Stimulation Technologies for Deep Well Completions DE-FC26-02NT41663

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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 producers[1] 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 Program[4] 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^{o}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.

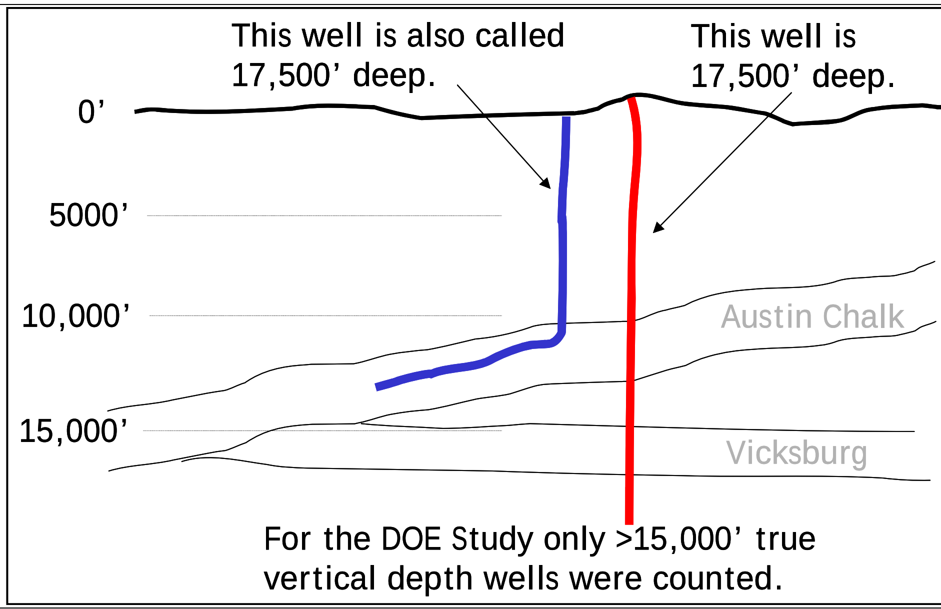

Figure 1. The problem of separating well depth from well length

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.

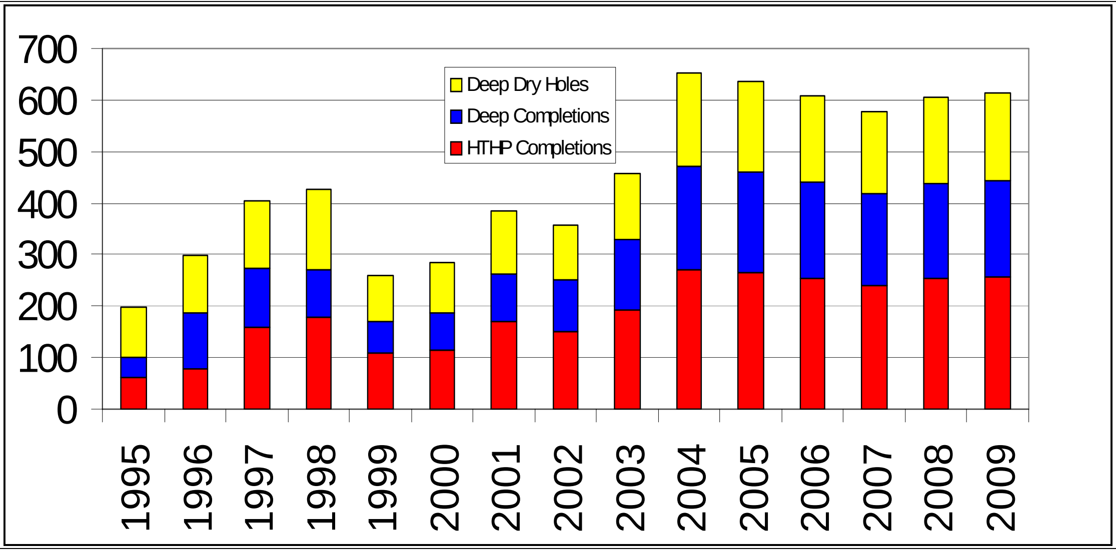

Figure 2. Deep gas well drilling forecast

1.1.4 Deep Gas Resources and Drilling By Region

Deep natural gas[5] 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.

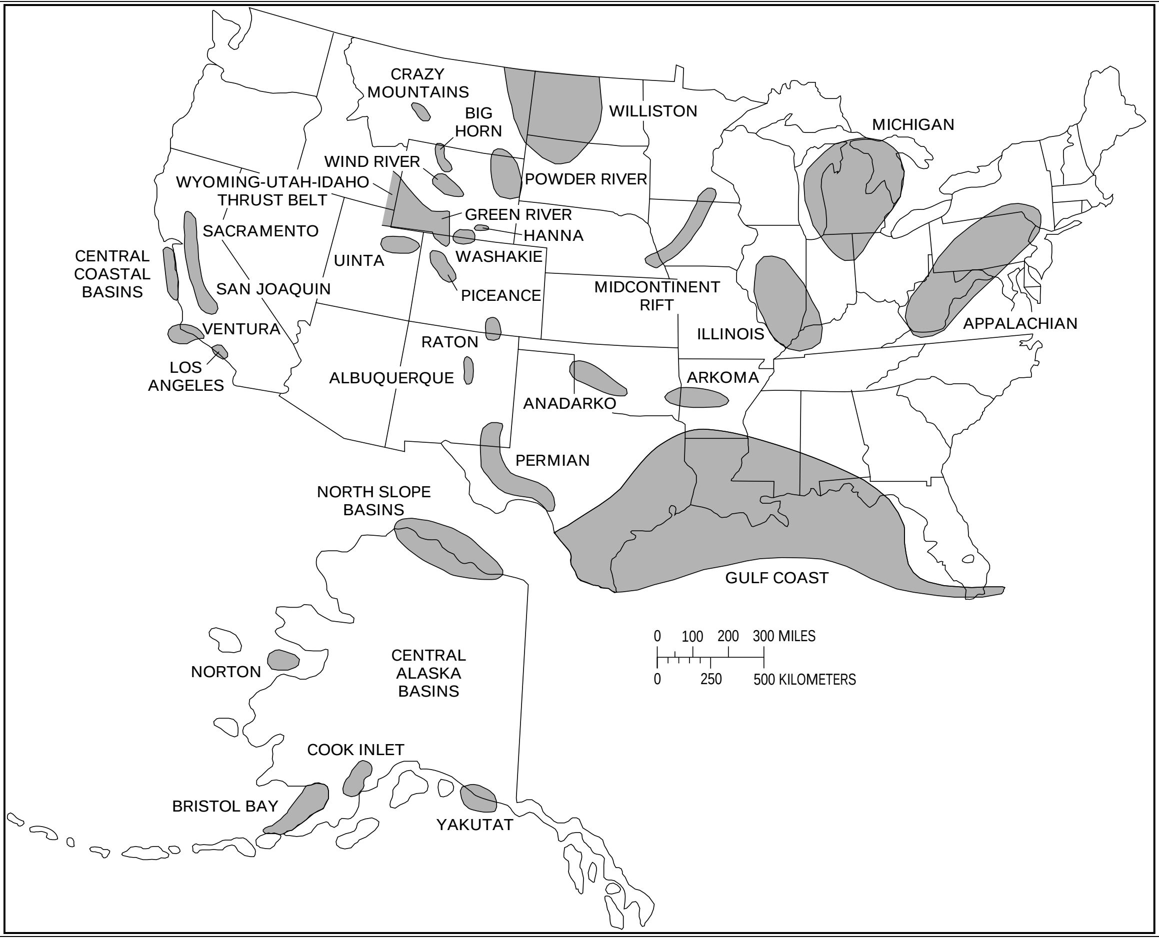

Figure 3. Deep gas basins in the U.S. (USGS Bulletin 2146)

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 CO_2, H_2S and N_2), 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 – $10x10^6$ 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 – $1.0x10^6$ 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 GOM[6] and the North Sea[7]. 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.

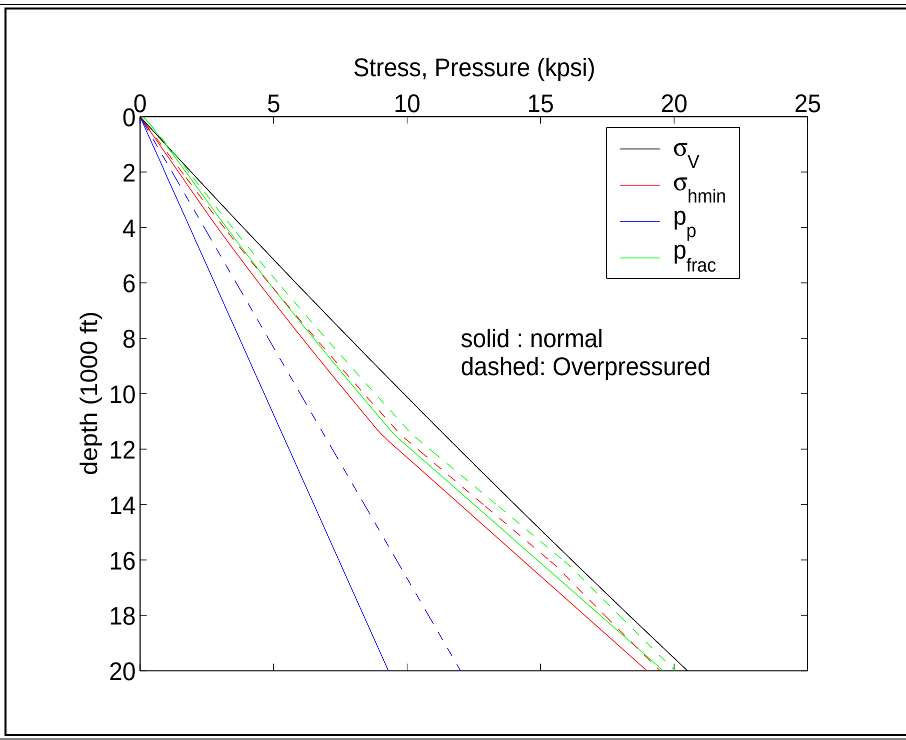

Figure 4. Stress and pore pressure trends versus depth for GOM data (Breckels, *et al.*, 1982[6])

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 CO_2-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^oF) 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^oF for more than two hours. High-temperature application of conventional fracturing polymers requires the use of O_2 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^oF or 250^oF. 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^oF) 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.

H_2S/CO_2: High concentrations of H_2S and/or CO_2 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^{o}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.

