Increasing Production from Low-Permeability Gas Reservoirs by Optimizing Zone Isolation for Successful Stimulation Treatments

Summary Report

April 30, 2005

Fred Sabins

Issued April 30, 2005

DOE Award Number
DE-FC26-02NT41438

Submitted by
CSI Technologies
2202 Oil Center Court
Houston, TX 77073

Disclaimer

Abstract

Maximizing production from wells drilled in low-permeability reservoirs, such as the Barnett Shale, is determined by cementing, stimulation, and production techniques employed. Studies show that cementing can be effective in terms of improving fracture effectiveness by "focusing" the frac in the desired zone and improving penetration. Additionally, a method is presented for determining the required properties of the set cement at various places in the well, with the surprising result that uphole cement properties in wells destined for multiple-zone fracturing is more critical than those applied to downhole zones. Stimulation studies show that measuring pressure profiles and response during Pre-Frac Injection Test procedures prior to the frac job are critical in determining if a frac is indicated at all, as well as the type and size of the frac job. This result is contrary to current industry practice, in which frac jobs are designed well before the execution, and carried out as designed on location. Finally, studies show that most wells in the Barnett Shale are production limited by liquid invasion into the wellbore, and determinants are presented for when rod or downhole pumps are indicated.

Table of Contents

Introduction

Producing hydrocarbons from low-permeability reservoirs, such as the Barnett Shale, is inhibited by the inherent characteristics of the reservoir formations. Historically, these wells are stimulated as a matter of course in order to obtain economically-viable production rates, and a great number of completion, stimulation, and production techniques have been employed with mixed results. Cementing, stimulation, and production techniques are inherently related, and determine the ultimate productivity of a given well. The subject project seeks to explore these interactions in order to improve production, yielding guidelines for cementing, stimulation design and execution, as well as production techniques.

The original site of field focus for this project was the Ardmore Basin of Oklahoma. This gas reservoir is similar in lithology to the Anadarko Basin adjacent to it. Traditionally, wells completed in this basin suffer from productivity rates that are less than predicted considering the stimulation treatments applied. An industry partner was recruited with two candidate wells planned for drilling in the course of the project. This partner re-evaluated the drilling program during the initial phase of this project and decided to postpone drilling the planned wells that were to be test wells for the study. The partner did recruit another producer working in the Barnett Shale reservoir who was willing to join the project.

The shifting of industry partners caused the original project tasks to be altered. For instance, drilling, budget, and well partner constraints prevented the project from targeting 2 wells, imposing optimized cement design, and imposing optimized fracture design from start to finish. To accommodate this constraint, the tasks of this project were changed. Since cementing programs could not be altered without reason, the research was done to monitor the cementing practices currently in place and to measure the performance of cement compositions currently used. Stimulation treatments conducted while the project was ongoing were not adequately monitored for sufficient data to allow analysis of the treatment's effectiveness. Therefore, archived treatment data that was complete was acquired and analyzed. Further historical data was reviewed to yield conclusions regarding completion and production operations.

In the end, the project yielded significant outcomes concerning methodology of planning, cementing, stimulating, and completing a well in the Barnett Shale. These outcomes, recommendations, and methodologies have application in any other low-permeability reservoir.

Project Objectives

The primary objective of this project was to increase gas production in low-permeability reservoirs. To meet this objective, the project focused on developing completion methods for low-permeability reservoirs that result in better-contained stimulation treatments and less formation damage. Strategies for accomplishing the project objectives included:

1. Relating the effectiveness of sealing capability of a cemented casing / wellbore annulus specifically to the effectiveness of pressure isolation (hydraulic seal). Evaluate the hydraulic seal's effectiveness as it relates to low-permeability reservoir fracture initiation out-of-zone. Develop a post-cementing analytical technique to assess the hydraulic seal's effectiveness and a methodology for remediation if necessary.
2. Use conventional fracture height diagnostics and possibly newly-developed techniques as well as post-fracture treatment production data from low-permeability reservoirs to confirm the effectiveness of the stimulation treatment. Longer effective fracture lengths will imply the effectiveness of the annular hydraulic seal in preventing near-wellbore fracturing out-of-zone.
3. Quantify the effects of well construction fluid (drilling fluid, cement filtrate, and stimulation fluid) invasion in reducing production from low-permeability reservoirs, whether from a reduction in matrix permeability or from the plugging of natural fractures.
4. Assess the procedures needed for annular seal in vertical wells to determine applicability and feasibility in horizontal wells. Assess potential production benefits to completing horizontal wells in the study reservoir. Determine overall benefit to production, seal, damage, and stimulation containment.

Work Plan

The following outline presents the scope of work described herein:

PHASE I Provide Historical and Laboratory Input

TASK 1. ***Literature Review***
Conduct a literature review of zonal isolation, formation damage, stimulation, and fracture propagation in low-permeability reservoirs.

TASK 2. ***Gather Data***
Gather well-construction, rock-property, and reservoir-production data for the candidate wells.

TASK 3. ***Testing***
Conduct the necessary physical property tests on appropriate cements and other materials.

PHASE II ***Conduct Lab Analysis of Hydraulic Seal***

TASK 1. ***FEM Modeling***
To define the limits of effective hydraulic seal, conduct finite element modeling (FEM) of pressure gradients through a partially cemented annulus, as well as through a completely cemented annulus.

TASK 2. ***Confirmation***
Confirm FEM results with laboratory-scale experiments.

PHASE III ***Limit Formation Damage to Maximize Production***

TASK 1. ***Cement Slurry Penetration***
Analyze the extent and effects of cement-slurry penetration into naturally-occurring fractures.

TASK 2. ***Balanced Cementing***
Analyze the problems and benefits derived from cementing in balanced or underbalanced states.

TASK 3. *Vertical / Horizontal Well Comparison*
Conduct a comparative study of horizontal vs vertical well completion in the reservoir under investigation.

PHASE IV *Design Field Applications Based on Laboratory Results*
TASK 1. *Decision Matrix*
Develop a decision matrix for designing cement treatments to maximize hydraulic seal.

TASK 2. *Cement Application*
Apply cementing treatments to candidate wells.

TASK 3. *Cement Assessment*
Analyze the success of the cementing treatments.

TASK 4. *Stimulation Application*
Perform the Stimulation Treatments.

TASK 5. *Stimulation Assessment*
Analyze the success of the stimulation treatments.

PHASE V *Technology Transfer*
TASK 1. *Decision Matrix Application*
Develop a computer-based application of the decision matrix developed in Phase IV, Task 1 that allows an operator to enter pertinent well data and receive an appropriate cement treatment design.

TASK 2. *Well Data Capture*
Provide distinct methodologies and procedures for operators to capture specific well data for analysis.

TASK 3. *Tech Transfer Documents*
Develop technology-transfer documents covering the entire project and outlining the application of the process developed therein.

TASK 4. *Prepare Workshops*
Prepare a workshop curriculum based on Tasks 1 and 3.

TASK 5. *Deliver Workshops*

Prepare and deliver workshop and technology transfer with PTTC.

Observations and Conclusions

Cementing

Observations

6 systems were lab-tested as candidate systems for application in unconventional reservoirs. These slurries consisted of Baseline, Baseline with Fibers, Foam, Latex, HEP 1, HEP 2. The first four slurries are typical candidates for completion of wells in the region of study, and the slurries designated HEP 1 and HEP 2 are actual field blends from cement jobs observed as part of the project execution. Detailed compositions for each slurry, as well as detailed test results are contained in Appendix XI.

Developed a full suite of application data.

- Thickening times were performed on all systems. All systems gave acceptable performance levels.
- Ultrasonic Cement Analyzers were performed on all but the baseline with fibers system. All systems gave acceptable performance levels. The baseline with fibers system was unable to achieve a signal due to the presence of fibers.
- Static Fluid Loss tests were performed on all systems. The HEP 1 system did not contain any fluid loss control additive, thus no control was observed. All other systems gave acceptable performance levels.
- Static Gel Strength Analysis was performed on all systems except baseline with fibers. The HEP 2 system performed the best with a transition time from 75 $lb_f/100ft^2$ to 500 $lb_f/100ft^2$ of 28 minutes. This was followed by HEP 1 system with a transition time of 54 minutes. The Baseline system gave 55 minutes for the transition time. The Latex and Foam systems did not perform well with extremely long transition times.
- Rheology tests were performed on all systems. All systems gave acceptable performance levels. The baseline with fibers was not able to have rheological values recorded due to the interference of fibers with the instrument.

Developed a full suite of mechanical property testing data.

- Compressive strength values performed on the cylindrical samples for testing Young's Modulus were cured for 48hrs at 185°F under atmospheric conditions.

- Young's Modulus testing was performed under various confining conditions on the Baseline, Baseline with fibers, Latex and Foam systems. Young's Modulus was also performed in house on all 6 systems.
- Tensile strengths were performed on all systems. Baseline with fibers outperformed all other systems with a tensile value of 930psi.
- Expansion/shrinkage tests were performed on all systems. There was no shrinkage observed in any of the systems. HEP 1 was the only system with a large amount of expansion, all other systems performed with low amounts of expansion (0.01 to 0.02 % expansion).
- Frac Model tests were performed on all systems. Baseline with fibers outperformed all other systems.

Shearbond tests were performed on all systems. No exact correlations were observed between shearbond tests and frac model results, indicating that sealing performance is related to the interaction of many mechanical properties of the cement as well as placement mechanics, rather than associated with a single property.

Conclusions

There has been a great deal of debate in unconventional reservoirs regarding the necessity of cementing specific pay zones, especially the bottom-most zone in a multiple pay-zone well. Field tests in the Barnett Shale clearly show that cementing improves fracturing efficiency, by concentrating the fracture energy in the vicinity of the perforations. Tracer logs after stimulation activities in wells that were uncemented show a "stringing" of the tracer material throughout the interval and poor frac penetration. Logs done in cemented intervals show improved frac penetration, and little vertical growth away from the perfs.

Additionally, cementing uphole across multiple pay zones in wells that are stimulated multiple times revealed the necessity of more competent cement in the uphole zones. As the energy analysis shows, repeated intervention activities (such as multiple hydraulic fracturing operations) expose the cement in the uphole zones to repeated high pressure fluids inside the tubing. The tubing imposes stress in the cement sheath, which causes cumulative damage to occur in the cement.

Unconventional reservoirs, especially those drilled through multiple pay zones, require subsequent stimulation in order to produce economic quantities of hydrocarbons. Intervention activities result in unusual stresses imposed on the cement sheath, which can result in long-term failure and abandonment of upper pay zones. The energy analysis is useful in determining the properties of the cement needed in all zones, given anticipated loads applied for the life of the well.

Stimulation

Observations

- Formation characteristics, especially clay content, can have a significant effect on production due to water sensitivity the resultant decrease in effective permeability to gas flow.
- Communication between the induced hydraulic fracture and the natural frac network is essential to realize maximum production potential of a given well.
- Pre-treatment injection tests represent an economical (much quicker) method to determine a well's likely response to a stimulation treatment than pressure build up testing. As experience with the pressure build-up technique is more extensive than pump-in testing / pressure decline testing, much is still to be learned from the technique. Reservoir flow mechanisms and fracture leak-off must be understood to refine hydraulic fracture treatment design, and the pre-treatment injection test is an excellent method to gain this information. Properly designed and executed, these tests can yield Closure pressure, Reservoir pressure, and Permeability (matrix versus natural fractures).
- Refracs can be effective to rejuvenate production in depleted zones.
- Many producing wells are fluid-limited, and pumps may be needed to remove the fluid in order to maximize gas production.
- Smaller proppant may be effective in some wells.
- Staged stimulation treatments appear to the most effective way to stimulate all the desired pay zones in the most productive manner.
- Uncontrolled frac height growth does not appear to be a significant issue in the Lower Barnett.

Conclusions

While there is not unanimity among those producing from low permeability reservoirs, there is a substantial body of belief that the primary mechanism of gas storage and transportation to the wellbore is through a series of natural and interconnected fractures in the formation. Without this mechanism, production would be impossible from formations that have neither matrix porosity nor permeability. Further, improving production through hydraulic fracturing relies on exposing the natural fracture network to the imposed hydraulic fracture. As the natural fracture network is formed by in-situ stresses over time, it can be highly variable well by well in many characteristics, even in "similar" offset wells. These natural frac network characteristics include extent, orientation, dimensions, and interconnectivity. In this environment, Pre-Frac Injection Test procedures, performed prior to hydraulic fracturing operations, are essential to determine if the stimulation procedure will be successful in improving production. For example, if the orientation of the natural frac network is such that an imposed hydraulic fracture will not intersect pathways, or if there is insufficient interconnectivity, there is little hope that imposing a hydraulic fracture will substantially improve production. The formation pressure response to Pre-Frac Injection Test operations is essentially a measure of these characteristics, and therefore is indicative of the results that can be expected from a frac job. Hydraulic fracturing of unconventional reservoirs without benefit of the Pre-Frac Injection Test information will yield highly variable results because of the highly variable nature of the formations. Pre-Frac Injection Tests can prevent the expenditure of money on wells that will not respond to stimulation efforts, thereby improving return on investment when considering the field as a whole.

Discussion

All tasks (except those noted as not completed by mutual agreement) assigned to the project were completed and outcome of each task is summarized below.

PHASE I Provide Historical and Laboratory Input

TASK 1. *Literature Review*

The literature search task of the subject project concentrated on the potential stressors on casing and cement, as well as the technical development history of the Barnett Shale play. Included in this portion are details about technological developments with the observed results of these developments over time. Used as a backdrop for the current project, this information builds a framework in which to develop tests and methodologies for improving the productivity of wells drilled (specifically) in the Barnett Shale, and by extension, in other unconventional reservoirs.

A literature review was conducted concentrating on the casing and cement stressors, such as temperature and pressure cycling. The literature discusses some of the resulting damage that can occur from the stressors, ways to model the stressors, and guidelines for minimizing or preventing the damage. No work relating directly to the topic of this investigation was discovered. However several papers discuss work relating to Portland cement's ability to maintain a durable long-term annular seal.

Thiercelin *et. al.* (1) and Di Lullo and Rae (2) present work done to model mechanical failure of a cement sheath under in situ conditions in a well. The studies related the cement's classic mechanical properties, Young's Modulus, tensile strength, and Poisson's Ratio, to mechanical failure. These mathematical studies did not consider level of damaging effects resulting from the failure, only that failure could occur.

Bosma *et. al.* (3, 4) describe studies of cement and other sealants. Behavior of Portland cement was modeled via FEM with conclusions that cement sheath seal could definitely fail if the sealant was not engineered to possess the correct mechanical properties. A laboratory device is described that measures bulk shrinkage absolute shrinkage and permeability. The results from this device indicated Portland cement was less than ideal as an oilwell sealant.

Expanding cement to prevent microannulus formation was studied by Baumgatrte *et. al.* (5). This work focused on failure of a cement sheath under long-term exposure to gas flowing from a producing reservoir. Reduction of down hole pressure with time and cyclic thermal and hydraulic stresses from well operation were cited as cause for failure.

Gas leaks in wells have also been attributed to cement shrinkage, which creates circumferential fractures that become paths for gas flow. Baumgarte *et. al*. (5) looked at expanding cement (which is used to prevent some gas flow problems) and found that, although helpful in many situations, expanding cement can actually lead to a microannulus between the casing and cement when it is placed in soft formations.

Jackson and Murphey (6) examined the effect of casing pressure on annular cement seal. They used near-full-scale laboratory simulation and found that 5-in. casing that is pressure tested to 70% of its burst pressure could potentially lead to a loss of cement integrity and create a path for gas flow. They also tested for a reduced hydrostatic situation where the casing was pressured to 10,000 psi while the cement set and then the pressure was released; this situation also created a path for gas flow.

Krilov and Loncaric (7) describe a field study of deterioration of cement seal integrity with CO2 and H2S exposure. Cement bond logs run subject on wells at various times indicated cement seal deterioration.

This literature exemplifies the knowledge that cement can fail to maintain seal integrity during life of a well. Effects of specific well operations, stimulation treatments in the case of this study, have not been widely investigated. Specific requirements for well integrity and hydraulic fracture optimization in low permeability reservoirs have not been addressed at all.

The Barnett Shale is located in North Texas, in the Dallas-Ft Worth basin, and represents the largest gas producing field in Texas, and is the 11th largest onshore US field in terms of proved gas reserves (8). Officially termed the Newark, East Field, the Barnett extends in a core area and an extension area, marked by interactions with other surrounding formations. The core area is generally located in Wise and Denton counties, and the extension area extends northwest to Clay County, southwest to Hill County. 12 counties are contained spanned by the core and extension areas, including Clay, Montague, Jack, Wise, Denton, Parker, Tarrant, Dallas, Hood, Johnson, Bosque, and Hill. In the core area the Barnett sets above the Viola formation, while it sets on the Ellenburger formation in the extension area. Producing intervals can be as much as 1,000′ in the core area and as low as 50′ in the extension areas. The Barnett is characterized by low porosity (2% to 6%) and permeabilities measured in nano-darcies (9). In many areas, the Barnett is split into two regions (Upper Barnett and Lower Barnett), with the Forestburg Limestone separating the regions.

Estimated reserves have been successively revised upward over time, based on tests conducted in various wells and reflecting technology developments in drilling and stimulation. In 1990, the field was estimated at 1.4 TCF. In 1996, the figure was revised to 3.4 TCF, and then to 10.0 TCF in 1998. Current estimates, made in 2004, estimate the recoverable reserves at 26.2 TCF (10, 11). Gas storage mechanisms include free gas within formation porosity, free gas contained in natural fractures, and gas adsorbed on organic materials and clays.

The first well was drilled in 1981 by Michell Energy Corp in Wise County, and approximately 100 more wells were drilled over the next 10 years. Vertical wells were drilled exclusively until recent years, and typically early stimulation efforts involved foam fracs, followed by gel fracs and finally water fracs. Refrac procedures on existing wells has been highly successful, resulting in gains as high as 60% of the initial production. Multiple refracs in some wells have extended economic production life significantly. Completion technologies have shifted increasingly in later years from vertical wells to horizontal completions. The shift from gel fracs to water fracs has done the most to spur development of the Barnett Shale, due to economy and improved results. Tracer studies have shown that water fracs stay in zone better than gel fracs, have generally better half lengths, and are able to stimulate in some wells the natural fracture network (12). Refrac activities are believed to be successful in depleted reservoirs because of stress reorientation in the near-wellbore area, which allows the frac orientation to extend (generally) perpendicular to the original frac to some distance away from the wellbore, and then reorient parallel to the original frac direction (13). This effectively increases the drainage area almost as effectively as the first frac on a new well. Due to the improvements in technologies over the years as well as steady increase in estimated reserves, the total number of wells drilled in the field exceeds 2,500. Table 1 summarizes stimulation strategies over the years since the first well was drilled.

Table 1 – Stimulation Strategies in the Barnett Shale

Years	Well Orient	Formation	Frac Type	Total Volume - gallons	Sand - lbs	Notes
1981-1985	Vertical	Lower Barnett	Foam	150K – 300K	300K – 500K	40 bpm
1985-1997	Vertical	Lower Barnett	X-L gel	400K – 600K	1 mil – 1.5 mil	N2 assist, FL adds, clay stabilizers
1998-present	Vertical	Upper & Lower	Fresh water, frac separately	900K (Lower) 500K (Upper)	200K	50-70 bpm
1999 - present	Refrac	Upper & Lower	Fresh water, frac separately	900K (Lower) 500K (Upper)	200K	50-70 bpm
2003-present	Hor, 1,000' - 3,500' laterals	Lower Barnett		2 mil – 6 mil	400K – 1 mil	100 bpm+

Horizontal drilling in the Barnett Shale began in 1992 with the first well, which achieved marginal results. A 1993 GRI report concluded that vertical wells were indicated in the field. Two subsequent test wells drilled in the late 1990's achieved better results, with significant increases when nearby vertical wells were stimulated. In recent years, Devon drilled 7 horizontal wells with outstanding results, and the horizontal drilling strategy is the most significant recent trend in the area. The horizontal well strategy raises many new questions regarding cementing and stimulation strategies, which may encompass acid-soluble cements and the interplay between cementing strategies and stimulation success. Additionally, as drilling extends from the core area to the extension areas, the significance of natural faults and other anomalies can prevent effective stimulation of the hydrocarbon-bearing formations. These factors have resulted in increased reliance on 3-D imaging data as well as Pre-Frac Injection Test evaluation techniques in order to properly plan stimulation treatments.

References, Phase I Task 1

1. Thiercelin, M.J.; Dargaud, B.; Baret, J.F.; and Rodriquez, W.J., "Cement Design based on Cement Mechanical Response," October 8, 1997.
2. Di Lullo, G. and Rae, O., "Cement for Long Term Isolation—Design Optimization by Computer Modeling and Prediction," IADC/SPE 62745, September 13, 2000.
3. Bosma, M.; Ravi, K.; van Driel, W.; and Schreppers, G. J., "Design Approach to Sealant Selection for the Life of the Well," SPE Paper 56536, October 3, 1999.
4. Bosma, M.G.R.; Cornelissen, E.K.; and Schwing, A., "Improved Experimental Characterization of Cement/Rubber Zonal Isolation Materials," SPE Paper 64762, November 10, 2000.
5. Baumgatrte, C.; Thiercelin, M.; and Klaus, D., "Case Studies of Expanding Cement to Prevent Microannular Formation," SPE Paper 56535, October 6, 1999.
6. Jackson, P.B. and Murphey, C.E., "Effect of Casing Pressure on Gas Flow Through a Sheath of Set Cement," SPE/IADC Paper 25698, February 25, 1993.
7. Krilov, Z. and Loncaric, B. "Investigation of a Long-Term Cement Deterioration Under a High-Temperature, Sour Gas Downhole Environment", SPE 58771, Feb 2000.
8. EIA Report, 2003, "U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves 2002 Annual Report", Energy Informational Administration, December, 2003
9. Bowker, K.A., "Recent Development of the Barnett Shale Play, Forth Worth Basin", West Texas Geological Bulletin, v. 42, no. 6, Feb 2003.
10. USGS, "Assessment of Undiscovered Oil and Gas Resources of the Bend Arch – Forth Worth Basin Province of North-Central Texas and Southwestern Oklahoma", National Assessment of Oil and Gas Fact Sheet, March, 2004.
11. Kuuskraa, V.A., Koperna, G., Quinn, J.C, and Schmoker, J.W., "Barnett Shale Rising Star in Fort Worth Basin", Oil and Gas Journal, May 25, 1998.
12. Warpinski, N.R., "Diagnostic Imaging of Water-Frac Behavior", Sandia National Labs, oral presentation, date unknown.
13. Siebrits, E. and Elbel, J., "Refracture Reorientation Enhances Production from Tight Gas Wells", DOE Gas Tips, Summer 2001.

TASK 2. *Gather Data*

Well-construction, rock-property, and reservoir-production data for the candidate wells are contained in the presentation presented in Appendix XIV. Because of the shift in emphasis later in the project to the Barnett Shale, and the reluctance of operators to allow access to this information pre-treatment, the data presented is for the LE Jones Burchett #1-35 (Dornick Hills B). The data that is available for the Barnett work is contained in the Technology Transfer Presentations presented in Appendix VII.

TASK 3. *Testing*

Significant lab testing was performed on six cement slurries. The slurries included a baseline class H slurry, the baseline slurry modified with microfibers, a foamed cement (lightweight) slurry, and a latex slurry. Additionally, testing was done on two slurries used on wells drilled by HEP. Tests conducted included mechanical property tests (tensile strength, compressive strength via UCA data, and shearbond), as well as rheology and thickening time tests. Finally, frac model tests were done, in which a simulated wellbore in a representative geometry is loaded via internal pipe pressure and sealing performance is observed. The frac model represents a performance measure that is dependent on the complex interaction of many mechanical properties of the cements. Another performance testing methodology is called the annular seal test, in which resistance to gas flow is measured with loading consistent with real well scenarios. The difference between the frac model and the annular seal testing is the flowing medium (water in the frac model, gas in the annular seal), and the absence of the simulated perf in the annular seal model. Although no annular seal tests were done specifically for the Low Permeability project, tests were conducted with very similar slurries on a different project. Results of these tests were applied to the subject project, and are contained in Appendix XI. Details of these test are contained under the discussion for Phase II, Task 2. Also included are results of anelastic strain testing. Anelastic strain is the tendency of cement to permanently deform when subjected to loading cycles that are well below the load required to catastrophically fail the sample. Anelastic strain is an important measure of the resiliency of the cement to load, and varies widely with different cements. Along with other properties of the cement, the property is important to the sealing performance of cement in the wellbore.

Laboratory Procedures used to perform all tests are detailed in Appendix XII, and the data and test slurry compositions are detailed in Appendix XI.

PHASE II *Conduct Lab Analysis of Hydraulic Seal*

TASK 1. *FEM Modeling*

Two FEM studies were applied to the subject project. The first (FEM Analysis Of Cement Systems Under Stress Conditions) was commissioned during the performance of another project, aimed at improving long-term cement integrity in deepwater environments. The results of this study and the application to unconventional reservoirs are significant, and therefore are included in this report. The complete study is presented in Appendix VIII, and the primary conclusions and applications are presented in this Task 1 and the following Task 2 discussions. The second FEM study, commissioned specifically for the subject project and building on the Cement Systems Under Stress Conditions study, deals with fracture containment and pressure transmission in the downhole environment, complete with filter cake and low permeability formations. The study was followed by frac model lab testing, in which the sealing ability of various cements was studied in a simulated wellbore geometry. The complete study is presented in Appendix IX, and the results of the study are presented in this Task 1 and the following Task 2 discussions.

Wellbore Stresses and Strains

FEM Modeling of wellbore environments, in which the pipe, cement, and formations of different strengths were considered as a single system, was performed in order to determine how the system responds to imposed stresses and strains. This system concept is critical and novel. Traditionally, well construction parameters are engineered in relative isolation from cementing considerations. Casings are usually designed for maximum economy, given the constraints of lithology and wellbore conditions. Casing design is a complicated issue, and represents a significant portion of well construction costs, and as such is necessarily given much engineering attention. Cement, on the other hand, while technically sophisticated and critical to the ultimate life span of the well, is usually “turn-keyed” to a service company when it is time to cement the casings. Parameters for successful zonal isolation are rarely considered during the well planning and design stages.

The FEM Analysis of Cement Systems Under Stress Conditions was conducted by the University of Houston. The purpose of the work was to model the pipe / cement / formation system in situ in order to assess the relative importance of the various components of the systems.

The analysis clearly shows that the pipe is effective in "shielding" the cement from destructive stresses due to the much lower Young's Modulus of the cement when compared with steel. Casing wall thickness was not varied in this study, although Young's Modulus and Poisson's Ratio was varied over a range. Thicker wall thickness tubulars will result in similar stress distributions across the steel, but will change at a lower rate. This supports the observation from lab testing that tubulars are effective in absorbing stresses and protecting the cement sheath.

Similarly, stresses in the cement sheath decrease with increased formation Young's Modulus for the same reason. The important issue is the relative values of cement and formation properties. If the formation is relatively weak, the Young's Modulus forces compressive stresses in the cement sheath higher, increasing the likelihood of failure.

Hydraulic Seal Analysis

The wellbore was modeled, assuming perforations through the pipe, cement, and mud filtercake and extending into the formation as a conduit for frac fluids to enter the formation. Frac fluid at pressure is applied to the perforations, and the model is analyzed to determine the likelihood of frac height growth. The key mechanisms for frac containment generated by this study include:

- Cement remains intact
- Flow through the relatively high permeability filter cake
- Stress analysis in the continuously centric geometry, in which stress contrasts at the cement – formation interface and the shear bond strength of the cement are important.
- Pressure transmission through mud filter cake
- Energy dissipation due to vertical height growth

Results show that even though the mud filtercake is many orders of magnitude higher in permeability than the formation, the filtercake behaves as a visco-elastic solid and therefore pressure transmission attenuates significantly with distance from the pressure source. Pressure loss due to flow transmission through the filtercake is on the order of 83% in only 10 feet of height from the perfs. Because of the very small radial dimensions of the filtercake thickness (the flow channel), high flow velocities require very high differential pressures. With the differential pressures available in the fracturing process, there is not sufficient differential pressure to affect significant flow through the filtercake. Further, as formation porosity and permeability increase, less energy (differential pressure and resultant flow) are available to transmit fracture-initiation and especially frac propogation energies through the filter cake.

In order for uncontrolled frac height growth to occur at the wellbore, sufficient pressure must be available to initiate a crack, and sufficient flow path must be available to feed the crack with propagation flow. Results of this study show that in a cemented annulus assuming the cement does not mechanically fail and crack to produce flow channels, the only mechanism for initiation pressure away from the perfs is pressure transmission through filter cake. Pressure falls very quickly vertically along the filtercake, so initiation pressure must be confined to the near-perf region. In the event that the filtercake is sufficiently permeable, or a microchannel exists to allow a crack to initiate away from the perf area, there is insufficient flow area to allow frac propagation.

The study clearly shows that cement is useful for containing frac height growth in the region near the perfs, so long as the cement is sufficiently resilient to maintain integrity, and that height containment is important for maximizing useful frac penetration.

TASK 2. ***Confirmation***

Annular Seal / Energy Analysis

Cement sheaths subject to loads imposed by well conditions and intervention activities are subject to failure at some point in time. The time at which failure occurs, if it does occur, has been related based on extensive laboratory studies to the amount of energy that is imposed on the cement sheath during the life of the well. Cement strength is important, but there are other cement and non-cement variables that affect the long-term integrity of the cement sheath. These variables include:

- Cement properties
    - Cement tensile strength
    - Cement Young's Modulus
    - Anelastic strain (permanent deformation of set cement as a result of repeated low-stress loading)
    - Radius of cement sheath
- Well Properties
    - Size and wall thickness of casings
    - Hole size
    - Formation Young's Modulus
- Loading data
    - Planned stimulation profiles (pressures)

In the well, a strong formation and heavy pipe essentially back up the cement, resulting in more energy absorption before cement failure. Laboratory testing focused on loading the cement sheath with internal pipe pressure and measuring the time at which low pressure gas can flow through the cement sheath. Figure 1 shows the annular seal model:

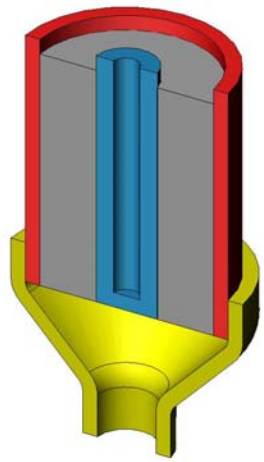


Fig 1 – Annular Seal Model

Gray – Cement sheath
Red – External pipe simulating formation – steel pipe simulates "strong" formations, PVC pipe simulates intermediate-strength formations, and a dense sand pack simulates weak or unconsolidated formations.
Blue – Internal pipe (casing) the blue pipe
Yellow – adapter for applying low-pressure gas to the cement sheath

In practice, repeated pressure applications inside the blue pipe loads the cement. The strength of the formation (red pipe) limits the amount of deformation the cement sheath can undergo during loading. The stronger the formation, the less the cement is able to deform under stress. During load application, low-pressure gas is introduced through the yellow section and is blocked from flow by the cement sheath. When the cement fails, gas can readily flow, as indicated by a flowmeter.

Testing on a variety of cements and simulated formations resulted in a clear correlation between cement, casing, and formation properties, related to the amount of energy imposed on the cement sheath before cement was observed to flow.

The correlation produced is expressed in terms of two dimensionless variables, E1A and E1R. E1A represents the amount of energy applied to the system, and E1R represents the resistive ability of the cement/pipe/formation system to resist the applied energy. When plotted, E1R vs E1A produces a "failure curve", defined by the locus of observed gas flow points from multiple model tests. When applied to an actual well condition, E1A and E1R are compared to the failure curve to describe the likelihood of cement failure in the well.

$$E1A = \frac{\text{Applied Energy} * \text{Hole Radius}}{\text{Mass Cement} * \text{Pipe CS Area}}$$

$$E1R = \frac{\text{Formation Factor} * \text{Volume Cement} * \text{Cement Tensile Strength}}{\text{Applied Energy} * \text{Cement Young's Modulus} * \text{Anealstic Strain}}$$

Formation Factor = Formation Young's Modulus / 2,000,000

It should be noted that the energy analysis represents a correlation, and that the "failure curve" does not represent an absolute pass/fail criteria for cement integrity. The further the field point (E1A, E1R) is above the failure curve, the less likelihood the cement will fail in the application. The further the field point lies below the curve, the higher the likelihood that the cement will fail in the application. The failure curve and the energy analysis methodology is codified in a spreadsheet-based program, distributed with this report.

In practice, the program is arranged such that, given wellbore geometry, pressure history, and two of the three cement properties correlated, the third cement property is calculated as a minimum or maximum value required to place the field point on the failure curve. Improvement in any three of the properties will result in improved confidence that the cement will not fail in the application.

One result of the energy methodology is that the wellbore is subjected to multiple fracturing treatments (typical in low-permeabilty reservoirs with multiple pay zones), the cements requiring the best properties are those up the hole rather than the cement in the bottom pay zone. This is because the bottom zone cements are isolated from the frac pressures imposed on pay zones higher up. This observation correlates well with field reports in which cements in higher pay zones fail before those zones can be stimulated, sometimes resulting in abandonment of those zones for production purposes.

Frac Model / Sealing Integrity

Laboratory testing to confirm the results of the hydraulic seal model were performed with frac model testing. While it is very difficult to model in the lab all the stresses and conditions present in the wellbore, the frac model test allows fracture containment in the continuously concentric geometry interrupted by a simulated perforation, by measuring the pressure required to catastrophically break the cement seal. The frac model testing apparatus is shown in Figure 2 below.

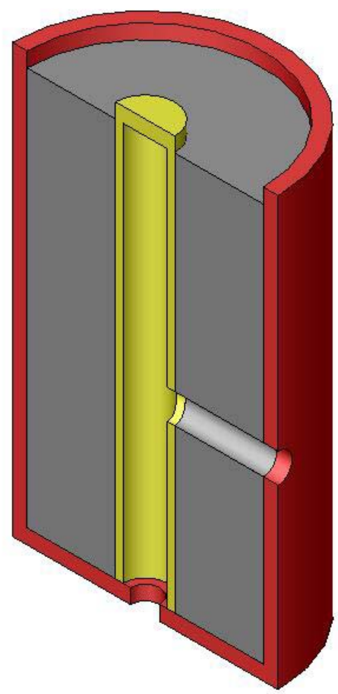


Figure 2 – Frac Model

In practice, the cement is poured into the red outside pipe, with the yellow inside pipe in position shown, and allowed to cure. The horizontal hole is then drilled through the outer pipe, cement sheath, and inner pipe. The resulting hole in the outer pipe is then threaded and plugged. Testing consists of pressurizing the inside yellow pipe at increasingly higher pressures (simulating fracturing fluid in a perforation) until this “frac pressure” fails the cement catastrophically. Four values are reported:

- Flow initiation pressure
- Flow associated with flow initiation pressure
- Seal failure pressure
- Flow associated with seal failure pressure

The flow initiation pressure and volumetric flow rate are the values at which water flows through the matrix of the cement, and can be observed on the free face of the cement. Bond failure pressure is the pressure at which the shear bond to the pipe fails and the water can flow through the fractured bond. This value must be interpreted as differential pressure across a length, because the model has no pressure applied to the free face of the cement. In the actual well condition, the flow is inhibited by confining pressures and the weight of the material above the perf, so the pressures reported should be interpreted as differential pressures.

Results show that bond failure pressures are not strongly correlated to either tensile strengths or shear bond strengths alone. This suggests that frac model test gives only a relative indicator of cement performance in the wellbore geometry, and that ultimate failure is related to an as-yet unknown interaction of a number of cement mechanical properties. For the purpose of the current study, the important issue is not to predict specifically and on the basis of cement mechanical properties when failure will occur, but rather the differential pressure per unit length that the cement sheath can withstand. Comparison with the calculated pressure loss through filtercake (applied differential pressure) confirms that pressure drops are sufficiently high to prevent crack initiation significantly away from the perforations.

PHASE III *Limit Formation Damage to Maximize Production*

TASK 1. *Cement Slurry Penetration*

At the request of DOE, this task was eliminated from the project. This information is documented in an internal project meeting summary dated 4-23-02.

TASK 2. *Balanced Cementing*

This topic was included as an option for minimizing damage to formations due to cement filtrate leakage. Operators working as industry partners for this project when it was switched to Barnett Shale were totally opposed to application of any sort of underbalanced drilling or cementing. Therefore this topic was abandoned for this project.

TASK 3. *Vertical / Horizontal Well Comparison*

Because of the nature of this project's history, no comprehensive work was done to compare the vertical and horizontal well comparison. The primary reason for this is the shift from the Anadarko Basin to the Barnett Shale during the study, as a result of the industry partner's decision not to drill the planned test wells. At the time the shift was made to concentrate on the Barnett Shale, horizontal work was neither being done nor considered, other than a few disappointing tests in the early 1990's. The conclusions on the basis of that work were that there was no reason to horizontally drill the Barnett, and that subsequent field development should concentrate on vertical wells. That situation began to change in 2003, when Devon began work on several horizontal wells that became very successful. Unfortunately, the timing of these wells was such that the bulk of the work on this project was complete by the time results were available. At this point in time, it appears that there is significant work to be done in horizontal wells in the Barnett.

PHASE IV *Design Field Applications Based on Laboratory Results*

TASK 1. *Decision Matrix*

The cement properties decision matrix, based on the FEM work done at the University of Houston and confirmed by subsequent laboratory work, is codified in the energy analysis described in Phase II, Task 2. The decision matrix inputs comprise:

- Geometry Data
  - Hole Size
  - Pipe OD
  - Pipe ID
  - Cemented Interval
- Formation Data
  - Formation Young's Modulus
- Anticipated Frac Plan
  - Anticipated Frac Pressures
  - Number of pressure applications

- Cement Data
    - Two and only two of:
        - Tensile Strength
        - Anelastic Strain
        - Young's Modulus

Output is the calculated minimum (or maximum, as appropriate) value of the third cement parameter. This allows the cement designer to choose a cement in terms of properties as opposed to composition that will yield the minimum (maximum) recommended values for long-term integrity. The failure curve (blue line on the graph) is not an absolute measure of failure, but is coincident with the failure line observed in the lab for a variety of different cements. The further the field point is above the line, the less likely the cement will fail under the imposed loading, and the further below the line the point lies is a relative measure of the likelihood that failure will occur.

As discussed, the decision matrix is codified in a spreadsheet program that determines required cement properties to effect a long-term seal for the well and frac design strategies planned for the well. The next page shows a screen shot of the Input/Output page of the spreadsheet. Operating details are contained in Appendix X, and the spreadsheet is distributed with this report.

Low Perm Reservoir
Cement Energy Analysis
Note - Spreadsheet Annotation is in Appendix X

Input Data

Geometry Data

Hole Dia	**7.00**	in
Pipe OD	**5.50**	in
Pipe ID	**5.00**	in
Cemented Interval	**1,000**	ft
Formation Data		
Formation YM	**1.E+06**	psi

Known Cement Properties (enter two and only two)

Tensile Strength		psi
Young's Modulus	**100,000**	psi
Anelastic Strain	**3.75E-09**	

Output Data

Required Cement Properties

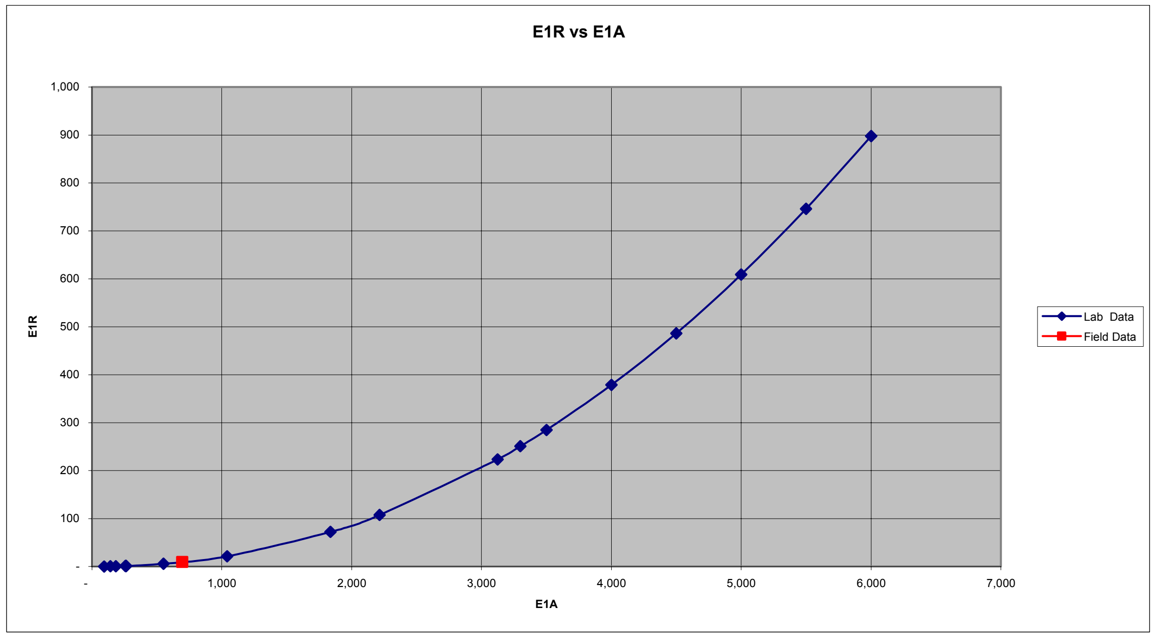
Min Tensile Strength	363	psi
Max Young's Modulus	100,000	psi
Max Anelastic Strain	3.75E-09	

Frac History

	Bottom	*Top*	*Pressure*
	8,000	**7,000**	**8,500**
	7,550	**7,400**	**8,200**
	7,210	**6,990**	**8,000**
	6,700	**6,490**	**7,700**
Current Zone			
	6,250	**6,000**	**7,500**

Pressure Loading Schedule

Total Applied Energy -->		9.40E+09
Pressure	Applications	Applied Energy in - lbs
8,500	1	2.00E+09
8,200	1	1.93E+09
8,000	1	1.88E+09
7,700	1	1.81E+09
-	-	0.00E+00
-	-	0.00E+00
7,500	1	1.77E+09



TASK 2. *Cement Application*

Drilling and budgetary constraints for the operator kept the optimum cementing recommendations from this work from being applied on a well. Instead, the scope of the project shifted to monitoring current cementing practice, adjusting recommendations to modify and improve the current practice, and evaluation of the mechanical properties of the currently used cement compositions. Cementing of the production casings on two wells were witnessed and monitored. Results are presented in Appendix XIII of this report.

The first treatment, referred to herein as HEP 1, was for the 5-1/2 inch production casing for the Lland Browder "B" well #1. The Cement Job Report filed by the field consultant is presented in Appendix XIII. This report presents a cementing operation in which some critical details were handled and others were not. 70 barrels of cement were mixed and pumped. The cement composition was a proprietary blend referred to as “Fort Worth Basin Premium Cement”, marketed by BJ Services. It is interesting to note that with a marketing effort that justifies a named blend, all wells in the area are regarded as equivalent, with no special requirements for cementing. As noted in this report, wellbore geometry, lithology, and stimulation strategy all are factors in designing and choosing a cement appropriate for the intended purpose, in order to achieve long-term sealing integrity, as well as to maximize the effectiveness of stimulation actions. Efforts were made to condition the drilling fluid prior to cementing, but additional circulation time was recommended. No float collar was run, leaving the plugs to land at the casing shoe. Elimination of a shoe track increased the chances for drilling fluid contamination around the outside of the shoe across the production zone.

The second treatment, referred to herein as HEP 2, was for the 5-1/2 inch production casing on the Bailey #1. The Cement Job Report and Supplemental Cement Job Report filed by the field consultant are contained in Appendix XIII. These reports describe a less-than-textbook execution. 140 total barrels of cement, divided into 82 barrels lead and 58 barrels tail cement were mixed and pumped. The lead cement was a 65/35 Pozzalan / Class H blend, with 6% gel, and 6% salt, mixed at 12.8 lbs/gal. Insufficient effort was made to maximize displacement for the treatment. Condition of the drilling fluid prior to cementing was poor and little was done to condition the hole prior to cementing.

TASK 3. *Cement Assessment*

Again, drilling and budgetary constraints of the operator precluded any analytical testing of the integrity of the cement treatment. However, samples of cement and other treatment materials were taken during the treatments and shipped to CSI for evaluation.

Application tests on the samples were preformed and are reported in Appendix XI. Results for both cements indicate that neither of the slurries designated HEP 1 or HEP 2 are likely to yield acceptable cementing results, with improved displacement mechanics. The HEP 1 slurry showed high expansion and essentially no fluid loss control. Application of this slurry in soft formations could cause a microannulus, and application in loss circulation zones may result in incomplete displacement. This slurry was the one designated as "Forth Worth Basin Premium Blend", and the deficiencies in the slurry design, coupled with indiscriminate marketing for all wells in the region could have undesirable results. The overriding theme in the Barnett Shale is that even apparently similar wells may be very different in terms of cementing and fracturing, and therefore cement and frac design should be considered unique to each well.

Mechanical property testing for both cements was also conducted and is reported in Appendix XI. Results for both cements indicate that neither of the slurries designated HEP 1 or HEP 2 are likely to yield acceptable cementing results, with improved displacement mechanics. The HEP The Anelastic Strain test was not performed on these slurries, so a definitive opinion regarding acceptability in terms of the Energy Analysis cannot be made..

The following general cementing guidelines are recommended for future treatments:

- Consider the requirements of each well independently to other wells in the area, and design a cement appropriate for the characteristics of that well. Parameters that should be considered are:
    - Thickening time
    - Transition time
    - Mechanical properties
    - Rheology
    - Compatibility with mud and spacer
    - Temperatures and pressures
    - Lithologies
- Properly condition the mud prior to cementing. Circulate as long as required, and add to the mud chemistry as required to break down gelled pockets.
- Use sufficient spacer, and check compatibility with both the mud and the cement.

- Rotate and reciprocate the pipe during displacement to improve mud removal efficiency.

TASK 4. ***Stimulation Application***

The shifting of industry partners caused the original project tasks to be altered. For instance, drilling, budget, and well partner constraints prevented the project from targeting 2 wells, imposing optimized cement design, and imposing optimized fracture design from start to finish. To accommodate this constraint, the tasks of this project were changed. Stimulation treatments conducted while the project was ongoing were not adequately monitored for sufficient data to allow analysis of the treatment's effectiveness. Therefore, archived treatment data that was complete was acquired and analyzed. Further historical data was reviewed to yield conclusions regarding completion and production operations.

A total of four wells were analyzed under this task. These were the Linda Cox # 1, Fen-Fen #7, Jonas #8, and Collier #6. The first three wells were initially analyzed. All had sufficient reservoir frac treatment and post treatment production data to perform a successful evaluation. Results are presented in Appendix VII. The Collier #6 well was completed later in the study and it also had sufficient data to provide useful information.

These wells provide the basis for all the analysis, conclusions, and recommendations regarding stimulation treatments in the Barnett Shale.

TASK 5. ***Stimulation Assessment***

The results of the comprehensive analysis are also presented in Appendix VII of this report.

Comparison of logs (Sonic, Neutron, Electric in open hole and CBL cased hole), treatment data and production data led investigators to conclude originally that drainage radius of the wells was much smaller than expected after the treatments. This indicated that some of the target zones may not have been fractured as planned. No data was available to confirm or deny this indication.

A new data set from the Collier #7 was analyzed later in the project. This well was cemented and two Barnett Shale zones were fractured in stages. Results from this treatment indicated both zones were fractured according to plan as opposed to previous treatments studied in which one zone fractured preferentially. This information emphasized the importance of cementing across multiple zones in order to provide isolation if the zones were to be treated independently.

PHASE V *Technology Transfer*

TASK 1. *Decision Matrix Application*

The Decision Matrix Application for Cementing is the Energy Analysis Spreadsheet, Phase IV, and Task 1. Operating instructions for the spreadsheet are detailed in Appendix X.

There is no discreet Decision Matrix Application for stimulation as a result of this project. Best practices, embodied in recommendations for Pre-Frac Injection Test operations prior to the stimulation treatments, are clearly indicated as a result of the work done in this project. Historically, operators use frac job designs with which they have had success in the past, or the latest job design that was successful on an offset well, rather than analyzing the well in question for job design parameters. The specific analysis methodology of the Pre-Frac Injection Test process is presented in some detail in the Technology Transfer documentation in Appendix VII, but the specific computer-based analysis programs are comprised of commercial frac analysis packages, and as such are proprietary to the companies that market those services.

TASK 2. *Well Data Capture*

In order to properly evaluate wells for cementing and stimulation recommendations, a great deal of information is necessary. In this section, the salient data is defined.

