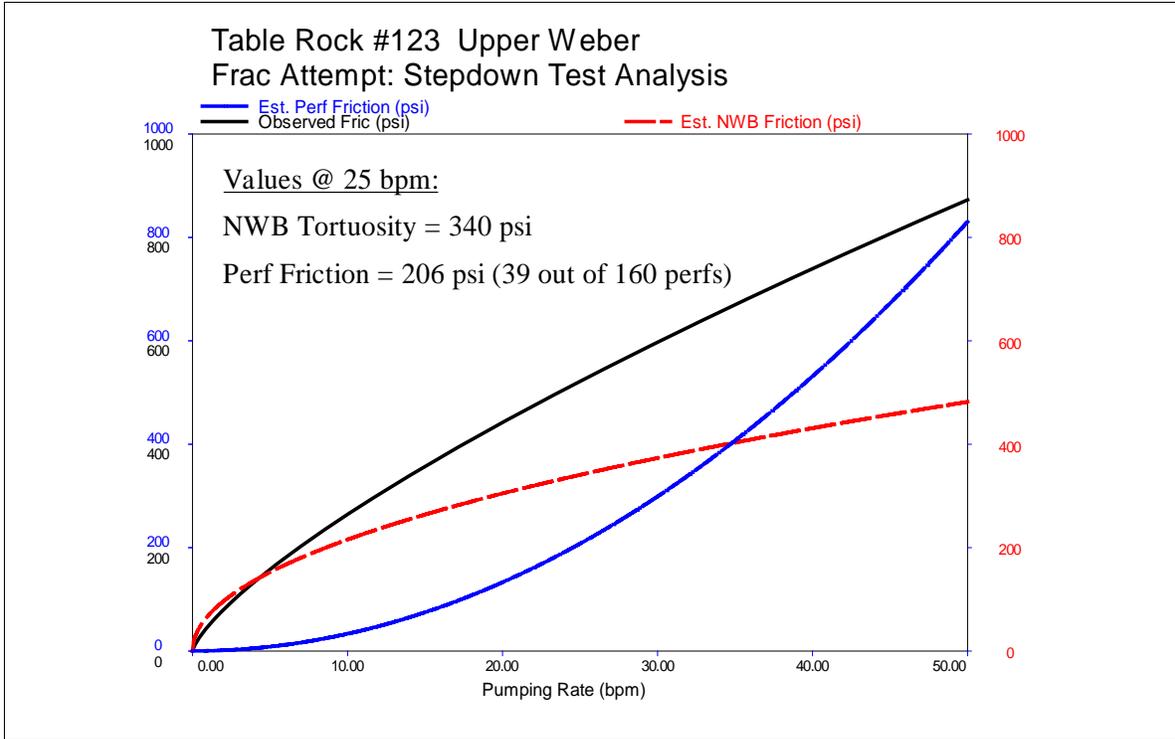


Figure 98. Estimating tortuosity and perforation friction: Table Rock #123 Upper Weber

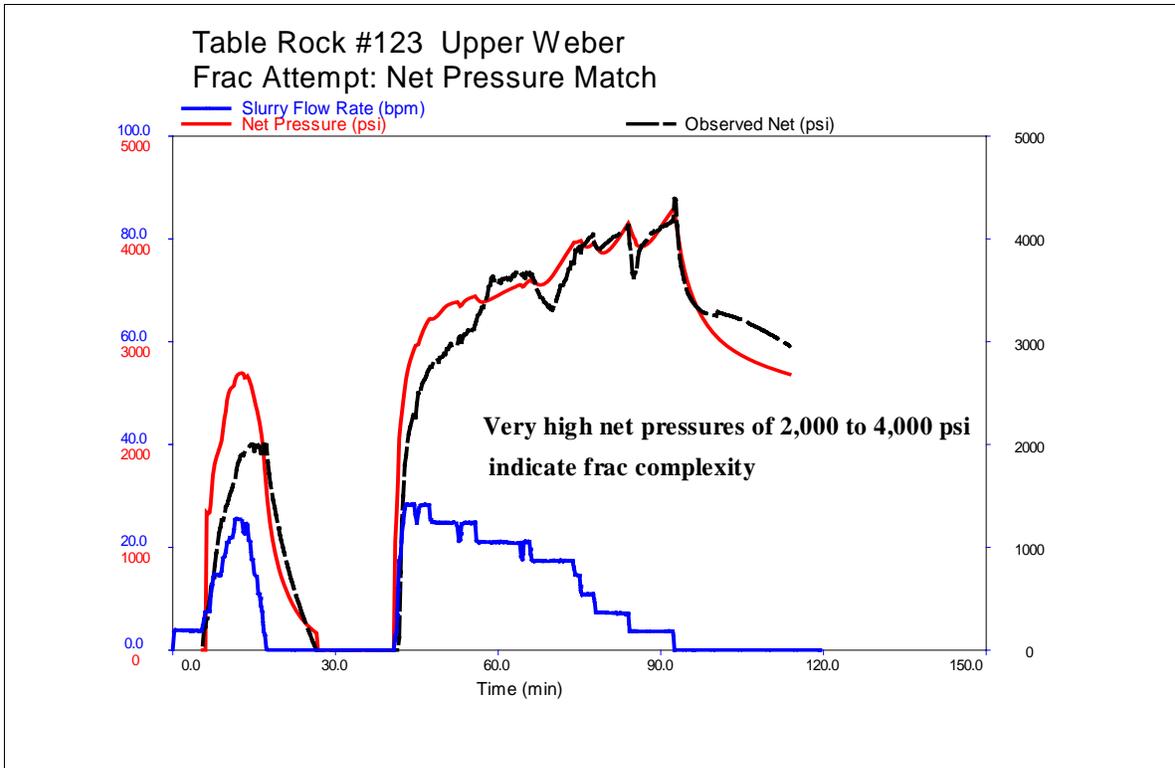
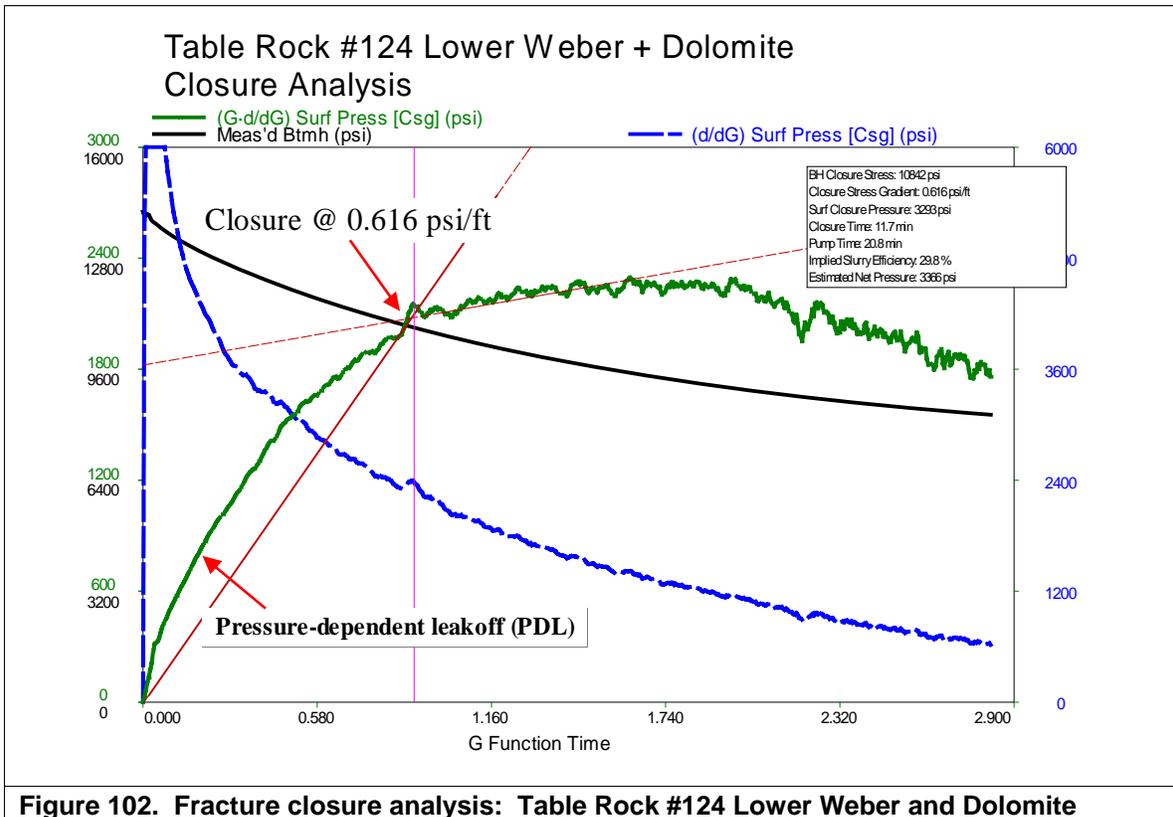
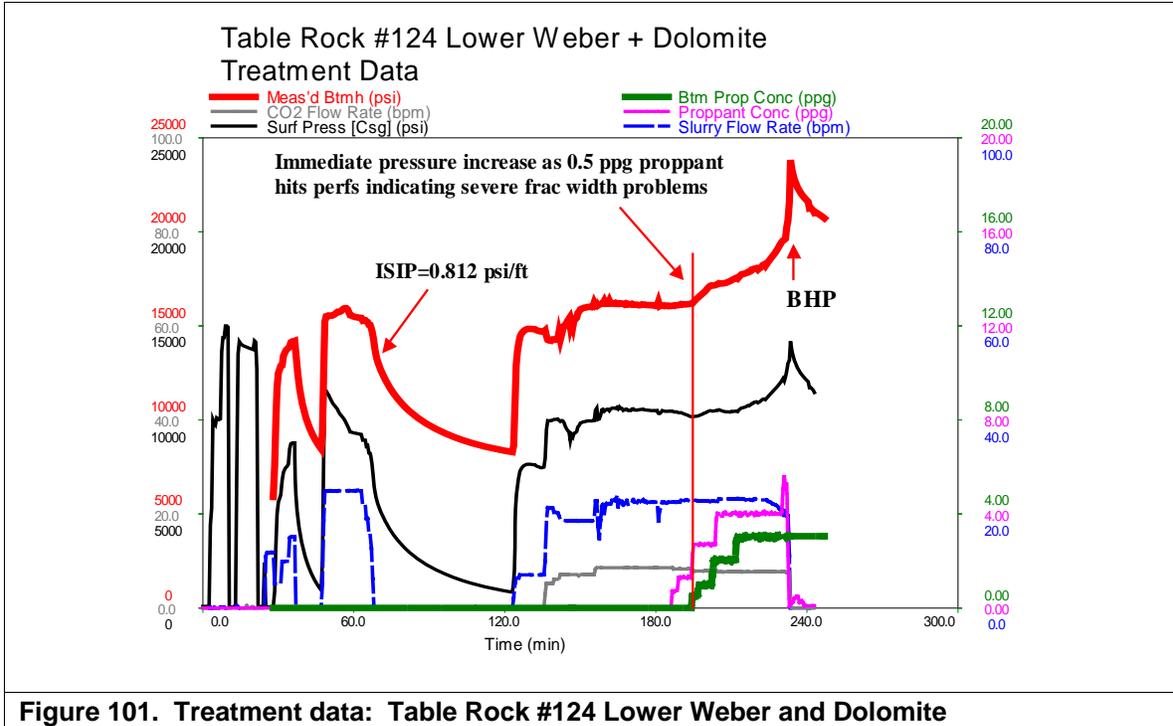
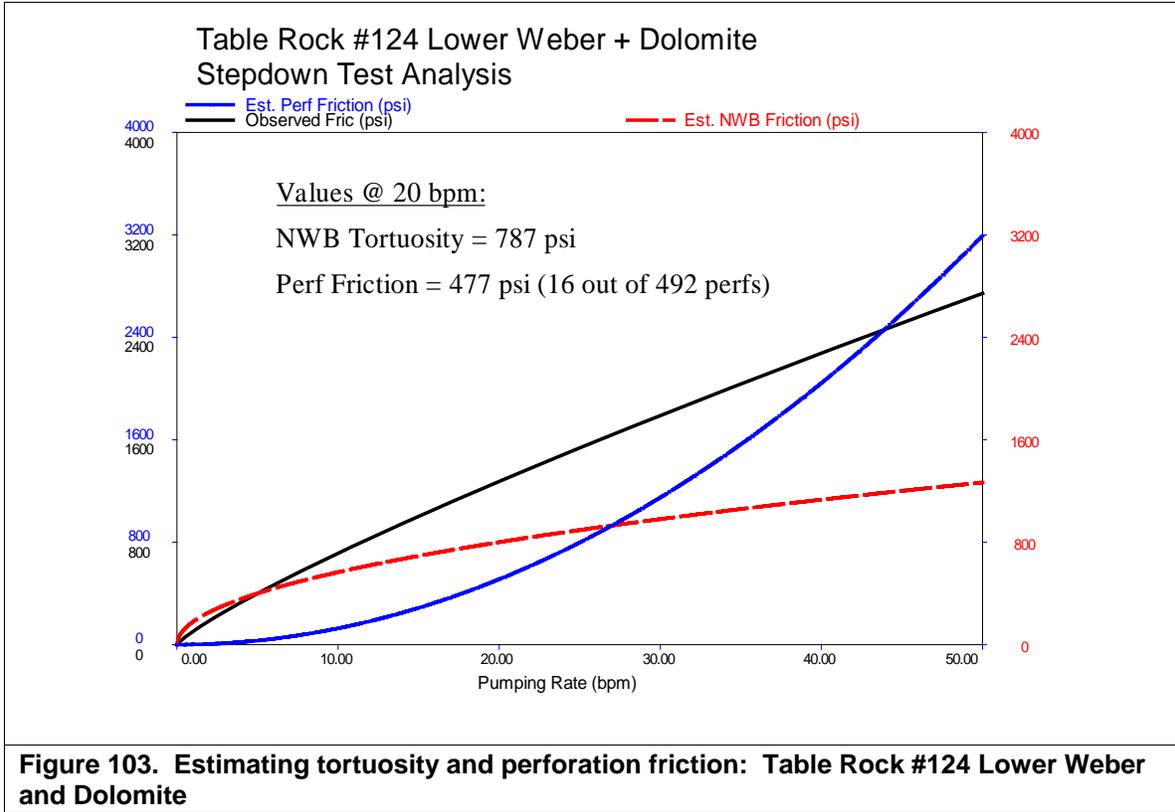
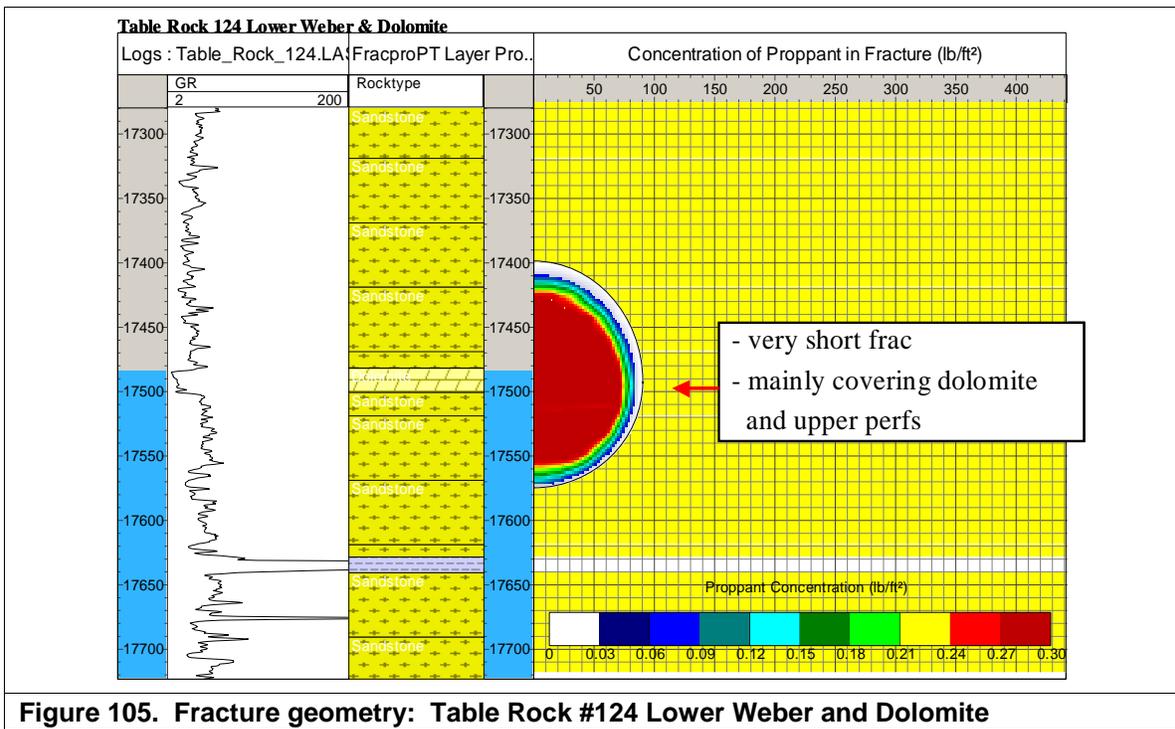
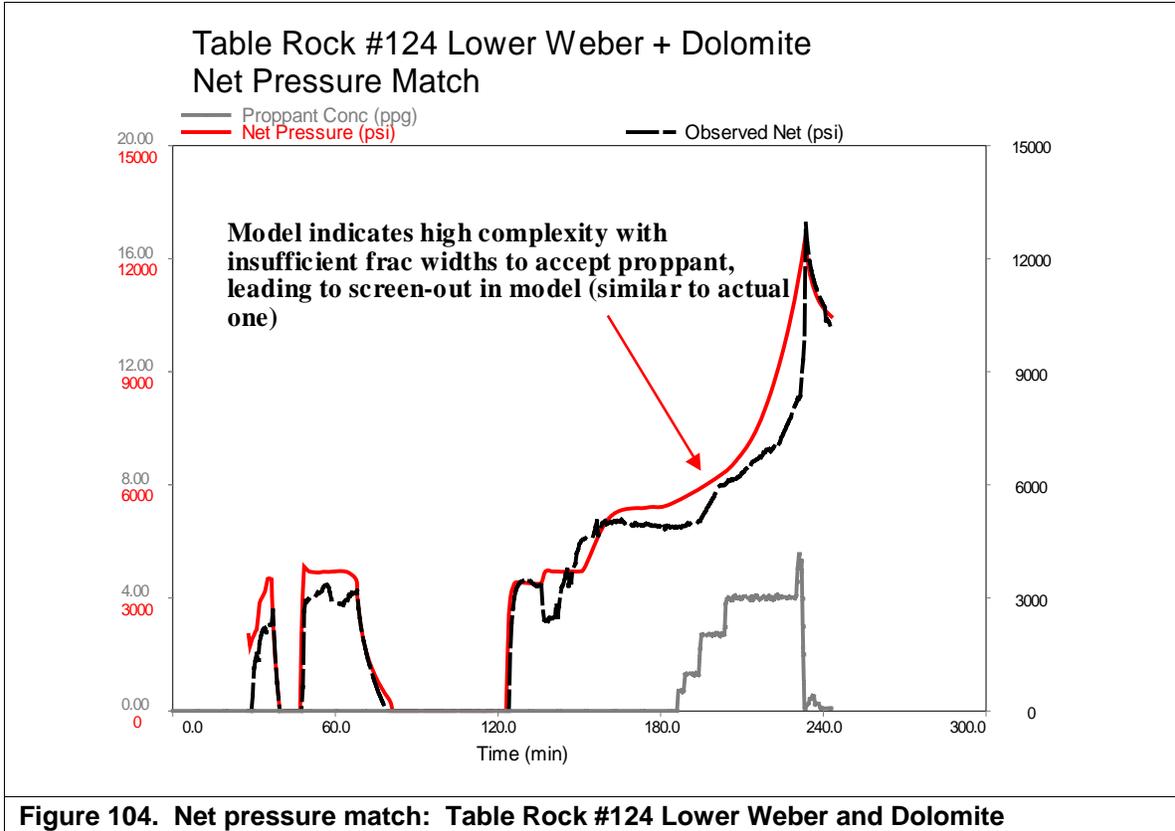


Figure 99. Net pressure match: Table Rock #123 Upper Weber frac attempt





5. Case History of Hydraulic Fracturing in Table Rock Field, WY



5.2.5 Table Rock #124 Upper Weber

The Upper Weber was fractured with a 25% CO₂-assisted 50 to 60 lb/Mgal crosslinked gel (YF 850/860LPH). The mini-frac pressure falloff analysis (**Figure 106**) indicates rapid fluid leakoff with a closure stress of about 0.69 psi/ft. Although not as pronounced as in the other cases, the falloff exhibits some pressure-dependent leakoff. Similar to the lower stage, the treatment data in **Figure 107** shows that bottomhole pressures immediately increase as 0.5 ppg, 30/60-bauxite enters the fracture, indicating small fracture widths and high fracture complexity. Treating pressures continued to rise but in this case the treatment was flushed and pumped to completion. The net pressure was matched using high fracture complexity and is shown in **Figure 108**.

The resulting model fracture geometry indicates a very short, 120-ft fracture (**Figure 109**). The after-frac tracer log for this stage (**Figure 110**) indicates that the two lowest set of perforations took most of the fracturing fluid and proppant, although some tracer was also found in some of the upper perforations. When comparing the tracer log with the fracture modeling results, it is unclear if the tracer is showing the total fracture height since fractures may not be fully aligned with the wellbore. If the fracture height covers the interval from the uppermost indication of tracer to the lowest, it coincides fairly well with the overall modeled fracture height of 230 ft. The tracer log generally shows that tracer is confined to each set of perforations with no apparent connection in between. This may indicate separate fractures not growing together. In the Lower Weber, only the lowest set of perforations was not stimulated. The tracer log appears to confirm the conclusion from fracture modeling that fracture complexity is high. Except for the exact position along the wellbore, the overall fracture heights of the top and bottom tracer roughly correspond to the overall fracture model heights. Once all zones were commingled, the well produced at an initial rate of about 6.5 MMCFD, with the Upper Weber contributing about 1.5 to 2 MMCFD.