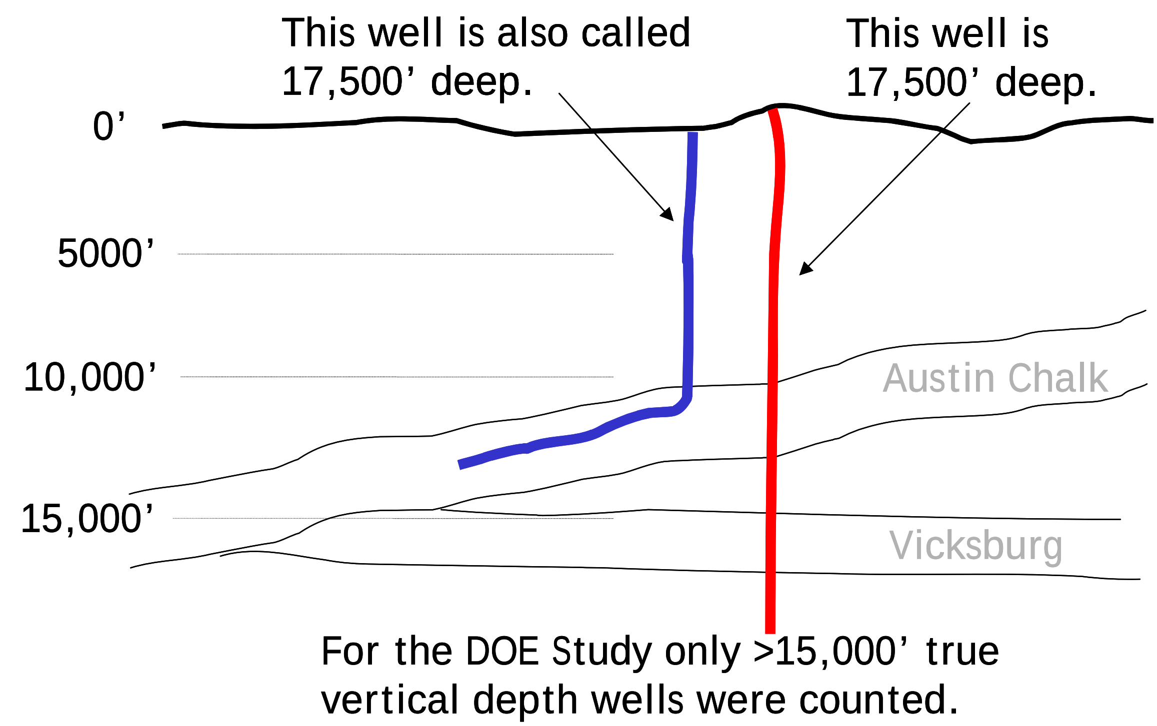


Figure 5. The problem of separating well depth from well length

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).

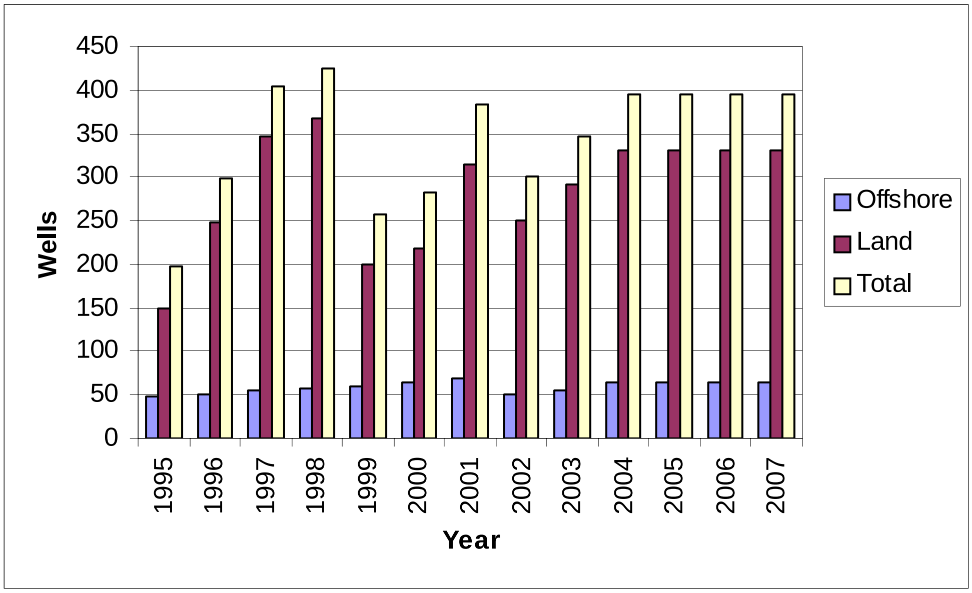


Figure 6. Deep gas drilling in the U.S. (onshore and GOM Shelf), 2003 forecast

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.

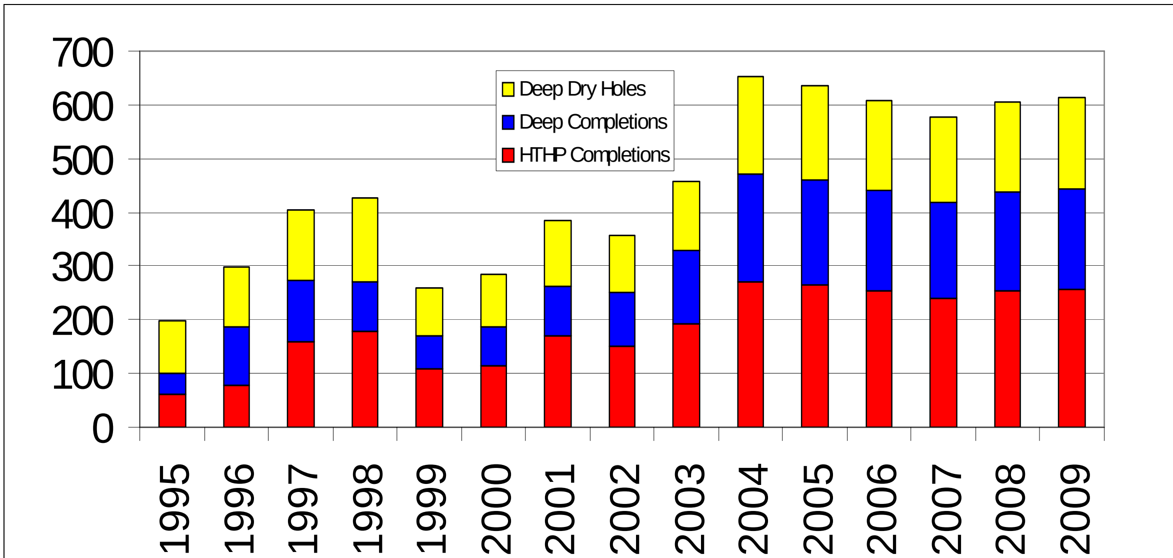


Figure 7. Deep gas drilling in the U.S. (onshore and GOM Shelf), 2004 forecast

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 CO_2, H_2S and N_2), 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**.

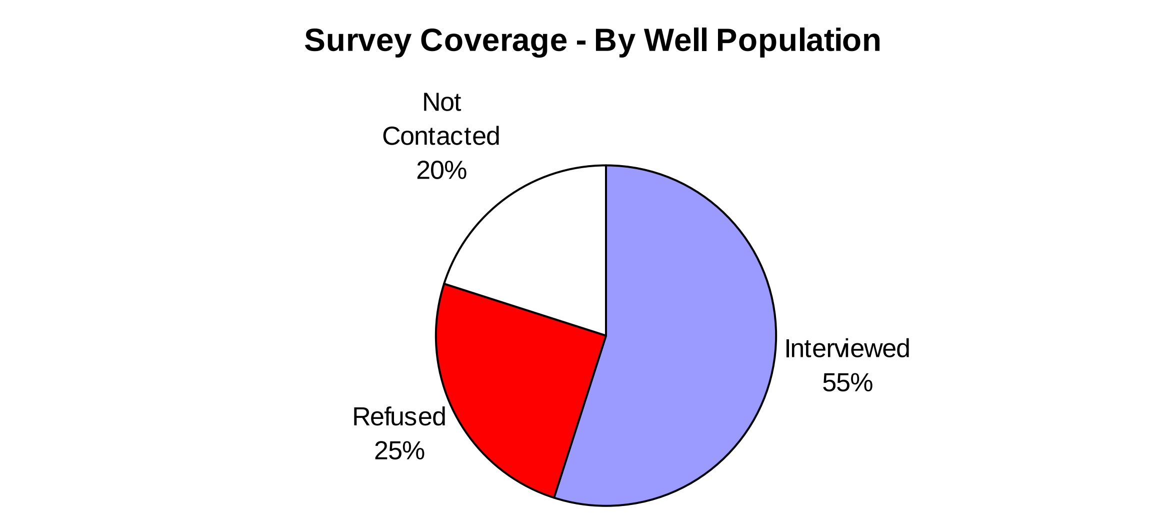


Figure 8. Survey coverage by deep well population

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

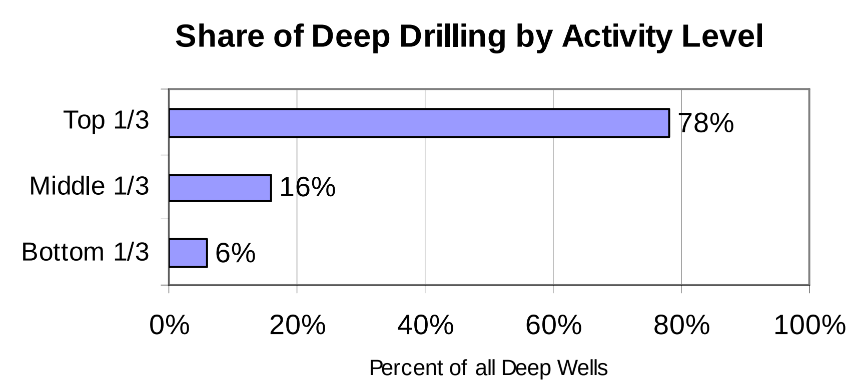


Figure 9. Share of deep well drilling by activity level

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.

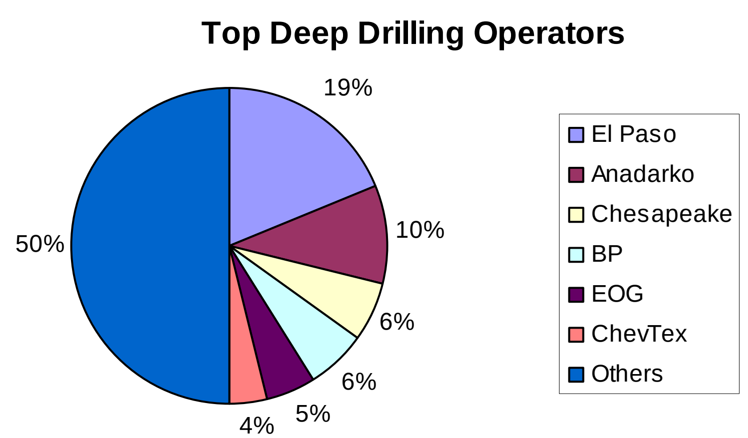


Figure 10. Top deep drilling operators

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.

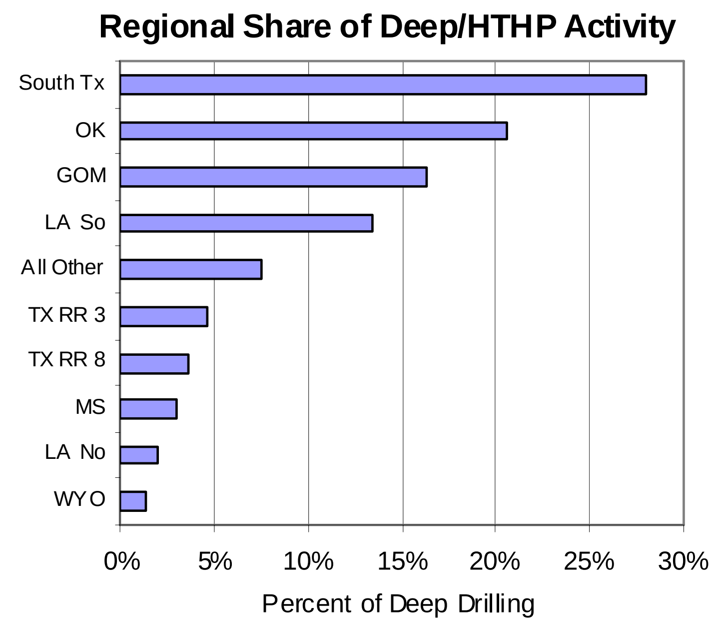


Figure 11. Regional share of deep and HT/HP activity

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 tests[2] and flow tests[3] on their extreme wells, while very few ran extra logs[4] 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.

