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Cement Plug Testing: Weight vs. Pressure Testing to Assess Viability of a Wellbore Seal Between Zones

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Objective

The objective of this project was to establish an optimized method for evaluating cement plug seal integrity for well abandonment built on a comprehensive engineering study of the fundamentals governing cement plug seal performance. This project consisted of laboratory and field investigations to assess the necessary attributes of the seal formed by a cement plug, and to determine the effects of wellbore geometry, cement properties, and placement methods on these attributes. Bond and seal effectiveness determined by current plug evaluation methods required by 30CFR250.1715(b) were evaluated in light of potential leak pathways and failure mechanisms. Analysis of the information from the assessment of current verification methods, leak pathways, failure modes, cement properties, wellbore geometry, and placement methods identified an optimum verification method for cement plug seal, as well as a correlation relating well geometry, cement properties, and placement methods to potential for forming an effective seal.

Recommendations

Based on the results and conclusions from this work, the recommended optimal method of testing cement plug seal integrity is:

- All cement plugs should be tagged for verification of cement top, tagging can be performed with slick-line and no specific weight test is required
- All cement plugs should be pressure tested to current specified pressure test values (1000psi)
- A negative pressure gas bubble observation should be performed on all plugs after wait-on-cement time to verify seal against gas migration

CSI interviewed several service companies that are currently performing cementing operations in the Gulf of Mexico as well as a Decommissioning Operators Group to gain a better insight on current industry best practices and the slight differences between current regulatory requirements. These recommendations were based on comprehensive research supplemented by engineering studies, laboratory testing, and field observation.

Conclusions

- Weight test measures plug location not seal effectiveness
- Weight test isn't operationally feasible in rig-less operations and poses a higher safety concern
- Weight test is less stringent of a seal effectiveness test when compared to surface pump pressure test
- Surface pressure verification of cement seal integrity is significant only on the initial plug covering perforated zones or formation. Pressure leaks detected in subsequent plug testing indicate casing leaks rather than plug seal failure (see section "Future Work")
- Several factors affect cement seal integrity: cement fluid characteristics, well-bore deviation, placement techniques, slurry volume, etc.
- Few engineering studies have examined cement seal performance testing.

- Required bond strength varies depending on the cement plug geometry and the effective length of the cement plug.
- Placement success varies greatly depending on: cement density, pipe condition, crystalline expansion properties, and the use of bonding agents in cement blend such as latex or surfactants
- Cement plug stability plays a very large role in bond strength development.
- There is a fundamental difference in failure modes between the weight test and the pressure test.
- Longer cement cure times generally reduce the risk of failure because cement bond strength develops over time.
- As long as there is bond, there is no need to worry about long term cement/pipe interface gas migration from hydration volume reduction.
- Plug integrity and location are greatly affected from fluid swapping in balanced plug conditions
- Use of an artificial bottom (CIBP, Viscous pill, etc.) greatly decreases the risk of plug instability
- Most field operations generally utilize neat cement blends for P&A operations
- It is currently not required to test plug stability on intermediate plugs

Future Work

Although this report did investigate the best way to evaluate cement plugs in P&A applications there still remains several issues that should be investigated further. First as specified in the conclusions the pressure test recommended only applies differential pressure across the bottom plug in the wellbore. The other plugs further up the hole do not experience the differential pressure when the 1000 psi test pressure is applied. Other techniques and methods may be available or developed to provide more applicable information about the “integrity” of these upper plugs. This would require some additional research to determine.

Secondly the degree of intermixing of the cement plugs with wellbore fluids should be investigated more thoroughly. It was shown by this work that the cement would readily intermix with the sea water below it. The degree of mixing and the ultimate length of plug needed to insure competent cement once placed was not determined. A method could be developed to determine the diluted plug length based upon various parameters to insure plug integrity. This would also require additional research focus.

Summary of Results

Current Seal Integrity Evaluation

After evaluation of current seal integrity tests, it was found that the weight test measures plug location and not seal effectiveness. It was also found that the surface pressure test verifies perforation or casing leaks and not the integrity of the cement. Neither of the current testing methods verifies plug stability on intermediate plugs because testing is not currently required for these very important plugs. CSI recommends that all flow path barriers, including mechanical barriers, should be tested for seal effectiveness when plugging a well.

Literature Review

Plugging methods are generally rudimentary, but special attention is needed to design sufficient P&A operations. Several factors affect cement plug seal integrity including: cement fluid characteristics, well-bore deviation, placement techniques, in-situ drilling/completion fluid, fluid contamination, insufficient slurry volume, and poor communication between operators and service companies. The majority of technical documents touched on the critical nature of job execution. On the whole, there are a limited number of studies regarding cement seal performance testing.

Engineering Study

Current seal integrity verification methods allow for large variances in required plug bond strength. Required bond strength varies depending on the cement plug geometry and the effective length of the cement plug. Effective plug length is defined as the length of the cement plug which is sufficiently bonded to the outer walls. Cement plug integrity plays a very large role in bond strength development. Cement plug integrity is influenced by the cement density, the condition of the pipe, and the additives used in the cement.

Laboratory Evaluation

There is a fundamental difference in failure modes between the weight test and the pressure test. This difference in failure modes causes hydraulic bond failure strengths to differ greatly from shear bond failure strengths. It was found that longer cure times of the cement will reduce the risk of failure because cement bond strength develops, and in some cases retrogresses, over time. Plug integrity and location is greatly affected from fluid swapping in balanced plug conditions where a higher density fluid is placed on top of a lower density fluid.

Field Operations

The majority of plug operations performed in the Gulf of Mexico use neat cement with few additives. The pump pressure test is the preferred method of seal integrity verification, especially in shallow water or rig-less abandonment operations. One additional test performed on location to verify gas migration risks is the static bubble observation. Several case studies were completed and laboratory confirmation testing to simulate field operations was also performed.

Engineering Correlation

Utilizing realistic bond strength based on cement and well conditions rather than a single magnitude of pressure or force application will yield a much more standardized approach to plug testing. Minimum bond strengths of 15 psi were used to calculate weight tests and pump pressures for failure. It was found that the pump pressure test is the more severe and feasible method for plug testing.

Detailed Discussion of Results

Literature Review

An extensive literature review was performed which covered plugging and abandoning wells, problems and issues with seal integrity, and assessment of seal effectiveness. Results from this literature review have been applied to fine-tune and finalize testing and analysis. Detailed summaries of technical literature documents can be found in Appendix A. The findings from the literature review are discussed below.

Well Plugging Methods

From review of technical literature, the three most commonly used plugging methods are:

1. Balanced Plug Method
2. Wire Line Dump Bailer Method
3. Coiled Tubing "Pump and Pull" Method

These three plugging methods all have their own advantages and disadvantages and have case specific applications. The balanced plug method is one of the most widely used methods for plugging and/or abandoning. Generally if cement plugs of small volume are needed to be placed very accurately then the dump bailer method is preferred. When long plugs are required, then the CT "Pump and Pull" method should be used.

Other notable, but somewhat infrequent plugging methods which were discussed within the technical documentation were:

- Pumping/Pouring resin downhole to form plugs at required depths
- Using sacrificial fiberglass tubing which is left in cement during setting
- Various wire line combination tools (e.g. perforate and dump)
- 2 part activator and silica plug blends and methods of placement

Well Plugging Fundamentals from Case Studies

Upon review of technical literature, the majority of case studies revealed that special attention has to be given to plug and abandonment design. Improper initial design of cement plugs will increase the likelihood of failed plugging operations. It was found that cement plugs generally fail because of many factors which include, but are not limited to: cement fluid characteristics/density, well-bore deviation, placement techniques, in situ drilling/completion fluid, fluid contamination, insufficient slurry volume, and poor communication. Most case studies commented that some or all of these factors had detrimental effects on cement plug success.

Current Guidelines for Plugging Methods and Quality Assurance

The review of technical literature relating to plug and abandonment revealed multiple industry best practices used during plugging operations. Some of the best practices were related to case specific procedures but many of them were general to all plug and abandonment operations. These best practices include, but are not limited to:

- General Industry Best Practices
  - Hole preparation prior to plugging operations is very important
  - Mechanical barriers are strongly recommended for all plugging operations
  - Cement slurry should be tested for stability
  - Accurate placement of cement is a must
  - Cement must be allowed sufficient time to set before continuing operations

- Balanced Plug Method Best Practices
  - The use of spacers/pre-flushes to remove mud and water wet annular surfaces
  - The use of diverters on the end of the work string are recommended
  - Pull drill string out of plug at very slow rates after placement

- Wire Line Dump Bailer Method Best Practices
  - Very low gel strength development of slurry is a must
  - Cement should be dumped as close to the bridge as possible to minimize dilution
  - The use of resin is a better choice for plugging gravel packs

- Coiled Tubing "Pump and Pull" Method Best Practices
  - Surface batch mixing cement prior to placement
  - Monitor mixing energy
  - Use of diverters on the end of the tubing

Plugging State of the Art, Issues, and Technology Deficits

Upon review of technical literature the current plugging state of the art can be separated into three categories: Initial design/planning, field execution, and plug performance testing/evaluation.

Initial Design/Planning

Before the BSEE (formally MMS) amendment to plug design regulations which now requires professional engineer certification of plug designs, there was very little scrutiny relating to the design process for abandonment operations.

Issues:

Generally, the plug and abandonment design process is an overlooked issue which is considered rudimentary and only given serious thought once the well is in actual need of abandonment operations. Related technical literature generally comments that operators can never start planning abandonment operations too early. Ideally, a well abandonment plan should be part of the process of planning the development of a field.

Technology Deficits

The major technology deficit relating to the design of abandonment plugs generally relates to poor initial designs of plugging operations because of partially undefined well conditions. The engineer initially designing these plugs with expectations of success must have a clear representation of the downhole conditions in order to design accordingly. Normally, there are multiple unknown circumstances whose risk potentials are estimated throughout the design process.

Field Execution

The value of all plug designs depends on how the design was executed in the field. Job execution is critical to plug and abandonment success. Plugging operations that follow design and placement procedures described achieve better results than guesstimating implementation on location. Cementing success is considered to be 10% design and 90% placement/execution.

Issues

There are two major issues relating to successful field execution of abandonment plugs currently; communication and equipment. Lack of proper communication between engineers and operators on location generally leads to execution inaccuracies which increase the likelihood of plug failure after placement. The quality of the cement mixing equipment on location plays a very large role in plug success as well.

Technology Deficits

Cement contamination is considered the major technology deficit that plagues the industry during plug and abandonment operations. There are many methods and best practices that are used to minimize the cement contamination but as of current, there is no documented procedure that completely eradicates the likelihood of even partial cement contamination. The general practice in anticipation of cement contamination is to pump larger volumes than needed such that the volume of uncontaminated cement will be equivalent to the desired plug length. This practice, although helpful, is still a large technological deficit in regards to field execution.

Plug Performance Testing/Evaluation

Cement plug performance testing/evaluation is the cornerstone to all abandonment operations. An insufficient isolation of a zone can lead to many unwanted well conditions and may even pollute the environment. This is the main reason why all oilfield regulatory bodies require cement plug performance testing/evaluation for abandonment operations.

Issues

One of the major issues relating to plug performance testing is the dichotomy between laboratory and field performance testing procedures. Currently there are only a few specific methods of testing cement plug success from a laboratory standpoint and even fewer methods in the field. Also, there is no simple way of accurately testing cement plugs under expected downhole conditions in laboratories. Most laboratory testing specific to cement plug testing assumes best case scenario in regards to cement contamination and bonding ability.

Technology Deficits

The major technology deficit related to cement plug performance testing is laboratory validation. Most laboratories do not have access to equipment that is sophisticated enough to run tests that are specific to plugging operations. These tests include: cement mechanical properties, shear bond, hydraulic bond, fluid migration analysis, static gel strength analysis, and annular seal performance testing. From review of literature, there is also very few studies conducted on plug performance testing/validation. Generally the only validation of a successful cement plug is by field testing after placement either by the pump pressure test or the drill pipe tag test.

Engineering Study

Best practices for evaluating cement plug seal for well abandonment, built on a comprehensive engineering study of the fundamentals governing cement plug seal performance are discussed within this section. This portion of study evaluates cement mechanical properties required to maintain seal integrity under various well conditions and plug configurations.

- Hydraulic bond strength requirement vs. pipe diameter and plug length required to satisfy hydraulic pressure requirement. (1,000 psi pump pressure test) were calculated
- Shear bond strength requirement vs. pipe diameter and plug length required to satisfy weight support criterion. (15,000 lb drill pipe tag test) were calculated
- Qualify mechanical properties of cement and other possible sealing materials across a range of applicable densities.

Qualitative Analysis

The resulting placement quality of any size cement plug generally varies with the effect of these properties

- Cement Density
- Pipe Condition
- Crystalline Expansion Properties
- The Use of Bonding Agents in Cement Blends (Latex/Surfactants)

These four properties will be briefly discussed as to how they affect the overall outcome of plug cementing and the cements ability to build bond strength in a well bore.

Cement Density

Density plays a very large role in cements ability to build compressive strength and bond strength. The general industry practice is to pump cement plugs that are as close to their neat composition such that the blends will develop well documented compressive strengths. Certain downhole situations dictate the modification of cement density. These situations can lead to cement with much lower bond strengths than expected. Table 1 shows 24 hour compressive strength development of Class H cement extended with bentonite to lower densities for different temperatures.

Slurry Density (lb/gal)	24 hr Compressive Strength (psi)		
	100°F	140°F	180°F
15.6	1700	2480	3000
14.8	1240	1700	2010
14.2	795	1130	1335
13.3	450	605	710
12.6	265	420	485

Table 1: Compressive Strength Development for Class H Cement at Different Densities

This data was compiled from a cementing field data handbook. It can be observed from the table that a decrease in density of Portland cement greatly reduces the compressive strength that the slurry can develop. It is generally accepted that the bond strength of a cement blend will be approximately 10% of its compressive strength.

Pipe Condition

The overall downhole conditions where cement is being placed in a well have almost the largest effect on bond strength development. Studies have shown that placement of cement inside pipe that has oil-wet surfaces will result in lower bond strength development as compared to placement in a pipe with water-wet surfaces. The pipe condition also varies the quality of the cement bond. Casing with rough inner surfaces generate higher bond strengths as compared to casing with smooth inner surfaces. Figure 1 shows a qualitative graph of the effects of various well conditions on cement bond strength. This graph is for illustrative purposes only.

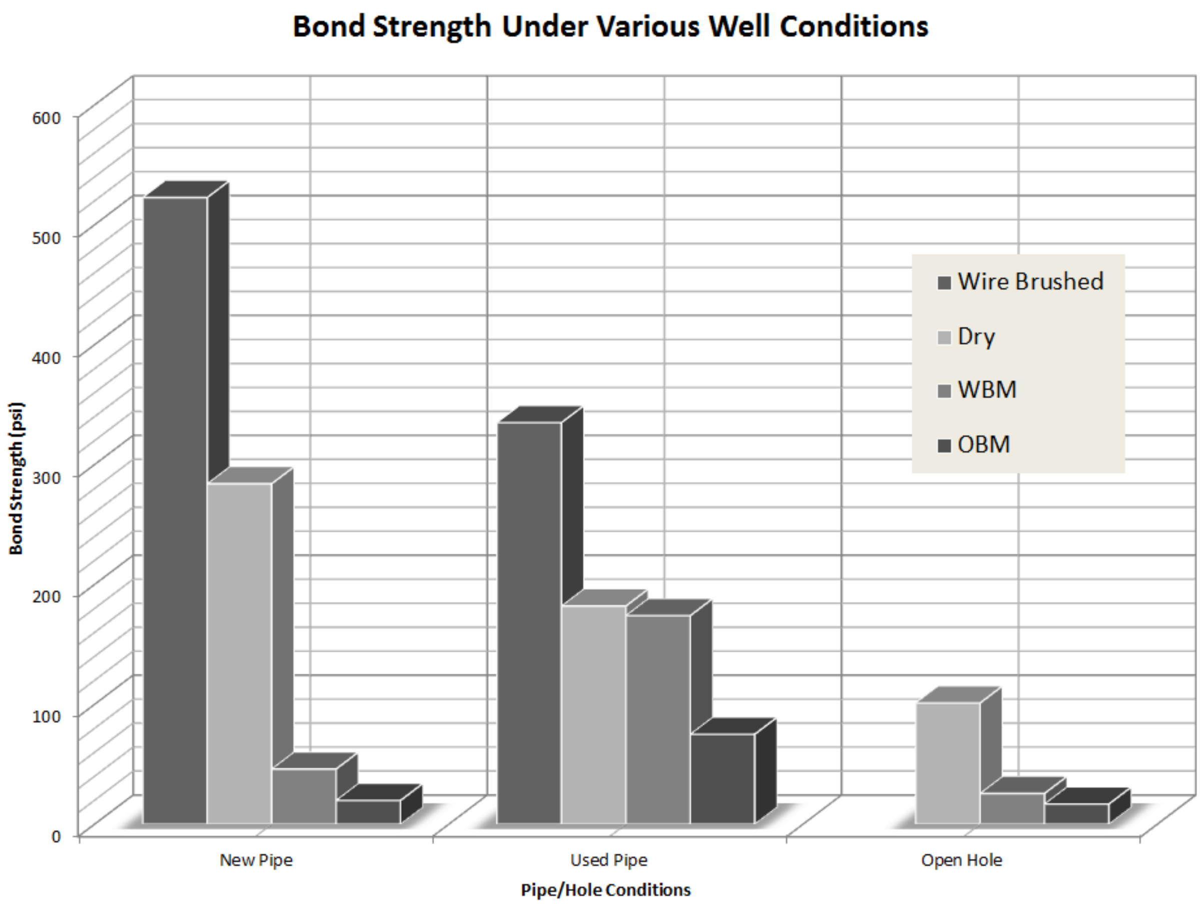

Figure 1: Cement Bond Strength under Various Well Conditions.

Crystalline Expansion Properties

Additives in cement blends that enhance expansion properties greatly improve cement bond strength characteristics. Generally, calcium sulfate (Gypsum) is used as an expansion additive for cement slurries at temperatures below 140°F. Higher temperature applications require the use of magnesium oxide for expansion properties. As the cement is setting, these expansion additives help increase the overall cement sheath surface area against the pipe. Larger contact surface area helps increase the amount of force the plug can withstand before failure. Tettero et al. (2004)[1] explains that cement with expanding properties "will ensure excellent bonding with the casing and prevent the development of microannuli between casing and cement plugs so the wells remain properly abandoned over time."

The Use of Bonding Agents in Cement Blends

Additives such as latex and surfactants help cement blends adhere to casing and pipe walls effectively increasing bond strengths. The use of latex in cement slurries increases the adhesion of the cement to pipe walls through a reduction in surface area. Soter et al. (2003)[2] states that "latex cement bonding is enhanced by improvement to the slurry's wetting characteristics and the low viscosity of the slurry itself during the setting of the cement plugs. Inclusion of the latex additive can lower the surface tension between the slurry and the casing and its low viscosity can aid in evenly displacing the wellbore fluid to help minimize cement contamination." Surfactants also help in removing oil-wet surfaces from annular walls allowing better bonding contact during setting.

Engineering Analysis

Hydraulic Bond Strength

When calculating the required hydraulic bond strength that a cement blend must have, the surface area of the top of plug and the estimated bonded cement plug length must be known values. Required hydraulic bond strength is calculated by finding the resulting force acting on a cement plug from the hydraulic pressure on a given surface area. This resulting force is divided by the bonded cement sheath area which results in a required hydraulic bond strength. The following figures discussed are representations of required bond strengths in order to comply with BSEE P&A regulations. The representative figures do not take into account various downhole conditions that may adversely affect cement plug placement and the ability of the cement to develop bond strengths.   Figure 2 shows required hydraulic bond strength in relation to pipe diameter and plug length.