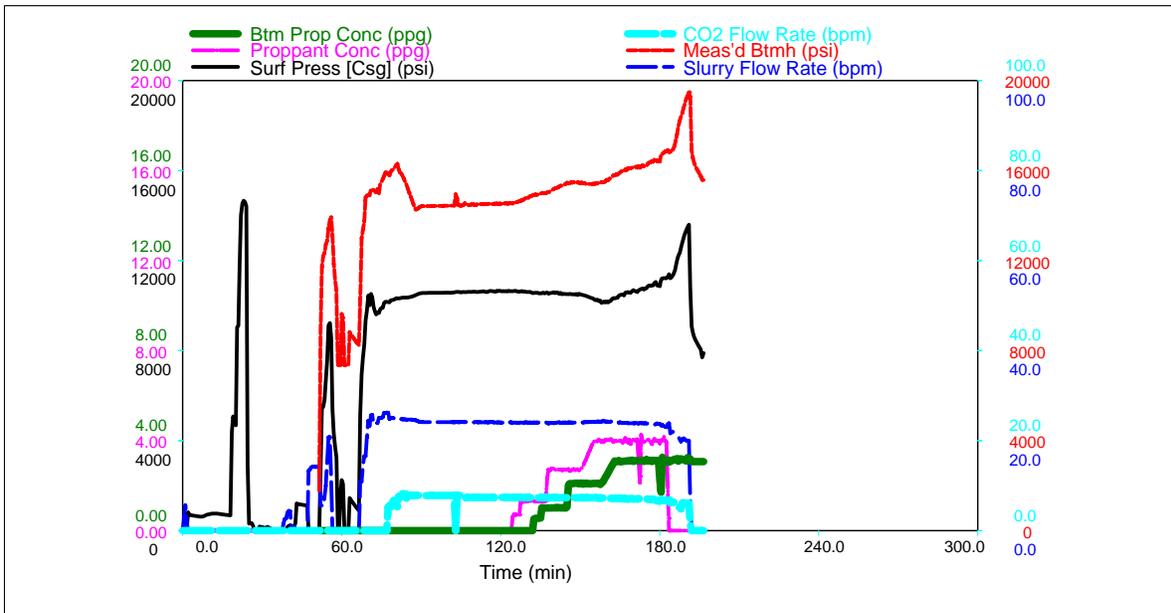


Figure 106. Treatment data: Table Rock #124 Upper Weber

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

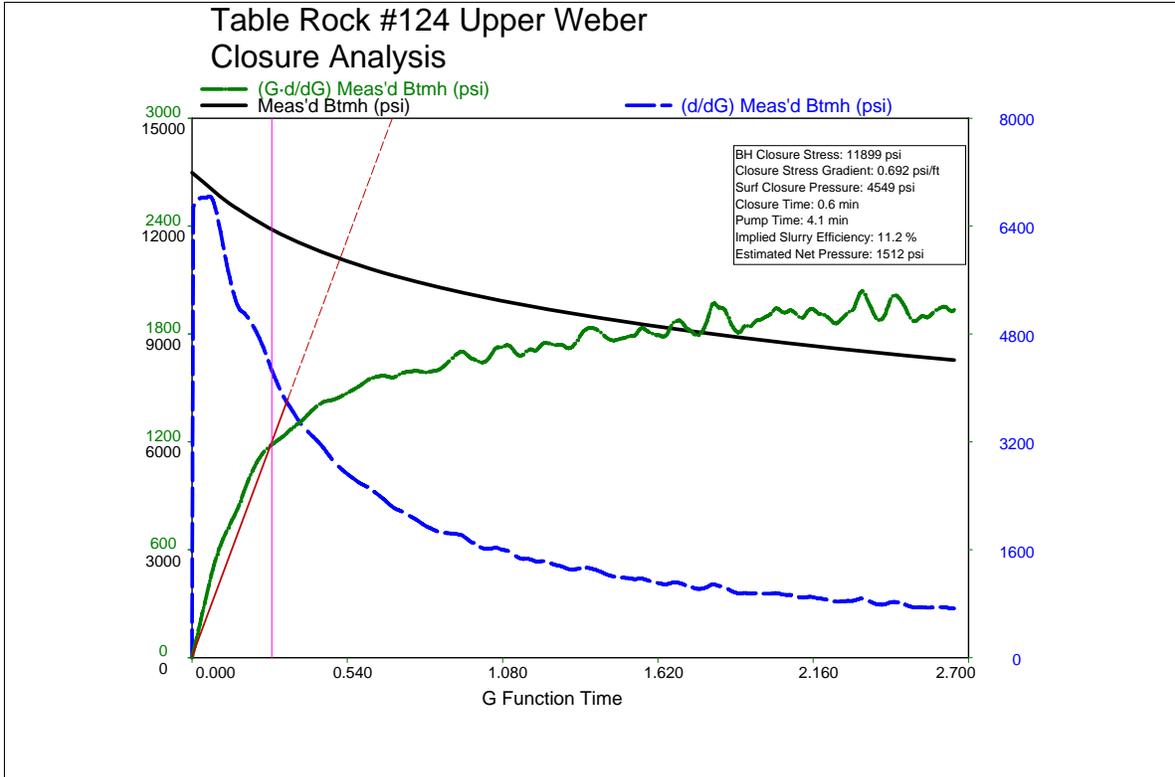


Figure 107. Fracture closure analysis: Table Rock #124 Upper Weber

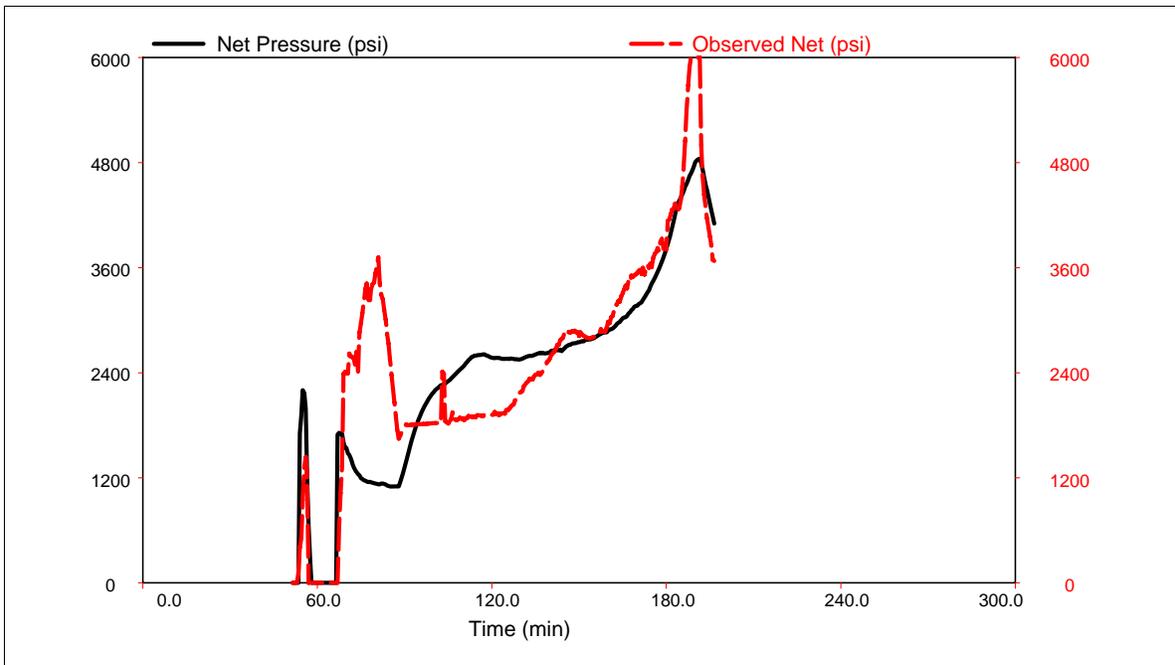
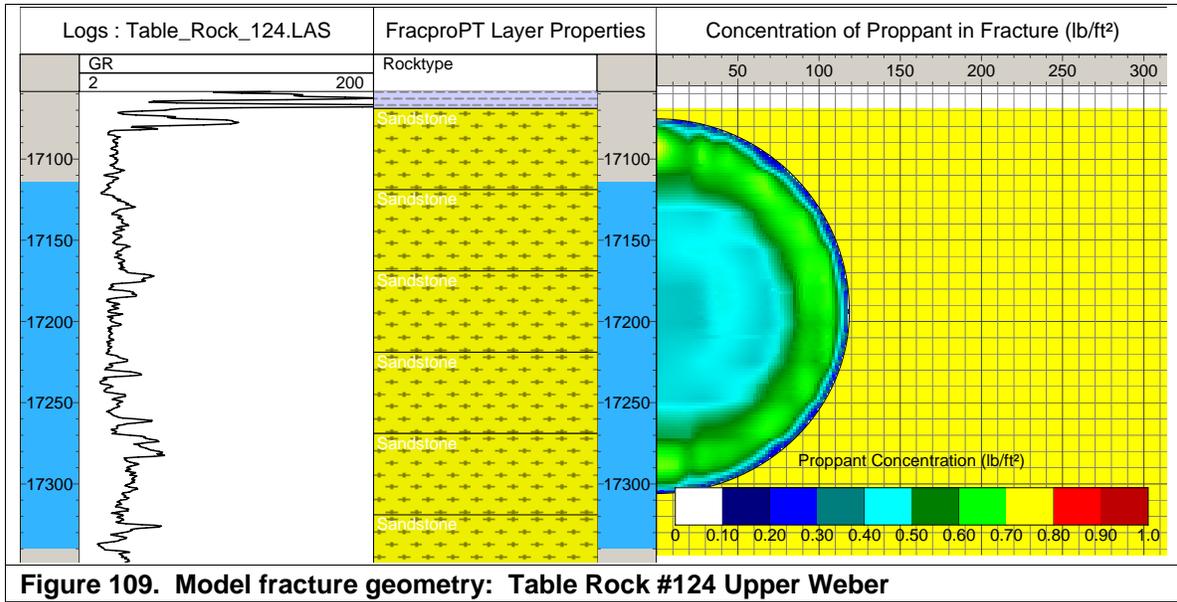


Figure 108. Net pressure match: Table Rock #124 Upper Weber

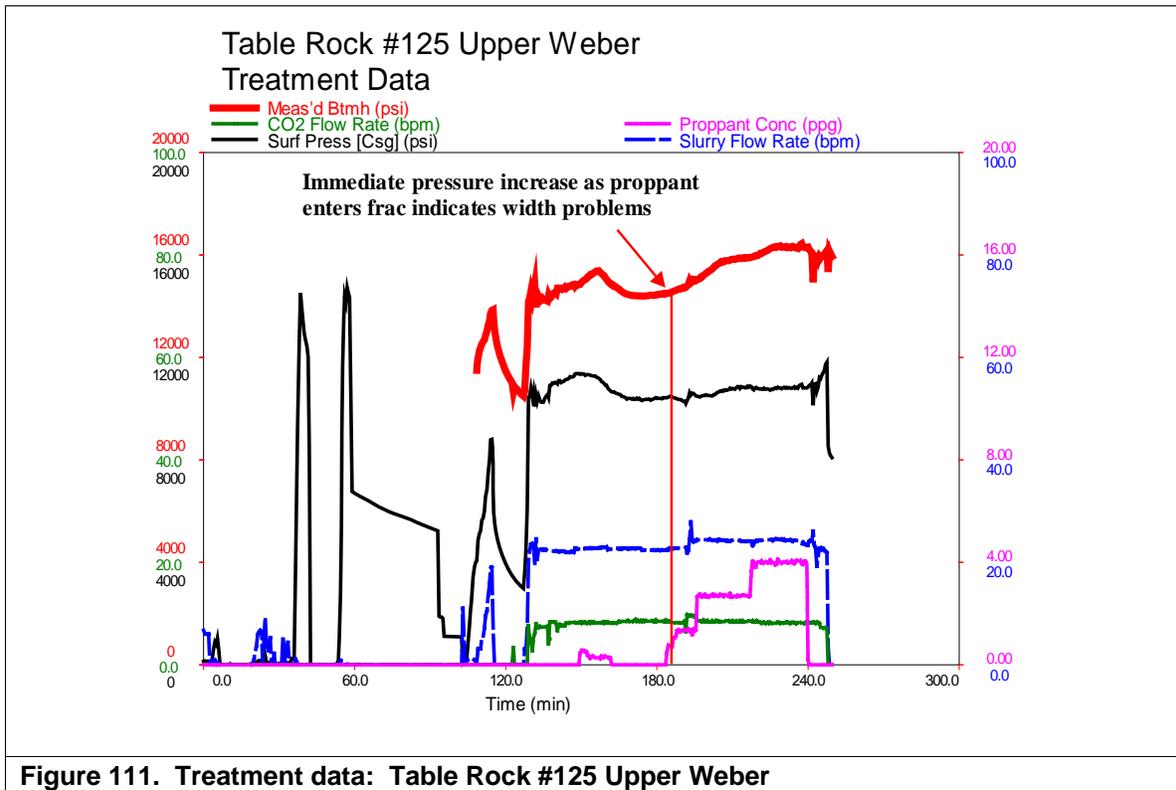
5. Case History of Hydraulic Fracturing in Table Rock Field, WY



5.2.6 Table Rock #125 Upper Weber

In this well only the Upper Weber was fracture treated using a 25% CO₂-assisted 50 to 60 lb/Mgal crosslinked gel (YF 850/860LPH). The mini-frac pressure falloff analysis (**Figure 112**) indicated rapid fluid leakoff with a closure stress of about 0.66 psi/ft. The falloff also indicates pressure-dependent leakoff, an indication of fissure opening and susceptibility to complex fracturing. The treatment data in **Figure 111** shows that bottomhole pressure immediately increases as 0.5 ppg, 30/50 bauxite enters the fracture. Again, this is an indication of very small fracture widths and high fracture complexity resulting in a continuous rapid increase of bottomhole treating pressures. In this case, the fracture treatment was pumped to completion without screenout. The net pressure was matched using high fracture complexity and is shown in **Figure 113**.

The resulting model fracture geometry indicates a very short, 150-ft fracture (although longer than in the previous Table Rock #124 treatment (**Figure 114**)).



5. Case History of Hydraulic Fracturing in Table Rock Field, WY

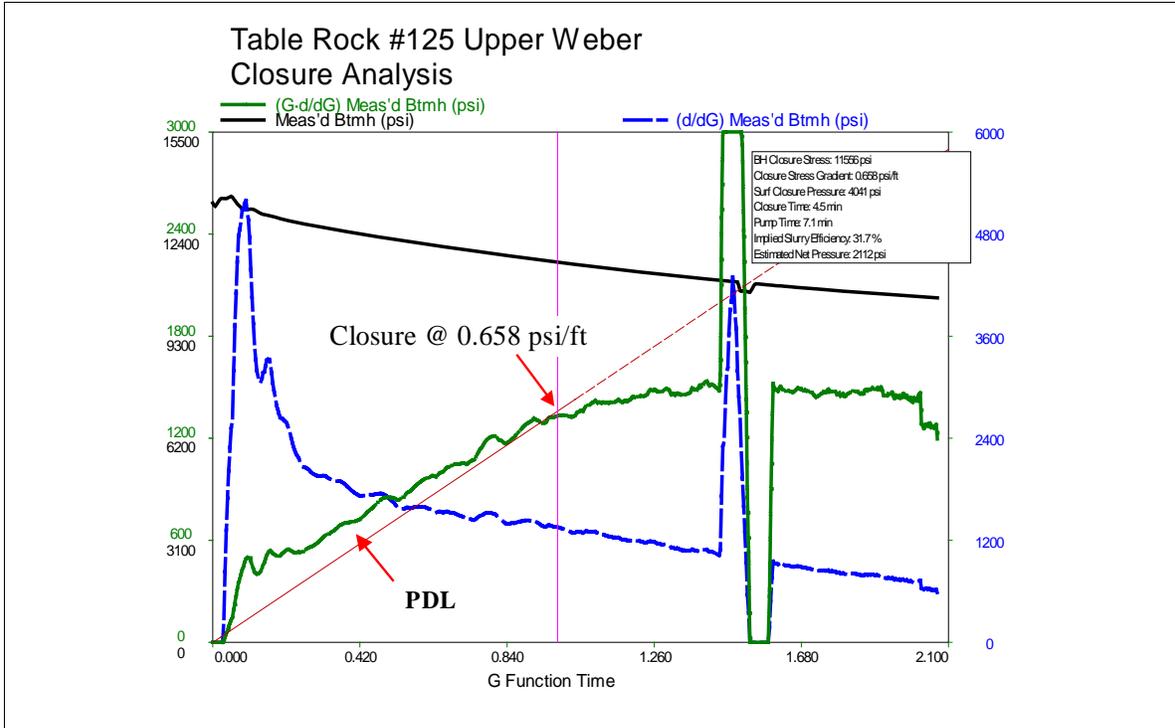


Figure 112. Fracture closure analysis: Table Rock #125 Upper Weber

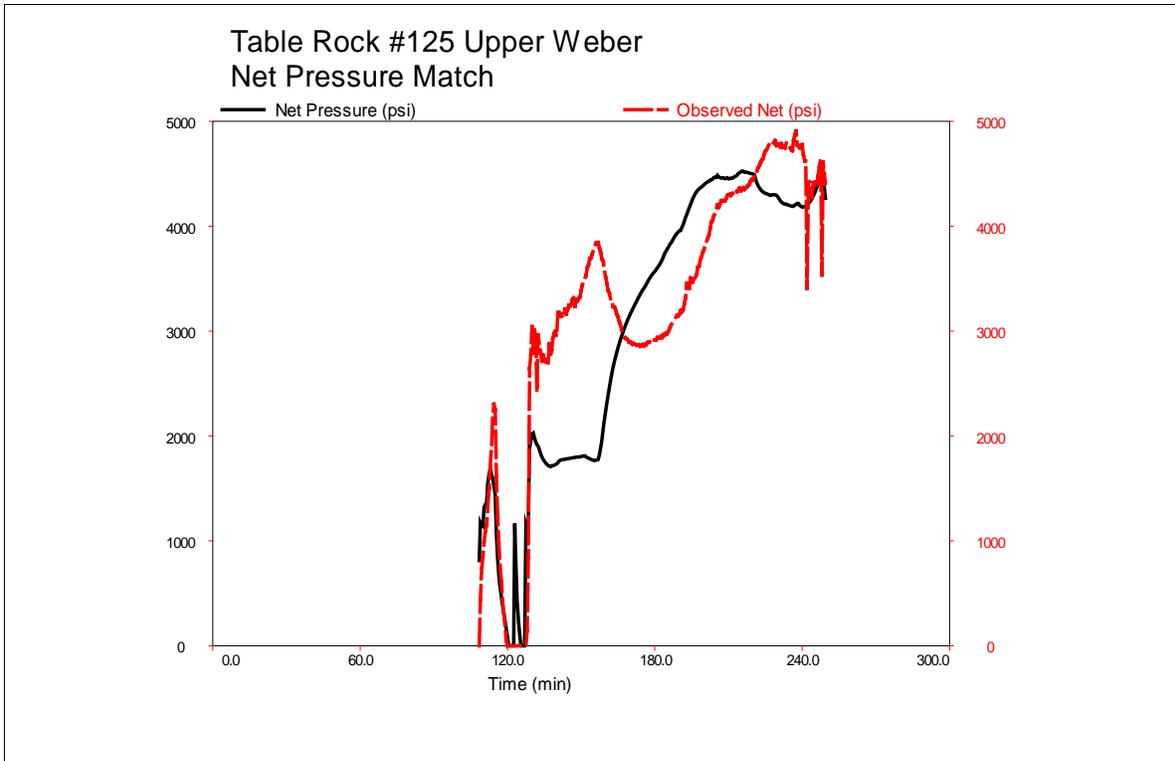


Figure 113. Net pressure match: Table Rock #125 Upper Weber

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

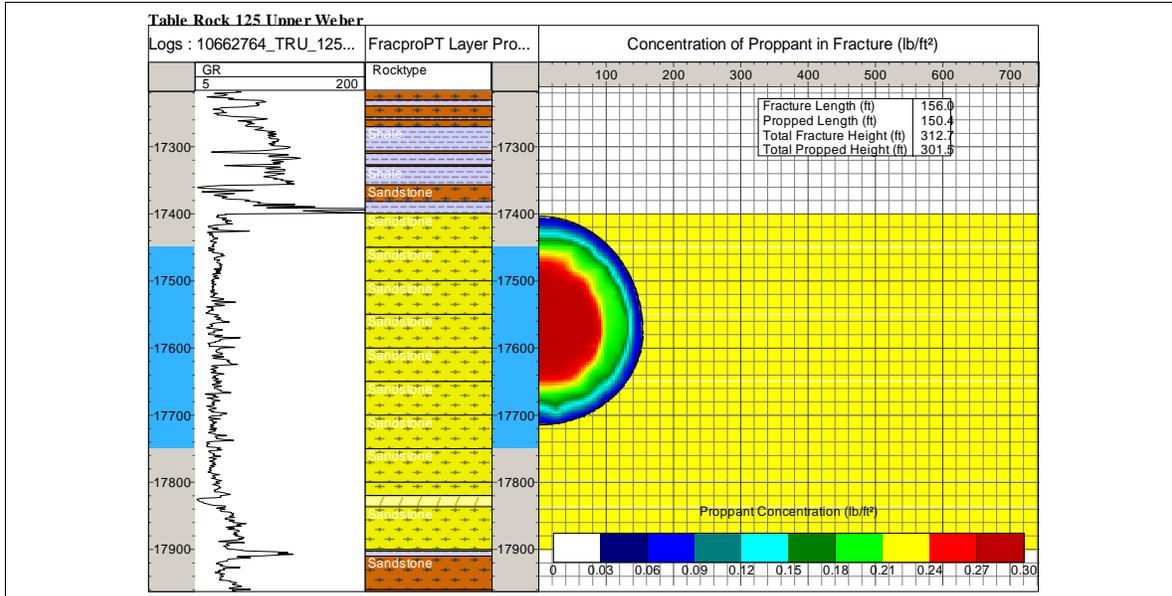


Figure 114. Model fracture geometry: Table Rock #125 Upper Weber

5.2.7 Higgins #19 Lower Weber

This treatment could not be pumped as planned due to extremely high treating pressures, which reached the surface pressure limitation almost immediately after pumping was started. The design in this treatment was different than in the previous Table Rock wells and is similar to hybrid fracs pumped in East Texas. It included pumping a large slickwater pad followed by a crosslinked 32-lb/Mgal crosslinked gel (Vistar 3200) and lower proppant concentrations of 0.25 to 2 ppg. The mini-frac injection ISIP was already 1.106 psi/ft (**Figure 115**). The mini-frac pressure falloff analysis (**Figure 116**) indicated pressure-dependent leakoff, which in conjunction with high ISIPs is a recipe for complex fracturing, possibly even in different planes (vertical, subvertical, or even horizontal). Entry friction was not a problem as tortuosity was low. It was not possible to determine closure stress since it was not reached within the time-frame of the falloff (one hour).