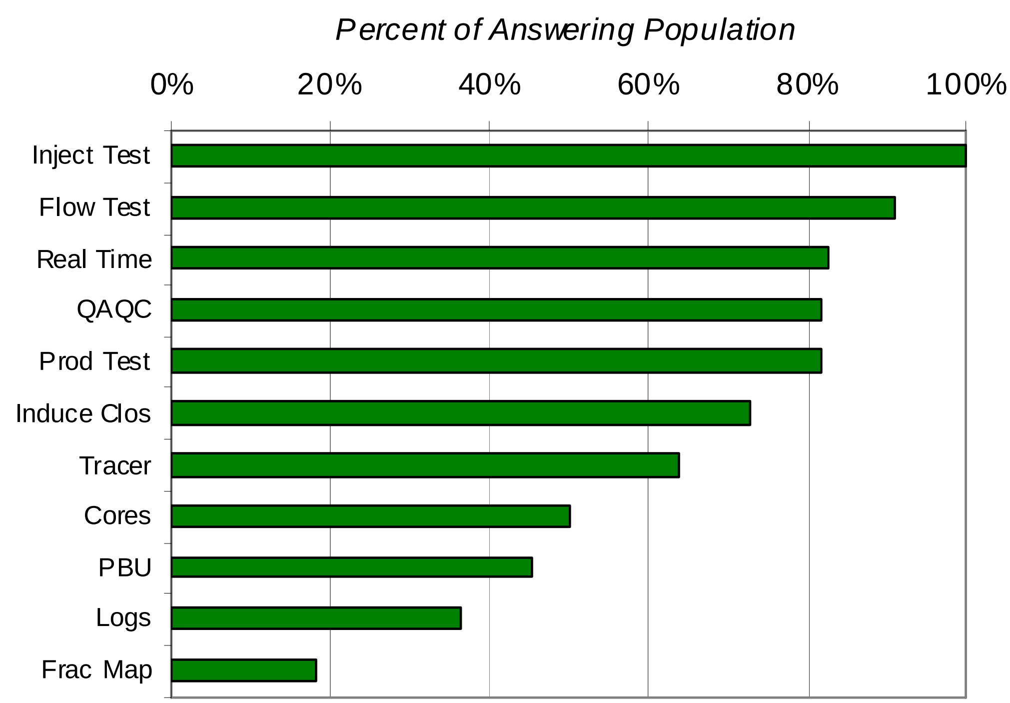


Figure 12. Use of fracture diagnostics on deep wells

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.

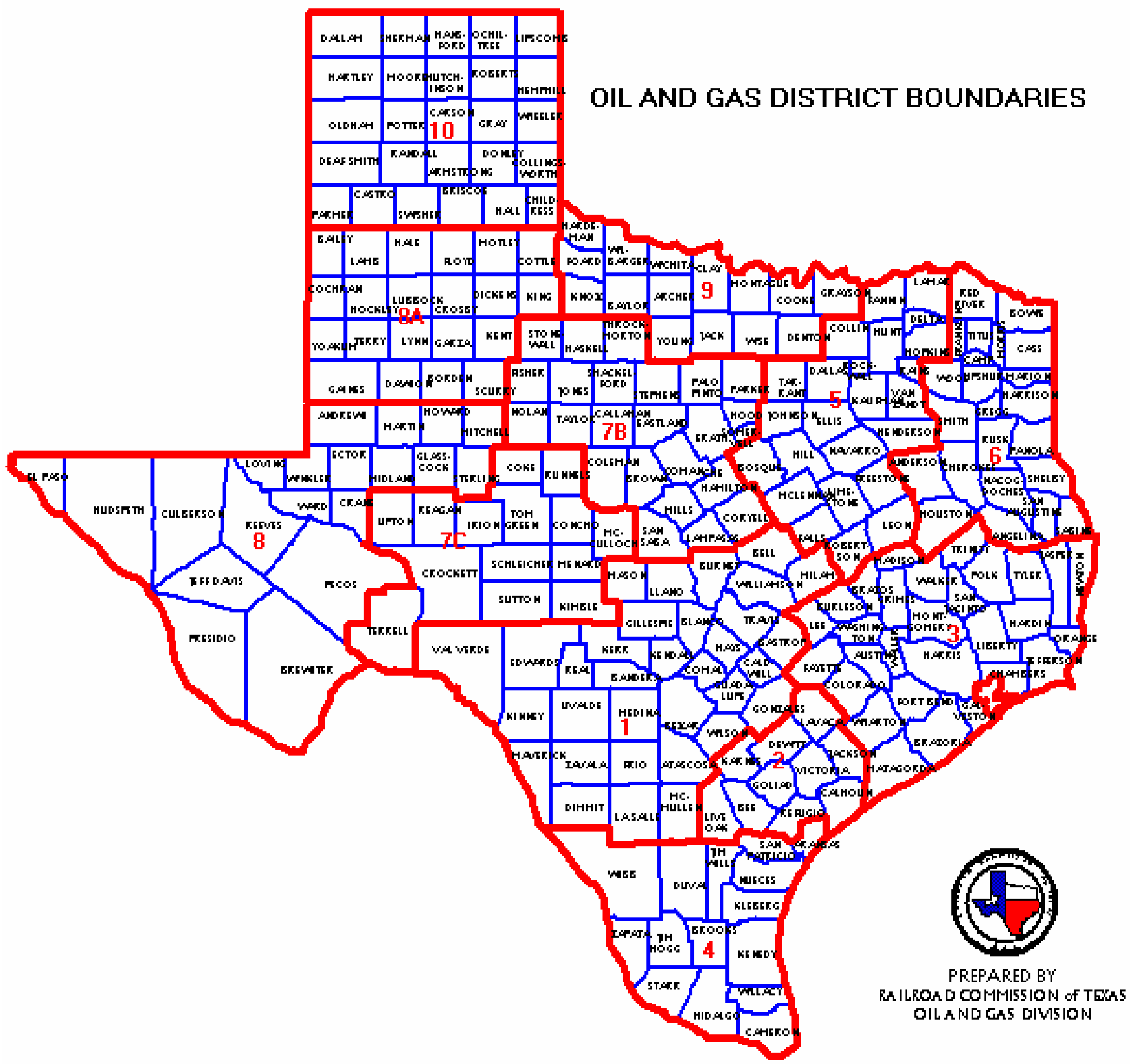


Figure 13. Oil and gas district boundaries for the state of Texas

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.

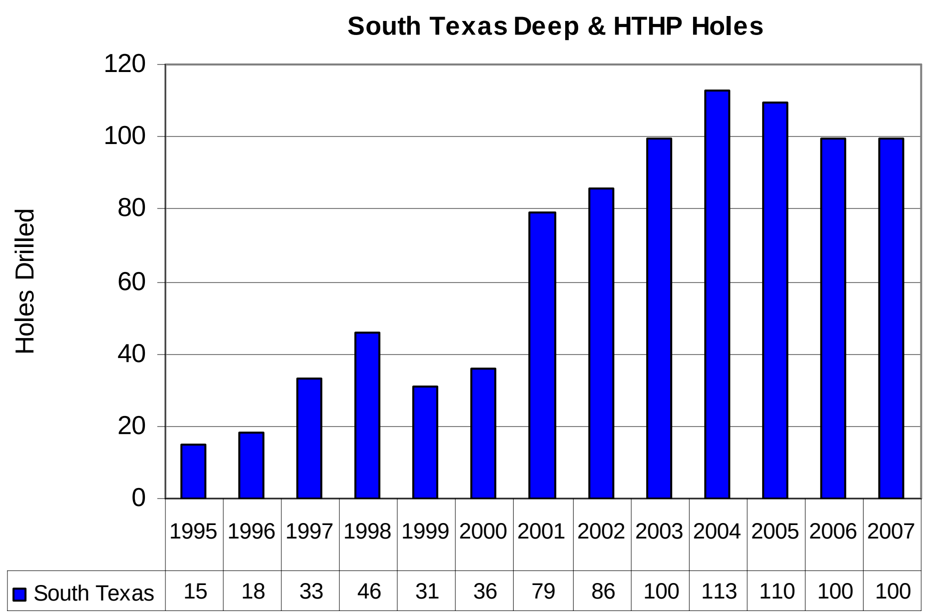


Figure 14. South Texas deep and HT/HP holes

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

- 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

<u>Paced Development Completion</u>

- 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.

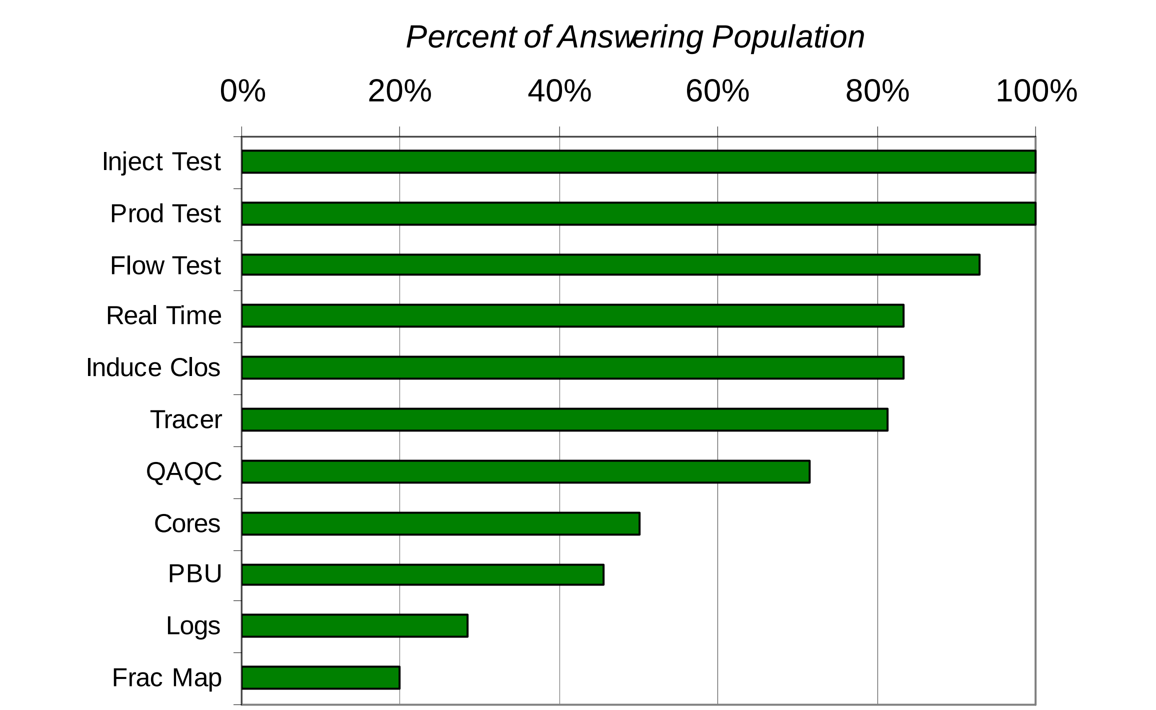


Figure 15. Use of fracture diagnostics in South Texas

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.