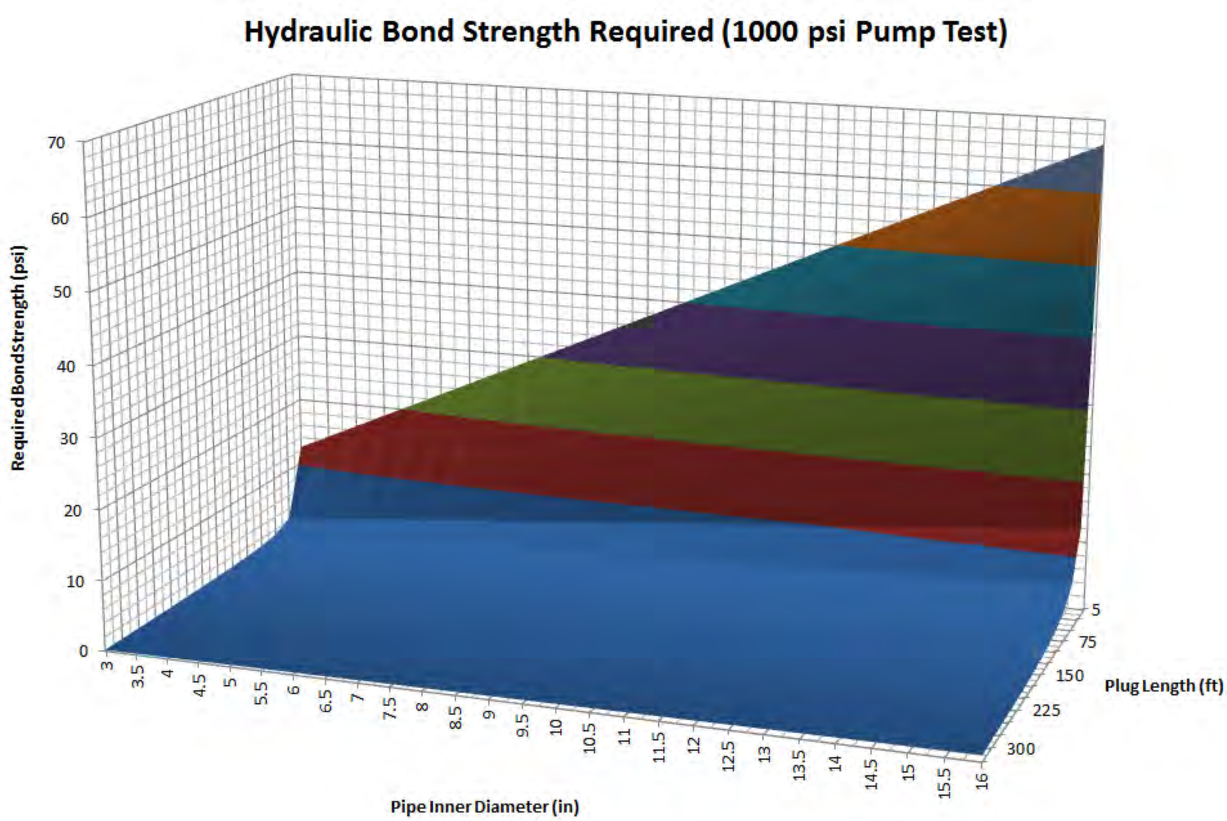

Figure 2: Hydraulic Bond Strength Required (1000 psi Pump Test)

As seen from this figure, a much larger amount of bond strength is required for short cement plugs placed inside large diameter holes. For example: a 5 foot plug of cement in a 13 inch inner diameter pipe would require a minimum bond strength of 54 psi to comply with regulatory pump pressure test requirements, whereas the same pipe with a 300 foot plug would need a bond strength of only 1 psi. It can also be noticed that for most cement plugs which range in length between 75 foot and 300 foot, very little bond strength is required to comply with regulatory standards.

Shear Bond Strength

When calculating the required shear bond strength that a cement blend must have, only the bonding cement sheath area must be a known value. Required shear bond strength is calculated by dividing the force applied on the cement by the bonded cement sheath area. Figure 3 shows the required shear bond strength in relation to pipe diameter and plug length.

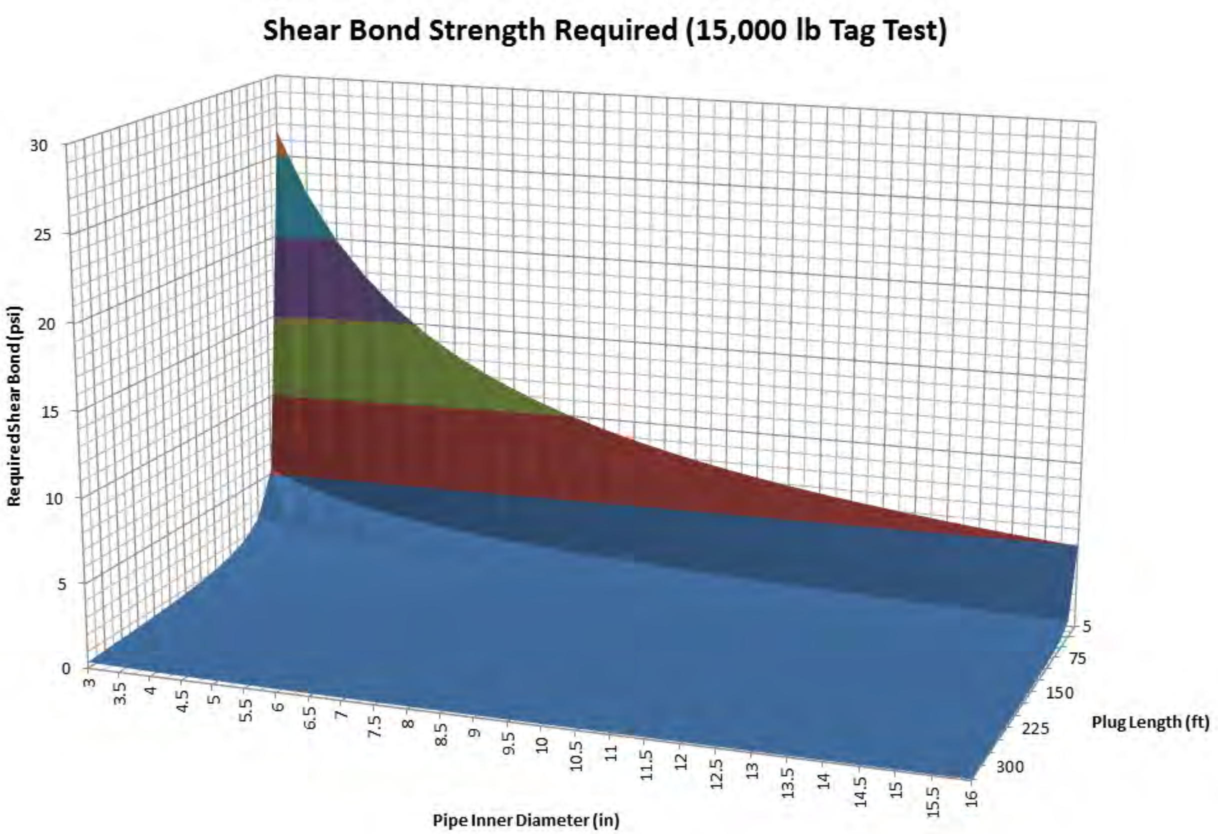

Figure 3: Shear Bond Strength Required (15,000 lb Drill Pipe Tag Test)

As seen from Figure 3, a much larger amount of bond strength is required for short cement plugs placed inside small diameter holes. For example: a 5 foot plug of cement in a 3 inch inner diameter pipe would require a minimum bond strength of 26.5 psi to comply with regulatory drill pipe tag test requirements, whereas the same pipe with a 300 foot plug would need a bond strength of only 0.5 psi. It can also be noticed that for most cement plugs which range in length between 75 foot and 300 foot, very little bond strength is required to comply with regulatory standards.

Cement Bond Strength Requirement

Upon review of Figure 2 and 3, it is apparent that the downhole pipe configuration dictates which cement plug testing method has more stringent requirements. Figure 4 shows the required bond strength to satisfy both cement plug testing procedures in relation to pipe diameter and plug length.

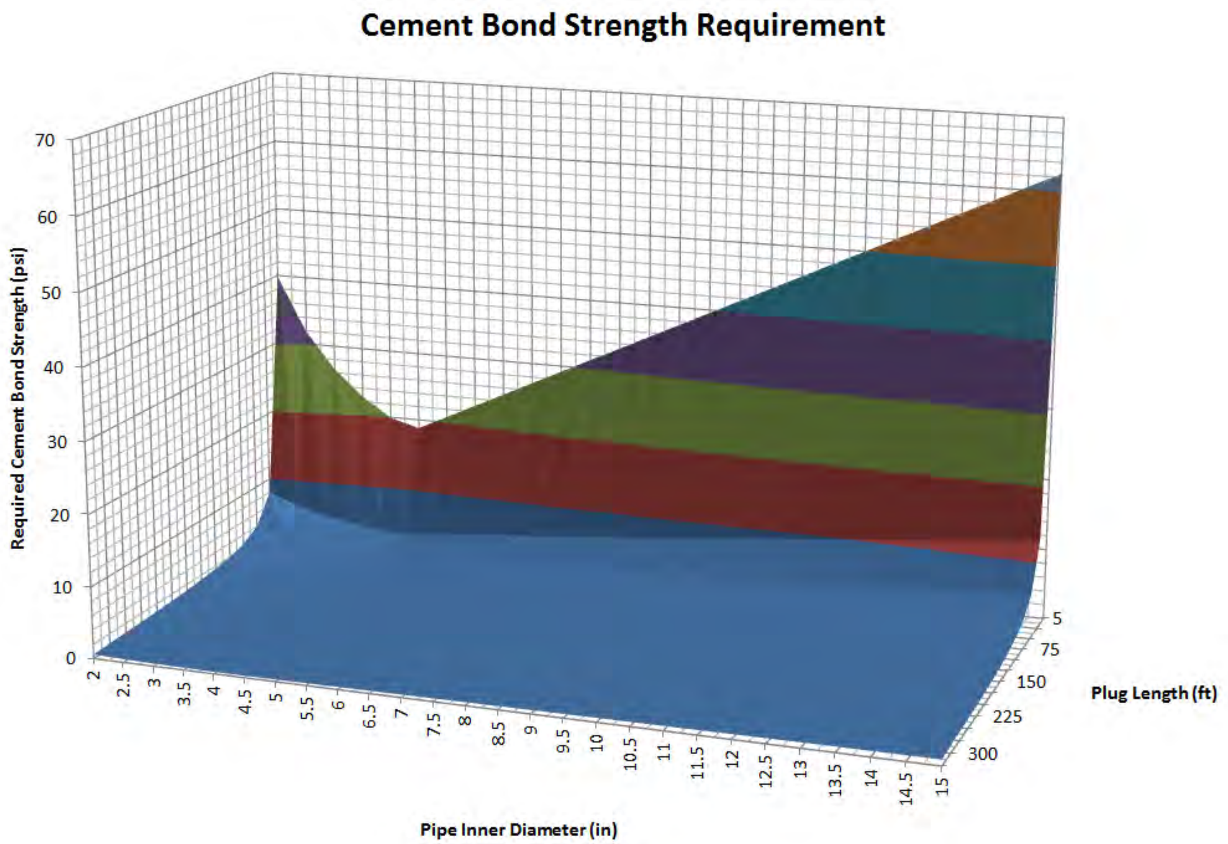

Figure 4: Cement Bond Strength Requirement

This Figure was plotted by calculating both the required hydraulic and shear bond strengths, then plotting the higher of the two values in anticipation that both tests would be performed on said cement plugs. For example: a 25 foot plug of cement in a 14 inch inner diameter pipe would require a minimum bond strength of 11.7 psi to comply with both regulatory testing methods, whereas the same plug length in a 3 inch pipe would require a 5.3 psi bond strength. It should still be noted that for most cement plugs which range in length between 100 foot and 300 foot, very little bond strength is required to comply with regulatory standards.

Bond Strength Comparison

Upon review of Figure 4, It was also noticed that for approximate inner pipe diameters less than 4.5 inches, the drill pipe tag test requires higher bond strengths than the pump pressure test method. Unfortunately, tagging cement plugs with drill pipe in these situations may be more difficult than running a simple pump pressure test. In order to express a pump pressure that would be considered equivalent to drill pipe tag weight for these conditions, one must set the resulting hydraulic bond strength equal to the resulting shear bond strength. Required shear bond strength in terms of drill pipe tag weight is calculated as:

$$Bond\ Strength \quad \frac{Drill\ Pipe\ Tag\ Weight}{Cement\ Sheath\ Area} \quad \frac{Drill\ Pipe\ Tag\ Weight}{D \quad L}$$

Required hydraulic bond strength in terms of pump pressure is calculated as:

$$Bond\ Strength \quad \frac{Pump\ Pressure * Cross\ Sectional\ Area}{Cement\ Sheath\ Area} \quad \frac{Pump\ Pressure * \frac{D}{4}}{D \quad L}$$

By solving the above equation for pump pressure, the result is as follows:

$$Pump\ Pressure \quad \frac{Bond\ Strength * Cement\ Sheath\ Area}{Cross\ Sectional\ Area} \quad \frac{Bond\ Strength * \quad D \quad L}{\frac{D}{4}}$$

By substituting the shear bond strength values that were calculated from drill pipe tag weight one can get an equivalent pump pressure in terms of drill pipe tag weight shown below:

$$Pump\ Pressure \quad \frac{\frac{Drill\ Pipe\ Tag\ Weight}{D \quad L} \quad D \quad L}{\frac{D}{4}} \quad \frac{Drill\ Pipe\ Tag\ Weight}{Cross\ Sectional\ Area}$$

It was observed that because the pump pressure is now calculated from tag weight bond strengths, the cement sheath areas cancel out of the equation making equivalent pump pressures independent of plug length. Figure 5 depicts the equivalent pump pressure test requirement to adhere to the drill pipe tag test method for small pipe inner diameters.

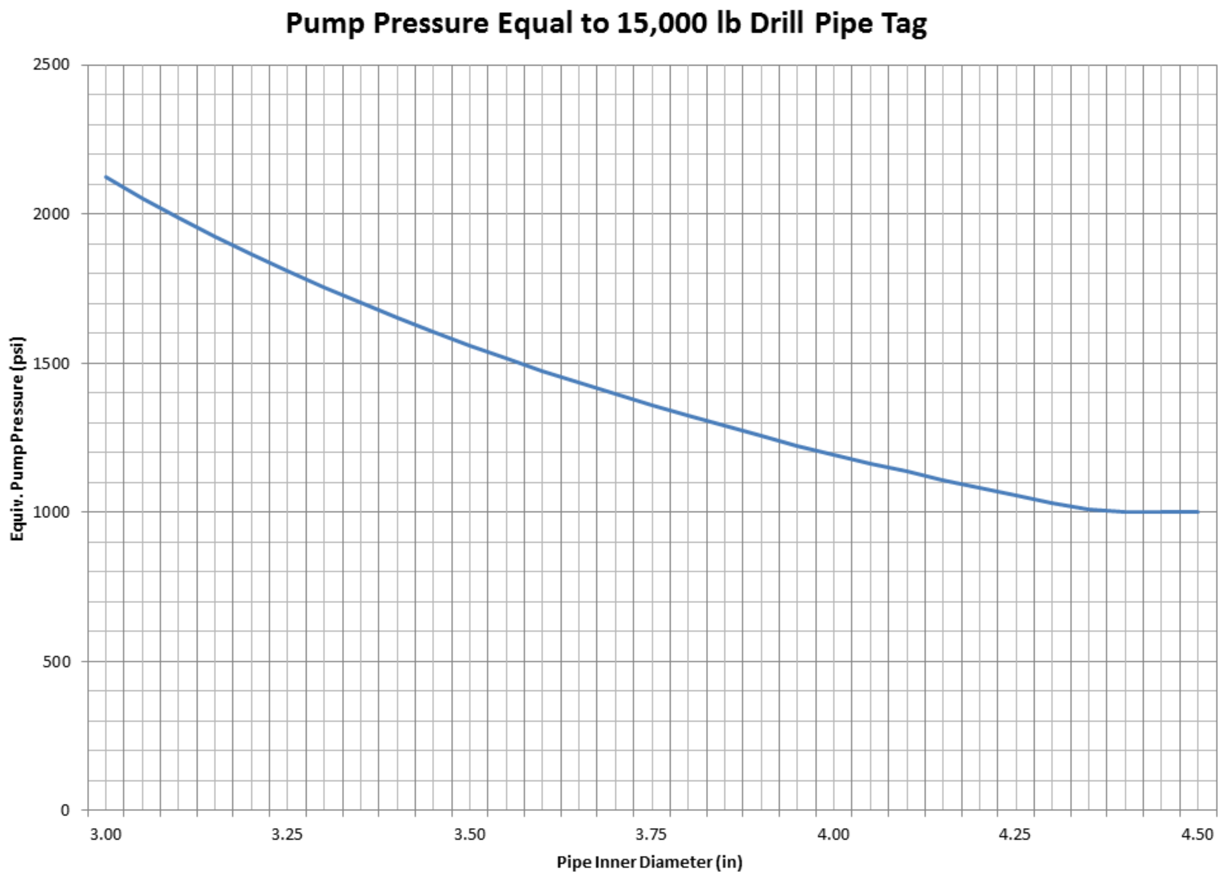

Figure 5: Pump Pressure Equal to 15,000 lb Drill Pipe Tag

It is noticed that a somewhat small increase of pump pressure is required to equate the amount of force that is applied using the drill pipe tag test method for small diameter plugs.

Horse Collar Calculations

In anticipation of testing "Horse Collar" cement plugs which are periodically performed during plug and abandonment operations, two more representative figures are presented. Since these annular plugs cannot be tested using the drill pipe tag test method, only the calculated required hydraulic bond strength is plotted to adhere to the pump pressure test method. Figures 6 and 7 show the required annular hydraulic bond strength for testing with 3.5 inch and 5.5 inch production tubing in place respectively. Generally, the required hydraulic bond strengths for plugs between 10 foot and 300 food range between 1 psi and 10 psi for most annular configurations as shown below.