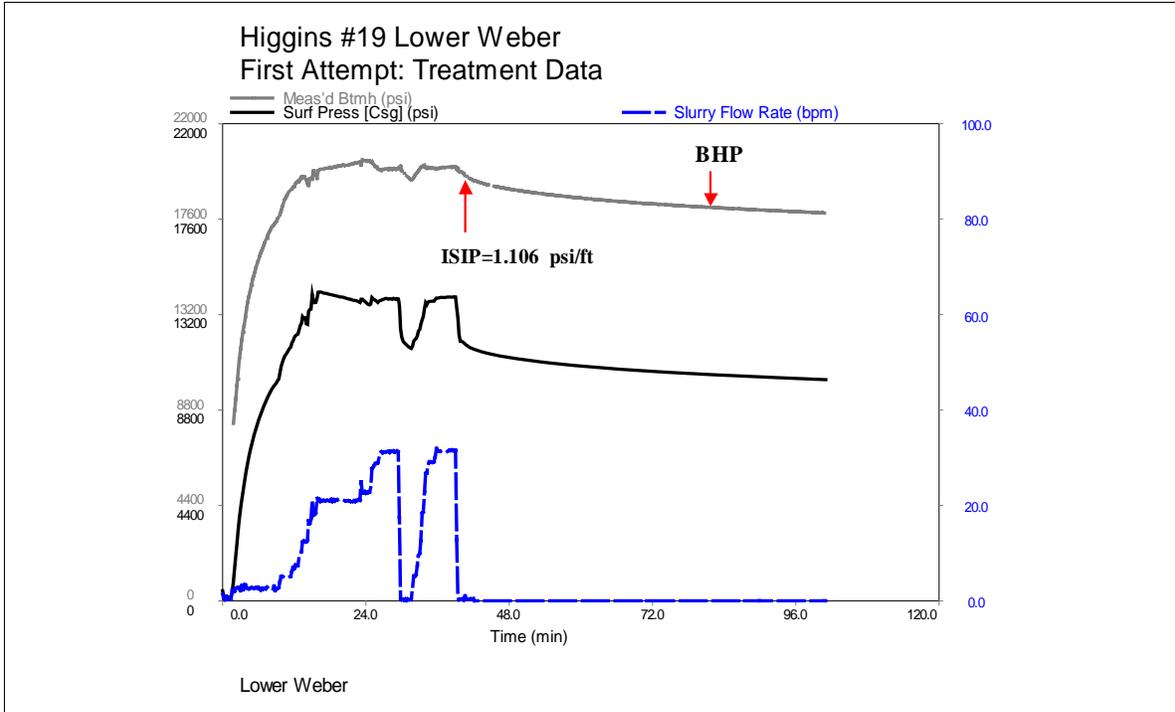


Figure 115. Treatment data mini-frac: Higgins #19 Lower Weber frac attempt

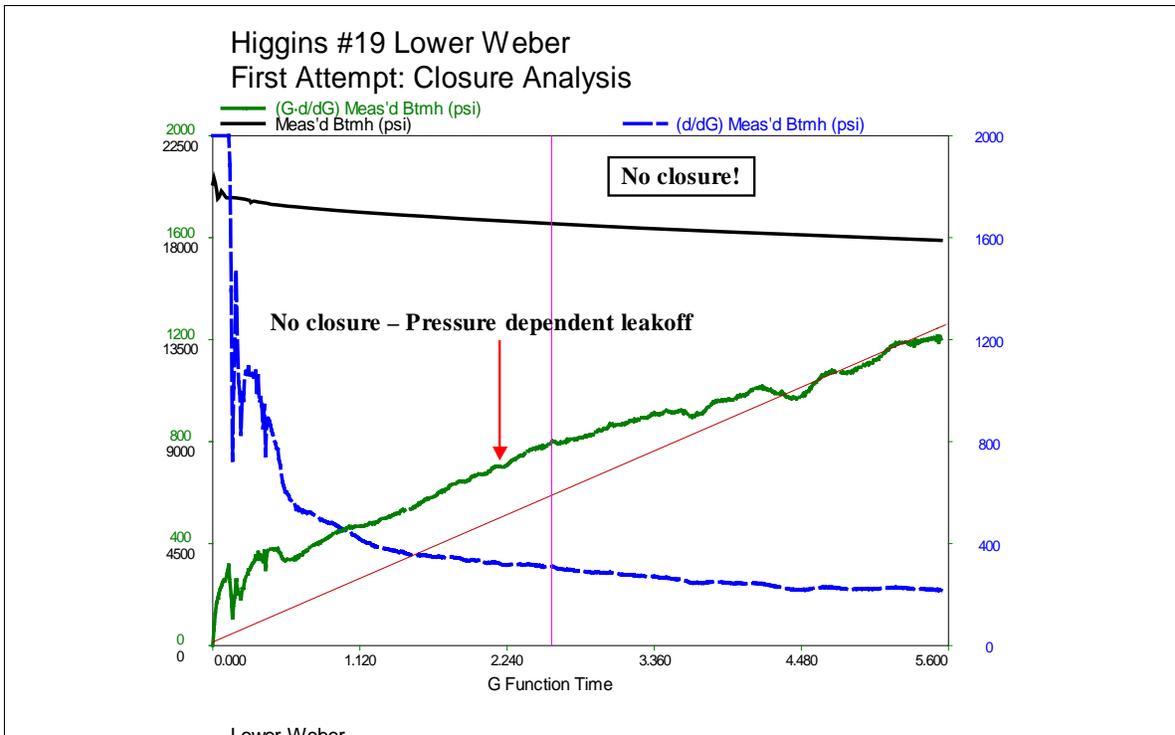
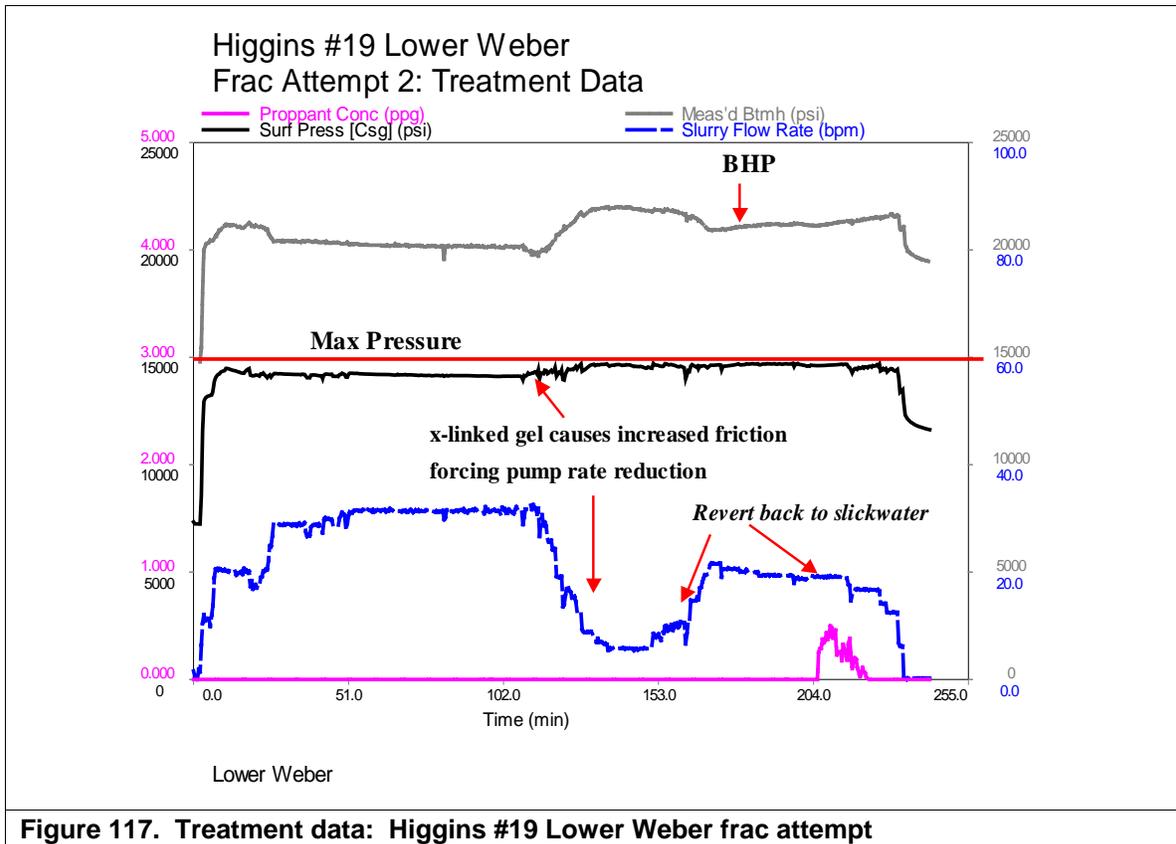


Figure 116. Fracture closure analysis: Higgins #19 Lower Weber frac attempt

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

The treatment data in **Figure 117** shows the difficulties of pumping the treatment. Surface treating pressures were continuously just below the limit, and when crosslinked gel was pumped the higher friction pressures required a rate reduction down to 5 bpm. At this point, it was decided to revert back to linear gel which helped re-establish injectivity; however, after pumping just 3 klb of proppant, it was decided to shut down the treatment since pressures were continuously rising towards the maximum allowable pressure. The net pressure was matched using high fracture complexity and is shown in **Figure 118**. Even though virtually no proppant was placed in the formation, the treatment did manage to inject a large amount of fluid (5,000 bbl); however, it is unlikely that an un-propped fracture will be successful at this depth and in these reservoir conditions unless it manages to enhance and maintain the conductivity of existing natural fractures under production conditions. The net pressure match is shown in **Figure 118** and the resulting model fracture geometry in **Figure 119** indicating an un-propped 300 ft fracture.



5. Case History of Hydraulic Fracturing in Table Rock Field, WY

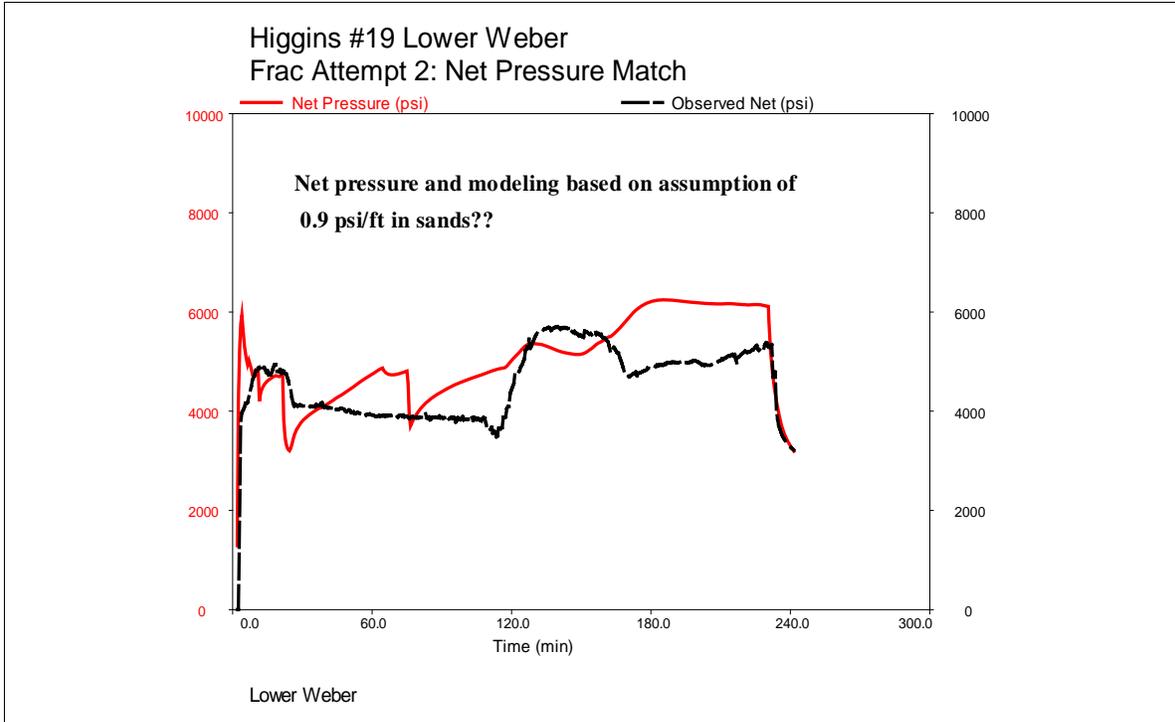


Figure 118. Net pressure match: Higgins #19 Lower Weber frac attempt

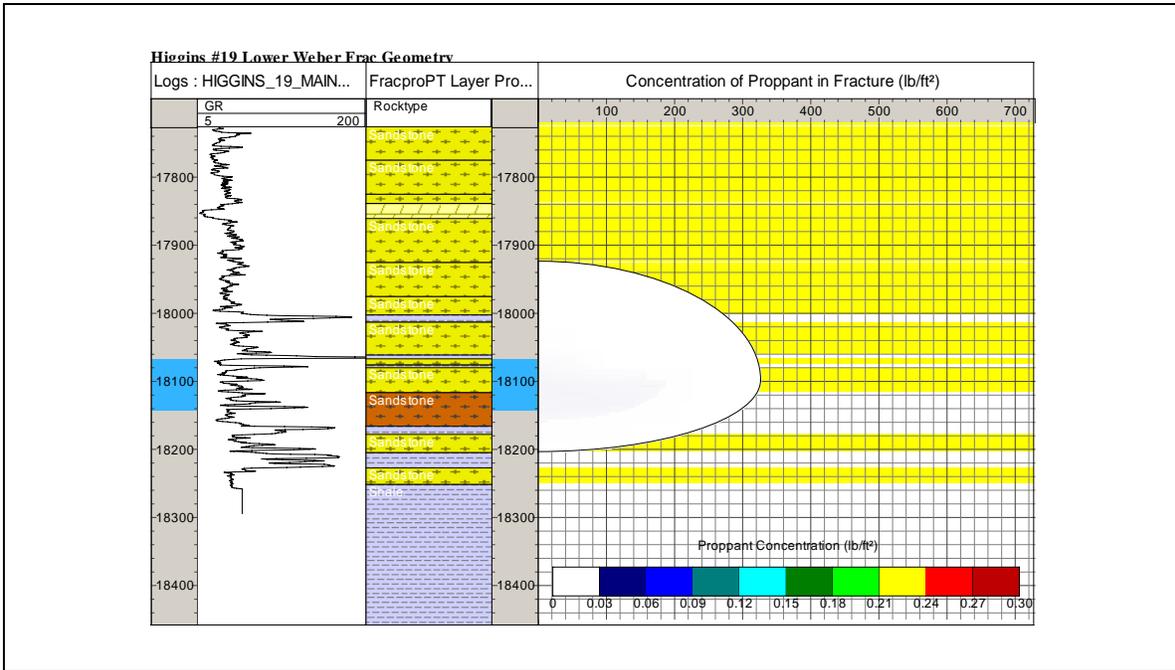


Figure 119. Model fracture geometry: Higgins #19 Lower Weber frac attempt

5.2.8 Higgins #19 Upper Weber

The Upper Weber treatment behaved completely differently than the Lower Weber. Treating pressures were about 6,000 psi lower than in the Lower Weber and posed no problems for treatment execution. Due to the high pressures in the Lower Weber treatment and operational considerations, the Lower Weber perforations were left open for the Upper Weber fracture treatment with the hope that the stress differential in the two zones would be enough for diversion into the upper interval.

The mini-frac injection ISIP was only 0.69 psi/ft (**Figure 120**). The mini-frac pressure falloff analysis (**Figure 121**) indicated pressure-dependent leakoff and a closure of about 0.66 psi/ft. The step-down test after the mini-frac indicated no tortuosity.

The treatment data in **Figure 120** shows that the treatment was pumped as planned, with no significant pressure increase as proppant entered the fracture, but the overall treating pressures still increased by about 3,000 psi from mini-frac to the end of the treatment as a result of increasing fracture complexity (increase was mainly during the pad). The net pressure was again matched using high fracture complexity and is shown in **Figure 122**. The model fracture geometry in **Figure 123** indicates a propped fracture length of about 300 ft.

Figure 124 shows the after-frac tracer log in the Higgins #19 indicating that the Upper Weber intervals took the majority of the fluid and proppant, although there appears to be some small-scale stimulation in the Lower Weber. Interestingly, the tracer distribution again shows very limited height growth at the wellbore around the perforations with no apparent connection, pointing to the possibility of independent fracture growth at each set of perforations.

It is not clear at this point if this new type of treatment resulted in better hydraulic fracture performance although it did appear to facilitate placing a larger fracture treatment with reduced risk of screenout. Two weeks of flowback for the Weber completions indicated initial gas flow rates of about 800 to 1,000 MCFD at 150 to 600 psi flowing wellhead pressures.