Cementing

- General Well information
    - Depths
    - Casing points
    - Geometry
    - Casing weight
    - Previous history of problems during drilling
    - Static and circulating temperatures, pressure
    - Hole stability
- Lithology
    - Formation competence (Young's Modulus)
    - Circulation thief zones
    - Minerology
    - Permeability and Porosity
    - Frac gradient
    - Pore pressure of all fluid-bearing formations

- Mud Characteristics
    - Type
    - Condition in the hole
    - Weight
    - Compatibility with spacer and cement

Stimulation

- Reservoir pressure
- Pay zone thickness and depth
- Permeability
- Porosity
- Minerology
- Water sensitivity
- Presence of natural frac networks
- Faults and karsks that may "steal" frac fluid and prevent frac growth
- Fracture conductivity
- Frac Closure pressure
- Cementing history
- Cased and open hole log information
- Tracer logs

TASK 3-5. ***Tech Transfer Documents, Workshops***

Three Tech Transfer Workshops were held to disseminate the results of this project to industry.

HEP Meeting, Dec 20, 2004

As a courtesy to our industrial partner, the first meeting was conducted Dec 20, 2004 in Gainesville, TX exclusively for HEP personnel. George Todd and Cliff Stover attended the meeting, with Fred Sabins and Kevin Edgley from CSI Technologies, and Mike Conway from Stim-Lab. The data from the HEP wells was presented, with the conclusions that cementing does help to concentrate the fracture energy in the area of the perfs, and appears to yield a longer effective frac length. HEP was appreciative of the work done, and offered to assist in setting up more meetings. Also discussed was the importance of the Pre-Frac Injection Test as a diagnostic tool and determinant of the best frac job design for the well.

Chesapeake Energy, January 6, 2005

Introduction

The objectives of the Low Perm project were twofold:

1. Develop methodologies to assure competent annular seal in tight gas formations, subject to multiple hydraulic fracturing treatments
2. Develop stimulation methodologies to optimize production from tight gas reservoirs

Technical Transfer

CSI Technologies and Stim-Lab are required, as part of the project contract, to present the project findings to industry representatives. The first of these presentations was to Chesapeake Energy Corporation at their headquarters in Oklahoma City, on January 6, 2005.

Chesapeake Personnel Present

Operator personnel present at the meeting included:

Ron Goff (Drilling Manager)	Chad Anton
Jason Clark	Keith Curtis
Todd Nance	JD Hertweck
David DeLaO	Theo Djimpe
Kerry LeTourneau	Emily Balask
Steven Donely	

CSI Technologies Personnel Present included:
Loran Galey
Kevin Edgley
Jerry Browning

Discussion

The presentation entitled "Chesapeake Low Perm Lunch & Learn (Jan 2005)", distributed with this report, contains the topics covered in this meeting related to the Low Perm project. As the audience was primarily drilling engineers, the presentation was geared toward the cementing project objective, concentrating on the Energy Analysis, the importance of the tubulars in determining the life of the cement, and the importance of planning for success early in the well design.

Dallas Low Perm Presentation, March 15, 2005

With the assistance of HEP personnel, a list of 13 companies was drawn up who might be interested in the work done in the Barnett Shale. Contact personnel were contacted, and 8 attended the session. More have expressed interest, but could not attend that session. The presentations are included, in their entirety, in Appendix VII. Notes of the meeting are as follows:

Introduction

The objectives of the Low Perm project were twofold:

1. Develop methodologies to assure competent annular seal in tight gas formations, subject to multiple hydraulic fracturing treatments
2. Develop stimulation methodologies to optimize production from tight gas reservoirs

Technical Transfer

CSI Technologies and Stim-Lab are required, as part of the project contract, to present the project findings to industry representatives. The second Tech Transfer presentation was held March 15, 2005 in Dallas, TX. Representatives of a number of companies working in the Barnett Shale were invited, and 4 companies were represented in the meeting. There is continued interest from customers in the Houston area, and another meeting may be set up in Houston.

Personnel Present

Operator personnel present at the meeting included:

David Martineau	Exploration Manager	Pitts Oil Company
Cliff Thomson		Chief Oil and Gas
Gary Patterson	Drilling Engineer	Chief Oil and Gas
Charles Foster	Operations Engineer	Chief Oil and Gas
Ed Benton		Chief Oil and Gas
Mike Hallford		Chief Oil and Gas
Gerald Coulter	Consultant	Chief Oil and Gas
George Todd	Petroleum Engineer	HEP Oil Company, LTD

CSI Technologies, LLC personnel included:

Fred Sabins

Kevin Edgley

Stim-Lab, Inc was represented by Dr. Michael Conway

Discussion

Previous Work:

Mr. Fred Sabins and Dr. Mike Conway presented the findings from the project, contained in the presentations distributed with this report. Primary points included:

- Barnett Shale production is often limited by fluid loading in the wells. Pumping this fluid is essential to realizing maximum production.
- Proper Cement placement has a significant effect in the frac design, by concentrating the frac fluid in the desired zones.
- Upper and Lower Barnett Shales exhibit different Frac Gradients, and therefore must be stimulated differently.
- Frac design is highly dependent on the results of Pre-Frac Injection Testing and adjustment of the desired frac design on the basis of the tests. This might mean increasing the amount of proppant pumped, which means that the material must be available on site. It also might mean that the frac job is abandoned as uneconomical. The critical issue is that although wells are drilled into the same formation, factors individual to each well are critical to the success of increasing production through fracturing.

New Initiatives:

The material was exceptionally well-received by the attendees, and interest was expressed in continuing the work under a JIP, perhaps with DOE funding. Chief Oil and Gas concentrates in an area of the Barnett in which horizontal drilling is common, and they indicate that 100% of their wells are horizontal. A proposal was made to extend the work completed in the original Low Permeability Project, utilizing the pre-testing and various frac techniques. While CSI Technologies and Stim-Lab personnel originally envisioned a single project, the participants discussed a two-phase subsequent project in which vertical wells are studied in the first phase and horizontal wells are studied in the second phase.

Project Progress Reports are presented in their entirety in Appendices I thru V. Most of these reports are brief descriptions of progress made, but the final update is in the form of a Powerpoint presentation.

Appendix I

August 2002 Progress Report

Increasing Production from Low Permeability Gas Reservoirs
August 2002 Update

Phase I: Historical and Laboratory Input

Task 1
Data collection is on going.

Task 2
Research and analysis is being done on the information collected on the Harris #1 and the Burchett 1-35.Cores from the Burchett 1-35 have been located and will be tested for permeability and other properties. These tests are expected to be performed next month.

Task 3
A detailed testing program has been initiated. We have tested the cement that is commonly used on these types of wells to establish a base line for future tests. Slurries that have been tested are: Class H base slurry @ 16.4 ppg, foam cement @ 13.5 ppg and latex cement @ 15.8 ppg. Results from these tests include: static fluid losses, rheologies, shear bond, thickening time, tensile strength and UCAs. Pending tests include Young's Modulus and Shrinkage tests. Other slurries that are being tested are Class H with fibers.

Phase II: Conduct Lab Analysis of the Hydraulic Seal

Task 1
Annular seal hydraulic models are being designed to help define the limits of effective hydraulic sealing. The first annular seal model to study the effects of pressure transfer up through a completely cemented annulus has been designed and the first test has been run with some very encouraging results. The second annular seal model to study the effect of pressure transfer up the annulus through filter cake has been designed and the first test is scheduled this month.

Task 2

University of Houston is conducting finite element modeling (FEM). A parametric study is being performed studying cement properties such as Compressive Young's Modulus, tensile strength, and Poisson's ratio as well as borehole geometry and rock properties to determine the effect of pressure transmission up the annulus and to the formation. A number of computer runs have been performed and the analysis of the data is ongoing.

Appendix II

October 8, 2002 Progress Report

Increasing Production from Low Permeability Gas Reservoirs

Stimulation Progress Report 1 - 8 October 2002 - Mary Van Domelen

Phase I: Historical and Laboratory Input

Historical

The selected area of study is the Ardmore Basin of south central Oklahoma. This basin contains petroleum bearing sedimentary rock formations that range in age from Cambrian to Cretaceous. The target formation is the "Dornick Hills" in the McMillian Field of Marshall County, OK. The Dornick Hills a member of the Atokan Sandstone and most often is normally oil bearing, therefore, this field might be considered an unconventional gas play.

L.E. Jones Production Company has provided extensive data for the two wells comprising our case study. The Burchett #1-35 was drilled, completed and fracture stimulated in late 1998 – early 1999. The Burchett well is still on production. The Harris #1-2 was originally drilled in early 1999. It was recompleted in March 2002. The Harris well was not considered a commercial success.

Data Review

There is extensive data available for the Burchett well. General information includes detailed drilling, cementing, completion, perforation, and stimulation reports. Formation data includes a detailed mud logs, a full suite of electrical logs (high resolution induction, spectral density/DS Neutron and micrologs) and a post-stimulation pressure buildup (PBU) test. This well was cored over the target interval "Dornick Hills B" from a depth of 11,175 to 11,225 feet. Routine core analyses (permeability, porosity, mineralogical composition) and geological deposition/formation interpretations were previously conducted.

There is comparable drilling and completion data for the Harris well, but notably less formation data and stimulation data available for the Harris well. The electrical logs, however, indicate that the target formations in the Harris wells are very similar (depth, thickness, log responses) to the Burchett well. It is believed that data from the Burchett well will be directly applicable to the Harris well.

Notably different treatment designs were used when the Burchett and Harris wells were fracture stimulated. Some of the most significant differences include:

a) A change in the target zone (lower vs. upper Dornick Hills),
b) Considerable decrease in treatment size (Harris job much smaller)
c) Change in propping agents employed (Harris used lower quality material)
d) Lower treatment rate in Harris job, yet comparable treatment pressures
e) Possible operational problems during the Harris job.

Laboratory Analyses

The cores from the Burchett well have been located (this was quite an undertaking) and shipped to Duncan, OK. There are 57 feet of core total; all have been slabbed. The 1/3-slabs are currently being held at the Watters Engineering Office. The 2/3-slabs have been provided to Dr. Mike Conway, Stim-Lab. Stim-Lab is conducting permeability and porosity tests under a series of confining pressures and water saturations. This data will help to define the degree of water sensitivity.

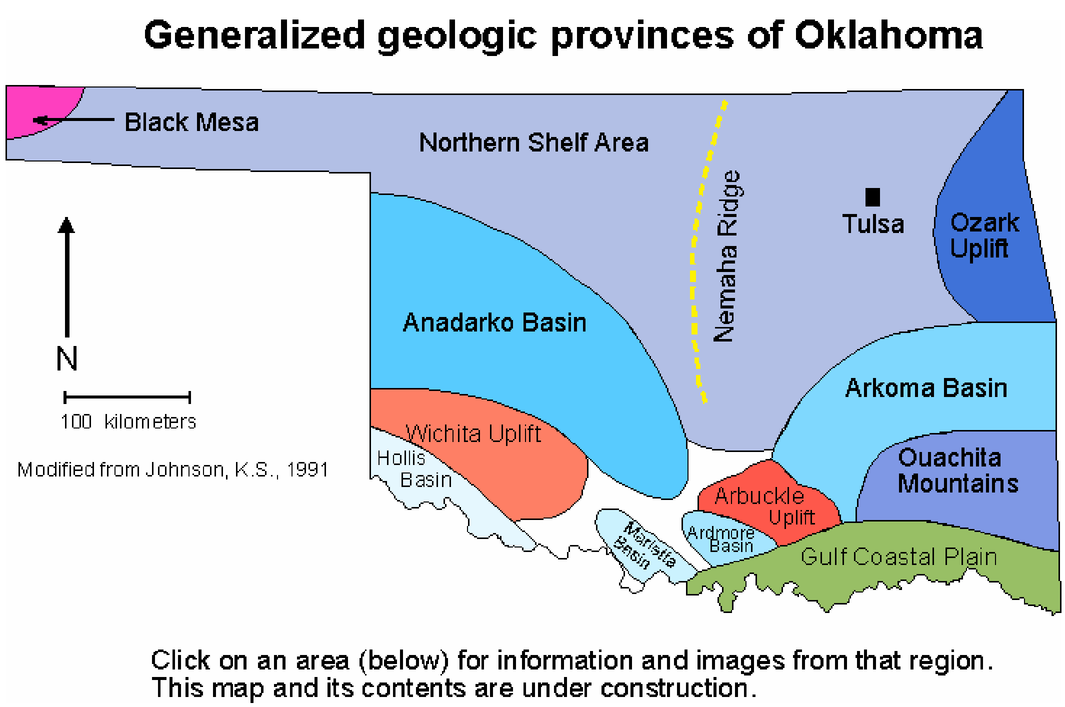
Stim-Lab will use the formation density data (neutron log) along with a proprietary correlation to indicate in-situ closure stress variations that can then be used to better model the height growth during a fracturing treatment.

Once the results of these first two studies are made known, we will proceed to select and optimize a suitable fracturing fluid system for future treatments. Both the Burchett and Harris jobs utilized a 65 Quality foamed linear guar fracturing fluid system. The breaker schedule designs are questionable. It is believed that an optimized fluid system would yield enhanced stimulation results.

Documentation

A detailed summary/data analysis report needs to be written for both the Harris and Burchett wells. This is my priority at the moment. I will be working with Mike Turkett to generate "attractive" figures to go into the report. Examples of "starting sketches" follow as Figures 1 and 2.

Figures



Appendix III

October 30, 2002 Progress Report

Increasing Production from Low Permeability Gas Reservoirs

Stimulation Progress Report 2 – October 30, 2002

Phase I: Historical and Laboratory Input

Historical

Data review and analyses of L.E. Jones Production Company's Burchett #1-35 and Harris #1-2 well files have been completed. The original presumption was that these two wells were producing below potential due to less than optimum stimulation treatments. It was postulated that the hydraulic fractures grew out of zone as a result of poor zonal isolation, e.g. poor cementing practices. We were not able to find any evidence that cement quality caused the low production. The cementing reports and bond log on the Harris #1-2 well looked fine. Further, there was no data available to support the presumption that the fracs grew out of zone.

There is, however, a significant disparity between the production rate of the Burchett and Harris wells. In attempt to determine the cause, the formation characteristics of the target zone were examined in detail. Except for a slight change in depth, the electrical logs for the two wells look nearly identical over the Dornick Hills B interval. In the Burchett well, the Dornick Hills B is found at 11,183 to 11,238 ft. In the Harris well, the interval is at 11,252 to 11,310 ft. Thus both are about the same gross thickness. Gamma ray, resistivity and porosity logs were very similar. The porosities look very promising: averaging around 15%. The cementing, completion and perforation programs for the two wells were nearly identical. There were differences in the fracturing treatments. The Burchett well has consistently produced at rates in the range of 200 to 400 Mscf/day since being fractured in January 1999. The Harris well has not had any significant production since it was fractured in March 2002.

Data Review and Laboratory Input

Since the Burchett well is considered successful, we first looked at the formation core and production data for this well. Conventional core analyses conducted by David K. Davies & Associates indicated permeabilities in the range of 0.01 to 0.05 md with some higher permeabilities (0.2 to 0.9 md) measured. Notes included with the analyses stated that these higher permeabilities were due to fractures induced by coring operations and that they should not be considered representative.

As part of this project, Stim-Lab conducted permeability and porosity analyses on Dornick Hills B formation cores. Stim-Lab's testing differed from Davies' in two significant ways: 1) testing was conducted under a series of increasing overburden stress and 2) Klinkenberg permeabilities were also measured. Illustrative test results are included in Table 1. It can be seen that the air permeabilities decrease by a factor of about 5 with the application of realistic downhole closure stresses. The Klinkenberg permeabilities, which incorporate the affects of turbulent gas flow, indicate about a 10-fold decrease in permeability. In summary, the Stim-Lab data indicates that the gas permeability of the Dornick Hills B is probably on the order of 0.003 to 0.004 md.

A post-frac Pressure Build-Up (PBU) Test was conducted on the Burchett well. Two different analysis methods were used. The critical interpretation results from the PBU test are included in Table 2. The differences in the calculated results are minor and can be attributed to slight differences in input parameters and the model calculations. Results of this test indicate that the effective formation permeability in the Burchett well is +/- 0.002 md. The effective fracture length is about 110 ft and the conductivity of the fracture is infinite in comparison to the low formation permeability.

Examination of the mineralogy data leads to the conclusion that Dornick Hills B might be water sensitive. Initially this would be assumed due to the total clay content of 10-25%. Closer examination of the porosity and pore structure data indicates that a more critical sensitivity problem might exist: severe potential for water blockage. In point count analyses, the total visible porosities ranged from 13-17%. The primary porosity was negligible with only trace amounts of secondary porosity. Nearly all of the porosity was classified as "micro porosity" – which generally translates to high capillary pressures.

Stim-Lab conducted brine/gas flow tests on Dornick Hills B cores to evaluate the degree of water sensitivity. Illustrative results are show in Figure 1. This plot shows that the initial permeability to brine (4% KCl) is on the order of 0.0035 md. After brine flow, a differential pressure of 300 psi (over a 1" core plug) was required to initiate gas flow. At the end of the test, the gas permeability was about 0.0002 at a differential pressure of 600 psi. The major conclusion/observation is that the gas permeability of a water saturated formation sample is an order of magnitude lower than the Klinkenberg or PBU determined permeability for the Burchett well (e.g. 0.0002 md in the presence of brine compared to 0.002 md without brine).

The next question was: Does the Burchett well really have an effective formation permeability of 0.002 md? To answer this question, Stim-Lab performed production history matches using the Burchett PBU data and production data supplied by L.E. Jones Company. Illustrative input and calculated results from these analyses are summarized in Figure 2. Using a formation permeability of 0.0023 md, fracture half-length of 105 feet, and other representative formation data; very good matches were achieved between the actual and simulated production rates. This indicates that the Burchett well is producing "about what it should be". Or more specifically, producing at a rate that would be expected based upon the formation characteristics and fracturing treatment performed.

Future Work

Given that the formation characteristics in the Burchett and Harris wells are so similar; it is believed that the Harris well could produce at rates comparable to the Burchett well if is was re-treated. Future work will need to concentrate on determining the best possible re-stimulation technique for the Harris 1-2 well.

Table 1: Permeability and Porosity at Stress

Sample ID	Depth (feet)	Overburden Stress (psi)	Helium Porosity (%)	Air Permeability @ 800 psi (md)	Klinkenberg @ 800 psi (md)	Grain Density (g/cc)
1	11,198	800	15.4	0.054	0.036	2.69
		2000	14.8	0.029	0.009	
		4000	14.3	0.028	0.008	
		6000	14.1	0.026	0.008	
		9000	14.0	0.015	0.004	
2	11,223.4	800	15.7	0.053	0.045	2.68
		2000	14.6	0.022	0.007	
		4000	13.9	0.029	0.005	
		6000	13.8	0.020	0.006	
		9000	13.7	0.011	0.003	

Table 2: Pressure Build-up Test Interpretation Results

	Method 1	**Method 2**
Estimated Initial P_{res} (psi)	10,570	9,835
Effective Permeability (md)	0.0023	0.00184
Fracture Half Length (ft)	105	113
Fracture Conductivity (md-ft)	Infinite	4990
Skin	0.00155	0

Figure 1

The Brine and Gas Permeability of Burchett 1-35: 11,198'

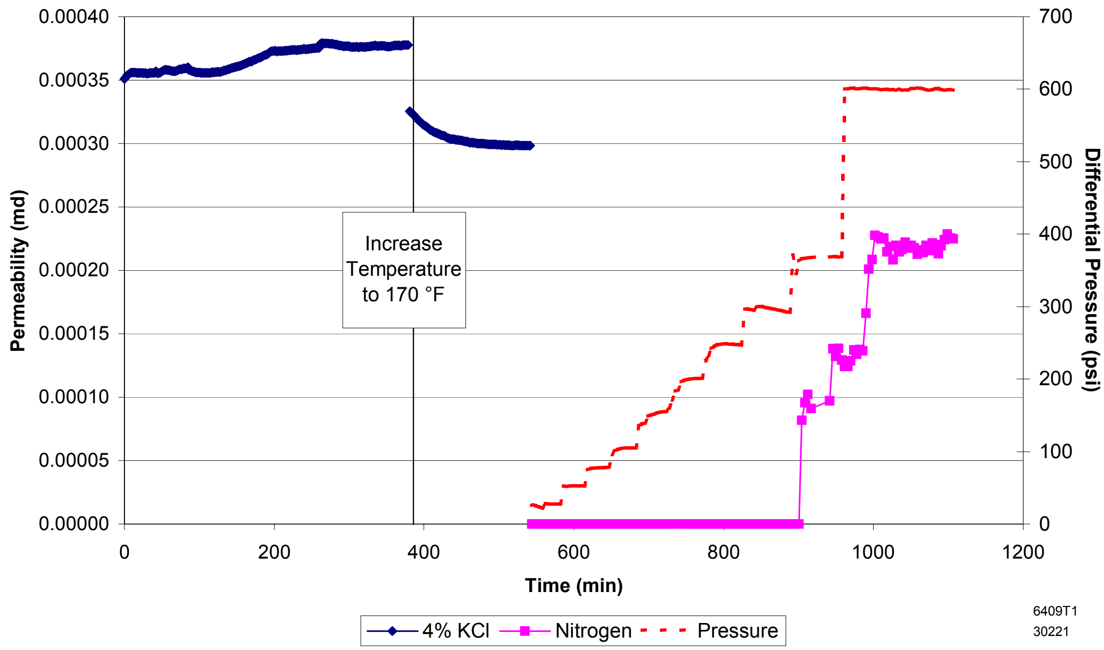
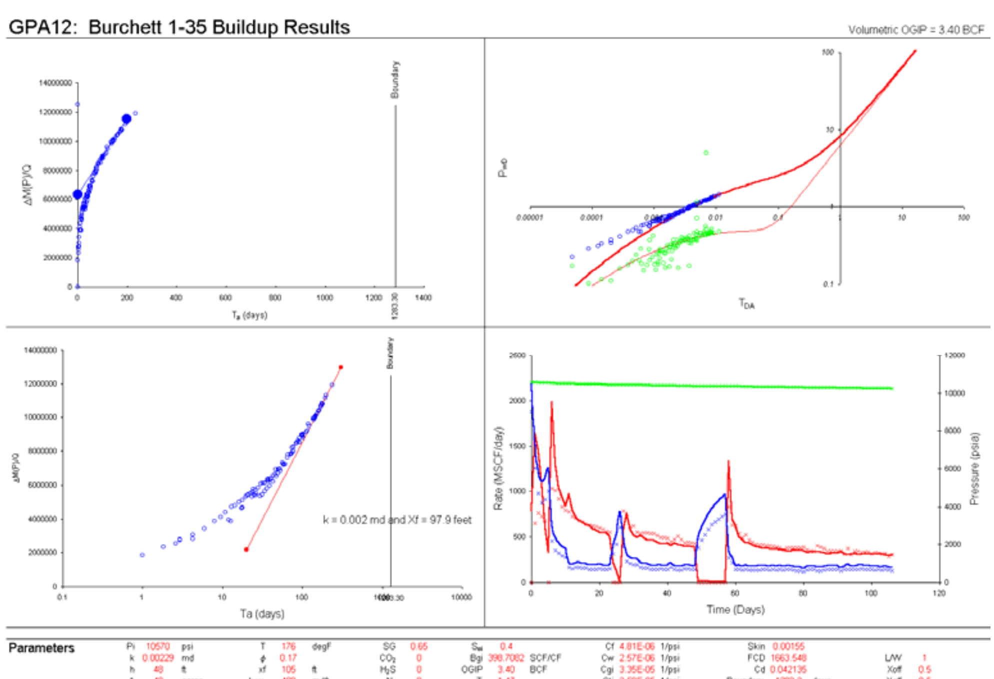


Figure 2

Production Analysis of Burchett 1-35 (using Pressure Build-up Data)



Appendix IV

February 2003 Progress Report

Increasing Production from Low Permeability Gas Reservoirs
January, 2003 Update

Phase I: Historical and Laboratory Input

Task 1
Complete.

Task 2
Complete except for the pending re-fracture of the Harris well.

Task 3
The testing program is complete except for shrinkage/expansion data for all compositions. This testing is awaiting availability of specimen molds.

Phase II: Conduct Lab Analysis of the Hydraulic Seal

Task 1
Further numerical modeling is pending completion of APCF testing in Task 2. Data from these laboratory tests will be modeled to confirm accuracy of the mathematical model.

Task 2
Annulus Pressure Containment while Fracturing (APCF) testing in models with filter cake is pending confirmation that the simulated formation made from epoxy and sand is sufficiently uniform in permeability to produce adequate drilling fluid filter cake for the testing.

Phase IV: Design Field Applications Based on Laboratory Results

The candidate well sites in the Ardmore Basin chosen for this project were determined to be non-commercial. Therefore, the operator, Jones Drilling, Inc., chose not to drill at these locations. Instead, Jones directed the field application to an operating partner, HEP Oil, Inc. HEP is drilling in the Barnett shale in north Texas, and wells in that area fit the low-permeability criteria for this project. Plans are to identify candidate well sites scheduled for drilling by HEP and to begin collecting well construction, rock property, and reservoir data for these candidates (Phase I, Task 2).

Appendix V

June 2003 Progress Report

Increasing Production from Low Permeability Gas Reservoirs
June, 2003 Update

Phase I: Historical and Laboratory Input

Task 1
Complete.

Task 2

Complete. The fracture treatments were not personally witnessed. Rather, fracture treatment data from several wells were analyzed to develop a composite treatment profile to act as a basis for recommending improved treatment methods.

Task 3
The testing program is complete except for shrinkage/expansion data for all initial compositions. A complete suite of laboratory data is being gathered for the cement compositions used on the two wells on which cement jobs were witnessed.

Phase II: Conduct Lab Analysis of the Hydraulic Seal

Task 1
Small amount of numerical modeling has been performed after completion of APCF testing in Task 2.

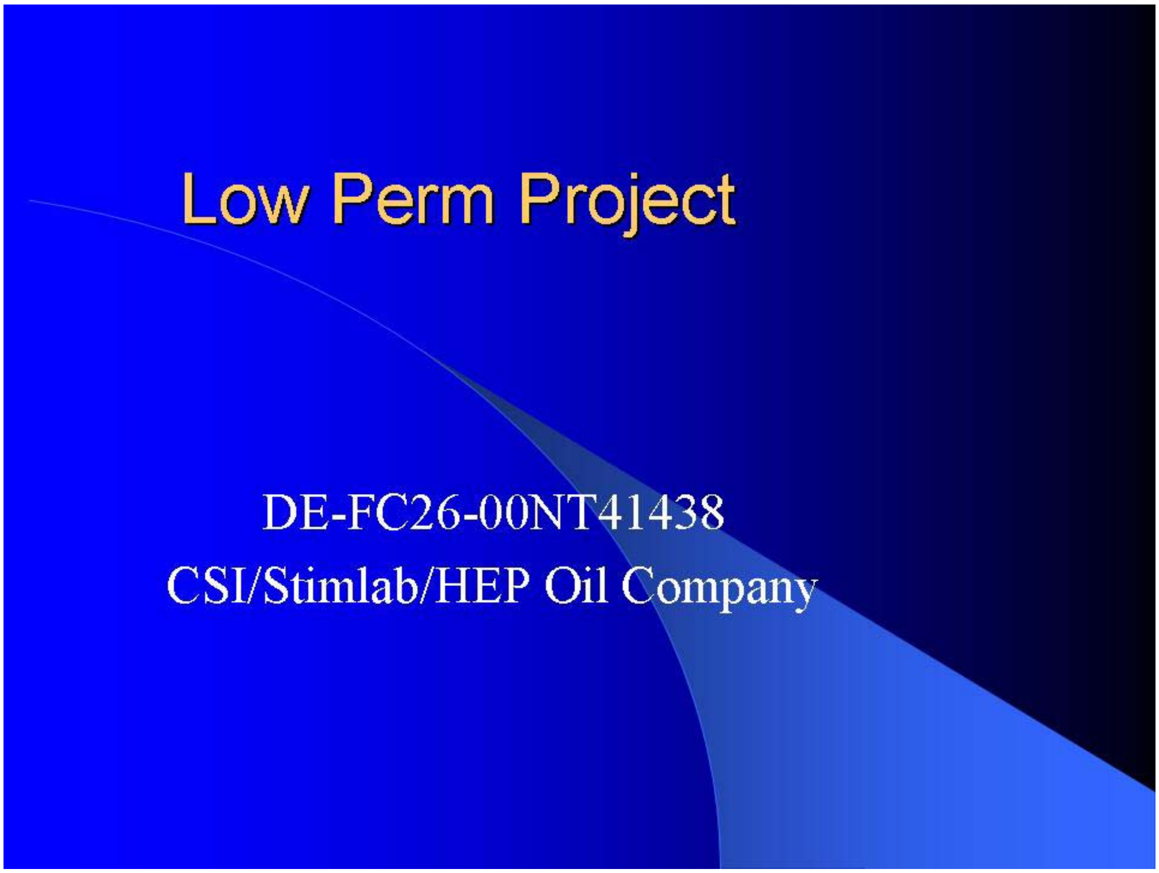
Task 2
Several Annular Pressure Containment while Fracturing (APCF) test models were cured and tested.

Phase IV: Design Field Applications Based on Laboratory Results

Preliminary improved fracture treatment recommendations are being prepared. Cementing recommendations will be developed pending review of all of the data gathered to date.

Appendix VI

October 2003 Progress Report

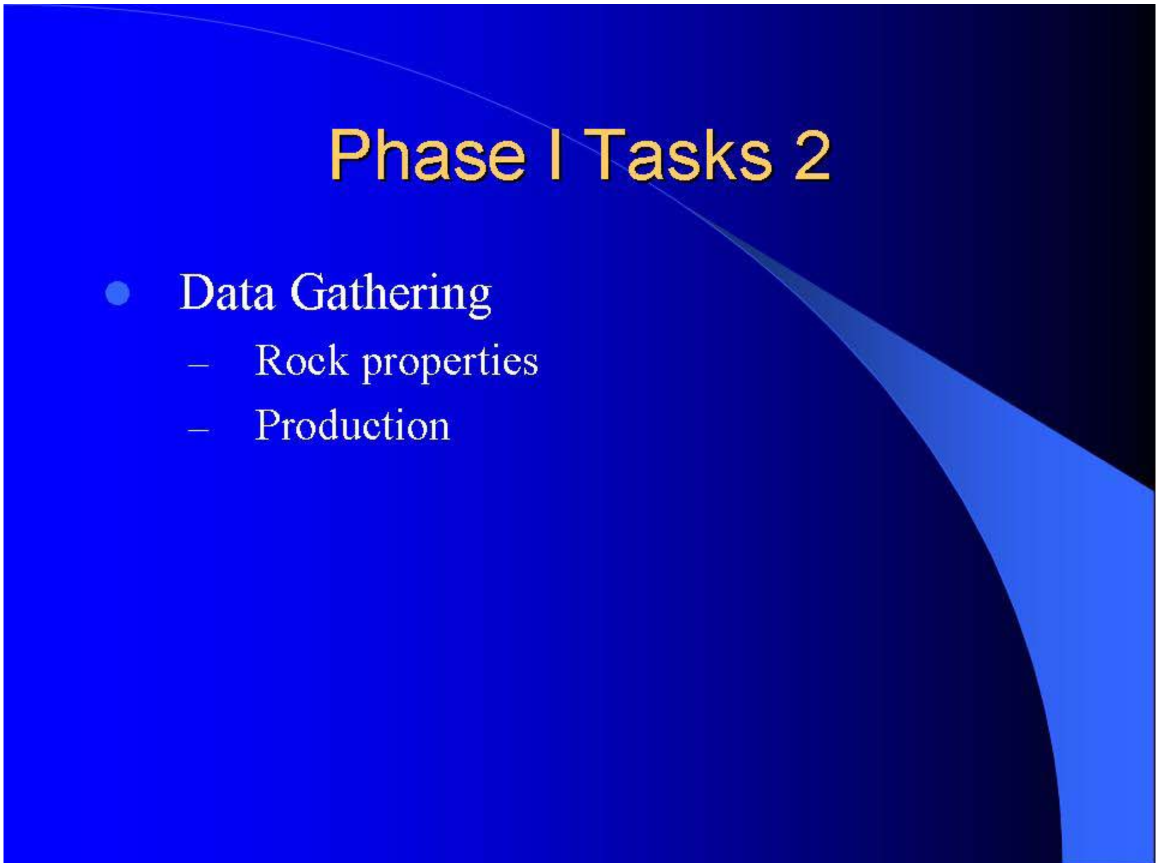


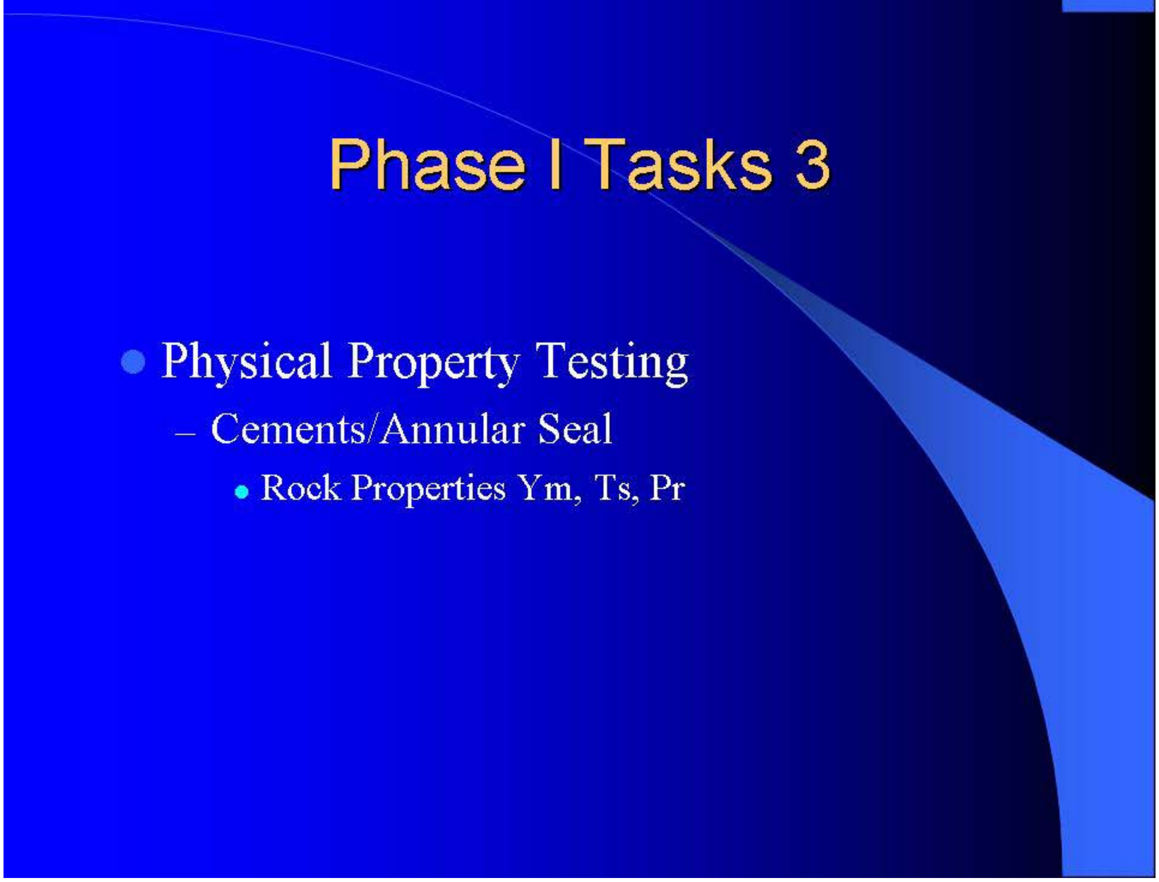
Project Budget

- Phase 1 $69,294 ($1,250)
- Phase 2 $139,287 ($1,200)
- Phase 3 $152,259 ($380,000)
- Phase 4 $67,406 (0)
- **Total $427,246 ($382,450)**

Phase I Tasks 1

- Literature Review of Low-Perm Operations
  - Zonal isolation
  - Formation damage
  - Stimulation
  - Fracture propagation


Phase I Tasks 2
Data Gathering
– Rock properties
– Production


Phase I Tasks 3
Physical Property Testing
– Cements/Annular Seal
Rock Properties Ym, Ts, Pr

Phase II

- Modeling Hydraulic Seal of Cemented Annulus
  - Physical
  - Numerical
    - University of Houston

Phase III

- Phase IV—Field Trials: Application of results from first three phases (3 wells)
  - Task 1 Decision Matrix
  - Task 2 Cementing Treatments
  - Task 3 Cementing Evaluation
  - Task 4 Stimulation Treatment
  - Task 5 Stimulation Evaluation
  -

Phase IV

- Develop Tech Transfer Materials
  - Tech Transfer Documents
  - Workshop Development
  - Joint PTTC workshops

Proposal

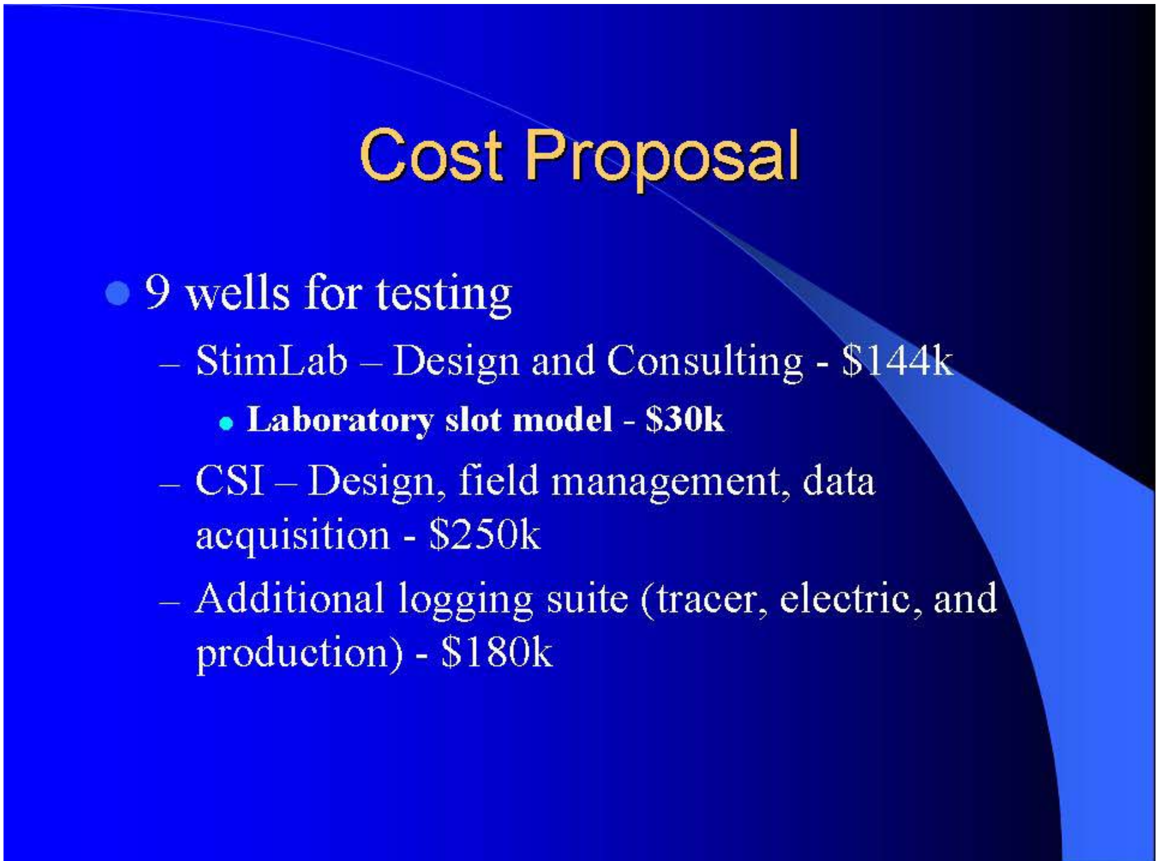
- Significant discoveries
  - Cementing/Stimulation
- HEP Oil is ecstatic about findings to date
  - Willing to commit up to 12 additional wells for research
  - Additional research will profoundly impact the Barnett Shale production

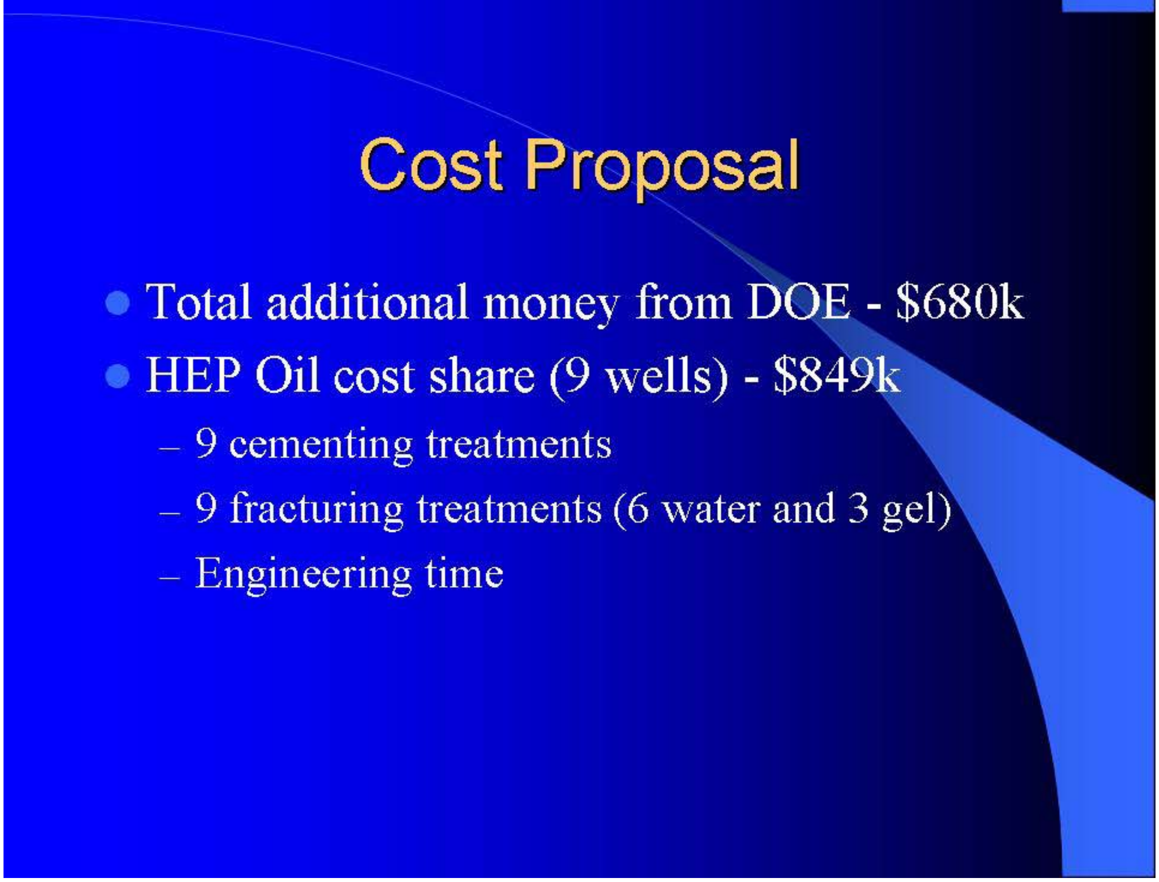
Proposal

- Expand project for the evaluation of Cementing and Stimulation:
- Concepts
  - **1. Optimize the cementing of production or upper boundary**
  - **2. Optimizing fracture treatment size and amount of proppant and type of job**
  - **2. Optimize production methods**
  - **3. Three distinct regions of the Barnett Shale**

Methods

- **Cementing Compositions and Placement optimization**
- **Frac**
  - **High Water Fracs with High Proppant concentrations**
  - **Gel Fracs**
  - **Injection/fall-off treatments**
- **Completion methods**
  - **Plungers/pump**
  - **3D fracture design GOHFER**
- **Production Protocols**


Cost Proposal
9 wells for testing
– StimLab – Design and Consulting - $144k
Laboratory slot model - $30k
– CSI – Design, field management, data acquisition - $250k
– Additional logging suite (tracer, electric, and production) - $180k


Cost Proposal
Total additional money from DOE - $680k
HEP Oil cost share (9 wells) - $849k
– 9 cementing treatments
– 9 fracturing treatments (6 water and 3 gel)
– Engineering time

How do we proceed?