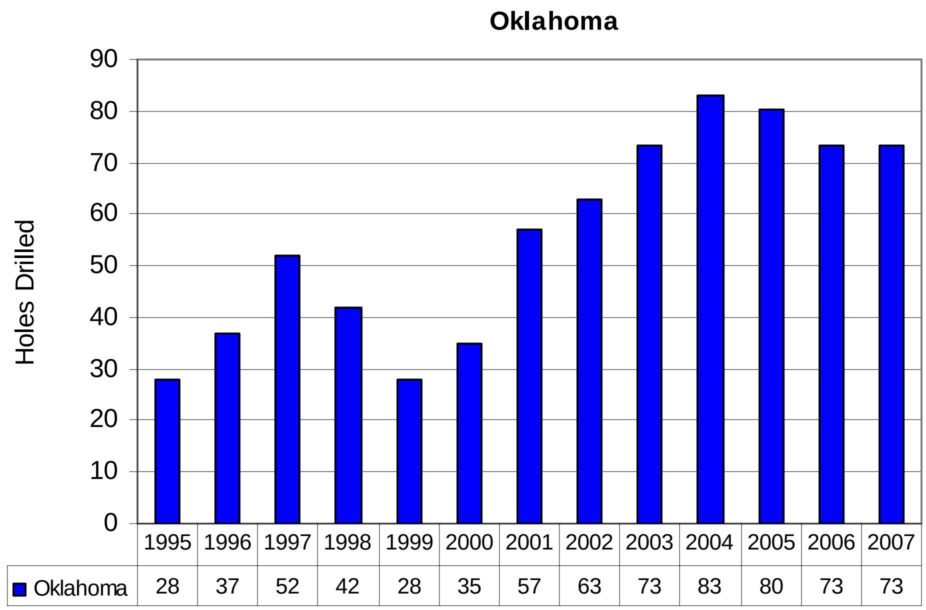


Figure 16. Oklahoma deep and HT/HP holes

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.

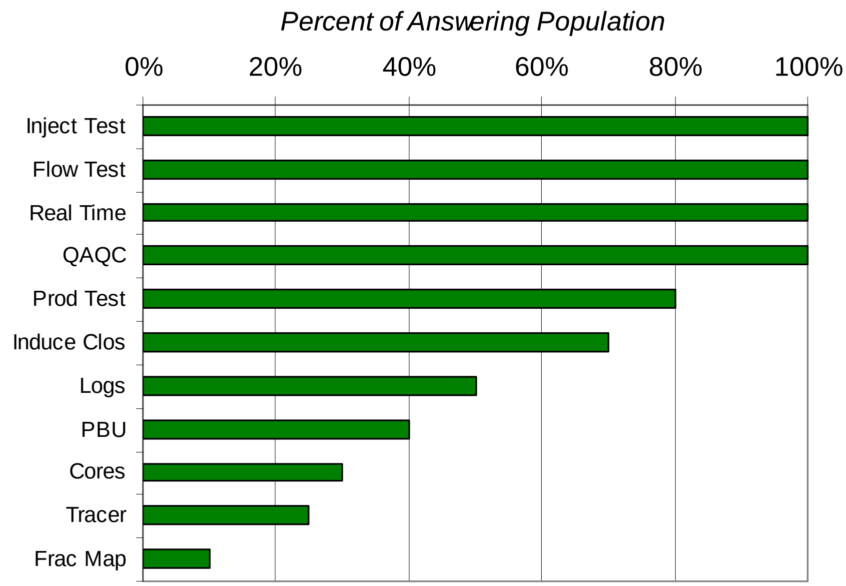


Figure 17. Use of fracture diagnostics in Oklahoma

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.

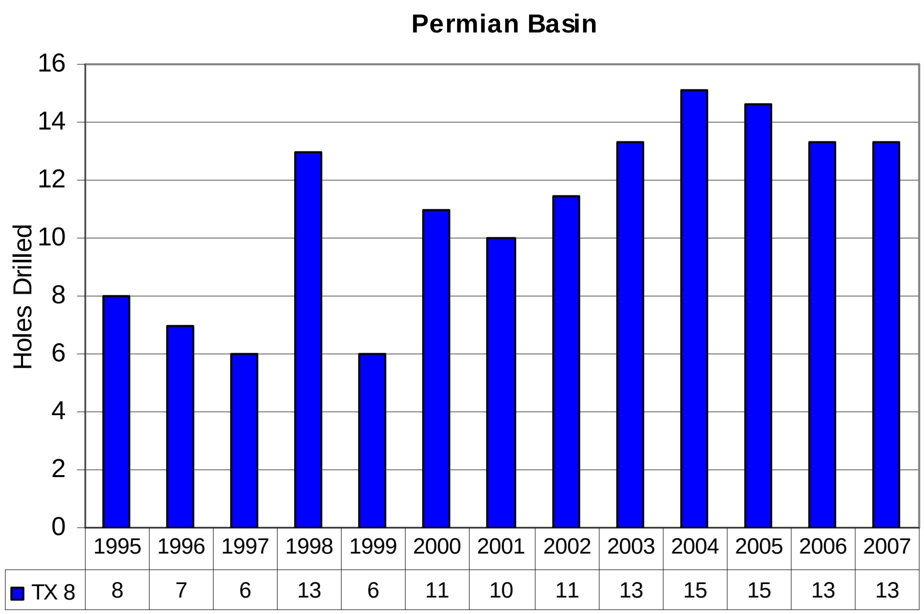


Figure 18. Permian Basin deep and HT/HP holes

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

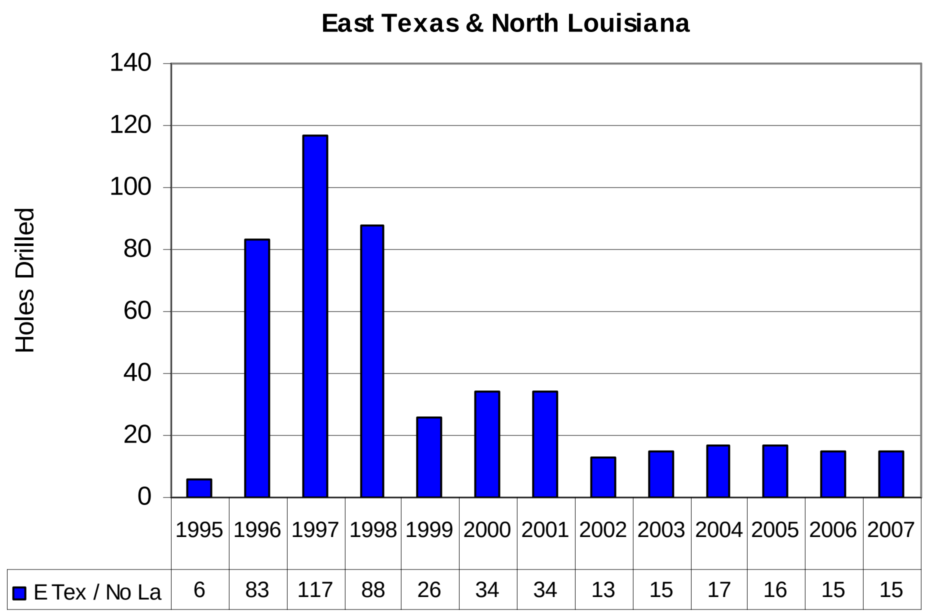
SAI interviewed a variety of producers in the Permian Basin, including frac engineers for the service companies. We found no producers interested in participating in the survey. Additionally, stimulation service companies noted that very few wells are completed below 15,000 ft and that there are no HT/HP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

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.



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
E Tex / No La	6	83	117	88	26	34	34	13	15	17	16	15	15

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.

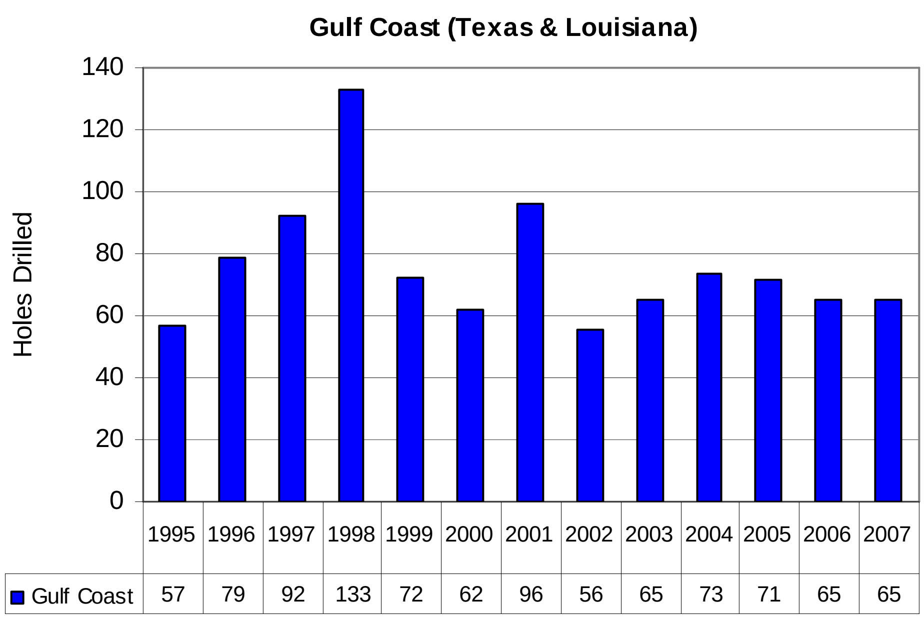


Figure 20. Gulf Coast deep and HT/HP holes

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.

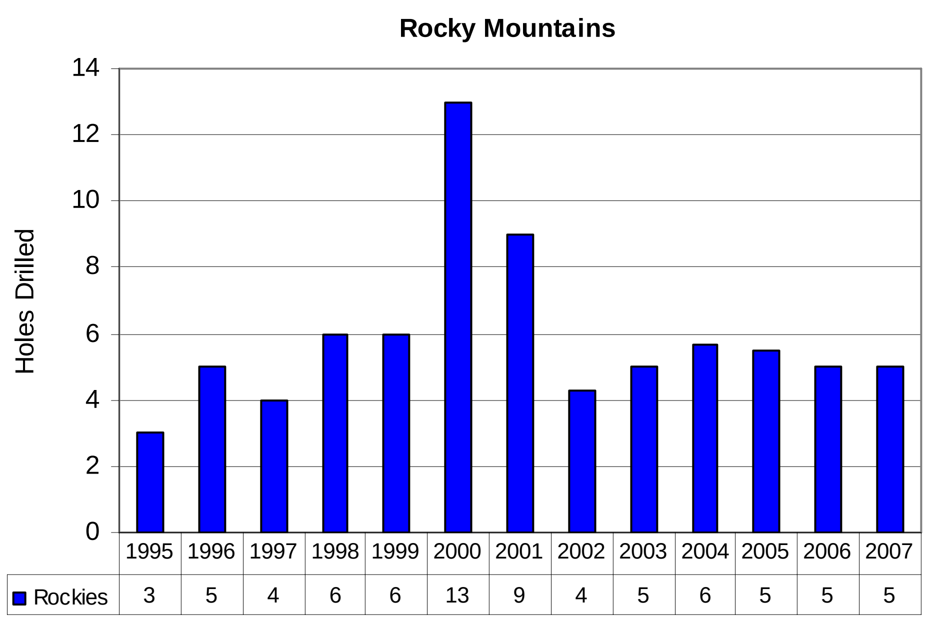


Figure 21. Rocky Mountain deep and HT/HP holes

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.