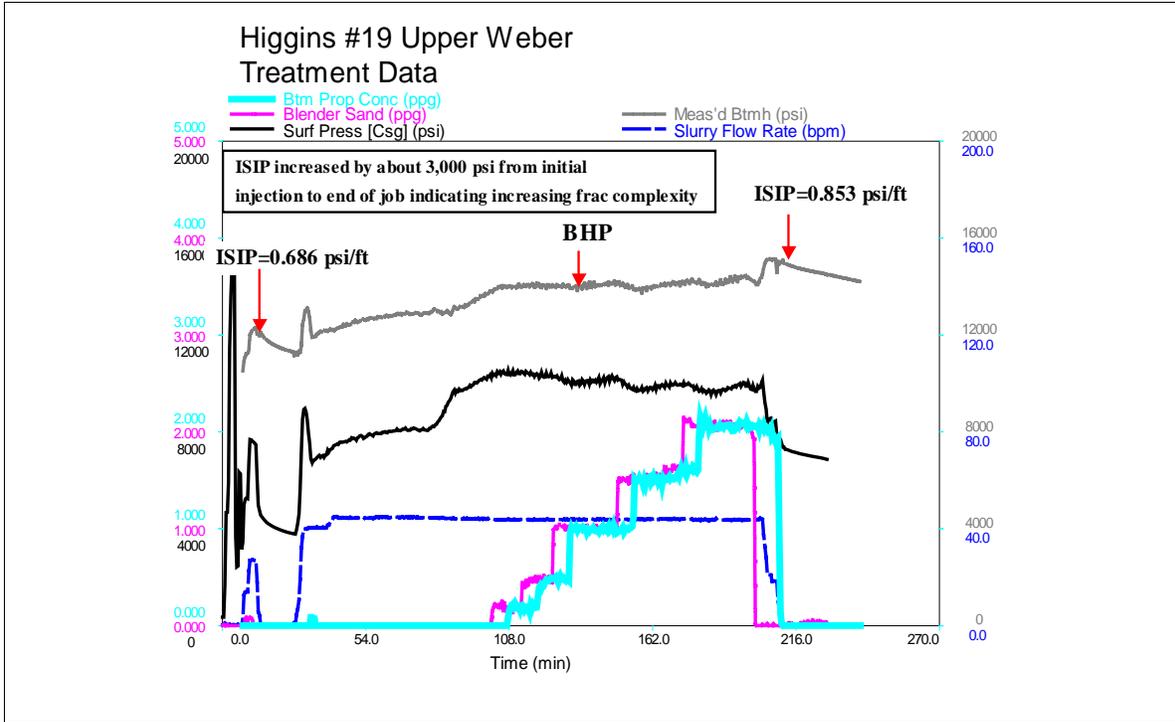


Figure 120. Treatment data: Higgins #19 Upper Weber frac

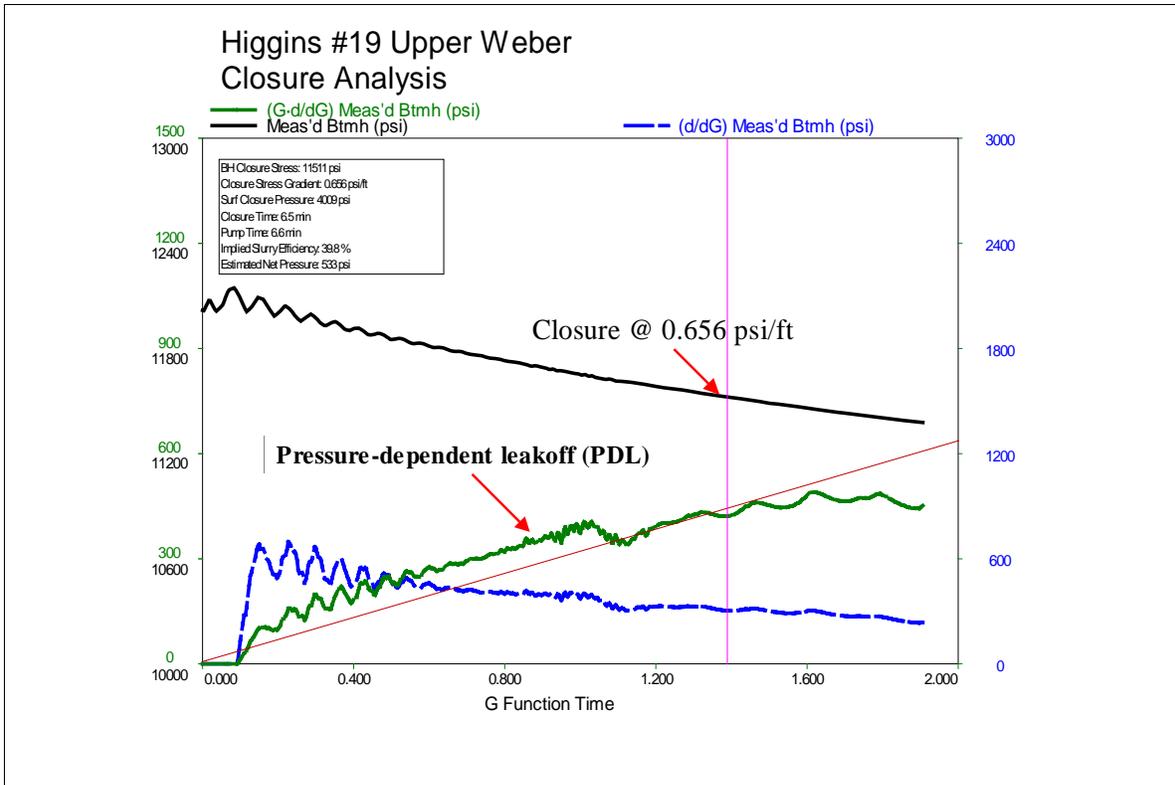


Figure 121. Fracture closure analysis: Higgins #19 Upper Weber frac

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

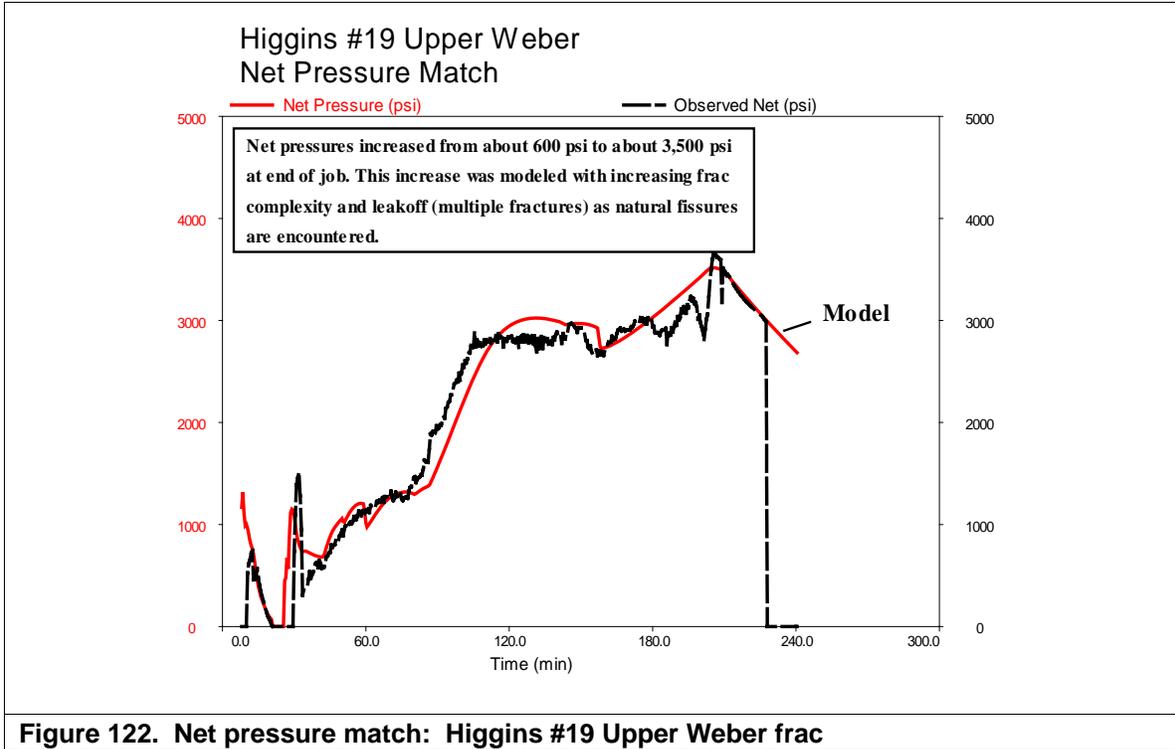


Figure 122. Net pressure match: Higgins #19 Upper Weber frac

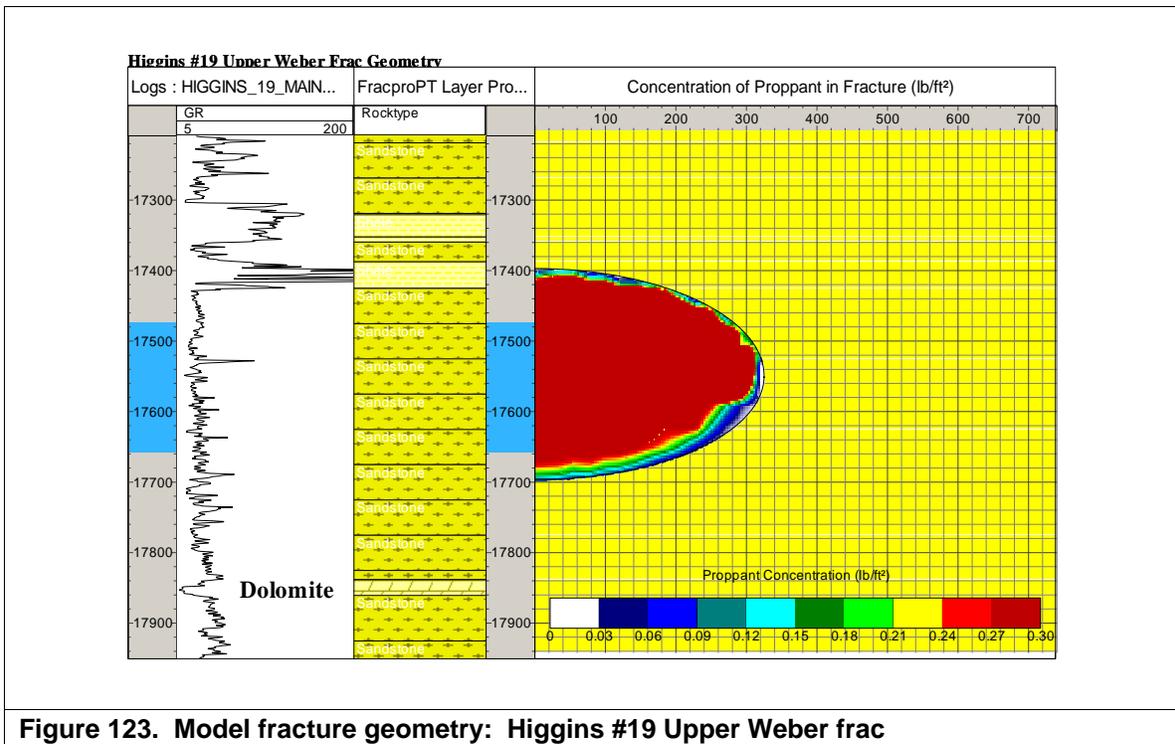


Figure 123. Model fracture geometry: Higgins #19 Upper Weber frac

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

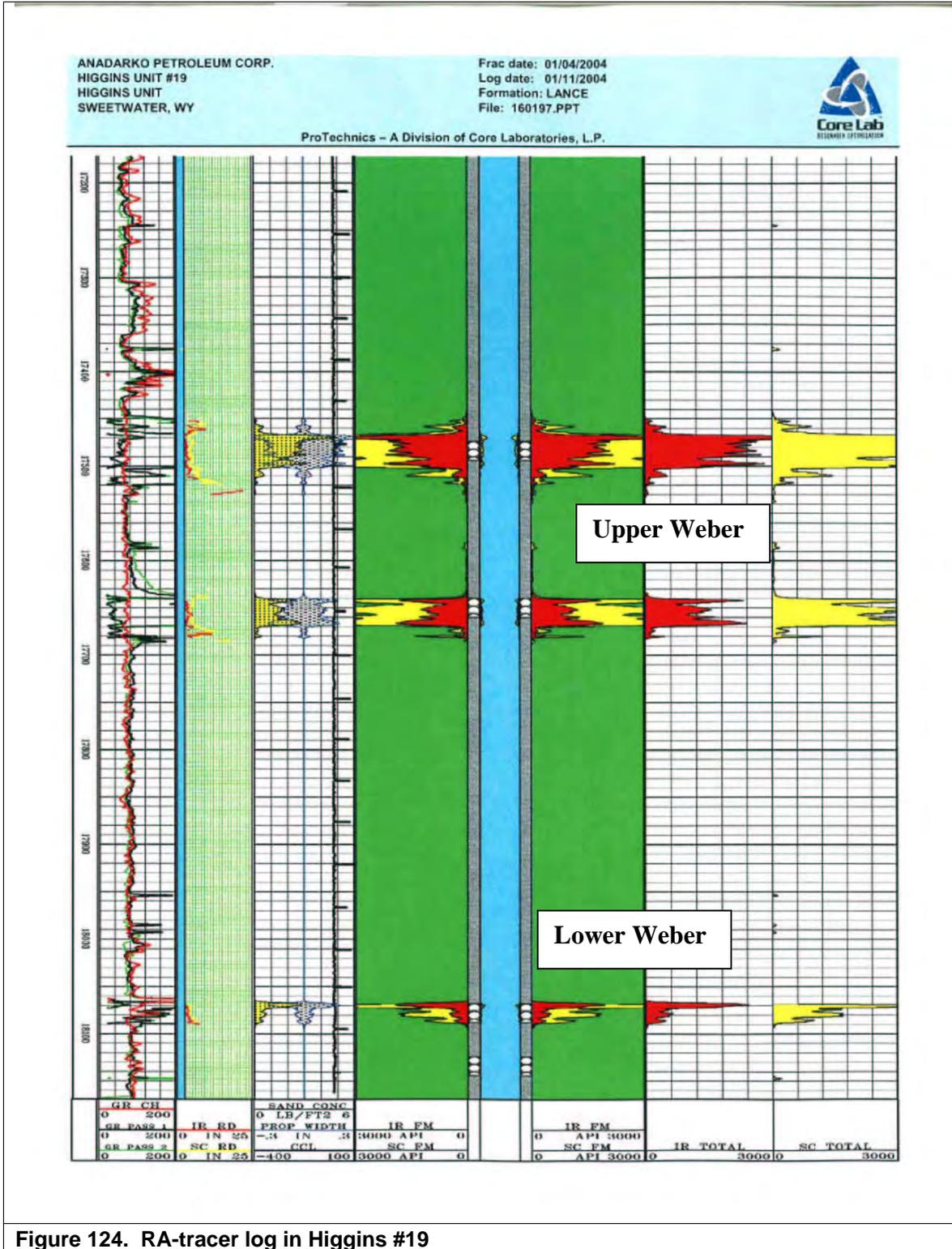
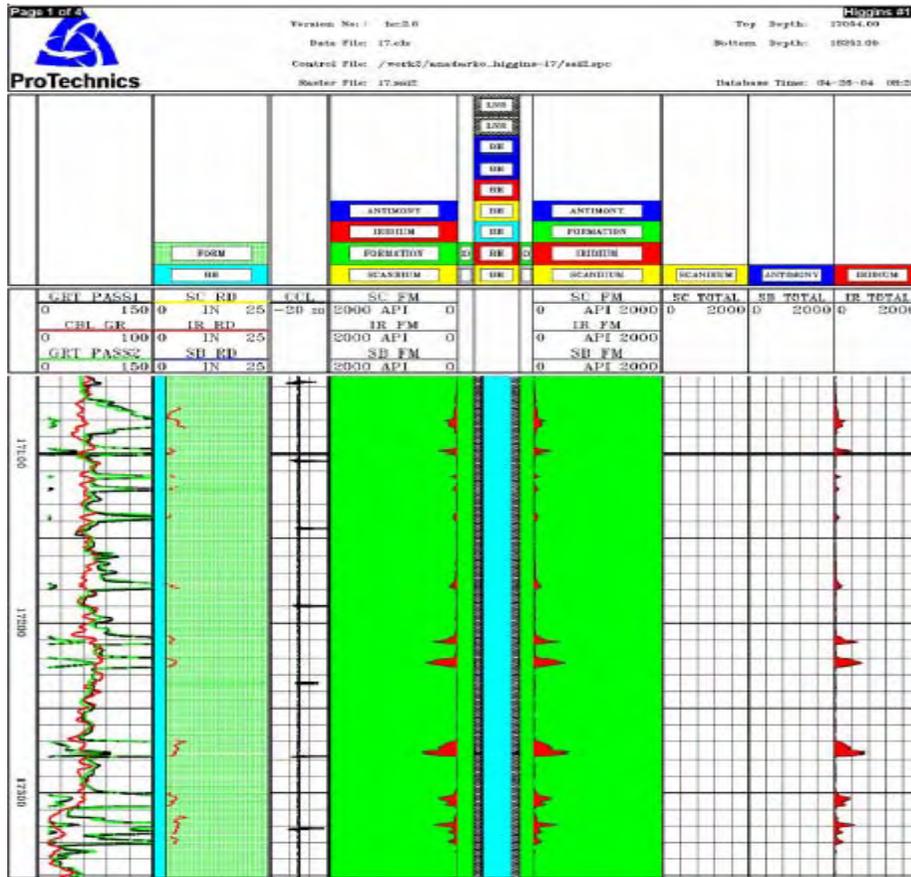


Figure 124. RA-tracer log in Higgins #19

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

5.2.9 Higgins #17 Dolomite

The prolific Dolomite pay zone in the Higgins #17 well was treated by acid fracturing on April 21, 2004. A tracer log was run to understand fluid coverage and fracture growth in the near-wellbore region for the acid fracture treatment. As shown in the after-frac tracer log in **Figure 125**, the treatment fluids were taken over a very large wellbore interval from a depth (MD) of 17,610 to 18,040 ft. Note from **Table 1** that the perforation interval is located between 17,967 and 17,975 ft. Confirmed from the operator, the fluid coverage over such a long interval was caused by a poor cement job behind the casing.



5. Case History of Hydraulic Fracturing in Table Rock Field, WY

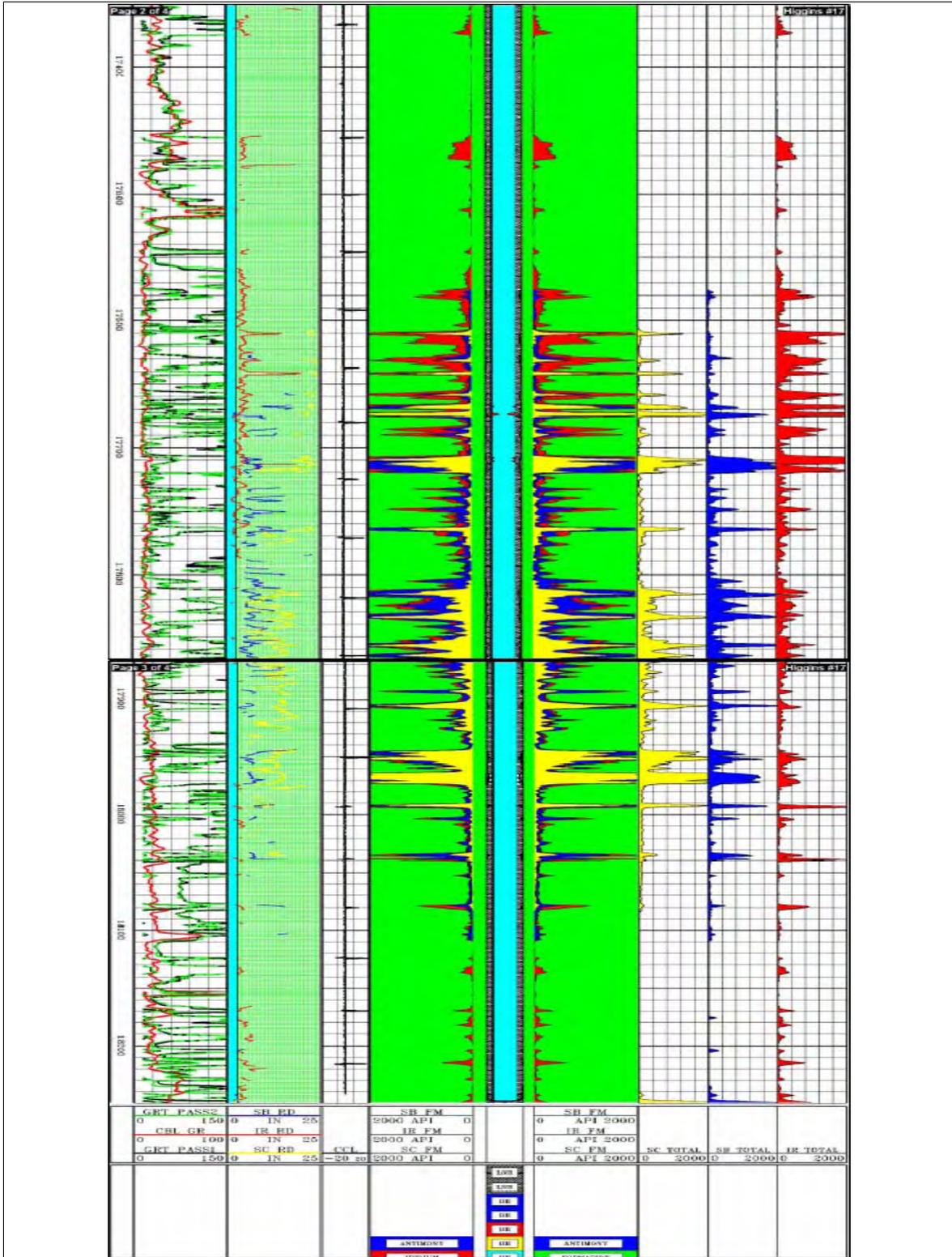
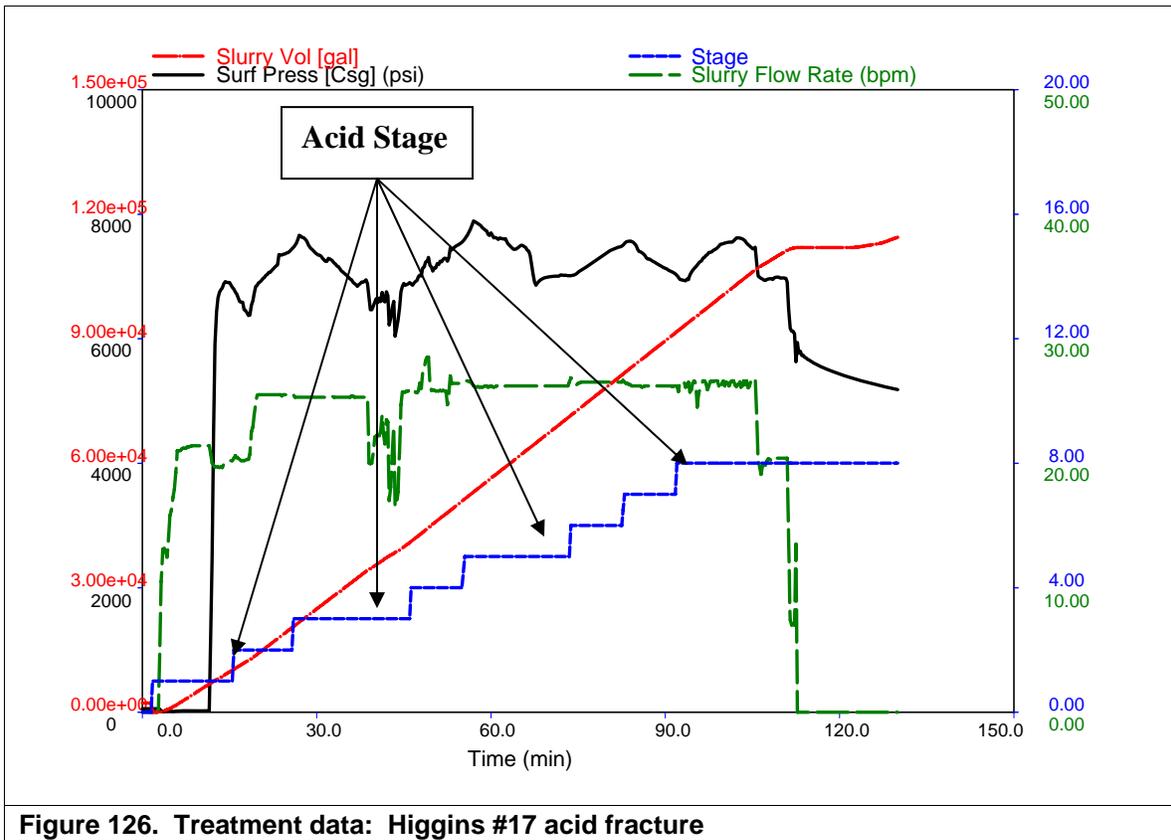


Figure 125. RA-tracer log in Higgins #17

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

Unlike propped fracture treatments, acid fracture treatments do not run into any risk of screenout. As shown in **Figure 126**, the treatment was executed to completion and a total volume of 2,692 bbl of fluids was pumped. No mini-frac was conducted prior to the main acid treatment. The treatment schedule consisted of 1,197 bbl of pad (239 bbl of linear gel in the first pad stage and 960 bbl of 30# PURGEL III crosslinked gel in the remaining stages) and 1,495 bbl of 15% HCl gelled acid. The treatment was pumped by alternating pad and acid stages to facilitate differential etching and deep acid penetration. The treatment data indicated a surface ISIP of 5,765 psi and an ISIP gradient of 0.75 psi/ft. Note that there was no wellhead pressure during the first nine minutes of pumping, which indicated that the wellbore was partially filled prior to the treatment and that the reservoir pressure was lower than expected.



Fracture growth behavior in the region is very complex. For example in Higgins #19, the propped treatment in the Lower Weber could not be pumped due to extremely high treating pressures and multiple fracture growth with excessive fluid leakoff and very high net pressure was observed in the Upper Weber during the propped treatment. As summarized in **Table 2** and **Table 4**, fracture modeling analysis for the Higgins #17 acid treatment indicated a high net pressure of 2,300 psi and complex fracture growth of six multiple fractures, but a low leakoff factor of 1.2. To model the frac upward growth in the Higgins #17, the following stress data were used: 0.62 psi/ft for dolomite, 0.75 psi/ft for shale, 0.80 psi/ft for the sandstone layer right below the dolomite, and 0.70 psi/ft for all other sandstone formations. The same rock mechanical properties such as Young's modulus from Higgins #19 were used for the modeling in Higgins #17. The Dolomite pay zone was initially (prior to the acid fracture treatment) estimated to have a permeability

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

around 1.0 to 5.0 mD, but net pressure match of the treatment data indicated a lower permeability of 0.5 mD. The net pressure was matched and is shown in **Figure 127**.

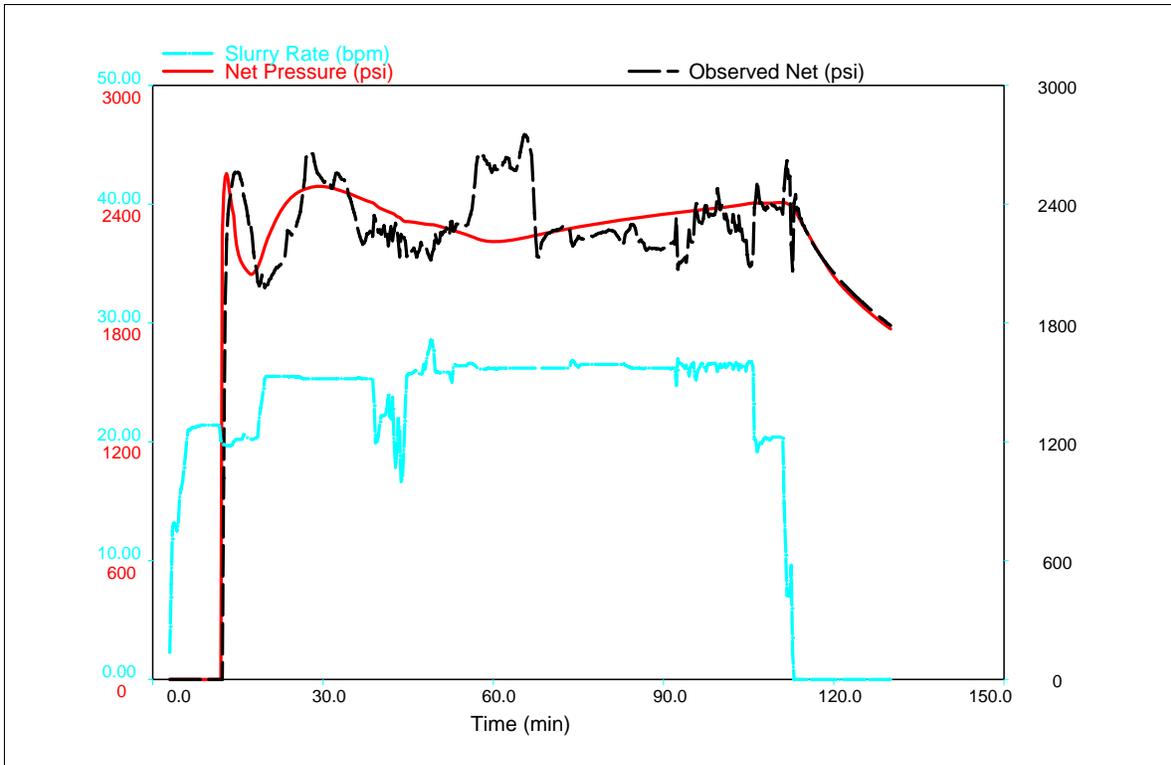


Figure 127. Net pressure match of Higgins #17 acid fracture treatment Data:

The predicted fracture geometry and acid-etched profile obtained from the net pressure match are shown in **Figure 128** and **Figure 129**, which indicate the following modeling results: fracture half-length = 326 ft, total fracture height = 360 ft, depth to fracture top = 17,682 ft, depth to fracture bottom = 18042 ft, etched fracture half-length = 223 ft, average conductivity = 384 mD-ft, and FcD = 3.5. Acid spending is a function of reaction rate, acid concentration and temperature. As a result, the maximum acid-etched conductivity did not occur in the near-wellbore region; a maximum conductivity of 1,130 mD-ft at a distance of 127 ft away from the wellbore. If a CFA (closed fracture acidizing) stage was pumped at the end of the job, the near-wellbore conductivity could have been improved. It is worth pointing out that the overall fracture height is over 40 times larger than the net Dolomite zone thickness, which is only 8.4 ft. The vast fracture area that was covered by the acid includes sand/shale formations, which are not reactive with HCL acid.