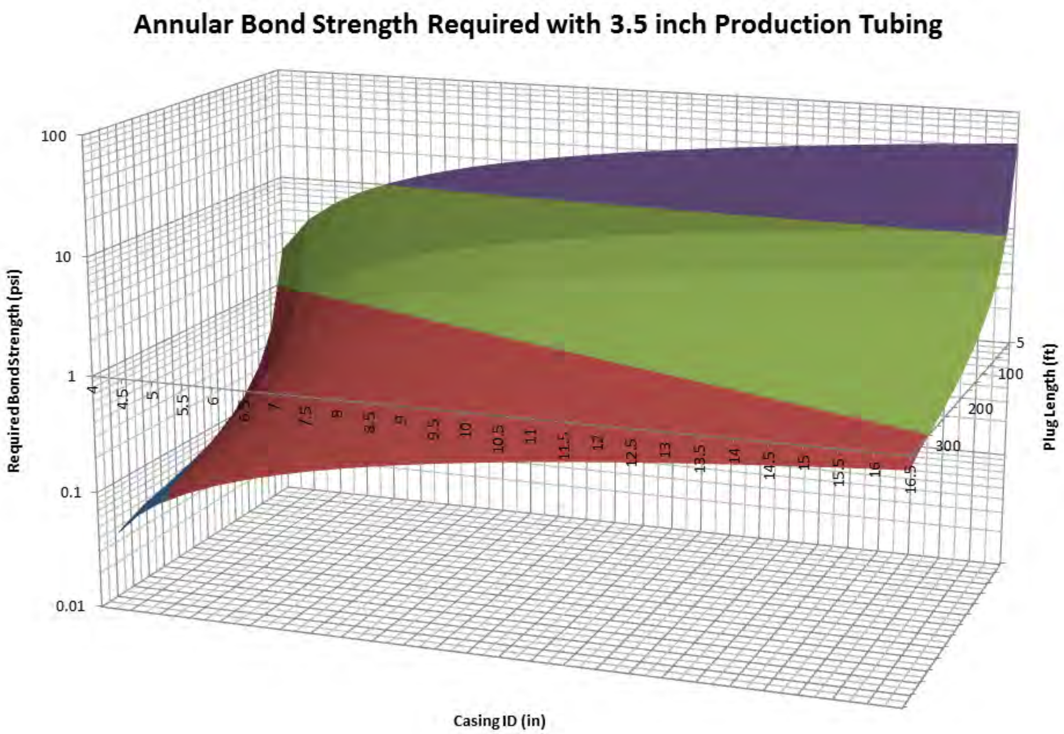

Figure 6: Annular Bond Strength Required with 3.5 inch Production Tubing

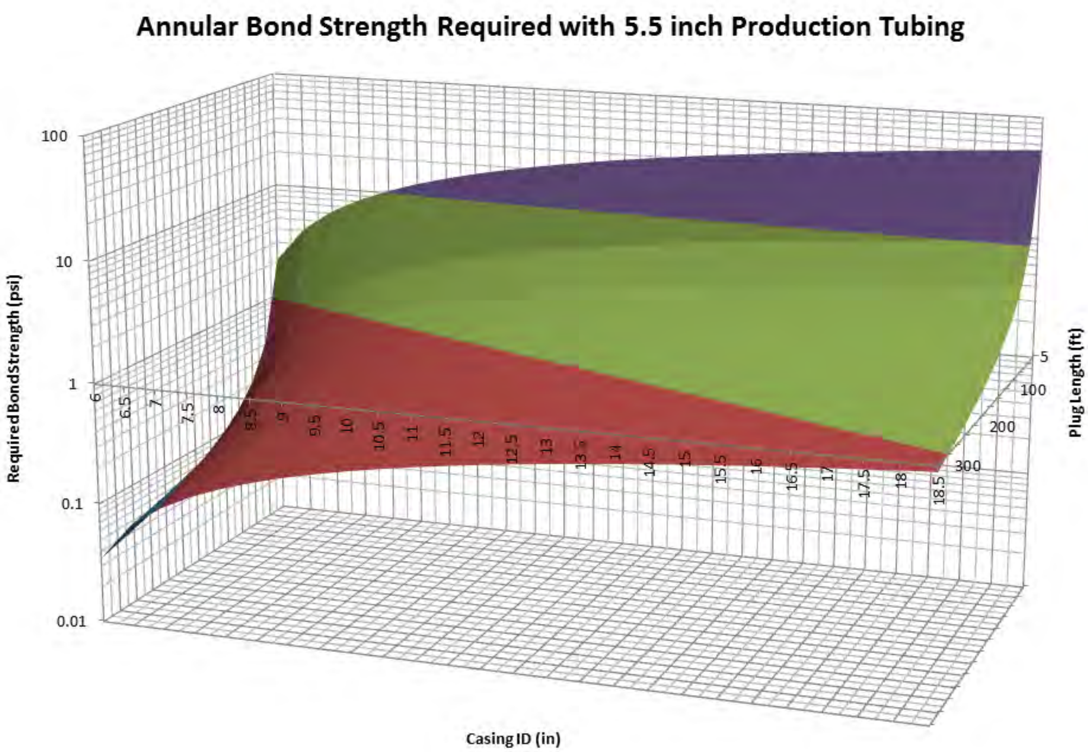

Figure 7: Annular Bond Strength Required with 5.5 inch Production Tubing

Laboratory Evaluation

An extensive laboratory evaluation of cement properties that affect plug seal integrity was conducted. Cement properties that were studied included strength development and admixtures to improve bond strength or prevent gas cut. Both small scale and large scale testing was performed on several blends to better match a wider range of plugging conditions. Blend formulations and laboratory data summaries of blends are shown in Appendix B. The results are discussed below.

Small Scale

All small scale testing was performed within the laboratory. All general laboratory testing such as thickening time or rheology was performed prior to specific blend testing such as shear/hydraulic bond and pressure annular seal

Blend Formulations

Table 2 shows the blend formulations for all cement blends.

Blend Composition (All Blends at 16.4ppg Density)				
	80°F	120°F	190°F	240°F
Neat	Class H	Class H	Class H + 0.04gps Retarder	Class H + 0.06gps Retarder
Latex	Class H + 1.5gps Latex + 0.01gps Antifoam	Class H + 1gps Latex + 0.01gps Antifoam	Class H + 1.5gps Latex + 0.1gps Stabilizer + 0.05gps Dispersant + 0.04gps Retarder + 0.01gps Antifoam	Class H + 1.5gps Latex + 0.1gps Stabilizer + 35% Silica + 0.05gps Dispersant + 0.04gps Retarder + 0.01gps Antifoam
Surfactant	Class H + 0.05gps Surfactant	Class H + 0.05gps Surfactant	Class H + 0.05gps Surfactant + 0.04gps Retarder	Class H + 35% Silica + 0.05gps Surfactant + 0.035gps Retarder
Gas Migration	Class H + 0.2gps GMA	Class H + 0.2gps GMA	Class H + 0.25gps GMA	Class H + 35% Silica + 0.3gps GMA + 0.035gps Retarder
Expanding	Class H + 5% Gypsum	Class H + 5% Gypsum	Class H + 3% MagOX-M + 0.04gps Retarder	Class H + 3% MagOX-H + 0.06gps Retarder

Table 2: Blend Formulations used for testing

These five blends were re-designed at four different temperatures for slurry stability and compressive strength development properties. Extensive testing was performed at various curing times and simulated temperatures. Generic cement additives were used in blend compositions such that comparable results would be observed in similar situations using additive of a related nature.

Mechanical Properties

Figure 8 illustrates the apparatus for measuring mechanical properties.

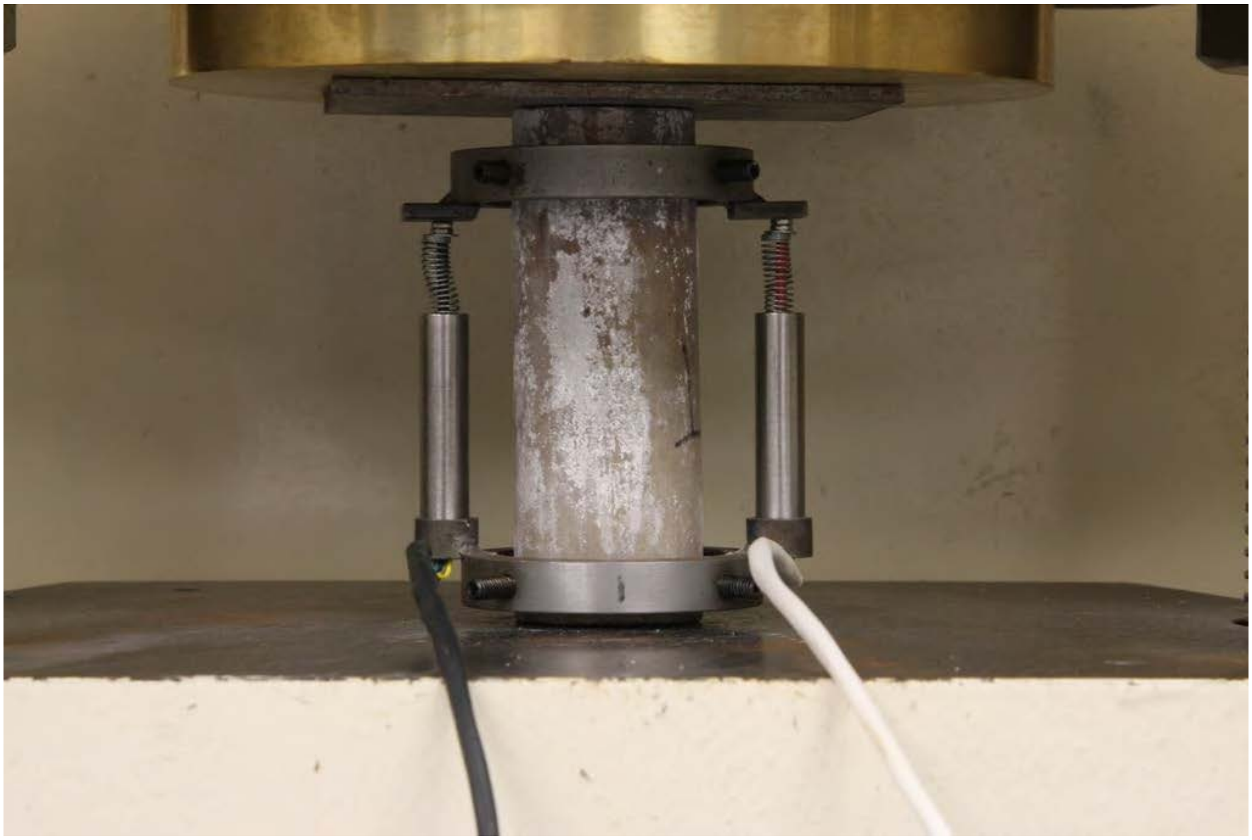

Figure 8: Apparatus for Measuring Mechanical Properties of Cement

The cement blends were cured in cylindrical molds and deformation was measured from an applied load. The low voltage deformation transducers (LVDT) positioned on each side of the cylinder measure linear deflection of cement. This deflection along with applied force is used to calculate Young's Modulus of elasticity. Poisson's ratio was also measured by use of a third LVDT in the radial axis. Table 3 shows the average mechanical properties data of each cement blend at different curing times and temperatures. Cement blend compositions had mechanical properties which were within tolerable ranges of documented values.

Cement System		Neat		Latex		Surfactant		GMA		Expanding	
Temperature	Curing Time (hr)	Young's Modulus (psi)	Poisson's Ratio	Young's Modulus (psi)	Poisson's Ratio	Young's Modulus (psi)	Poisson's Ratio	Young's Modulus (psi)	Poisson's Ratio	Young's Modulus (psi)	Poisson's Ratio
80°F	12	2.28E+05	0.14	2.41E+06		2.99E+05	0.03	2.41E+05	0.57	2.08E+05	0.10
	24	8.00E+05	0.09	5.74E+05	0.47	7.56E+05	0.66	1.01E+06	0.29	5.07E+05	0.02
	168	2.63E+06	0.03	8.87E+05	0.18	1.16E+06	0.13	9.69E+05	0.41	2.80E+06	0.16
120°F	12	8.67E+05	0.08	9.26E+05	0.13	1.00E+06	0.07	1.56E+06	0.11	2.90E+06	0.76
	24	1.61E+06	0.18	5.58E+05	21.32	3.72E+07	0.37	1.02E+06	0.57	9.84E+05	0.65
	168	2.90E+06	0.15	4.56E+05	0.17	5.71E+06	0.12	2.58E+06	0.55	2.16E+06	
190°F	24	2.39E+07		5.50E+05	0.10	1.03E+06	0.18	9.55E+07		6.73E+07	
240°F	24	1.01E+06	0.20	8.20E+05	0.20	1.09E+06	0.16	9.30E+05	0.13	1.09E+06	0.13

Table 3: Mechanical Properties of Cement Blends

Shear/Hydraulic Bond Strength

Both shear and hydraulic bond strength testing was performed on each blend at different curing times. Curing time ranged from 12 and 24 hours to 168 hours (one week). Shear bond strength was measured by applying force, by use of a hydraulic press, to a cement plug cured inside a 2 inch pipe. Hydraulic bond strength was measured by attaching a positive displacement pump to one end of the pipe and applying pressure until the cement seal failed. Figures 9 through 12 show a comparison of measured hydraulic to measured shear bond strength. It can be noticed that most hydraulic bond strength failure values were much lower than shear bond strength failure values. This can be partially attributed to expansion of the pipe which creates micro-annuli paths for fluid flow.