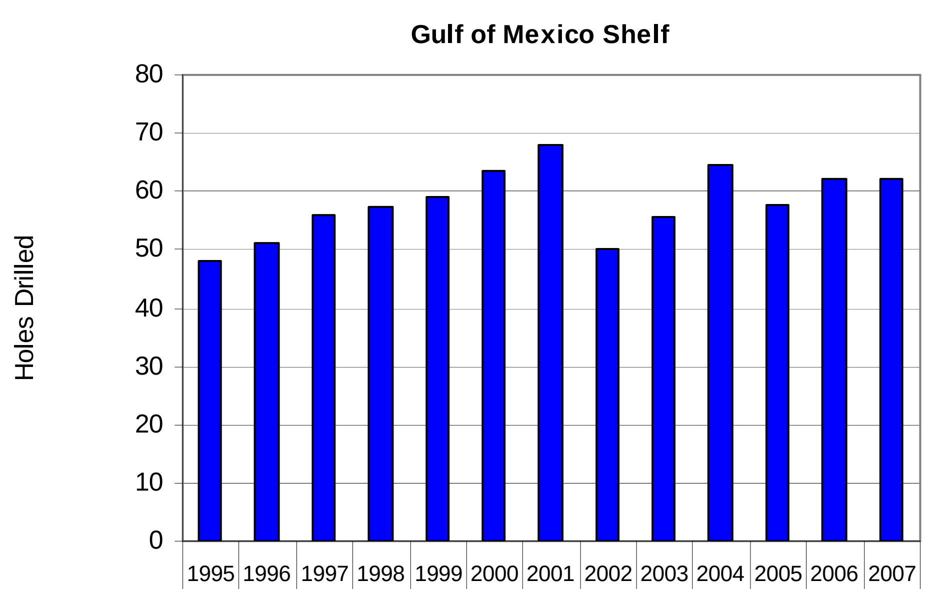
Completion Techniques

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.



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Gulf of Mexico	48	51	56	57	59	64	68	50	56	65	58	62	62

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

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**).

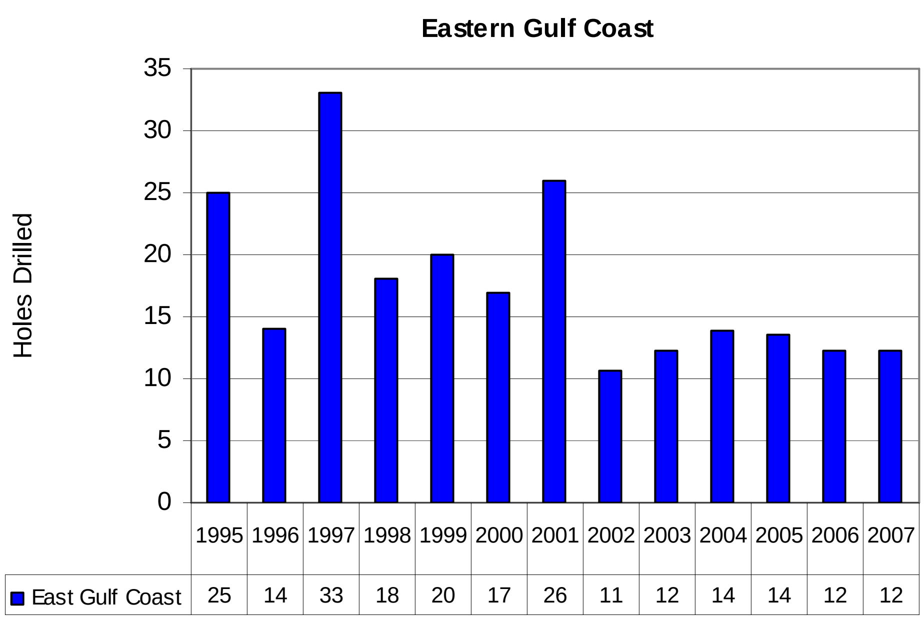


Figure 23. Eastern Gulf Coast deep and HT/HP holes

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 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.

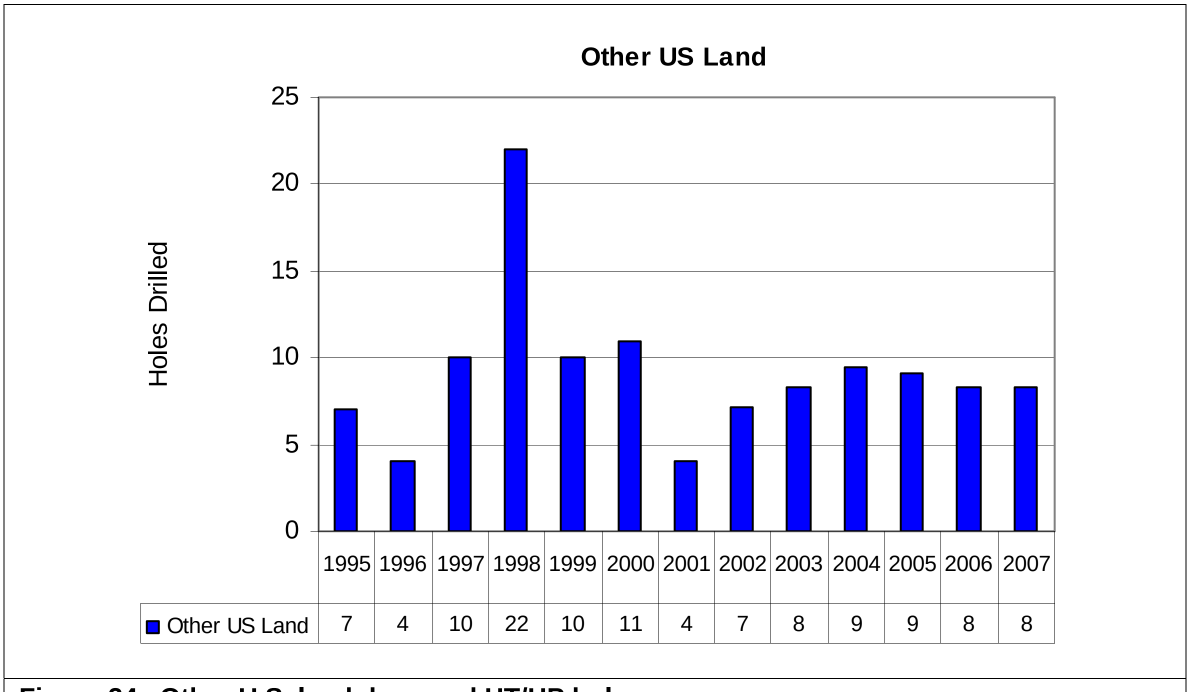


Figure 24. Other U.S. land deep and HT/HP holes

Regions of Interest

<u>California</u>

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.

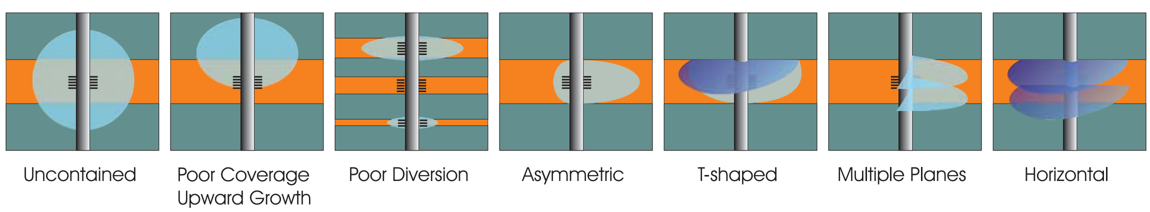


Figure 25. Fracture complexities

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 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.

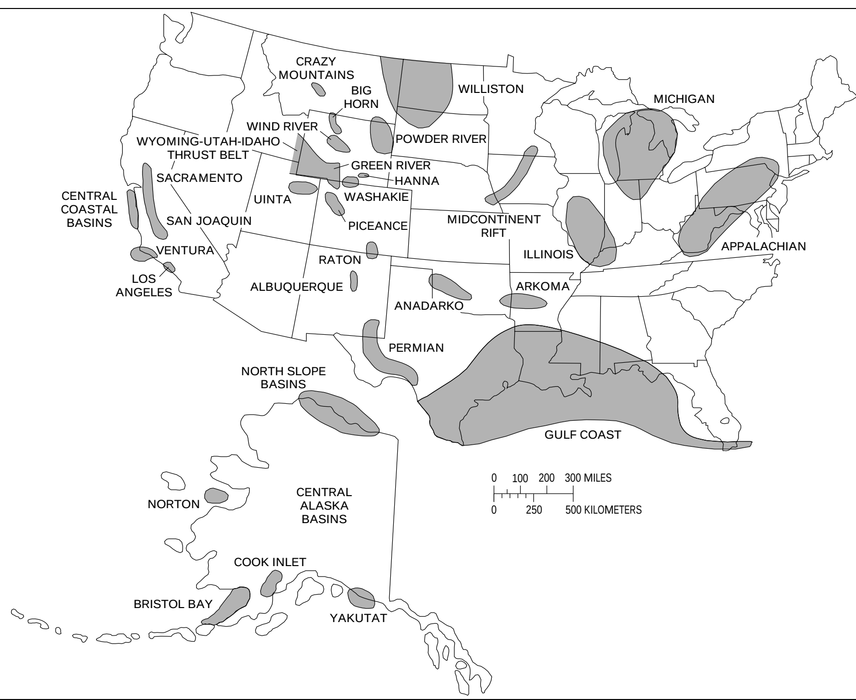


Figure 26. U.S. deep gas basins (Dyman, *et al.*, 1997)

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, lithology[5], 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.

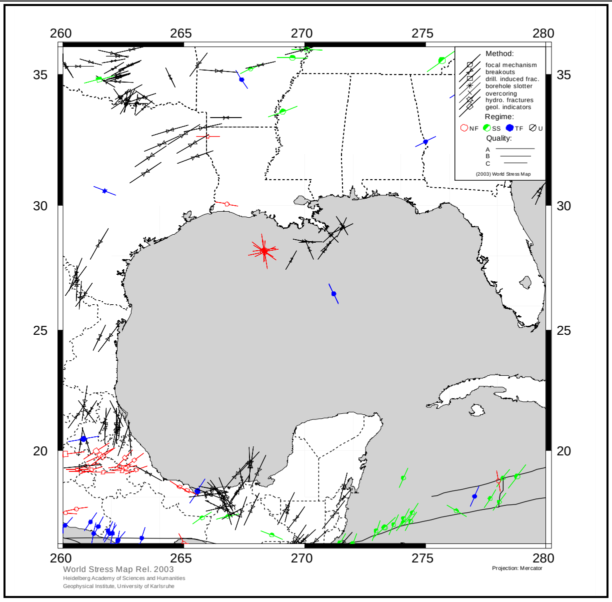


Figure 27. Stress map of Gulf of Mexico (Reineker, *et al.*, 2003)

- 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 ⅔ 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.