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

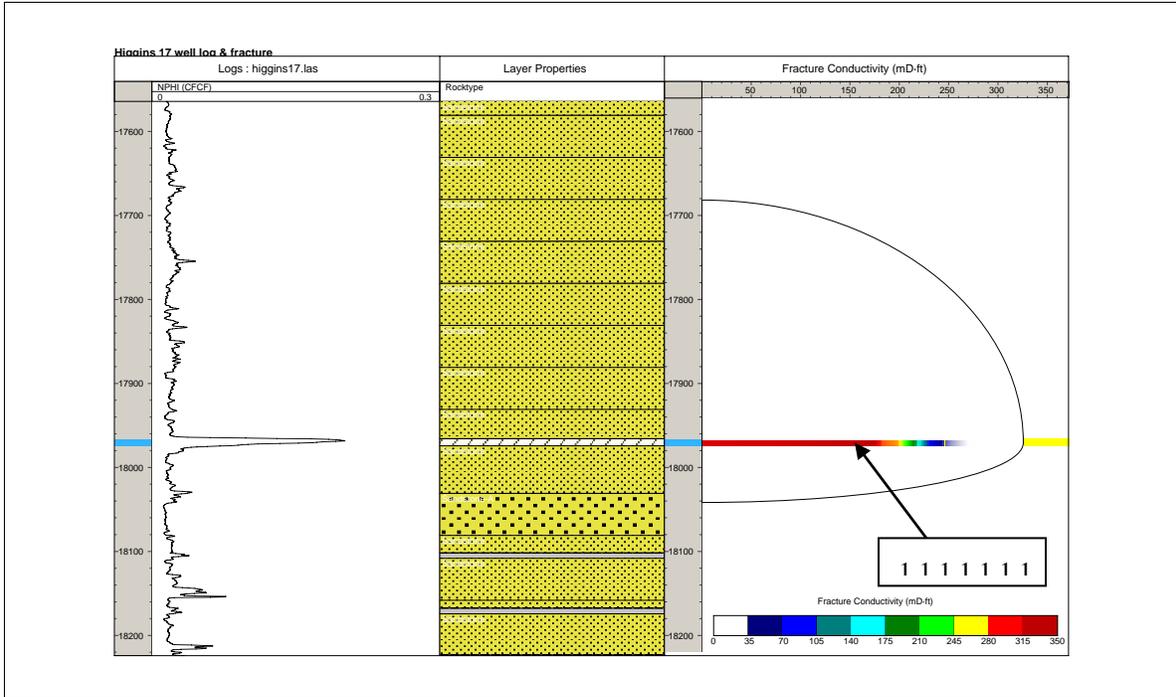


Figure 128. Model fracture geometry for Higgins #17

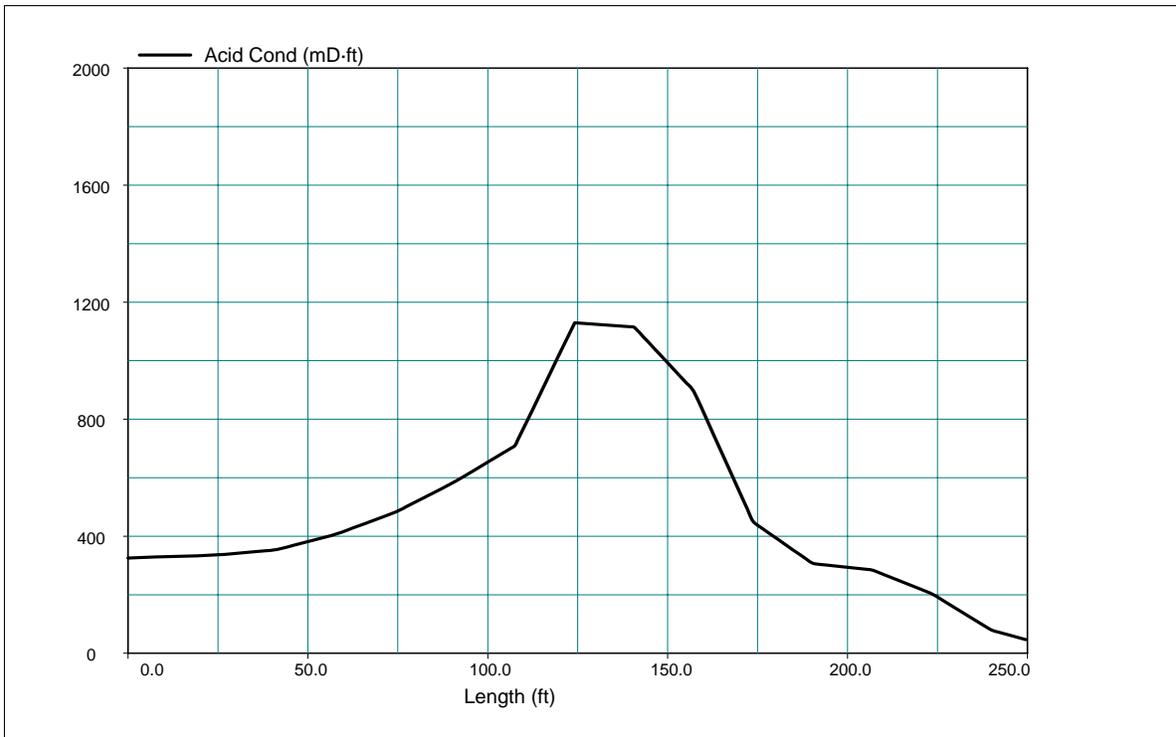
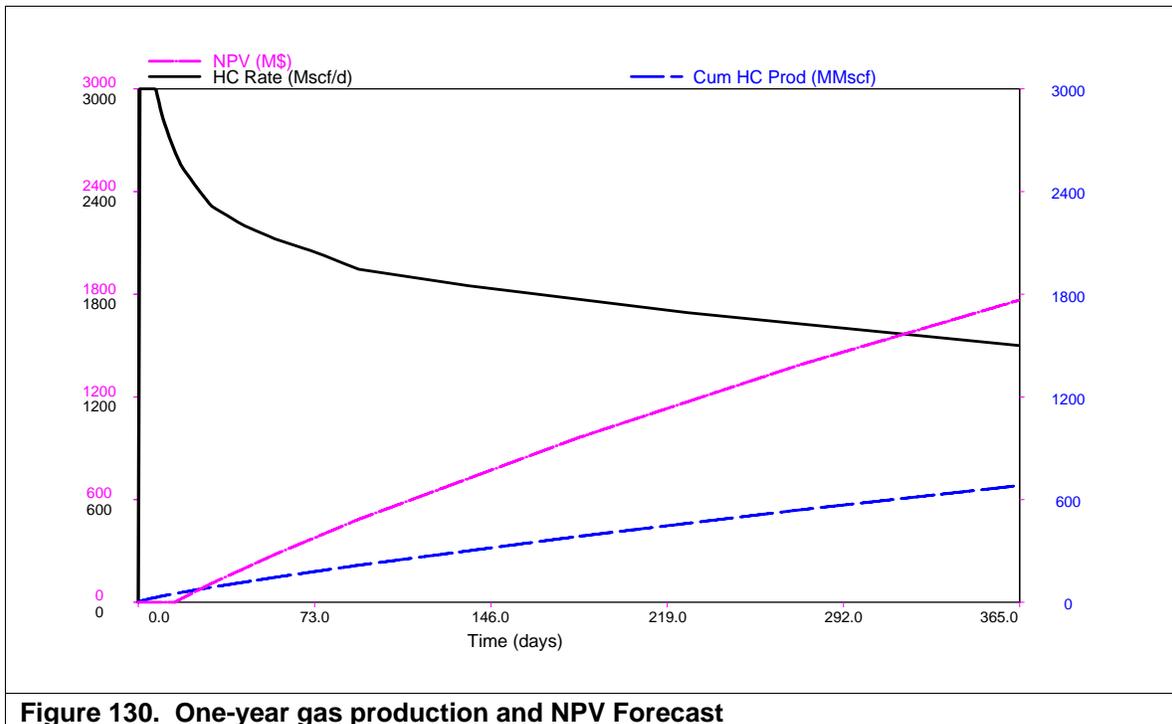


Figure 129. Acid etched fracture conductivity and length for Higgins #17

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

Based on modeling results in **Figure 128** and **Figure 139**, production forecast and economic analysis for the acid fracture treatment in the Higgins #17 were carried out. The following assumptions were used for the study: drainage area = 640 acres, net pay = 8.4 ft, water saturation = 35%, porosity = 11%, initial reservoir pressure = 5,800 psi, etched fracture half-length = 223 ft, average etched conductivity = 384 mD-ft, gas price = \$3.00, discount rate = 12%, cost of the acid fracture job = \$150,000, reservoir permeability = 0.5 mD, and wellhead flowing pressure = 300 psi. As shown in **Figure 132**, early gas production yielded about 2 MMscft/day using the actual post-treatment flow-back/production pressure. The predicted production is consistent with actual data. Also shown in the same figure, the predicted one-year NPV is \$1.5 million dollars.



Two acid fracture models (FracproPT™ default and ADP) were used to study the impacts of acid-etched length/conductivity prediction uncertainties on post-treatment production. Both models use the same fracture geometry predicted by the FracproPT™ 3-D fracture growth model. The two models differ in acid transport – the default model tracks the acid inside the fracture using elliptical rings, with each ring representing an acid stage or a fraction of an acid stage, while the ADP model assumes piston-like acid transport and that the acid covers the entire fracture height. The default model could over-predict acid etched length, while the ADP model tends to under-predict acid etched length. The ADP modeling prediction is shown in **Figure 131**. Using an endpoint conductivity value of 200 mD-ft as the cut-off point, the following results were obtained from the ADP model: an etched fracture half-length of 107 ft, an average conductivity of 298 mD-ft, and Fcd of 5.6. The etched fracture half-length predicted from the ADP model is 50% of that from the FracproPT™ default model; however, as shown in **Figure 132**, the production rate from the ADP model is only about 10% lower than that from the FracproPT™ default model.

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

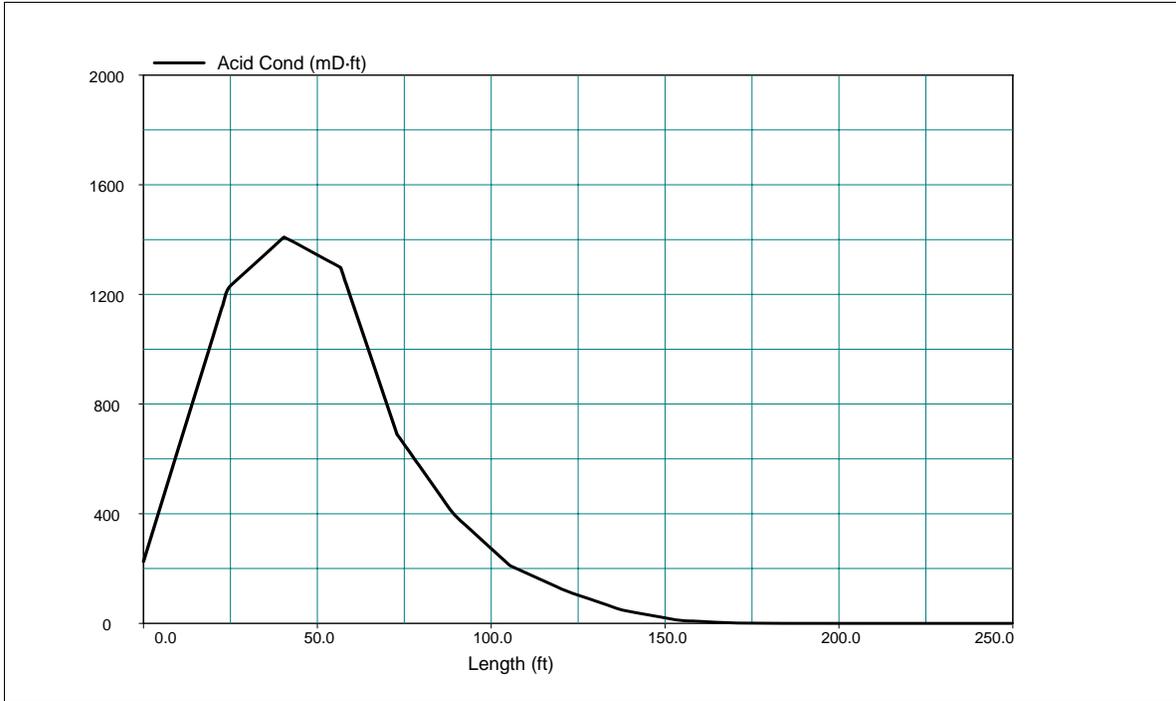


Figure 131. Acid etched fracture conductivity and length predicted by the ADP model

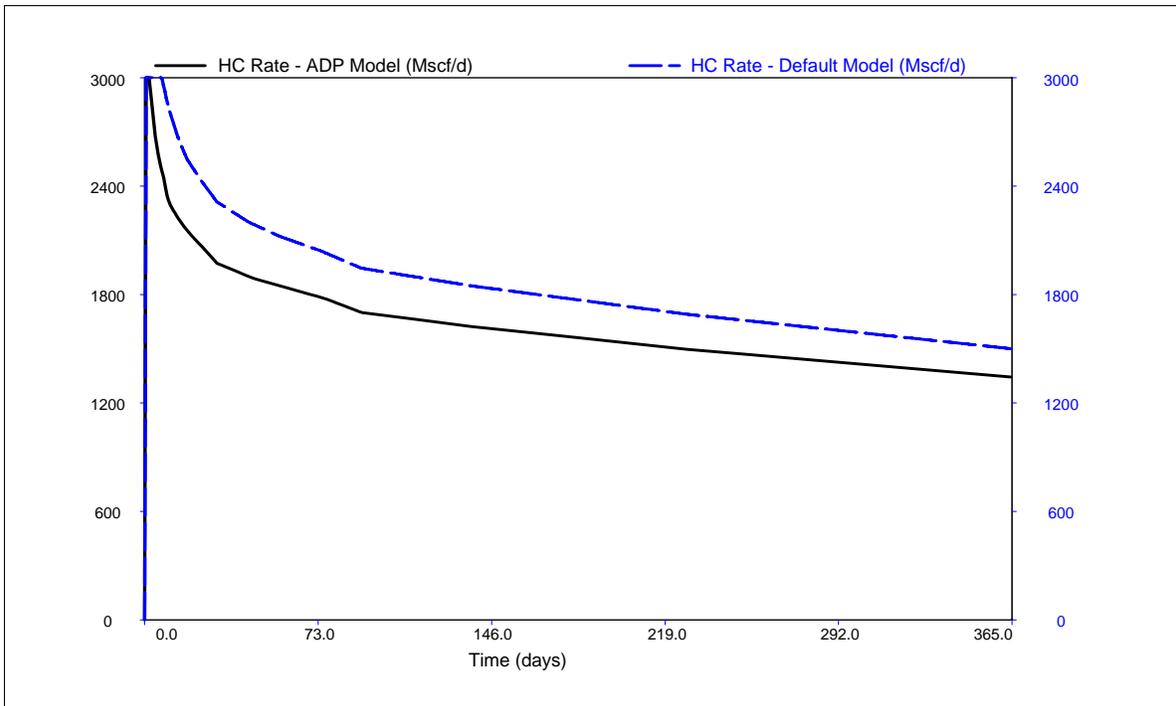


Figure 132. Production comparison based on the FracproPT™ default and ADP acid models

5. Case History of Hydraulic Fracturing in Table Rock Field, WY

Prior to the acid fracture treatment, the Dolomite pay zone was initially estimated to have a permeability around 1.0 to 5.0 mD; however, post-treatment net pressure analysis indicated a lower permeability of 0.5 mD. Permeability is a major factor in affecting reservoir performance. To evaluate permeability uncertainties on production, simulations with permeability values of 0.5, 1.0 and 5.0 mD were conducted. As shown in **Figure 133**, the reservoir permeability has dramatic impacts on gas production. The short-term post-treatment production of 2 MMscfd seems to match well the production forecast with a dolomite permeability of 0.5 mD.

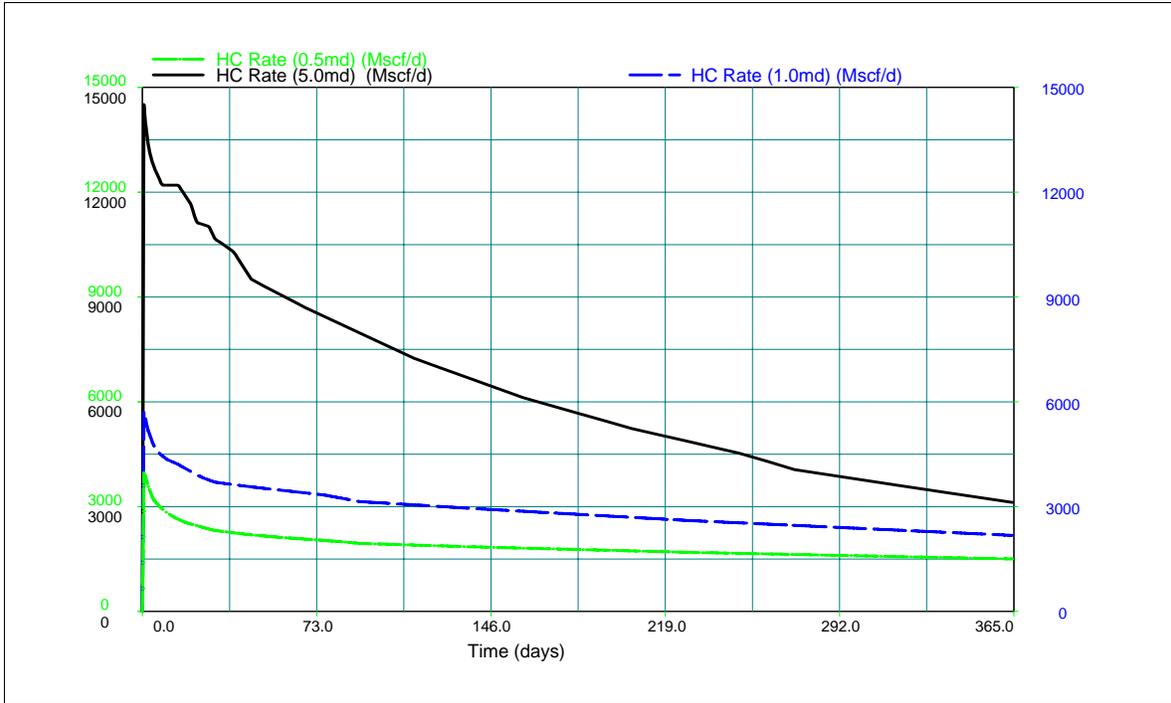


Figure 133. Production comparison with permeability values of 0.5, 1.0 and 5.0 mD

5.2.10 Post-Frac PBU in Table Rock #124 Lower Weber and Dolomite

The post-frac PBU in the Table Rock #124 was performed for the Lower Weber and Dolomite completion. The well had been on production for about five days with gas rates climbing to about 4.5 MMCFD. The analysis and final match of the post-frac PBU is shown in **Figure 134** and the results are summarized in **Table 12**. The PBU does not indicate the presence of a conductive hydraulic fracture. There is no indication of formation linear flow at any time during the buildup. The pressure derivative (red curve) flattens out fairly quickly indicating immediate radial flow in the formation. It appears that this buildup is mainly showing the flow contribution from a slightly stimulated dolomite (skin is about -3) with a permeability of about 0.63 md (19 md-ft) but there is no evidence of a conductive hydraulic fracture at this point of production.

As discussed previously, the fracture treatment encountered a screenout with a possible model length of only 100 ft. Since the tracer log showed that all perforations accepted fluid and proppant, it is very likely that at the time of the PBU, the hydraulic fracture had not cleaned up yet and was still damaged from the treatment as a result of high screenout pressures that may have

caused a “polymer squeeze-off” into the natural fractures. Another possibility is that the complexity of the hydraulic fractures may be so extreme that fractures are very short and in different planes (“shattered zone” around the wellbore), negating any dominant linear flow from fractures in a single plane.

Table 12. Post-frac Analysis Results Table Rock #124

xf (ft)	k (md)	kh (md-ft)	Fc (md-ft)	FcD	Skin	Pi (psi)
0	0.629	18.9	0	0	-3.06	4949

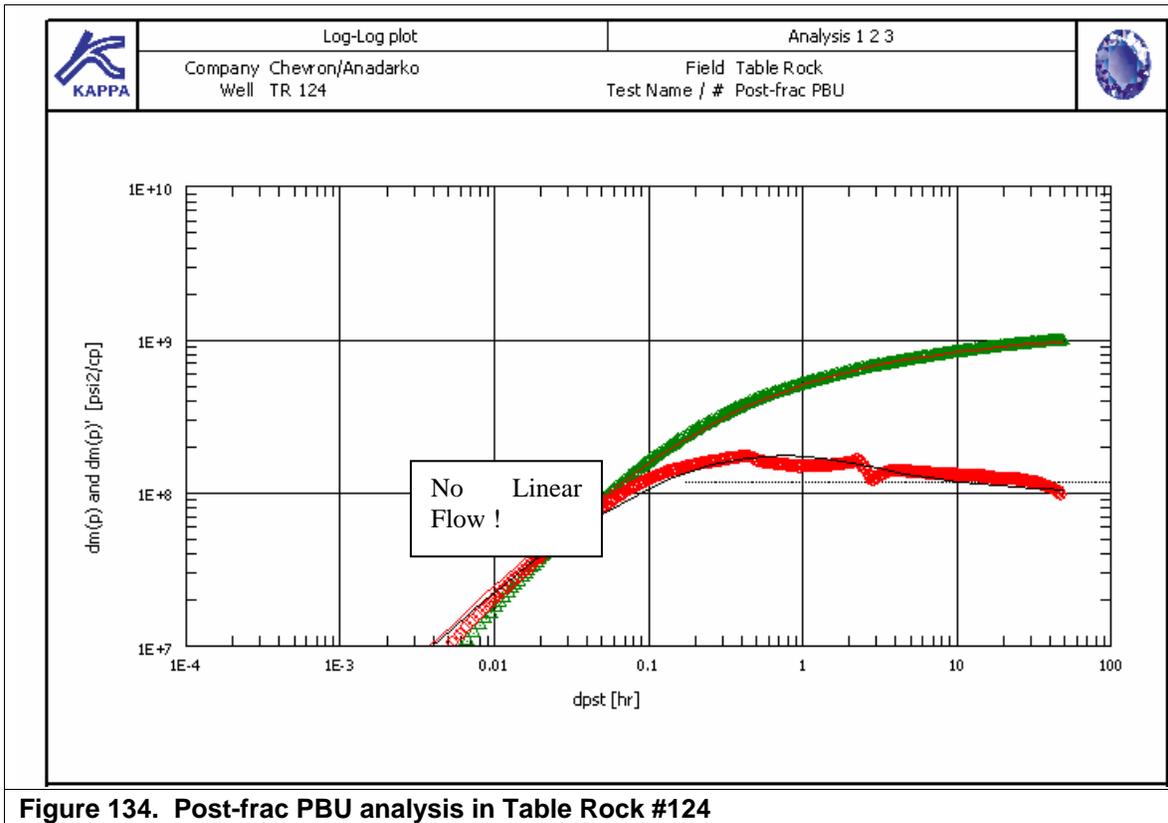


Figure 134. Post-frac PBU analysis in Table Rock #124

6. Case History of Hydraulic Fracturing in the Springer, Granite Wash and Arbuckle Formations in Oklahoma

This study focused on deep gas productive horizons in Stephens and Caddo County, Oklahoma operated by Marathon Oil Company. The primary targets are the Springer and Granite Wash Sands and Arbuckle Carbonate Formations (dolomitic limestone) at depths of roughly 15,000 to 18,700 ft. The Arbuckle is the deepest target and produces gas with a sour gas content of 2 to 4.5%. The study shows treatment examples from all three formations. Less information was available for these wells, compared to the other two case studies, so a reduced engineering effort was spent on this area of the project.