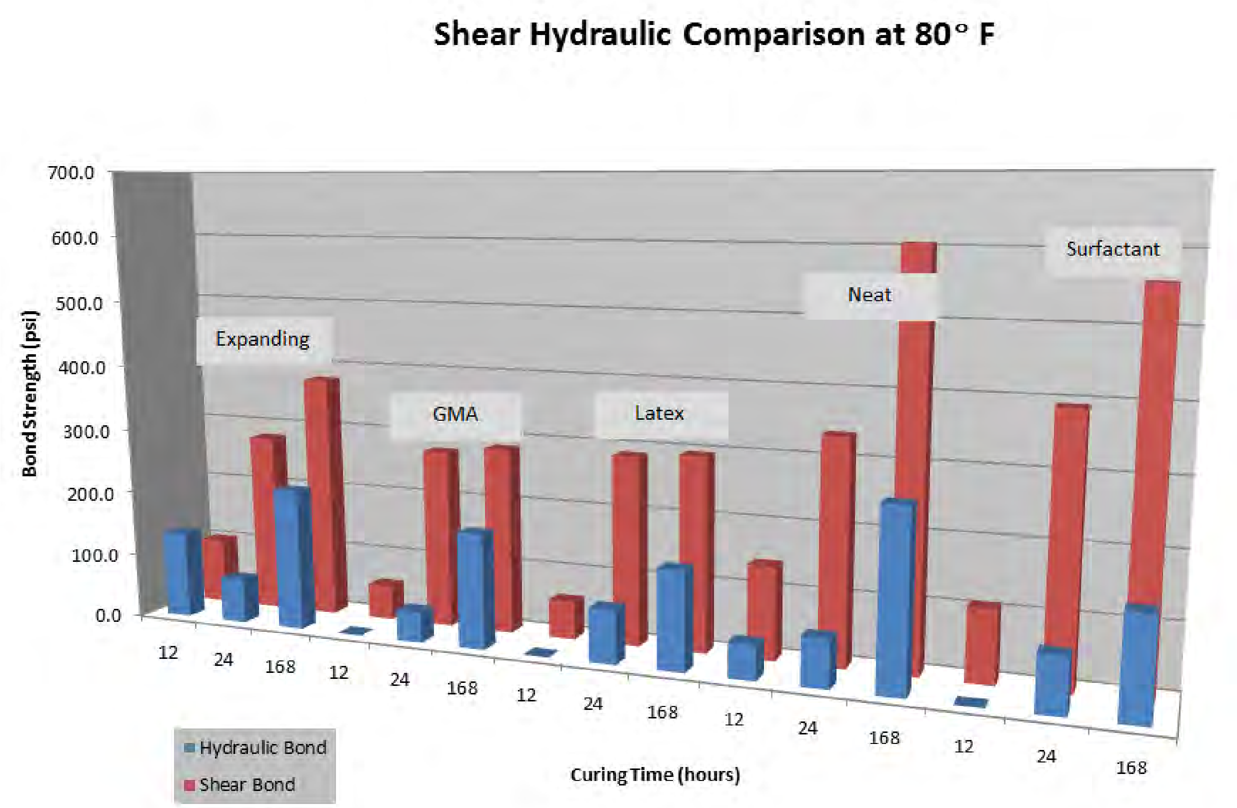

Figure 9: Bond Strength Comparison at 80° F

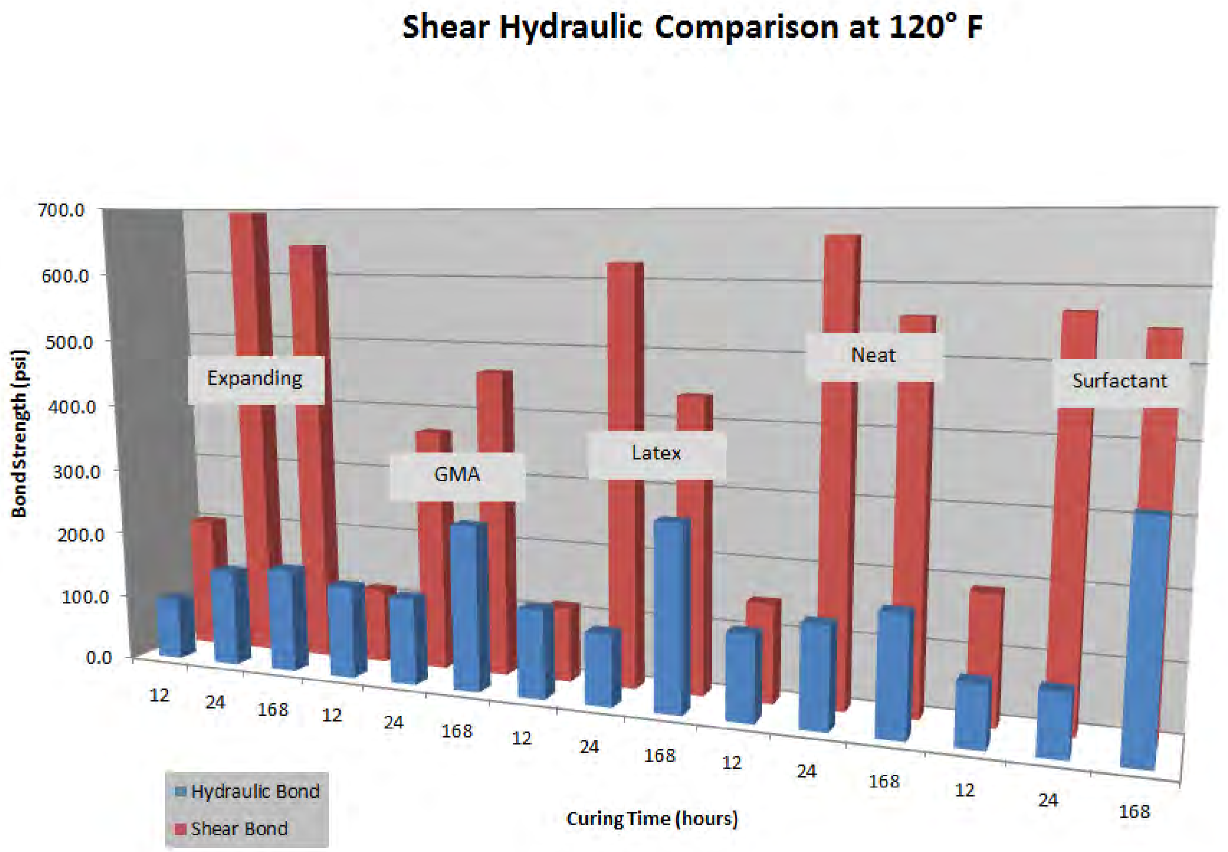

Figure 10: Bond Strength Comparison at 120° F

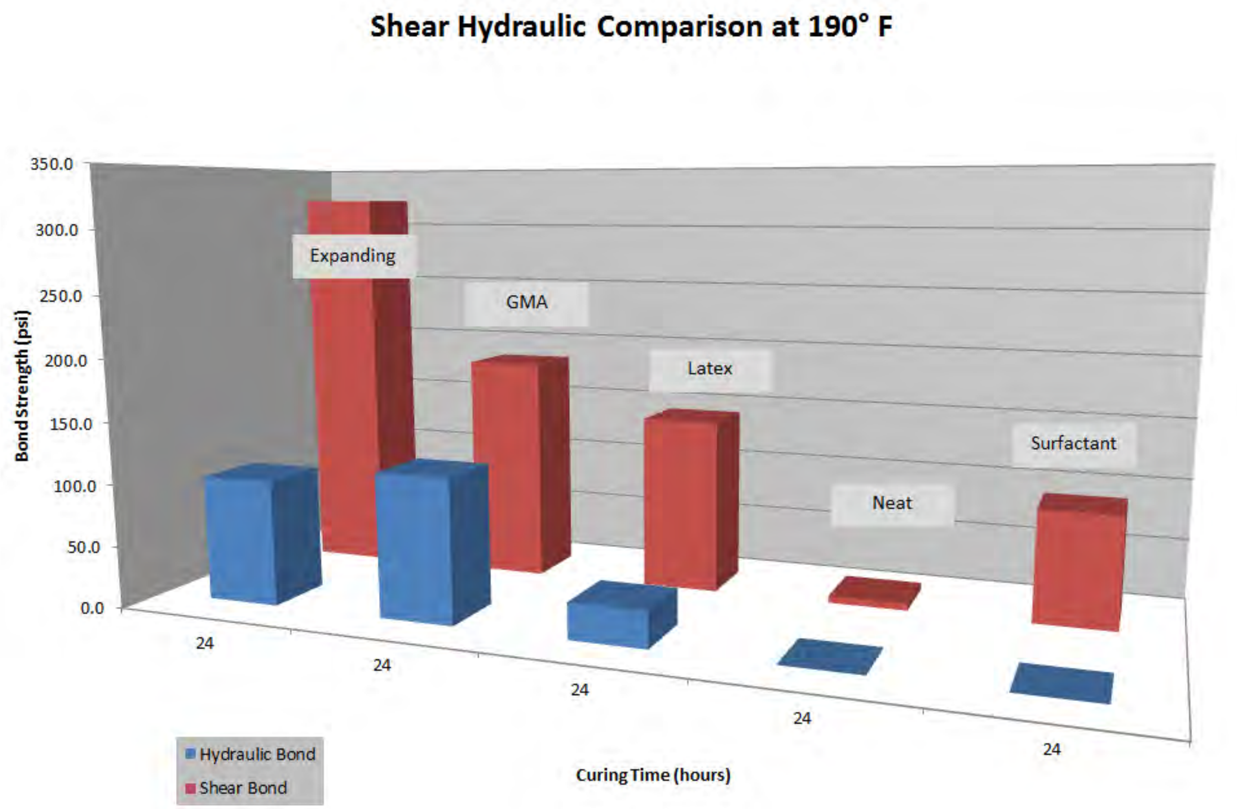

Figure 11: Bond Strength Comparison at 190° F

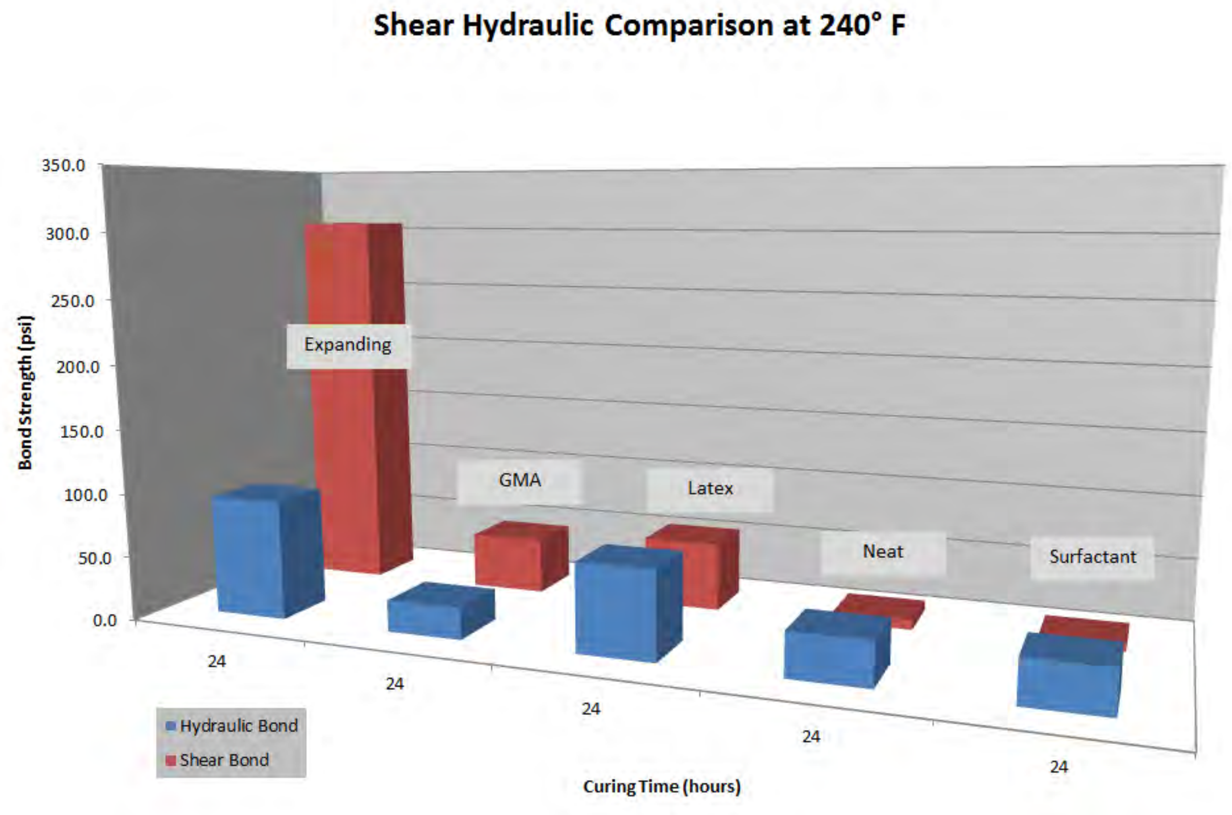

Figure 12: Bond Strength Comparison at 240° F

Compressive Strength Development

Compressive strength development was measured two separate ways. The first method was by use of the ultrasonic cement analyzer and the second was destructive measurement using the hydraulic press. All ultrasonic data is presented within Appendix B and table 4 below illustrates the compressive strengths of the blend formulations for various temperatures and curing times.

		Compressive Strength (psi)				
Temperature	Curing Time (hours)	**Neat**	**Latex**	**Surfactant**	**GMA**	**Expanding**
80°F	12	165	347	436	197	436
	24	1230	753	1222	1817	1215
	168	3465	1267	1886	2104	2175
120°F	12	2168	2249	1933	764	1227
	24	2637	1027	2049	2247	1831
	168	3104	811	1083	3521	2405
190°F	24	609	1512	2645	2645	2308
240°F	24	4439	3757	5273	5273	4817

Table 4: Compressive Strength Development of Cement Blends Using Crush Test Method

Observations from compressive strength and bond strength testing shows that longer cure times decrease the likelihood of cement plug failure.

Pressure Annular Seal Testing

The Pressure Annular Seal Apparatus is designed to place the cement in a geometry consistent with a wellbore. The central loading pipe provides the simulation of the wellbore tubuluars, and is the means by which the cement is stressed. The outer pipe provides a means by which the cement can bond and be supported. Figure 13 shows a cross section of the pressure annular seal apparatus.

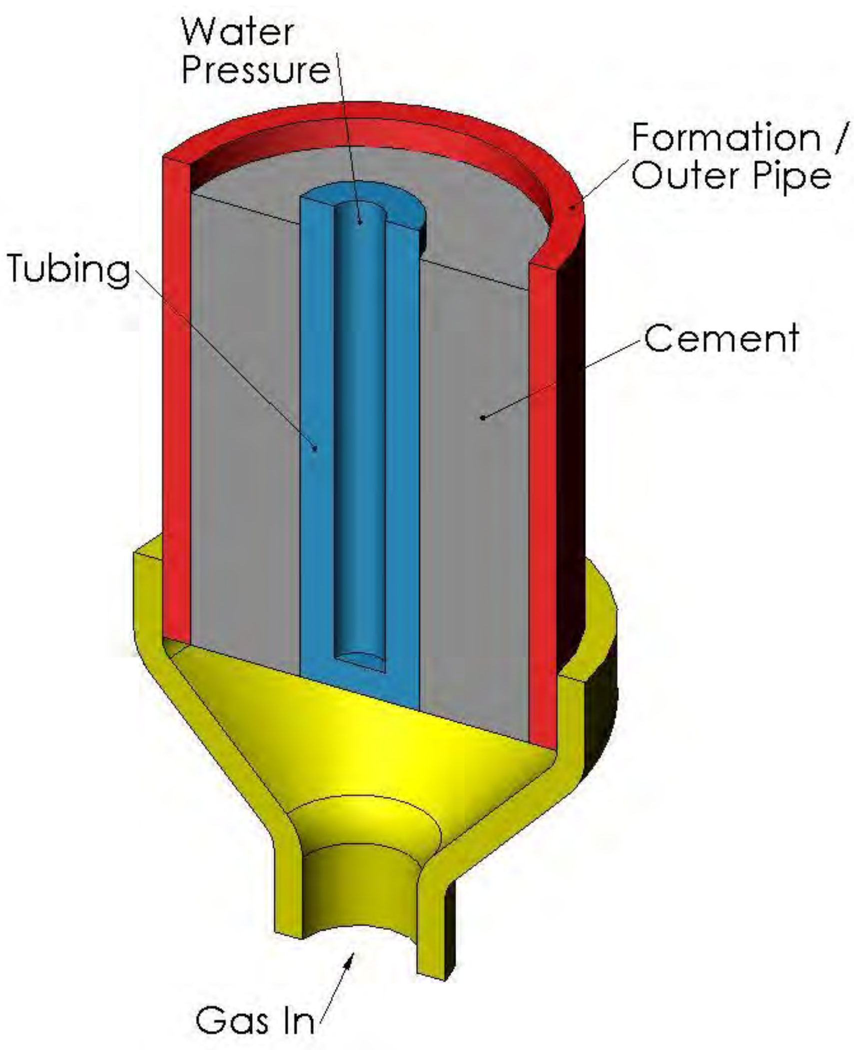

Figure 13: Pressure Annular Seal Apparatus Cross Section

The primary components include the outside pipe (simulates the formation), cement sheath, central loading pipe, and the reducer for channeling the gas. In practice, cement is poured into the annulus between the central pipe and the outer pipe. After curing at ambient temperature under 150 psi, low-pressure gas is conducted through a flowmeter and into the inner end of the cement plug via the reducer. The central pipe (blue) is alternately pressurized and depressurized to stress the cement sheath. As long as the cement seal is intact, gas will not flow. This test measures the integrity of the cement annular seal when stressed by imposing pressure in the internal pipe. Cement integrity is determined by the ability of the cement to block nitrogen flow from the bottom to the top of the cell. The gas pressure is maintained at 15 psi.

Results of the Annular Seal tests are presented in terms of the amount of energy required to create a failure in the annular seal and are shown in Table 5.

		Cement System				
		Neat	Latex	Surfactant	GMA	Expanding
Pressure Applied (psi)	1,000	No Flow	No Flow	No Flow	No Flow	No Flow
	2,000	No Flow	No Flow	No Flow	No Flow	No Flow
	3,000	No Flow	No Flow	No Flow	No Flow	No Flow
	4,000	No Flow	No Flow	No Flow	No Flow	No Flow
	5,000	No Flow	No Flow	No Flow	No Flow	No Flow
	6,000	No Flow	No Flow	No Flow	No Flow	No Flow
	7,000	No Flow	No Flow	No Flow	No Flow	No Flow
	8,000	No Flow	No Flow	No Flow	No Flow	No Flow
	9,000	No Flow	No Flow	No Flow	No Flow	No Flow
	10,000	No Flow	No Flow	No Flow	No Flow	No Flow
	10,000 x 15	No Flow	No Flow	No Flow	No Flow	No Flow
	Energy to Failure	N/A	N/A	N/A	N/A	N/A

**Note – energy to failure is based on the closed interval of 0 to 10,000 psi.*

Table 5: Pressure Annular Seal Energy to Failure Data

All five cement slurries were subjected to cyclical pressure loading, scrutinizing the compressive integrity of each system. Each sample was cured for a period of 24 hours at an ambient temperature of 80°F and 150 psi. Cyclic pressure loading entailed repeatedly subjecting tubing encased in cement to varying hydraulic pressure. Specifically, samples were pressured up in 1,000 psi increments to 10,000 psi for a total of 10 cycles. At each interval, pressure was held for 15 seconds and then subsequently released for 15 seconds before proceeding to the next interval. Following the 10 cycles of 1,000 psi increments, each sample was immediately pressured up to 10,000 psi for an additional 15 cycles. During these cycles Backside Pressure was maintained at 15 psi while an in line flow-meter monitored annular communication. All systems proved extremely competent with bond integrity never being compromised. Each and every system withstood cyclic pressure loading and upheld annular isolation.

Large Scale

Several large scale tests were performed on the cement blends to help develop a better understanding of cement plug seal integrity, plug stability during placement, and long term seal effectiveness against gas migration. The testing procedures and results are discussed below.

8ft Perm

Large scale laboratory tests were performed to observe long term seal efficiency of cement plugs using the five different cement blends discussed earlier. Cement blends were cured within 8 foot steel pipes as shown in figure 14.

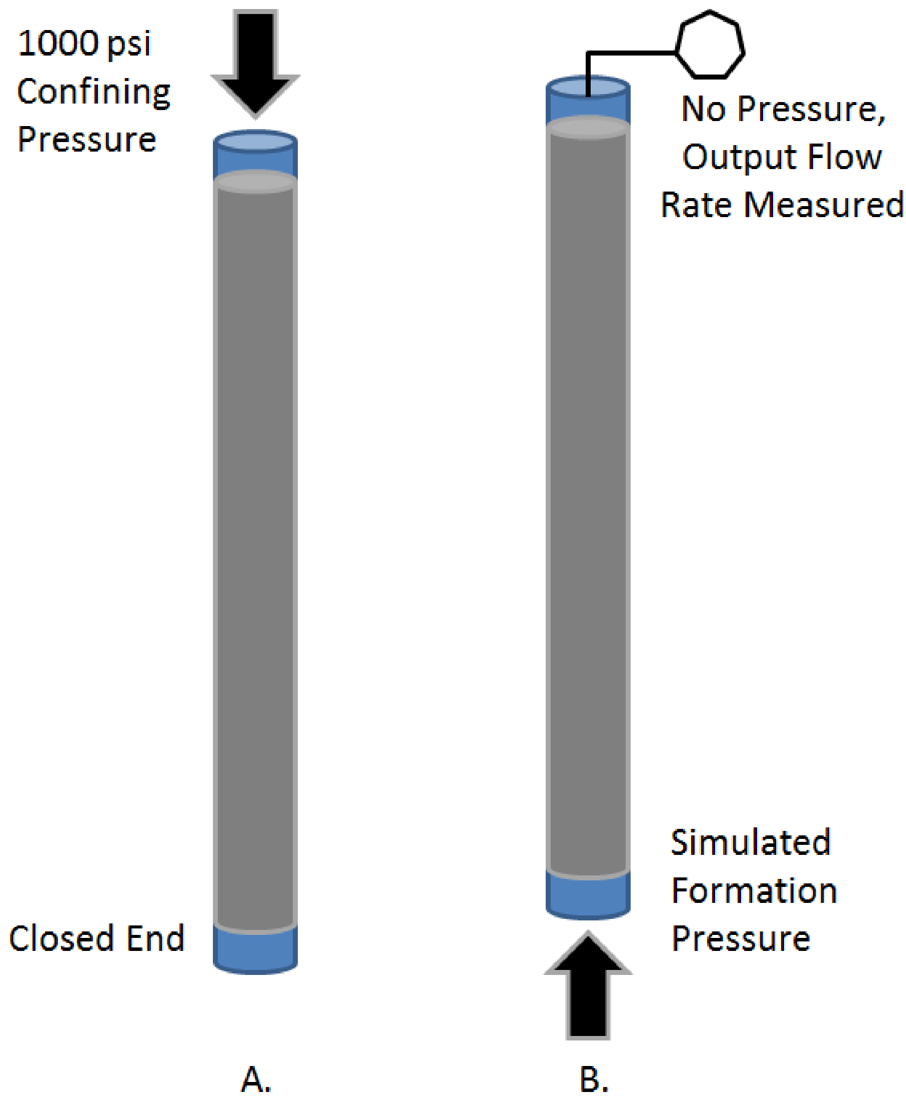

Figure 14: A, 8 foot perm test arrangement during cement cure time. B, 8 foot perm test arrangement during long term seal effectiveness test

These pipes were schedule 40 with 2 inch diameters. Cure time of the cement was one week with 1000 psi confining pressure applied to the top of the columns. Pressure was removed from the pipes after curing, and nitrogen pressure was applied to the bottom of the pipes with open-ended tops. Gas flow rate out of the top of the pipes was measured daily to determine total number of days before the cement plug would allow gas to migrate and be considered a failed plug. All cement plugs resisted gas migration for a total of 62 days. At this point, the nitrogen gas pressure was incrementally increased by 100 psi each week to a maximum of 1000 psi, which was the maximum pressure the nitrogen regulators were able to output. After 184 days (6 months), none of the cement plugs had allowed gas to migrate through the pipes. At this point, all cement blends were deemed sufficient to hold back gas migration for long term seal effectiveness. Test data for this is shown in Appendix B.

Hydration Volume Reduction

A critical part of all cementing operations which is generally overlooked is the volume reduction while the cement hydrates. It is well known that although the bulk volume of cement remains constant, the absolute volume tends to decrease during hydration. This volume decrease can affect the transmission of hydrostatic pressure to the formation as well as the cement's ability to prevent annular fluid migration. A large scale test apparatus was developed to measure the effect that hydration volume reduction has on a cement slurry during the critical hydration period. Neat cement was chosen for this test because most plugging operations in the Gulf of Mexico are with neat cement. First, the cement was placed in a vessel and cured at constant pressure using a syringe pump with constant feedback looping technology. The test apparatus is shown in figures 15 and 16.

Figure 15: Volume Reduction Measurement during Cement Hydration Test Apparatus

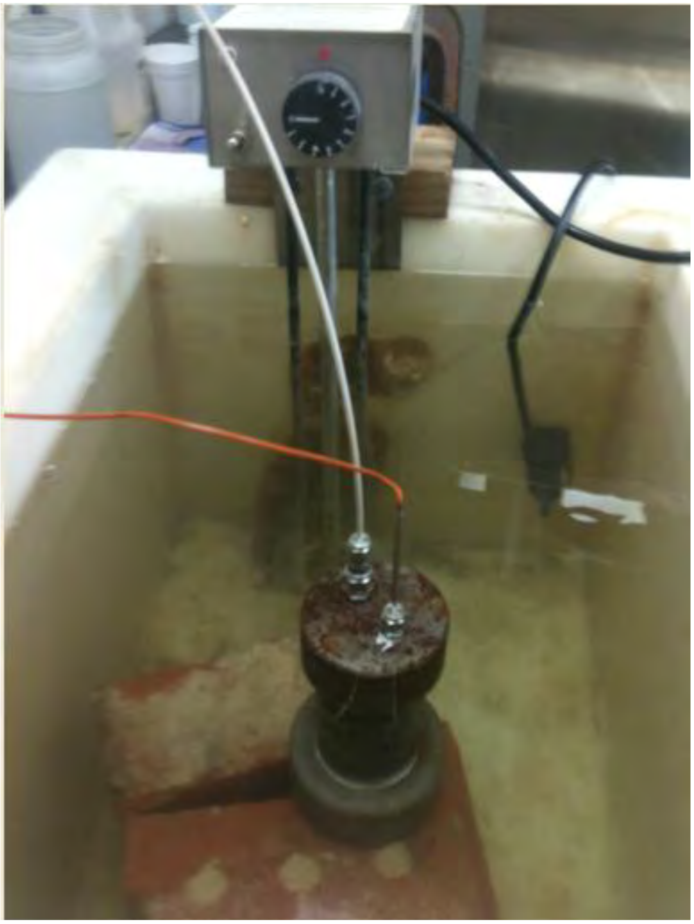

Figure 16: Volume Reduction Measurement during Cement Hydration Test Apparatus

The injected water volume was measured throughout the test and is shown in figure 17. It was noticed that cement absolute volume reduction takes place during the first 24 hours and additional injected volume can be attributed to permeation.