DOE Low Perm – Slurry Compositions

Baseline System

- Class H Cement + 0.48% Natrosol 250 + 0.32% Melcret + 0.15% Marabond 21 mixed with 4.23 gal/sk Water at 16.4ppg (1.06 cuft/sk)

Foam System

- Type I Cement + 0.03gal/sk Witcolate + 0.02gal/sk Aromox C-12 + 0.50% Natrosol 250 + 0.30% Marabond 21 mixed with 5.04gal/sk Water at 13.5ppg(1.18cuft/sk)

Latex System

- Type I Cement + 1.0gal/sk LT- D500 +0.50% Marabond 21 mixed with 4.2ppg Water at 15.8ppg(1.18cuft/sk)

DOE Low Permeability - Testing Summary

Conventional Testing				
Slurry Type	**Density(ppg)**	**Fluid Loss**	**Thickening Time(hh:mm)**	**10 Day Compressive Strength(psi)**
Baseline	16.4	62	4:02	4035
Foam	13.5	219	3:15	3436
Latex	15.8	24	6:09	3630

Tensile Strength(psi)		Young's Modulus			Poisson's Ratio
Slurry System		**PC0**	**PC250**	**PC500**	
Baseline	673	$1.3e^{6}$	$1.4e^{6}$	$1.0e^{6}$	
Foam	578	$7.9e^{5}$	$7.6e^{5}$	$7.2e^{5}$	
Latex	504	$5.6e^{5}$	$8.9e^{5}$	$9.4e^{5}$	
Baseline with Fibers	930				

DOE Low Permeability - Testing Summary (Continued)

	Shear Bond Strength(psi)				
Configuration	**Slurry System**	**Sample 1**	**Sample 2**	**Sample 3**	**Average**
Pipe-in-Pipe	Baseline	663	555	341	520
Pipe-in-Pipe	Foam	362	281	321	321
Pipe-in-Pipe	Latex	489	495	311	432
Pipe-in-Pipe	Baseline w/ Fibers	403	327	408	379
Pipe-in-Soft	Baseline	229	177	N/A	203
Pipe-in-Soft	Foam	174	129	139	147
Pipe-in-Soft	Latex	223	233	254	237
Pipe-in-Soft	Baseline w/ Fibers	233	320	213	277

Hydraulic Seal Tests/Cement

Frac - Modeling		
Slurry System	**Failure Pressure**	**Resulting Flow Rate**
Baseline	833 psi	3.9 mL/ second
Foam	-	-
Latex	-	-
Baseline with Fibers	-	-

Appendix VII

Technology Transfer Package

Part A – Cementing

Optimizing Production in Low Perm Reservoirs

- Objectives

1. Develop methodologies to assure competent annular seal in tight gas formations, subject to multiple hydraulic fracturing treatments
2. Develop stimulation methodologies to optimize production from tight gas reservoirs

CSI Technologies

Optimizing Production in Low Perm Reservoirs

- Approach & Conclusion

1. Field studies
2. Pre-project theory – with natural frac barriers, cementing is unimportant
3. Conclusion – cementing is important for optimal zonal stimulation

CSI Technologies

Low Perm Reservoir Cementing: Energy Methodology

- Energy is applied to the pipe / cement / formation system via intervention and production operations
- Energy is resisted by the pipe / cement / formation system mechanical properties

CSI Technologies

Low Perm Reservoir Cementing: Energy Methodology

- Lab correlations between dimensionless factors E1A (applied energy factor) and E1R (resistive energy factor) generate a cement failure curve
- Correlation represents likelihood of annular seal failure or success

CSI Technologies

Low Perm Reservoir Cementing: Energy Methodology

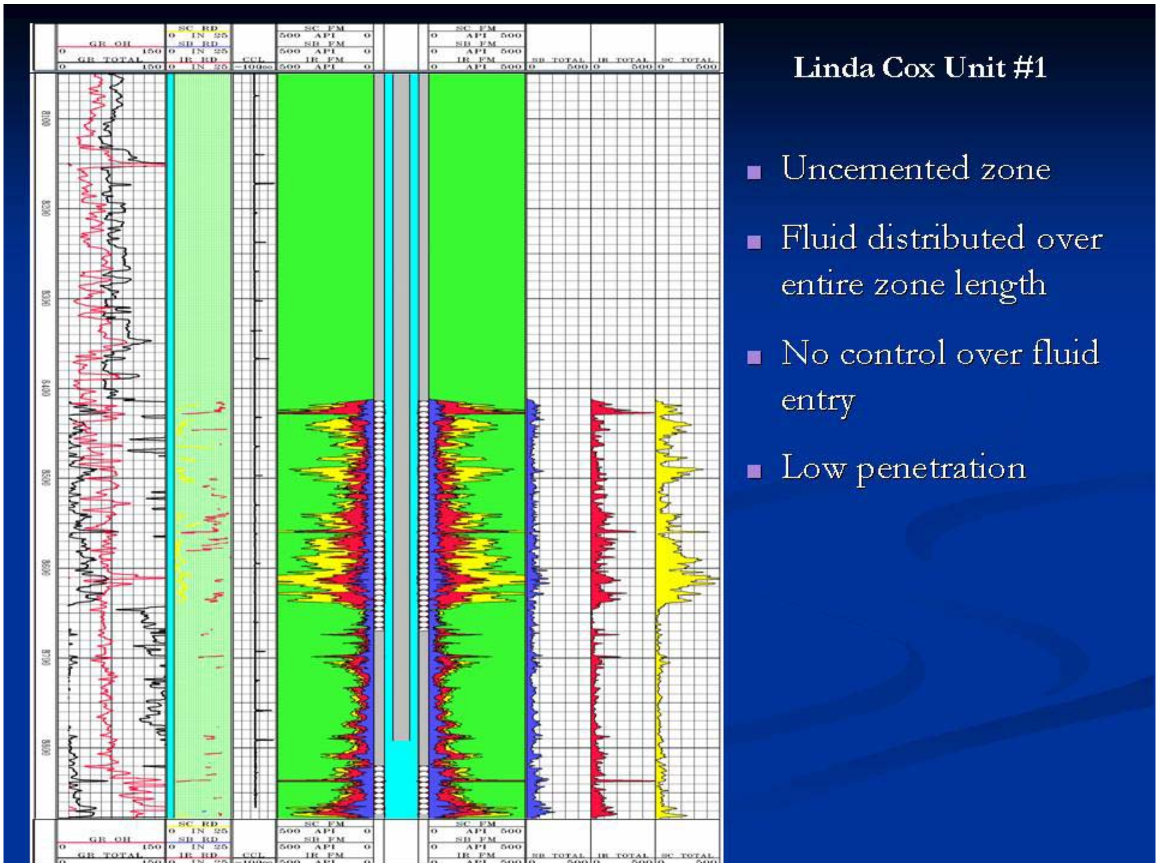
- Calculate minimum-acceptable dimensionless factor E1C, from applied energy vs resisted energy analysis
  - Minimum E1C based on calculated applied energy factor E1A and correlated E1R
  - E1C strips out all but cement properties factors
  - E1C = TS / (YM * AS)
  - Ranges of TS, YM, and AS can be acceptable
    - Calculated values are minimums (TS) or maximums (YM & AS).
    - Success in the well depends on probabilities
    - Exceeding maximums and minimums by a margin give greater confidence of success

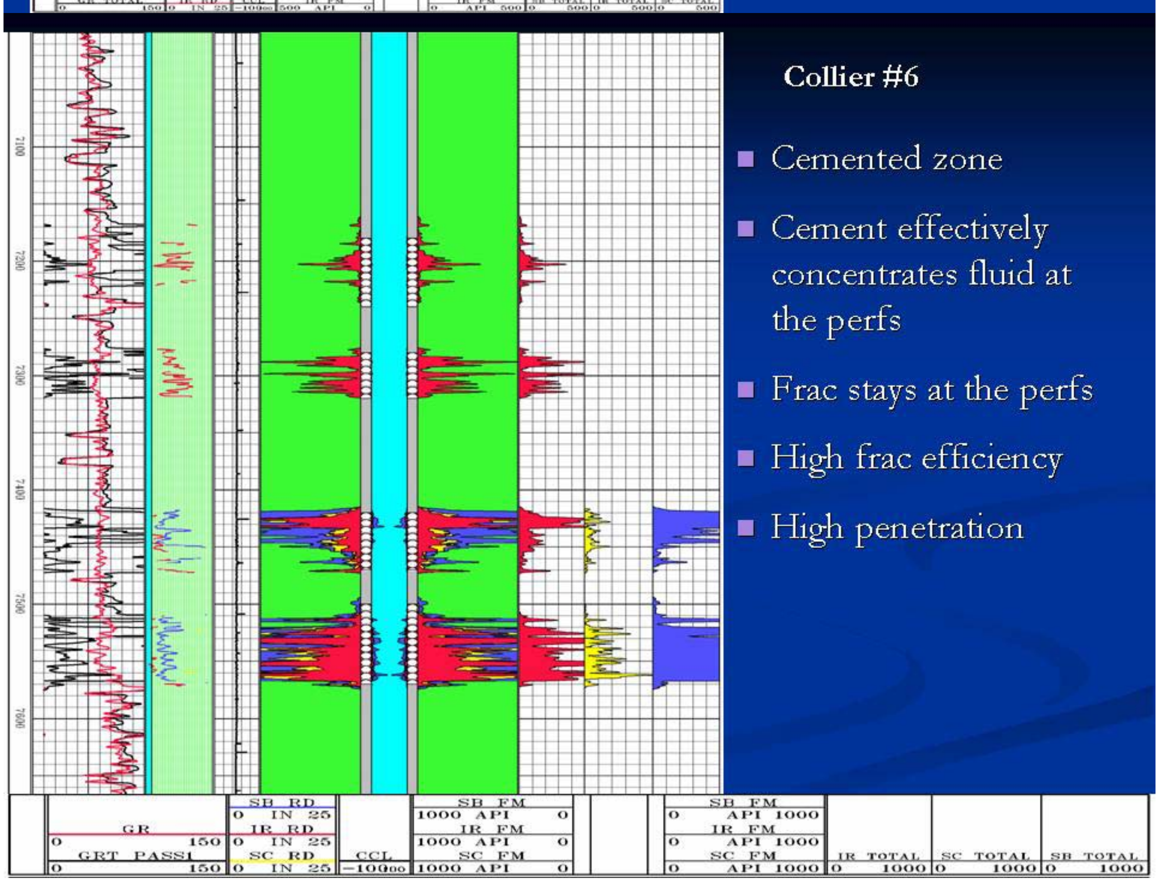
CSI Technologies

Low Perm Reservoirs: Cementing the Bottom Zone

- Studies in the Barnett Shale clearly show improved fracture efficiency with well-cemented pipe
  - Clearly-defined frac tops and bottoms
  - Cement concentrates fluid at the perfs
  - Improved penetration due to reduced fluid losses

CSI Technologies


Linda Cox Unit #1
Uncemented zone
Fluid distributed over entire zone length
No control over fluid entry
Low penetration


Collier #6
Cemented zone
Cement effectively concentrates fluid at the perfs
Frac stays at the perfs
High frac efficiency
High penetration

Low Perm Reservoirs: Guidelines for Cementing Lower Zone

- System approach – Pipe / Cement / Formation
  - Pipe shields cement from destructive stresses
  - Formation supports cement during frac stress
- Cement Property Requirements Guidelines:
  - TS, YM, AS determined by Energy Analysis
  - Maximize shear bond
  - Maximize toughness

CSI Technologies

Low Perm Reservoirs: Guidelines for Cementing Lower Zone

- Single frac pressure history relaxes cement property requirements
  - Moderate tensile strength
  - Young's Modulus lower than formation
  - Higher anelastic strain can be tolerated
  - High shear bond

CSI Technologies

Low Perm Reservoirs: Uphole Cementing

- Multiple frac jobs accumulate damage in uphole cement jobs
- Multiple frac jobs dramatically increase the demands on cement properties
- Energy analysis should be used to help determine casing design
- Uphole cement integrity, casing design, and frac strategy should all be considered in the design of the well

CSI Technologies

Low Perm Reservoirs: Uphole Cementing - Example

Zone	*Frac Press*	*Energy In-lb x 10^9*	*Max Cmt YM, ksi*	*Min Cmt TS, psi*	*Max Cmt AS x 10^{-9}*
1	8,500	2.00	100	153	200.00
2	8,200	3.93	100	190	30.00
3	8,000	5.82	100	259	12.00
4	7,700	7.63	100	303	6.00
5	7,500	9.4	100	363	3.75

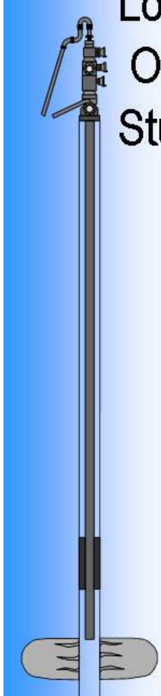
CSI Technologies

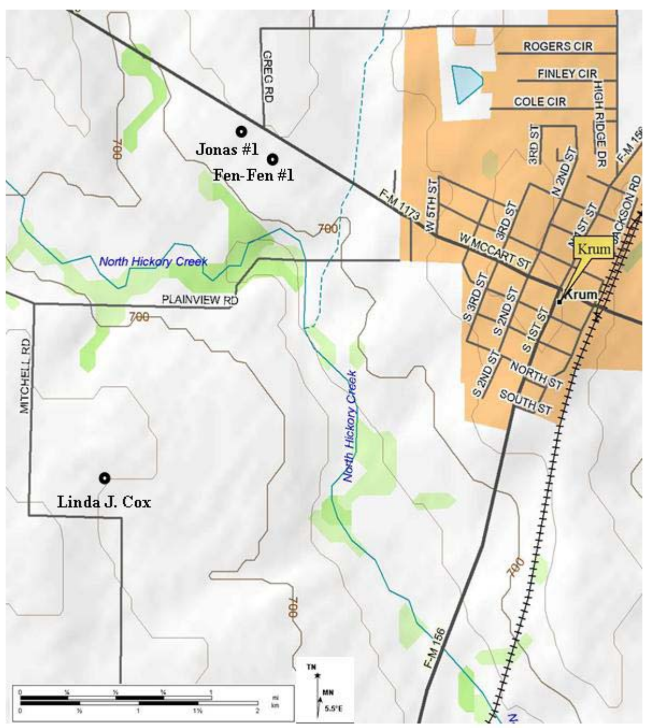
Barnett Shale Completions:
Zone Isolation and Fracture Growth

Michael W. Conway
Stim-Lab, Inc.

Stim-Lab
A CORE LABORATORIES COMPANY

Location of Original Study Wells



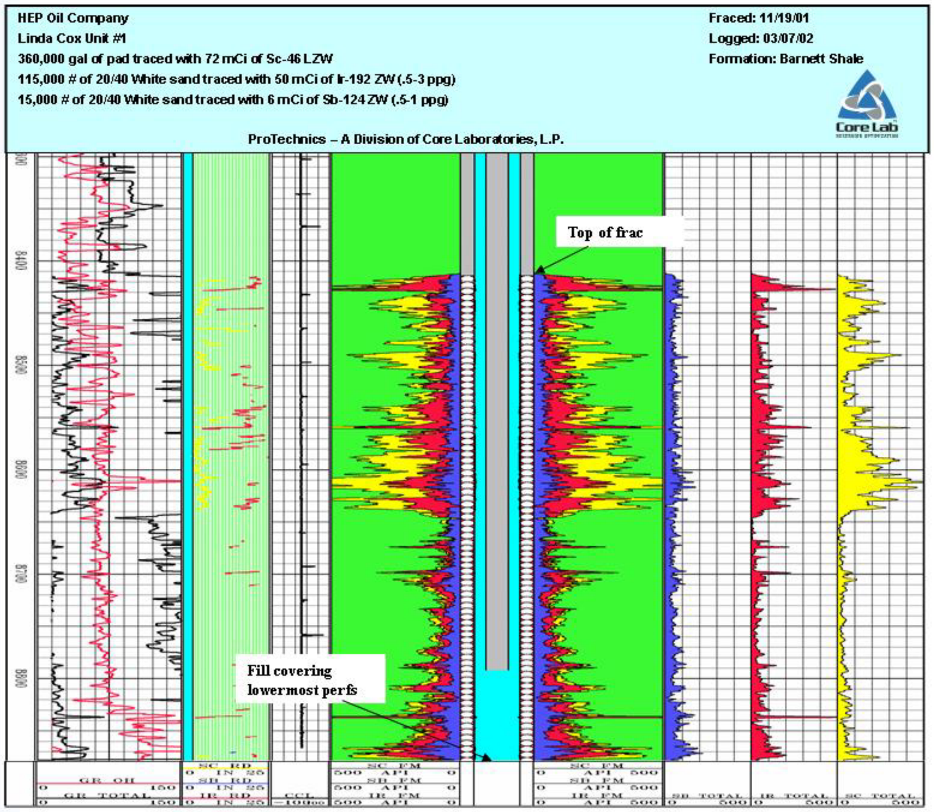


Study Area 1: Krum Area Wells

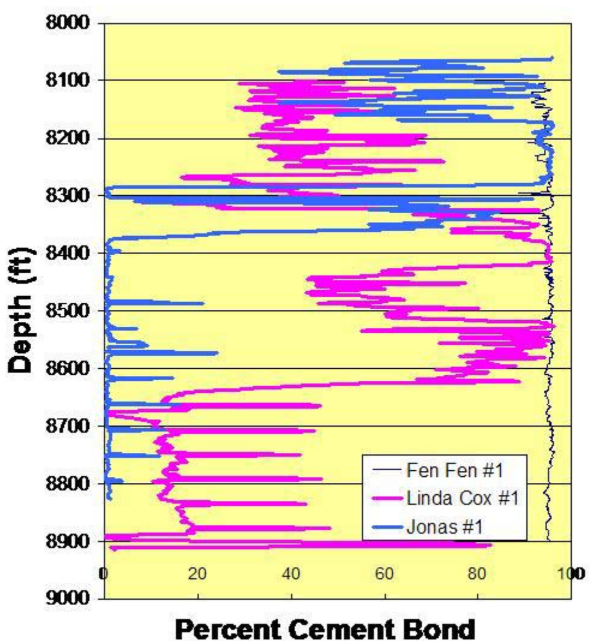
- Linda Cox #1 (11/19/01)
  - Cement basket set at 8400' in lower Barnett
  - Cement dropped below basket
  - Perforated 8414 – 8910' and fractured the lower Barnett with a perforated, uncemented liner
  - Perforated 7940-8120'; 8135-8150' and fractured upper Barnett
- Fen-Fen #1 (12/14/01)
  - Cemented Casing
  - Perforated 8445 – 8870' and fractured lower Barnett
  - Perforated 7780-8080' and fractured upper Barnett
- Jonas #1 (3/27/02)
  - Cement basket set at 8343' in lower Barnett
  - Perforated 8460-8860' and fractured the lower Barnett with a perforated, uncemented liner

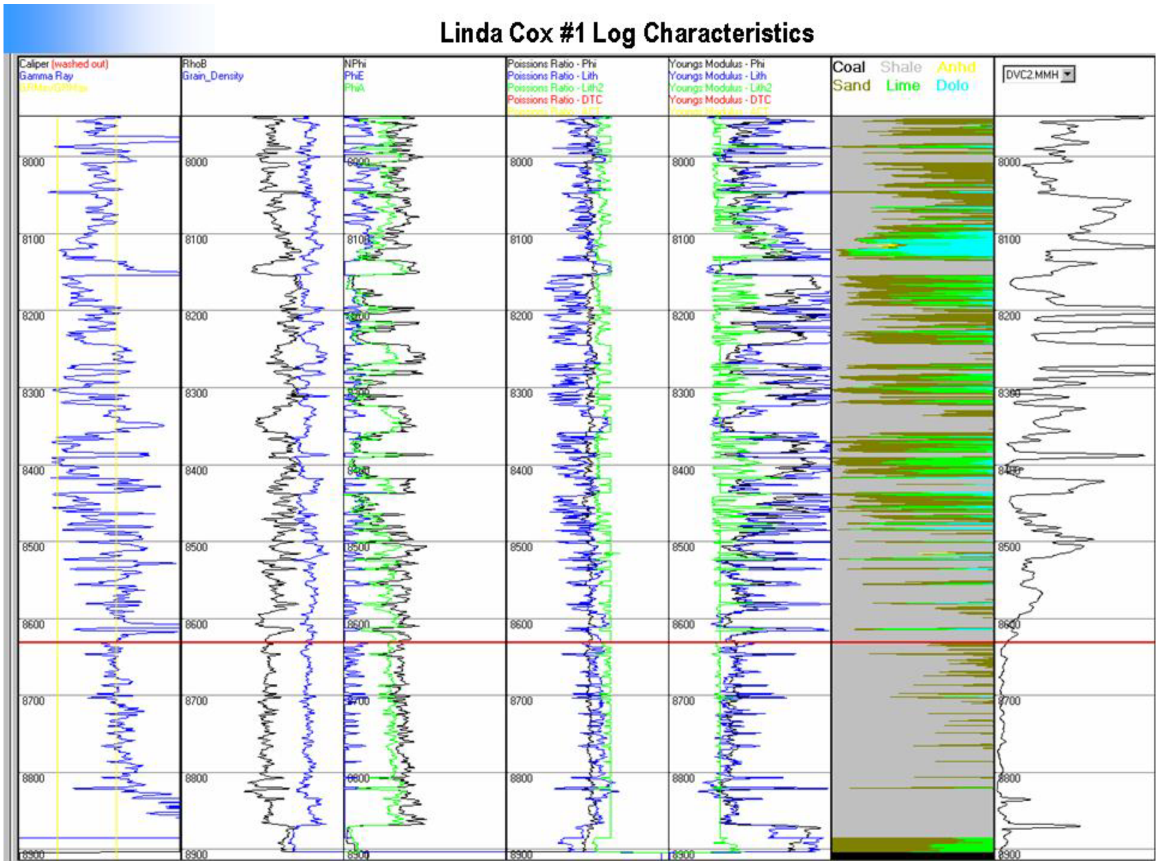
Chronology of Investigational Approach to Understand Fracture Geometry

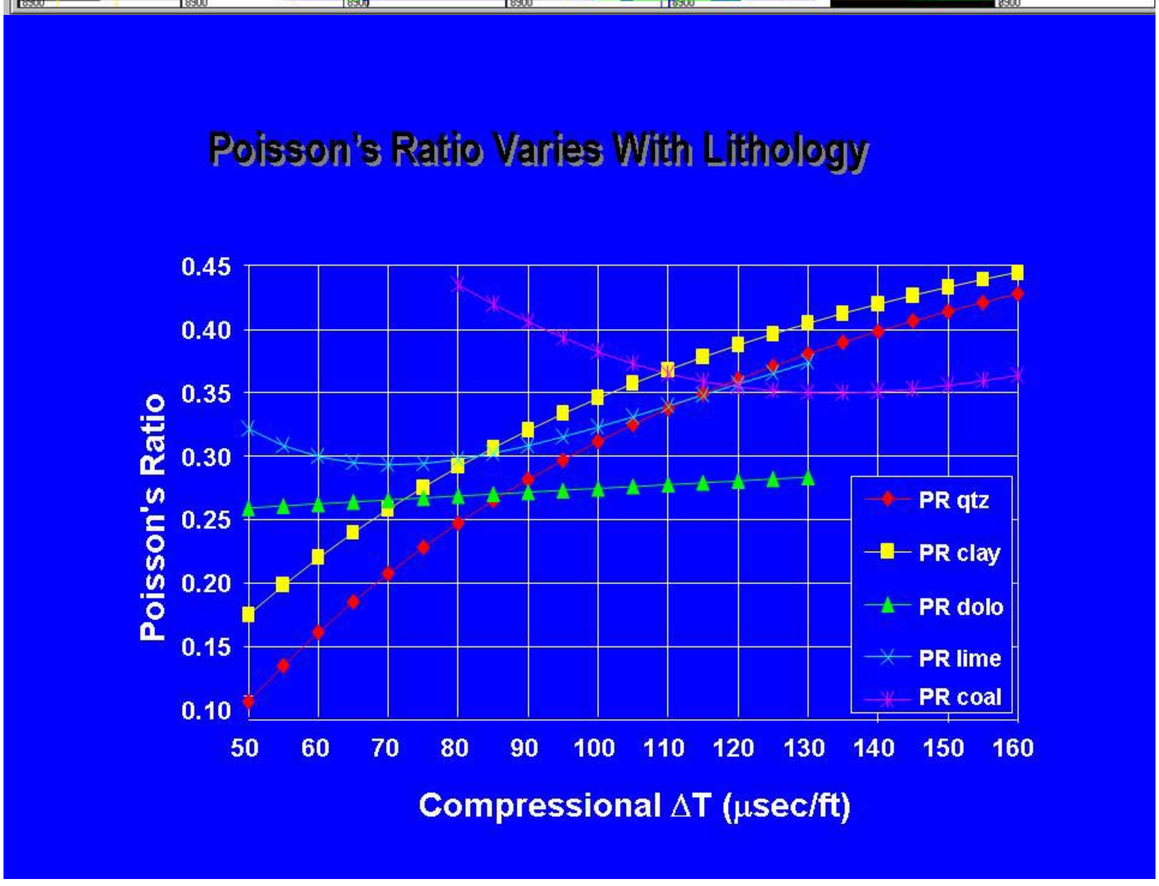
- The Linda Cox #1 was the most data rich well in the group
- A tracer log had been run which was the starting point for describing the fracture geometry in the uncemented wellbore's

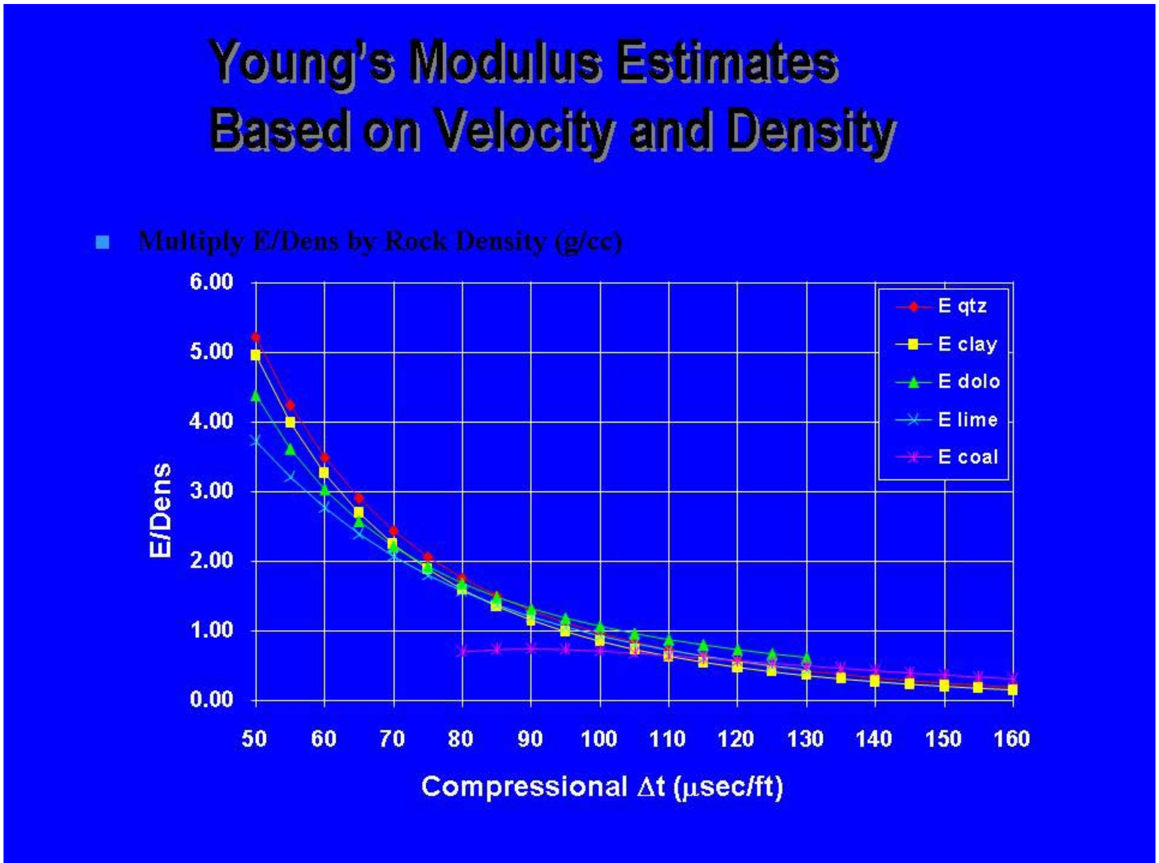


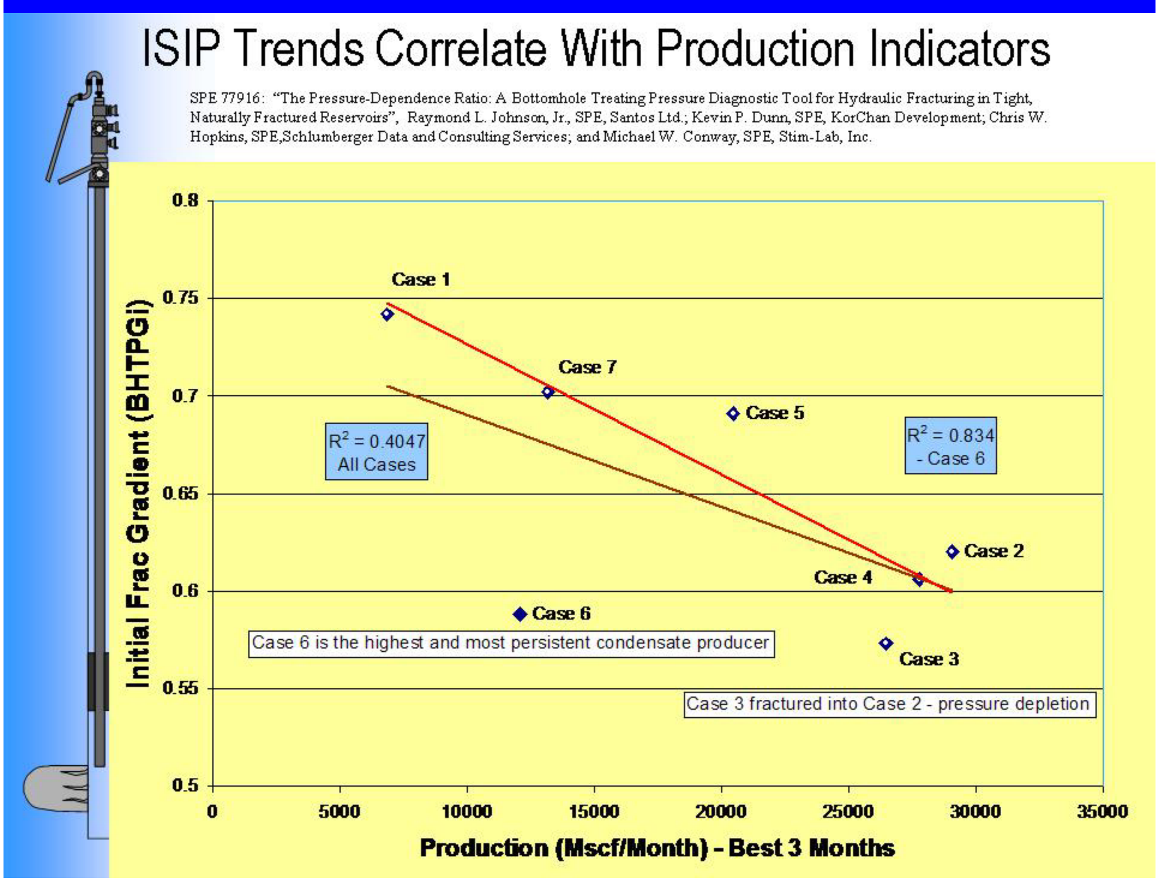
Cement Bond Logs in Study Wells




Linda Cox #1 Log Characteristics
Caliper (washed out)
Gamma Ray
RhoB
Grain_Density
NPhi
PhiE
PhiA
Poissons Ratio - Phi
Poissons Ratio - Lith
Poissons Ratio - Lith2
Poissons Ratio - DTC
Youngs Modulus - Phi
Youngs Modulus - Lith
Youngs Modulus - Lith2
Youngs Modulus - DTC
Coal
Shale
Anhd
Sand
Lime
Dolo
DVC2.MMH
8000
8100
8200
8300
8400
8500
8600
8700
8800
8900


Poisson's Ratio Varies With Lithology
Poisson's Ratio
0.45
0.40
0.35
0.30
0.25
0.20
0.15
0.10
50
60
70
80
90
100
110
120
130
140
150
160
Compressional ΔT (μsec/ft)
PR qtz
PR clay
PR dolo
PR lime
PR coal

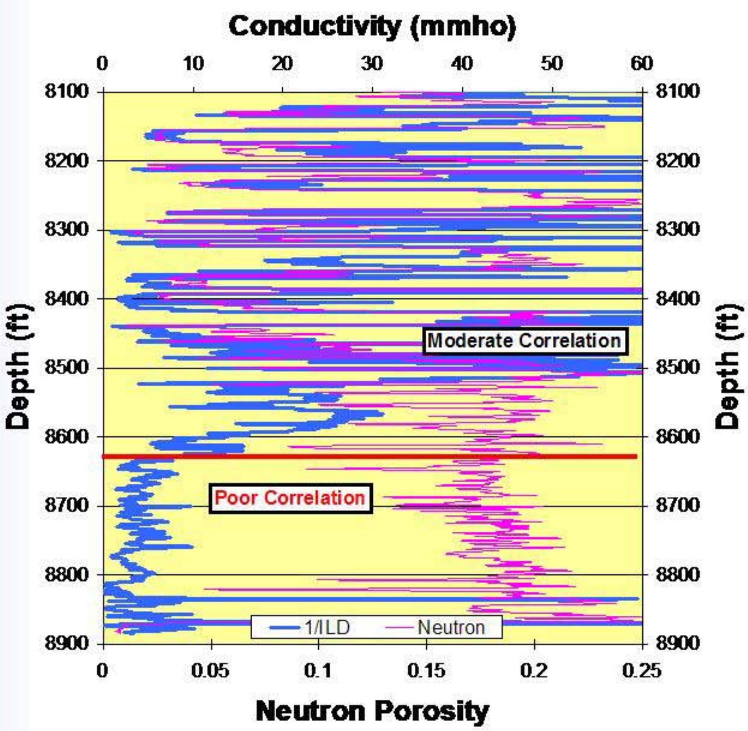

Young's Modulus Estimates
Based on Velocity and Density
Multiply E/Dens by Rock Density (g/cc)
E/Dens
6.00
5.00
4.00
3.00
2.00
1.00
0.00
50
60
70
80
90
100
110
120
130
140
150
160
Compressional Δt (μsec/ft)
E qtz
E clay
E dolo
E lime
E coal


ISIP Trends Correlate With Production Indicators
SPE 77916: "The Pressure-Dependence Ratio: A Bottomhole Treating Pressure Diagnostic Tool for Hydraulic Fracturing in Tight, Naturally Fractured Reservoirs", Raymond L. Johnson, Jr., SPE, Santos Ltd.; Kevin P. Dunn, SPE, KorChan Development; Chris W. Hopkins, SPE,Schlumberger Data and Consulting Services; and Michael W. Conway, SPE, Stim-Lab, Inc.
Initial Frac Gradient (BHTPGi)
0.8
0.75
0.7
0.65
0.6
0.55
0.5
0
5000
10000
15000
20000
25000
30000
35000
Production (Mscf/Month) - Best 3 Months
Case 1
Case 7
Case 5
Case 2
Case 4
Case 6
Case 3
R² = 0.4047
All Cases
R² = 0.834
- Case 6
Case 6 is the highest and most persistent condensate producer
Case 3 fractured into Case 2 - pressure depletion

Frac Gradients in Krum Area

Well	Initial FG	Final FG
Linda Cox #1: Lower Barnett	0.67	0.73
Linda Cox #1: Upper Barnett		0.82
Fen-Fen #1: Lower Barnett	0.68	0.69
Fen-Fen #1: Upper Barnett	0.70	0.71
Jonas #1: Lower Barnett		0.71

Linda Cox #1 Neutron and Conductivity Correlation



Results from Fracture Mapping: Vertical Growth in Lower Barnett

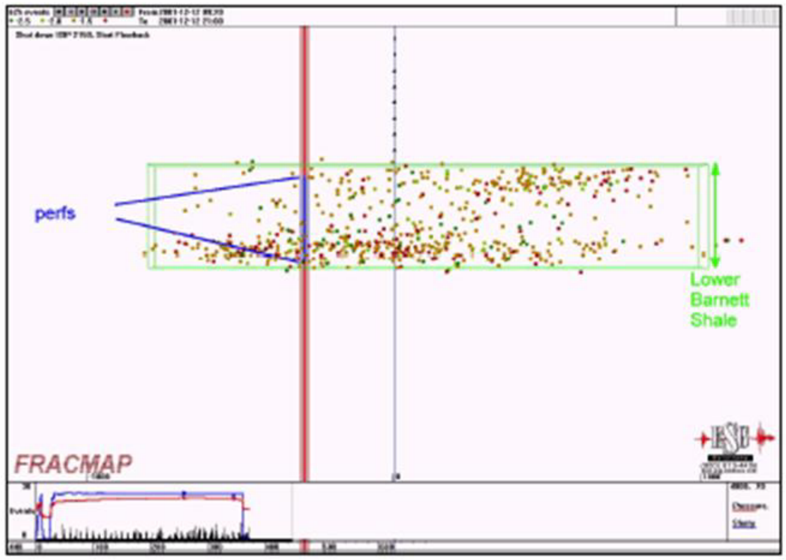
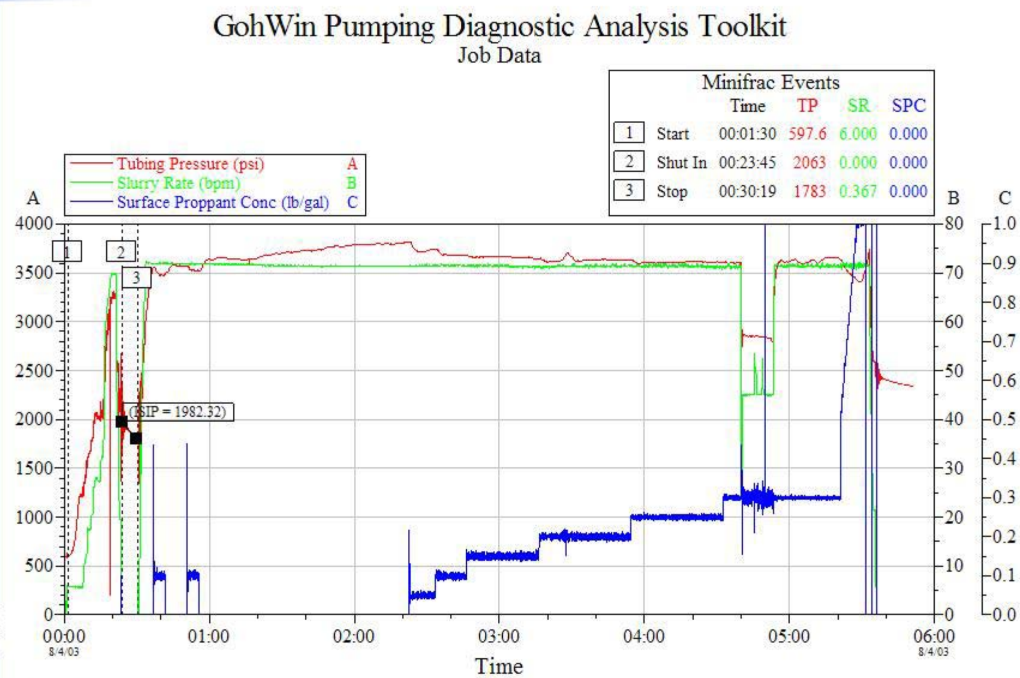


Figure 9. Longitudinal section of a stimulation in the Lower Barnett. Reference on the next slide.

Fracture Stimulation Treatment in the Lower Barnett in the Linda Cox #1

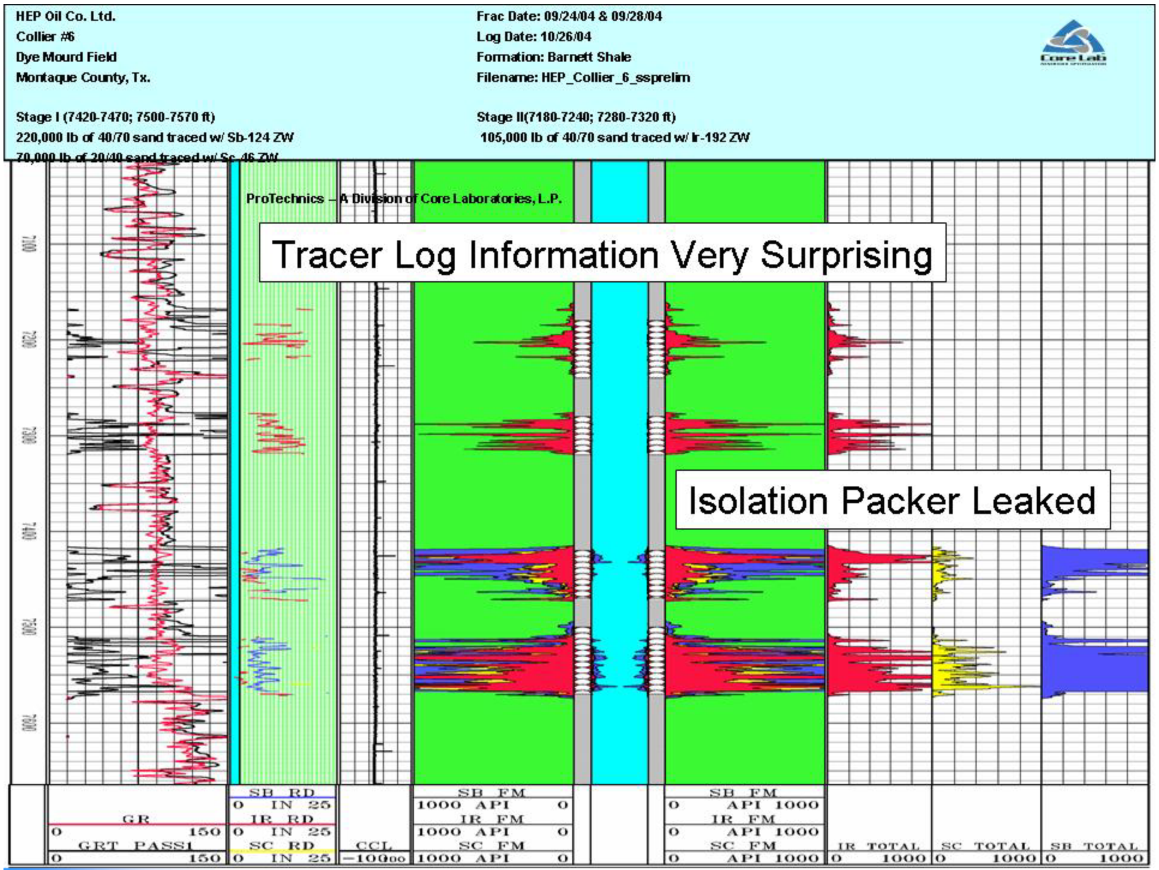


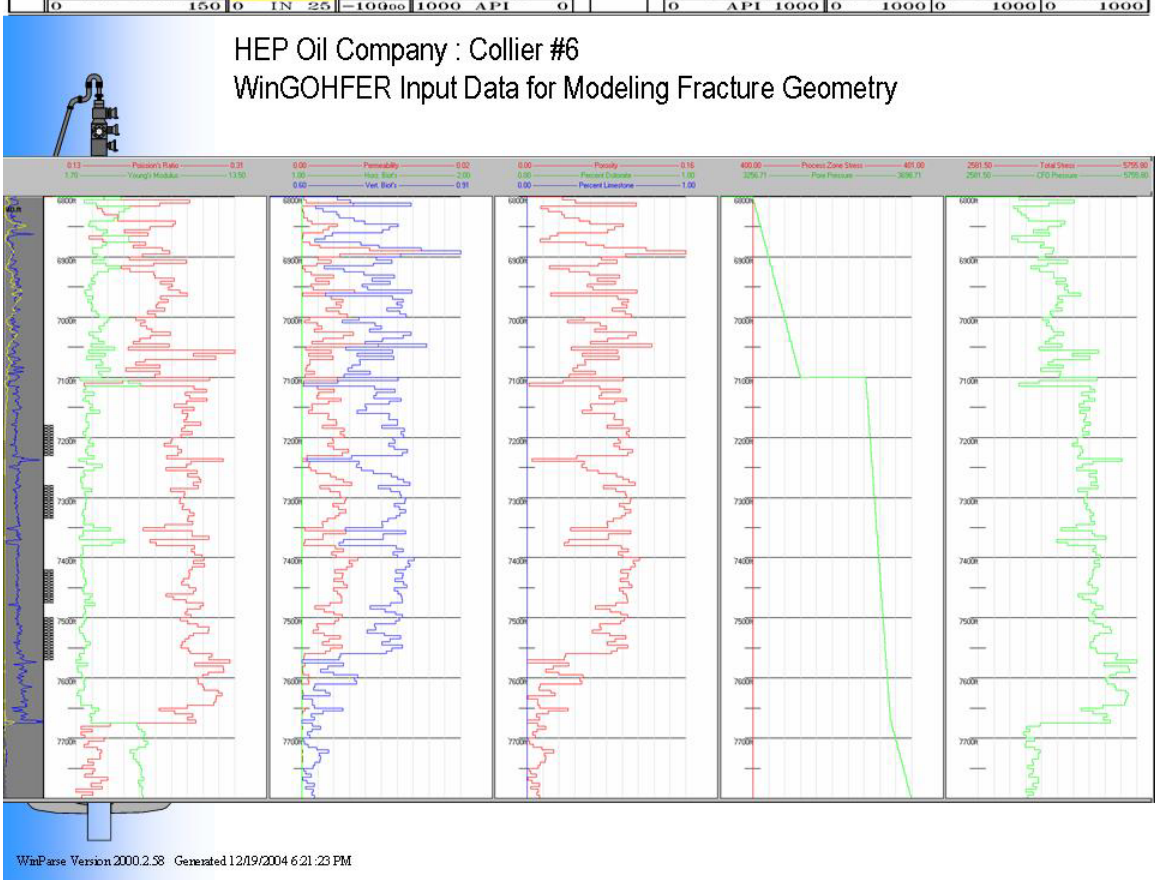
Summary of Analysis

- This group of 3 wells have similar permeability and fracture length characteristics in the Barnett
  - Pseudo radial flow was not developed because of the small effective drainage area
- It is easy to conclude that cementing practices did not materially affect the well producibility
  - Apparent fracture top could easily occur in the same equivalent cemented interval in all wells
  - Similar zones perforated in all wells
- Production characteristics suggest that there could be value to targeted completions but there was no data available that suggest that it has been seriously attempted, at least in this area when these wells were completed in early 2002

New Trends in Barnett Shale Completions

- Microseism and tracer logging in many parts of the Barnett concluded:
  - *Significant intervals in the perforated zone were being missed in many wells*
- Staged treatments are currently being explored in the Lower Barnett
- Smaller proppant is being utilized
  - Some operators claim better production by increasing the amount of proppant used in the treatments
- The Collier #6 was completed in 2004
  - Cemented
  - Two stage treatment in Lower Barnett with 4 sets of perforations
  - Sonic and triple combo logs were run
  - Treatments were traced with radioactive tracer


HEP Oil Co. Ltd.
Collier #6
Dye Mourd Field
Montaque County, Tx.
Frac Date: 09/24/04 & 09/28/04
Log Date: 10/26/04
Formation: Barnett Shale
Filename: HEP_Collier_6_ssprelim
Stage I (7420-7470; 7500-7570 ft)
220,000 lb of 40/70 sand traced w/ Sb-124 ZW
70,000 lb of 20/40 sand traced w/ Sc-46 ZW
Stage II(7180-7240; 7280-7320 ft)
105,000 lb of 40/70 sand traced w/ Ir-192 ZW
ProTechnics – A Division of Core Laboratories, L.P.
Tracer Log Information Very Surprising
Isolation Packer Leaked
GR
0 150
GRT PASS1
0 150
SB RD
0 IN 25
IR RD
0 IN 25
SC RD
0 IN 25
CCL
-10 0
SB FM
1000 API 0
IR FM
1000 API 0
SC FM
1000 API 0
SB FM
0 API 1000
IR FM
0 API 1000
SC FM
0 API 1000
IR TOTAL
0 1000
SC TOTAL
0 1000
SB TOTAL
0 1000


HEP Oil Company : Collier #6
WinGOHFER Input Data for Modeling Fracture Geometry
WinParse Version 2000.2.58 Generated 12/19/2004 6:21:23 PM

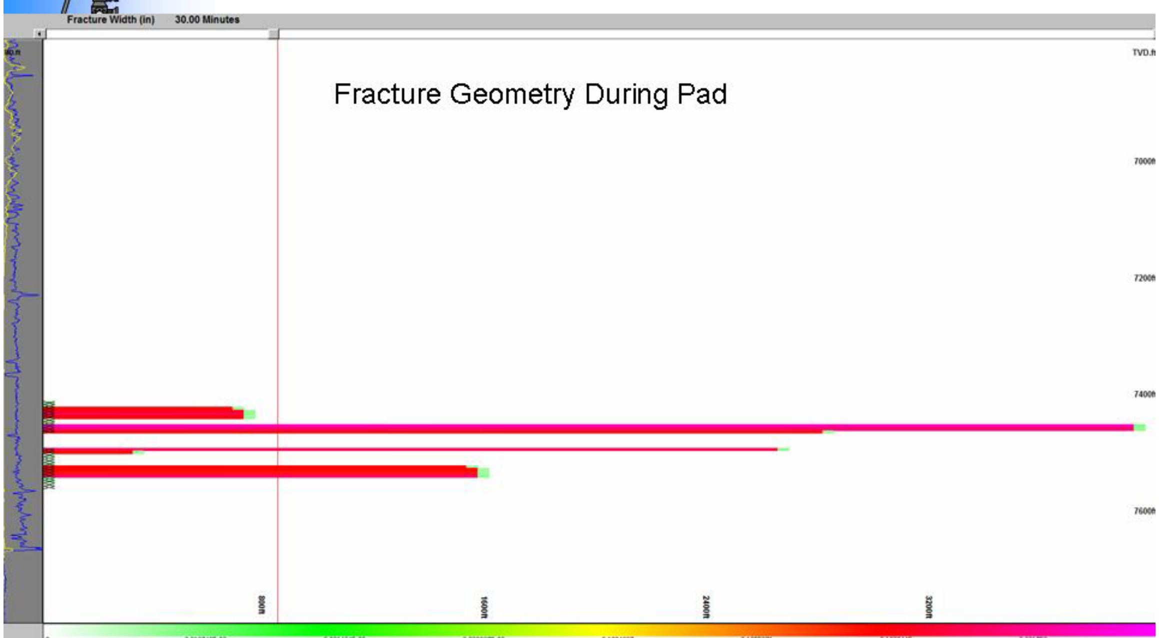
HEP Oil Company : Collier #6
WinGOHFER Design Pumping Schedule

The initial attempt to understand geometry was to simulate approximately 1/10 of the treatment with the schedule shown below