The geologic setting of the Arbuckle is an anticline with possible thrust faulting and is believed to contain a fine network of natural fractures. The Springer and Granite Wash Sands are a seismic stratigraphic play removed from structure. Temperatures range from about 240 F to 270 F and pore pressures from about 7,000 to 13,000 psi, with most target zones being over-pressured (0.65 to 0.75 psi/ft). The Springer and Granite Wash Sands are usually completed with crosslinked gel fracture treatments and high strength proppants. The carbonates in the Arbuckle are completed with acid fractures (some are hybrid treatments including high-strength proppant).

Fracture treatments in the Springer and Granite Wash Sands show fairly high fracturing net pressures and, in some cases, high tortuosity (near-wellbore fracture complexity). This indicates a tendency towards fracture complexity (multiple fractures) and higher risk of screenouts. Marathon has been combating some of these challenging issues with specific perforating strategies (such as low-density, zero-degree phasing) that can limit the amount of multiple fractures. In addition, large pad sizes with lower proppant concentrations are employed to reduce the risk of early screenouts.

Completions in the deep (17,900 to 18,700 ft) Arbuckle Carbonate Formations face the challenge of achieving economically successful wells in a challenging environment with 2 to 4.5% sour gas production. So far, four wells have been completed with mixed success. Initial production can be fairly high (10 to 12 MMCFD) followed by a rapid decline. From a completion point of view, the biggest challenge is to find the best acid fracture stimulation technique that will maintain enough fracture conductivity at these large depths.

6.1 Discussion

6.1.1 Introduction

This study focused on deep gas productive horizons in Stephens and Caddo County, Oklahoma operated by Marathon Oil Company. The primary targets are the Springer and Granite Wash Sands and Arbuckle Carbonate Formations (dolomitized limestone) at depths of roughly 15,000

6. Case History of Hydraulic Fracturing in the Springer, Granite Wash and Arbuckle Formations in Oklahoma

to 18,700 ft. The Arbuckle is the deepest target and produces gas with a sour gas content of 2 to 4.5%. The geologic setting of the Arbuckle is an anticline with possible thrust faulting and is believed to contain a fine network of natural fractures. The Springer and Granite Wash Sands are a seismic stratigraphic play removed from structure. Temperatures range from about 240 F to 270 F and pore pressures from about 7,000 to 13,000 psi, with most target zones being over-pressured (0.65 to 0.75 psi/ft). The Springer and Granite Wash Sands are usually completed with crosslinked gel fracture treatments and high strength proppants. The carbonates in the Arbuckle are completed with acid fractures (some are hybrid treatments including high-strength proppant).

The study shows treatment examples from all three formations. **Figure 135** shows a typical log section of the Springer Sand intervals, **Figure 136** a log section of the Granite Wash and **Figure 137** a log section of the Arbuckle Carbonate Formations.

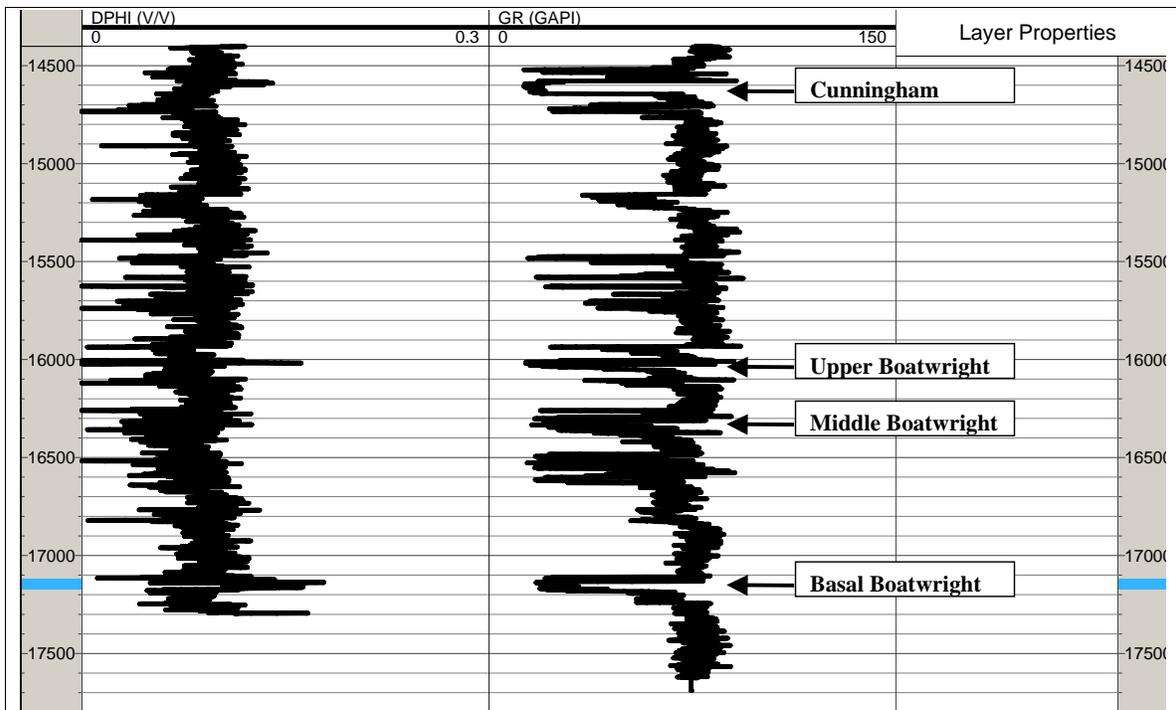


Figure 135. Well log example: Springer Sands

6. Case History of Hydraulic Fracturing in the Springer, Granite Wash and Arbuckle Formations in Oklahoma

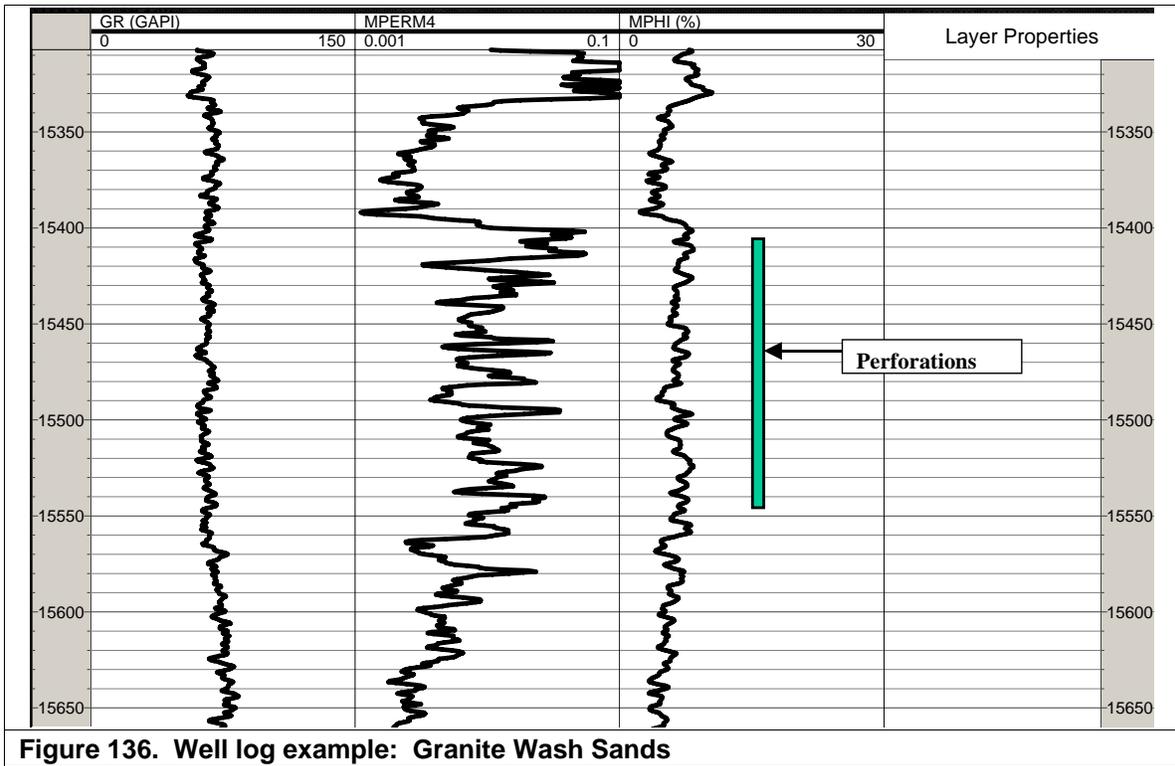


Figure 136. Well log example: Granite Wash Sands

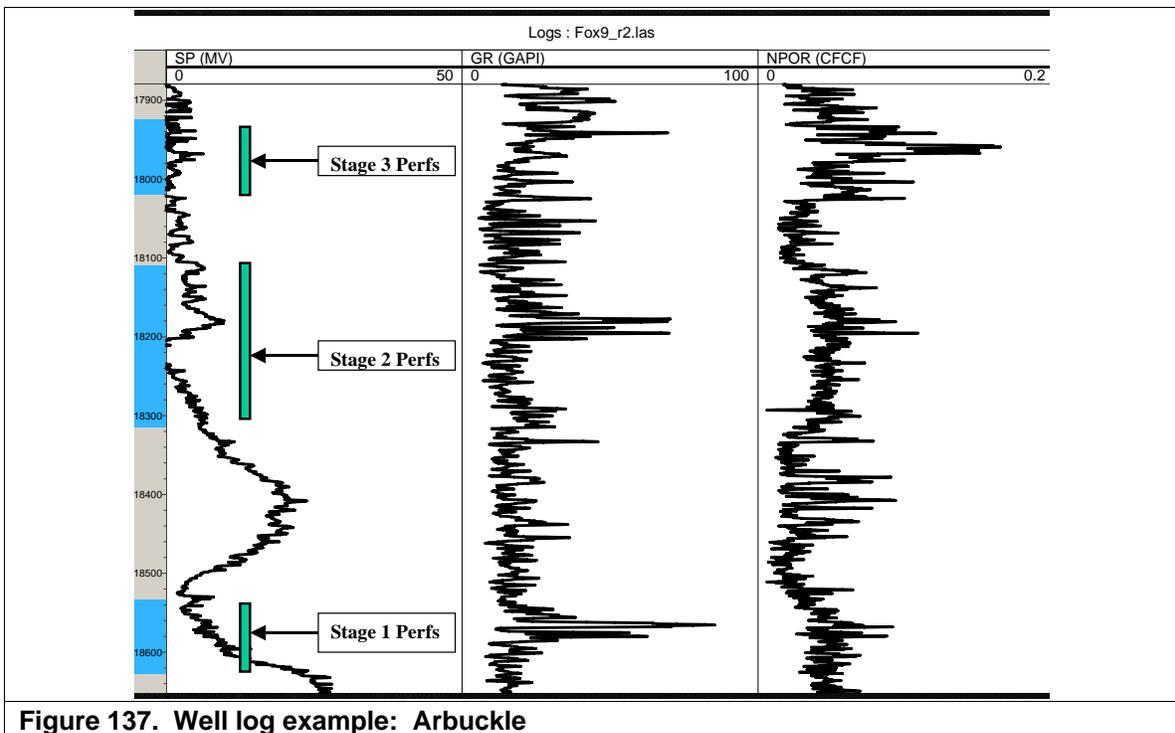


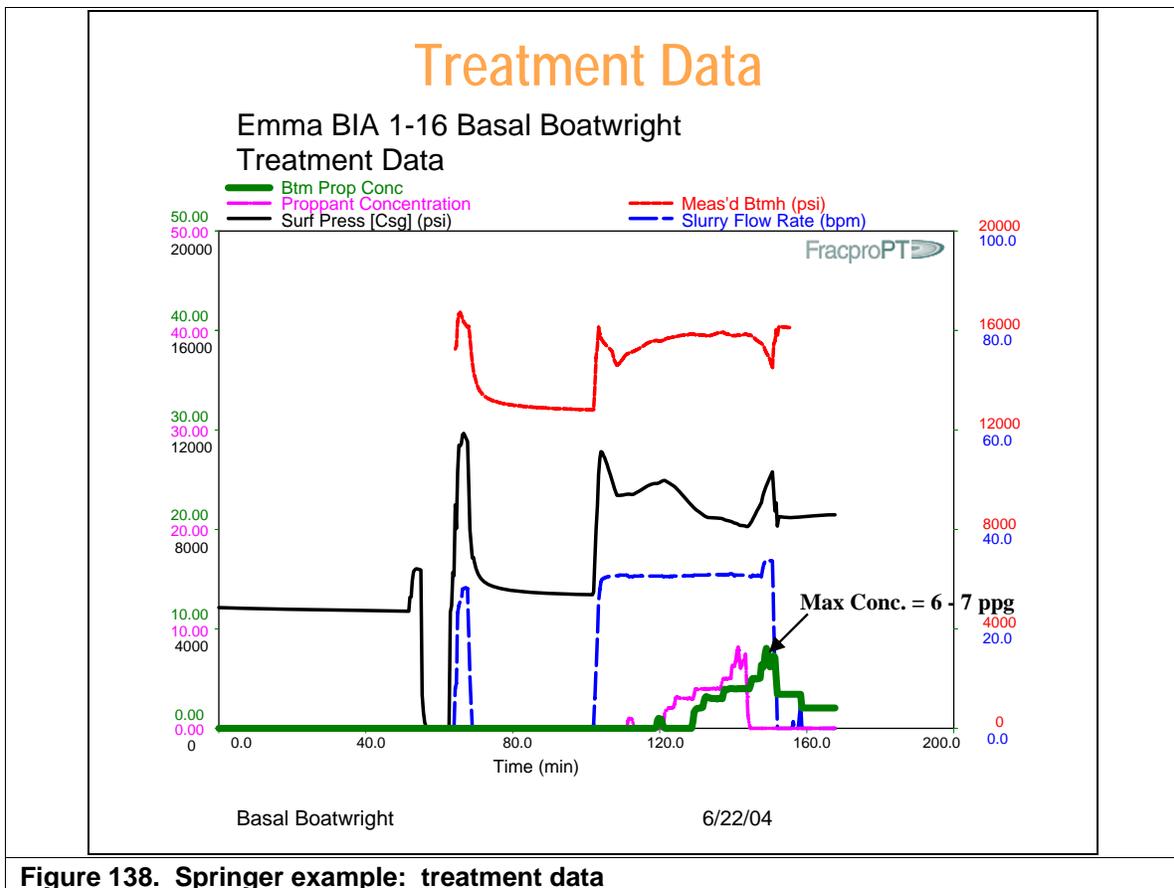
Figure 137. Well log example: Arbuckle

6.2 Engineering Data

The following shows fracture treatment examples and analyses from the Springer Sands, Granite Wash and Arbuckle.

6.2.1 Springer Sands

The Springer Sands are generally completed in multiple fracture stages using a borate crosslinked fracturing fluid with 20/40 high-strength bauxite. **Figure 138** shows an example of a fracture treatment in the so-called Basal Boatwright. The perforated interval was 17,119 to 17,172 ft at four shots-per-foot and 120 degree phasing. Closure pressure was estimated to be about 0.806 psi/ft (**Figure 139**). **Figure 140** shows the net pressure match and **Figure 141** the estimated model fracture geometry showing a 200-ft tall and 300-ft long fracture. A step-down test showed fairly high tortuosity (near-wellbore fracture complexity) of 1,250 psi at 28 BPM; however, the tortuosity decreased as the treatment with proppant was pumped, and was successfully completed.



6. Case History of Hydraulic Fracturing in the Springer, Granite Wash and Arbuckle Formations in Oklahoma

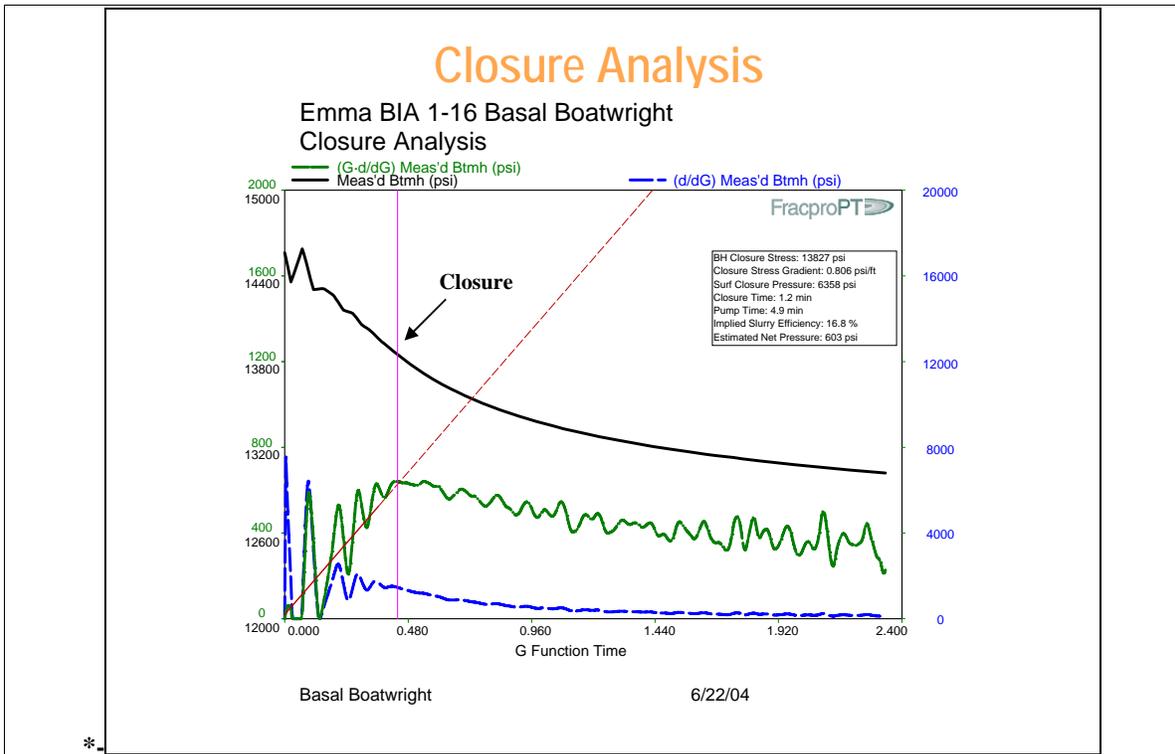


Figure 139. Springer example: fracture closure analysis

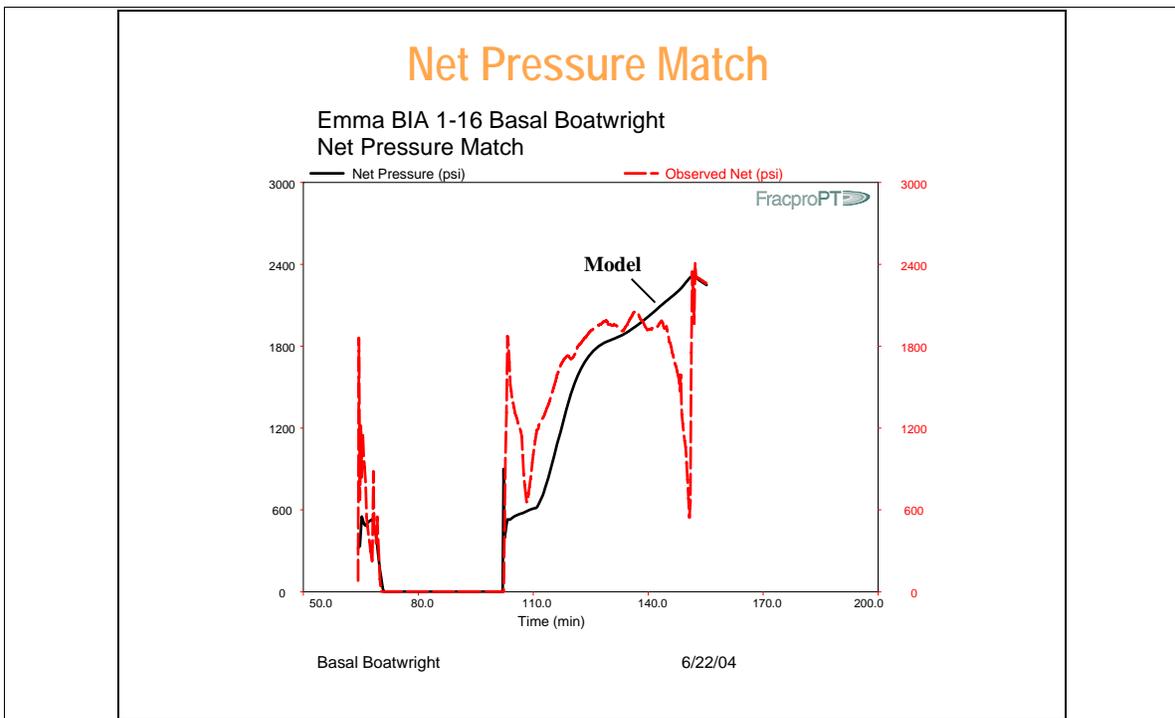


Figure 140. Springer example: net pressure match

6. Case History of Hydraulic Fracturing in the Springer,
Granite Wash and Arbuckle Formations in Oklahoma

Model Fracture Geometry

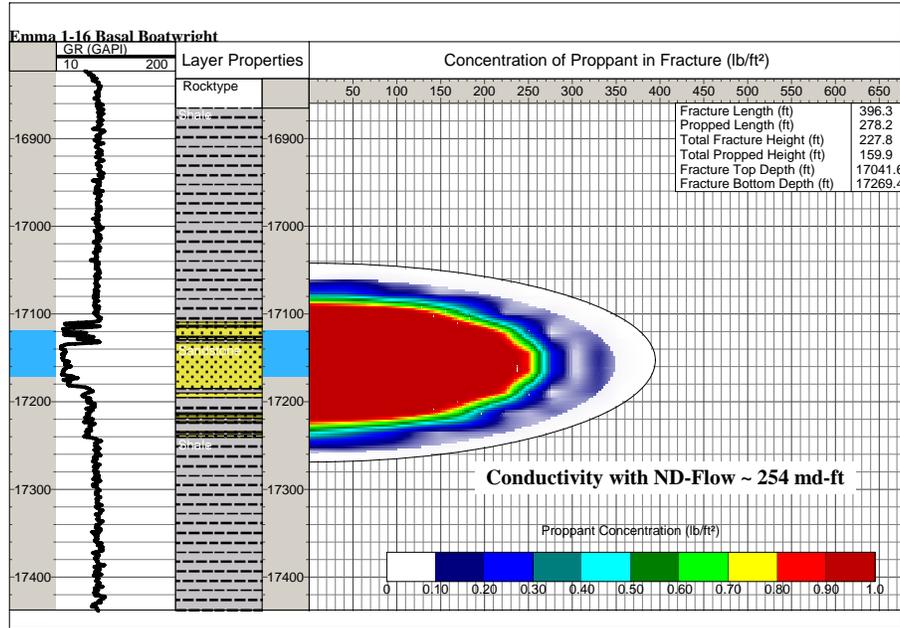


Figure 141. Springer example: model fracture geometry

6.2.2 Granite Wash

Similar to the Springer Sands, the Granite Wash is generally completed in multiple fracture stages using a borate crosslinked fracturing fluid with 20/40 high-strength bauxite. In this area screenouts are more frequent. Due to the increased risk of screenouts, 100-mesh sand is frequently pumped in the pad. **Figure 142** shows an example of a fracture treatment that encountered a screenout in the 4-ppg proppant stage. The perforated interval was 15,170 to 15,316 ft at one-shot-per-foot and 120-degree phasing. Closure pressure was not reached within the timeframe of the mini-frac falloff (**Figure 143**). **Figure 144** shows the net pressure match up to the screenout and **Figure 145** the estimated model fracture geometry showing a 250-ft tall and 300-ft long fracture. Tortuosity was not the cause of the screenout since the step-down test showed very low tortuosity (near-wellbore fracture complexity); however, the mini-frac showed some minor pressure-dependent leakoff due to fissure opening, which may indicate some far-field fracture complexity that could have caused the screenout.