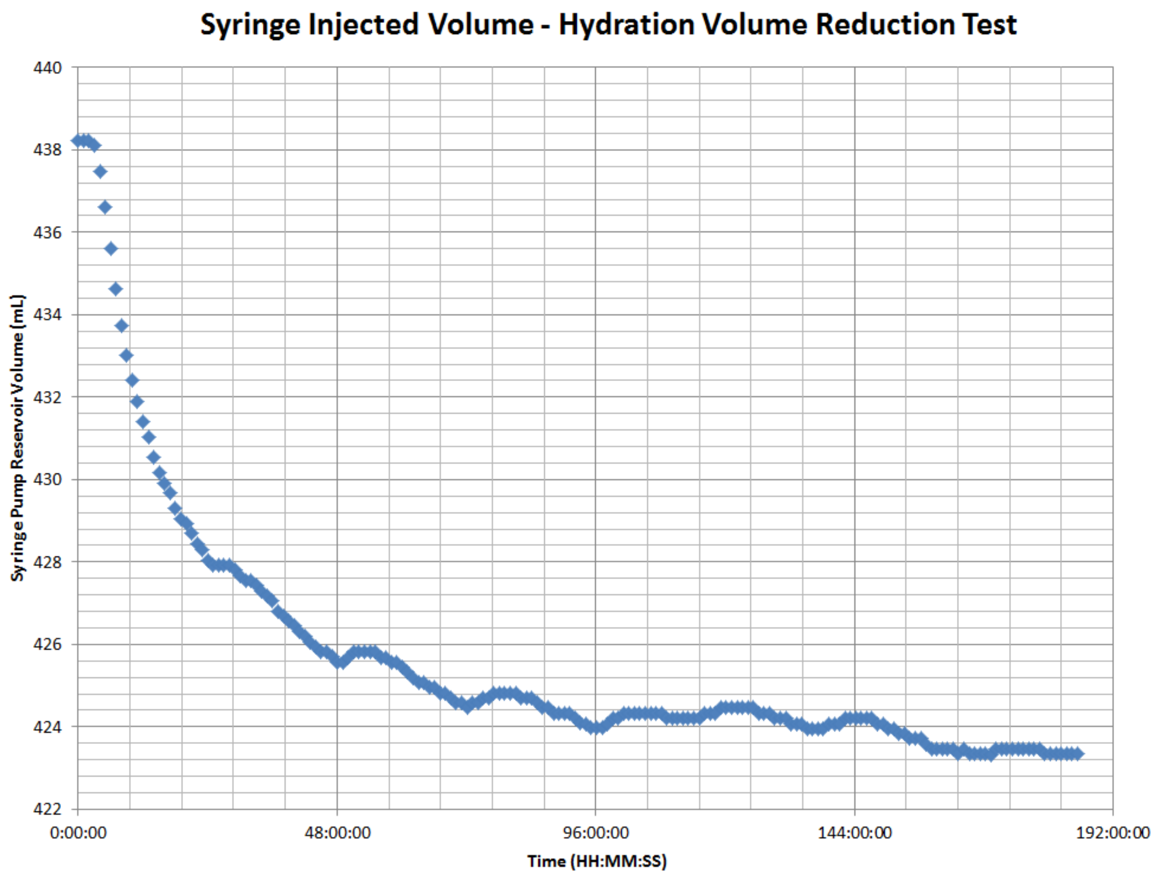

Figure 17: Syringe Injected Volume – Hydration Volume Reduction Test

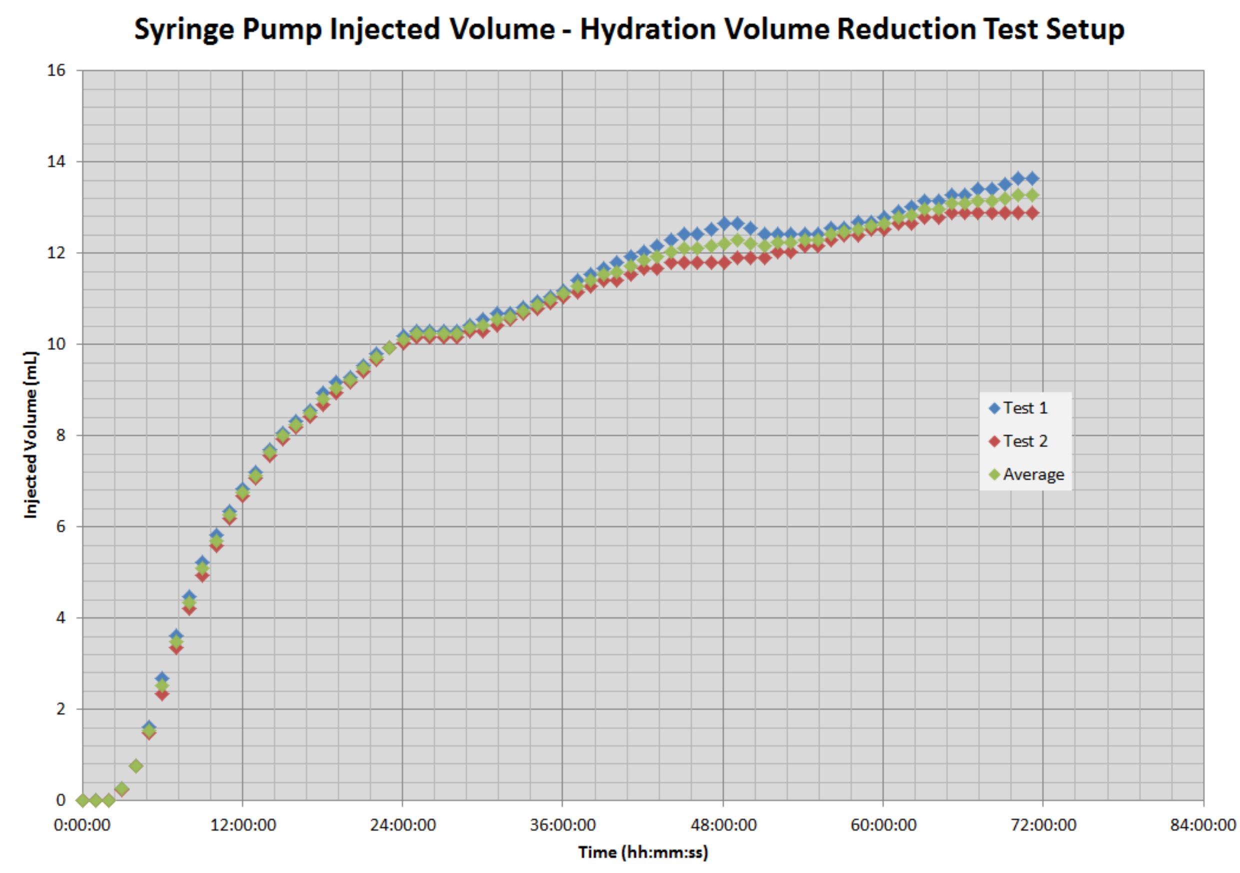

Figure 18: Syringe Pump Average Injected Volume – Hydration Volume Reduction Test Setup

This test was performed twice to show repeatability, which is shown in figure 18. The average injected volume was calculated and extrapolated to show volume removal necessary to simulate a 100 foot cement plug as shown in figure 19.

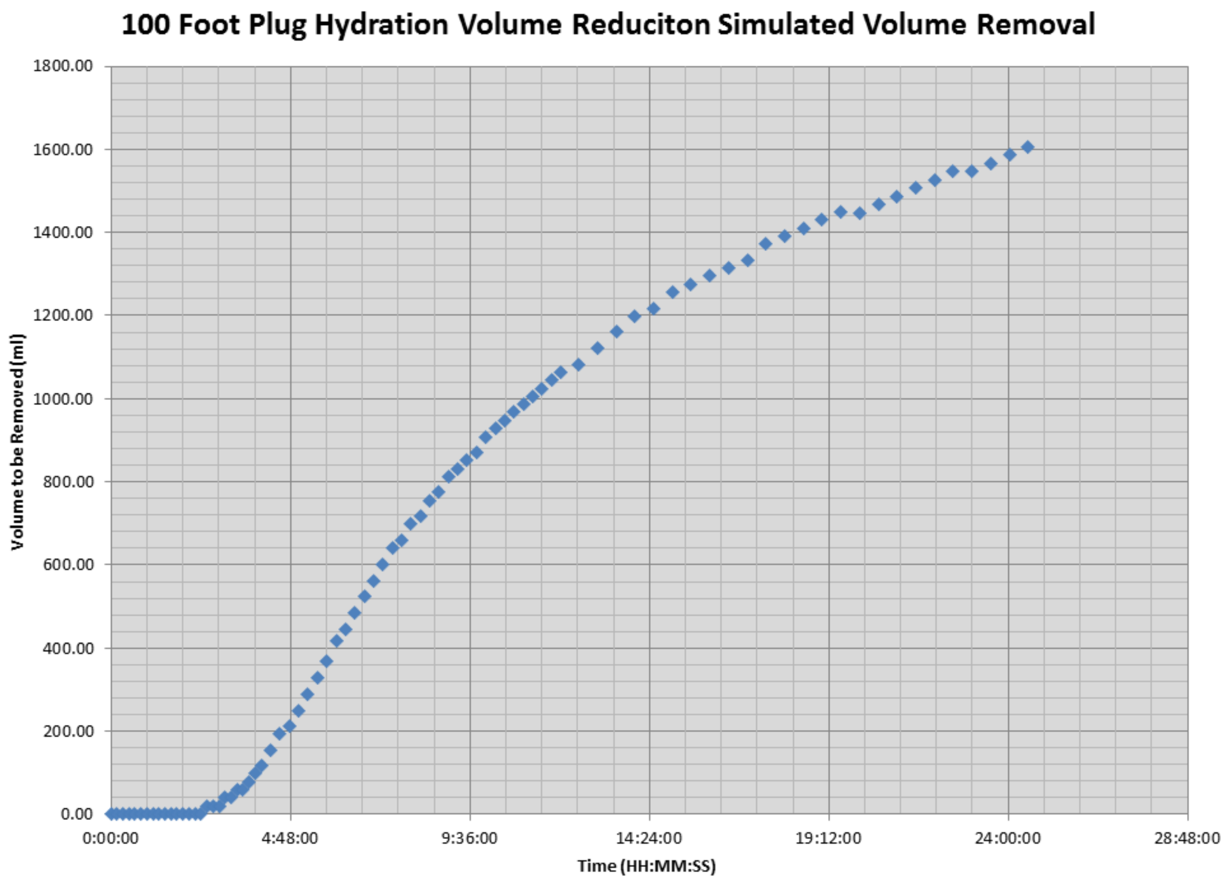

Figure 19: 100 Foot Plug Hydration Volume Reduction Simulated Volume Removal

Three separate static gel strength measurements were performed on the cement blend using a rotational gel strength analyzer. The gel strength development time was then averaged which can be seen in figure 20.

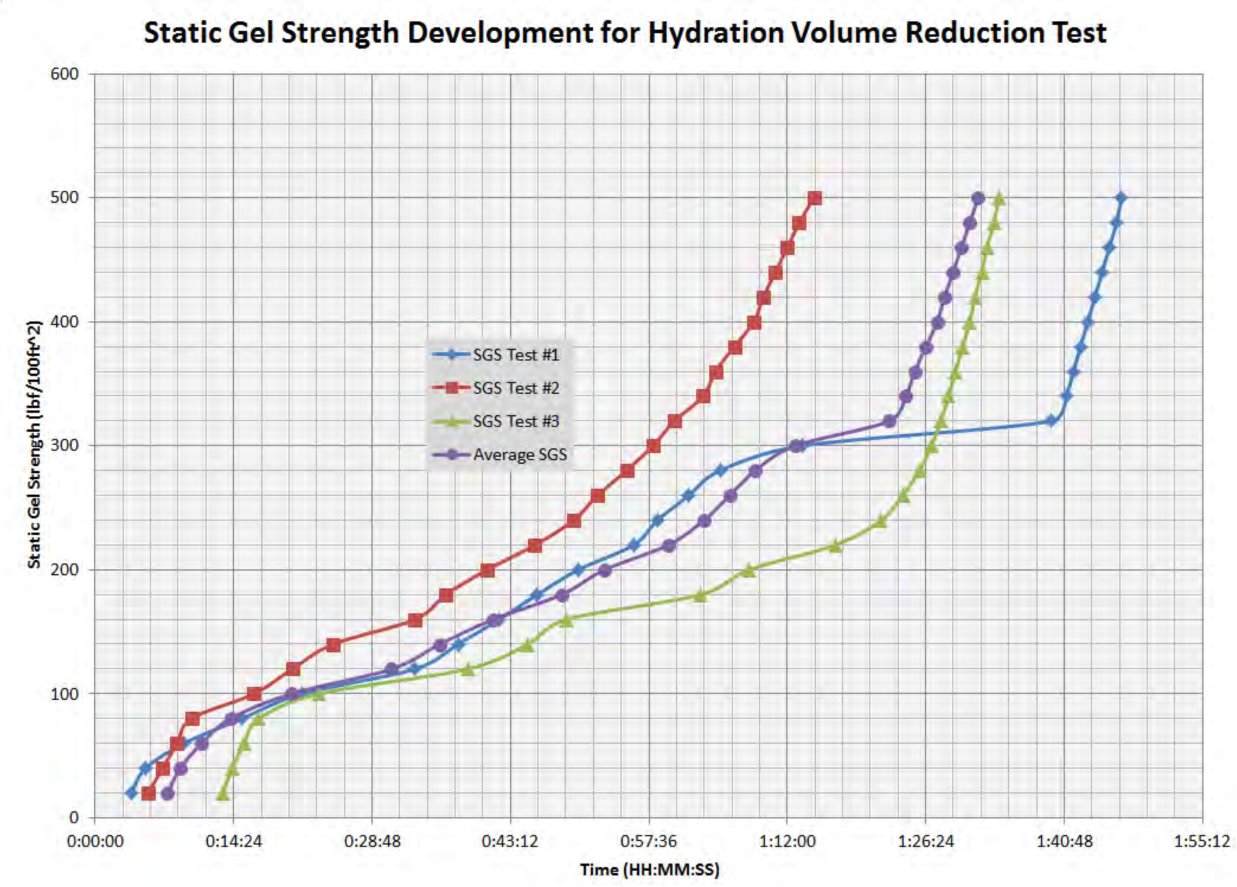

Figure 20: Static Gel Strength Development for Hydration Volume Reduction Test

The static gel strength development was then compared to the simulated hydration volume reduction of a 100 foot cement plug by placing 20 foot of cement into a pipe and cumulatively removing volume from the pipe while measuring the differential pressure across the column of cement. It was noticed that the hydration volume reduction increases after the static gel strength has reached a value of 500 $lb_f/100ft^2$ which is after the critical hydration period as shown in figure 21. Cement gel strengths above $500lb_f/100ft^2$ are considered sufficient to prohibit gas migration thorough the cement.

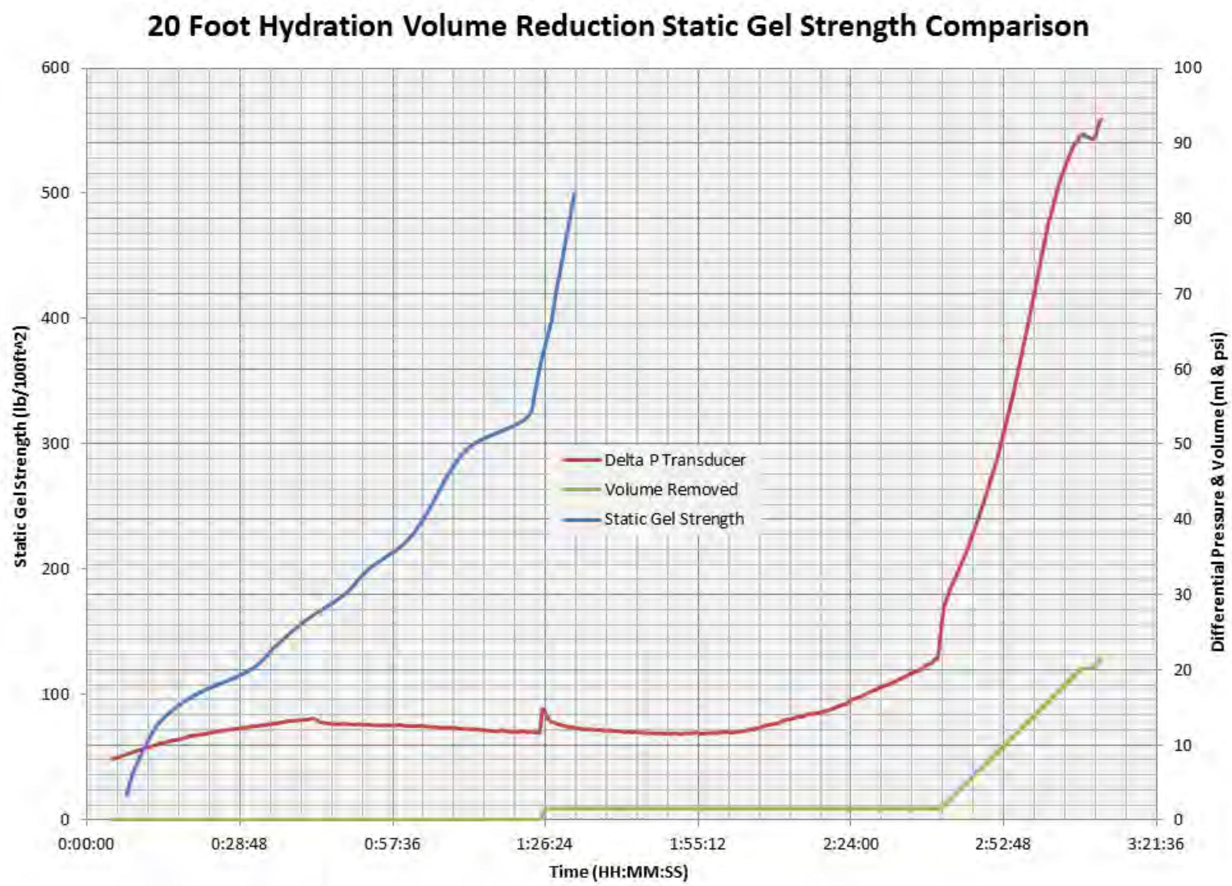

Figure 21: 20 Foot Hydration Volume Reduction Static Gel Strength Comparison

From observation of figure 21, the hydration volume reduction does not pose as crucial of a risk factor as compared to the critical hydration period in short term gas migration situations. Hydration volume reduction can still pose a problem in long term gas migration situations through microannulus paths.

20 foot Perm

Large scale laboratory tests of plug stability and dilution during and after placement and long-term seal effectiveness were performed. These tests were performed in two separate plug configurations: balanced plug with simulated tubing perforations and pump and pull method with tubing removed after cement placement. Plug configurations are shown in figure 22. In the figure, A and B show initial conditions of the two pipes, B and E show planned cement plug placement after setting, C and F show cement plug location after setting. The results are discussed below.