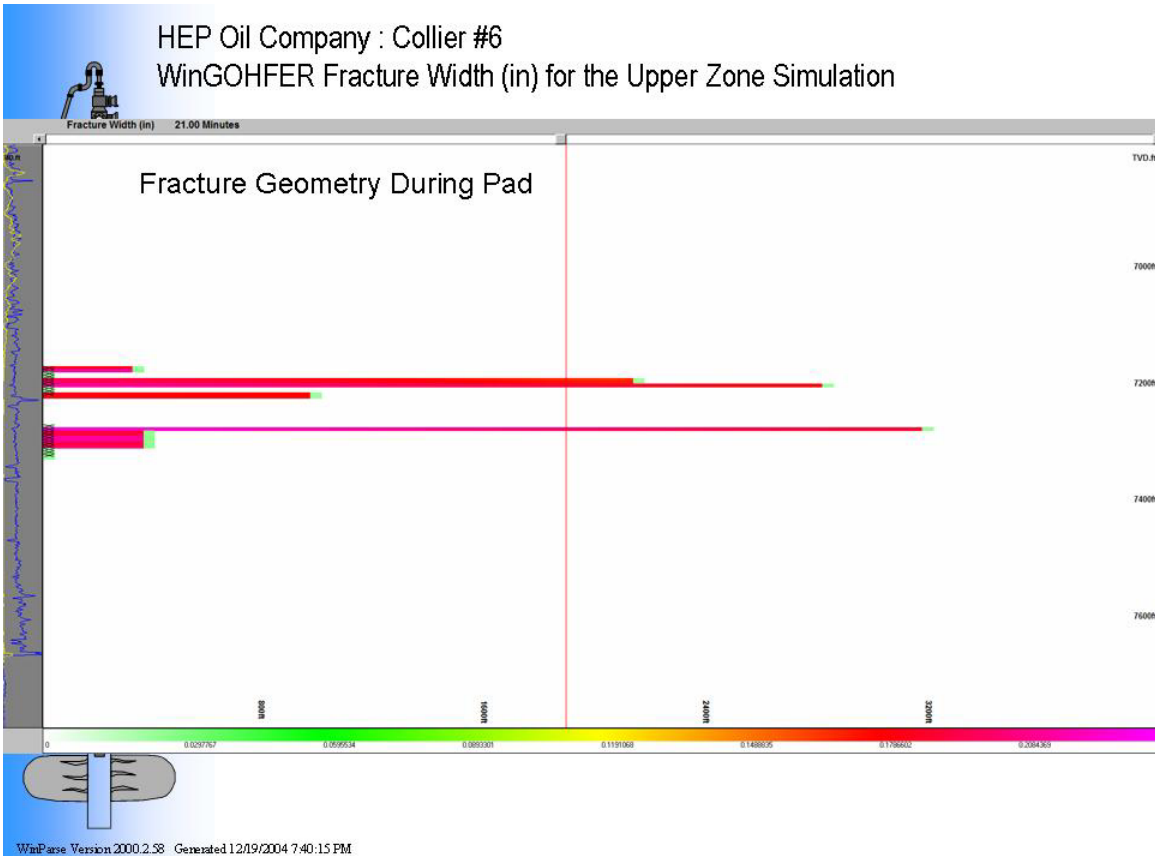
Wellbore Design	Prop. Name	Prop Conc. (lb/gal)	Clean Vol. (gal)	Fluid Name	Slurry Rate (bpm)	Acid Type	% Acid	Dirty Vol. (gal)	Stage Time (min)	Cum. Time (min)	Cum. Slurry (gal)	Cum. Clean (gal)	Stage Prop. (lb)	Cum. Prop. (lb)	N2 Quality	N2 Quality
1	Brady Sand 40/60	0.00	3000.00	2%KCL Slick Water_180_0_3000 psi_0	40.00	NONE	0.00	3000.00	1.79	1.79	3000.00	3000.00	0.00	0.00	0.00	0.00
2	Brady Sand 40/60	0.00	12000.00	2%KCL Slick Water_180_0_3000 psi_0	75.00	NONE	0.00	12000.00	3.81	5.60	15000.00	15000.00	0.00	0.00	0.00	0.00
3	Brady Sand 40/60	0.00	50000.00	2%KCL Slick Water_180_0_3000 psi_0	75.00	NONE	0.00	50000.00	15.87	21.47	65000.00	65000.00	0.00	0.00	0.00	0.00
4	Brady Sand 40/60	0.10	20000.00	2%KCL Slick Water_180_0_3000 psi_0	75.00	NONE	0.00	20090.78	6.38	27.85	85090.78	85000.00	2000.00	2000.00	0.00	0.00
5	Brady Sand 40/60	0.20	20000.00	2%KCL Slick Water_180_0_3000 psi_0	75.00	NONE	0.00	20181.56	6.41	34.25	105272.30	105000.00	4000.00	6000.00	0.00	0.00
6	Brady Sand 40/60	0.30	20000.00	2%KCL Slick Water_180_0_3000 psi_0	75.00	NONE	0.00	20272.33	6.44	40.69	125544.60	125000.00	6000.00	12000.00	0.00	0.00
7	Brady Sand 40/60	0.40	20000.00	2%KCL Slick Water_180_0_3000 psi_0	75.00	NONE	0.00	20363.11	6.46	47.15	145907.70	145000.00	8000.00	20000.00	0.00	0.00
8	Brady Sand 40/60	0.00	30.00	2%KCL Slick Water_180_0_3000 psi_0	0.00	NONE	0.00	30.00	30.00	77.15	145937.70	145030.00	0.00	20000.00	0.00	0.00
Totals:			145030.00					145937.80					20000.00			

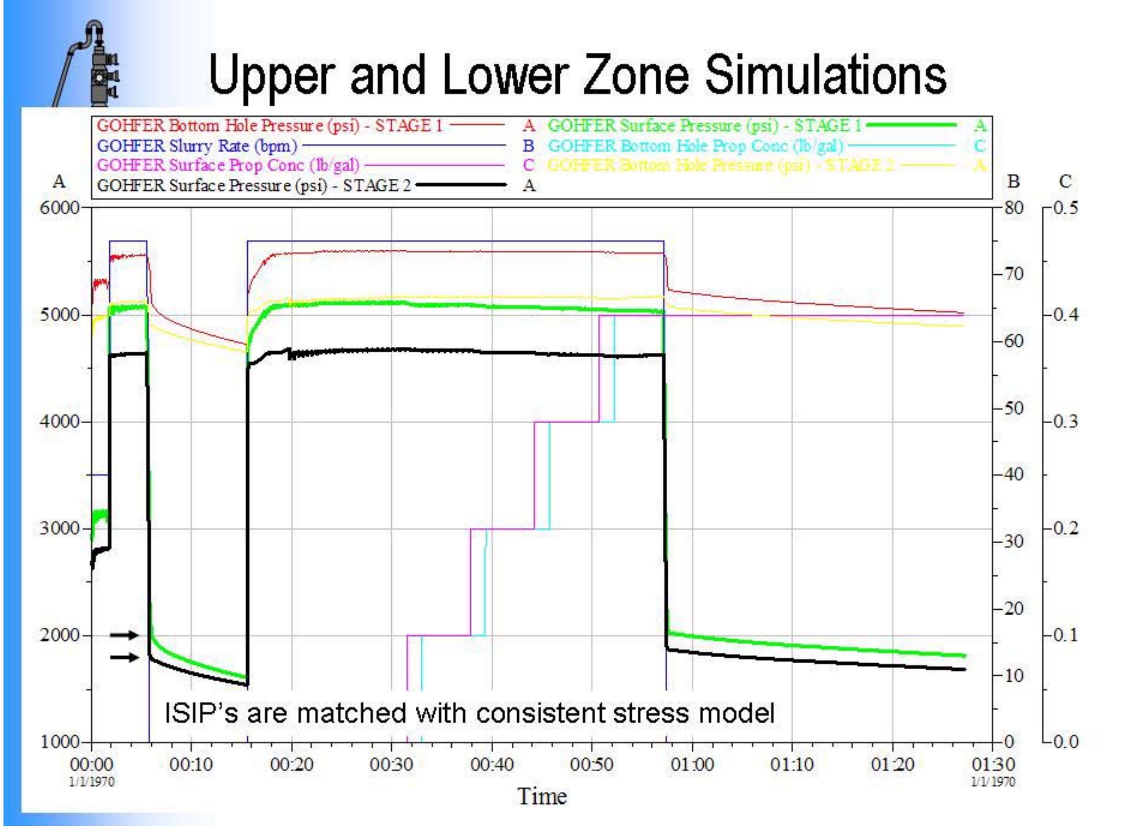
WinParse Version 2000.2.58 Generated 12/19/2004 6:21:37 PM

HEP Oil Company : Collier #6
WinGOHFER Fracture Width (in) for the Lower Zone Simulation



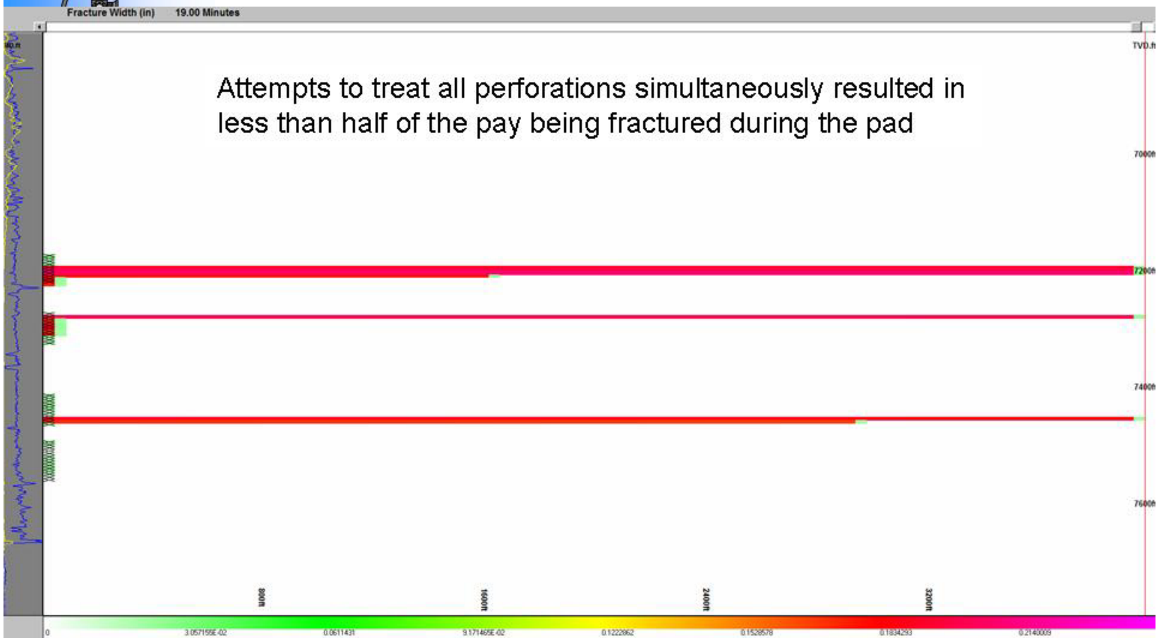
WinParse Version 2000.2.58 Generated 12/19/2004 7:42:34 PM


HEP Oil Company : Collier #6
WinGOHFER Fracture Width (in) for the Upper Zone Simulation
Fracture Width (in) 21.00 Minutes
Fracture Geometry During Pad
TVD,ft
7000ft
7200ft
7400ft
7600ft
800ft
1600ft
2400ft
3200ft
WinParse Version 2000.2.58 Generated 12/19/2004 7:40:15 PM


Upper and Lower Zone Simulations
GOHFER Bottom Hole Pressure (psi) - STAGE 1 A
GOHFER Slurry Rate (bpm) B
GOHFER Surface Prop Conc (lb/gal) C
GOHFER Surface Pressure (psi) - STAGE 2 A
GOHFER Surface Pressure (psi) - STAGE 1 A
GOHFER Bottom Hole Prop Conc (lb/gal) C
GOHFER Bottom Hole Pressure (psi) - STAGE 2 A
A
B
C
ISIP's are matched with consistent stress model
Time
1/1/1970

HEP Oil Company : Collier #6

WinGOHFER Fracture Width (in)



WinParse Version 2000.2.58 Generated 12/19/2004 8:15:55 PM

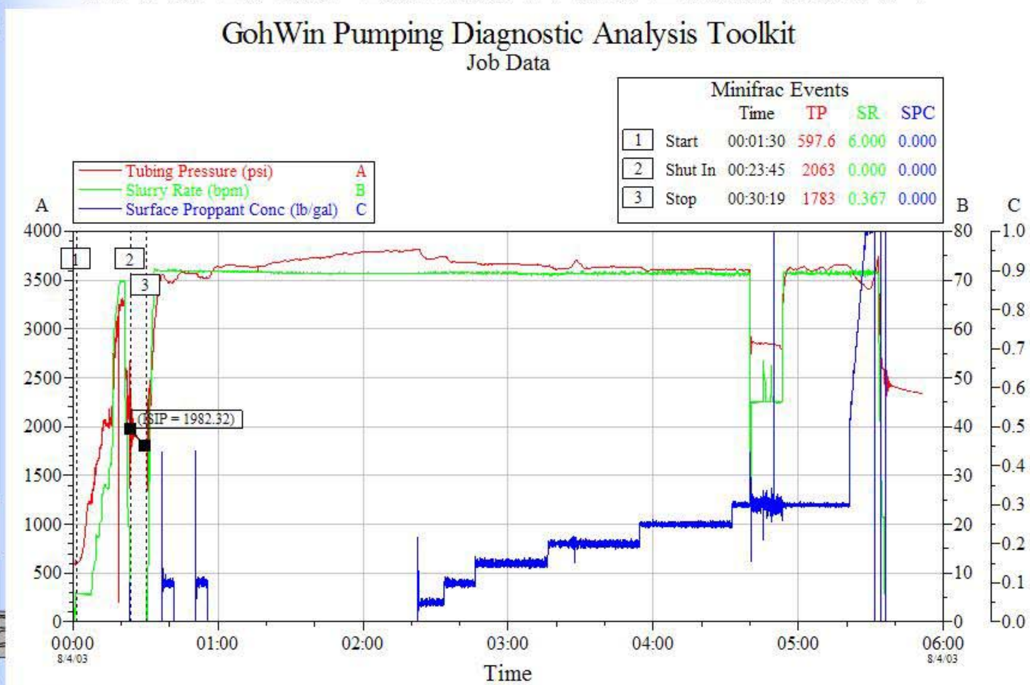
Conclusions From Fracture Simulations

- The simulator confirms the limited frac height growth seen by the tracer log
- Staged treatments are justified
  - Limited entry perforating should be considered
- Drainage area is significantly less than created length
- Reservoir flow mechanisms and fracture leak-off must be understood to refine hydraulic fracture treatment design

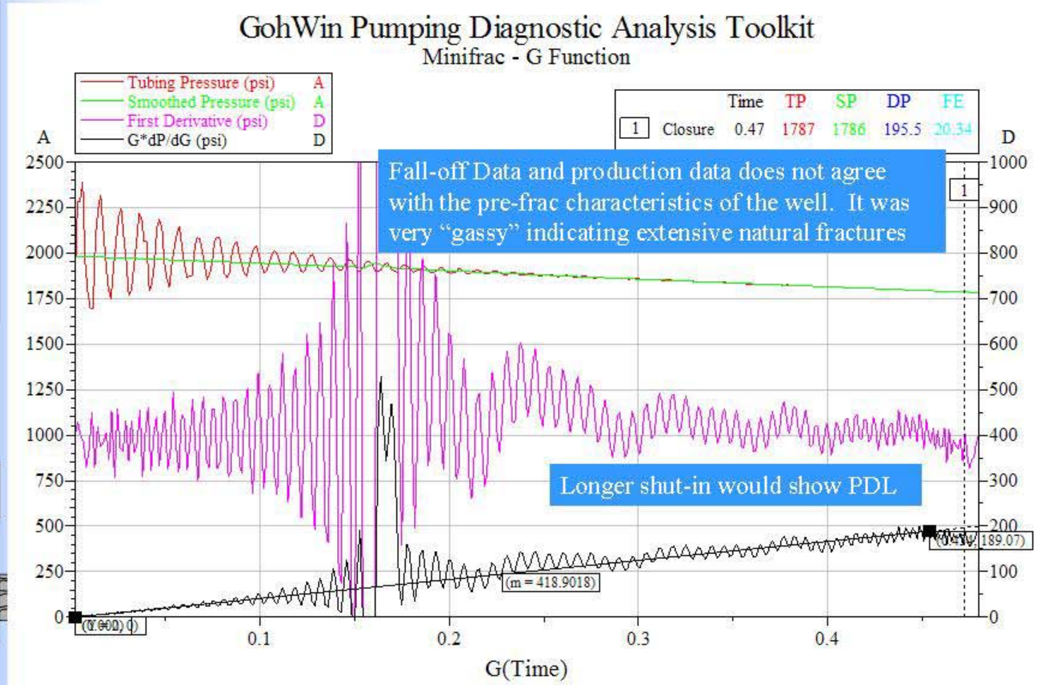
Few Opportunities to Assess Reservoir Quality

- In low permeability, multizone completions the only time you can look at the individual zones cost effectively is before or during the frac job
  - *Buildup tests require excessive shut in times to get answers*
- The answer: Pre-frac water injection fall-off tests
- *Properly designed and conducted can give*
  - *Closure pressure*
  - *Reservoir pressure*
  - *Permeability*
    - *Matrix versus natural fractures*
- *Opportunity to know reservoir properties in advance rather than explain problems after the fact*

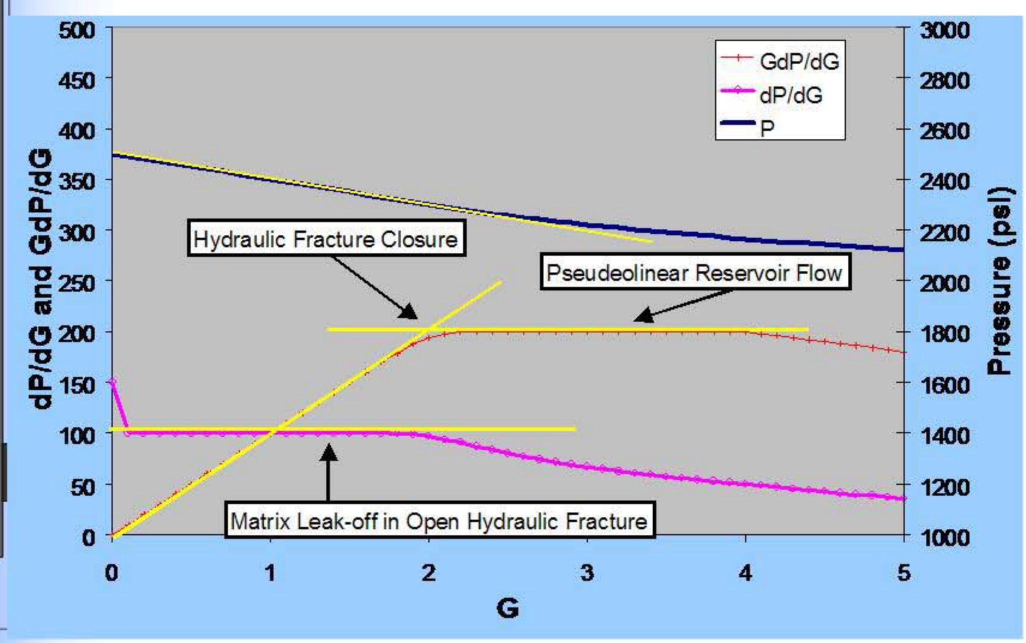
Fracture Stimulation Treatment in the Lower Barnett in the Linda Cox #1

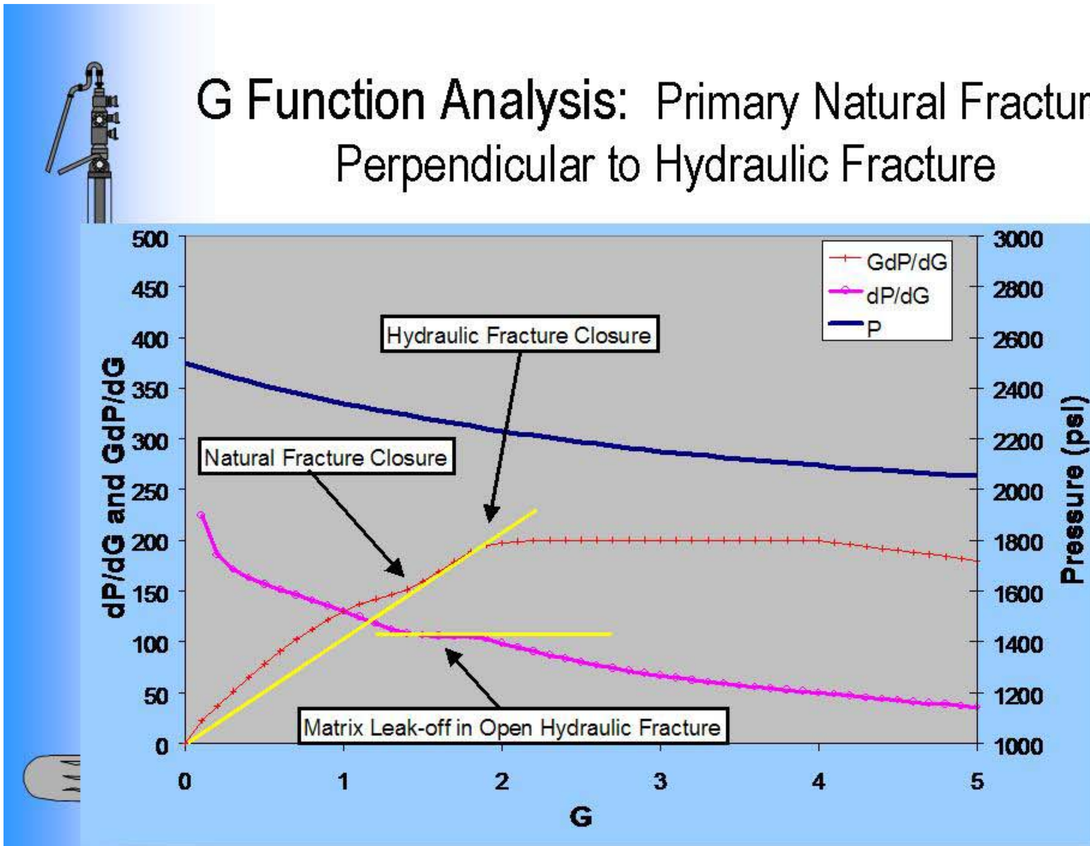


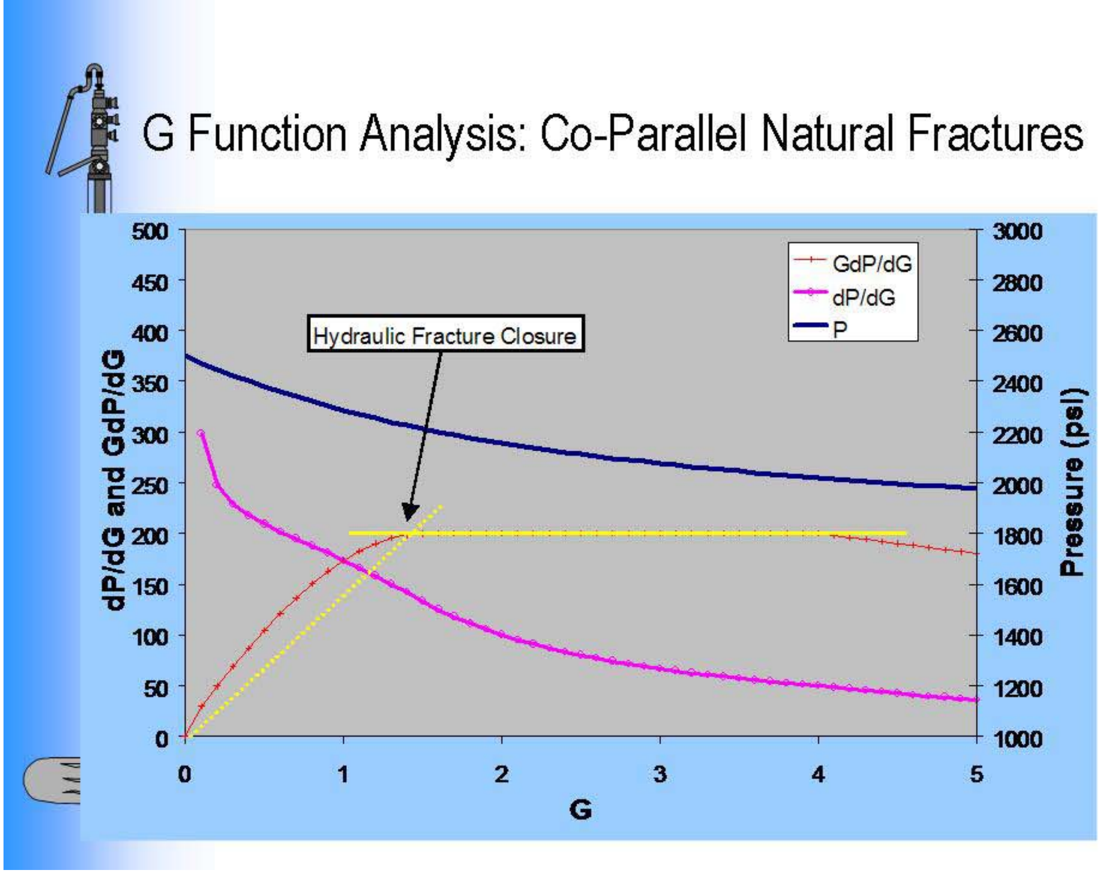
G Function Analysis of Early Shut-in in the Lower Barnett in the Linda Cox #1



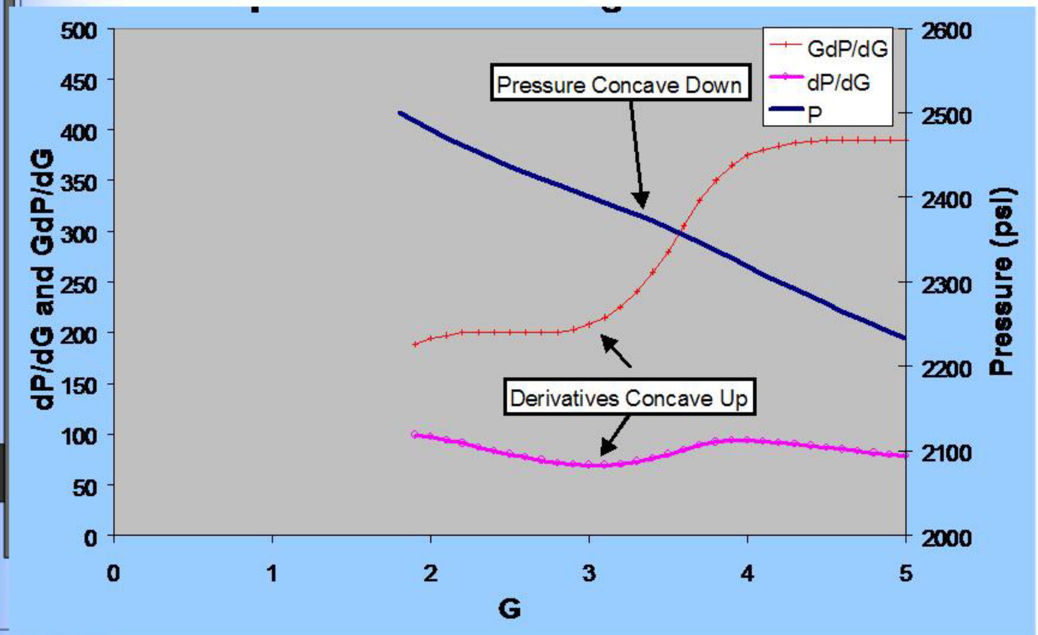
G Function Analysis: Matrix Leakoff




G Function Analysis: Primary Natural Fractures Perpendicular to Hydraulic Fracture
GdP/dG
dP/dG
P
Hydraulic Fracture Closure
Natural Fracture Closure
Matrix Leak-off in Open Hydraulic Fracture
dP/dG and GdP/dG
Pressure (psi)
G


G Function Analysis: Co-Parallel Natural Fractures
GdP/dG
dP/dG
P
Hydraulic Fracture Closure
dP/dG and GdP/dG
Pressure (psi)
G

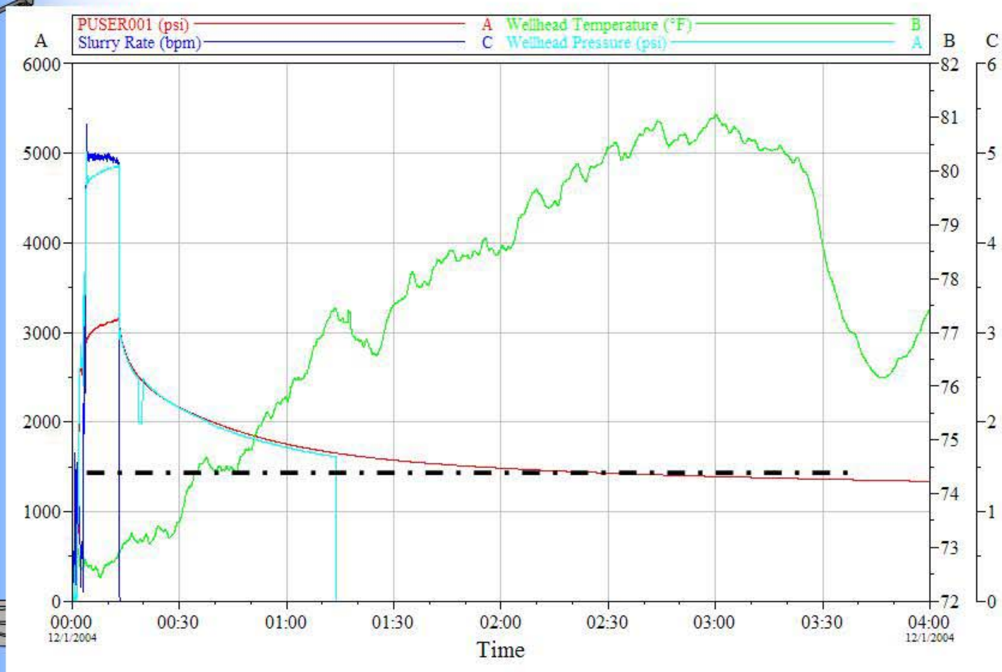
Late Time "Height Recession" out of High Stress Regions or Extensive Natural Fracture Leak-off



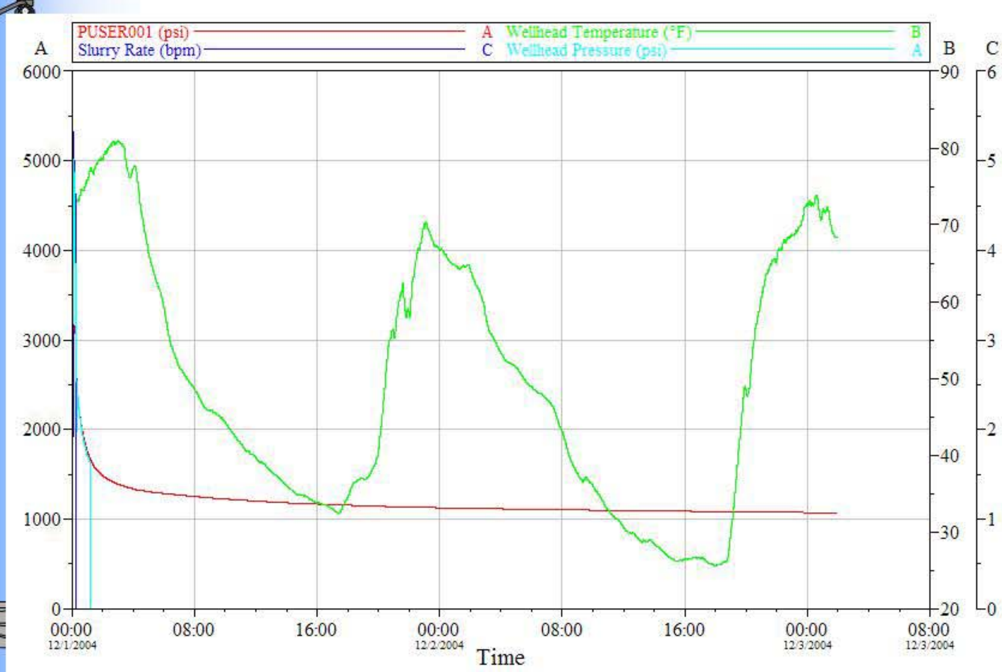
New Example

- We continue daily to encounter fall-off tests which provide a wide variety of fracture and reservoir characteristics
- With very low permeability, the fall-off test must be conducted long enough or the data will not uniquely define the reservoir properties
  - The key difference is that 3 days shut-in after a short injection can identify the properties of even the poorest quality reservoir
  - A conventional buildup typically requires up to a month to achieve the same data quality
- Injection/fall-off analysis is still in its infancy compared to pressure transient analysis

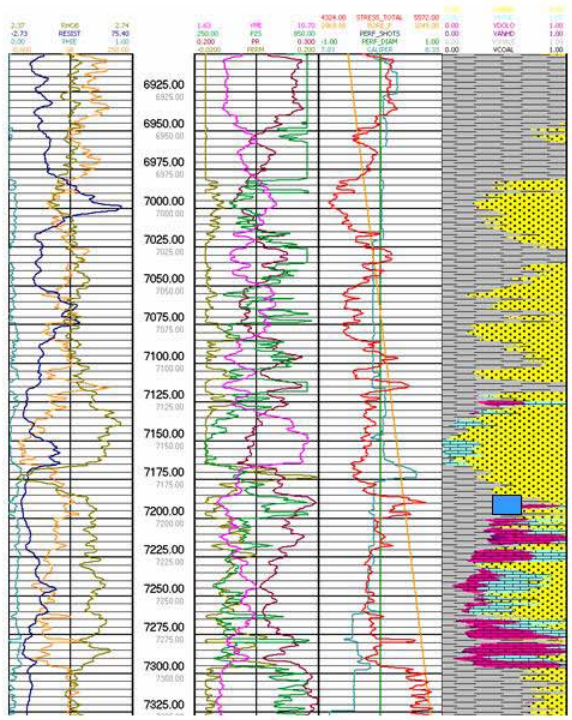
Injection Data for Second Example



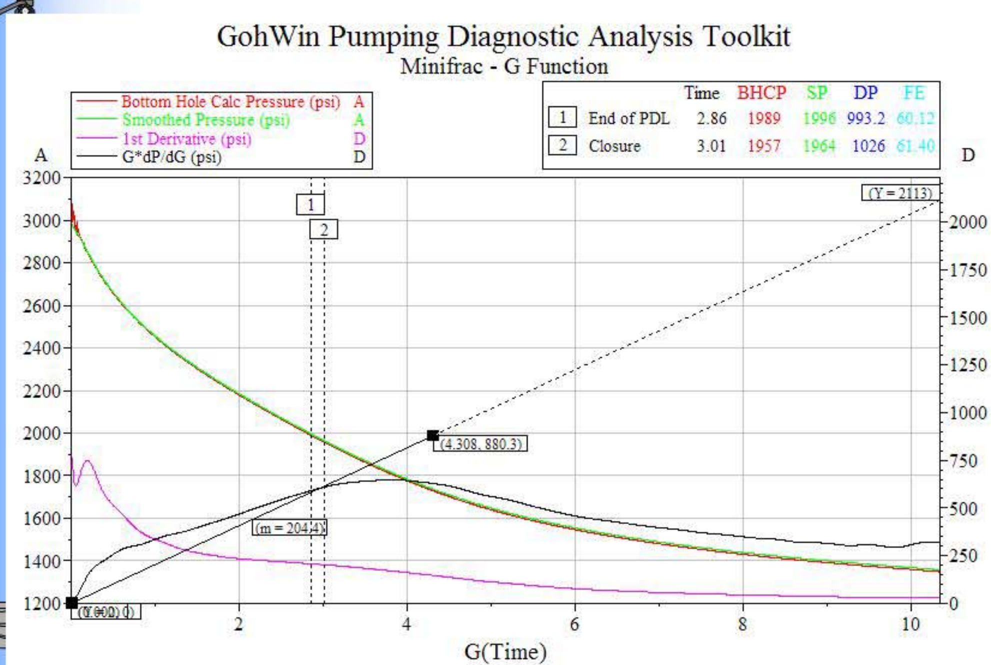
Complete Data Set for 50 hr Fall-off



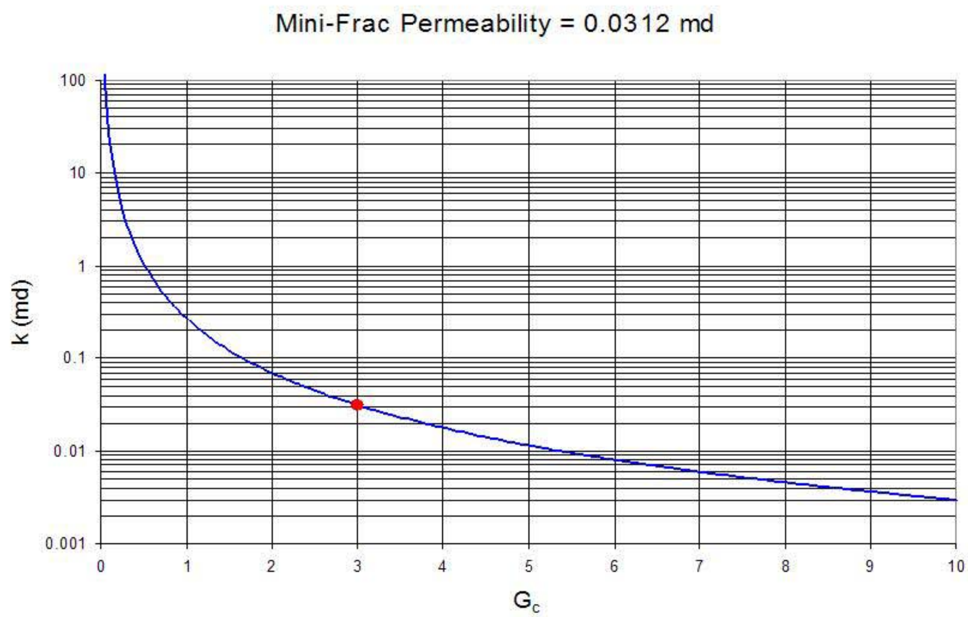
Processed Log Data



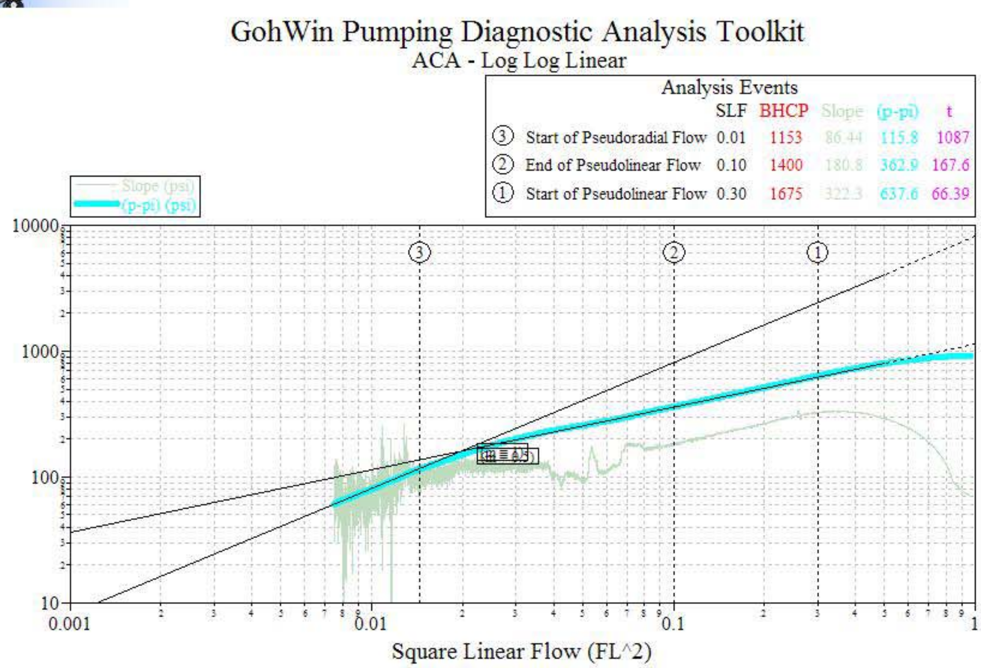
G-function Analysis of Fall-off Data



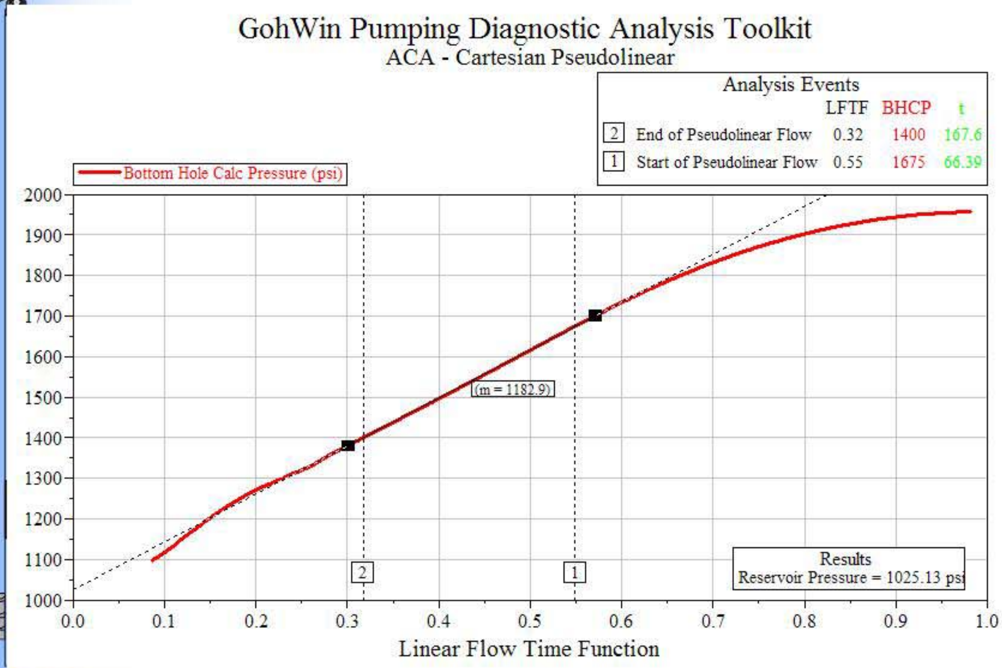
Estimated Perm from Closure



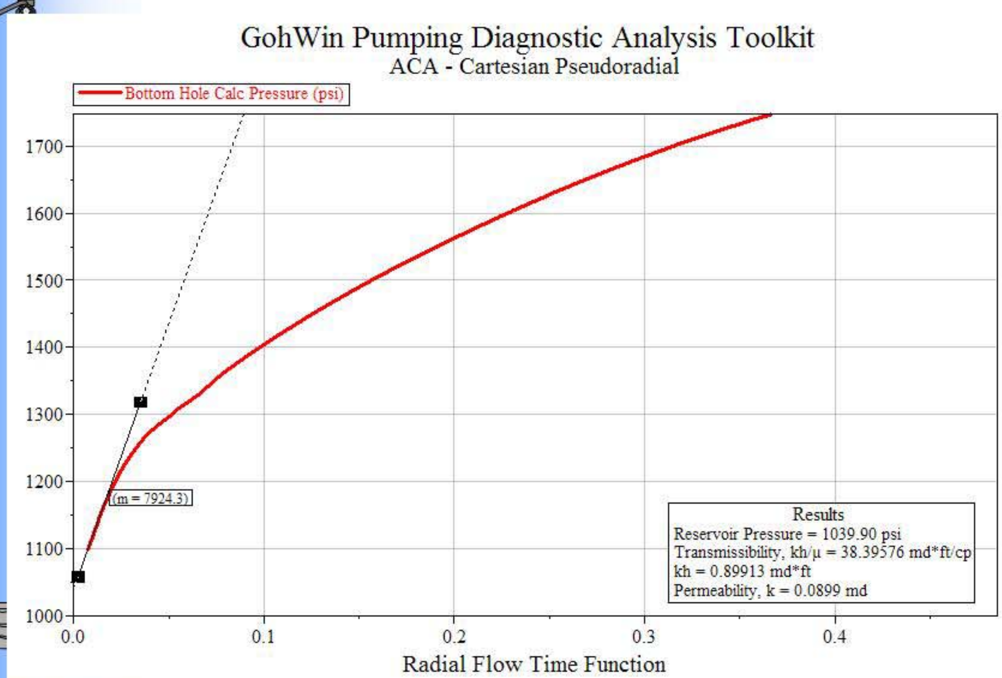
After Closure Analysis Log-Log Plot

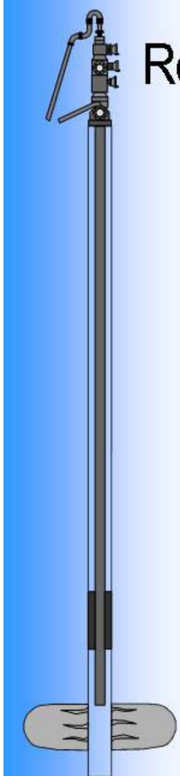


ACA Linear Flow Plot



ACA Radial Flow Plot





Reservoir Properties Determined from Fall-off

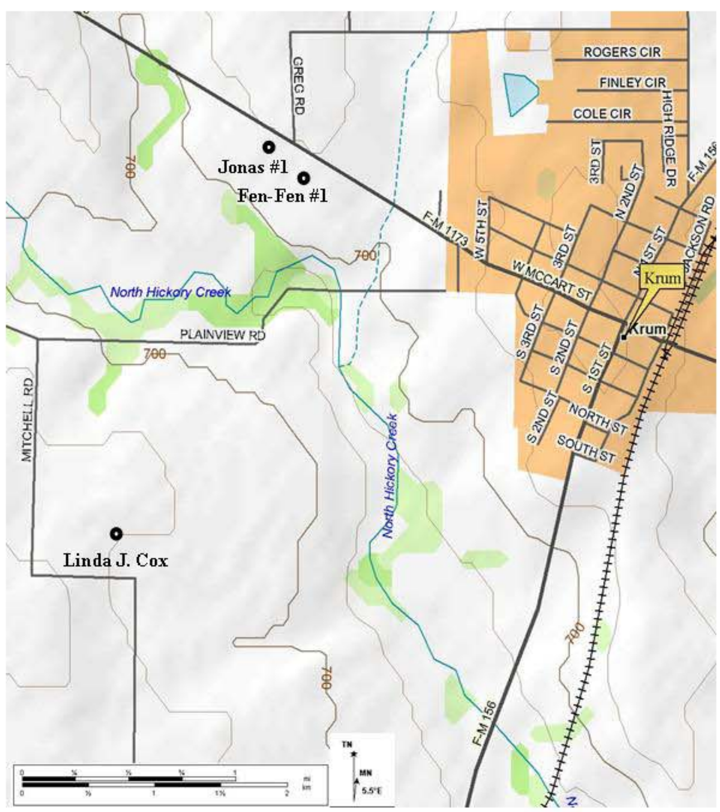
- Fracture extension pressure is 2983 psi WHP, 6102 psi BHP, or 0.851 psi/ft
- Fracture closure pressure is 1957 psi WHP, 5076 psi BHP, or 0.708 psi/ft
- Pore pressure is 1035 psi WHP, 4153 psi BHP, or 0.580 psi/ft
- Reservoir kh is approximately 0.9 md-ft
- Permeability is 0.03-0.09 md depending on the analysis method used and net pay height
- Early leakoff is dominated by variable PDL with a fissure opening pressure 32 psi above closure and initial coefficient of 0.0014

Part C - Production

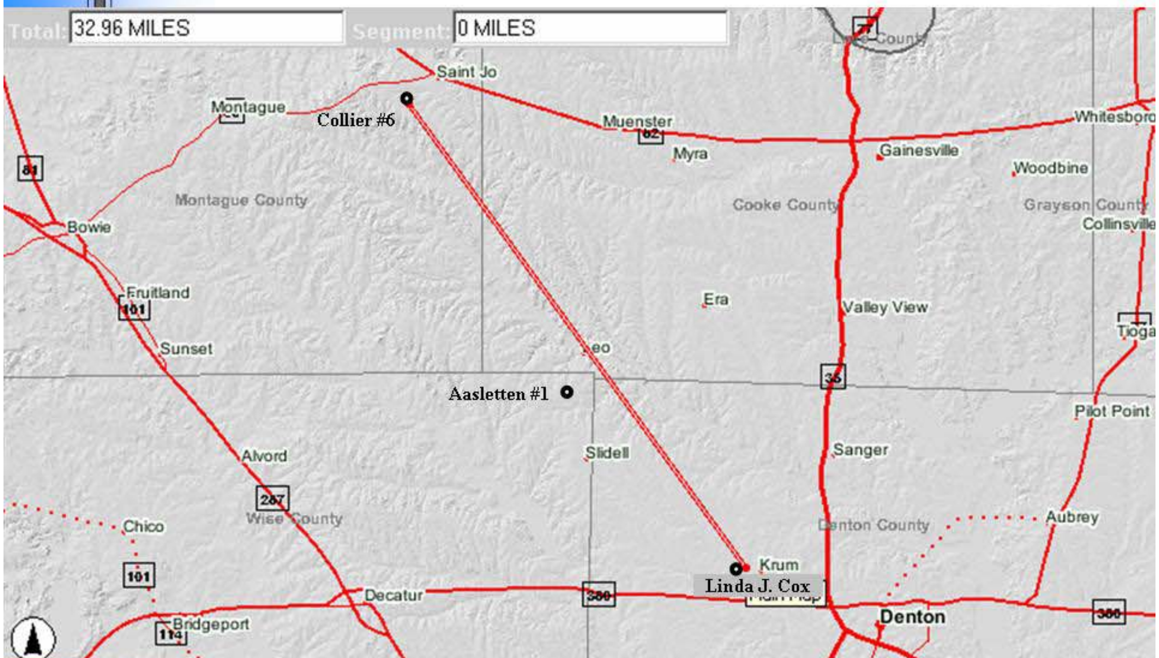
Analysis of Production Characteristics

- Required to assess effect of cementing strategy on completion efficiency
- Identifies other potential production limiting issues
  - Drainage area
  - Liquids management
- Parameters Determined
  - Permeability
  - Fracture length
  - Drainage area and shape