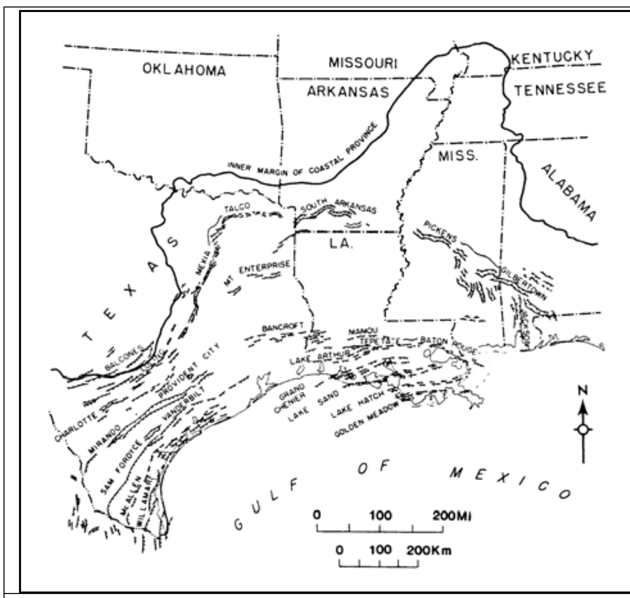


Figure 28. Principal fault systems in Gulf Coast region (Nunn, 1985); The general trend in the coastal province would be extensional onshore and compressional offshore owing to bending of the sediment body

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) 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:

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

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

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

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.

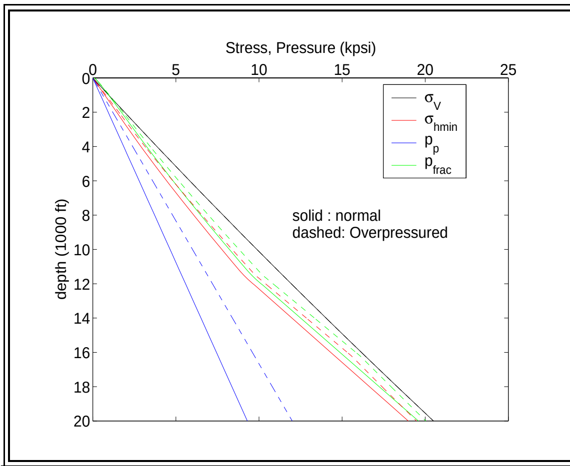


Figure 29. Stress and pore pressure versus depth for GOM data (Breckels, *et al.*, 1982)

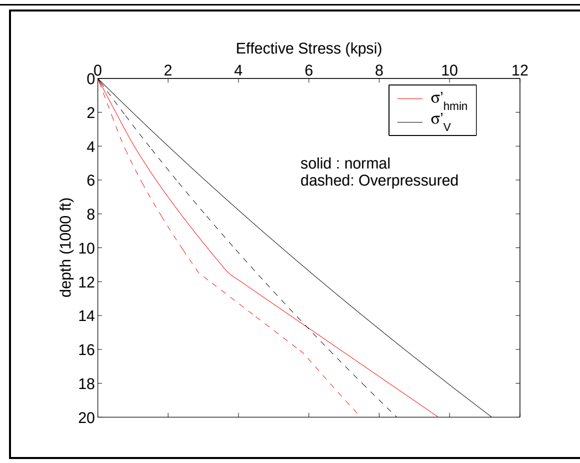


Figure 30. Effective stress versus depth for GOM data (Breckels, 1982)

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.

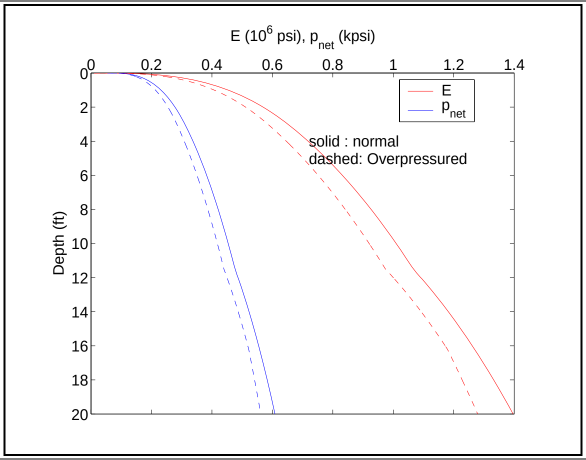


Figure 31. Net pressure and modulus versus depth; the modulus is assumed to depend on the effective stress only

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 – $10x10^6$ 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 – $1.0x10^6$ 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.

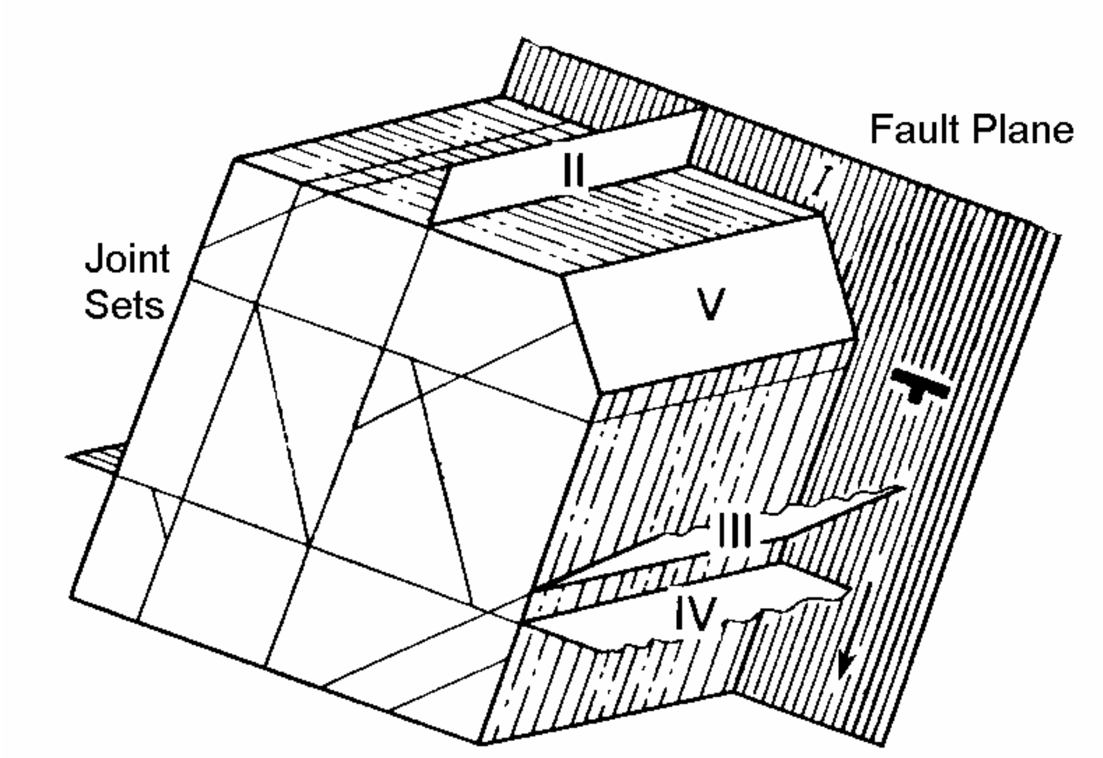


Figure 32. Fault plane and joint sets; I: fault, II-V: vertical, horizontal and oblique joint sets (taken from Chernyshev, 1991)

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).

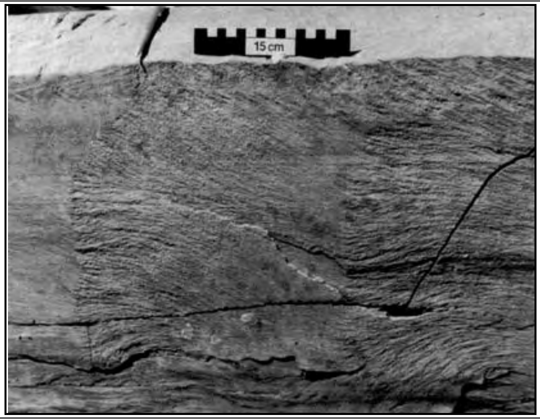


Figure 33. Natural hydraulic fracture showing characteristic roughness pattern and crack bridging (Lacazette, *et al.*, 1993)

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.

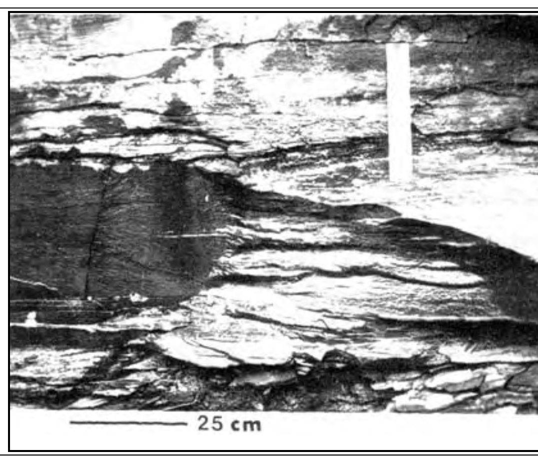


Figure 34. Crack branching upon reorientation (Engelder, 1987)

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 facture 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.

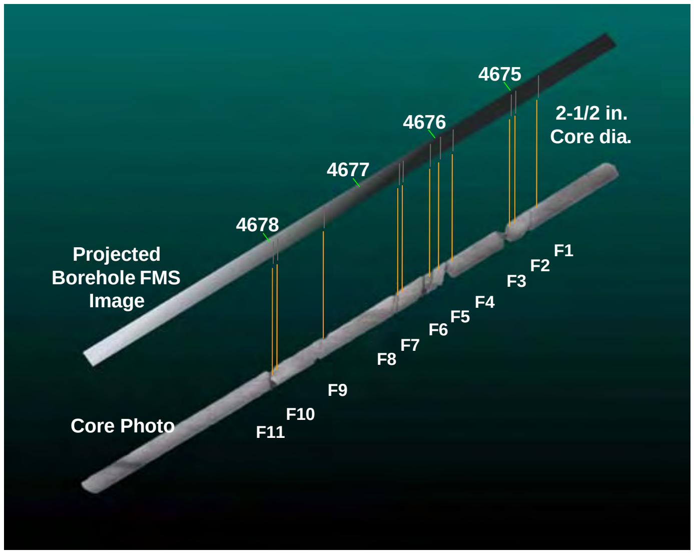


Figure 37. Multiple fractures found in core, fracture F2 ended in the core, indicating that the branches were not very long (Branagan, *et al.*, 1998)

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 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.