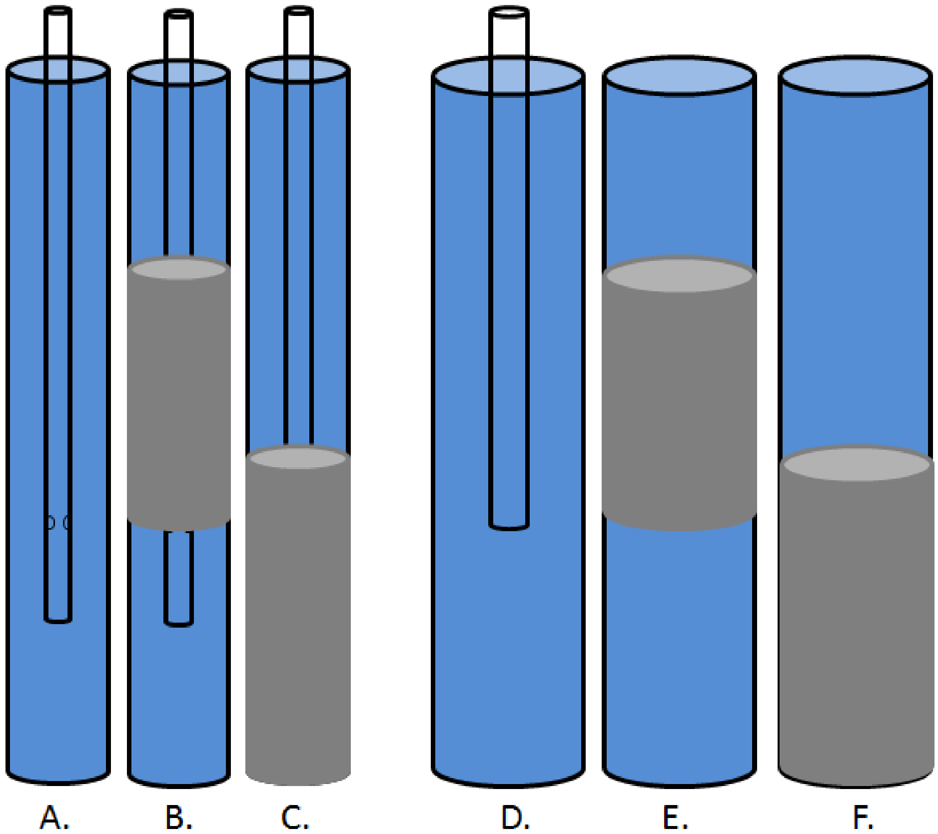

Figure 22: 20 foot Plug Configurations

Plug Placement Methods

Both pipe configurations were 20 foot pipes with a cement plug placed 5 foot from the bottom of the pipe. Neat cement was chosen for this test because most plugging operations in the Gulf of Mexico are with neat cement. The pipes were filled with sea water prior to cement placement. Cement plugs were allowed 1 week to cure in a vertical orientation. The pipes were then cut into 4 foot sections to observe plug stability, plug location and calculate density variation. It was noticed that all 4 plugs fell through the sea water and set at the bottom of the pipes. This fluid swapping made the measured top of cement much different than anticipated top of cement. A hole was drilled and tapped into the bottom of each pipe and the cement plug was pressure tested to measure failure bond strength. The results are shown in table 6.

Pipe #	Plug Configuration	Hydraulic Pressure (psi)	Calculated Failure Bond Strength (psi)
1	Balanced	1000	6.8
2	Pump and Pull	1500	25.7
3	Balanced	1700	11.2
4	Pump and Pull	1400	33.3

Table 6: Calculated Failure Bond Strength for 20 foot Perm Test

All cement plugs held a minimum of 1000psi pump pressure before failure. Figures 23 through 26 show the cross sections of the pipes after cutting. It should be noted after observation of these figures that the tubing top of cement differs from the annulus top of cement in the balanced plug configurations. In both instances, the tubing top of cement is lower than the annular top of cement. This can be attributed to dilution during placement. While the cement is balanced between the tubing and annulus right after placement, the intermixing of sea water contaminated the cement in the annulus leading to a lower annular density. This density difference between cement in tubing and annular cement created a variance in TOC because of the hydrostatics naturally wanting to balance within the two pipe strings.

Figure 23: Pipe #1, 20 foot Perm Test

Figure 24: Pipe #2, 20 foot Perm Test

Figure 25: Pipe #3, 20 foot Perm Test

Figure 26: Pipe #4, 20 foot Perm Test

Density Variations

Small pieces of cement were chipped out of the cut sections of the pipes and their density was measured using Archimedes Principle to see the variances throughout the cement plugs. Figures 27 through 30 show the variance of density in each pipe.

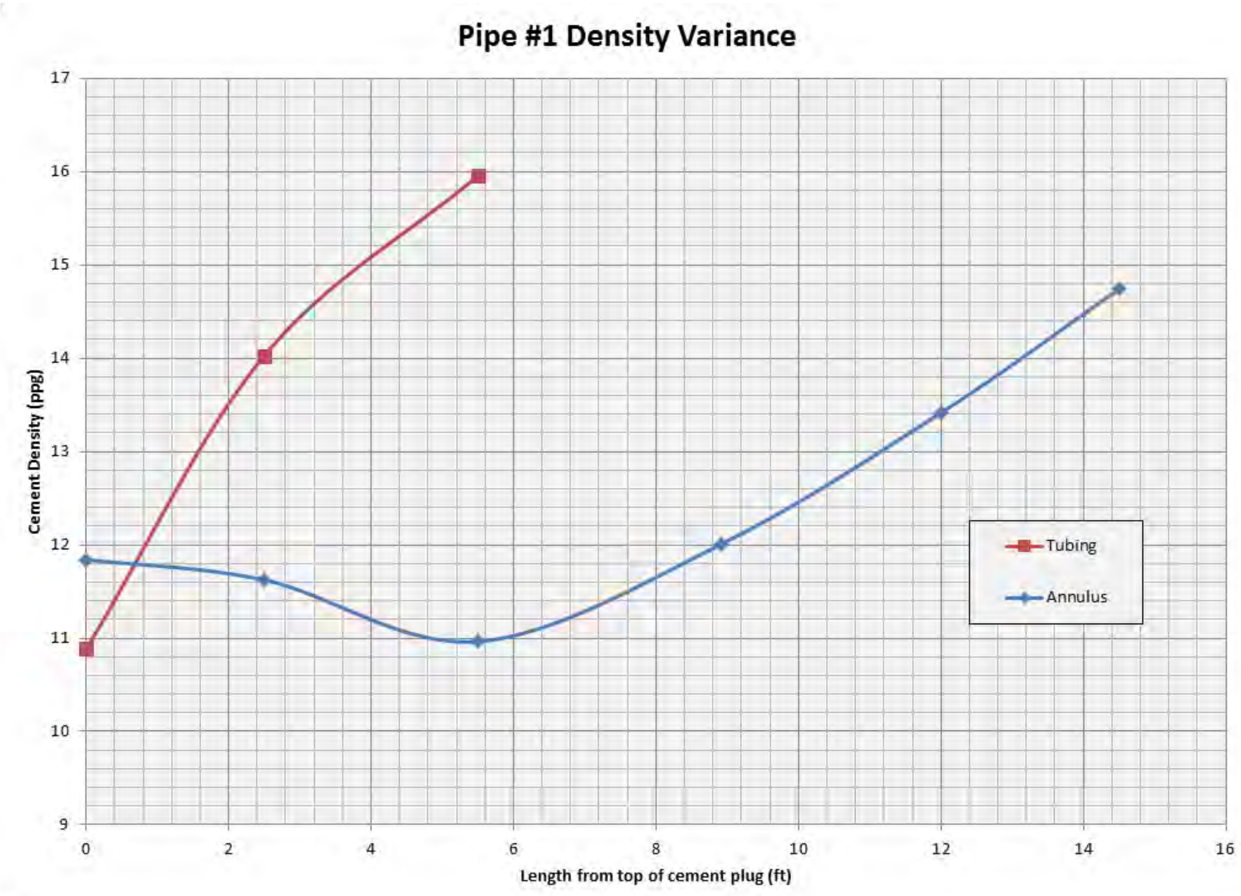

Figure 27: Pipe #1 Density Variance

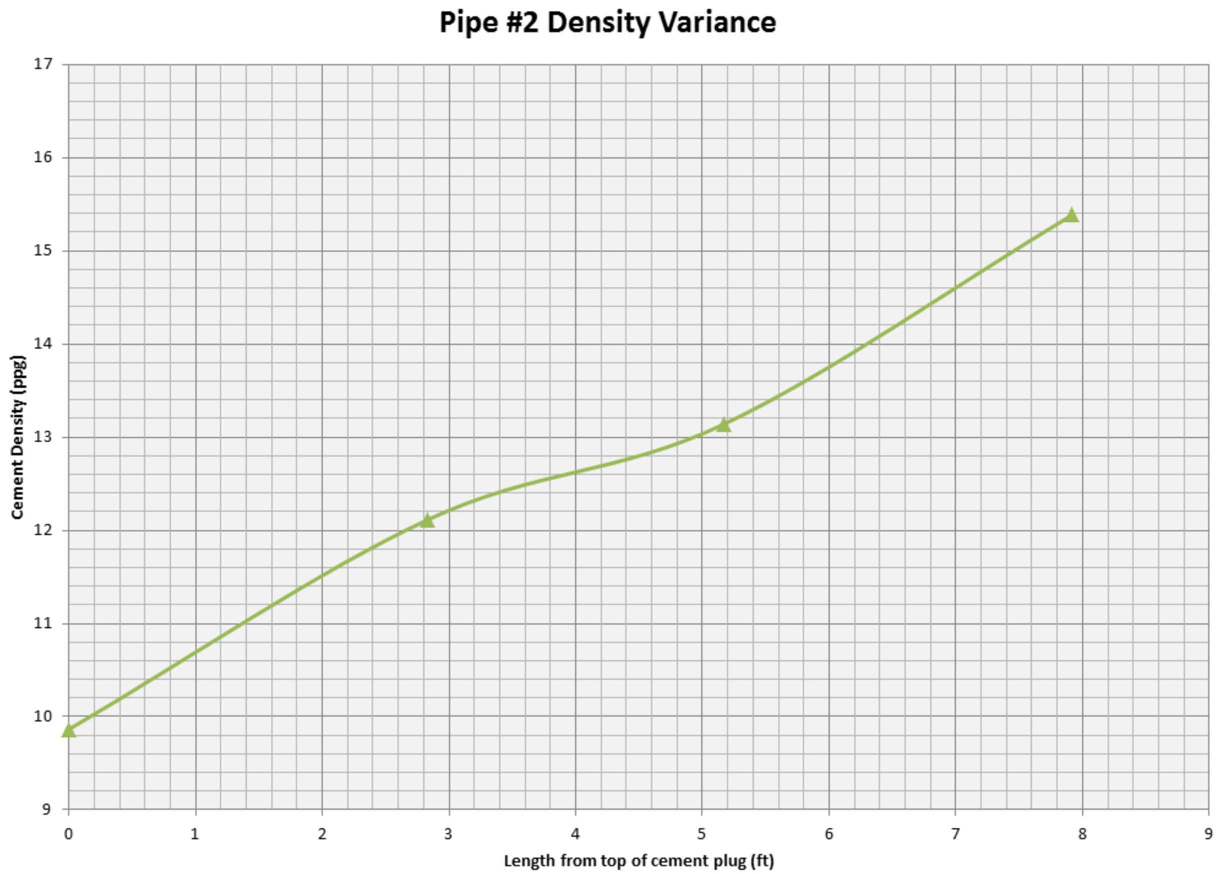

Figure 28: Pipe #2 Density Variance

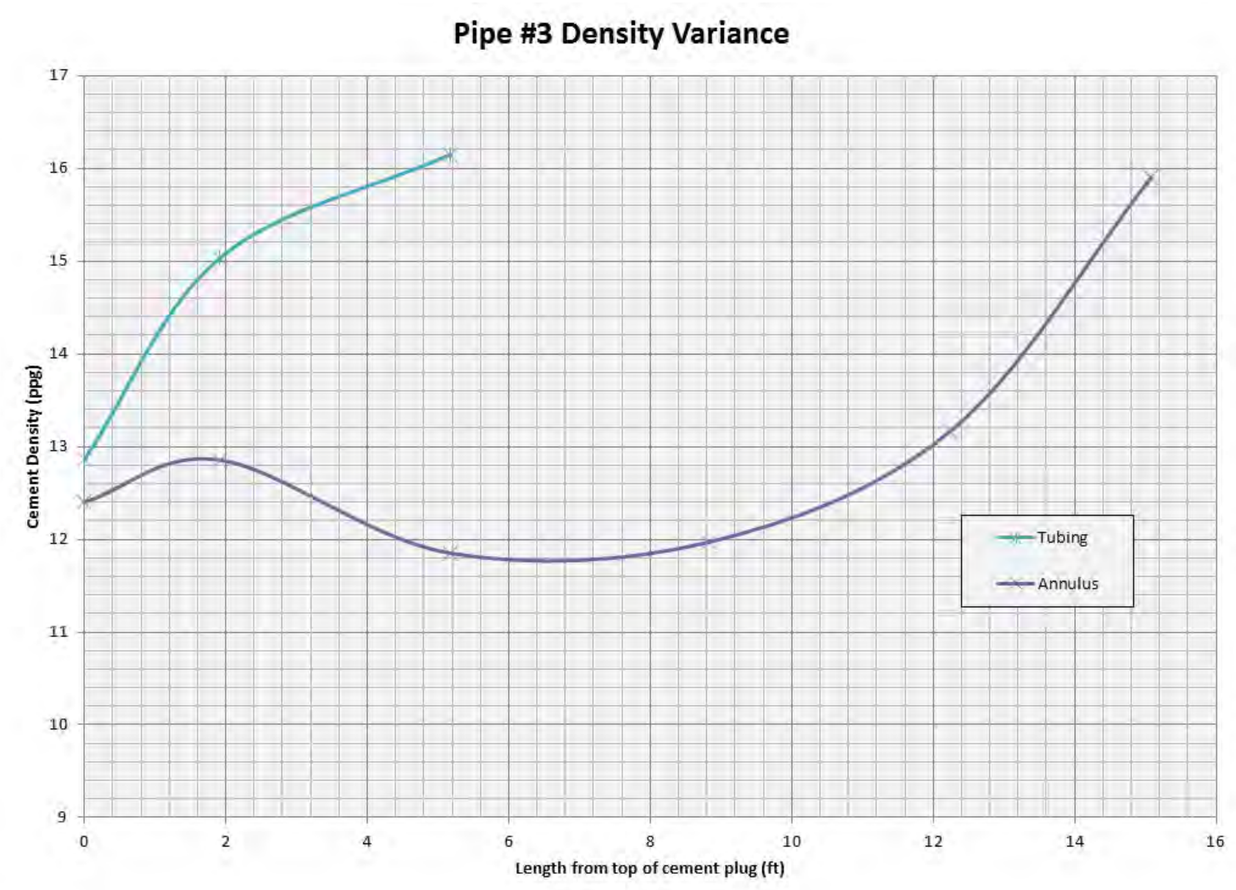

Figure 29: Pipe #3 Density Variance

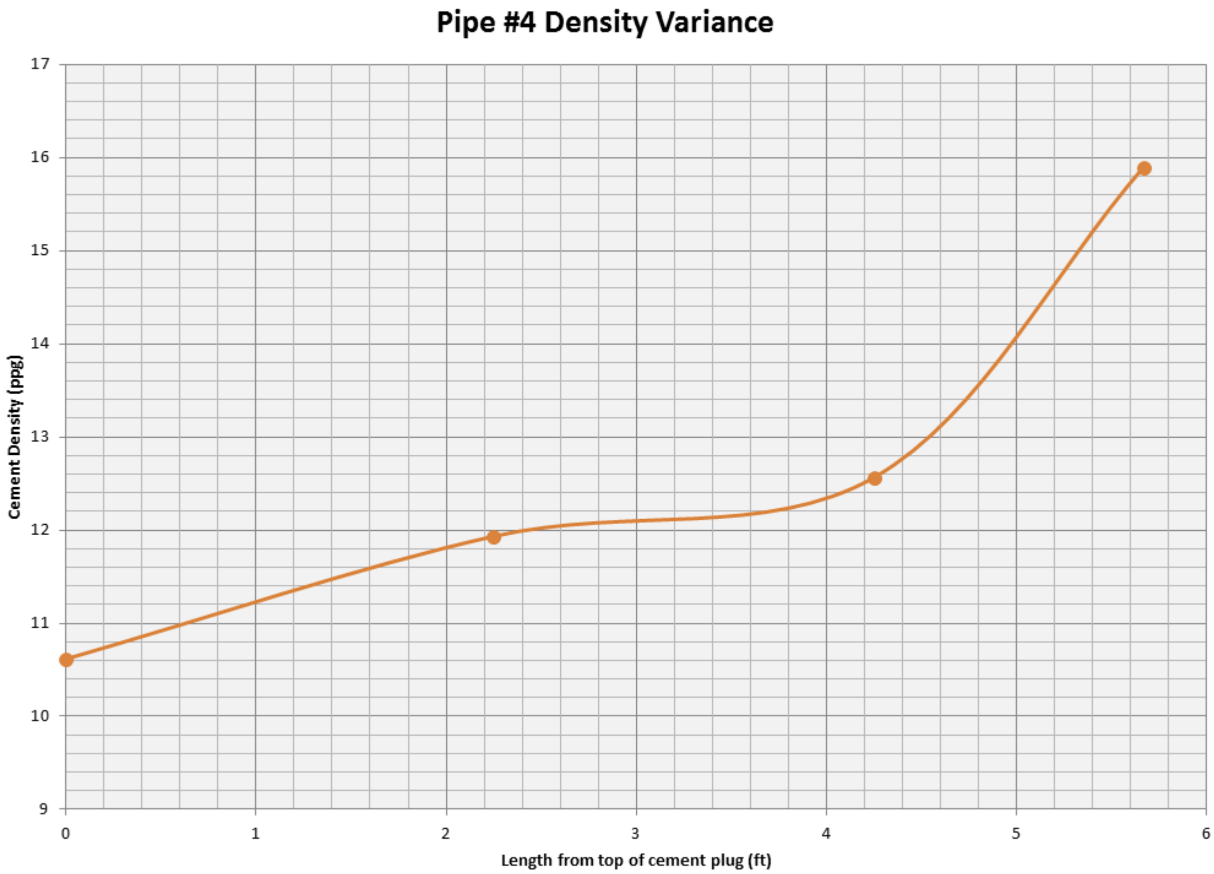

Figure 30: Pipe #4 Density Variance

Each pipe had similar results where the density near the top of the plug was much lower than the density at the bottom of the plug showing that intermixing is unavoidable between the cement and sea water during placement. This intermixing can lead to unstable cement plugs because cement systems are generally designed to perform in somewhat smaller density ranges. After review of this data and current plugging methods performed in the field, some major changes to current plugging state of the art must be made. For every plug placed in the Gulf of Mexico that isn't tagged after placement, there is no guarantee that the cement plug is actually where it is expected to be. When cement plugs of higher density are placed on top of fluids of lower density in a well bore, fluid swapping is too great of a risk to ignore. Current regulations only require that the plug below the surface cement plug and plugs covering lost circulation zones in open hole must be tested for seal effectiveness, which allows operators to overlook checking all other plugs placed in the well bore for location of plug and seal effectiveness. There are several methods used to reduce the risks of fluid swapping such as: pumping viscous pills, pumping higher density fluids into the wellbore, and use of mechanical barriers such as Cast Iron Bridge Plugs. These three methods are the most common, but there are other methods as discussed within the literature study which can be used. Generally, all other methods are case specific though and aren't as practiced in the field.

Field Operation Study

Several cement plugging operations performed during the study were observed on location for: job design, field execution, setting depths and heights of abandonment plugs, and wait time prior to testing plugs as per the BSEE's requirements. A discussion of each cement job is below.

Cement Jobs Completed Summary

Job A

Well Parameters

Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 7 5/8 in @ 29.7 lb/ft
Bottom Hole Temperature: 227°F
Bottom Hole Pressure: 4819 psi
Estimated Plug Temperature: 102°F

For this job, a 500 ft balanced plug was to be placed at a depth of 8139-7639 ft. A mechanical bridge plug was placed in the well and cement was pumped above in order to achieve this depth. The cement design was Class H cement and sea water mixed at 15.6 lb/gal. 105 sacks of cement were pumped and at an actual density average of 15.7 lb/gal. The cement was displaced to its depth by sea water. After 14 hours the cement was tagged using wire line at 7896 ft. and a pressure test was performed. The plug successfully held 1000 psi for 30 minutes. Lab testing of the exact cement and water used on the job showed that at 14 hours, the cement had approximately 36 psi/ft of hydraulic bond and 40 psi/ft of shear bond strength. The well schematic is shown in figure 31.