6. Case History of Hydraulic Fracturing in the Springer,
Granite Wash and Arbuckle Formations in Oklahoma

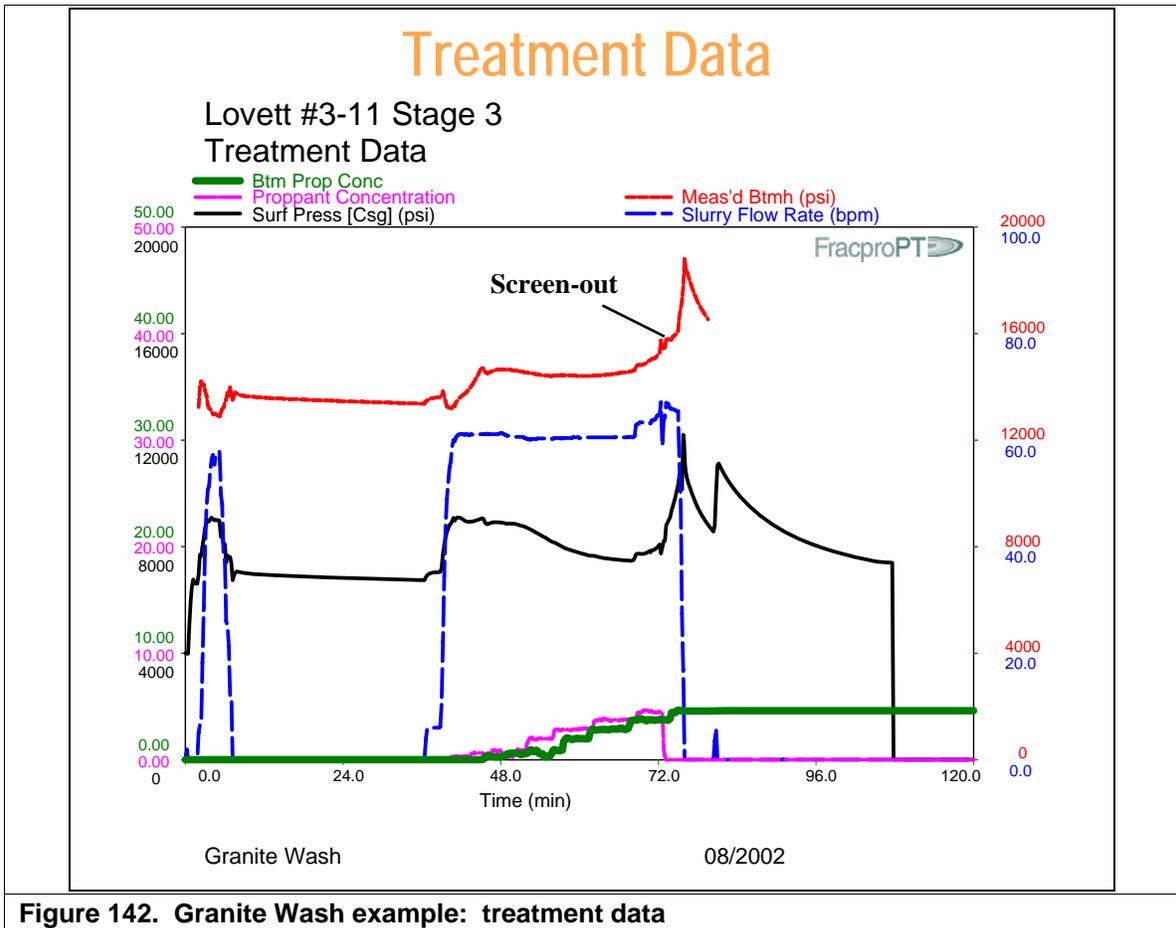


Figure 142. Granite Wash example: treatment data

6. Case History of Hydraulic Fracturing in the Springer, Granite Wash and Arbuckle Formations in Oklahoma

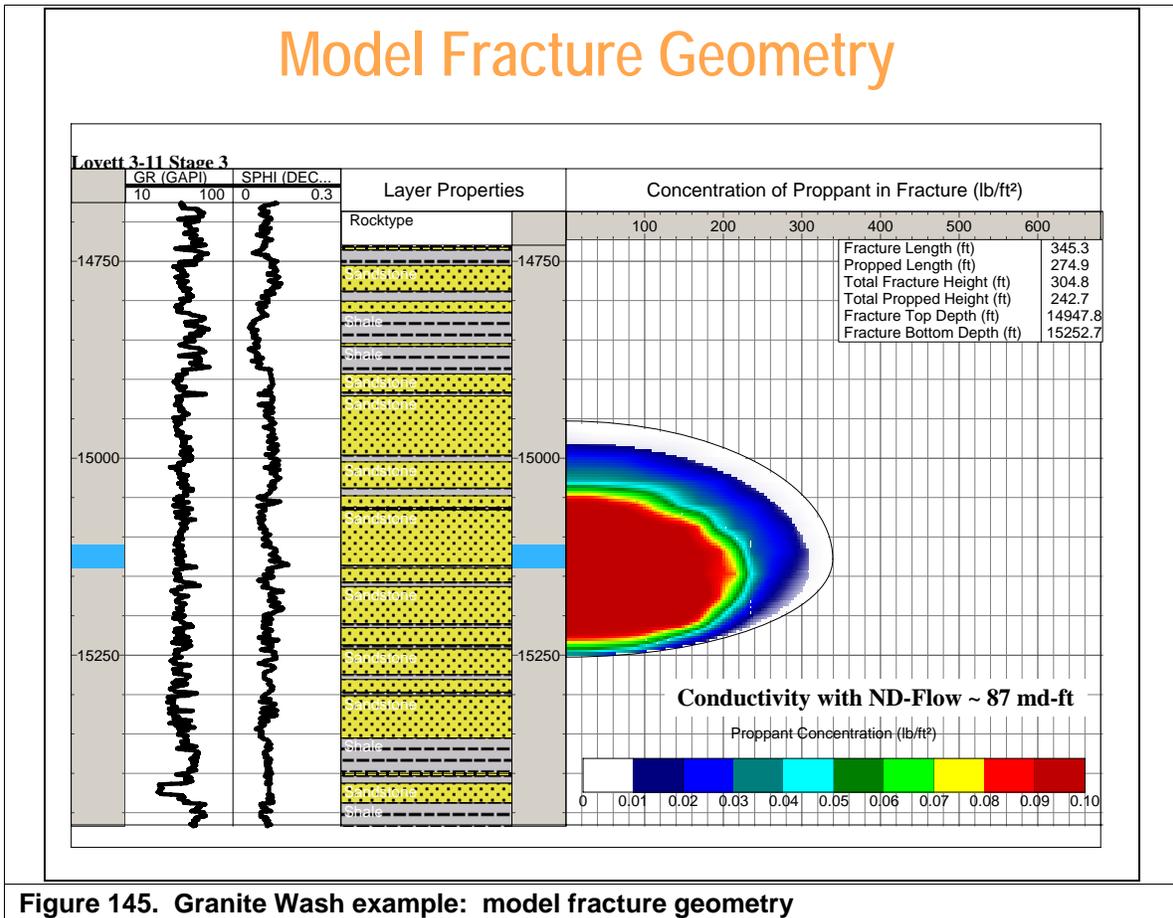


Figure 145. Granite Wash example: model fracture geometry

6.2.3 Arbuckle

The Arbuckle is fracture stimulated with acid fractures. To increase the effective fracture conductivity at this large depth, Marathon has attempted to pump high strength proppant after the acid stages. In the first couple of treatments, this resulted in screenouts due to insufficient fracture width for the 30/60-mesh proppant. Subsequently, Marathon modified the treatment design with more diverter stages and less aggressive proppant schedules and was successful at placing the designed treatment. Marathon is still evaluating conventional acid fractures without any proppant as the better alternative. In general, the acid fracture treatment designs were as follows:

- A diagnostic injection (or fluid efficiency test) was conducted for each zone
- 15% HCl neat acid was pumped to break down the formation
- A couple of cycles of 10# linear gel, 5% ZCA, and 15% ZCA were repeatedly injected, with 0.5 to 1.5 ppg of 100-mesh sand for fluid loss control
- ZCA (Zonal Coverage Acid) is a crosslink system designed for crosslinking to occur as the acid is nearly spent

6. Case History of Hydraulic Fracturing in the Springer,
Granite Wash and Arbuckle Formations in Oklahoma

- The stage of 5% ZCA is used as diverter as it is spent quickly
- 15% ZCA was the main stimulation acid
- 25# linear gel was then pumped with 30/60 proppant at 0.5 to 2.0 ppg (eliminated in some treatments)

Figure 146 shows an example of an Arbuckle acid fracture treatment. The perforated interval had five clusters (18,110 to 18,130 ft; 18,150 to 18,170 ft; 18,210 to 18,230 ft; 18,250 to 18,270 ft; 18,295 to 18,315 ft) perforated with one-shot-per-foot and spiral phasing. Closure pressure was estimated at about 0.57 psi/ft (**Figure 147**). **Figure 148** shows the net pressure match and **Figure 149** the estimated model fracture geometry showing a 300-ft tall and 300-ft long fracture.

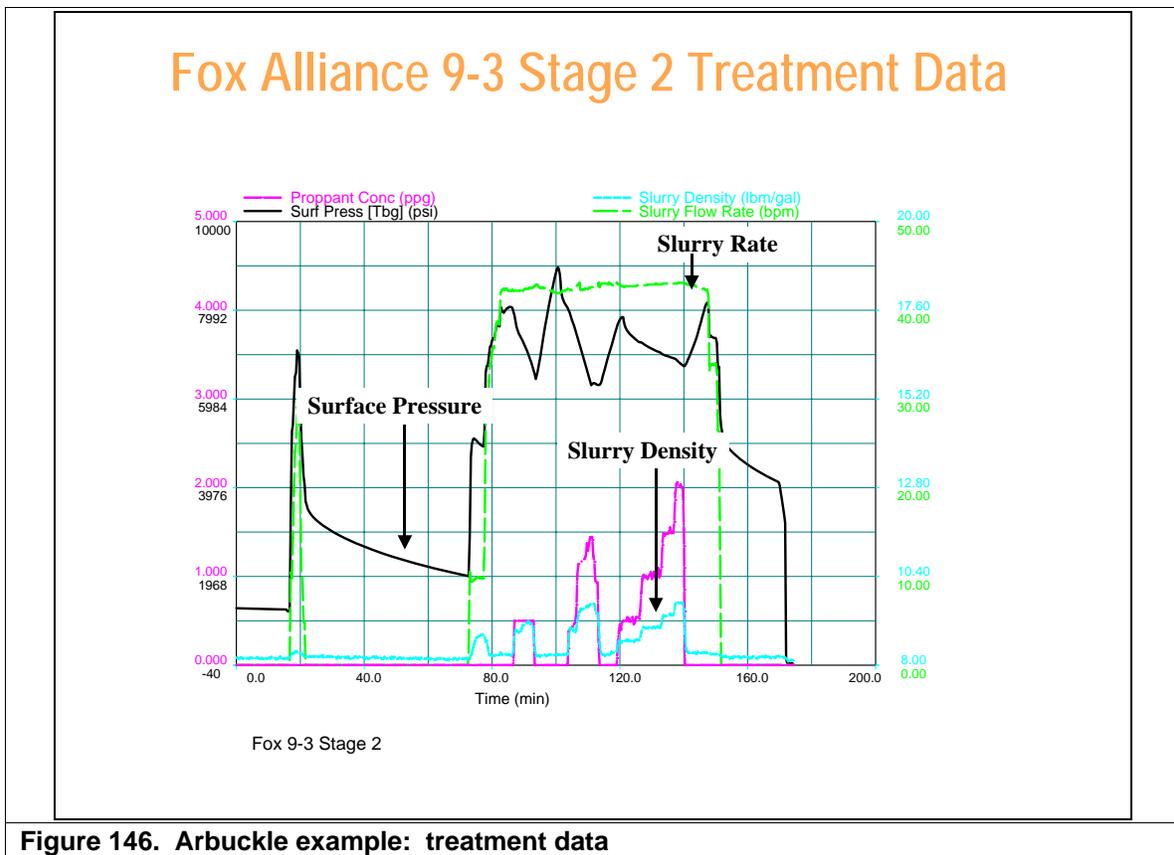


Figure 146. Arbuckle example: treatment data

6. Case History of Hydraulic Fracturing in the Springer, Granite Wash and Arbuckle Formations in Oklahoma

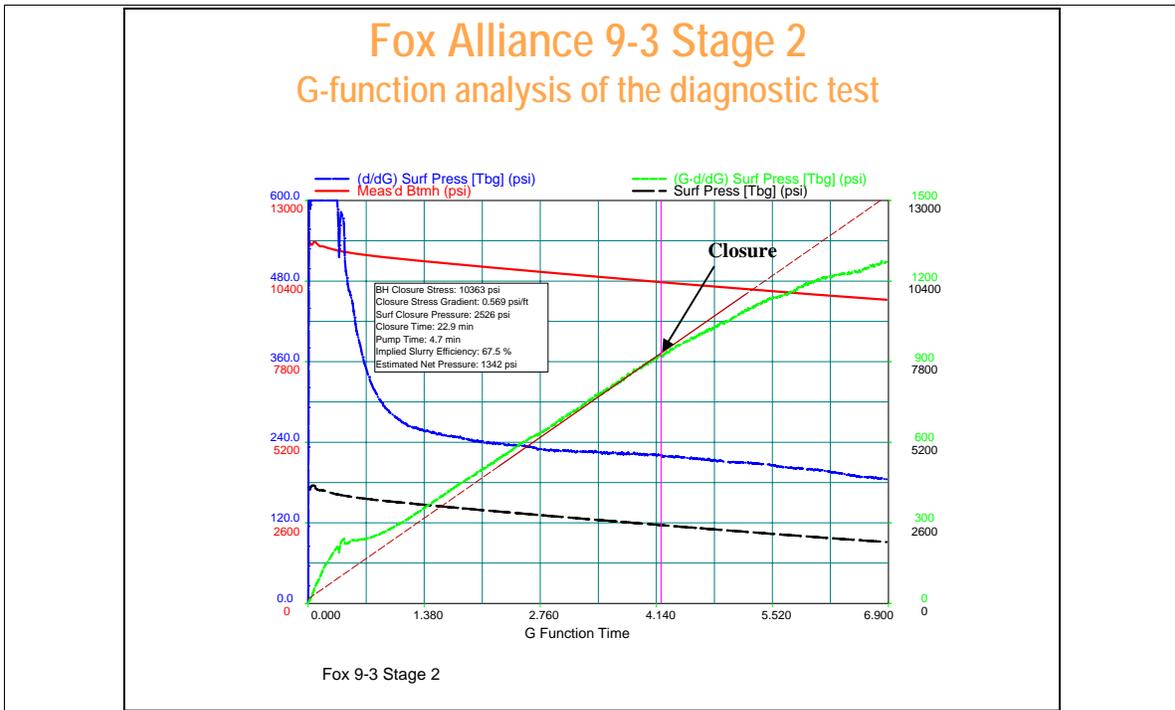


Figure 147. Arbuckle example: closure analysis

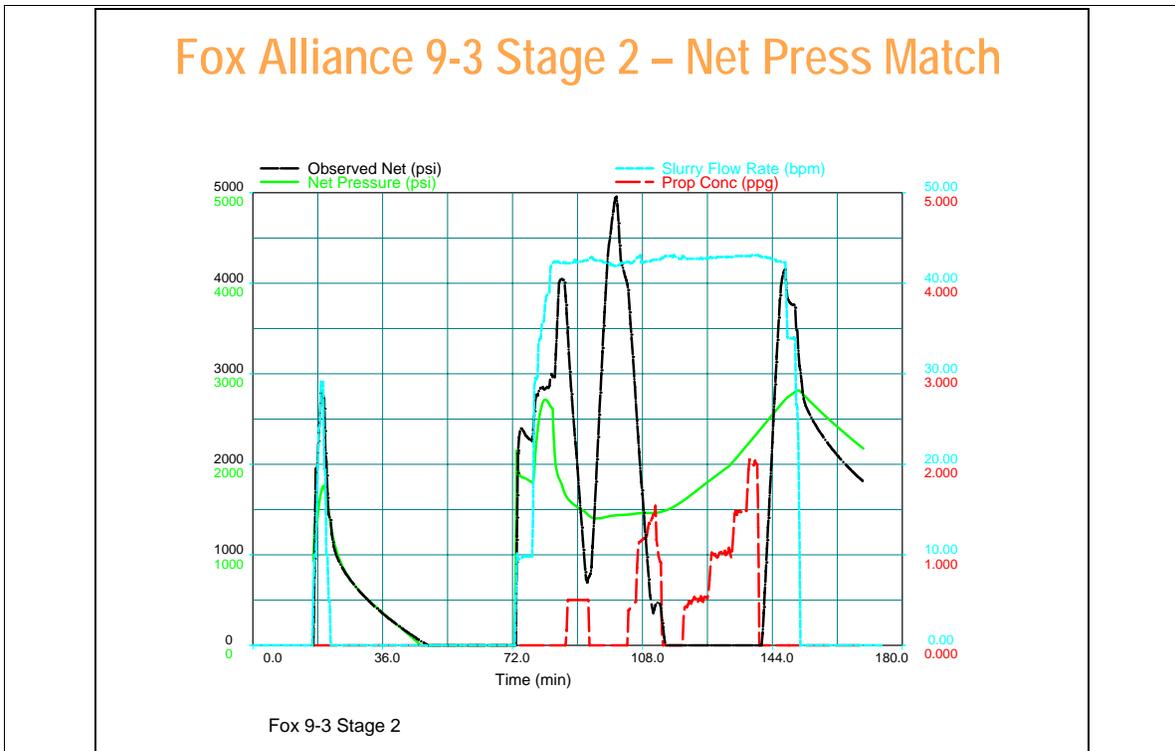


Figure 148. Arbuckle example: net pressure match

6. Case History of Hydraulic Fracturing in the Springer,
Granite Wash and Arbuckle Formations in Oklahoma

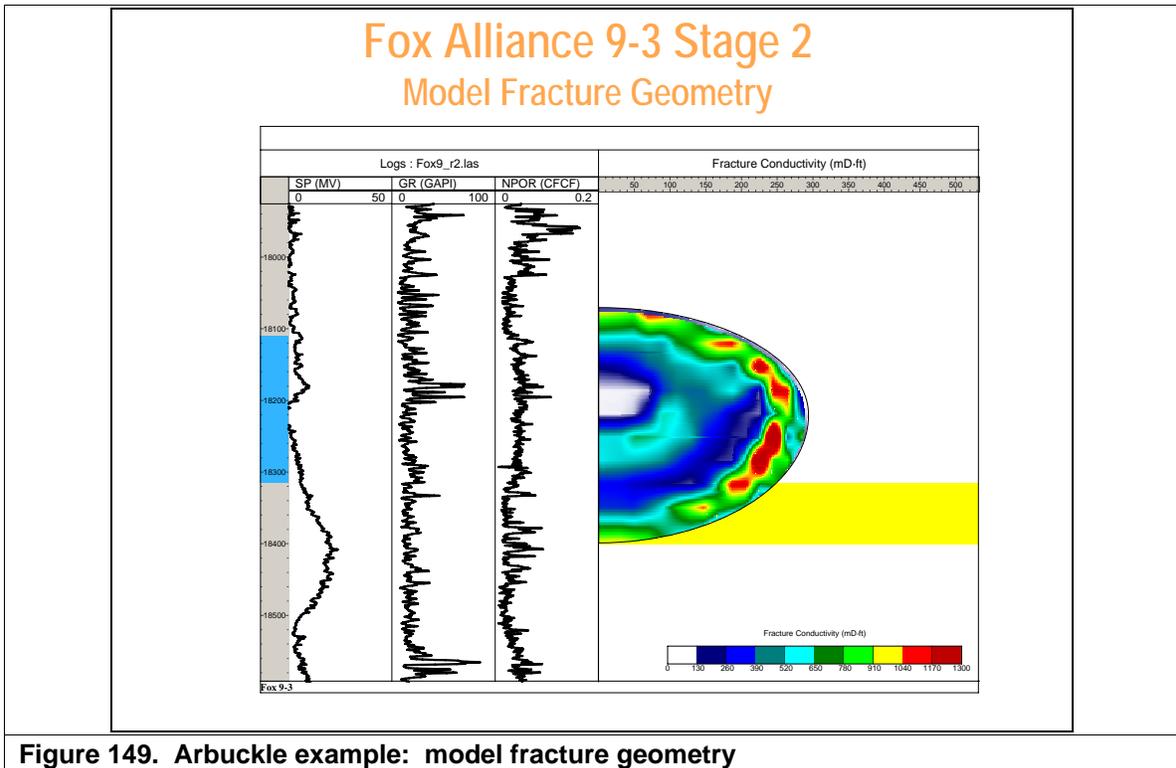


Figure 149. Arbuckle example: model fracture geometry

7. Bibliography: Deep Gas Well Stimulation

This bibliography was prepared as part of the U.S. Department of Energy's Deep Trek Program. The bibliography focuses on published material related to deep gas well stimulation. Some publications on domestic deep gas resources are included to provide information on the type of reservoirs that must be stimulated during deep gas field development. A few early publications (1960's to 1970's) are also listed to provide a historical view of deep gas well stimulation.

Ali, A. H. A., Frenier, W.W., Xiao, Z. and Ziauddin, M. (2002): "Chelating Agent-Based Fluids For Optimal Stimulation of High-Temperature Wells," SPE paper 77366.

Key words: matrix stimulation, chelating agents, acidizing, sandstones, carbonates

Content: Chelating agents are often used to formulate systems for matrix stimulation and to prevent precipitation of solids. Chelating agents with low corrosion rates at high temperature are discussed in this paper. Laboratory and field test results are presented.

Anderson, R. W., Johnson, D.E. and Diep, T. (2002): "New Resin Technology Improves Proppant Flowback Control in HP/HT Environments," SPE paper 77745.

Key words: proppant, proppant flowback, resin coating

Content: Discusses a new resin system for proppant flowback control under extreme conditions of stress, temperature and flow rate. The basics of resin coating are presented and laboratory testing of the new system is presented. No field results are shown.