Location of Original Study Wells



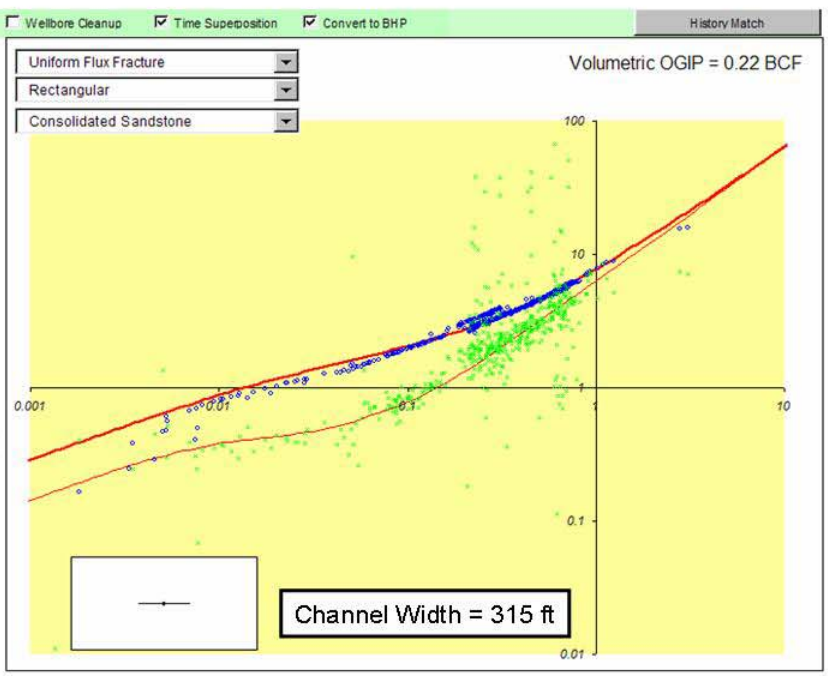
Location of All Project Wells



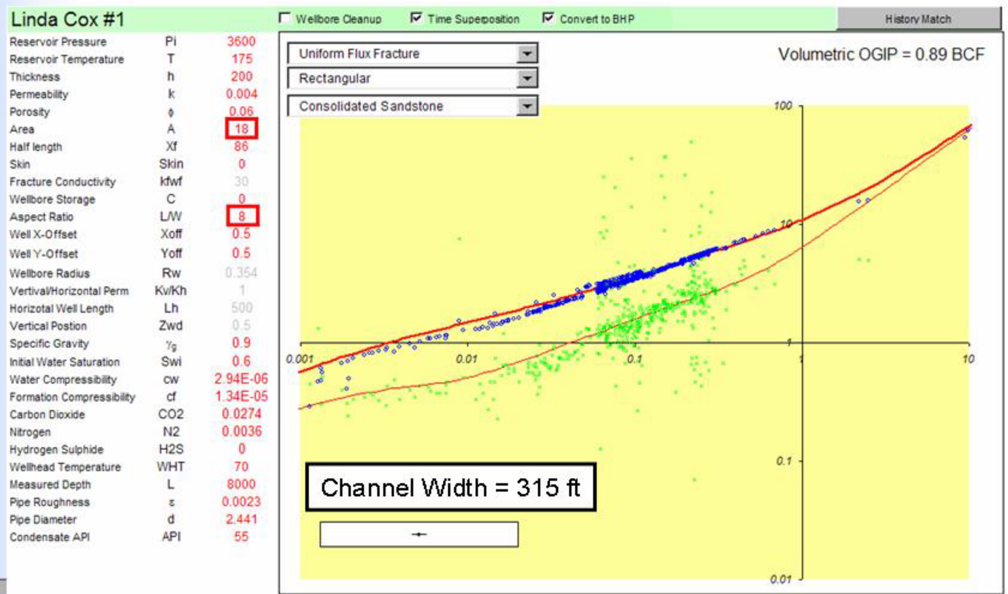
Linda Cox #1 Production Analysis

Linda Cox #1

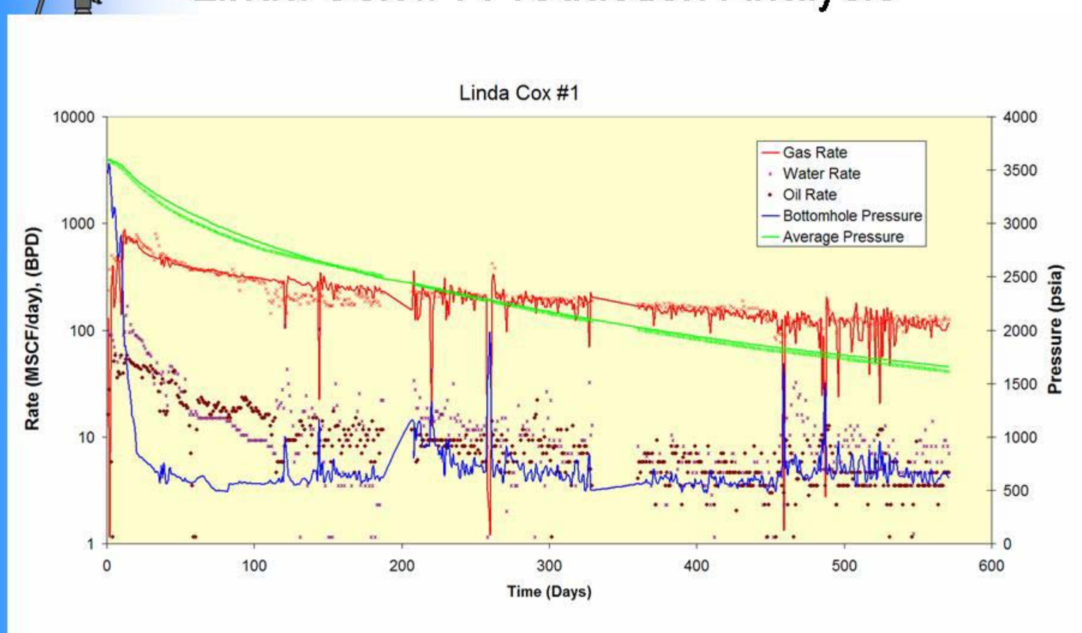
Reservoir Pressure	Pi	3600
Reservoir Temperature	T	175
Thickness	h	200
Permeability	k	0.004
Porosity	ϕ	0.06
Area	A	4.5
Half length	Xf	86
Skin	Skin	0
Fracture Conductivity	kfwf	30
Wellbore Storage	C	0
Aspect Ratio	L/W	2
Well X-Offset	Xoff	0.5
Well Y-Offset	Yoff	0.5
Wellbore Radius	Rw	0.354
Vertival/Horizontal Perm	Kv/Kh	1
Horizotal Well Length	Lh	500
Vertical Postion	Zwd	0.5
Specific Gravity	γ_g	0.9
Initial Water Saturation	Swi	0.6
Water Compressibility	cw	2.94E-06
Formation Compressibility	cf	1.34E-05
Carbon Dioxide	CO2	0.0274
Nitrogen	N2	0.0036
Hydrogen Sulphide	H2S	0
Wellhead Temperature	WHT	70
Measured Depth	L	8000
Pipe Roughness	ε	0.0023
Pipe Diameter	d	2.441
Condensate API	API	55



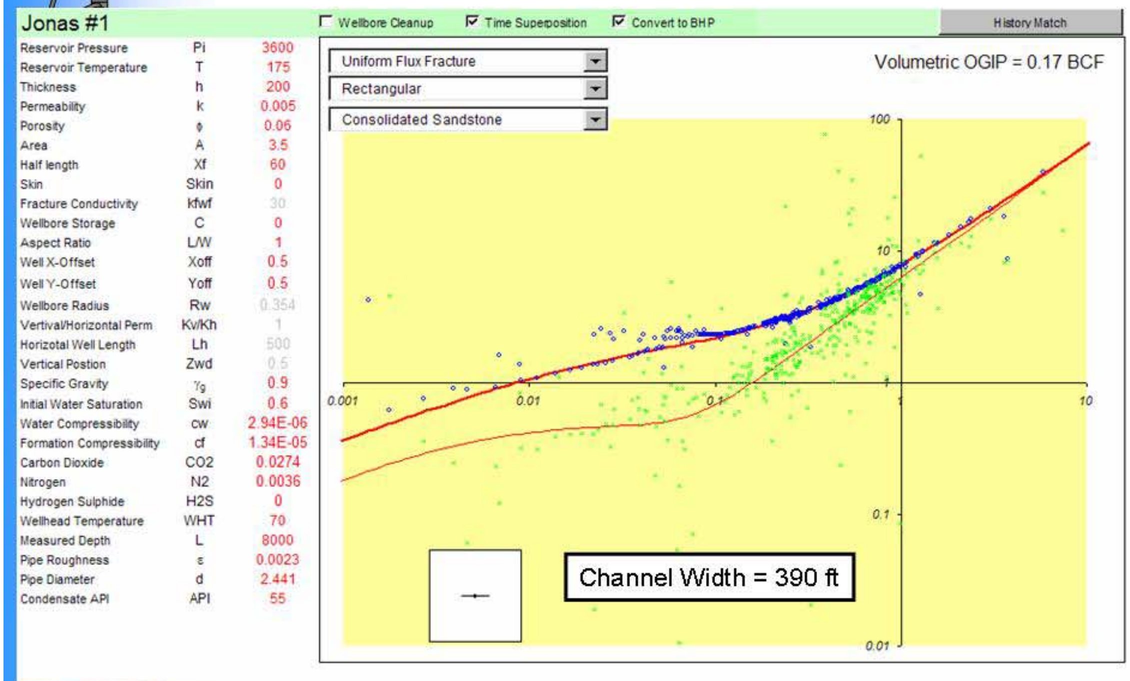
Linda Cox #1 Production Analysis: Channel Length Not Yet Defined



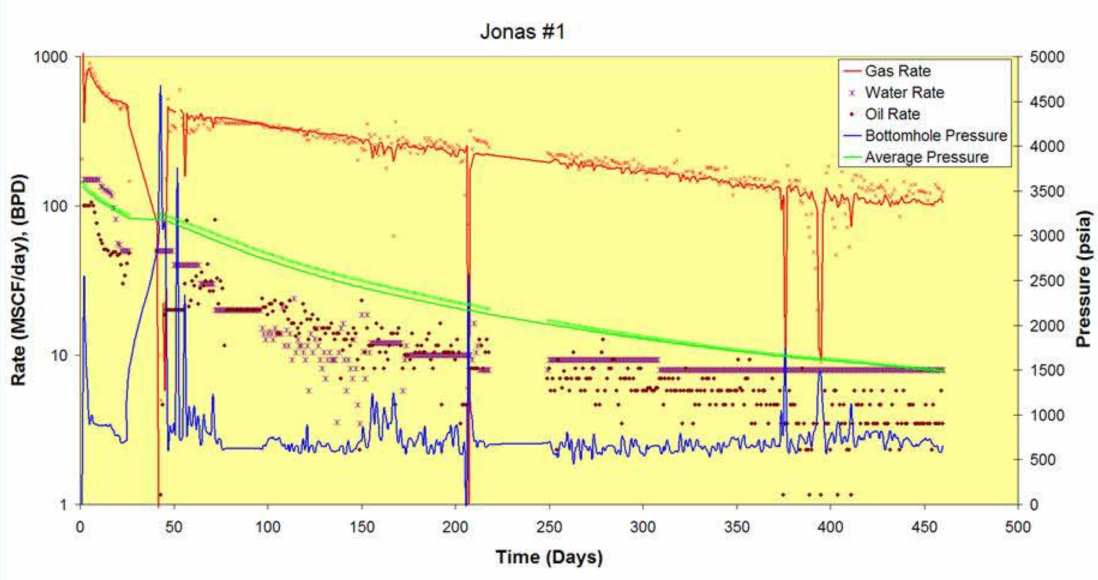
Linda Cox #1 Production Analysis



Jonas #1 Production Analysis



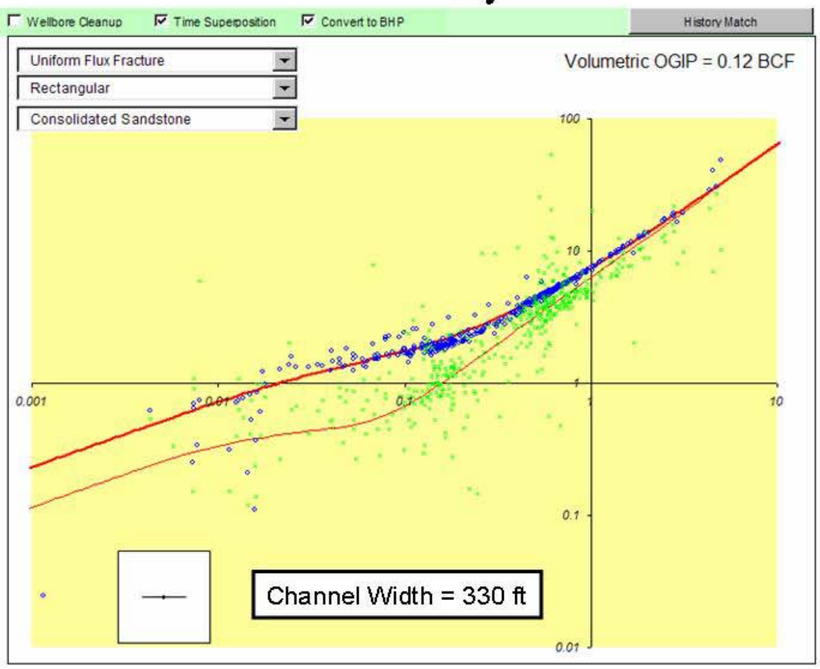
Jonas #1 Production Analysis



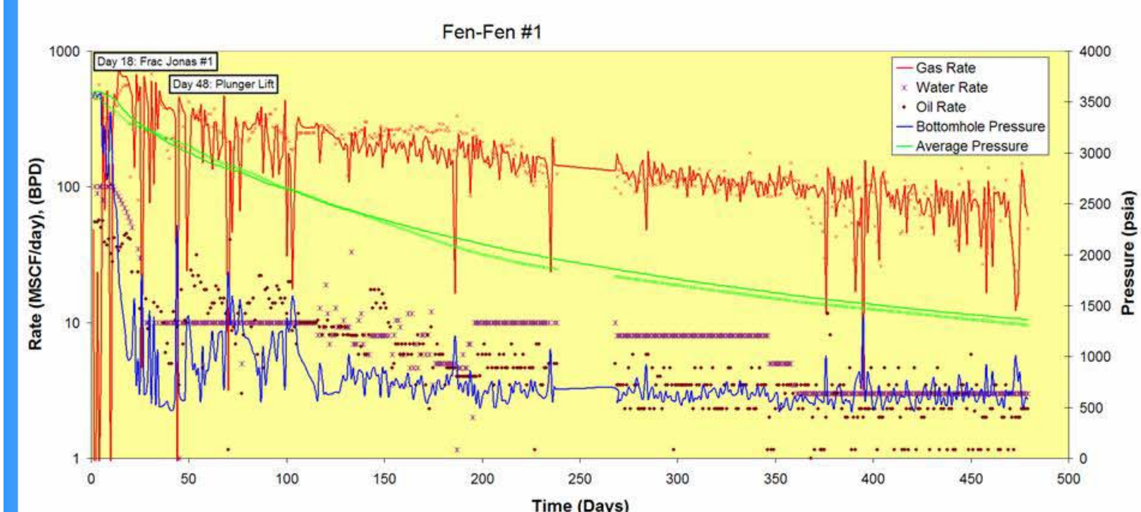
Fen Fen #1 Production Analysis

Fen-Fen #1

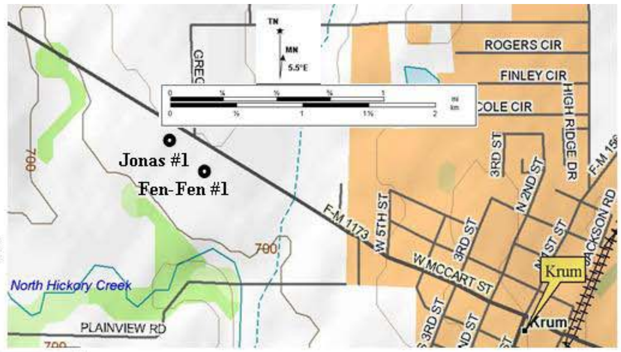
Reservoir Pressure	Pi	3600
Reservoir Temperature	T	175
Thickness	h	200
Permeability	k	0.003
Porosity	ϕ	0.06
Area	A	2.5
Half length	Xf	80
Skin	Skin	0
Fracture Conductivity	kfwf	30
Wellbore Storage	C	0
Aspect Ratio	L/W	1
Well X-Offset	Xoff	0.5
Well Y-Offset	Yoff	0.5
Wellbore Radius	Rw	0.354
Vertival/Horizontal Perm	Kv/Kh	1
Horizotal Well Length	Lh	500
Vertical Postion	Zwd	0.5
Specific Gravity	γ_g	0.9
Initial Water Saturation	Swi	0.6
Water Compressibility	cw	2.94E-06
Formation Compressibility	cf	1.34E-05
Carbon Dioxide	CO2	0.0274
Nitrogen	N2	0.0036
Hydrogen Sulphide	H2S	0
Wellhead Temperature	WHT	70
Measured Depth	L	8000
Pipe Roughness	ε	0.0023
Pipe Diameter	d	2.441
Condensate API	API	55

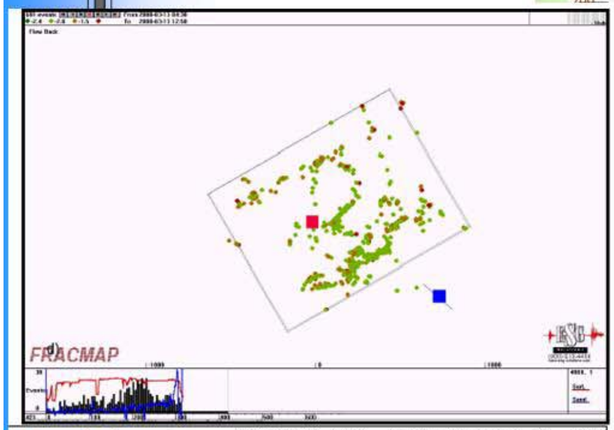


Fen Fen #1 Production Analysis



Results from Fracture Mapping: Square Drainage Areas





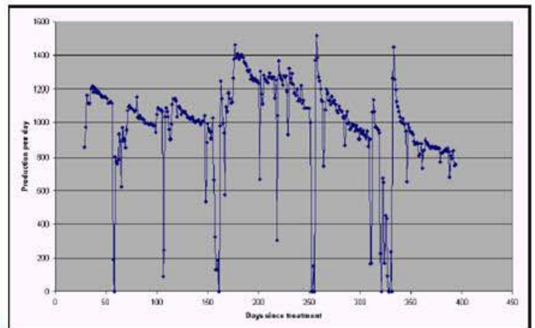
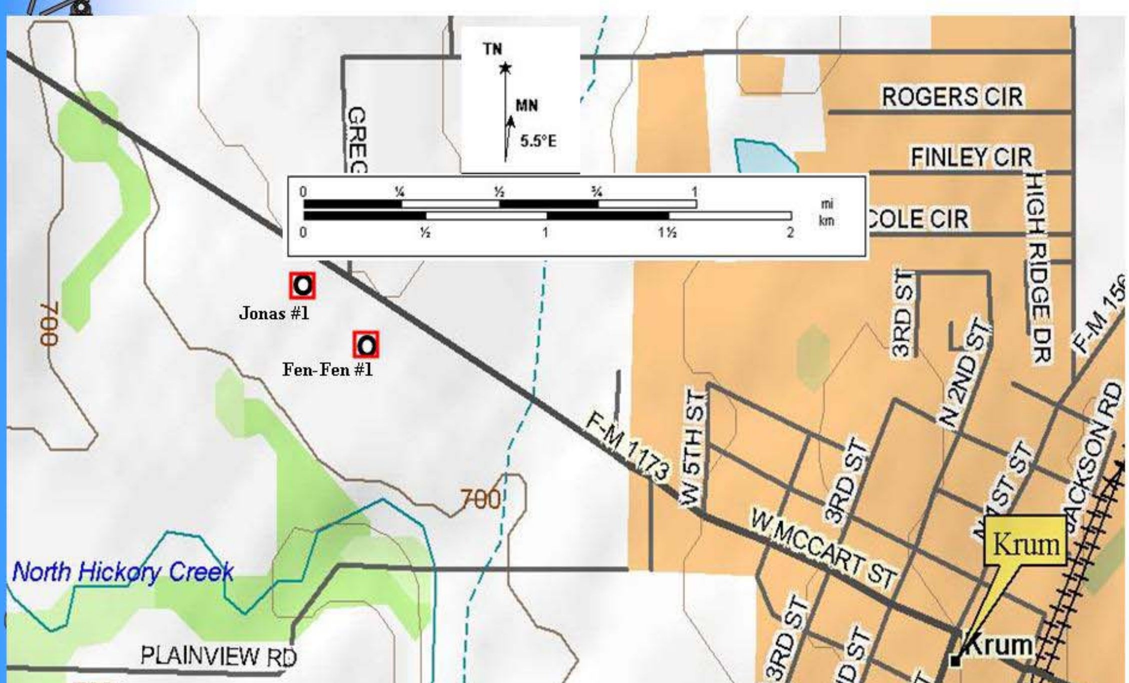
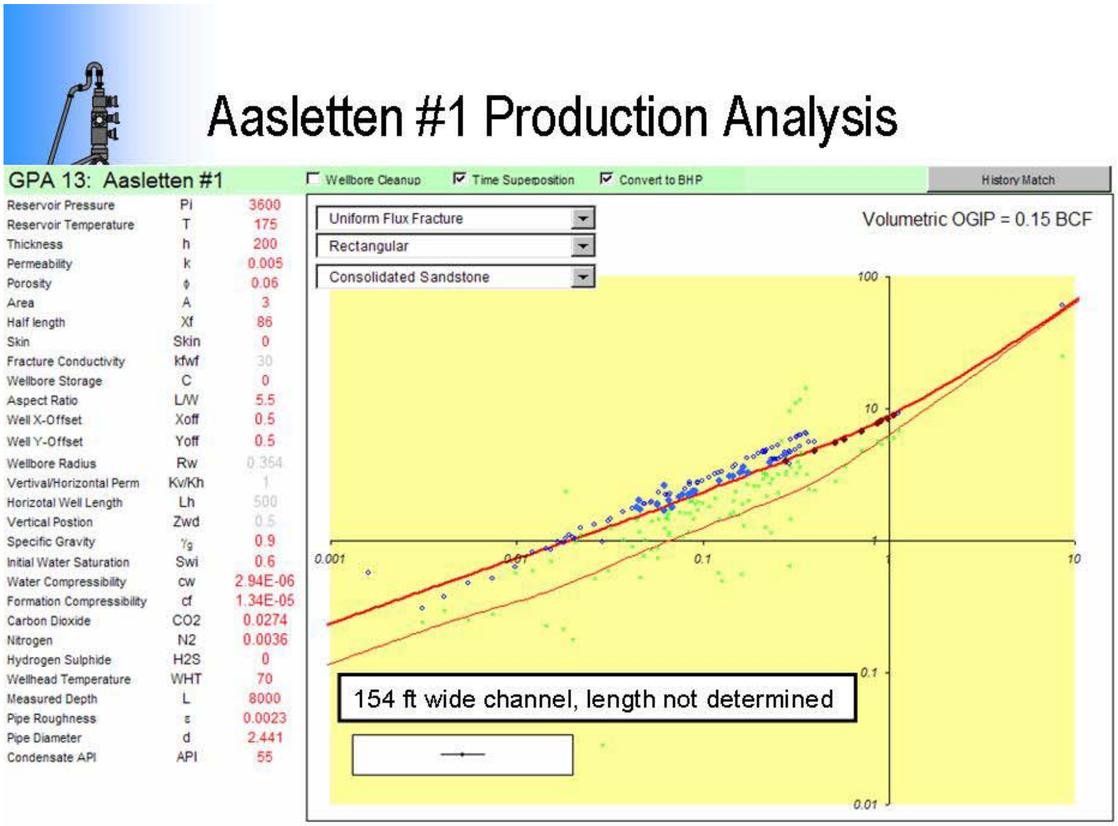


Figure 15. Daily production for well 'A'.

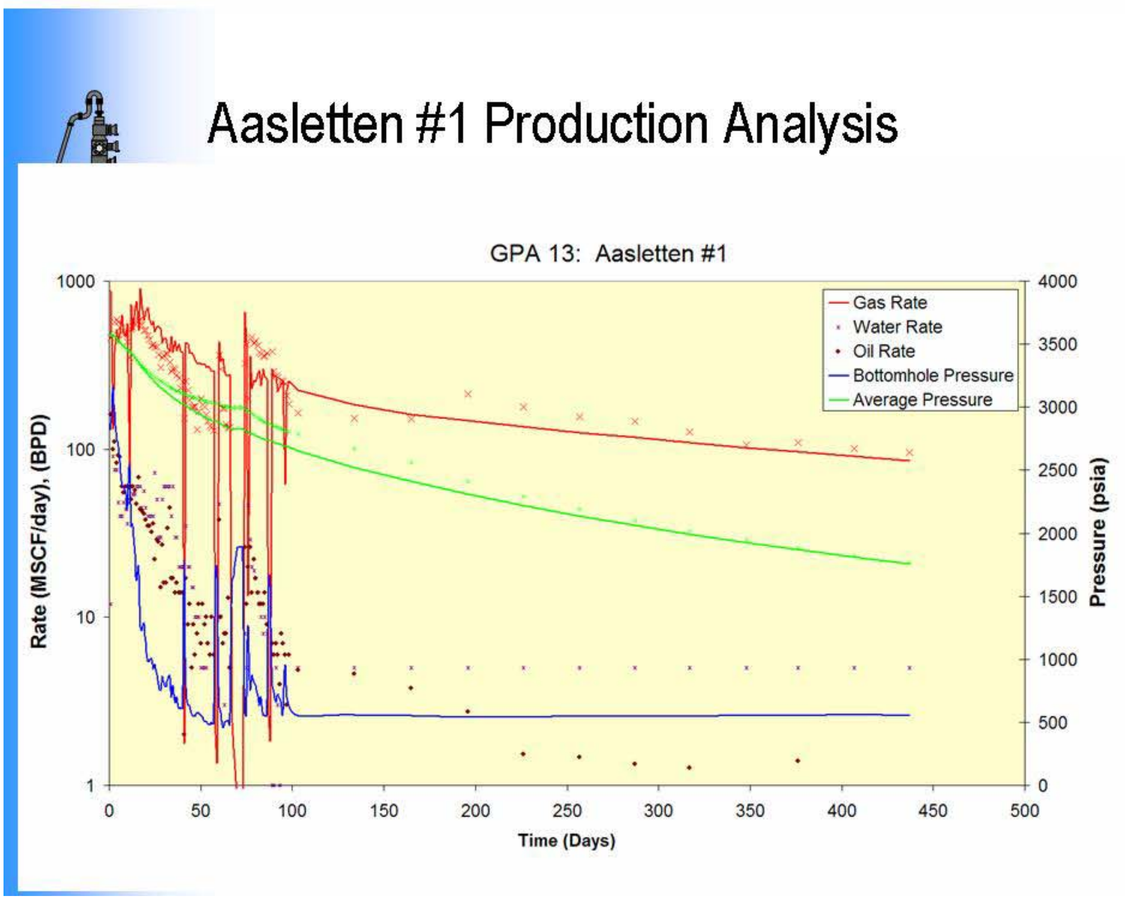
Maxwell, S.C., Steinsberger, N., and Zinno, R.: "Microseismic Imaging of Hydraulic Fracture Complexity in the Barnett Shale", paper SPE 77440 presented at the 2002 SPE Annual Technical Conference, San Antonio, Texas, Sept. 29-October 2, 2002.

Jonas and Fen Fen Drainage Are Anomalous





Aasletten #1 Production Analysis
GPA 13: Aasletten #1
Wellbore Cleanup
Time Superposition
Convert to BHP
History Match
Reservoir Pressure Pi 3600
Reservoir Temperature T 175
Thickness h 200
Permeability k 0.005
Porosity ϕ 0.06
Area A 3
Half length Xf 86
Skin Skin 0
Fracture Conductivity kfwf 30
Wellbore Storage C 0
Aspect Ratio L/W 5.5
Well X-Offset Xoff 0.5
Well Y-Offset Yoff 0.5
Wellbore Radius Rw 0.354
Vertival/Horizontal Perm Kv/Kh 1
Horizotal Well Length Lh 500
Vertical Postion Zwd 0.5
Specific Gravity γ_g 0.9
Initial Water Saturation Swi 0.6
Water Compressibility cw 2.94E-06
Formation Compressibility cf 1.34E-05
Carbon Dioxide CO2 0.0274
Nitrogen N2 0.0036
Hydrogen Sulphide H2S 0
Wellhead Temperature WHT 70
Measured Depth L 8000
Pipe Roughness ε 0.0023
Pipe Diameter d 2.441
Condensate API API 55
Uniform Flux Fracture
Rectangular
Consolidated Sandstone
Volumetric OGIP = 0.15 BCF
154 ft wide channel, length not determined



Aasletten #1 Production Analysis
GPA 13: Aasletten #1
Gas Rate
Water Rate
Oil Rate
Bottomhole Pressure
Average Pressure
Rate (MSCF/day), (BPD)
Pressure (psia)
Time (Days)

Results from Fracture Mapping: Channel Shape and Major Caution

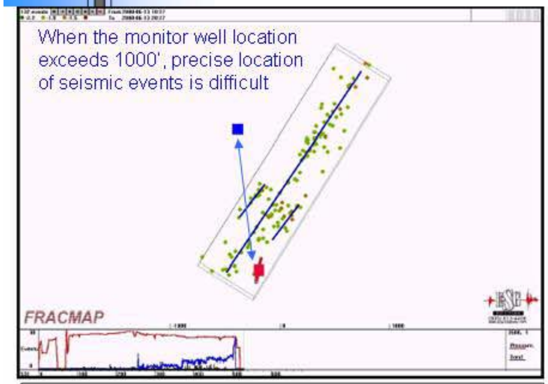


Figure 3. Plan view of stimulation of well 'B'.

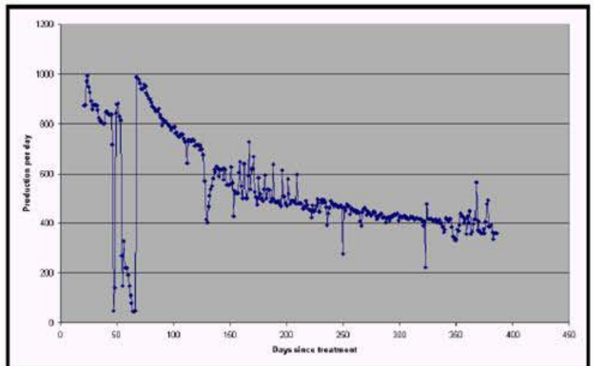


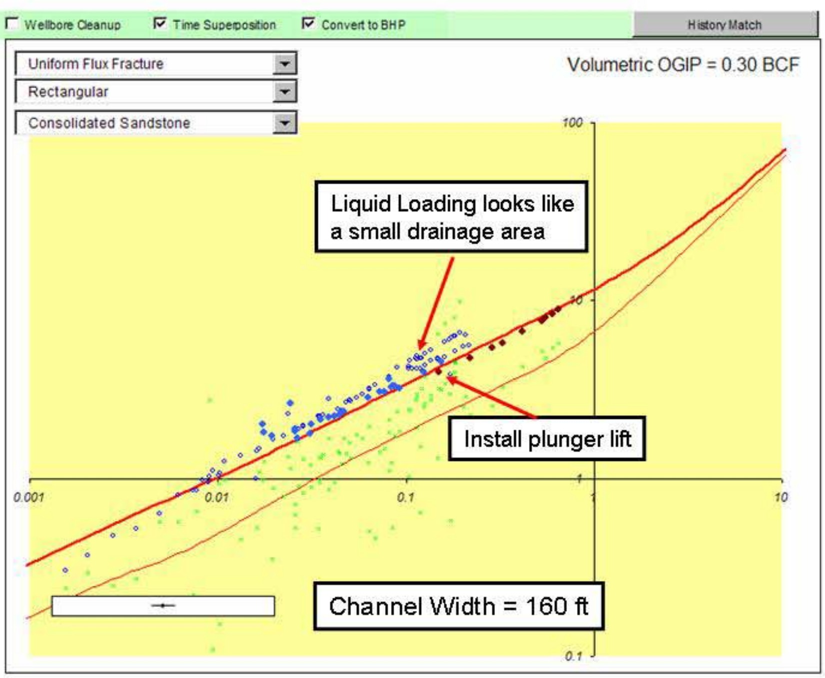
Figure 16. Daily production for well 'B'.

Maxwell, S.C., Steinsberger, N., and Zinno, R.: "Microseismic Imaging of Hydraulic Fracture Complexity in the Barnett Shale", paper SPE 77440 presented at the 2002 SPE Annual Technical Conference, San Antonio, Texas, Sept. 29-October 2, 2002.

Aasletten #1 Detailed Production Analysis

GPA 13: Aasletten #1

Reservoir Pressure	Pi	3600
Reservoir Temperature	T	175
Thickness	h	200
Permeability	k	0.005
Porosity	ϕ	0.06
Area	A	6
Half length	Xf	86
Skin	Skin	0
Fracture Conductivity	kfwf	30
Wellbore Storage	C	0
Aspect Ratio	L/W	11
Well X-Offset	Xoff	0.5
Well Y-Offset	Yoff	0.5
Wellbore Radius	Rw	0.354
Vertival/Horizontal Perm	Kv/Kh	1
Horizotal Well Length	Lh	500
Vertical Postion	Zwd	0.5
Specific Gravity	γ_g	0.9
Initial Water Saturation	Swi	0.6
Water Compressibility	cw	2.94E-06
Formation Compressibility	cf	1.34E-05
Carbon Dioxide	CO2	0.0274
Nitrogen	N2	0.0036
Hydrogen Sulphide	H2S	0
Wellhead Temperature	WHT	70
Measured Depth	L	8000
Pipe Roughness	ε	0.0023
Pipe Diameter	d	2.441
Condensate API	API	55



Summary of Production Analysis: Minimum Drainage Area

Well	Perm (md)	Area (acres)	Frac Length (ft)	Aspect Ratio
Linda Cox	0.004	4.5	80	2
Jonas	0.005	3.5	60	1
Fen-Fen	0.003	2.5	80	1
Aasletten	0.005	3.0	86	5.5

- Production characteristics do not correlate with differences in cementing practices

Summary of Production Analysis

- Economics of wells depends on effective drainage area
  - Drainage area may not represent "geographic extent" but the drained area in contact with a complex fracture geometry
  - Both square and channel drainage pattern observed
  - After one year production, the width of the channel was sensed but not necessarily the length of the channel
- Liquid loading can seriously limit apparent drainage area
  - Field studies in many fields show that gas EUR is inversely related to liquid yield starting at 10 barrels/mmcf
  - The liquid yield in the Krum area easily exceeds 100 bbl/mmcf
- Revised production practices could significantly improve the EUR
  - Liquids over the perfs reduce gas production far more than predicted by increased pressure due to hydrostatic head
  - Rod pumps set below the lowest perfs must be considered

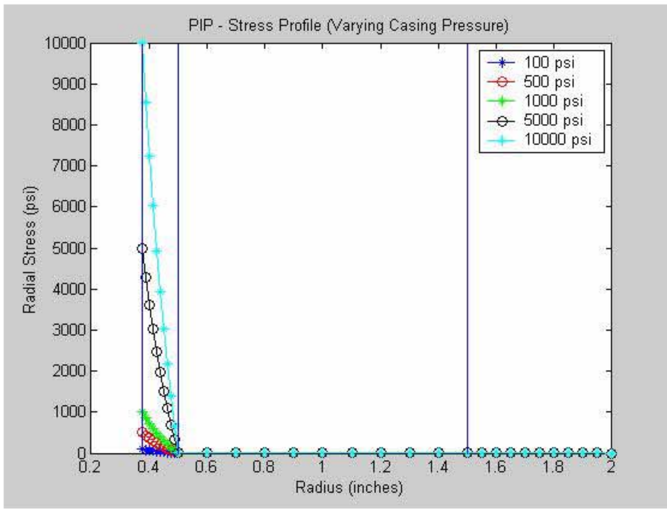
Appendix VIII

FEM – Cement Systems Under Stress Conditions

**FEM ANALYSIS
OF CEMENT SYSTEMS
UNDER STRESS CONDITIONS**

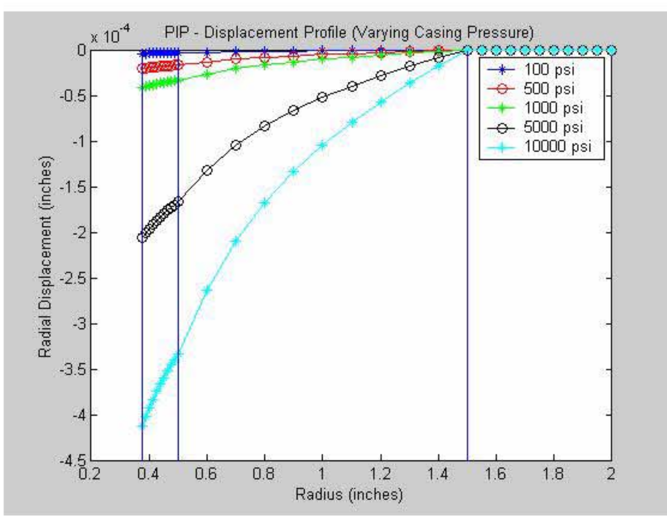
University of Houston

CASING PRESSURE (PIP)



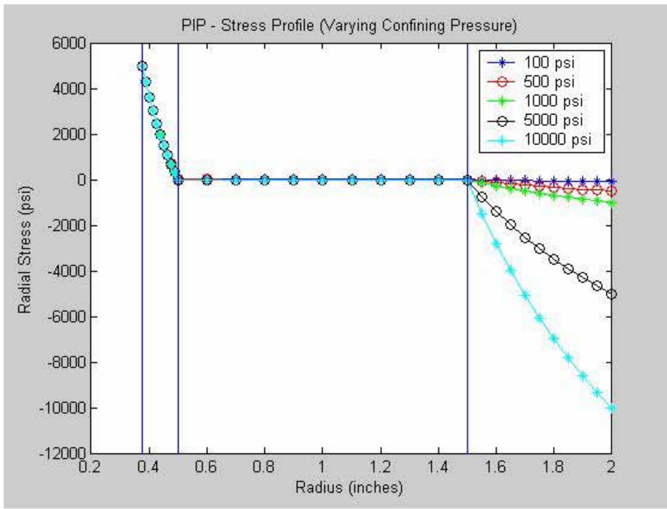
Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Confining Pressure	**0 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

CASING PRESSURE (PIP)



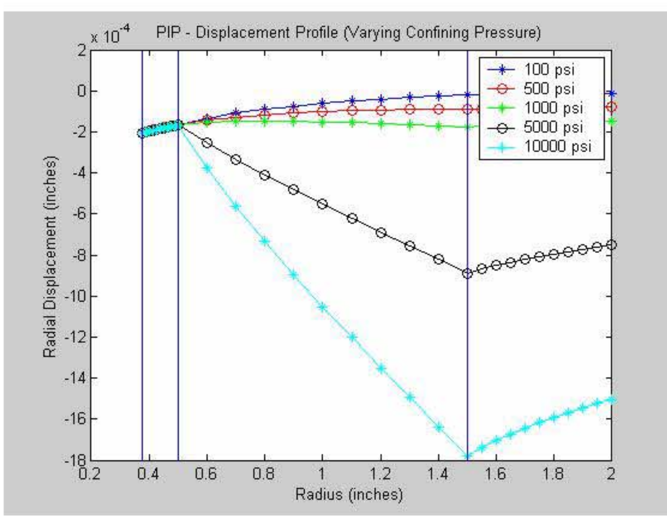
Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Confining Pressure	**0 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

CONFINING PRESSURE (PIP)



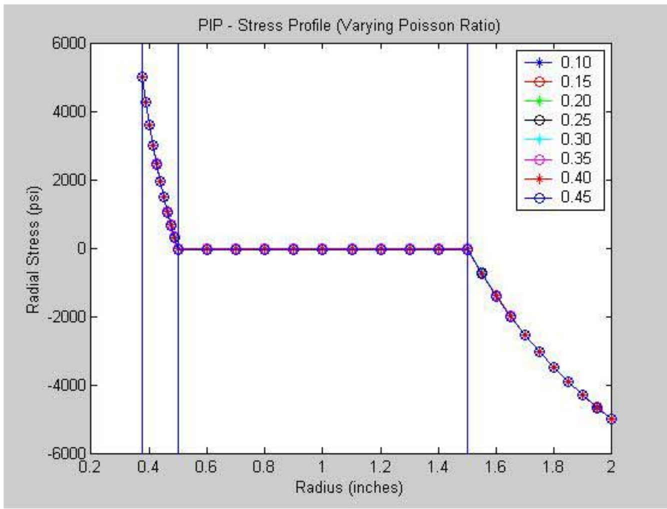
Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Casing Pressure	**5000 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

CONFINING PRESSURE (PIP)



Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Casing Pressure	**5000 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

POISSON RATIO (PIP)



Young's Modulus **5000 psi**

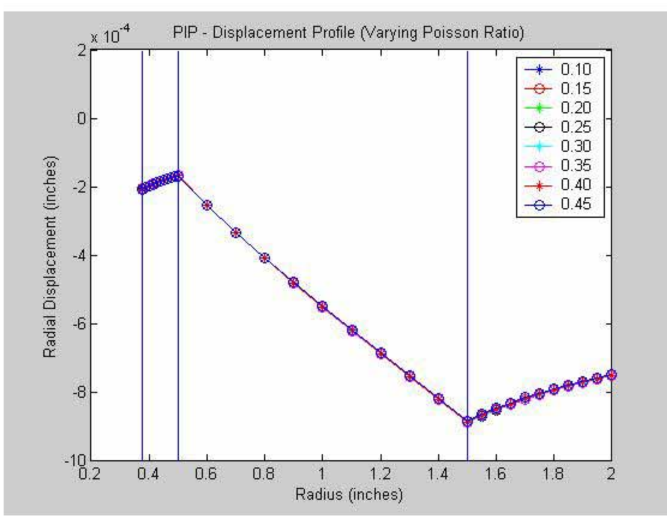
Casing Pressure **5000 psi**

Confining Pressure **5000 psi**

Cement Thickness **1 inch**

Temperature gradient **None**

POISSON RATIO (PIP)



Young's Modulus **5000 psi**

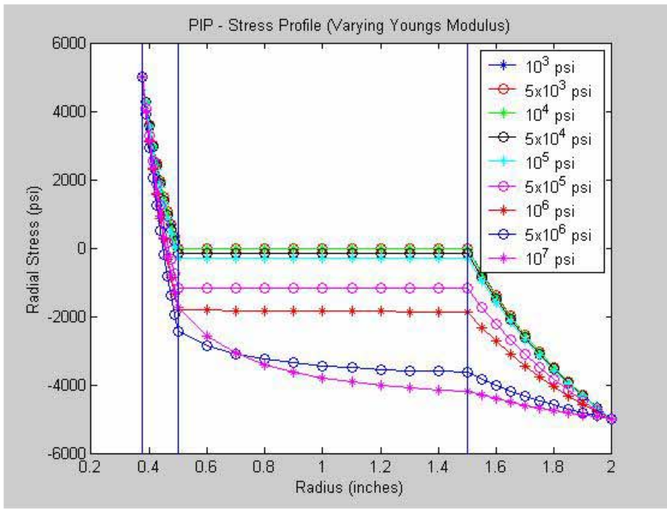
Casing Pressure **5000 psi**

Confining Pressure **5000 psi**

Cement Thickness **1 inch**

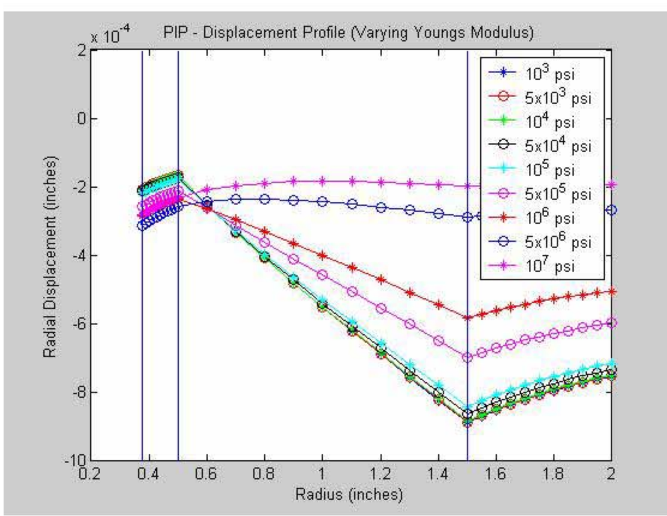
Temperature gradient **None**

YOUNG'S MODULUS (PIP)



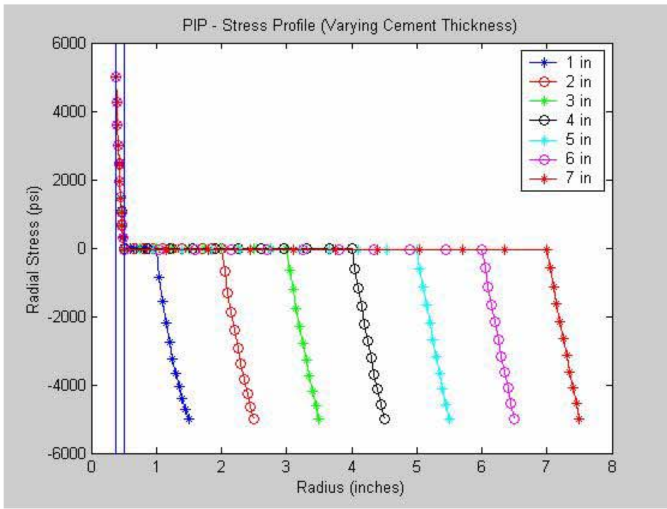
Casing Pressure	5000 psi
Poisson Ratio	0.35
Confining Pressure	5000 psi
Cement Thickness	1 inch
Temperature gradient	None

YOUNG'S MODULUS (PIP)



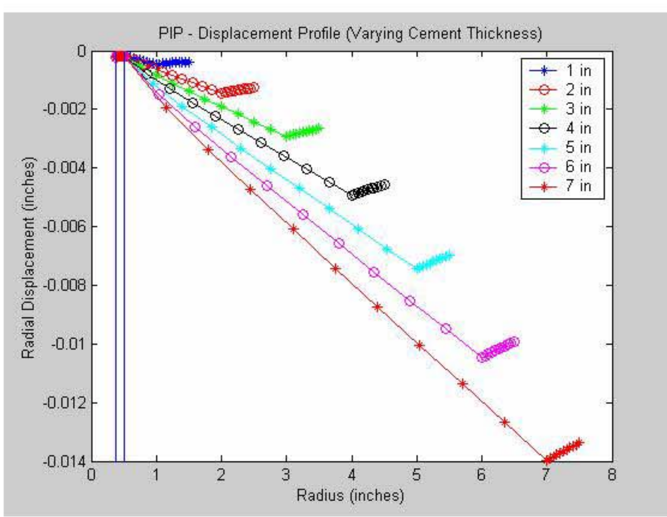
Casing Pressure	5000 psi
Poisson Ratio	0.35
Confining Pressure	5000 psi
Cement Thickness	1 inch
Temperature gradient	None

CEMENT THICKNESS (PIP)



Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Confining Pressure	**5000 psi**
Casing Pressure	**5000 psi**
Temperature gradient	**None**