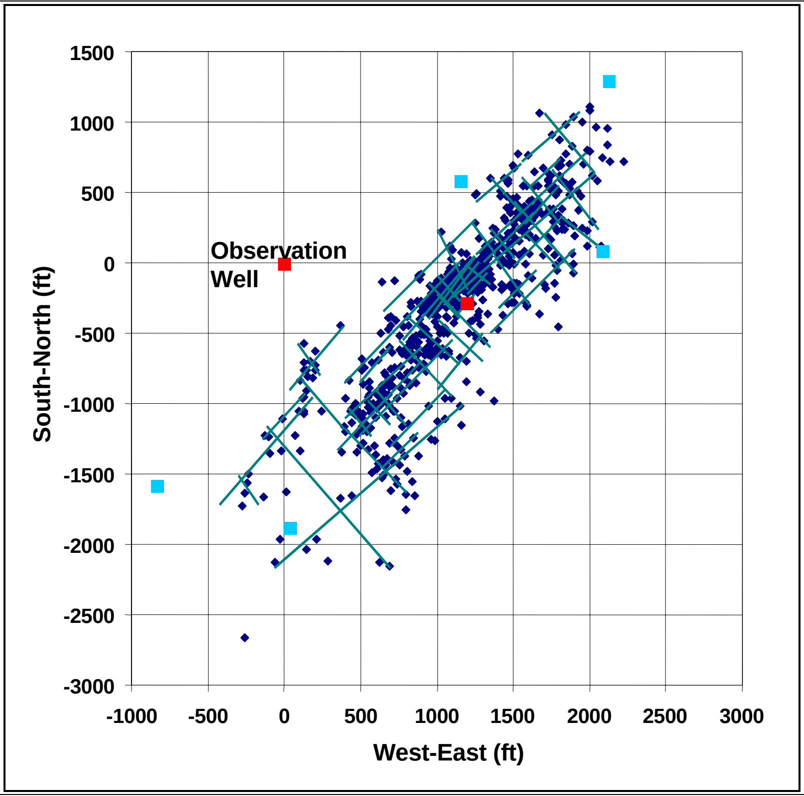


Figure 38. Plan view of microseismic events of waterfrac treatment in tight gas formation with extreme multiple fracture network. The width of the event cloud is much larger than the location uncertainty, so the width of the cloud could not be explained by a single fracture plane. During this treatment 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:

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

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:

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

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.

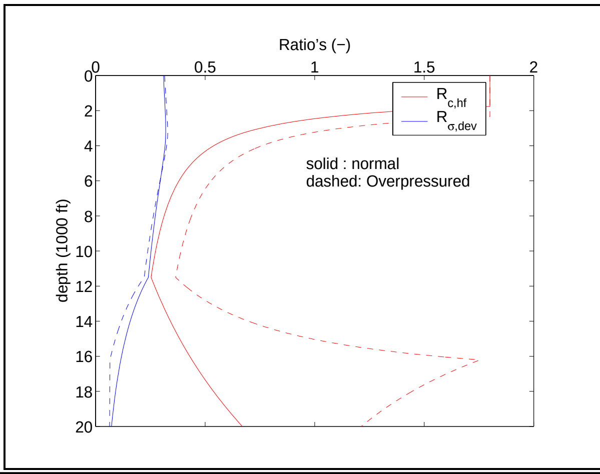


Figure 39. Ratios indicating fracture complexity versus depth for GOM data (Breckels, 1982)

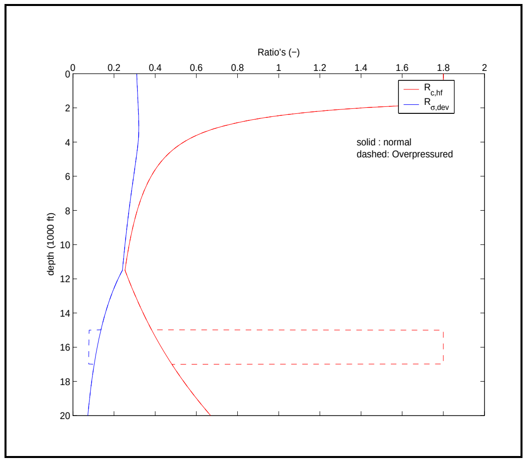


Figure 40. Complexity ratios for normal and over-pressured reservoir

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:

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

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

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

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

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

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.

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	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	$P_{n,mod}/p_{n,obs}$ -
		Input Parameters				Observed			Conventional Model		
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	V_{inj} bbl	q bpm	μ cP	E 10^6 psi	$L_{f,diag}$	$H_{f,diag}$ ft	η -	$P_{n,obs}$ psi	$L_{f,obs}$ ft	$L_{f,mod}$ ft	$P_{n,mod}$ psi	$P_{n,mod}/p_{n,obs}$ -
		Input Parameters				Observed					Conventional Model		
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

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.

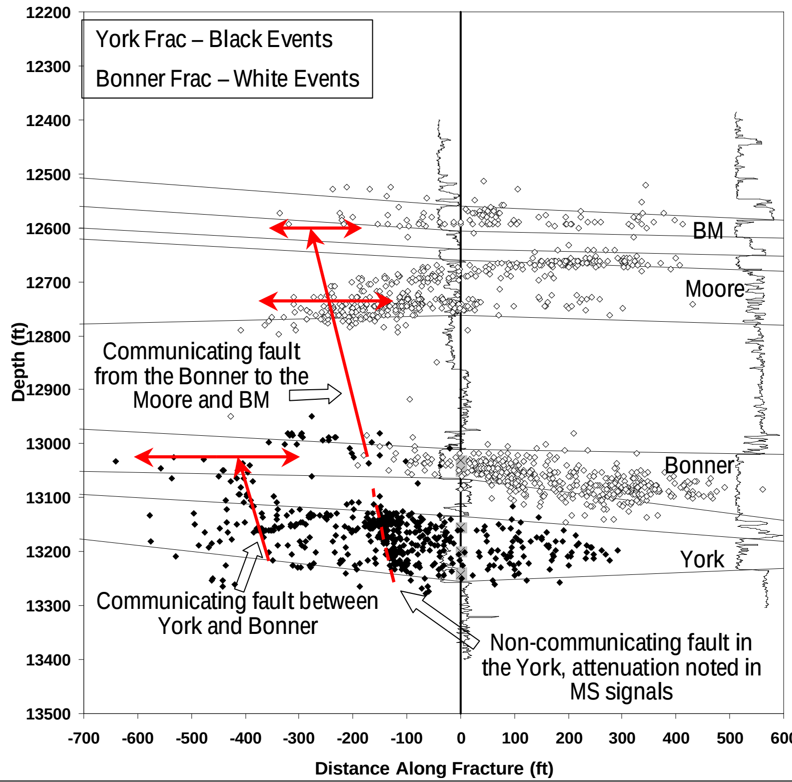


Figure 41. Side view showing microseismic results for the treatment stages 1 and 2 in the APC Anderson No. 2 well

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.

- 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^o, multiple fractures may start that do not link if the horizontal stress contrast is large. Fractures induced by drilling and perforating can exacerbate this multiple fracture problem, but natural fractures are also a source of fracture complexity.

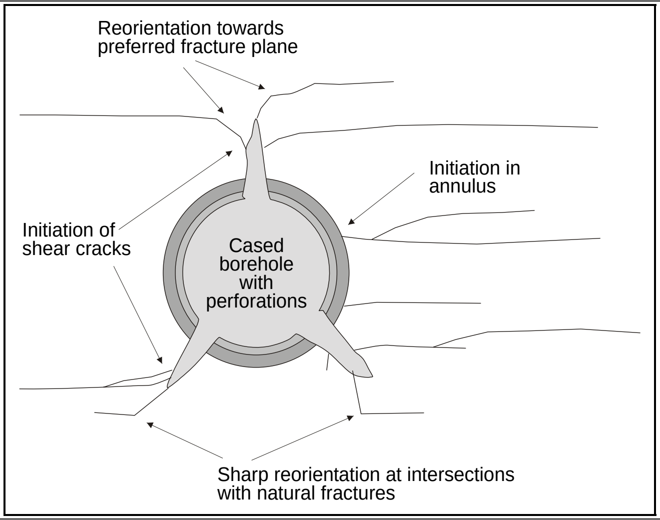


Figure 42. Several initiation sites near a cased, perforated completion

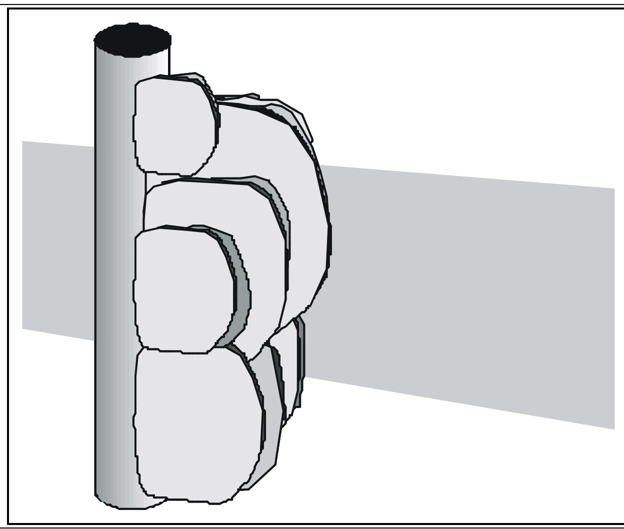


Figure 43. Multiple fracture network that extends far from the well

- **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,

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

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.

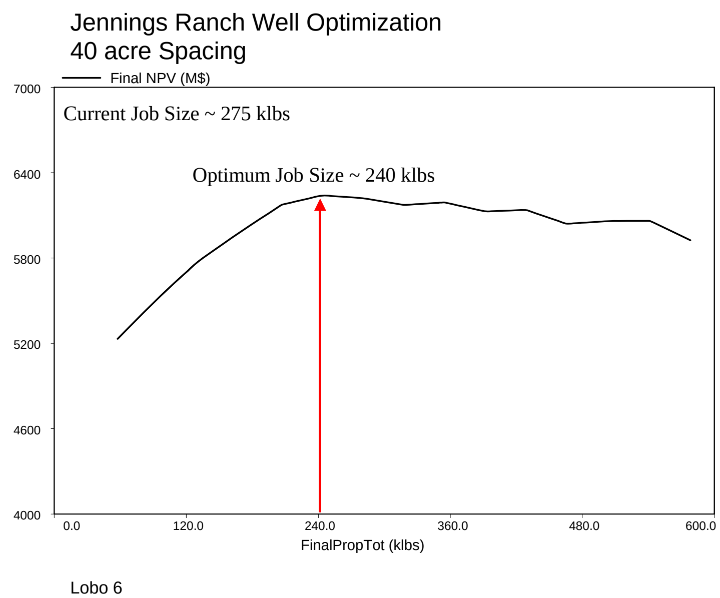

Figure 44. Fracture optimization generic well 40 acre spacing

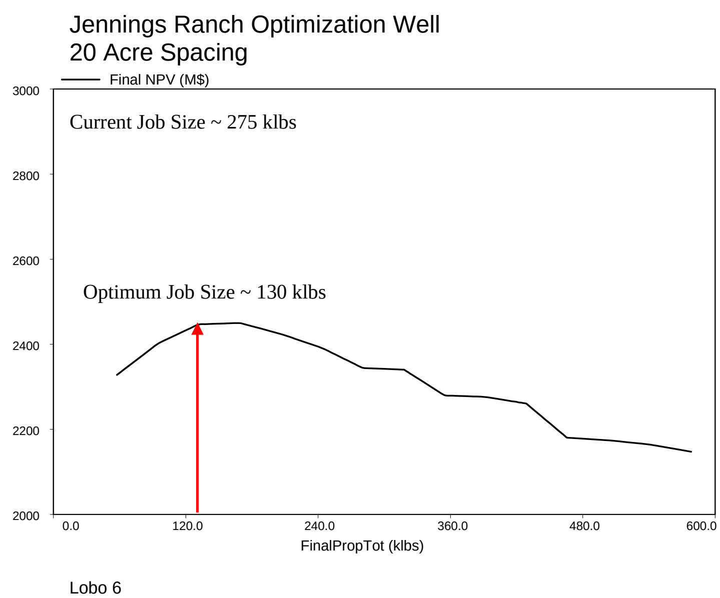

Figure 45. Fracture optimization generic well 20 acre spacing

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).