Bilia, R., Gordon, D., Watterson, E. and Mota, J. (2003): "South Texas Hybrid Monobore High-Pressure, High-Temperature Well Design," SPE paper 84267.

Key words: completion, South Texas, Wilcox Formation, tubing-less wells

Content: This paper covers tubing-less well completions in deep Wilcox wells in the Fandango Field. Conventional (tubing/packer) and tubing-less well designs and costs are compared.

Brannon, H.D. and Ault, M.G. (1991): "New, Delayed Borate-Crosslinked Fluid Provides Improved Fracture Conductivity in High-Temperature Applications," SPE paper 22838.

Key words: frac fluids, crosslinked fluids, Red Fork Formation, Oklahoma, Wilcox Formation, South Texas

Content: This paper talks about a borate-crosslinked fluid developed for high-temperature application. The evolution of high-temperature fracturing fluids is reviewed along with the chemistry of the new fluid. Laboratory data is presented along with case histories.

Chambers, M.R., Mueller, M.W. and Grossmann, A. (1995): "Well Completion Design and Operations for a Deep Horizontal Well with Multiple Fractures," SPE paper 30417.

Key words: case history, horizontal well

Content: Case history of a horizontal well stimulated with multiple hydraulic fracture treatments. Design considerations are presented to optimize completion operations (perforating, stimulation and zonal isolation). Well depth is over 15,000 ft (TVD) with a horizontal section over 2,000 ft in length.

Cikes, M. and Economides, M.J. (1992): "Fracturing of High-Temperature, Naturally-Fissured, Gas-Condensate Reservoirs," SPE paper 20973.

Key words: case history, naturally fissured, gas-condensate, low permeability

Content: This paper discusses eleven fracture treatments that were completed in extremely high-temperature (355 to 385°F), low-permeability zones. The paper covers the completion and stimulation treatment design, treatment execution and post-fracture evaluation.

Cikes, M. (1996): "Long-term Hydraulic-Fracture Conductivities Under Extreme Conditions," SPE paper 66549.

Key words: proppant, conductivity, case history

Content: This paper evaluates the performance of proppants subject to severe conditions of stress and temperature. Production histories and pressure buildup tests are evaluated from four wells completed in a hot, high-pressure reservoir. Reservoir temperatures ranged from 354 to 383°F and effective closure stress from 3,640 to 7,395 psi.

Cochener, J.C., and Hill, D.G. (2001): "Big League Potential Has Industry Going Deep for Gas," *American Oil & Gas Reporter*, V. 44, N. 3, pp 68-70, 72, 75-77.

Key words: deep gas resource, key deep gas regions, gas quality

Content: Overview of deep gas resource in the lower 48 U.S. Provides an assessment of resource and gas quality by region along with emerging plays.

Cochener, J. and Brandenburg, C. (1998): "Expanding the Role of Onshore Deep Gas," *GasTIPS*, V. 4, N. 3, pp 4-8.

Key words: deep gas resource, key deep gas regions, gas quality

Content: Overview of deep gas resource in the lower 48 U.S. Provides an assessment of resource and gas quality by region along with emerging plays along with a quick review of challenges in bringing deep gas to the market.

Collins, J.C. and Graves, J.R. (1989): "The Bighorn No. 1-5: A 25,000-ft Precambrian Test in Central Wyoming," SPE paper 14987.

Key words: case history, Wind River Basin, Madison Formation

Content: This paper reports on a deep (25,000 ft TVD) well drilled on the Madden anticline in 1983 to 1985. Drilling performance by section is discussed and production testing of the Madison is briefly described.

Conway, M.W. and Harris, L.E. (1982): "A Laboratory and Field Evaluation of a Technique for Hydraulic Fracturing Stimulation of Deep Wells," SPE paper 10964.

Key words: fracturing fluids

Content: This paper discusses treating fluids for stimulating deep wells. It covers a laboratory method and test results to evaluate the time-temperature stability of a crosslinked gel fluid system. Field results from Oklahoma and Texas wells are presented.

Cooke, C.E. (1976): "Hydraulic Fracturing with a High-Strength Proppant," SPE paper 6213.

Key words: proppant, high-strength proppant, conductivity

Content: This paper discusses laboratory studies of high-strength proppant and describes field applications of the proppant and summarizes factors affecting gas well stimulation.

Crow, R. and Craig, B.D. (1992): "Drilling and Completion Practices for Deep Sour Gas Wells in the Madden Deep Unit of Wyoming," SPE paper 24604.

Key words: Madison Formation, sour gas, completion design, Madden Deep Unit

Content: This paper presents the drilling and completion practices for two deep and hot sour gas wells in the Madison Formation of the Madden Deep Unit in Wyoming. The wells were drilled to approximately 25,000 ft. A corrosion study and tubular selection is discussed.

Crenshaw, P.L. and Flippen, F.F. (1968): "Stimulation of the Deep Ellenburger in the Delaware Basin," SPE paper 2075.

Key words: Delaware basin, acid fracturing, Ellenburger Formation, dolomite, limestone, case history

Content: This early paper covers problems stimulating deep wells completed in the Ellenburger Formation in West Texas. Problems include lack of treatment height confinement, lack of fluid-loss control and lack of knowledge about acid reaction at high temperatures and pressures.

Cutler, R.A., Jones, A.H., Swanson, S.R. and Carroll Jr., H.B. (1981): "New Proppants For Deep Gas Well Stimulation," SPE paper 9869.

Key words: proppants, conductivity

Content: This paper discussed the manufacturing and testing of high-strength proppants. Laboratory test results for conductivity under simulated downhole conditions are shown.

Davis Jr., W.E (1975): "Considerations for Fracture Stimulation of the Deep Morrow in the Anadarko Basin," SPE paper 5391.

Key words: case history, Anadarko Basin, Morrow Formation

Content: This paper discusses stimulation of the Morrow Formation in the Anadarko Basin of Oklahoma. Fluids, proppant, equipment and techniques for deep well stimulation are discussed. Results from four wells are shown.

de Pater, C.J., Zoback, M.D., Wright, C.A. and Engeser, B. (1996): "Complications with Stress Tests - Insights from a Fracture Experiment in the Ultra-deep KTB Borehole," SPE paper 36437.

Key words: *in situ* stress, stress tests, fracture mechanics

Content: This paper documents injection tests that were conducted in a 9,000-meter deep borehole to measure *in situ* stress.

Dyman, T.S. and Kuuskraa, V.A. (2003): "Geologic Studies of Deep Natural Gas Resources," USGS Digital Data Series 67, DDS-67 <http://geology.cr.usgs.gov/energy/DDS-67/> as of 6/26/03, CD-ROM.

Key words: deep gas resource, plays, deep gas potential

Content: This report summarizes major conclusions from ongoing USGS work on deep gas resources. The report includes chapters on the location and description of deep sedimentary basins, geochemical work on source rock and gas generation, assessment of Gulf Coast plays and deep gas drilling in the 1990's.

Dyman, T. S., Rice, D. D. and P. A. Westcott (1997): "Geologic Controls of Deep Natural Gas Resources in the United States," USGS Bulletin 2146, <http://pubs.usgs.gov/bul/b2146/b2146.pdf> as of 6/26/03.

Key words: deep gas resource, plays, deep gas potential

Content: This is an extensive collection of papers. Papers in this bulletin address major areas of geologic research funded by the United States Geologic Survey (USGS) Onshore Oil & Gas Program and the Gas Research Institute. During the first phase of the work, deep well data were tabulated and summarized, preliminary reservoir properties and structural settings for deep gas accumulations were identified and porosity and source-rock geochemistry studies were conducted. During the second phase of the work, general geologic controls governing natural gas distribution were determined, geologic and production data for significant reservoirs were tabulated and summarized, diagenetic controls for select reservoirs were established, production and pressure-test data were interpreted, geochemical controls and geologic settings for non-hydrocarbon gases were identified, the setting and controls of unusually high porosity in deeply buried rocks were defined, the source rock potential of Precambrian sedimentary rocks was investigated and the range of potential of kerogen at high levels of maturation was studied. Papers in this bulletin summarize major conclusions reached in both phases of work on deep natural gas resources.

Economides, M.J., Cikes, M., Pforter, H., Udick, T.H. and Uroda, P. (1989): "The Stimulation of a Tight, Very High-Temperature Gas-Condensate Well," SPE paper 15239.

Key words: case history, gas-condensate reservoir, low permeability, frac fluid selection

Content: This paper presents a pre-treatment analysis of the well, thermal and lithologic considerations for selection of the fracture-fluid system, treatment execution and post-frac analysis. Well performance is analyzed and the effects of gas condensate on production and refracture potential are discussed.

Economides, M.J. and Nolte, K.G. (editors) (2000): "Reservoir Stimulation – Third Edition, Schlumberger"

Key words: hydraulic fracturing, rock mechanics, formation evaluation, fracturing fluids, proppants, conductivity, fracture modeling, fracture diagnostics, treatment design, completion design, treatment analysis, economics, acidizing, formation damage

Content: Comprehensive publication covering formation stimulation including hydraulic fracturing, acid fracturing and matrix acidizing.

Ely, J.W., Martin, M.A. Duenas, J.J. and Trythall, J.R. (2003): "Enhanced Fracture Stimulation in the Deep Morrow Sandstone in Western Oklahoma," SPE paper 80932.

Key words: case history, Oklahoma, Morrow

Content: This paper covers a project to optimize treatments in the Deep Morrow Sandstone in western Oklahoma. Offset well results and diagnostic injections were used to optimize treatment design and to identify potential treatment execution problems. Production data is compared to offset wells fractured with other job designs.

Ely, J.W., Cobb, W.J., Elkin, B. and Bell, D.D. (1989): "Successful Proppant Fracturing of Ultradeep Sour Gas Reservoir," SPE paper 19768.

Key words: case history, Mississippi, Smackover, sour gas

Content: This paper reports on hydraulic fracturing of four sour gas wells completed in the deep (19,000 ft), hot (330°F) Smackover Formation in Mississippi. Stimulation treatment design and execution is discussed along with production results for each well.

Gibbs, M.A. (1968): "Ellenburger Stimulation – Past, Present and Future," SPE paper 2347.

Key words: Delaware basin, completion, dolomite, limestone, case history

Content: This early paper reviews stimulation practices in deep wells (up to 20,000 ft TVD) in the Delaware Basin in West Texas. A variety of completion techniques have been used to cope with the depth, high-temperature and large gross pay thickness of these wells.

Gidley, J.L., Holditch, S.A. Nierode, D.E. and Veatch, R.W. (editors) (1989): "Recent Advances in Hydraulic Fracturing," SPE Monograph Vol. 12.

Key words: hydraulic fracturing, rock mechanics, formation evaluation, fracturing fluids, proppants, conductivity, fracture modeling, fracture diagnostics, treatment design, completion design, treatment analysis, economics

Content: Comprehensive SPE monograph on hydraulic fracturing with contributions from 23 authors.

Griffin, L.G., Sullivan, R.B., Wolhart, S.L., Waltman, C.K., Wright, C.A., Weijers, L. and Warpinski, N.R. (2003): "Hydraulic Fracture Mapping of the High-temperature, High-pressure Bossier Sands in East Texas," SPE paper 84489.

Key words: case history, Bossier Sand, East Texas Basin, flowback, microseismic hydraulic fracture mapping, fracture diagnostics

Content: This paper presents the results of microseismic hydraulic fracture mapping for three wells completed in the Bossier tight gas sand play in the East Texas Basin. The paper shows fracture geometry (azimuth, height and length) results from monitoring both waterfrac and hybrid waterfrac treatments. Fracture length development and pay zone coverage is discussed.

Hahn, D.E., Pearson, R.M. and Hancock, S.H. (2000): "Importance of Completion Design Considerations for Complex, Hostile, and HP/HT Wells in Frontier Areas," SPE papers 59750.

Key words: completion design, frontier wells, tubular selection, sour gas

Content: This paper shows an engineering design approach for planning deep, difficult and complex wells. A methodology is presented that accounts for stress due to thermal effects, axial loads and pressure differentials. Selection of tubulars is emphasized but other aspects of completion design are discussed (packers, other downhole equipment, completion fluids and perforating).

Hahn, D.E., Burke, L.H. Mackenzie, S.F. and Archibald, K.H. (2003): "Completion Design and Implementation in Challenging HP/HT Wells in California," December 2003 SPE Drilling & Completion.

Key words: case history, completion design, tubular selection, California

Content: This paper covers the well design for deep (>20,000 ft), high-temperature (425°F) and high-pressure (18,000 psi) wells in the East Lost Hills field in California. Completion design (tubulars, packers, completion fluids and perforating) and operations are discussed.

Hickey, J.W. and Crittenden, S.J. (1981): "The Comparative Effectiveness of Propping Agents in the Red Fork Formation of the Anadarko Basin," SPE paper 10132.

Key words: proppant, conductivity, Red Fork Formation, Anadarko Basin, case history

Content: The paper presents the results comparing the effectiveness of various proppants and their relationship to production performance. The analysis is based on 25 wells completed in the Red Fork Formation in the Anadarko Basin.

Holditch, S.A. and Ely, J. (1973): "Successful Stimulation of Deep Wells Using High Proppant Concentrations," SPE paper 4118.

Key words: South Texas, Vicksburg Formation, case history

Content: This early paper on deep well stimulation discusses hydraulic fracturing of deep, hot, low permeability formations. Results from several formations are presented with an emphasis on the Vicksburg.

Jennings, A.R. (1996): "Fracturing Fluids – Then and Now," Journal of Petroleum Technology, Vol. 48, No. 7.

Key words: fracturing fluids

Content: This article, part of the JPT Technology Today Series, covers the evolution of fracturing fluids. Key technological advances are discussed and key references are listed.

Lindsey Jr., H.E. (1972): "Deep Gas Well Completion Practices," SPE paper 3908.

Key words: completion design, tubulars, Delaware Basin, Anadarko Basin

Content: This paper discusses early deep well completion designs and the evolution of practices in the Delaware and Anadarko Basins.

Mayerhofer, M.J., Wolhart, S.L. and Rogers, J.D. (2005): "Results of U.S. Department of Energy Deep Gas Wells Stimulation Study," SPE paper 95639.

Key words: deep gas well drilling activity, rock mechanics, Lobo, South Texas, Weber, Wyoming

Content: This paper summarizes deep gas well activity, review key rock mechanics issues in deep reservoirs and shows case histories from Wyoming and South Texas.

McDermott, J.R. and Martin III, B.L. (1992): "Completion Design for Deep, Sour Norphlet Gas Wells Offshore Mobile, Alabama," SPE paper 24772.

Key words: Norphlet Formation, Mobile Bay area, corrosive gas, sour gas

Content: This paper describes the evolution of completion design and equipment during the drilling of Norphlet gas wells in two fields in the Mobile Bay area. Conditions in this formation can be very challenging with well depths and temperatures exceeding 20,000 ft (TVD) and 400°F respectively. Highly corrosive gas is produced containing hydrogen sulfide and carbon dioxide.

McMechan, D.E. (1991): "Fracturing Fluid Loss at High ΔP : Laboratory Tests and Field Applications," SPE paper 21873.

Key words: fracturing fluids, fluid loss, fluid leakoff, frac design

Content: This paper reports on laboratory fluid loss tests conducted at high differential pressures (up to 9,000 psi) to determine the nature of fluid loss during fracture treatments. Results from field cases are reviewed to show where high fluid loss differential pressures have been observed.

National Energy Technology Laboratory, 2001, Deep Trek Workshop Proceedings, March 20-21, 2001, Houston, TX., <http://www.netl.doe.gov/scng/explore/ref-shelf/DeepTrek5-3%20FINAL.PDF> as of 6/26/02, 97 p.

Key words: deep gas resource, completion fluids, completion design

Content: The proceedings on this report include presentations made during the workshop; the breakout session results for the advanced smart drilling systems, drilling and completion fluids, completion-based well design and drilling diagnostics and sensor systems; and a list of workshop participants.

Osborne, M.W., McLeod Jr., H.O., Schroeder, H.D. (1981): "The Analysis and Control of Hydraulic Fracturing Problems," SPE paper 9868.

Key words: case history, South Texas, Anadarko Basin

Content: This paper analyzes problems fracturing wells in South Texas and the Anadarko Basin. Modifications to fracture fluid systems, treatment design and operations to improve results are documented.

Petzet, A.: "Ekho Deep Test Is Spud Amid San Joaquin Valley Uncertainty," Oil & Gas Journal, v. 98, n. 10, pp 71-72.

Key words: California, case history, Temblor sandstone

Content: Summary of recent (1999 to 2000) deep gas well activity in the San Joaquin Valley in California. Target formation is the Temblor sandstone.

Popov, M.A., Nuccio, V.F., Dyman, T.S., Gognat, T.A., Johnson, R.C., Schmoker, J.W., Wilson, M.S. and Bartberger, C. (2001): "Basin-Centered Gas Systems of the U.S.," USGS Open File Report 01-135, Version 1.0, CD-ROM.

Key words: basin-centered gas, deep gas resource, deep gas potential

Content: Many deep gas plays are basin-centered gas accumulations. This study identifies and characterizes 33 potential basin-centered gas accumulations throughout the U.S.

Rushing, J.A. and Sullivan, R.B. (2003): "Evaluation of a Hybrid Water-Frac Stimulation Technology in the Bossier Tight Gas Sand Play," SPE paper 84394.

Key words: case history, Bossier Sand, East Texas Basin, waterfrac, hybrid waterfrac

Content: This paper presents results from an evaluation of stimulation treatments in the Bossier tight gas sand play in the East Texas Basin. Detailed pressure buildup test and production data analysis is shown to evaluate and compare the performance of waterfracs, gelled fluid fracs, light sand fracs and hybrid waterfracs. Fracture half-length and conductivity estimates are used to evaluate stimulation effectiveness.

Samuelson, M.L. and Constien, V.G. (1996): "Effects of High Temperature on Polymer Degradation and Cleanup," SPE paper 36495.

Key words: fracturing fluids, fracture cleanup, conductivity

Content: This papers presents laboratory data of degraded fracturing fluids at temperatures up to 275°F. Field data is also shown to indicate trends in polymer cleanup at these temperatures and a procedure for polymer sampling during flowback is described.

Schueler, S. and Santos, R. (1996): "Fractured Horizontal Well Shows Potential of Deep Tight Gas," Oil & Gas Journal, v. 94, n. 2, pp 46-49, 52-43.

Key words: horizontal well, fracture stimulation, multiple-stage fracturing

Content: Article on horizontal well in NW Germany that was stimulated with multiple hydraulic fractures. The article summarizes formation evaluation, well design, drilling, completion, stimulation and production results for the well. This well demonstrated the technical feasibility of fracturing long horizontal sections completed in tight gas formations.

Sinclair, A.R. (1971): "Heat Transfer Effects in Deep Well Fracturing," SPE paper 3011.

Key words: fracture fluids

Content: This early paper considers heat transfer in the design of stimulation treatments. Temperature profiles for different fracture fluids are presented and fracture growth is discussed.

Soza, R. (2000): "Burlington Drills Ultradeep Wyoming Well," Oil & Gas Journal, v. 98, n. 50, pp 50-53, 56, 58-59.

Key words: Wyoming, case history, Madden Formation, Wind River Basin

Content: Summary of a deep well (25,000 ft TVD) drilled by Burlington in the Madden Formation in Wyoming. The history of deep well activity in the area is summarized and drilling of the Big Horn #5-6 is covered. This well achieved \$10 million in cost savings compared to earlier wells in the field.

Stephenson, C., Ward, B., Taylor, D.M., Brannon, H. and Rickards, A. (2002): "Exceptional Flowback Control for Most Extreme Well Environments: The Shape of Things to Come," SPE paper 77681.

Key words: proppant flowback, proppant, Lobo Formation, Wilcox Formation, South Texas

Content: Discusses the development of a deformable material for proppant flowback control under extreme conditions of stress, temperature and flow rate. Laboratory testing is discussed and case histories from South Texas are presented.

Tucker, R.L. (1979): "Practical Pressure Analysis in Evaluation of Proppant Selection for the Low-Permeability, Highly Geopressured Reservoirs of the McAllen Ranch (Vicksburg) Field," SPE paper 7925.

Key words: South Texas, Vicksburg Formation, proppant

Content: The paper presents an evaluation on proppant selection the McAllen Ranch Field. Historical fracture stimulation practices and effectiveness are also reviewed.

Volk, L.J., Raible, C.J., Carroll, H.B. and Spears, J.S. (1981): "Embedment Of High Strength Proppant Into Low-Permeability Reservoir Rock," SPE paper 9867.

Key words: proppant, conductivity, embedment

Content: Embedment of sintered bauxite into sandstone (Berea and Mesaverde) and shale (Mesaverde) cores is reported. Variables such as closure pressure, proppant size and distribution, proppant concentration, formation hardness and surface roughness are examined. Comparison is made with sand proppant.

Weijers, L., Griffin, L.G., Wright, C.A., Sugiyama, H., Shimamoto, T., Takada, S., Chong K.K. and Terracina, J.M. (2002): "The First Successful Fracture Treatment Campaign Conducted in Japan: Stimulation Challenges in a Deep, Naturally Fractured Volcanic Rock," SPE paper 77678.

Key words: case history, naturally fractured rock, fracture modeling, complex fracturing, real-time data analysis

Content: Case history of fracture treatments in a naturally fractured rock in Japan. Severe treatment placement problems and remedies are discussed. Pre-frac design, on-site operations and post-frac analysis are detailed.

West, E.R. and Lindsey, H.E. (1968): "Completion Practices and Techniques in Deep Gas Producers of the Delaware Basin," SPE paper 2078.

Key words: Delaware basin, completion, acid stimulation, dolomite, limestone, case history

Content: This early paper reviews completion practices in deep wells (up to 20,000 ft TVD) in the Delaware Basin in West Texas. Several deep completion types are discussed along with tubing expansion problems and acid treatment design.

Whitsitt, N.F. and Dysart, G.R. (1970): "The Effect of Temperature on Stimulation Design," SPE paper 2497.

Key words: fracturing fluids, acidizing

Content: This early paper looks at calculations of fracture fluid temperature distribution and the effect of high temperatures on fracture fluid properties and acid reaction rates.

Woodruff, R.A., Asadi, M., Leonard, R.S. and Rainbolt, M (2003): "Monitoring Fracturing Fluid Flowback and Optimizing Fracturing Fluid Cleanup in the Bossier Sand Using Chemical Frac Tracers," SPE paper 84484.

Key words: case history, Bossier Sand, East Texas Basin, flowback, chemical tracers, fracture diagnostics

Content: This paper discusses the use of chemical tracers to evaluate treatment effectiveness. Chemical tracers are pumped during the stimulation treatment and their recovery is monitored during fluid flowback. Results from wells in the Bossier tight gas sand play in the East Texas Basin are presented.

Xiong, H., Green, T.W., Guo, X. and Wang, M.: “Field Applications of Advanced Stimulation Technology in Deep and Hot Wells in Dagang Oilfield, China – Diagnostic Tests Made Fracturing Tests Successful,” SPE paper 51074.

Key words: case history, China, frontier areas, frac design, real-time data analysis

Content: This paper reviews fracture treatments in China and the utilization of diagnostics injections, real-time analysis and advanced fracture modeling to optimize stimulation treatments. Pre-frac design, on-site operations and post-frac analysis are detailed. Challenges that were overcome due to local operational limitations are covered.