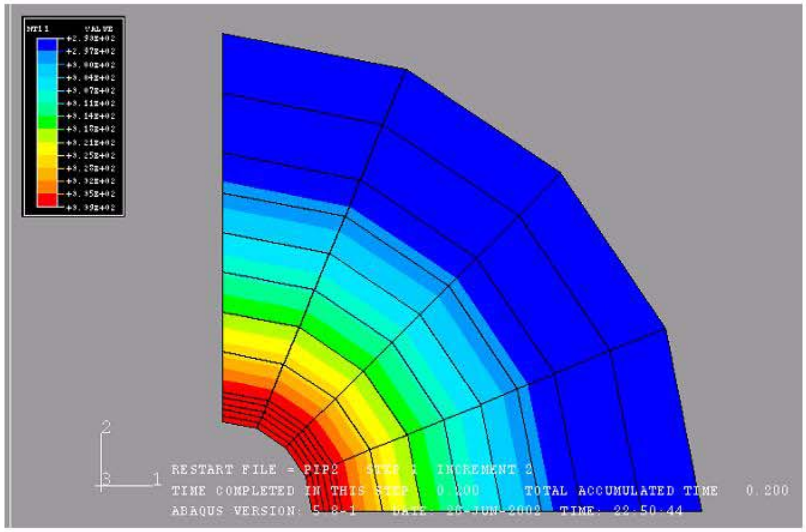
CEMENT THICKNESS (PIP)



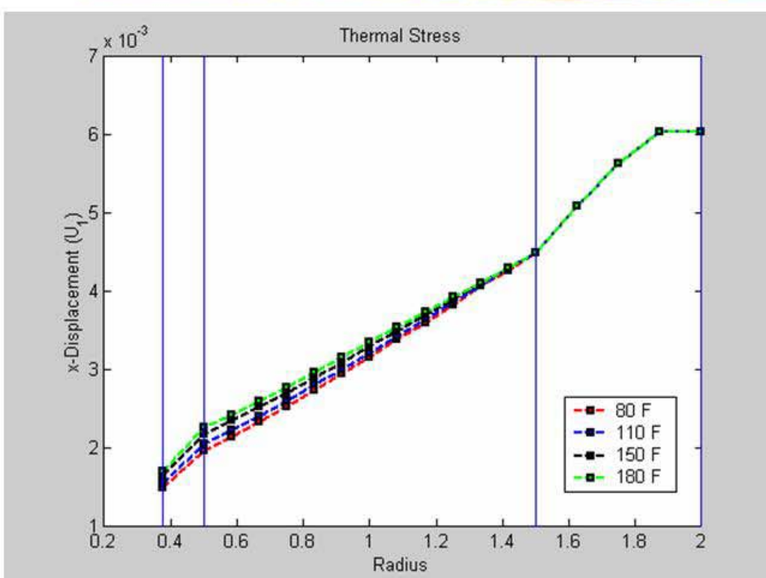
Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Confining Pressure	**5000 psi**
Casing Pressure	**5000 psi**
Temperature gradient	**None**

THERMAL STRESS (PIP)

TEMPERATURE PROFILE

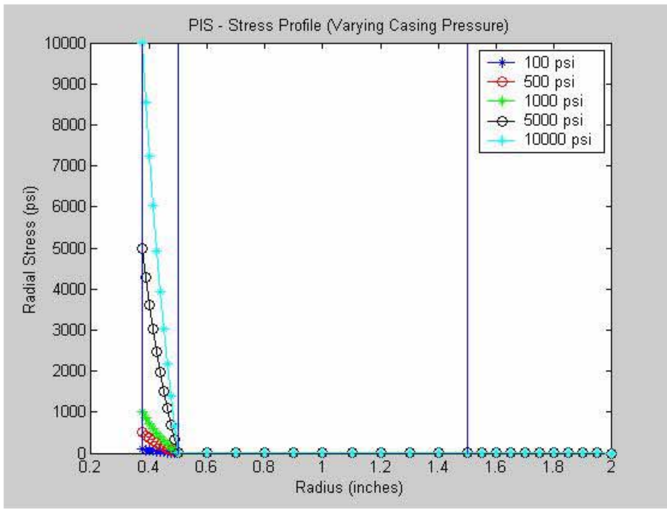


THERMAL STRESS (PIP)



Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Casing Pressure	**500 psi**
Confining Pressure	**500 psi**
Cement Thickness	**1 inch**

CASING PRESSURE (PIS)



Young's Modulus 5000 psi

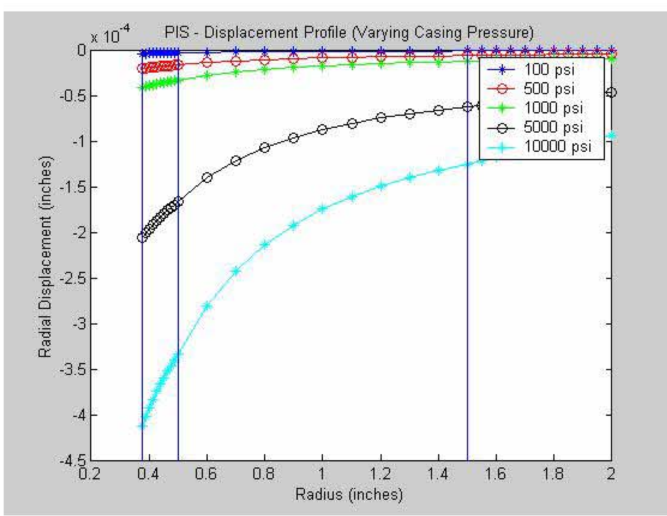
Poisson Ratio 0.35

Confining Pressure 0 psi

Cement Thickness 1 inch

Temperature gradient None

CASING PRESSURE (PIS)



Young's Modulus 5000 psi

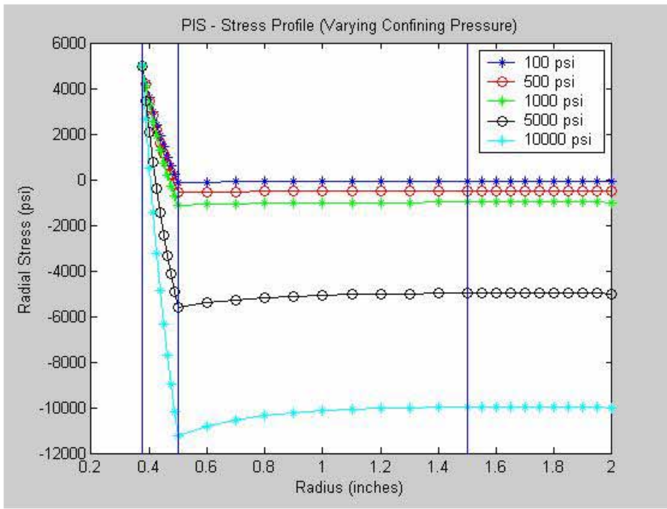
Poisson Ratio 0.35

Confining Pressure 0 psi

Cement Thickness 1 inch

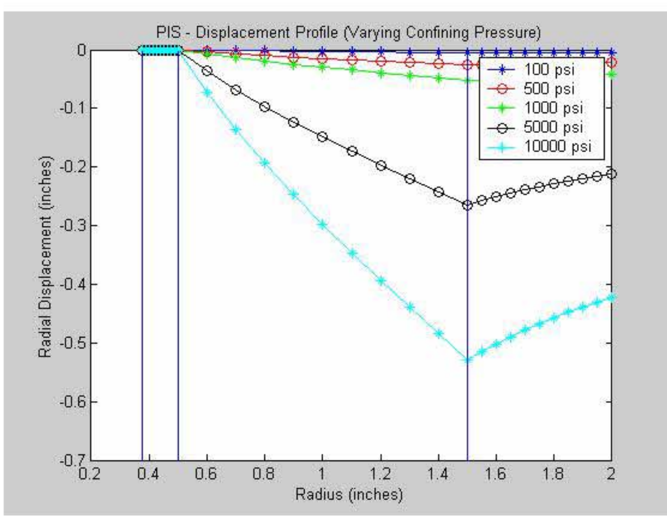
Temperature gradient None

CONFINING PRESSURE (PIS)



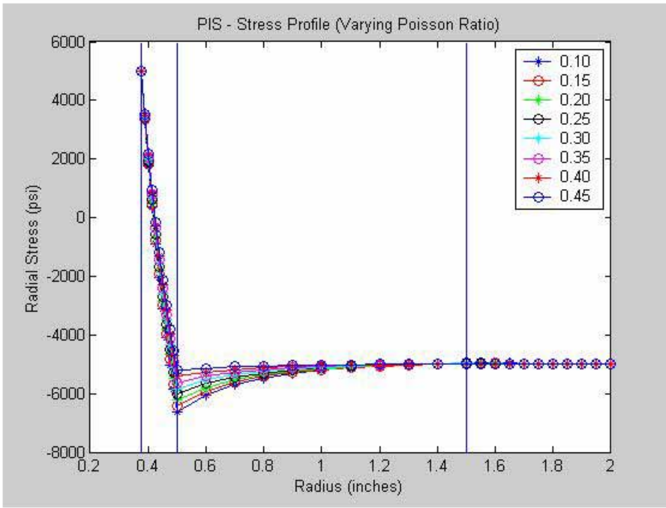
Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Casing Pressure	**5000 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

CONFINING PRESSURE (PIS)



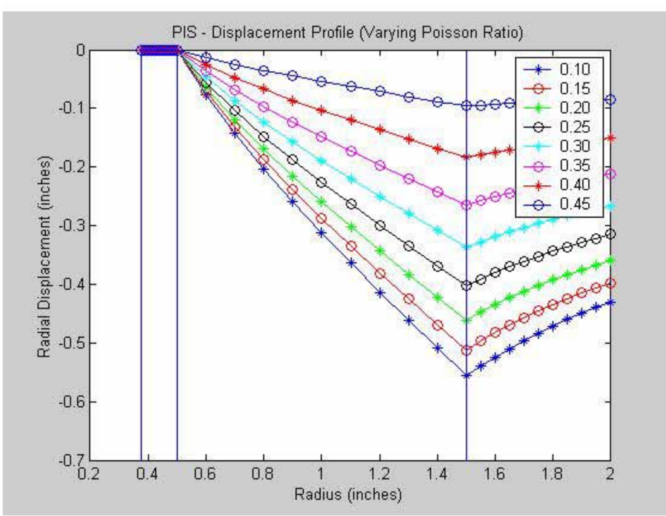
Young's Modulus	**5000 psi**
Poisson Ratio	**0.35**
Casing Pressure	**5000 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

POISSON RATIO (PIS)



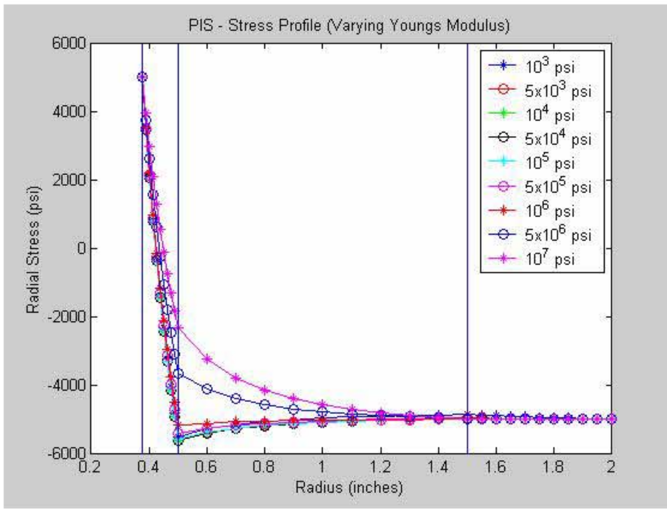
Young's Modulus	**5000 psi**
Casing Pressure	**5000 psi**
Confining Pressure	**5000 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

POISSON RATIO (PIS)



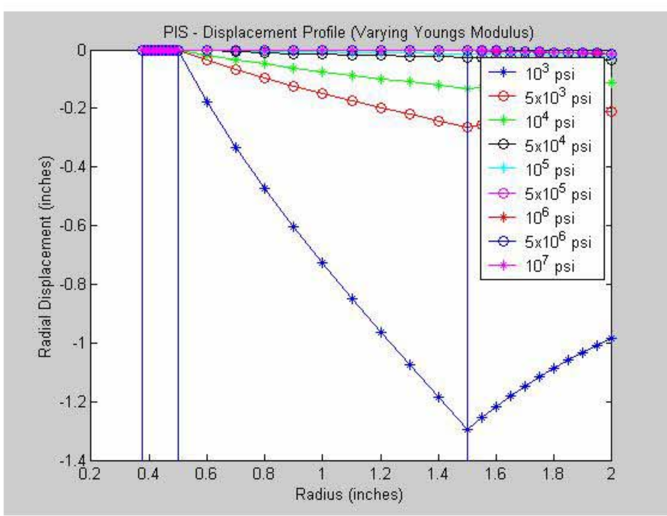
Young's Modulus	**5000 psi**
Casing Pressure	**5000 psi**
Confining Pressure	**5000 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

YOUNG'S MODULUS (PIS)



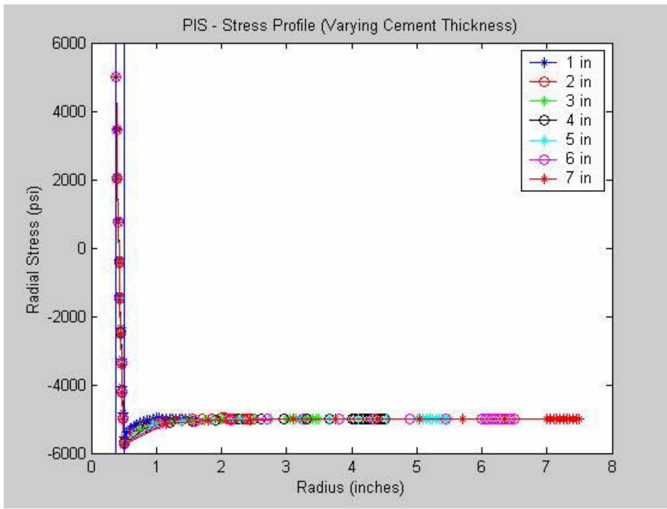
Casing Pressure	**5000 psi**
Poisson Ratio	**0.35**
Confining Pressure	**5000 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

YOUNG'S MODULUS (PIS)



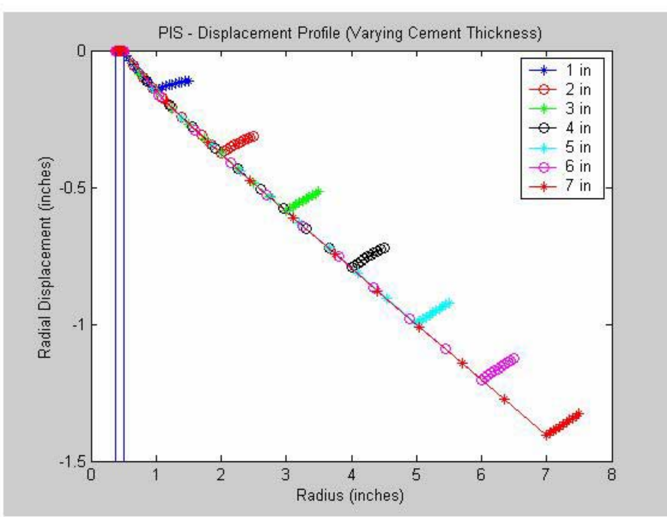
Casing Pressure	**5000 psi**
Poisson Ratio	**0.35**
Confining Pressure	**5000 psi**
Cement Thickness	**1 inch**
Temperature gradient	**None**

CEMENT THICKNESS (PIS)



Young's Modulus	5000 psi
Poisson Ratio	0.35
Confining Pressure	5000 psi
Casing Pressure	5000 psi
Temperature gradient	None

CEMENT THICKNESS (PIS)



Young's Modulus	5000 psi
Poisson Ratio	0.35
Confining Pressure	5000 psi
Casing Pressure	5000 psi
Temperature gradient	None

Appendix IX

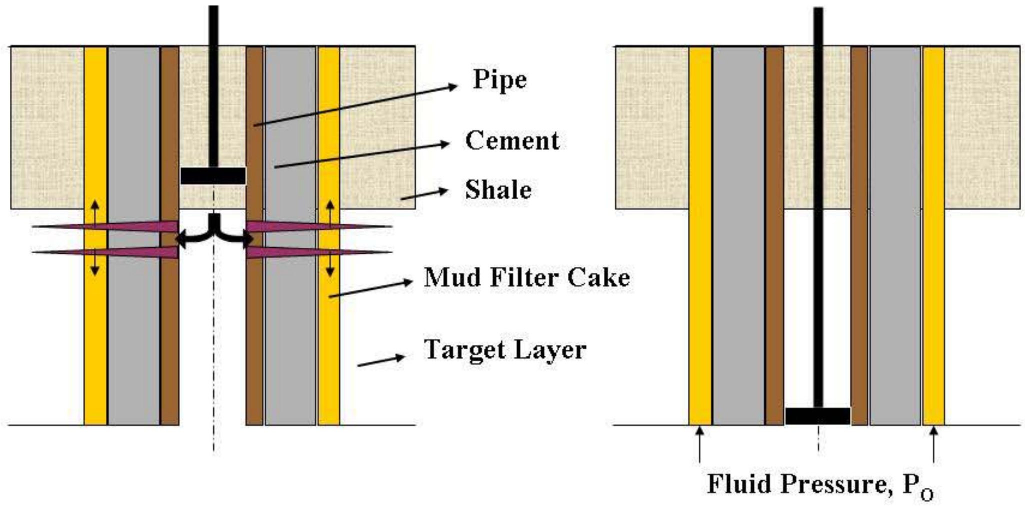
FEM – Hydraulic Seal Analysis

HYDRAULIC SEAL ANALYSIS

(DOE Low Perm Project)

University of Houston

PRESSURE TRANSMISSION THROUGH FILTER CAKE



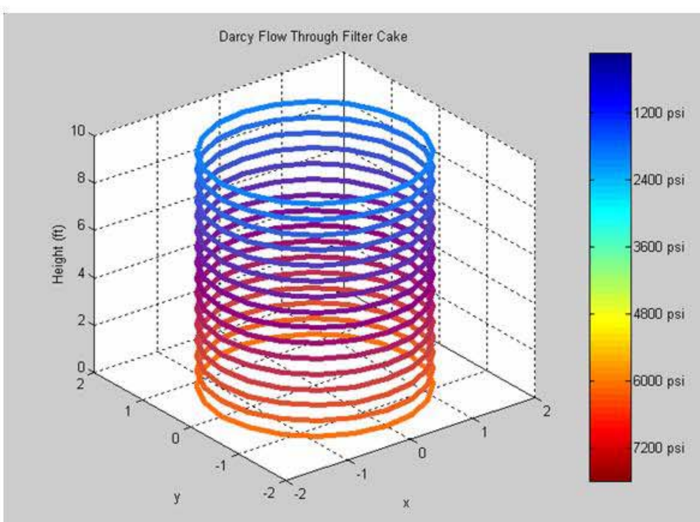
PRESSURE TRANSMISSION LOSS

- KEY MECHANISMS
  1. Fluid loss (Flow through filter cake)
     - → Flow through porous medium, Pin-holing or Tunneling
  2. Stress analysis in continuously concentric media
     - → Stress contrasts at cement-formation interface
     - → Cement bonding strength
  3. Pressure transmission through mud filter cake
     - → Vertical fracture migration through adjacent layers
  4. Energy dissipation in vertical fracture migration

FLUID LOSS –
FLOW THROUGH FILTER CAKE

- KEY IDEAS
  - Flow through porous media (Filter Cake)
  - Filter cake properties change with time (Permeability and Density)
- ASSUMPTIONS
  - Pseudo-steady state modeling
  - Formation permeability is very small compared to the filter cake (negligible flow through formation)
  - No pin-holing or cake lift-off

FILTER CAKE PERMEABILITY



Applied Pressure
50 MPa (7254 psi)

Fracturing Fluid Density
2000 Kg/m^3

Filter Cake Permeability
10000 md

Injection Rate
0.5 cc/sec

NON-DARCY FLOW EFFECT

- Non-Darcy flow at high velocities
- Reduces effective permeability of filter cake
- Forcheimer's equation for non-Darcy flow:

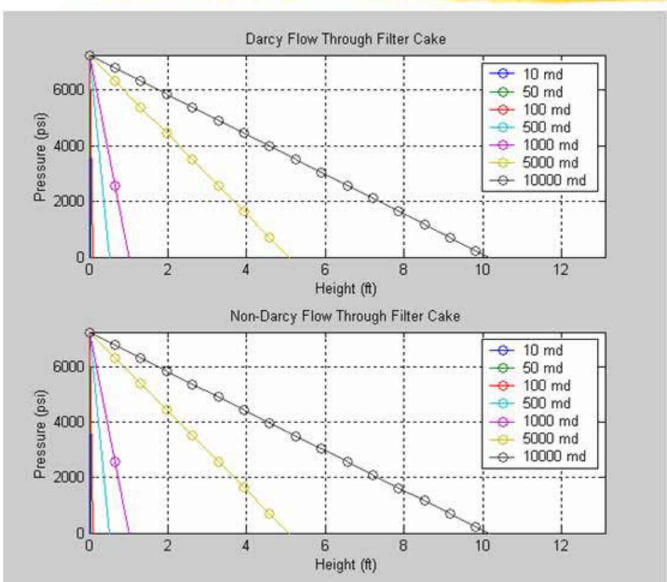
$$-\nabla P = \frac{\mu v}{k} + \beta \rho |v| v$$

v – Darcy Velocity

$$\beta = \frac{c}{k^{1.2}}, \text{ where } c = 8.4 \times 10^{-8}\, m^{1.4}$$

Firoozabadi & Katz (1979)

FILTER CAKE PERMEABILITY

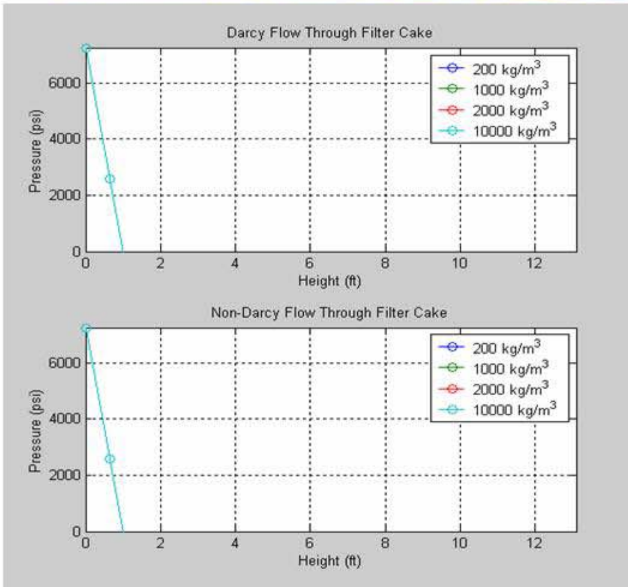


Applied Pressure
50 MPa (7254 psi)

Fracturing Fluid Density
2000 Kg/m^3

Injection Rate
0.5 cc/sec

FILTER CAKE DENSITY



Applied Pressure
50 MPa (7254 psi)

Fracturing Fluid
Permeability 1000 md

Injection Rate
0.5 cc/sec

MAIN RESULTS

- Non-Darcy flow effect is insignificant
  - Large velocities require high pressure gradient
- Fracturing fluid permeability plays an important role in pressure transmission through filter cake
- High permeability filter cakes transmit pressure more readily along its length
  - May cause undesired fracturing in adjoining layers

MAIN RESULTS (CONTD.)

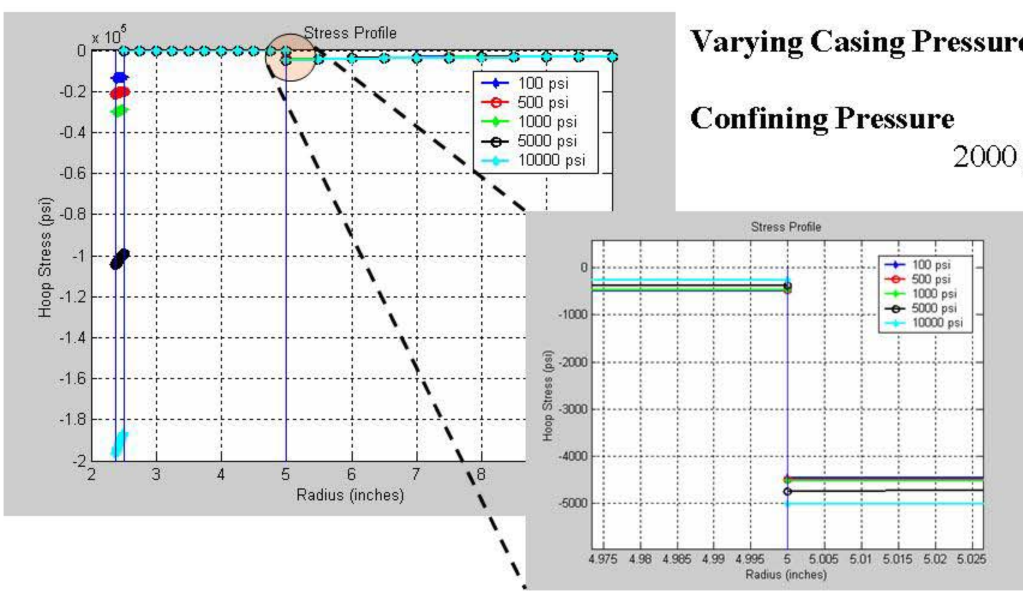
- Fracture height containment depends on breakdown pressure of adjoining layers
- Low permeability filter cakes behave as (visco-)elastic medium and are governed by regular solid body mechanics
- Porous formations further reduce pressure transmission through filter cake

SHEAR STRESS CONTRAST

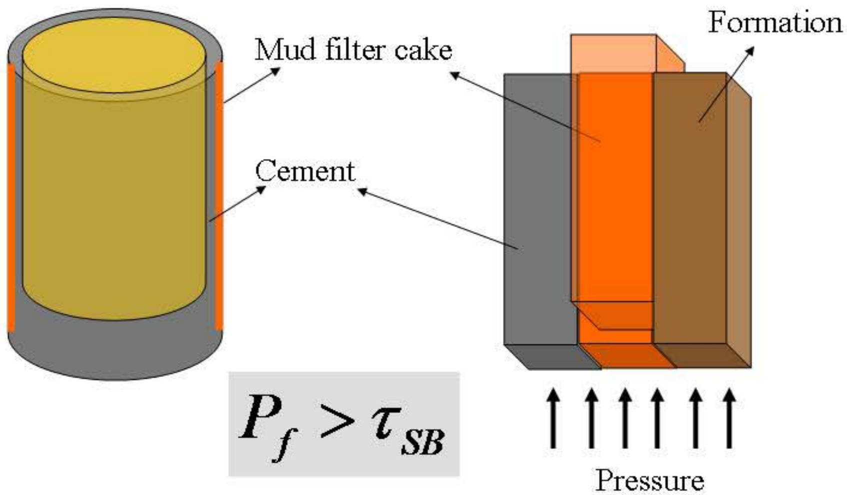
Varying Casing Pressure

Confining Pressure

2000 psi



SHEAR BOND STRENGTH

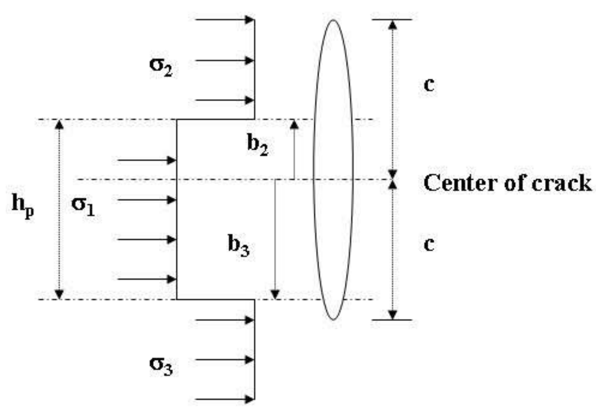


$$P_f > \tau_{SB}$$

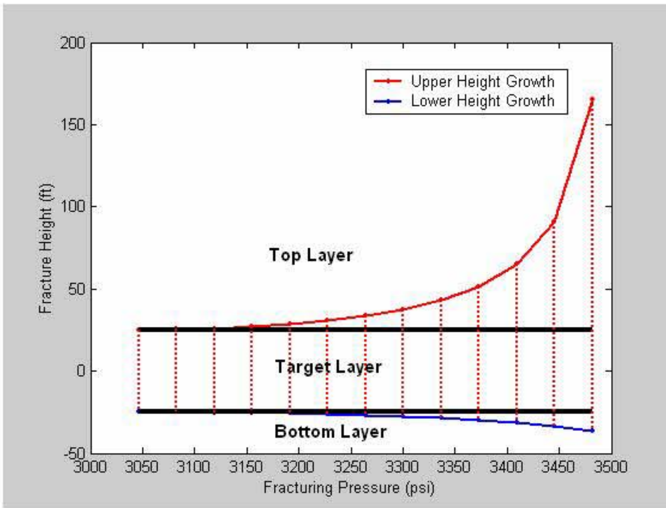
FRACTURE HEIGHT GROWTH

- Breaking cement-formation bond will expose adjacent layers to fracture growth
  - Shear stress contrast, Pressure leak or Pin-holing

Equilibrium Fracture Height



FRACTURE HEIGHT GROWTH



Target Layer Thickness 50 ft

Far-field Stresses
- Top Layer 3500 psi
- Target Layer 3000 psi
- Bottom Layer 4000 psi

Fracture Toughness
- Top Layer 1000 psi.in$^{1/2}$
- Bottom Layer 1000 psi.in$^{1/2}$

Neglect Hydrostatic Pressure Variation

FRACTURING ENERGY LOSS

- Useful energy is lost due to fracture migration, which could have produced deeper fractures

Strain energy spent to create upper wing,

$$W = \frac{1}{2}\delta\int_0^c p_n w(x)dx = \frac{4\delta}{\pi}\int_0^c \frac{\xi}{E'} g(\xi)^2 dx$$

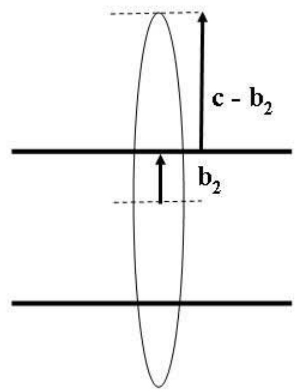
$$\text{where } g(\xi) = \int_0^\xi \frac{p_n(x)}{\left(\xi^2 - x^2\right)^{1/2}} dx, 0 < \xi < c$$

FRACTURING ENERGY LOSS

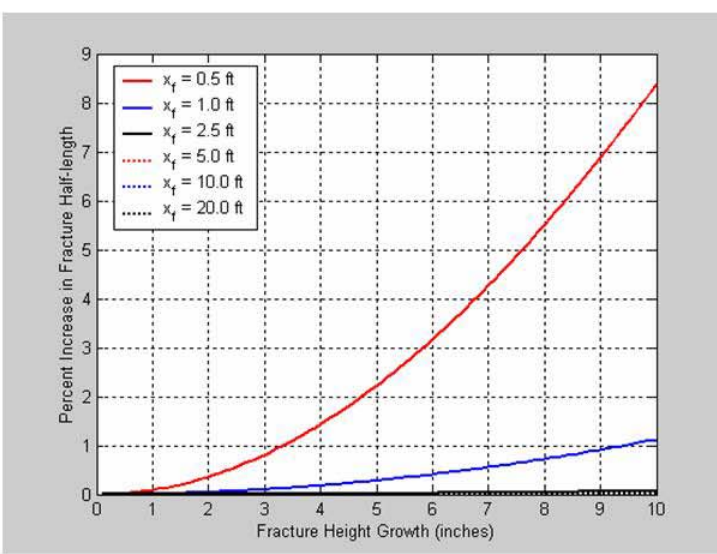
$$\int_0^c = \int_0^{b_2} + \int_{b_2}^c$$

$$W = \frac{\pi\delta}{2}\frac{p_{n,1}^2 b_2^2}{E_1'} + \boxed{\frac{\pi\delta}{2}\frac{p_{n,2}^2\left(c^2 - b_2^2\right)}{E_2'}}$$

↓ **Target Layer** ↓ **Top Layer**



FRACTURING ENERGY LOSS

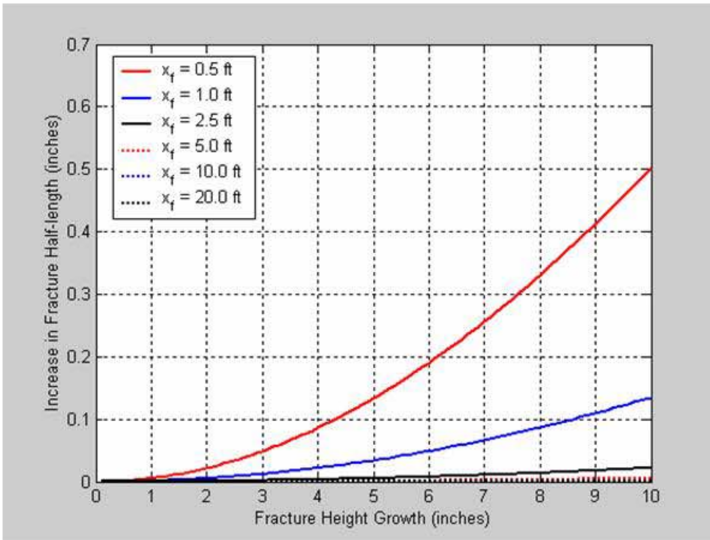


Equivalent Percent Increase in Fracture Penetration

Target layer only

$$\left(\frac{R - R_0}{R_0}\right) \times 100 \ \ \%$$

FRACTURING ENERGY LOSS

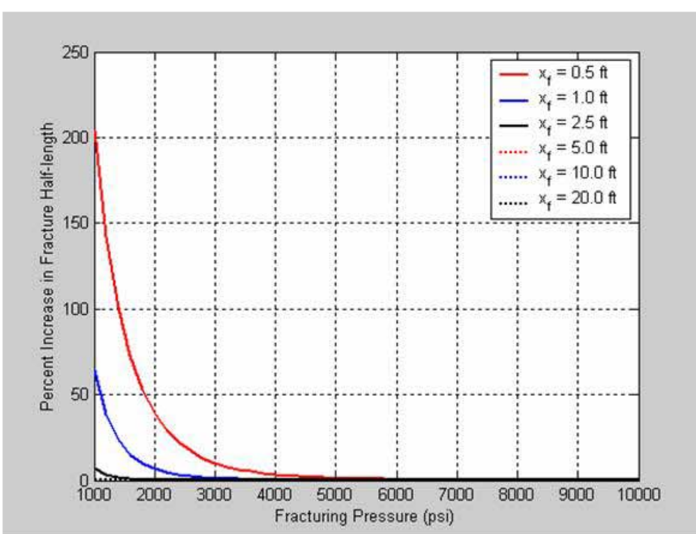


Equivalent Percent Increase in Fracture Penetration

Target layer only

$$\Delta R = R - R_0$$

FRACTURING ENERGY LOSS



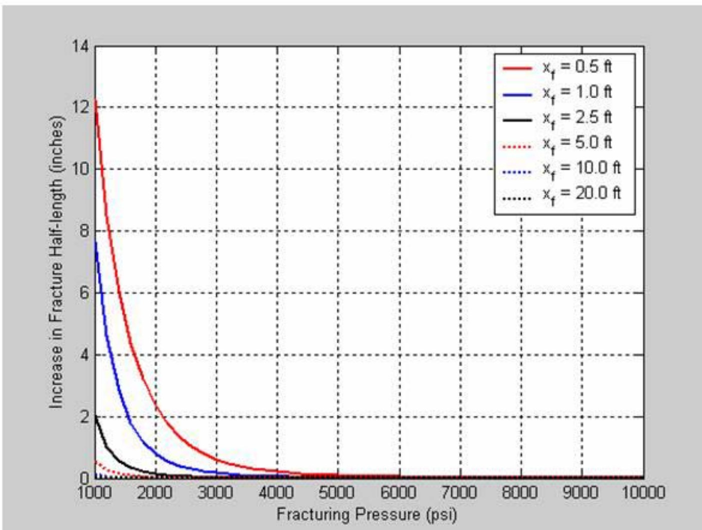
Equivalent Percent Increase in Fracture Penetration

Target layer only

$$K_I = p_n c^{1/2}$$

Equilibrium Fracture Height

FRACTURING ENERGY LOSS



Equivalent Length Increase in Fracture Penetration

Target layer only

$$K_I = K_{IC}$$

Equilibrium Fracture Height

Appendix X

Energy Analysis User's Guide

Theory

The Energy Analysis Spreadsheet is the Decision Matrix for cementing for the Low Perm Project. The basis for the Decision Matrix is the failure curve identified in laboratory testing for sealing performance of a variety of different cements in a model wellbore environment. Failure is determined by a complex interaction of a number of mechanical properties parameters as wellbore geometries and lithology parameters, all of which are captured in the comparison of two dimensionless variables.

Spreadsheet Organization

The Excel spreadsheet is organized in three tabs labeled Input_Output, Calcs, and Pressure Power Plot.

The Calcs tab contains all the calculations necessary to relate real-well parameters to laboratory-generated failure curves. Changes to cells in this tab are neither required nor recommended.

The Pressure Power Plot tab contains the correlated failure curve of E1R vs E1A (dimensionless energy resistance factor vs dimensionless energy application factor). This information is presented for reference only. The blue line on this plot is the failure curve generated in the lab, and the red point represents the field data point for the conditions entered on the Input_ Output tab. Note that slurries with values above the line are less likely to fail, while slurries with points below the line are more likely to fail.

The Input_Output tab is the section in which formation, well geometry, cement data, and anticipated frac history is input, and the tab in which the results are displayed. The balance of this section will concentrate on how to use this tab. Note that each discreet "run" in the spreadsheet concentrates on the cement property requirements for a particular zone. Each zone will require different "runs", because of changing parameters, including frac history.

Data Entry

1. Red cells are data entry cells. Note that the spreadsheet is selected so that you cannot enter data, nor make the active cell, in a protected (black-font) cell. This is to prevent accidental corruption of the spreadsheet.
2. Enter well geometry data in B7 through B10.
3. Enter Formation Young's Modulus in cell B12.
4. Enter any two of known or anticipated cement mechanical properties in cells F7 through F9. Entering all three data values will result in a red error message in cell E10 stating that two and only two values must be entered. To remove a data point, select the cell and then "delete".
5. Enter the planned previous history of frac or significant intervention or production pressures in cells A16 through C23. As presented, the current frac zone is from 6,000 ft to 6,250 ft, and the anticipated frac pressure is 7,500 psi. In addition to the currently-planned frac in this zone, lower zones were previously treated and the frac pressures recorded. There will be more data in upper zones, because the lower zones have already been stimulated. In the presented case, four lower zones have been previously frac'd at the depths and pressures noted.

Output

Output is noted as two items. The first are the required mechanical cement properties in the table in cells J7 through L9. Here, the table contains minimum tensile strength, maximum cement Young's Modulus, and Maximum anelastic strain required. These results place the field data point (red point) on the lab-generated failure curve (blue line). This means that the cement should provide annular sealing for the conditions specified. Note that cement property values higher than the minimums calculated, and/or values lower than the maximums calculated will result in less likelihood of cement failure.

Appendix XI

Laboratory Data

Test Cement Compositions

Baseline Slurry
Class H Cement
0.48% bwoc Natrosol
0.32% bwoc Melcret
0.15% bwoc Marabond 21
4.23 gal/sk fresh water
Density: 16.4 lb/gal
Yield: 1.06 cu ft/sk

Foamed Cement
Class A Cement
0.03 gal/sk Witcolate
0.02 gal/sk Aromox C-12
0.50% bwoc Natrosol
0.30% bwoc Marabond 21
5.04 gal/sk fresh water
Density: 15.6 lb/gal
Yield: 1.18 cu ft/sk
Foamed Density 13.5 lb/gal

Baseline Slurry with Fibers
Class H Cement
0.48% bwoc Natrosol
0.32% bwoc Melcret
0.15% bwoc Marabond 21
3.50% bwoc Carbon Fibers
4.23 gal/sk fresh water
Density: 16.4 lb/gal
Yield: 1.09 cu ft/sk
Fibers are milled, pitch-based carbon fibers manufactured by Conoco:

9 μm Diameter
10-100 μm Length
2.00 specific gravity

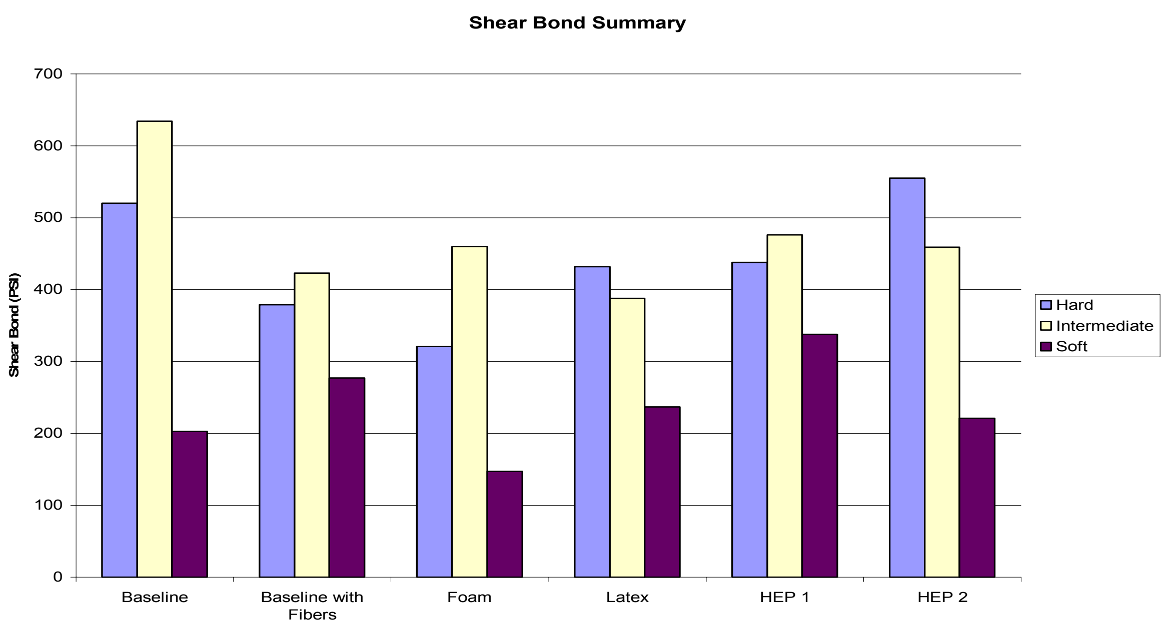
Latex
Class A Cement
1.00 gal/sk LT D500
0.50% bwoc Marabond 21
4.20 gal/sk fresh water
Density: 15.6 lb/gal
Yield: 1.18 cu ft/sk

Tensile Strength Summary						
	Baseline	Baseline with Fibers	Foam	Latex	HEP 1	HEP 2
Tensile Strength (PSI)	673	353	578	504	233	349

Frac Model Test Summary						
	Baseline	Baseline with Fibers	Foam	Latex	HEP 1	HEP 2
Fracture Pressure (PSI)	333	1050	400	367	633	433
Resulting Flow (mL/sec)	0.8	5	3.2	0.5	2.9	0.5
Catastrophic (PSI)	900	-	667	1033	867	700
Catastrophic (mL/sec)	32.8	-	575	136.3	249	2000

Young's Modulus Summary						
	Baseline	Baseline with Fibers	Foam	Latex	HEP 1	HEP 2
Young's Modulus	5.83 E5	2.64 E5	0.45 E5	7.95 E5	1.36 E5	2.70 E5

DOE Low Permeability Shearbond Summary						
	Baseline	Baseline with Fibers	Foam	Latex	HEP 1	HEP 2
Hard	520	379	321	432	438	555
Intermediate	634	423	460	388	476	459
Soft	203	277	147	237	338	221



DOE Low Permeability Testing Summary

SYSTEM	Thickening Time	Static FL	Ultrasonic Cement Analyzer (hh:mm) / (psi)								SGSA (hh:mm)
Slurry	(hh:mm) to 70Bc	(ml/30min)	50 psi	500 psi	12 hrs	24 hrs	2 Days	5 Days	8 Days	10 Days	75-500 lbƒ/100ft²
Baseline	4:02	62	9:08	9:52	874	2805	3800	4026	4032	4035	0:55
HEP 1	4:02	No Control	4:50	6:10	1263	1350					0:54
HEP 2	2:09	78	2:11	6:57	1758	2013					0:28
Foam	3:15	219	9:32	12:08	487	2200	2990	3436	3436	3436	4:15
Latex	6:05	24	20:59	0:05	20	778	3000	3606	3623	3630	7:08

DOE Low Permeability Testing Summary

SYSTEM	Tem.	Rheology										
Slurry	°F	300 rpm	200 rpm	100 rpm	60 rpm	30 rpm	6 rpm	3 rpm	10 sec Gel	10 min Gel	PV	YP
Baseline	**80**	510	380	230	160	90	30	20	18	34	420	90
	150	300	220	130	90	54	20	14	12	34	255	45
HEP 1	**80**	52	36	20	18	12	8	6	6	6	48	4
	150	44	30	20	16	12	10	8	8	4	36	8
HEP 2	**80**	148	104	52	30	24	4	2	2	10	144	4
	150	86	58	30	16	10	4	2	2	6	84	2
Foam	**80**	72	60	44	38	30	22	20	20	44	42	30
	150	74	64	50	46	40	26	20	24	24	36	38
Latex	**80**	110	90	70	62	50	40	30	30	50	60	50
	150	140	120	100	90	90	68	64	32	47	60	80

Annular Seal

Results presented in Table 8 indicate that all cyclic testing specimens failed in the soft formation simulation while all specimens in the hard-formation tests maintained seal. These results indicate the need for a simulated formation with intermediate strength to further differentiate seal effectiveness. Additional stresses for the hard-formation simulation must be imposed through application of heat or pressure.

Table 8—Annular Seal Tests

Condition Tested	Formation Simulated	Type I Slurry	Foamed Slurry	Bead Slurry
Initial Flow	Hard	0 Flow	0 Flow	0 Flow
	Soft	0 Flow	0.5 (md)	0 Flow
Temperature-Cycled	Hard	0 Flow	0 Flow	0 Flow
	Soft	0 Flow	123 md	43 md*
Pressure-Cycled	Hard	0 Flow	0 Flow	0 Flow
	Soft	27 md	0.19 md*	3 md

* Visual inspection revealed samples were cracked.

Modified annular seal testing procedures were employed as outlined in Appendix A page 31 and all three formations including hard, intermediate, and soft were retested using this new procedure. Results for both temperature and pressure cycling are found in Tables 9 through 13. The test methods are explained in Appendix A page 32.

Failure of annular seals was achieved in all formations by increasing cycling until achieving flow. The general trend as can be seen in Tables 9 through 13 was that hard formations needed the greatest amount of cycling to achieve failure. Intermediate formations required less cycling to achieve failure and Soft formations required the least amount of cycling to achieve failure.

Annular seal testing with intermediate-strength formation and increased cyclic loading indicated all materials failed to maintain a seal. Interestingly, foam cement faired best in pressure cycling and worst in temperature cycling.

Table 14 represents a quantifiable measurement of the energy needed whether pressure or temperature induced to produce failure of annular seal. Results of these energy measurements are graphed and compared in Figures 15 and 16.