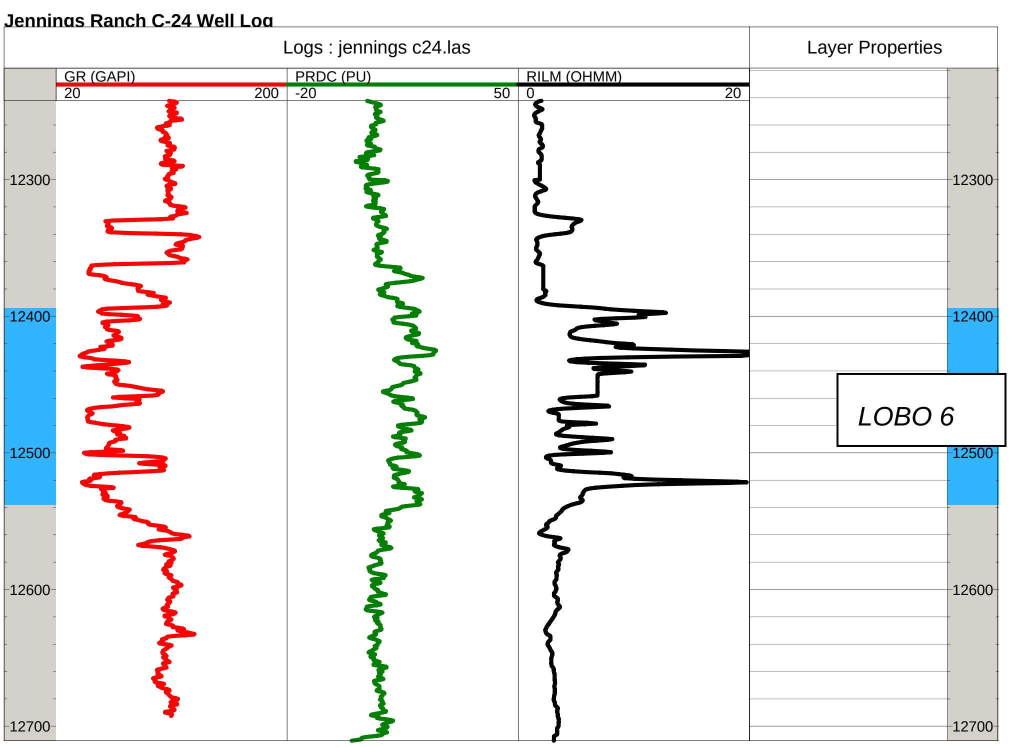

Figure 46. Typical well log Jennings Ranch field: Lobo 6 Sand

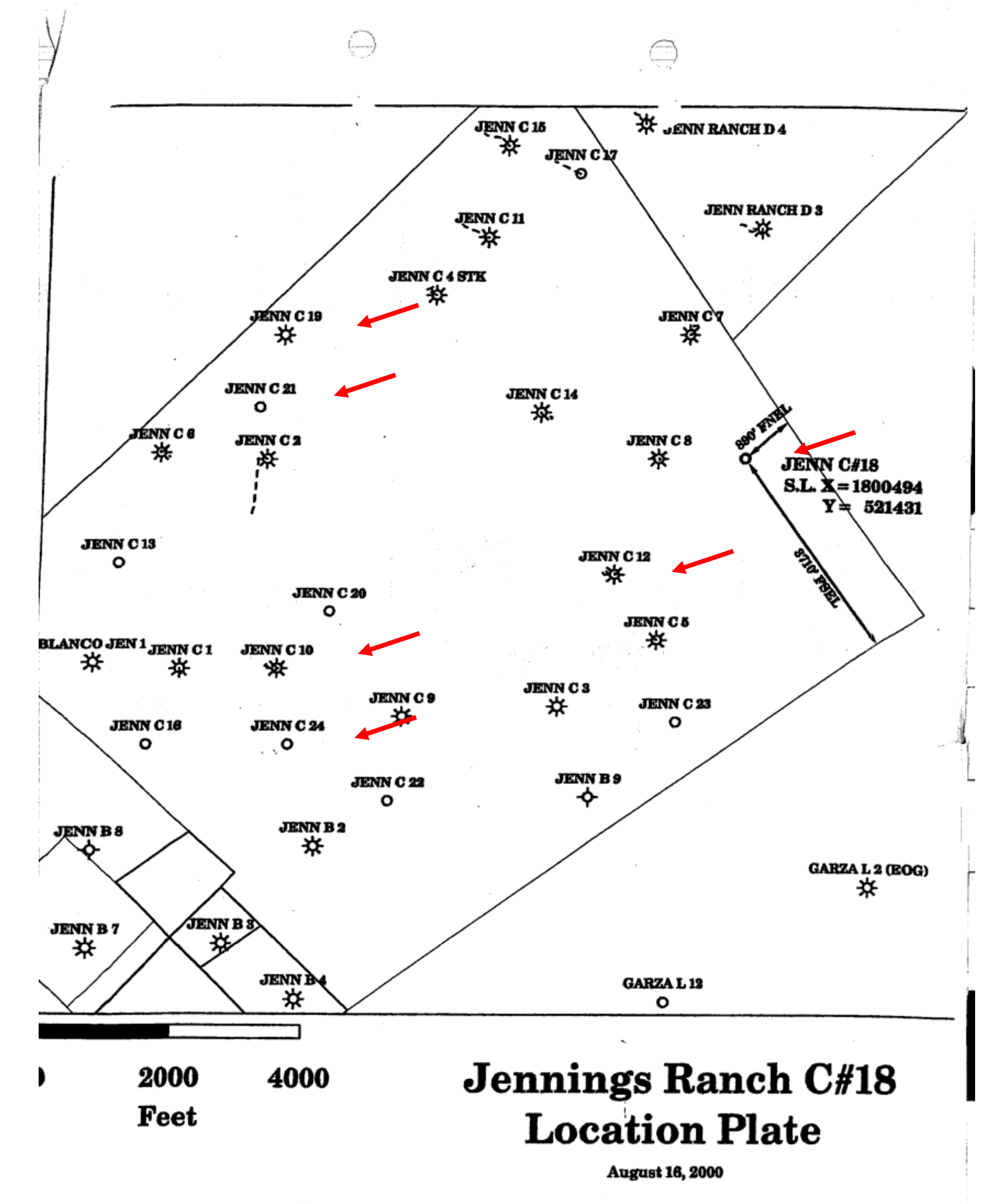

Figure 47. Field map with study well locations

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								
				Vol bbls	Rate bbls/min	Prop klbs	ISIP(BH) psi	ISIP Grad psi	Net P psi	Screen Out?	Net P Increase psi	Comments
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

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 effective stress (stress-sensitive permeability can occur in over-pressured reservoirs with large drawdowns). Of course, the reason for rapid declines could also be caused by a deteriorating hydraulic fracture (such as fines migration into the proppant pack, stress–sensitive behavior of frac conductivity, and multi-phase flow inside the fracture). These effects cannot be distinguished from production analysis alone. Other tests such as pressure transient tests combining a drawdown with a buildup could be used to evaluate hydraulic fracture quality.

Production analysis results in **Table 7** show a wide range of formation flow capacity (kh) ranging from less than 0.1 md-ft (C-10) to almost 4 md-ft (C-21) with drainage areas between 7 acres and 70 acres. Of course, these results highly depend on the assumptions of net pay, porosity and water saturations.

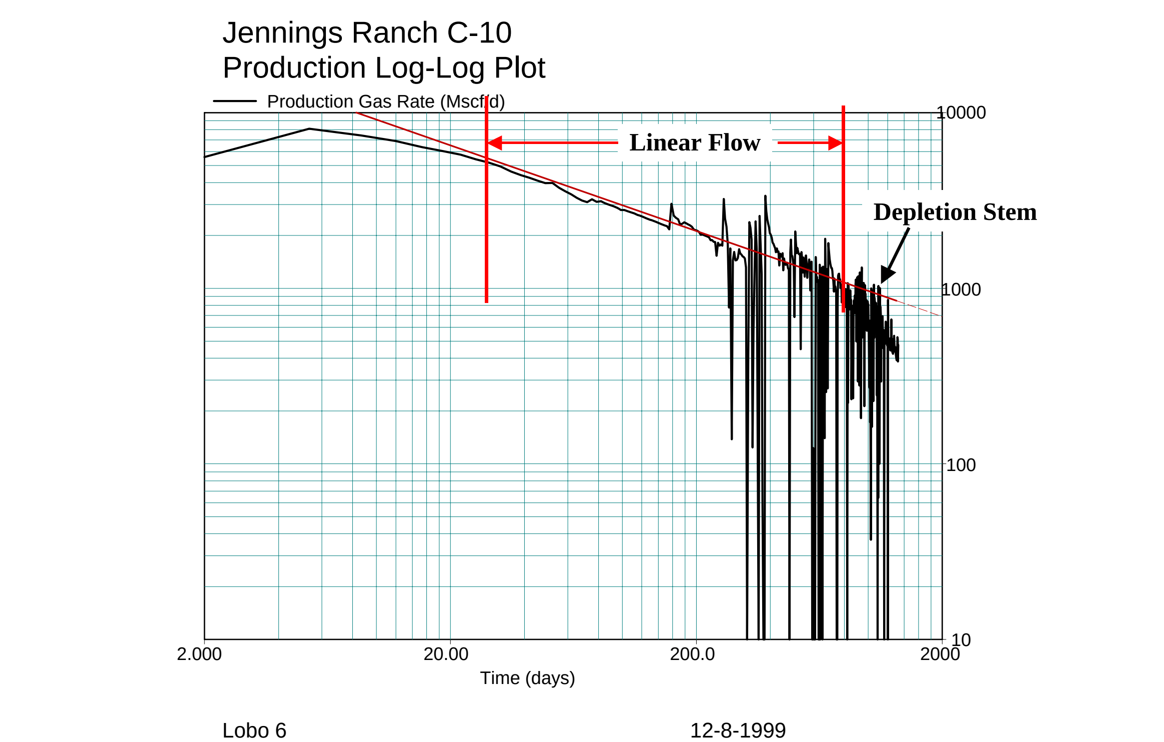

Figure 48. Production log-log diagnostic plot

Table 7. Summary of Production Analysis Results

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Net Pay ft	Porosity %	Sw %	k md	kh md-ft	DA acres
C-10	L6	12201.0	12350.0	40	17	54	0.0900	3.60	70
C-12	L6	12494.0	12617.0	17	15	56	0.0400	0.68	54
C-18	L6	12220.0	12360.0	60	18	56	0.0150	0.90	45
C-19	L6	12253.0	12431.0	125	21	46	0.0014	0.18	10
C-21	L6	12496.0	12744.0	114	16	52	0.00038	0.043	7
C-24	L6	12394.0	12538.0	94	16	49	0.0065	0.61	16