Job B

Well Parameters

Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 7 5/8 in @ 29.7 lb/ft
Bottom Hole Temperature: 227°F
Bottom Hole Pressure: 4819 psi
Estimated Plug Temperature: 88°F

For this job, a 500 ft balanced plug was to be placed at a depth of 7000-6500 ft. A mechanical bridge plug was placed in the well and cement was pumped above in order to achieve this depth. The cement design was Class H cement and sea water mixed at 15.6 lb/gal. 105 sacks of cement were pumped and at an actual density average of 15.7 lb/gal. The cement was displaced to its depth by sea water. After 14 hours the cement was tagged using wire line at 6598 ft. and a pressure test was performed. The plug successfully held 1000 psi for 30 minutes. Lab testing of the exact cement and water used on the job showed that at 14 hours, the cement had approximately 21 psi/ft of hydraulic bond and 34 psi/ft of shear bond strength. The well schematic is shown in figure 31.

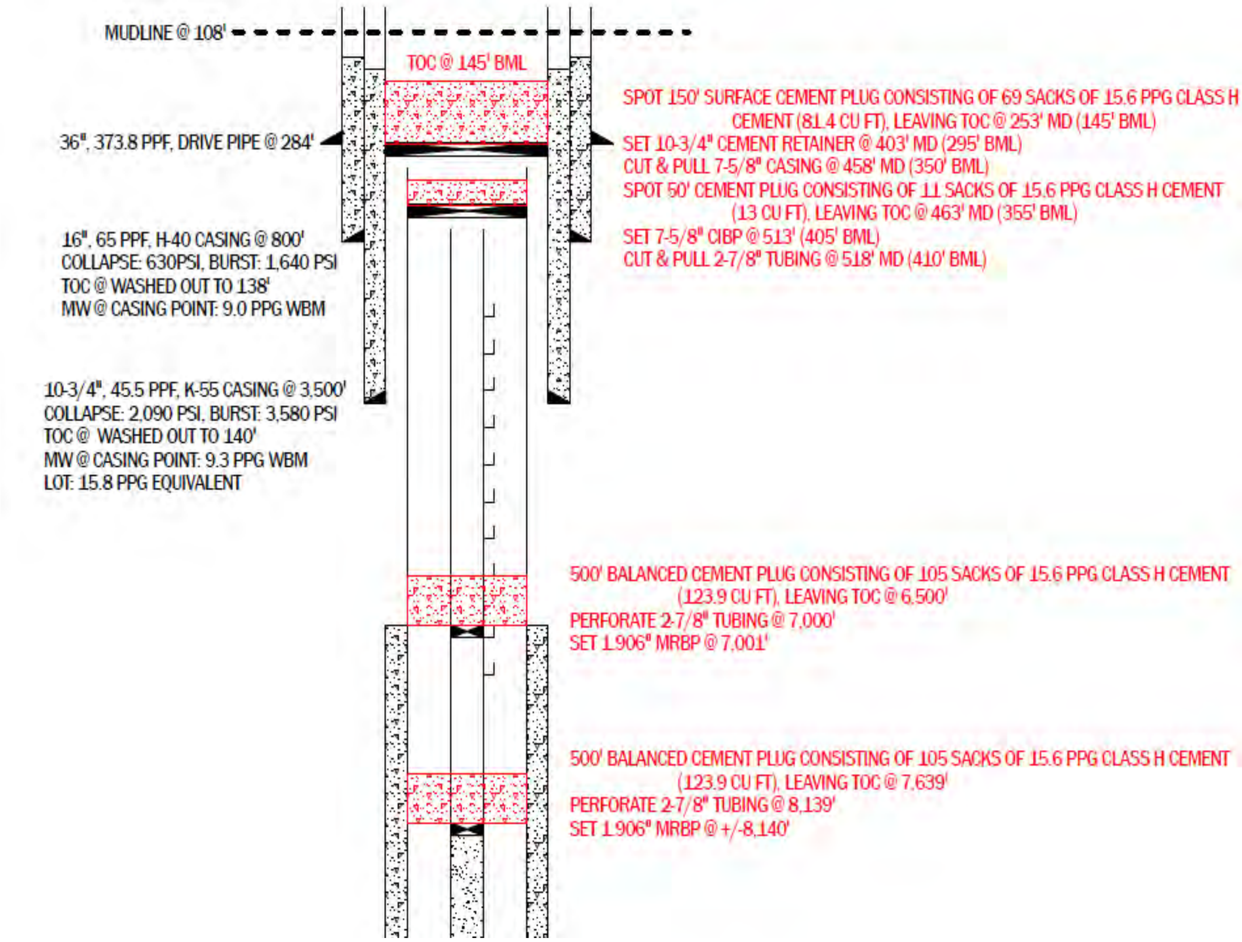

Figure 31: P&A Well Schematic for Jobs A and B

Job C

<u>Well Parameters</u>
Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 10 3/4 in @ 45.5 lb/ft
Estimated Plug Temperature: 84°F

For this job, a 200 ft surface plug was to be placed in the 10 ¾ in casing at a depth interval of 300-100 ft below the mud line. The well schematic is shown in figure 32.

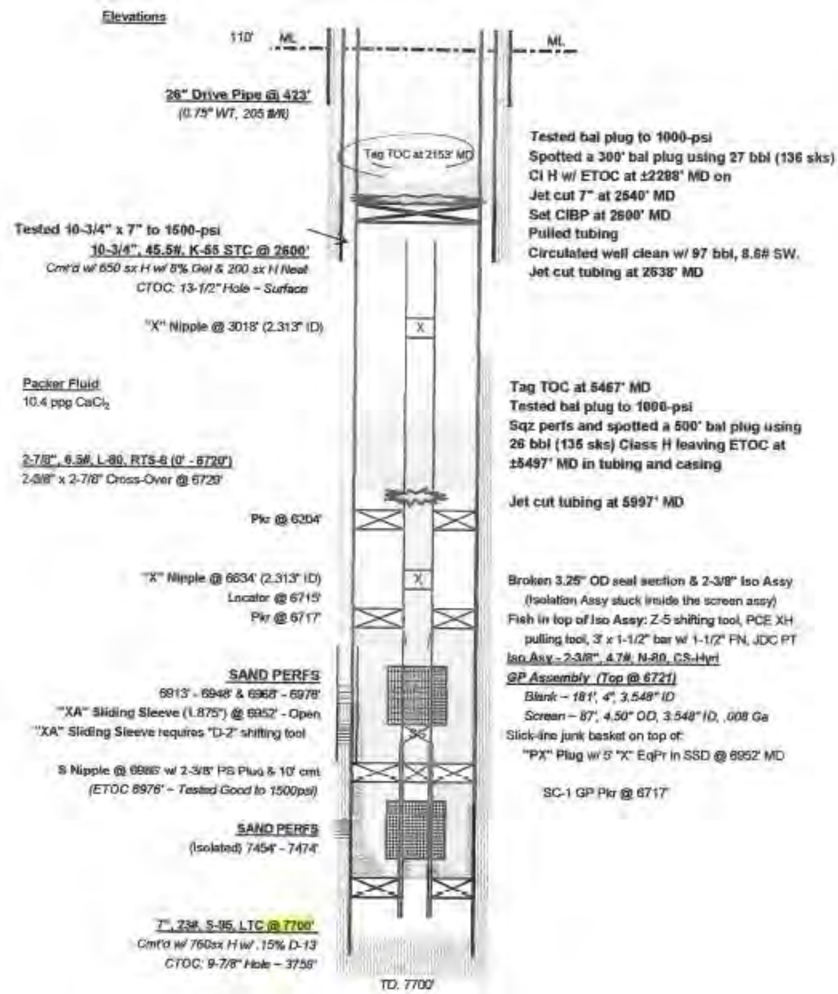

Figure 32: P&A Well Schematic for Job C

Samples were caught of the actual materials used on location. The cement design was to pump 104 sacks of class H cement mixed with sea water at a density of 16.2 lb/gal. The plug was successfully placed and lab testing of the collected samples showed that the plug had a shear bond strength of 149 psi and a hydraulic bond strength of 23 psi.

Job D

Well Parameters
Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 10 3/4 in @ 45.5 lb/ft
Estimated Plug Temperature: 83°F

For this job, a 200 ft surface plug was to be placed in the 10 ¾ in casing at a depth interval of 300-100 ft below the mud line. The well schematic is shown in figure 33.

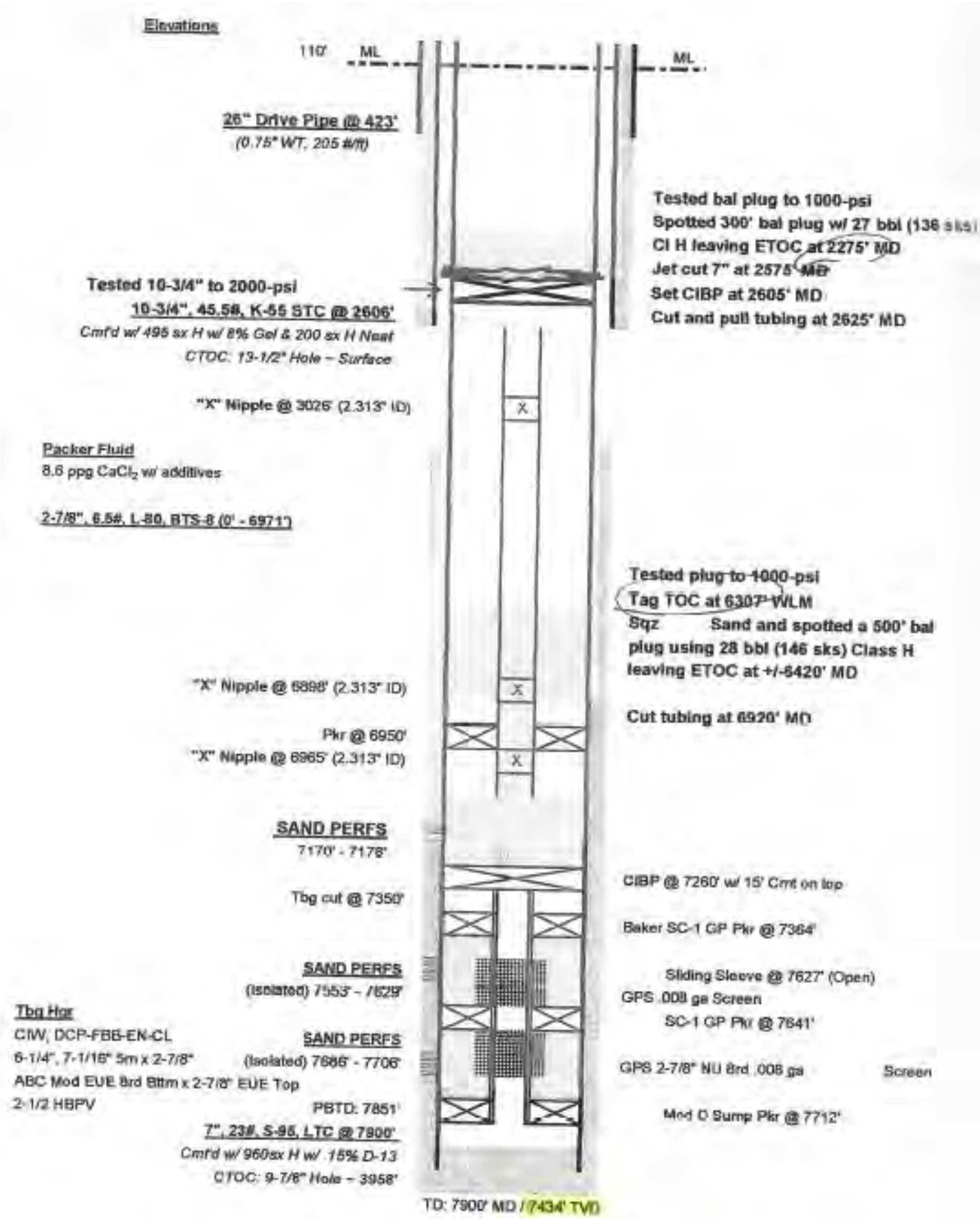

Figure 33: P&A Well Schematic for Job D

Samples were caught of the actual materials used on location. The cement design was to pump 104 sacks of class H cement mixed with sea water at a density of 16.2 lb/gal. The plug was successfully placed and lab testing of the collected samples showed that the plug had a shear bond strength of 197 psi and a hydraulic bond strength of 24 psi.

Job E

<u>Well Parameters</u>
Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 10 3/4 in @ 45.5 lb/ft
Estimated Plug Temperature: 83°F

For this job, a 200 ft surface plug was to be placed in the 10 ¾ in casing at a depth interval of 300-100 ft below the mud line. The well schematic is shown in figure 34.

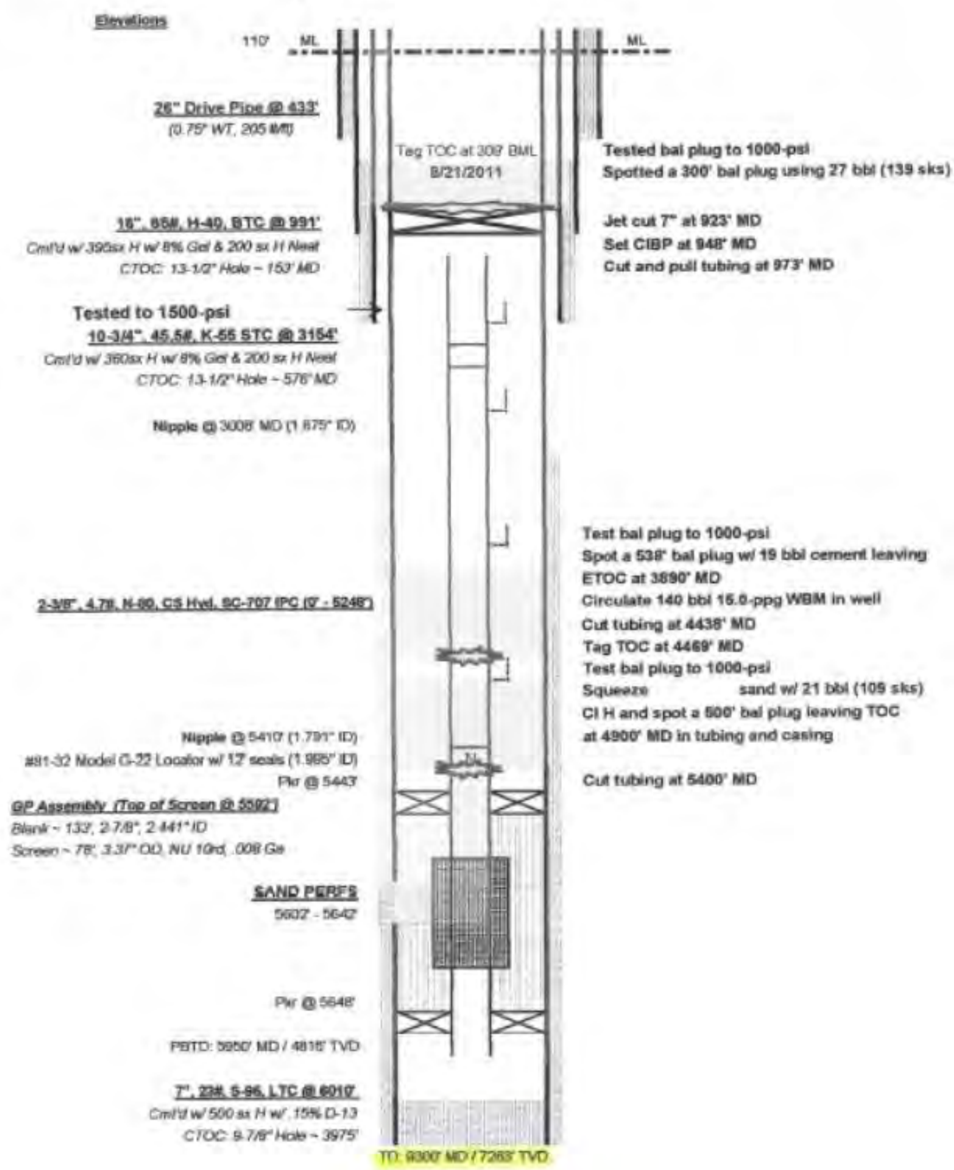

Figure 34: P&A Well Schematic for Job E

Samples were caught of the actual materials used on location. The cement design was to pump 104 sacks of class H cement mixed with sea water at a density of 16.2 lb/gal. The plug was successfully placed and lab testing of the collected samples showed that the plug had a shear bond strength of 178 psi and a hydraulic bond strength of 56 psi.

Job F

Well Parameters
Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 10 3/4 in @ 45.5 lb/ft
Estimated Plug Temperature: 83°F

For this job, a 200 ft surface plug was to be placed in the 10 ¾ in casing at a depth interval of 300-100 ft below the mud line. The well schematic is shown in figure 35.

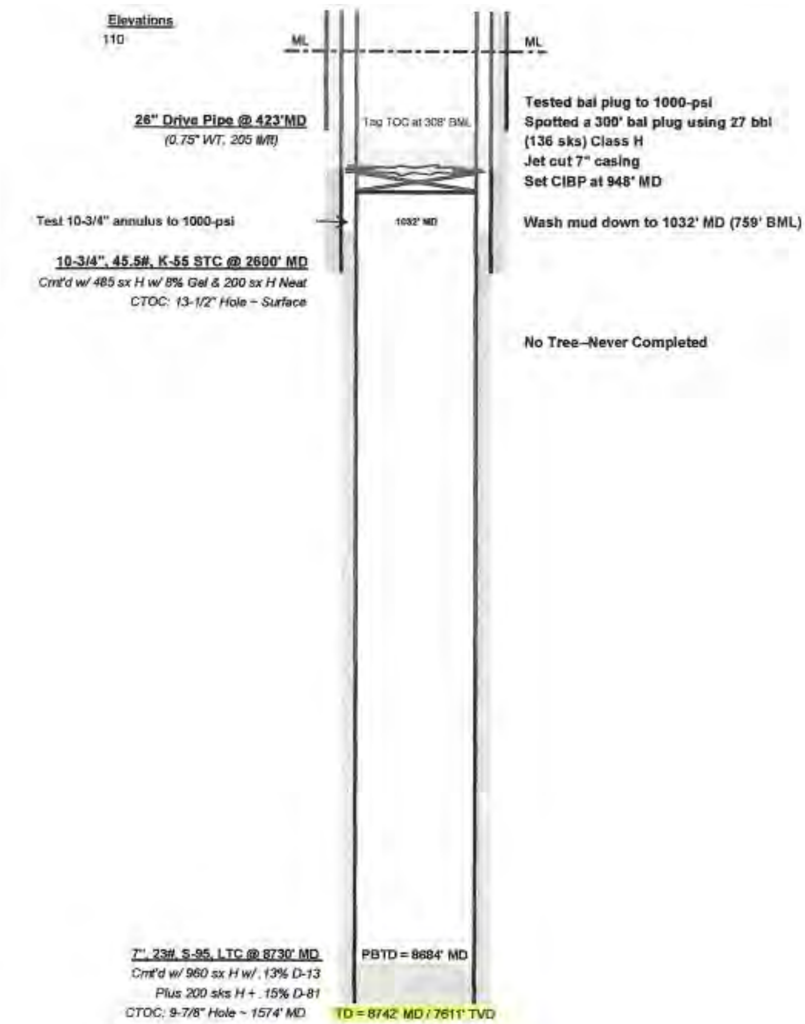

Figure 35: P&A Well Schematic for Job F

Samples were caught of the actual materials used on location. The cement design was to pump 104 sacks of mixed with sea water at a density of 16.2 lb/gal. The plug was successfully placed and lab testing of the collected samples showed that the plug had a shear bond strength of 103 psi and a hydraulic bond strength of 52 psi.

Job G

Well Parameters
Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 7 5/8 in @ 26.4 lb/ft
Bottom Hole Temperature: 87°F
Bottom Hole Pressure: 300 psi
Estimated Plug Temperature: 77°F

For this job, a 200 ft balanced plug was to be placed at a depth of 607-807 ft. A mechanical bridge plug was placed in the well and cement was pumped above in order to achieve this depth. The cement design was Class H cement and sea water mixed at 16.2 lb/gal. 84 sacks of cement were pumped. The cement was displaced to its depth by sea water. Lab testing of the exact cement and water used on the job showed that at 12 hours, the cement had approximately 75 psi/ft of hydraulic bond and 205 psi/ft of shear bond strength. After 24 hours, the cement had approximately 75 psi/ft of hydraulic bond and 200 psi/ft of shear bond strength. The well schematic is shown in figure 36.