Table 9—Annular Seal Pressure-Cycled Slurry Comparison

Slurry	Form.	Cycle	Pressure (psi)										
			1000-4000	5000	6000	7000	8000	9000	10,000	10,000	10,000	10,000	10,000
Type 1	Hard	1	0	0	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	0	0	0	0	0
		4	0	0	0	0	0	0	0	0	**0.14mD**	**0.42mD**	**2.10mD**
	Inter.	1	0	0	0	0	**0.01 md**	**1.1 md**	**1.31 md**	**2.04 md**	**-**	**-**	**-**
	Soft	1	0	0	**0.39 md**	**0.39 md**	**1.38 md**	**+6.69 md**	**-**	**-**	**-**	**-**	**-**
Foam	Hard	1	0	0	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	**0.14mD**	**0.28mD**	**0.42mD**	**1.12mD**
	Inter.	1	0	0	0	0	0	0	0	0	0	0	**0.79mD**
	Soft	1	0	0	**0.96 md**	**3.2 md**	**5.88 md**	**+6.4 md**	-	-	-	**-**	-
Bead	Hard	1	0	0	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	0	0	**0.28mD**	**1.68mD**	**2.24mD**
	Inter.	1	0	0	0	0	0	0	**0.66mD**	**0.18mD**	**0.80mD**	**0.56mD**	**0.80mD**
	Soft	1	0	0	0	**0.13 md**	**0.39 md**	**5.76 md**	**+6.4 md**	**-**	**-**	**-**	-
Latex	Hard	1	0	0	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	**0.03mD**	**0.14mD**	**0.28mD**	**1.4mD**	**2.1mD**
	Inter.	1	0	0	0	0	**0.80 md**	**2.10 md**	**-**	**-**	**-**	**-**	**-**
	Soft	1	0	**1.25 md**	**+6.4 md**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table 10—Annular Seal Pressure-Cycled Formation Comparison

Slurry	**Form.**	**Cycle**	**Pressure (psi)**										
			1000-4000	**5000**	**6000**	**7000**	**8000**	**9000**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**
Hard	Type 1	1	0	0	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	0	0	0	0	0
		4	0	0	0	0	0	0	0	0	**0.14mD**	**0.42mD**	**2.10mD**
	Foam	1	0	0	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	**0.14mD**	**0.28mD**	**0.42mD**	**1.12mD**
	Bead	1	0	0	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	0	0	**0.28mD**	**1.68mD**	**2.24mD**
	Latex	1	0	0	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	**0.03mD**	**0.14mD**	**0.28mD**	**1.4mD**	**2.1mD**
Interm	Type 1	1	0	0	0	0	**0.01 md**	**1.1 md**	**1.31 md**	**2.04 md**	**-**	**-**	**-**
	Foam	1	0	0	0	0	0	0	0	0	0	0	**0.79mD**
	Bead	1	0	0	0	0	0	0	**0.66mD**	**0.18mD**	**0.80mD**	**0.56mD**	**0.80mD**
	Latex	1	0	0	0	0	**0.80 md**	**2.10 md**	**-**	**-**	**-**	**-**	**-**
Soft	Type 1	1	0	0	**0.39 md**	**0.39 md**	**1.38 md**	**+6.69 md**	**-**	**-**	**-**	**-**	**-**
	Foam	1	0	0	**0.96 md**	**3.2 md**	**5.88 md**	**+6.4 md**	-	-	-	**-**	-
	Bead	1	0	0	0	**0.13 md**	**0.39 md**	**5.76 md**	**+6.4 md**	**-**	**-**	**-**	-
	Latex	1	0	**1.25 md**	**+6.4 md**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Failure of the cement sheath in a wellbore environment is due to imposed stresses that are greater than the cement can withstand. Measurement of stresses becomes difficult, even in laboratory models because of the non-homogeneous composite nature of the cement itself. Specifically, the different types of cements contribute to the difficulty, because of the very different ways in which they respond to applied pressure and temperature loads. While pressure loads can be related to gross stress relatively simply, the effect of temperature is problematic due to the complex wellbore geometry and the many and variable system constraints. To address this difficulty and quantify performance of the various test compositions in the annular seal model, failure was related to the total energy input to the wellbore / cement / formation system. Energy input is in one of two forms, pressure or temperature. Ultimately, the stresses imposed are caused by the input of energy to the system. This simplification bypasses the problem of the non-uniform distribution of these stresses in the non-homogeneous material.

The correlation of energy input to ultimate cement failure was done in order to better understand the mechanisms associated with wellbore cement integrity. The results of this correlation are presented in Tables 12 through 14 and Figures 11 through 16. Further work is required to fully understand the mechanisms by which hydraulic or thermal energy ultimately leads to cement failure. In the current small sample, the following observations are offered:

- With only two exceptions, the amount of energy (pressure or temperature) required to induce cement sheath failure increases with the competence of the formation. The stronger the formation, the more support it lends to the cement sheath so that it can withstand the imposed loads.
    - The two exceptions involve the temperature energy applied to Bead systems. In these cases, the energy to initiate failure is slightly higher in the intermediate formation than the hard, although statistically they may be equivalent. The explanation is that in the case of temperature, the superior insulating properties of the beads reduce the importance of formation competence, within limits. This represents an important finding supporting the use of beads in cases that may traditionally have indicated foam. The stronger encapsulation of the air pocket in bead vs foam means that the bead cements will withstand heat better than foam systems.
- Bead cements performed very well in all the testing, as evidenced in the cases of weaker formations. In the case of pressure energy, foam also performed better than Type 1 and Latex slurries with weaker formation support. This may be due to better anelastic behavior, in which the cement is more ductile than the higher-strength systems.
- In all cases, the amount of temperature energy required to initiate failure is much lower than the pressure energy to failure. The reason for this is believed to be the destructive effects of matrix water expansion with temperature.
-

At this point, with limited data, the results cannot be scaled up from lab to field geometries with confidence. More work is required to understand the energy absorption of the various wellbore components, so that the energy applied to the slurry itself is isolated and understood. As a qualitative example, heavier wall internal pipe will absorb more energy, thereby reducing the energy input to the slurry. More testing will allow in-depth understanding of energy distribution in the wellbore.

Anelastic Strain

Anelastic strain testing is a variation of hydrostatic testing and is designed to allow a more accurate evaluation of permanent strain resulting from stressing different test compositions. This procedure standardizes confining stress at 500 psi and calls for samples to be cycled to 25% and 50% of each composition's compressive strength or failure load under that confining stress. Measurement of anelastic strain with cycling provides a more comparable value of each composition's performance. See Figures 5 and 6.

Results of anelastic strain testing are presented in Table 6. Strain data are reported as final strain minus initial strain measurements, with final being at the end of three cycles. In order to analyze data for different compositions uniformly, a stress point was chosen on the stress-strain plot at a point that the strain appeared to be linear. Strains at this stress magnitude at the beginning and end of cycling were measured and used to calculate plastic deformation. This comparison point is listed also. Data were then normalized with respect to sample length so results appear in units of mm/mm. This step eliminates apparent variations in deformation data due to variations in sample size.

Table 6—Results of Anelastic Strain Testing

Composition	Failure (psi)	Comparison Stress (psi)	Strain (mm/mm)	
			25%	**50%**
Type I slurry	6000	600	0.0006	0.0007
Foam slurry	2000	400	0.0009	0.0007
Latex slurry	6000	600	0.0007	0.0009

Data generation also includes a round of samples tested to a common stress maximum as seen in Figures 7 through 10 to provide two alternate methods of comparison.

Figure 1— Anelastic strain failure load for neat Type 1 slurry at a load rate of 250 psi/min and confining pressure of 500 psi.

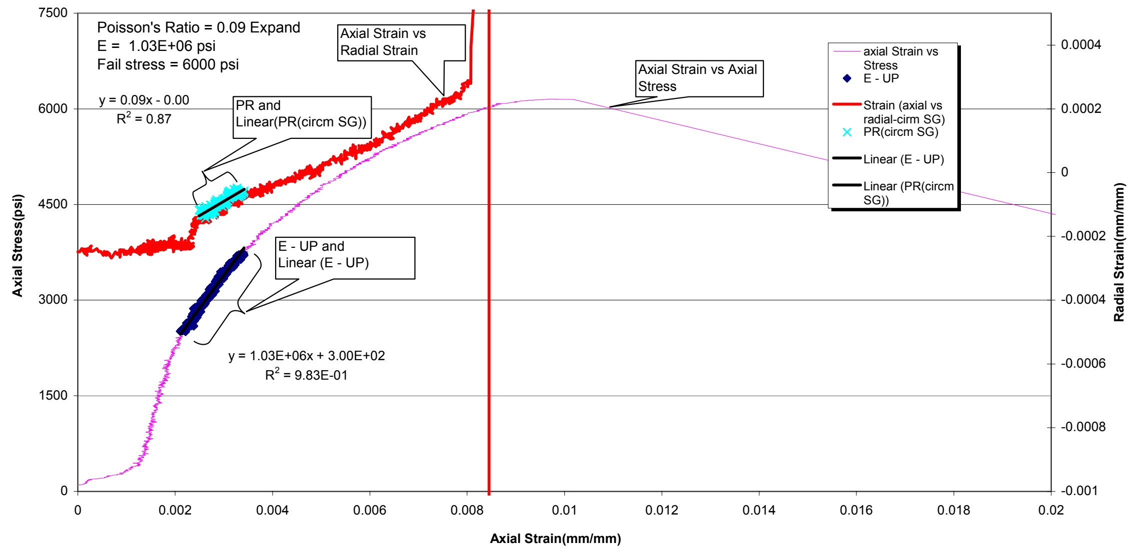


Figure 2— Anelastic strain failure load for foam slurry at a load rate of 250 psi/min and confining pressure of 500 psi.

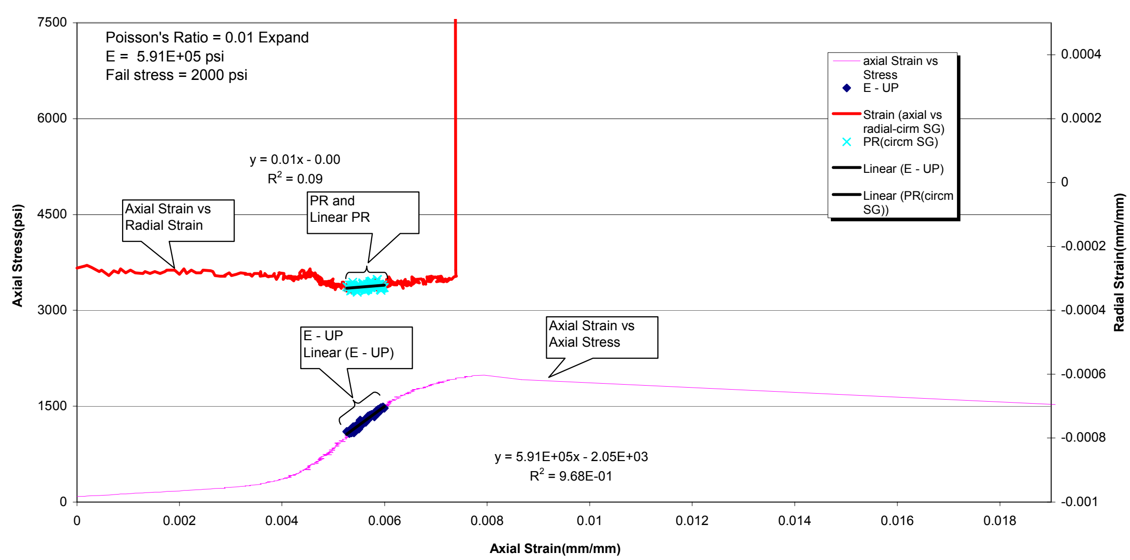


Figure 3— Anelastic strain failure load for bead slurry at a load rate of 250 psi/min and confining pressure of 500 psi.

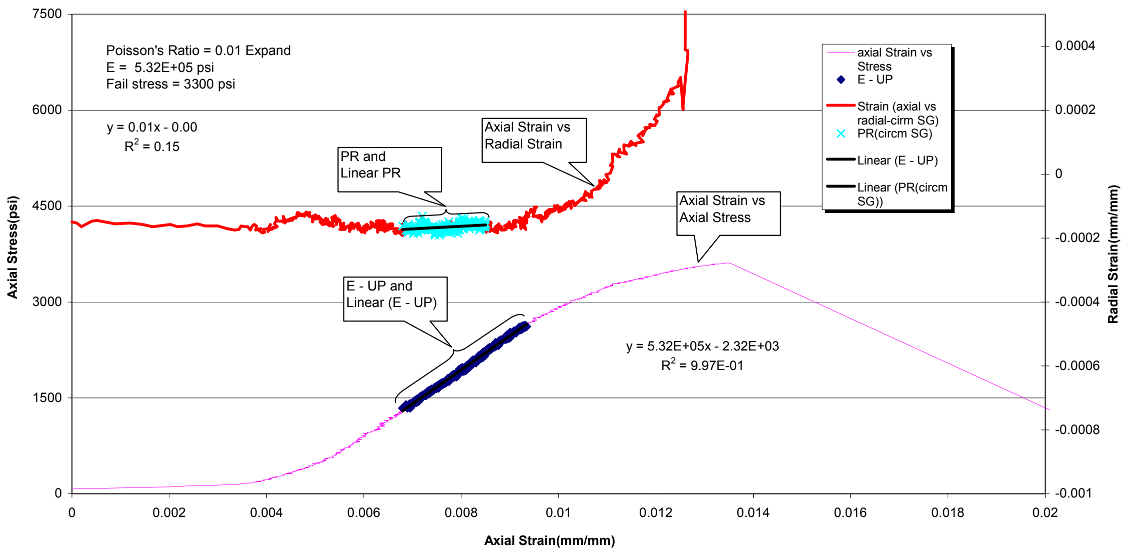
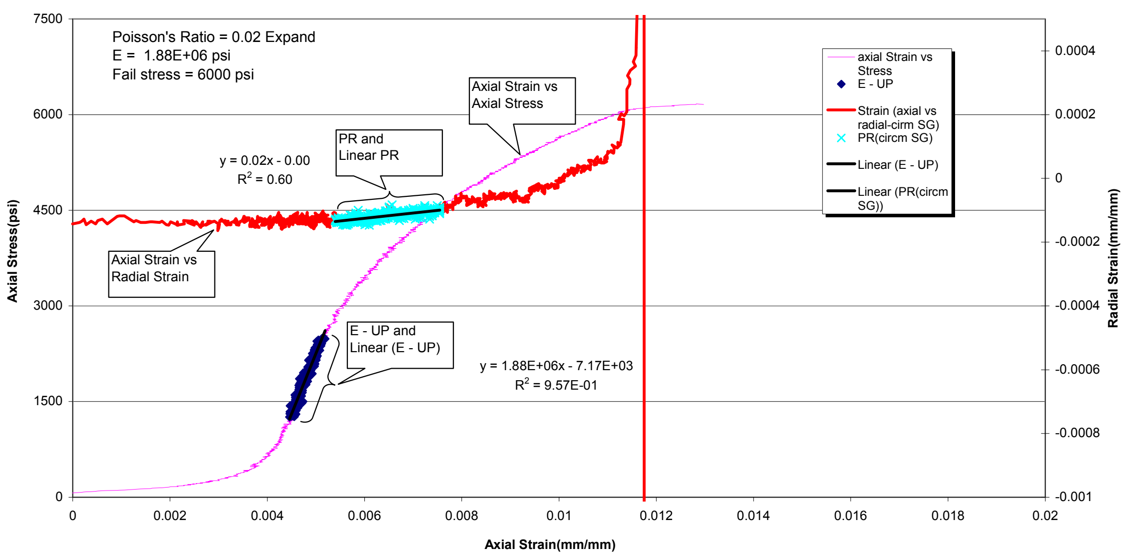


Figure 4—Anelastic strain failure load for latex slurry at a load rate of 250 psi/min and confining pressure of 500 psi.



Figures 5 and 6 present strain vs. cycle data for the four compositions at 25% and 50% of each composition's failure stress. Dashed lines represent the slope of each line. Note that all trends are increasing indicating that each specimen would undergo additional anelastic strain with increased cycles. Comparison of the data sets indicates larger strains for low density compositions than for normal density cements.

Figure 5—Anelastic strain comparison of cycles to 25% of failure load

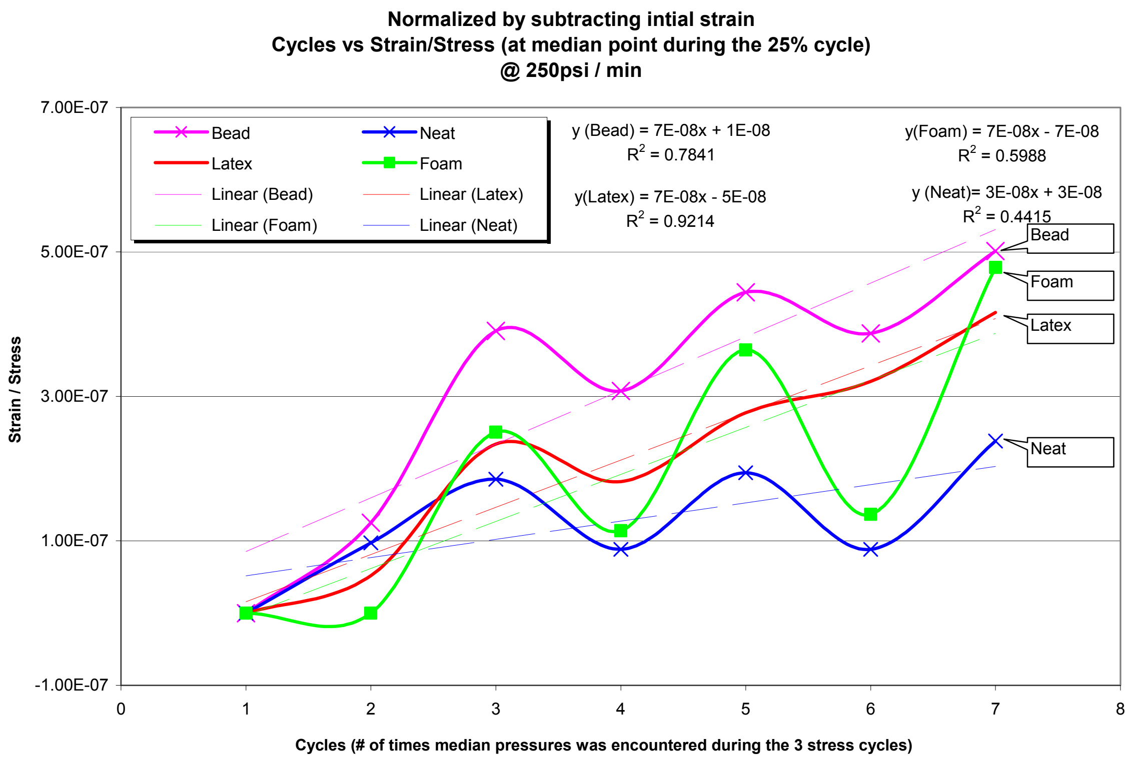
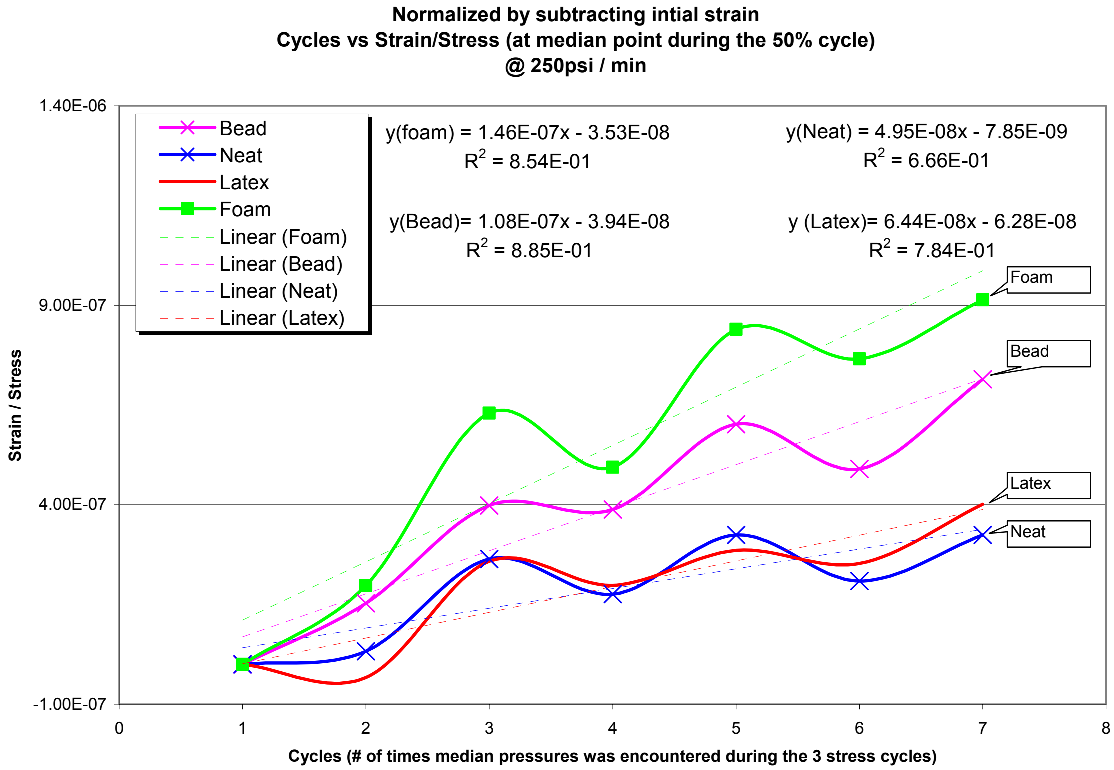


Figure 6—Anelastic strain comparison of cycles to 50% of failure load



Results of strain vs. time under stress testing are presented in Figures 7 and 8. These results indicate that both foam and bead cement exhibit increasing strain with time under stress. Foam cement's level of strain with increasing stress was slightly more than bead cement.

Figure 7—Anelastic strain vs. Time comparison of Foam and Bead

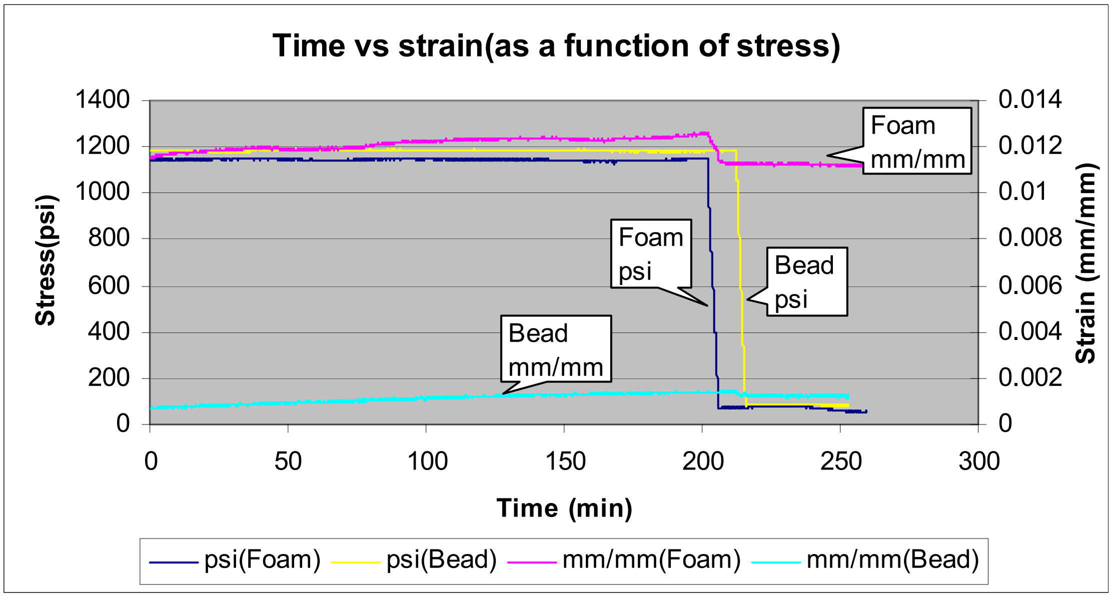
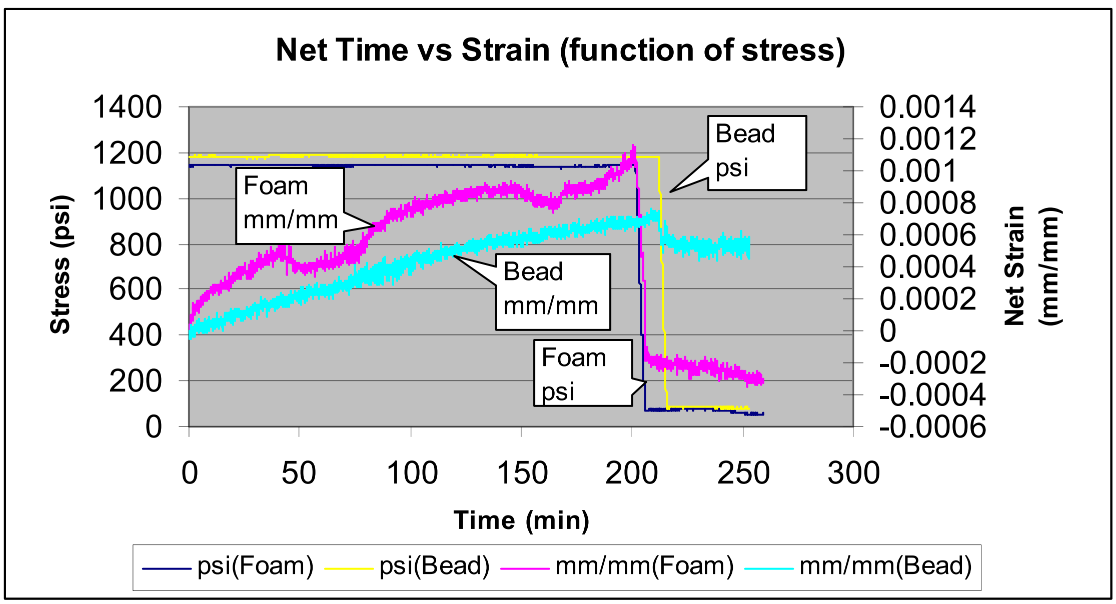


Figure 8—Anelastic strain comparison of Foam and Bead systems. Strain values from Figure 7 are normalized with respect to each sample's initial strain for comparison.



Figures 9 and 10 present results of strain measurement vs cyclic stress application. Data from Figure 9 are raw data while those in Figure 10 are normalized with respect to initial strain for each sample. These results indicate significant increase in cycling effect for foam compared to the other three compositions.

Figure 9—Cyclic Strain comparison of Bead, Foam, Neat and Latex systems

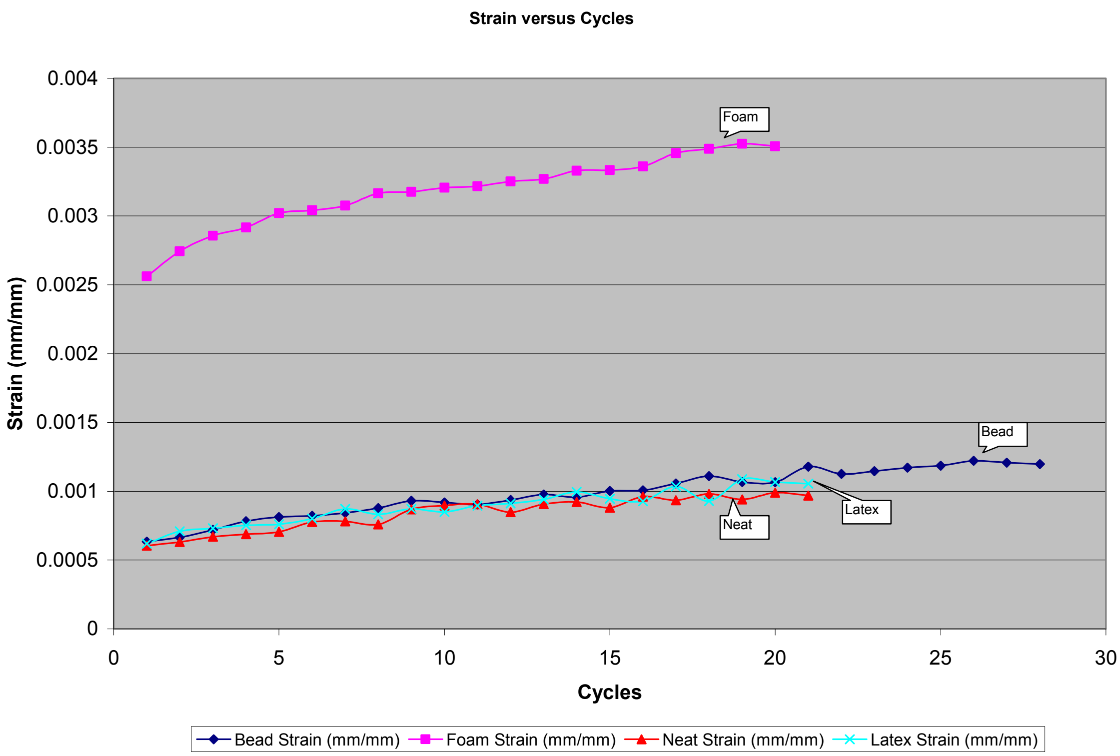
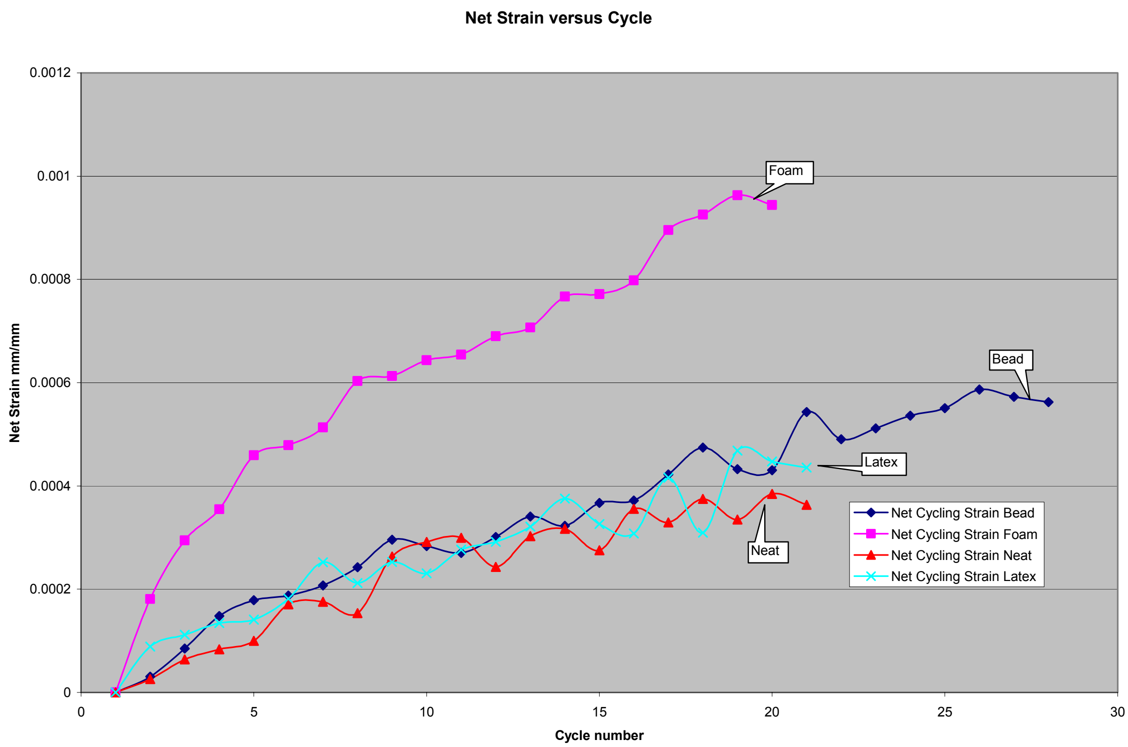


Figure 10—Net Cyclic Strain comparison of Bead, Foam, Neat and Latex systems



Anelastic strain testing, a variation of hydrostatic testing, is designed to allow a more accurate evaluation of permanent strain resulting from stressing different test compositions. Samples are cycled to 25%, 50%, and 75% of each composition's compressive strength under 500-psi confining stress. Measurement of anelastic strain with cycling provides a more comparable value of each composition's performance. The first step in the procedure involves compression testing a sample to failure in the load cell with 500-psi confining stress. Once this failure load value is determined, additional samples will be tested by applying axial loads equal to 25%, 50%, and 75% of the failure load, and cycling until samples fail. The cyclic loading rate will be maintained at 250 psi/min and the confining force will be maintained at 500 psi. Plastic deformation will be measured at the end of each cycle. Results will include cycles to failure and anelastic strain per cycle.

Appendix XII

Lab Test Procedures

Sample Preparation Procedure:

Testing methods for the foamed slurries were modified. For example, thickening time is performed on unfoamed slurries only. Because the air in the foam does not affect the hydration rate, the slurry is prepared as usual per API RP 10B and then the foaming surfactants are mixed into the slurry by hand without foaming the slurry. All other cement designs were prepared per API RP 10B.

Density Procedure:

After curing, the sample is extracted from the mold and cut into 1-in. ±1/8 in. sections in length. A ¼-in. section of the top surface of the sample is cut first. Next, the three 1-in. sections to be measured are cut. Each 1-in. ±1/8 in. section is identified as top, middle, and bottom and is measured for density. The remaining sample pieces are discarded. The density is calculated by suspending the cut-core samples in water and weighing them using a Denver Instruments Lab Balance, model TR-2102. This procedure is referred to as the Archimedes Principle method.

Cement Application Testing Procedure:

Standard cement design performance testing, including rheology, thickening time, static fluid loss, and compressive strengths obtained from a UCA are performed according to procedures outlined in API RP 10B.

Rheology measurements were made following guidelines of API RP 10B. Initial rheological values were taken followed by rheological values taken at 150°F after conditioning on an atmospheric consistometer for 20 minutes.

Thickening time tests were performed on HTHP consistometers at a temperature of 150°F with a final pressure of 8,000 psi reached in 40 minutes. Thickening times are reported to 70 Bc.

Static fluid loss tests were performed following guidelines of API RP 10B. The tests were performed at 150°F after conditioning the slurries for 20 minutes on atmospheric consistometers.

Compressive strengths were made following guidelines of API RP 10B. The non-destructive sonic cement test was performed utilizing an Ultrasonic Cement Analyzer. The slurries were tested at a temperature of 185°F and 3,000psi on the UCA.

Static gel strengths were performed utilizing the Static Gel Strength Analyzer. Samples of slurry were cured at 185°F with 3,000 psi.

Shear Bond Strength Testing Procedure:
Shear bond strength tests are used for investigating the effect that restraining force has on shear bond. Samples are cured in a hard-formation configuration (**Figure A2**) and in a soft-formation configuration (**Figure A3**). The hard-formation configuration consists of a sandblasted internal pipe with an outer diameter (OD) of 1 $^1/_{16}$ in. and a sandblasted external pipe with an internal diameter (ID) of 3 in. Both pipes are 6 in. long. A contoured base and top are used to center the internal pipe within the external pipe. The base extends into the annulus 1 in. and cement fills the annulus to a height of 4 in. The top inch of annulus contains water.

For the soft-formation shear bond tests, plastisol is used to allow the cement to cure in a less-rigid, lower-restraint environment. Plastisol is a mixture of a resin and a plasticizer that creates a soft, flexible substance. This particular plastisol blend (PolyOne's Denflex PX-10510-A) creates a substance with a hardness of 40 duro.

The soft formation configuration contains a sandblasted external pipe with an ID of 4 in. A molded plastisol sleeve with an ID of 3.0 in. and uniform thickness of 0.5 in. fits inside the external pipe. With the aid of a contoured base and top, a sandblasted internal pipe with an OD of 1 $^1/_{16}$ in. is then centered within the plastisol sleeve. The pipes and sleeve are 6 in. long. The base extends into the annulus 1 in. and cement fills the annulus to a height of 4 in. between the plastisol sleeve and the inner 1 $^1/_{16}$ -in. pipe. The top inch of annulus is filled with water.

The intermediate formation test fixture features the same configuration as the hard formation fixture except the outer pipe is made of PVC.

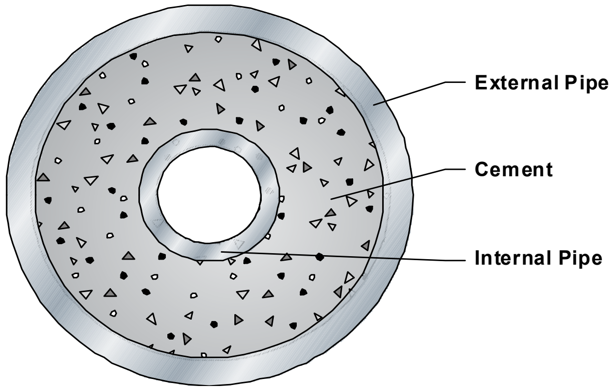


Figure A2—Cross-section of pipe-in-pipe test fixture configuration for shear bond test.

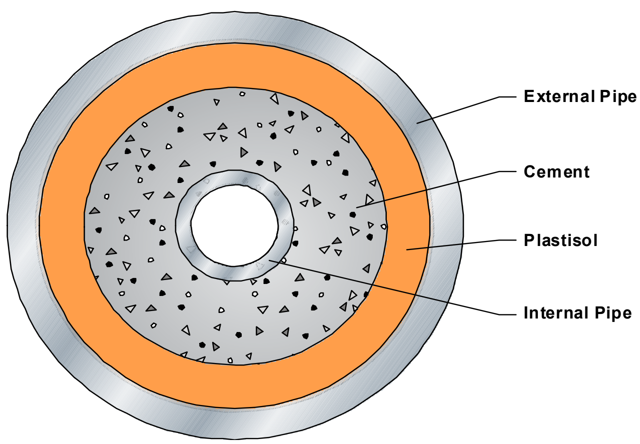


Figure A3—Cross-section of pipe-in-soft test fixture configuration for shear bond test.

The shear bond measures the stress necessary to break the bond between the cement and the internal pipe. This was measured with the aid of a test jig that provides a platform for the base of the cement to rest against as force is applied to the internal pipe to press it through. (Figure A4) The shear bond force is the force required to move the internal pipe. The pipe is pressed only to the point that the bond is broken; the pipe is not pushed out of the cement. The shear bond strength is the force required to break the bond (move the pipe) divided by the surface area between the internal pipe and the cement.

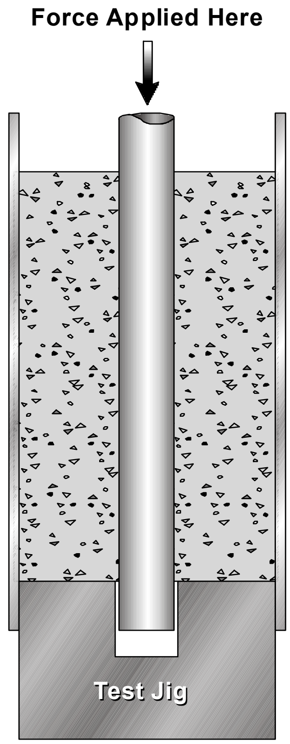


Figure A4—Test jig for testing shear bond strength

Compressive Strength Procedure:

After curing, the sample is extracted from the mold and cut into 1-in. ±1/8 in. sections in length. A ¼-in. section of the top surface of the sample is cut first. Next, the three 1-in. sections to be measured are cut. Each 1-in. ±1/8 in. section is identified as top, middle, and bottom and is measured for compressive strength in the test machine. The remaining sample pieces are discarded. The density of each sample is calculated before it is measured for compressive strength. The density is calculated by suspending the cut-core samples in water and weighing them using a Denver Instruments Lab Balance, model TR-2102.

Each sample is then placed in turn in a Carver Press (hydraulic). Force is applied in accordance with API specification 10B-7.5.6.1. A digital pressure gauge records the specimen's failure in PSI.

Calculate the specimen compressive strength at any age as follows:

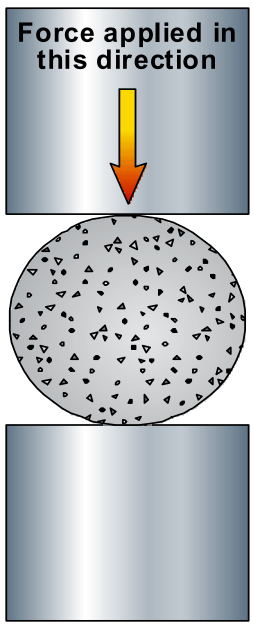
$$Cs = \frac{G \times 5.15}{SA}$$

Cs = compressive strength (psi)
G = digital gage reading (psi)
SA = surface area (sq in)
5.15 = press piston area (sq in)

Tensile Strength Procedure:

Tensile strength was tested using ASTM C496[1] (Standard Test Method for Splitting Tensile Strength of Cylindrical Concrete Specimens). For this testing, the specimen dimensions were 1.5 in. diameter by 1 in. long. **Figure A1** shows a general schematic of how each specimen is oriented on its side during testing. The force was applied by constant displacement of the bottom plate at a rate of 1 mm every 10 minutes.

Figure A1—Sample Orientation for ASTM C496-90 Testing



[1] "Standard Test Method for Splitting Tensile Strength of Cylindrical Concrete Specimens," ASTM C496-96, West Conshohocken, PA, 1996.

[3] ISO 10426-4: "Petroleum and Natural Gas Industries—Cements and Materials for Well Cementing,
Part 4: Recommended Practice for Atmospheric Foam Cement Slurry Preparation," working draft 2001.

[4] ISO 10426-2: "Petroleum and Natural Gas Industries—Cements and Materials for Well Cementing,
Part 2: Recommended Practice for Testing of Well Cements," 1998.

Expansion (bar) Procedure:

Test Apparatus

Molds for test specimens used in determining the length change of cement pastes and mortars produce 1×1×11 ¼-in. prisms with a 10-in. gage length (see Figure A-3). The gage length is the nominal length between the innermost ends of the gage studs.

Curing Procedures

Cure each test specimen at 185°F in a heated, circulating water bath.

1. Remove specimens from the molds at an age of 23 ½ hours. The age of each specimen is measured from the moment when water is added to the cement during the mixing operation.
2. Etch specimens for identification or positioning as required with a scriber, inscribed with slurry design and expansion bar number on each specimen as it applies.
3. Place the specimens in water maintained at 73.4 ±°F (23.0 ± 0.5°C) for a minimum of 15 min. This helps minimize variation in length measurements due to variation in temperature of the specimens.

Test Measurement

When the specimens are 24 ± ½ hours in age, remove them from water storage one at a time, wipe with a damp cloth, and immediately take a comparator reading. Then, return each specimen to the water bath at 185°F.

The comparator shown in Figure A-4 features a dial micrometer graduated to read in 0.0001-in. units, accurate within 0.0001 in. in any 0.0010-in. range, and within 0.0002 in. in any 0.0100-in. range, and sufficient range (at least 0.3 in.) in the measuring device to allow for small variations in the actual length of specimens.

Reference Bar

Place the reference bar (Figure A-4) in the instrument in the same position each time a comparator reading is taken. Check the dial gage setting of the measuring device by taking a comparator reading of the reference bar at least at the beginning and end of a series of specimen readings to span no more than a half-day, provided the apparatus is kept in a room maintained at constant temperature.

To obtain a comparator reading, perform the following steps.

1. Clean the hole in the base of the comparator into which the gage stud on the lower end of the bar fits.
2. Read and record the comparator indication of the length of the reference bar.
3. Take one bar out of curing bath, blot the pins, and place the bar in the comparator, read, and record the length.
4. Return the bar to curing bath and clean the hole in the base of the comparator.
5. Repeat the procedure with second and subsequent bars until all bars have been read, returned to curing bath, and the readings recorded.
6. After reading the last bar, clean the hole in the comparator base and read and record the reference-bar length. Blot only around the pins.

Calculate the specimen length change at any age as follows:

$$L = \frac{(L_x - L_i)}{G} \times 100$$

Where:

L = change in length at *x* age, %
Lx = comparator reading of specimen at *x* age minus comparator reading of reference bar at *x* age;
Li = initial comparator reading of specimen minus initial comparator reading of reference bar
G = nominal gage length, 10 in.

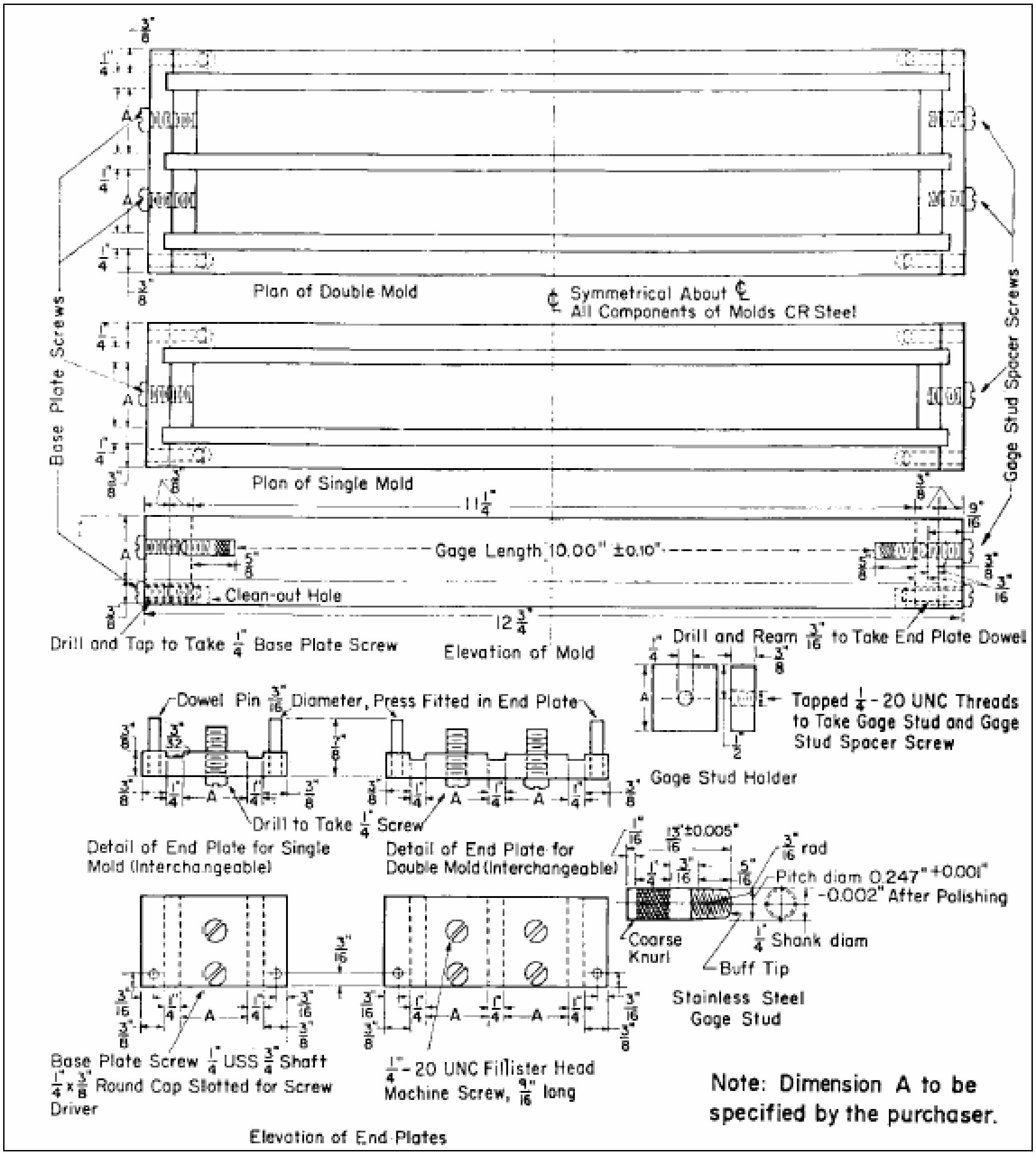
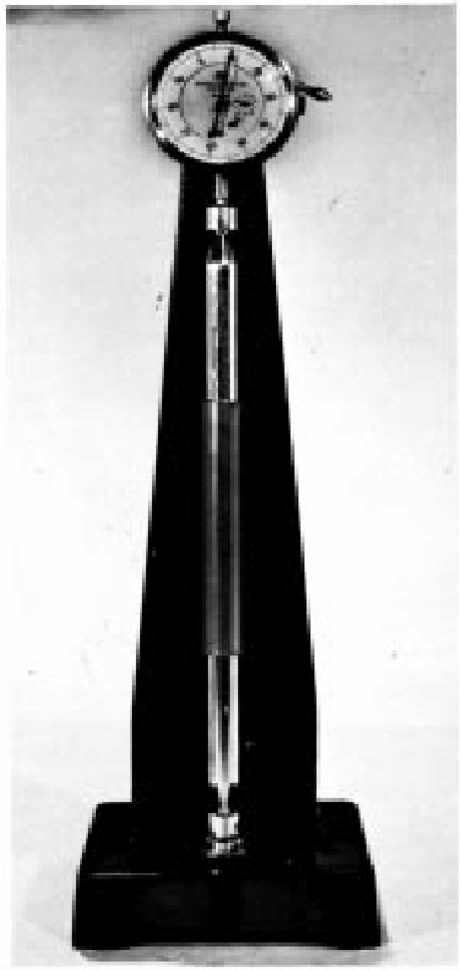


Figure A-3—Expansion test specimen mold schematics



Type of Suitable Apparatus for Measurement of Length Changes

Figure A-4—Reference bar

Young's Modulus Procedure:

Traditional Young's modulus testing was performed using ASTM C469[2], Standard Test Method for Static Modulus of Elasticity (Young's Modulus).

The following procedure is used for the Young's modulus testing.

1. Each sample is inspected for cracks and defects.
2. The sample is cut to a length of 3.0 in.
3. The sample's end surfaces are then ground to get a flat, polished surface with perpendicular ends.
4. The sample's physical dimensions (length, diameter, weight) are measured.
5. The sample is placed in a Viton jacket.
6. The sample is mounted in the Young's modulus testing apparatus.
7. The sample is brought to 100-psi confining pressure and axial pressure. The sample is allowed to stand for 15 to 30 min until stress and strain are at equilibrium. (In case of an unconfined test, only axial load is applied.)
8. The axial and confining stress are then increased at a rate of 25 to 50 psi/min to bring the sample to the desired confining stress condition. The sample is allowed to stand until stress and strain reach equilibrium.
9. The sample is subjected to a constant strain rate of 2.5 mm/hr.
10. During the test, the pore-lines on the end-cups of the piston are open to atmosphere to prevent pore-pressure buildup.

After the sample fails, the system is brought back to the atmospheric stress condition. The sample is removed from the cell and stored.

Frac Models Procedure:

1. Cure frac models with cement design @ 150ºF.
2. After cure, drill through cement and sidewall of inner tubing.
3. After drilling, plug side hole.
4. Place in secure apparatus for testing.
5. Attach regulated nitrogen line to top of water cylinder.
6. Attach line from bottom of water cylinder to top of frac model.
7. Turn on nitrogen bottle.
8. Increase nitrogen pressure to100 psi. (Verify pressure by using gauge on water cylinder).
9. Open line on top of frac model to be certain of water flow through line.
10. Allow model to sit at 100 psi for at least 10 min.
11. Increase nitrogen in increments of 100 psi and let each sit for at least 10 min until first visible water flow.
12. Record flow for 30 min at fracture psi. (This will be calculated for rate/min data at initial flow)
13. At this point increase psi in100 psi increments and hold for at least 10 min. at each increment until there is catastrophic failure.
14. When there is catastrophic failure, allow to flow for 10 min.
15. After 10 min., discard water and begin to record flow for an additional10 min. (This will be calculated for rate/min data at catastrophic flow)

After 10 min. is up, turn off nitrogen bottle and close off water valve and prepare for next test.

Laboratory Procedures for Foamed Cement:

The working draft of ISO 10426-4[3] outlines the recommended practices for the atmospheric generation and testing of foamed cement slurries and their corresponding unfoamed base slurries. The procedures discussed in this appendix and used for this project were borrowed from ISO 10426-4.

1 Preparing Unfoamed Base Slurry

1.1 Calculation of Base Cement With and Without Surfactants

Because the final slurry for foamed cement contains surfactant(s), these materials cannot be added to the base slurry for initial mixing. This will require that the density of the base slurry be adjusted to compensate for the later addition of the surfactant(s) prior to foaming.

Example: Slurry Design: Class G Cement + 0.2 gal/sk Surfactant

Base slurry density	=	14.5 lb/gal
Surfactant weight	=	10 lb/gal

Base Slurry Calculations:

	Weight	Volume
Cement	94 lb	3.59 gal
Surfactant	2 lb (0.2 gal * 10 lb/gal)	0.2 gal
Water	55.39 lb	6.65 gal
Total	151.39 lb	10.44 gal

Calculation of True Weight % Contributions:

Cement	62.1 %	(94/151.39)
Surfactant	1.3 %	(2/151.39)
Water	36.6 %	(55.39/151.39)

Slurry without Surfactants:

	Weight	Volume
Cement	94 lb	3.59 gal
Water	55.39 lb	6.65 gal
Total	149.39 lb	10.24 gal

Slurry Density without Surfactants: 149.39/10.24 = 14.59 lb/gal

[3] ISO 10426-4: "Petroleum and Natural Gas Industries—Cements and Materials for Well Cementing,
Part 4: Recommended Practice for Atmospheric Foam Cement Slurry Preparation," working draft 2001.

2 Equipment

2.1 Blender Container

A special blending container is required for preparing foamed cement at ambient pressure in the laboratory. (A typical blending container is shown in Figure B.1) The blending container is similar to the one used for standard slurry preparation except that it has a threaded cap with an O-ring seal. The cap has a small hole (approx. ¾-in. diameter) in the center fitted with a removable plug that has an O-ring seal.

2.2 Multi-Blade Assembly

The multi-blade assembly is what is used during this project. The multi-blade or stacked-blade assembly is constructed of a series of assemblies, each blade corresponding to the requirements of ISO 10426-2[4], clause 5. The assembly consists of five (5) standard blades attached to a central shaft, and spaced equally throughout the mixing container. A typical assembly is shown in Figure B.1.

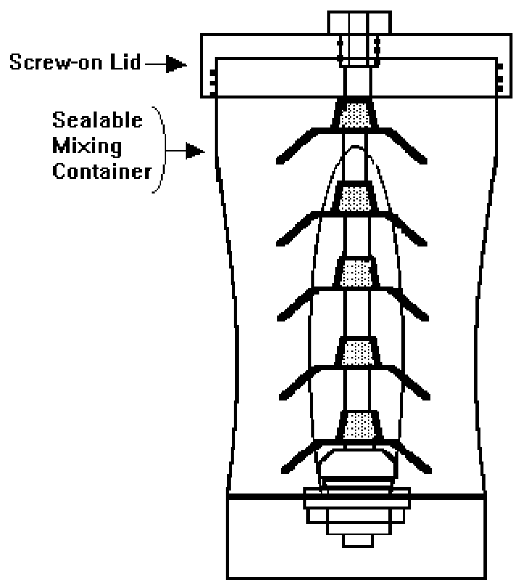


Fig. B.1—Example of a typical blending container

[4] ISO 10426-2: "Petroleum and Natural Gas Industries—Cements and Materials for Well Cementing,
Part 2: Recommended Practice for Testing of Well Cements," 1998.

3 Container Volume

Accurate determination of the volume of the blending container is critical to this procedure. The calculations for slurry volume and foamed cement density are based on this volume determination. Weigh the clean, dry, blending container (including mixing assembly, screw-on lid and screw-in plug for the lid). Remove the screw-on lid from the mixing container and then remove the screw-in plug from the lid. Fill the mixing container with water and then screw the lid on tightly. Pour additional water into the hole in the lid for the plug until the container is completely filled, and then screw the plug tightly into the lid. Wipe the excess water that exits from the plug's vent hole, and then weigh the container again. The weight of the water inside the container is then divided by the density of the water to determine an accurate volume for the mixing container.

4 Preparing Base Cement Slurry

This method assumes that the base slurry as described in Section 1.1 is being prepared in a separate mixing container, and this slurry is then to be weighed into the mixing container described in Section 2.1. To prepare sufficient volume may require multiple mixes with the standard mixing procedure.

Base slurries containing all additives except foaming surfactant(s) should be prepared according to ISO 10426-2[4], clause 5. When possible, the temperature of the cement sample, additives, and mix water should be within ± 2°C (3°F) of the respective temperatures recorded from the well site. The temperature of the mixing container should approximate that of the mix water being used in the slurry design. The mixing device should be calibrated annually to a tolerance of ± 3.3 rev/s (200 rpm) at 66.7 rev/s (4,000 rpm) and ± 8.3 rev/s (500 rpm) at 200 rev/s (12,000 rpm).
As required, the density of the unfoamed cement slurry can be determined by methods found in ISO 10426-2[4], clause 6.

5 Determining Slurry Volumes and Weights

5.1 Slurry Volume

Determine the volume of unfoamed cement slurry to be mixed. The total volume of unfoamed cement slurry should include the volume of the surfactant(s) to be added to the slurry. The surfactant(s) is to be added after the initial mixing of the base slurry. The volume of unfoamed slurry to be placed in the container may be determined by the following procedure.

When it is desired to foam a slurry with a specific amount of gas per unit volume of slurry (foam quality), the resultant density of the foamed slurry must be determined. This can be calculated by Equation 1.

$$FD = (100 - \%G) \div 100 \times UFDS \qquad (1)$$

Where:
- FD = Foamed density of the slurry
- %G = Percentage of gas in final foamed slurry
- UFDS = Unfoamed slurry density with surfactant(s)

When a desired foamed slurry density is known or after calculating it with Equation 1, determine the grams of cement slurry including surfactant(s) that is to be placed into the foam blender to prepare the foamed slurry. This can be calculated by Equation 2.

$$GUFS = CV \times FD \qquad (2)$$

Where:
- GUFS = Grams of unfoamed slurry including surfactant(s) to be placed into the foam mixer
- CV = Container volume of foam mixer (mL)
- FD = Foamed density of the slurry (g/mL)

Example:			
	Container volume	=	1170 mL
	Base slurry density	=	14.5 lb/gal (1.74 g/mL)
	Foamed cement density	=	10.0 lb/gal (1.2 g/mL)
	Unfoamed slurry weight	=	1170 mL × 1.2 g/mL = 1404 g

5.2 Surfactant(s) and Slurry Weight

The surfactant(s) weight is determined by taking the unfoamed slurry weight and multiplying by the percent by weight of surfactant(s). The slurry weight is determined by taking the unfoamed slurry weight and subtracting the surfactant(s) weight. This can be calculated by Equation 4.

$$GS = GUFS \times (\%Surfactant/100) \qquad (3)$$

Where:

GS = Grams of surfactants (total) to place into the foam mixer with the unfoamed slurry without surfactant(s)

GUFS = Total grams unfoamed slurry prepared in Section 1

$$GUSM = GUFS - GS \quad (4)$$

Where: GUSM = Grams of unfoamed slurry without surfactant(s) to be placed into the mixer.

Example: Unfoamed slurry weight = 1404.1 g
Percent by weight of surfactant = 1.3 %

Surfactant weight = 1404.1 × 0.013 = 18.5 g
Slurry weight = 1404.1 - 18.5 = 1385.6 g

6 Preparing the Atmospheric Foamed Slurry
Based on the volume calculated in Section B.5.1, weigh the appropriate amount of the prepared slurry into the special mixing container. Add the calculated amount of surfactant(s). The final weight of the cement slurry and added surfactant(s) should be checked against the final desired base slurry density. Before foaming, verify that the total weight of the slurry and added surfactant(s) corresponds to the weight calculated in Section B.5.2.

6.1 Generating a Foamed Cement
Make sure the mixing container is sealed. Using the blade assembly described in Section B.2.2, the slurry should be mixed at the 12,000 rpm setting for 15 seconds. Because of the increase in slurry volume and viscosity, the maximum rpm of the blender could be less than 12,000 rpm. The maximum attainable rpm will depend on the power of the blender, slurry density, and foam quality. Record and report the final rpm of the mixer.

During the mixing, there will be a noticeable change in the sound (pitch) from the blender. After mixing, there may be some slight pressure in the mixing container because of temperature increases and energy imparted to the foam during the foaming process. Be careful when removing the top of the mixing container. After mixing, open the sampling port or container lid, and verify that the slurry completely fills the slurry-mixing container. If the slurry does not fill the mixing container at the end of the 15-second mixing, it is doubtful the slurry will foam properly under field conditions. The slurry should be redesigned.

7 Atmospheric Testing of Foamed Cement Slurries
Because of the high air entrainment in a foamed cement slurry, it is necessary to

modify some of the standard testing procedures to prevent obtaining erroneous test results.

7.1 Determining Foamed Slurry Density

The density of the foamed slurry should be determined by pouring it into a container with a large open top that has a known volume when completely filled. Weigh the container, pour the foamed slurry into the container, and level the top with a straight blade. Wipe the outside of the container clean, and weigh the container with the foamed slurry. The density of the foamed slurry in the container is determined by dividing the slurry mass by the container volume and converting to the appropriate density units.

7.2 Determining Slurry Stability

7.2.1 Unset Slurry Stability

Evaluate the foam stability by pouring a sample of the foamed cement slurry into a container or graduated cylinder for 2 hours of continued evaluation. Cover or seal the top of the container to prevent drying or dehydration of the sample. Since the main purpose of this test is to check for settling and stability in the foamed slurry, the visual appearance of the foamed slurry (such as free fluid, settling, or bubbles concentrated in a specific area) must be noted. If desired, density measurements may be made of the foam at multiple locations in the cylinder after the 2-hour period. To determine the density of the slurry at various locations in the cylinder, a large syringe with a Tygon tube on it can be used to remove small portions from the top, middle, and bottom. The removed slurry can then be transferred to a smaller graduated cylinder to determine the weight of a known volume of the slurry. From there, the specific gravity and density can be determined.

Pour the foamed slurry into a standard 250-mL graduated cylinder that is used for free-fluid testing. Cover the top of the cylinder to prevent dehydration, place it onto the counter-top, and visually examine it during the 2-hour period. The cylinder cannot be cured at temperatures above the ambient temperature at which the foamed slurry was prepared because an increase in temperature will increase the bubble size and may have an effect on the slurry stability.

7.2.2 Set Slurry Stability

Check foam stability by curing samples until they are set for density gradient measurement throughout the sample. These may be cured in non-greased, covered 50.8-mm (2-in.) diameter, 101.6-mm (4-in.) tall cylinders or any appropriate covered container. Use of grease or other mold-release agents should be avoided as these materials may affect the stability of the foamed cement.

Cut or break the samples into sections, mark them from the top to the bottom, and measure the specific gravity of each section. The specimen should not be cut with a saw that uses water. The use of water may cause the specimen to absorb water and change the density of the specimen. Large variations in density from sample top to bottom are an indication of instability. When determining the specific gravity by Archimedes principal, it is recommended that a beaker of fresh water be placed on a scale and tared. The specimen is placed into a loop of fine string (or thread) and suspended in the water for the first measurement for determining the volume of the specimen (V). The volume of the specimen (mL) will be equal to the weight of the water displaced by the specimen when suspended in the water. The weight of the specimen being suspended in the water must be determined quickly to prevent the specimen from absorbing water and giving erroneous results. The specimen is then lowered to rest on the bottom of the beaker of water to obtain the actual weight of the specimen (W). The specific gravity (SG) is then determined by dividing the weight, W (in grams) by volume, V (in mL). The slurry density can also be determined (SG × 8.33 = lb/gal).

Signs of foam instability include the following:
- More than a trace of free fluid.
- Bubble breakout noted by bubbles appearing on the surface of the sample.
- Excessive gap at the top of the specimen. Minor meniscus effects are normal.
- Visual signs of density segregation as indicated by streaking or light to dark color change from top to bottom.
- Large variations in density from sample top to bottom.

7.3 Determining Compressive Strength
The foamed cement slurry is poured into a curing mold that can be sealed. The sealing lid prevents the foamed slurry from expanding out of the curing mold as it is heated. This expansion can result in an undesired density decrease. The mold can be a standard 50.8-mm (2-in.) cube mold with a cover clamped to the top.

The sealed mold containing the foamed cement slurry is then placed into an atmospheric water bath, cured, and the strength is determined as specified by API. The temperature is normally limited to approximately 65°C (149°F), but can sometimes be increased to 90°C (194°F) if there is sufficient seal to prevent the slurry from expanding out of the curing mold.

8 Determining Other Tests on Base Unfoamed Slurry
A slurry that is foamed at atmospheric pressure should not be tested under pressure. Applying pressure to a foamed slurry prepared at atmospheric pressure will compress the foam, changing the density and gas ratio. This can also allow contamination when tested in a HPHT consistometer for thickening time.

For the following tests, the base unfoamed slurry without the surfactant(s) is prepared according to ISO 10426-2[4], clause 5. After the slurry is prepared, the mixer is stopped and the surfactant(s) added and stirred gently with a spatula to distribute it uniformly in the slurry. It is recommended the slurry be transferred gently from the mixing container to a beaker and back three times to ensure a uniform distribution. The use of a small amount of material for preventing/breaking air entrainment in slurries that are not foamed is permitted for these tests. Materials to prevent/break air entrainment should not be used in any foamed slurries.

8.1 Determining Thickening Time
Since the surfactant(s) will affect the thickening time, and the foam itself does not affect the thickening time of a cement slurry, the thickening time test is normally performed using a standard HPHT consistometer on the base unfoamed cement slurry containing the surfactant(s).

The thickening time test of the unfoamed slurry containing the surfactant(s) will be performed using the procedures in ISO 10426-2[4], clause 9.

8.2 Determining Fluid Loss
Fluid-loss tests performed with a foamed cement prepared at atmospheric pressure will not yield reliable results. The fluid loss values obtained from a foamed cement slurry will be slightly less than that of the base unfoamed cement slurry. The fluid loss of the base unfoamed cement is normally used as an indication of the fluid loss of the foamed cement slurry.

The static fluid-loss test of the unfoamed slurry containing the surfactant(s) is performed using the procedures in ISO 10426-2[4], clause 10.

8.3 Determining Rheological Properties
With the concentration of gas in a foamed slurry changing continuously during

pumping of the job, it is impractical to perform rheological testing at all the foam quality concentrations that are needed to model the frictional pressures during pumping of a foamed slurry. Use of a rotational viscometer will result in separation of the gas from the slurry, causing erroneous results. Correlations can be used to convert the rheological properties of the base unfoamed slurry to that of a foamed cement with varying foam qualities to simulate the job.

The rheological test of the unfoamed slurry containing the surfactant(s) is performed using the procedures in ISO 10426-2[4], clause 12.

Anelastic Strain Procedure:

Anelastic strain testing, a variation of hydrostatic testing, is designed to allow a more accurate evaluation of permanent strain resulting from stressing different test compositions. Samples are cycled to 25%, 50%, and 75% of each composition's compressive strength under 500-psi confining stress. Measurement of anelastic strain with cycling provides a more comparable value of each composition's performance. The first step in the procedure involves compression testing a sample to failure in the load cell with 500-psi confining stress. Once this failure load value is determined, additional samples will be tested by applying axial loads equal to 25%, 50%, and 75% of the failure load, and cycling until samples fail. The cyclic loading rate will be maintained at 250 psi/min and the confining force will be maintained at 500 psi. Plastic deformation will be measured at the end of each cycle.

Appendix XIII

Field Cement Job Reports

Lland Browder "B" Well #1

Cementing Solutions, Inc.
Cement Job Report

CUSTOMER	DATE	PROJECT #	FIELD CONSULTANT
HEP OIL COMPANY, LTD.	4/27/03		RALPH PORTER

LEASE & WELL NAME OCSG	LOCATION	COUNTY-PARISH-BLOCK
Lland Browder "B" Well #1	Newark East (B Shale)	Parker Ct., Tx.

RIG PHONE/FAX	DRILLING CONTRACTOR RIG #	TYPE JOB
940 736 1226	Felderhoff #6	5.5" Longstring

SIZE & TYPE OF PLUGS	LIST-CSG-HARWARE	SLURRY WGT PPG	SLURRY YLD CUFT	WATER GPS	PUMP TIME HR:MIN	BBL SLURRY	BBL MIX WATER
TOP 5.5" Wetherford Model 1013 Latch in BTM None Used	5.5" Wetherford Model 303A Sure Seal Float Sure Seal Shoe 15 ea. Weatherford Bow Spring Centralizers						
CEMENT MATERIALS		14.4	1.27	5.56	2:24	70	42
310 Sacks (BJ) Fort Worth Basin Premium Cement							

Available Mix Water bbl.	Available Displ. Fluid bbl.	Total
		70 42

HOLE			TBG-CSG-D.P.				TBG-CSG-D.P.				COLLAR DEPTHS		
SIZE	% EXCESS	DEPTH	SIZE	WGT.	TYPE	DEPTH	SIZE	WGT	TYPE	DEPTH	SHOE	FLOAT	STAGE
9.25"	10	6647	5.5"	17	N-80	6645					6		1

LAST CASING				PKR-CMT RET-BR PL-LINER	PERF. DEPTH			TOP CONN		WELL FLUID	
SIZE	WGT.	TYPE	DEPTH	BRAND & TYPE	DEPTH	TOP	BTM	SIZE	THREAD	TYPE	WGT.
8 5/8	24.00	N-80	1000	N/A				5.5	8	WBM	9.

CAL. DISPL. VOL -BBL				CAL. PSI	CAL MAX PSI	OP. MAX	MAX TBG PSI	MAX CSG PSI			DISPL FLUID		WATER
TBG	CSG	CSG	TOTAL	BUMP PLUG	TO REV	SQ. PSI	RATED	OP.	RATE	OP.	TYPE	WGT.	SOURCE

									D				
	155		155	553					7	24	F water	8.4	City

EXPLANATION , TROUBLE SETTING TOOL, RUNNING CSG, ETC. PRIOR TO CEMENTING:
Small Independent Company w/ limited budget
Good knowledge and experience in Fort Worth Basin
Critical Formation Depths (estmated)
Upper Barnett Shale 6330-6415
Forestburg Lime 6415-6480
Lower Barnett Shale 6480-6800 (+or-)
Water bearing shale below Lower Barnett
Prognosis
The well was drilled w/o problems (L.C./ gas flow) to 6647'
Produce as much of the Lower Barnett as possible, leaving a buffer from the water below. (This being the reason for not running a float collar.)
There is no plan to produce from the Upper Barnett
Peremitures
TD 6647'
Shoe 6645'
Est. Static 190
Est. Circ 128
BH Log 167 / 6hrs. Static
Water Base Mud (No mud eng. on location) (Personal observation/ Static mud in pits looked very clabbered, Jetted, circulated mud good consistency viscosity.)
9.4#/gl (confirmed)
9.5 FL (off logs)
80 Vis (Derickman)
10.20 / 30 min Gell (off logs)
20 bbls. Fresh Water Spacer 8.4#/gl w/ 1gl.Claytreat & 1gal. Inflo 150
Cement (BJ Fort Worth Basin Premium) No additives listed on test report
310 sk. 70 bbl.
14.4 #/gl,
Est. pump time 2:24,
1.27c'/sk yield
5.56 gl./sk Fresh water mix
0.0 Free water
Fluid Loss (30/min) @ 140 286

Samples
Mud, Spacer & Mixing water were caught personally; A 3.5 gl. bucket was supplied to Mr. George Todd for cement sample.
Mr. Todd was given all samples to send to CSI for testing

Additional contact with experience in Fort Worth Basin cementing.
Tim Sicking Owner operator (X Halliburton)
Jet Star Cementing
Tel. 940-736-4094
Gainesville, Tx.

PRESSURE/RATE DETAIL						**EXPLANATION**
TIME HR:MIN.	**PRESSURE - PSI PIPE**	**ANNULUS**	**RATE BPM**	**Bbl FLUID PUMPED**	**FLUID TYPE**	**SAFTY MEETING: CSI ☐ CO. REP ☐** TEST LINES PSI
4/27/03						**CICULATING WELL-RIG ☒** **CEMENT CO. ☐**
1300						Arrive on location, P.OP. lay down drillpipe
1600						Finish lay down drill pipe rig up to run csg.
1630						Start RIH 5.5" csg., Place centrilizers on first and every third joint
2023						Tag up Bttm. at 6647', Break circulation, recipocate pipe
2200	400		10	400	WBM	Finish circulate Bttms up no

						gas to surface
2215	150		3.9			Start pump Spacer
2218	150		3.9	10	Spacer	
2221	200		3.9	20	Spacer	Finish pump Spacer
2223			4.4		Cement	Start pump 14.4# Cement
2228	200		4.3	22	Cement	14.4#
2233	150		4.3	45	Cement	14.4#
2238	103		3	58	Cement	14.3#
2241	77		3	68	Cement	14.4# Finish pump cement / Drop latchin plug
2243	103		8		WBM	Start displacement / Full Returns
2245	103		8.2	10	WBM	
2246	128		8.2	20	WBM	
2247	103		8	30	WBM	
2248	103		8	40	WBM	

BUMPED PLUG	PSI TO BUMP PLUG	TEST FLOAT EQUIP.	TOTAL BbL PUMPED	BbL CMT RETURNS/ REVERSED	PSI LEFT ON CSG	SPOT TOP CEMENT	FIELD CONSULTANT
Y/N Y	650	Y/ N Y	245	0	0	5380	R. Porter

Cementing Solutions, Inc.
Supplemental Cement Job Report

PAGE 2 OF 2

CUSTOMER HEP OIL COMPANY LTD.	**DATE** 4/27/03	**PROJECT #** D 00011	**FIELD CONSULTANT** RALPH PORTER
LEASE & WELL NAME OCSG Llano Browder "B" Well #1	**LOCATION** Newark East (B Shale)		**COUNTY-PARISH-BLOCK** Parker Ct., Tx.
COMPANY REP. George Todd	**DRILLING CONTRACTOR RIG #** Felderhoff #6		**TYPE OF JOB** 5.5" Longstring

PRESSURE / RATE DETAIL						**EXPLANATION**
TIME HR:MIN.	PRESSURE - PSI PIPE	ANNULUS	RATE BPM	Bbl FLUID PUMPED	FLUID TYPE	
2249	103		8	50	WBM	Displace Cement / Full Returns
2250	103		8	60	WBM	
2252	103		8	70	WBM	
2253	103		8	80	WBM	
2254	103		8	90	WBM	
2255	128		8	100	WBM	
2257	178		7	110	WBM	
2258	379		6.3	120	WBM	
2300	475		6.3	130	WBM	
2302	530		6.3	140	WBM	
2303	580		3.1	145	WBM	

2304	650		3	150	WBM	
2305	680		2	154	WBM	Bump plug / Full Returns Thru out job
2306	2400		1	155	WBM	Pressure up to seat Latch in Plug
2309	0					Release pressure / Float holding
						All samples turned over to HEP Rep. Gearge Todd for shipment
4/28/03						Travel home

Cementing Solutions, Inc.
Cement Job Report

PAGE 1 OF

CUSTOMER HEP	**DATE** 9-10 May 03	**PROJECT #** 11	**FIELD CONSULTANT** Neal Gray
LEASE & WELL NAME OCSG Bailey #1	**LOCATION** Gainsville Tx.		**COUNTY-PARISH-BLOCK**
RIG PHONE/FAX Co. rep -940 736 3132	**DRILLING CONTRACTOR RIG #** FDC #2	**TYPE JOB** 51/2 longstring	

SIZE & TYPE OF PLUGS TOP BTM	**LIST-CSG-HARWARE**	**SLURRY WGT PPG**	**SLURRY YLD CUFT**	**WATER GPS**	**PUMP TIME HR:MIN**	**BBL SLURRY**	**BBL MIX WATER**
CEMENT MATERIALS						12	
Spacer - 500 gal - unable to obtain info due to cmt co would							
Lead - 65/35 Poz w/ 6% gel - 6 % salt - (class H cmt.) 250		12.8	1.84	9.9		82	
Tail - Class H - 50 /50 Poz - 2 % Bent - 10 % salt - 0.3 % CDI		14.4	1.31	5.75		58	

Available Mix Water 400 bbl.	**Available Displ. Fluid 1000 bbl.**	**Total**

HOLE			**TBG-CSG-D.P.**				**TBG-CSG-D.P.**				**COLLAR DEPTHS**		
SIZE	**% EXCESS**	**DEPTH**	**SIZE**	**WGT.**	**TYPE**	**DEPTH**	**SIZE**	**WGT**	**TYPE**	**DEPTH**	**SHOE**	**FLOAT**	**STAGE**

77/8	13	8400	51/2	1	N80	8400				77	8400	

LAST CASING			PKR-CMT RET-BR PL-LINER		PERF. DEPTH			TOP CONN		WELL FLUID	
SIZE	WGT.	TYPE	DEPTH	BRAND & TYPE	DEPTH	TOP	BTM	SIZE	THREAD	TYPE	WGT.
85/8	24.00		760							wbm	9.4

CAL. DISPL. VOL -BBL				CAL. PSI	CAL MAX PSI	OP. MAX	MAX TBG PSI		MAX CSG PSI	DISPL FLUID		WATER	
TBG	CSG	CSG	TOTAL	BUMP PLUG	TO REV	SQ. PSI	RATED	OP.	RATED	OP.	TYPE	WGT.	SOURCE
	178										wbm	9.	LA

EXPLANATION , TROUBLE SETTING TOOL, RUNNING CSG, ETC. PRIOR TO CEMENTING:
Csg run too fast, mud not in proper condition - Not near enough circ done to clean hole
Had lost circ problems @ 6700 ft. while drilling well.

PRESSURE/RATE DETAIL						EXPLANATION
TIME HR:MIN.	PRESSURE - PSI PIPE	ANNULUS	RATE BPM	Bbl FLUID PUMPED	FLUID TYPE	**SAFTY MEETING: CSI ☐ CO. REP ☐** TEST LINES NO PSI
						CICULATING WELL-RIG ☒ CEMENT CO. ☐
						No safety meeting that I observed - This well was a turn-key job by drlg contractor. They experienced some lost circ at 6700 ft. while drlg. No logs at loc to look at - co rep stated that they desired TOC @ 6000 ft. He had calculated cmt vols allowing appx 13% excess ?? - Csg landed on btm. - 20 ea cents used. co rep decided placement of cents. 1 ea cmt basket @7710 in csg string - 1ea cmt basket @ 7730 attached to pipe with limit clamp.Appx. 5 hrs. to run csg = 1680 ft. per hr. highly excessive. Aggitation to mud pits was minimal and was a channel down center of pits with mud flow and on sides was viscus, unaggitated mud - mud properties from mud check sheet of 8 May 03 - wt. 9.4 - funnel vis 80 - vis. 600 rpm centiposes 44 - PV 24 - YP 28 - Gels 10 sec/ 10 min 4 / 24 -Filtrate 30 min @ 100 psi 8.4 - cake 2/32 - cl ppm 1,100 - PH (strip) 9.5 - Ca ppm 100 - solids 8% - sand content .30%. No action to adjust YP. with my swag method the ECD on this would be 11 ppg. There was no FIT or LOT performed on csg shoe. Pipe circulated @ _+ 750 pai

						on btm. drop ball to activate basket - open ports - circ. appx btms up - cmt csg. - Cement Co. - Jet Star Co. Had very decent equip (HES equip) Capable Hands and owner of co. ex HES and Knowledgeable. Toc not at desired spot as press to land plug below calculated.

BUMPED PLUG	PSI TO BUMP PLUG	TEST FLOAT EQUIP.	TOTAL BbL PUMPED	BbL CMT RETURNS/ REVERSED	PSI LEFT ON CSG	SPOT TOP CEMENT	FIELD CONSULTANT
Y/N Y	1050	Y/N	178		0	6000	Neal Gray

Cementing Solutions, Inc.
Supplemental Cement Job Report

CUSTOMER	DATE	PROJECT #	FIELD CONSULTANT
HEP	9-10 May 11, 2003	D00011	Neal Gray
LEASE & WELL NAME OCSG Bailey # 1	**LOCATION** Gainsville		**COUNTY-PARISH-BLOCK**
COMPANY REP. George Todd	**DRILLING CONTRACTOR RIG #** FDC #2		**TYPE OF JOB** 51/2 long string

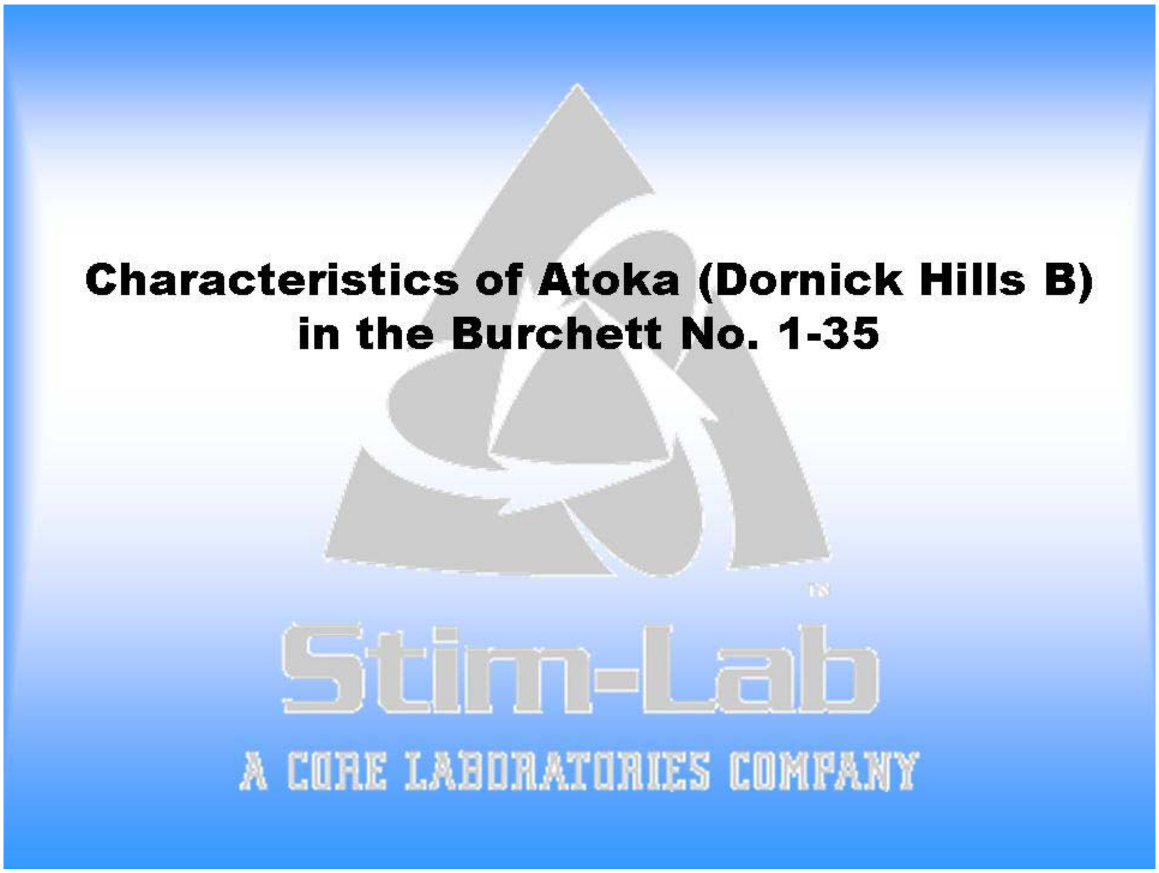
PRESSURE / RATE DETAIL

TIME HR:MIN.	PRESSURE - PSI PIPE	ANNULUS	RATE BPM	Bbl FLUID PUMPED	FLUID TYPE	EXPLANATION
14:35						P/U & run csg
19:30						Csg on Btm
19:35					WBM	Circ Csg
19:52						Drop ball - circ.
						did not see good ball seating indication
20:05						Hook up cmt head
20:45	860		3.7	12	Spacer	Pump spacer - Mud Flush type - Cmt Co. would allow to get sample- Spacer was highly viscous and stringey
20:48	790		8.2	82	lead	Pump lead cmt.
21:00	800		8.0	58	Tail	Pump Tail cmt.
21:10						Cmt complete - Drop latch down top plug
21:12	800		9.6	178	WBM	Displace Cmt.
21:16						Returns decreasing
21:19						Irratic flow of returns
21:25	800		8.3			Good returns
	1125		8.2	168		
	920		4.4	175		Decreased returns
21:34	1100			178		Land plug -
21:35						Release - Holding
						Observations: Csg run speed way yonder excessive - Attention to and conditioning of mud for running csg non existant. inability for co. rep or observer to get on cmt unit to monitor vols. or wts. of fluids being pumped. Samples of cement difficult to obtain due to bulk trucks not rigged to obtain

						samples. No truwate scales available. No wt available on electronic press - rate device that can be monitered. Cmt pump rate excessive for formations encountered Best statements from Location: That's the we have always done it and we ain't had no problems!

Appendix XIV

Data Collection, Burchett #1-35 (Dornick Hills B)



Permeability and Porosity at Stress

Company: ANATARA RESOURCES
Well: BURCHETT
Location: OKLAHOMA

Laboratory: STIM-LAB
Date: 10/4/02
File 6409

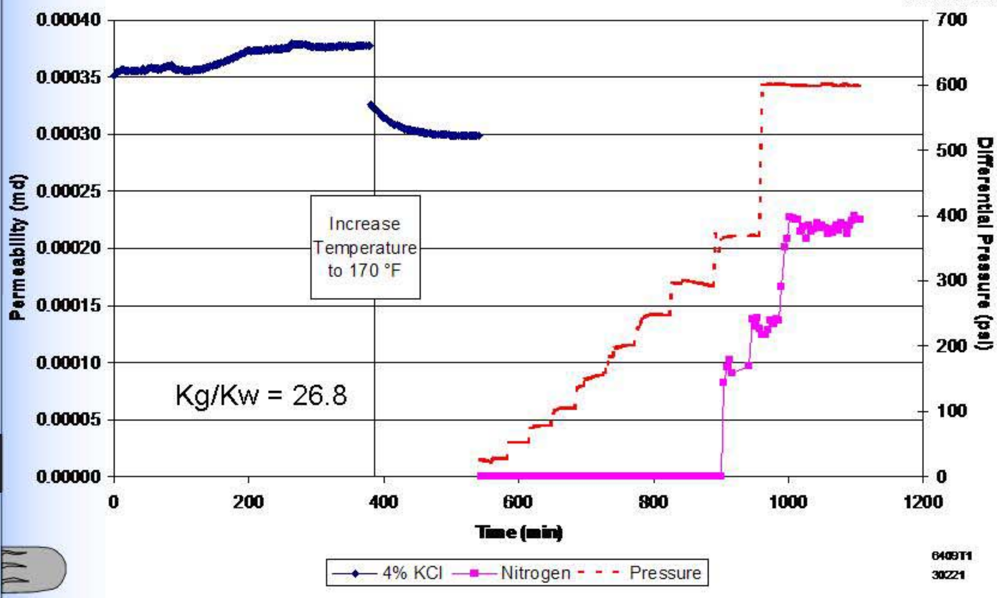
ROUTINE CORE ANALYSIS

Sample	Depth	Requested Overburden	Helium Porosity	Permeability (800psi)		Grain Density
				Air	Klinkenberg	
I.D.	feet	psi	%	md	md	g/cm
1	11198	800	15.4	0.054	0.036	2.69
		2000	14.8	0.029	0.009	
		4000	14.3	0.028	0.008	
		6000	14.1	0.026	0.008	
		9000	14.0	0.015	0.004	
2	11223.4	800	15.7	0.053	0.045	2.68
		2000	14.6	0.022	0.007	
		4000	13.9	0.019	0.005	
		6000	13.8	0.020	0.006	
		9000	13.7	0.011	0.003	

Flow Properties to Brine and Gas

Figure 1

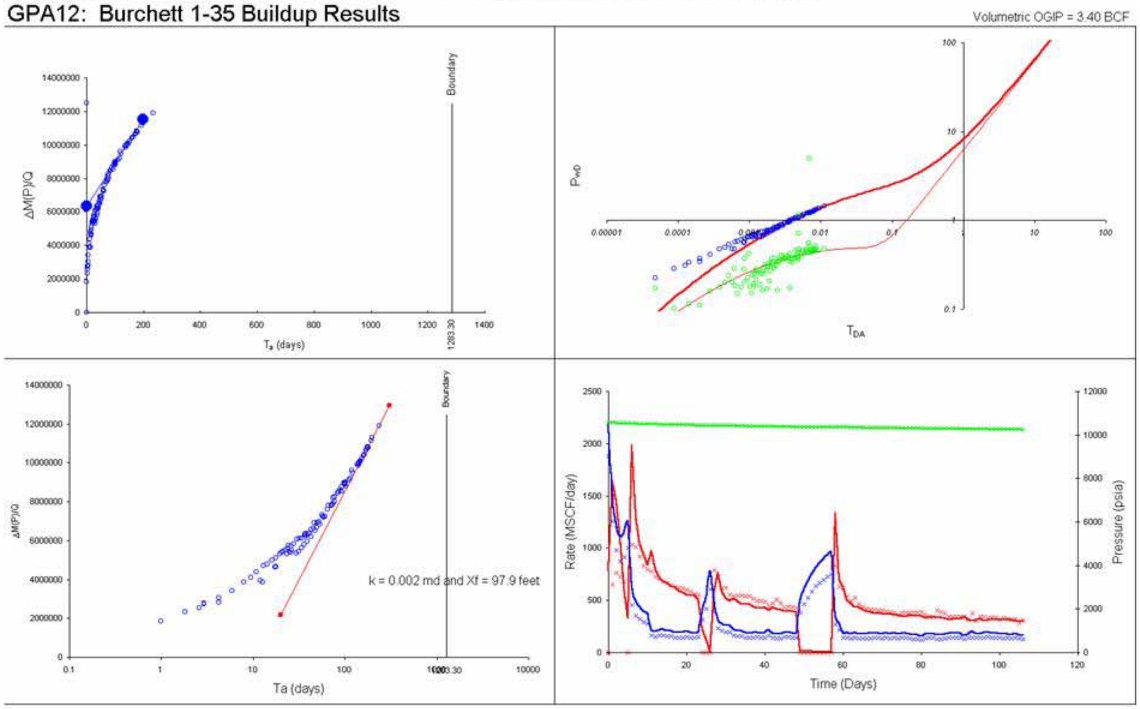
The Brine and Gas Permeability of Burchett 1-35: 11,198'



Production Analysis

GPA12: Burchett 1-35 Buildup Results

Volumetric OGIP = 3.40 BCF

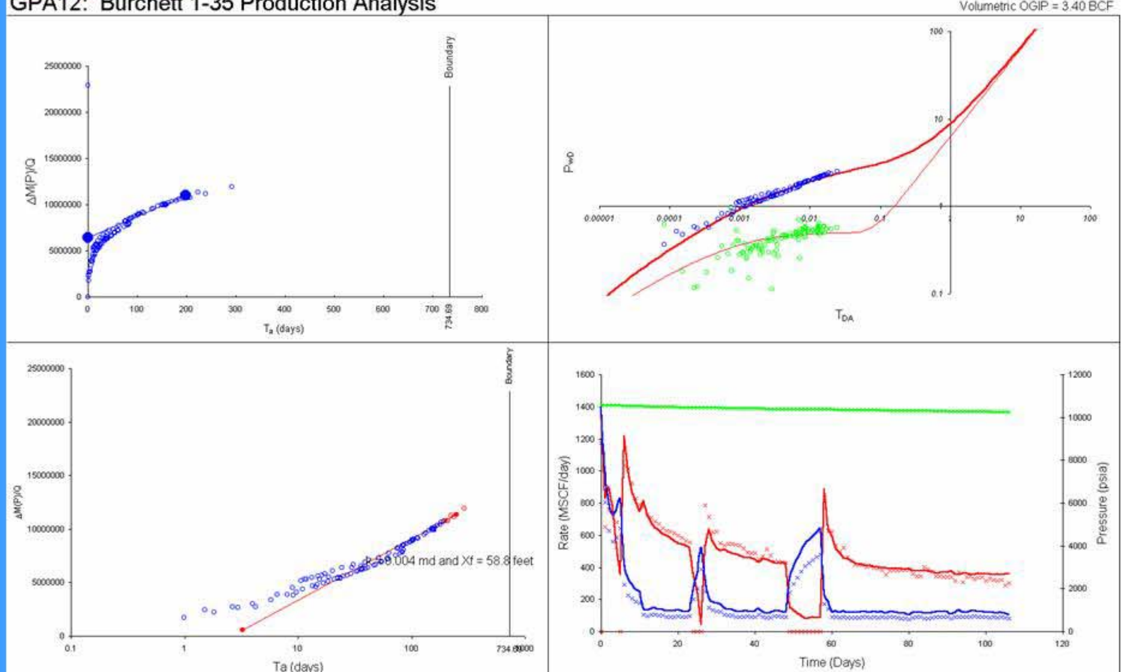


Parameters																				
	Pi	10570	psi	T	176	degF	SG	0.65	S_{wi}	0.4		Cf	4.81E-06	1/psi	Skin	0.00155				
	k	0.00229	md	ϕ	0.17		CO_2	0	Bgi	398.7082	SCF/CF	Cw	2.57E-06	1/psi	FCD	1663.548		L/W	1	
	h	48	ft	xf	105	ft	H_2S	0	OGIP	3.40	BCF	Cgi	3.35E-05	1/psi	Cd	0.042135		Xoff	0.5	
	A	40	acres	$k_f w_f$	400	mdft	N_2	0	Zi	1.47		Cti	2.59E-05	1/psi	Boundary	1283.3	days	Yoff	0.5	

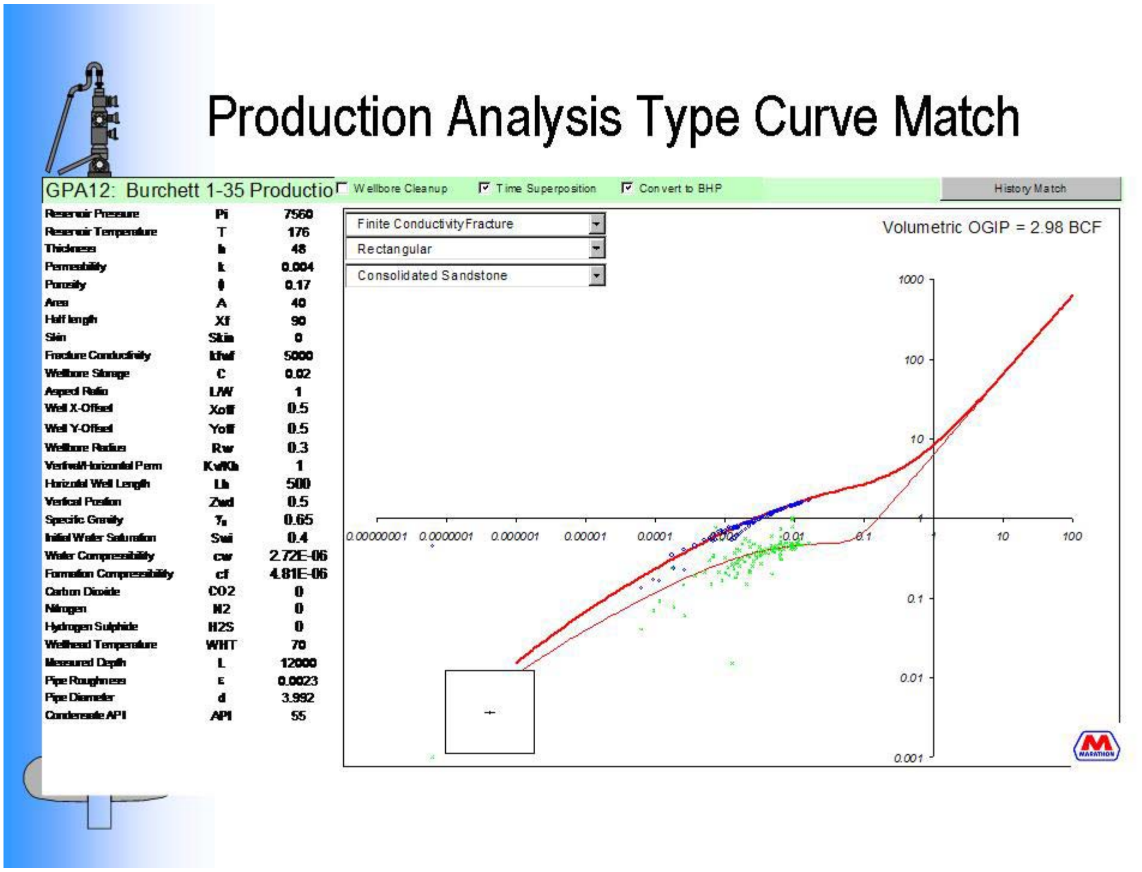
Production Analysis

GPA12: Burchett 1-35 Production Analysis

Volumetric OGIP = 3.40 BCF



Parameters																				
	Pi	10570	psi	T	176	degF	SG	0.65	S_{wi}	0.4		Cf	4.81E-06	1/psi	Skin	0				
	k	0.004	md	ϕ	0.17		CO_2	0	Bgi	398.7082	SCF/CF	Cw	2.57E-06	1/psi	FCD	833.3333		L/W	1	
	h	48	ft	xf	60	ft	H_2S	0	OGIP	3.40	BCF	Cgi	3.35E-05	1/psi	Cd	0.023462		Xoff	0.5	
	A	40	acres	$k_f w_f$	200	mdft	N_2	0	Zi	1.47		Cti	2.59E-05	1/psi	Boundary	734.7	days	Yoff	0.5	


Production Analysis Type Curve Match
GPA12: Burchett 1-35 Productio
Wellbore Cleanup
Time Superposition
Convert to BHP
History Match
Reservoir Pressure Pi 7560
Reservoir Temperature T 176
Thickness h 48
Permeability k 0.004
Porosity ϕ 0.17
Area A 40
Half length Xf 90
Skin Skin 0
Fracture Conductivity kfwf 5000
Wellbore Storage C 0.02
Aspect Ratio L/W 1
Well X-Offset Xoff 0.5
Well Y-Offset Yoff 0.5
Wellbore Radius Rw 0.3
Vertical/Horizontal Perm Kv/Kh 1
Horizontal Well Length Lh 500
Vertical Position Zwd 0.5
Specific Gravity γg 0.65
Initial Water Saturation Swi 0.4
Water Compressibility cw 2.72E-06
Formation Compressibility cf 4.81E-06
Carbon Dioxide CO2 0
Nitrogen N2 0
Hydrogen Sulphide H2S 0
Wellhead Temperature WHT 70
Measured Depth L 12000
Pipe Roughness ε 0.0023
Pipe Diameter d 3.992
Condensate API API 55
Finite Conductivity Fracture
Rectangular
Consolidated Sandstone
Volumetric OGIP = 2.98 BCF
1000
100
10
1
0.1
0.01
0.001
0.00000001
0.0000001
0.000001
0.00001
0.0001
0.001
0.01
0.1
1
10
100