Job H

Well Parameters
Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 7 5/8 in @ 29.7 lb/ft
Bottom Hole Temperature: 134°F
Bottom Hole Pressure: 2750 psi
Estimated Plug Temperature: 114°F

For this job, a 500 ft balanced plug was to be placed at a depth of 3975-4475 ft. The cement design was Class H cement and sea water mixed at 16.2 lb/gal. 114 sacks of cement were pumped. The cement was displaced to its depth by sea water. Lab testing of the exact cement and water used on the job showed that at 12 hours, the cement had approximately 75 psi/ft of hydraulic bond and 180 psi/ft of shear bond strength. After 24 hours, the cement had approximately 90 psi/ft of hydraulic bond and 375 psi/ft of shear bond strength. The well schematic is shown in figure 36.

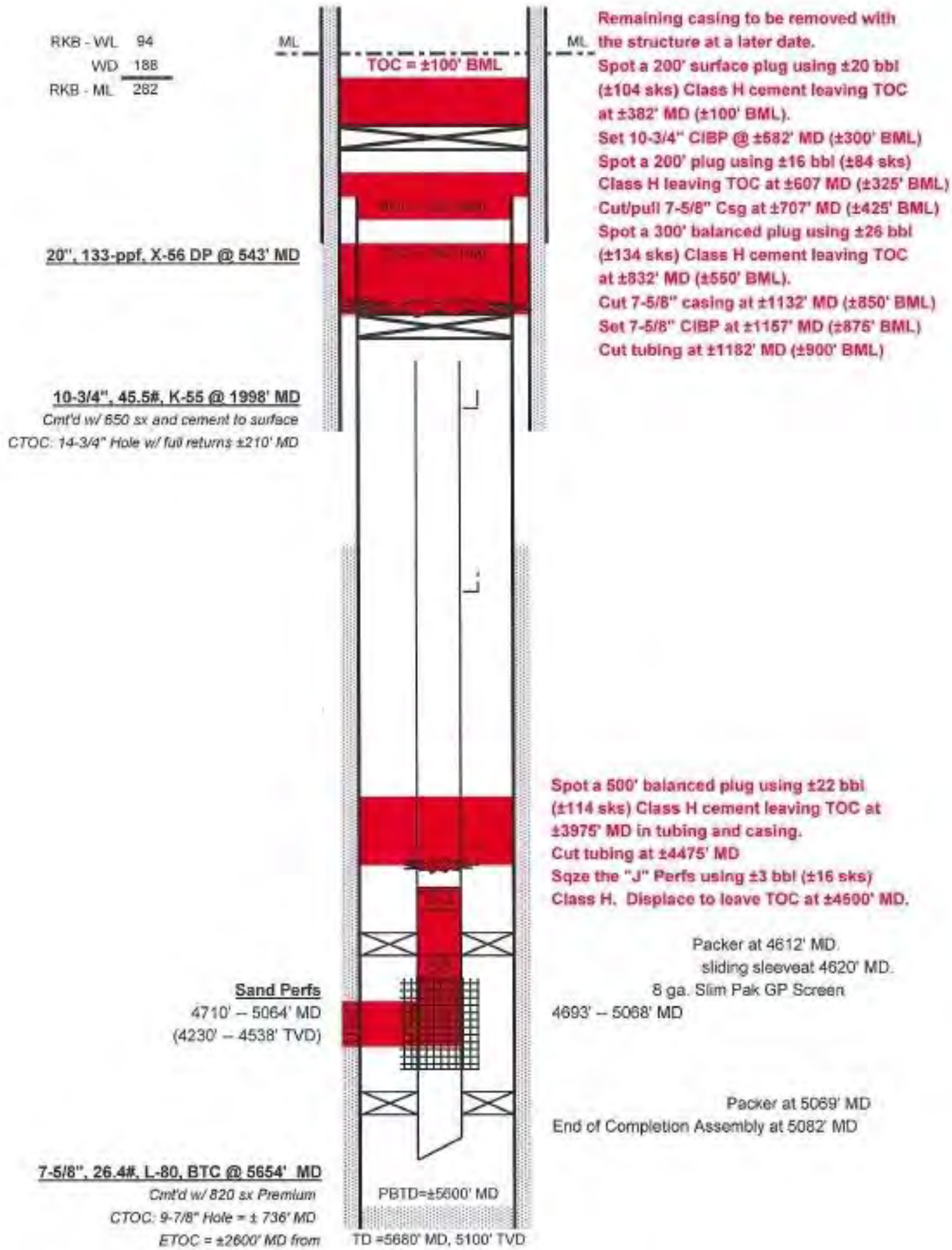

Figure 36: P&A Well Schematic for Jobs G and H

Job I

Well Parameters
Tubing Size: 3 1/2 in @ 9.3 lb/ft
Next Casing Size: 7 5/8 in @ 26.4 lb/ft
Bottom Hole Temperature: 87°F
Bottom Hole Pressure: 300 psi
Estimated Plug Temperature: 77°F

For this job, a 200 ft balanced plug was to be placed at a depth of 616-816 ft. A mechanical bridge plug was placed in the well and cement was pumped above in order to achieve this depth. The cement design was Class H cement and sea water mixed at 16.2 lb/gal. 84 sacks of cement were pumped. The cement was displaced to its depth by sea water. Lab testing of the exact cement and water used on the job showed that at 12 hours, the cement had approximately 75 psi/ft of hydraulic bond and 210 psi/ft of shear bond strength. After 24 hours, the cement had approximately 70 psi/ft of hydraulic bond and 200 psi/ft of shear bond strength. The well schematic is shown in figure 37.

Job J

Well Parameters
Tubing Size: 3 1/2 in @ 9.3 lb/ft
Next Casing Size: 7 5/8 in @ 29.7 lb/ft
Bottom Hole Temperature: 187°F
Bottom Hole Pressure: 5130 psi
Estimated Plug Temperature: 159°F

For this job, a 500 ft balanced plug was to be placed at a depth of 11,800-12,300 ft. The cement design was Class H cement and sea water mixed at 16.2 lb/gal. 114 sacks of cement were pumped. The cement was displaced to its depth by sea water. Lab testing of the exact cement and water used on the job showed that at 12 hours, the cement had approximately 105 psi/ft of hydraulic bond and 305 psi/ft of shear bond strength. After 24 hours, the cement had approximately 105 psi/ft of hydraulic bond and 655 psi/ft of shear bond strength. The well schematic is shown in figure 37.

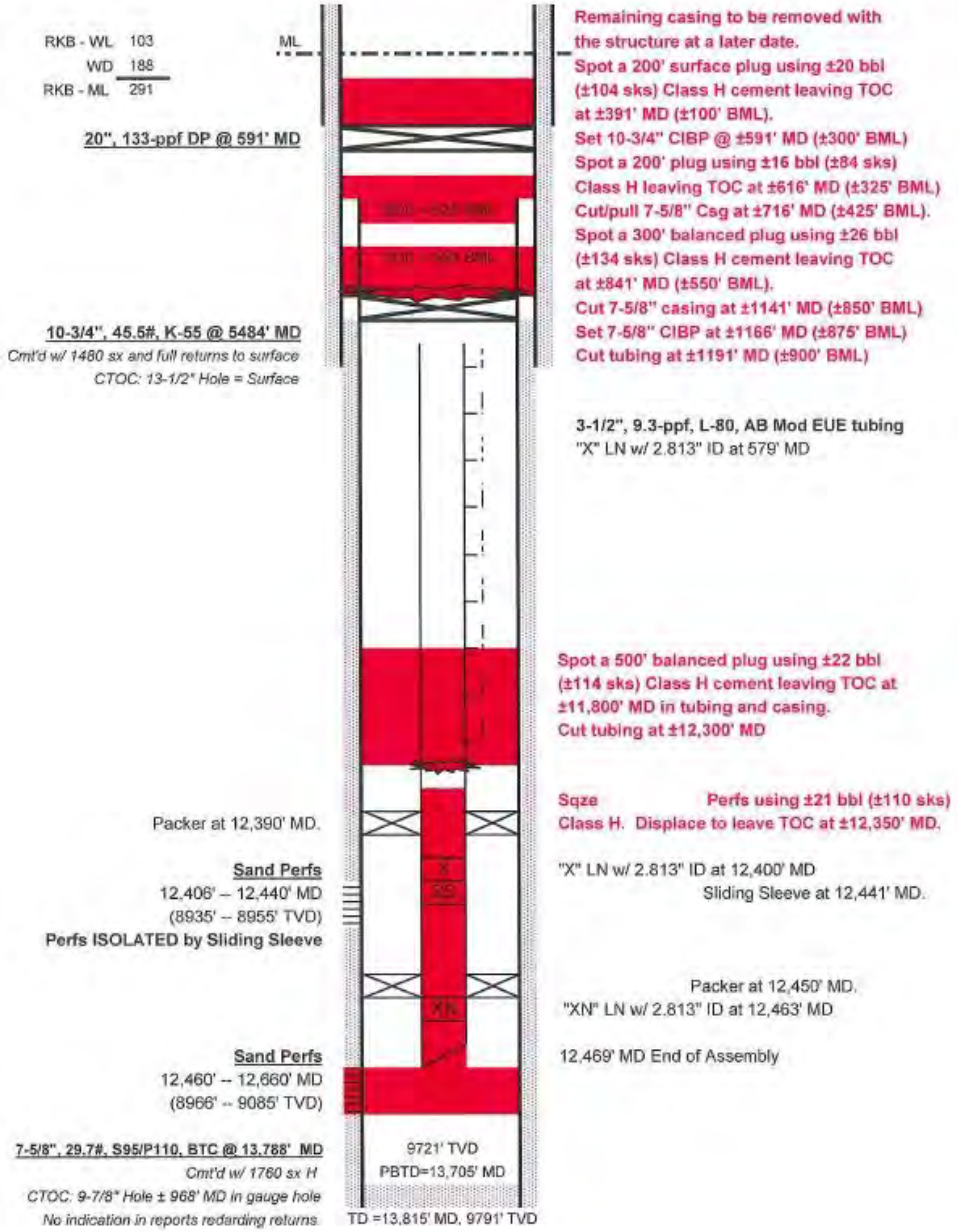

Figure 37: P&A Well Schematic for Jobs I and J

Job K

Well Parameters
Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 7 5/8 in @ 26.4 lb/ft
Bottom Hole Temperature: 87°F
Bottom Hole Pressure: 300 psi
Estimated Plug Temperature: 77°F

For this job, a 200 ft balanced plug was to be placed at a depth of 624-824 ft. A mechanical bridge plug was placed in the well and cement was pumped above in order to achieve this depth. The cement design was Class H cement and sea water mixed at 16.2 lb/gal. 84 sacks of cement were pumped. The cement was displaced to its depth by sea water. Lab testing of the exact cement and water used on the job showed that at 12 hours, the cement had approximately 70 psi/ft of hydraulic bond and 75 psi/ft of shear bond strength. After 24 hours, the cement had approximately 70 psi/ft of hydraulic bond and 200 psi/ft of shear bond strength. The well schematic is shown in figure 38.

Job L

Well Parameters
Tubing Size: 2 7/8 in @ 6.5 lb/ft
Next Casing Size: 7 5/8 in @ 29.7 lb/ft
Bottom Hole Temperature: 134°F
Bottom Hole Pressure: 2570 psi
Estimated Plug Temperature: 114°F

For this job, a 500 ft balanced plug was to be placed at a depth of 4,000-4,500 ft. The cement design was Class H cement and sea water mixed at 16.2 lb/gal. 94 sacks of cement were pumped. The cement was displaced to its depth by sea water. Lab testing of the exact cement and water used on the job showed that at 12 hours, the cement had approximately 75 psi/ft of hydraulic bond and 200 psi/ft of shear bond strength. After 24 hours, the cement had approximately 90 psi/ft of hydraulic bond and 375 psi/ft of shear bond strength. The well schematic is shown in figure 38.

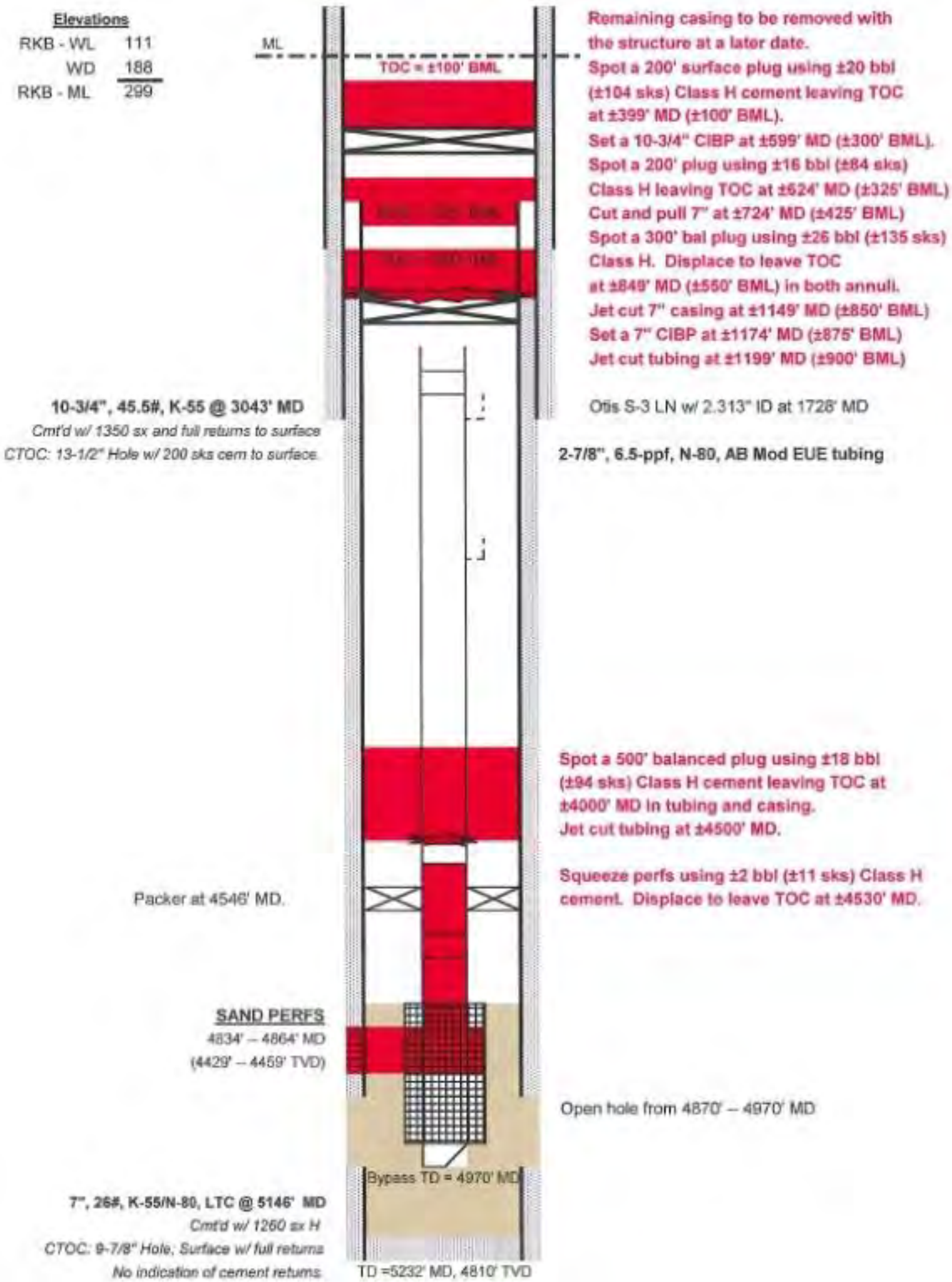

Figure 38: P&A Well Schematic for Jobs K and L

All of the bond strength data for the cement jobs caught is summarized in figure 39. As can be seen from this figure, the shear bond failure strengths are generally higher than hydraulic bond failure strengths. All plugging operations observed in the field utilized neat cement compositions with very few additives. Generally, neat cement is the preferred design for plugging operations, but different designs should be used for down-hole configurations where neat cement could not be used. Some examples of this are: high risks of gas migration requiring fluid loss additives, low fracture gradients requiring lower densities, and high pore pressure zones where heavier densities are required.

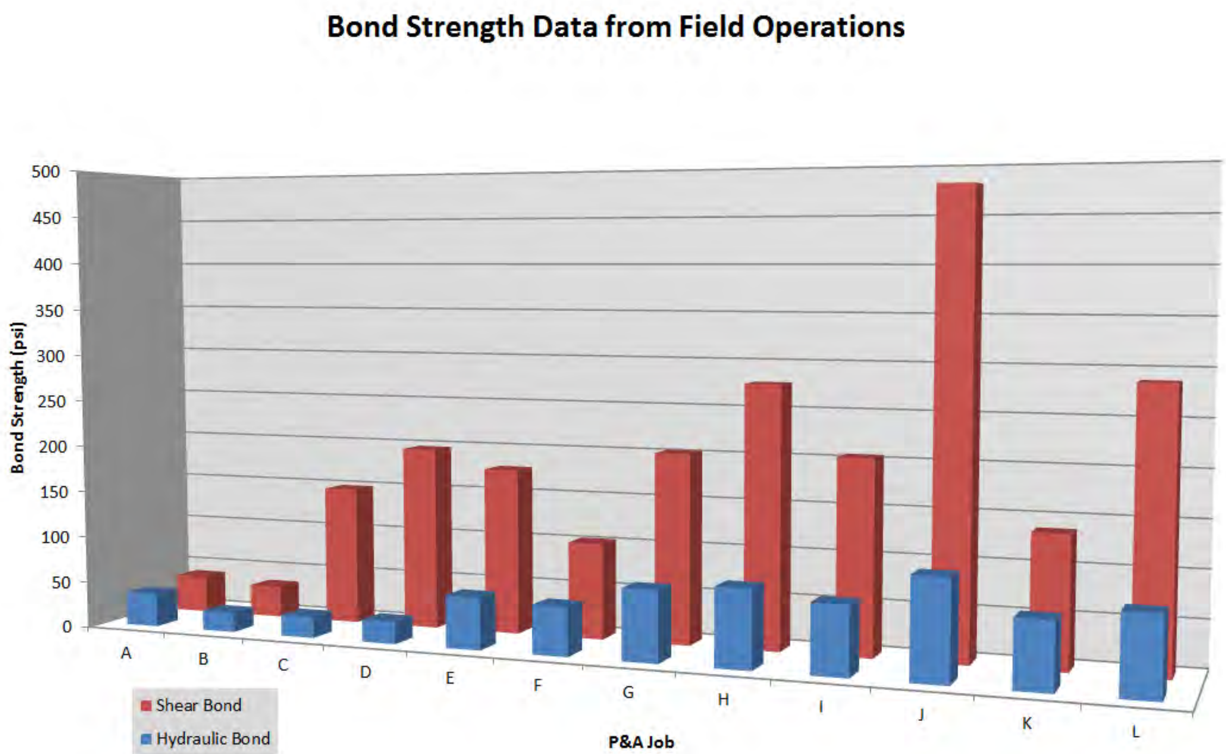

Figure 39: Bond Strength Data from Field Operations

Engineering Correlations

Upon review of engineering study and laboratory data on calculated bond strengths, the required pump pressures for constant bond strength was calculated for varying pipe diameters and plug lengths. This graphical representation was used to observe which of the testing methods is more severe. From analysis of current regulations on plugging operations, it was found that the minimum plug length required in P&A operations is 50 feet. A safety factor of 5 was added to this for effective plug lengths which are bonded equal to only 10 feet. Figure 40 shows the required pump pressure necessary to break a 15 psi hydraulic bond strength for a 10 foot, 50 foot, and 300 foot cement plug for varying plug diameters.

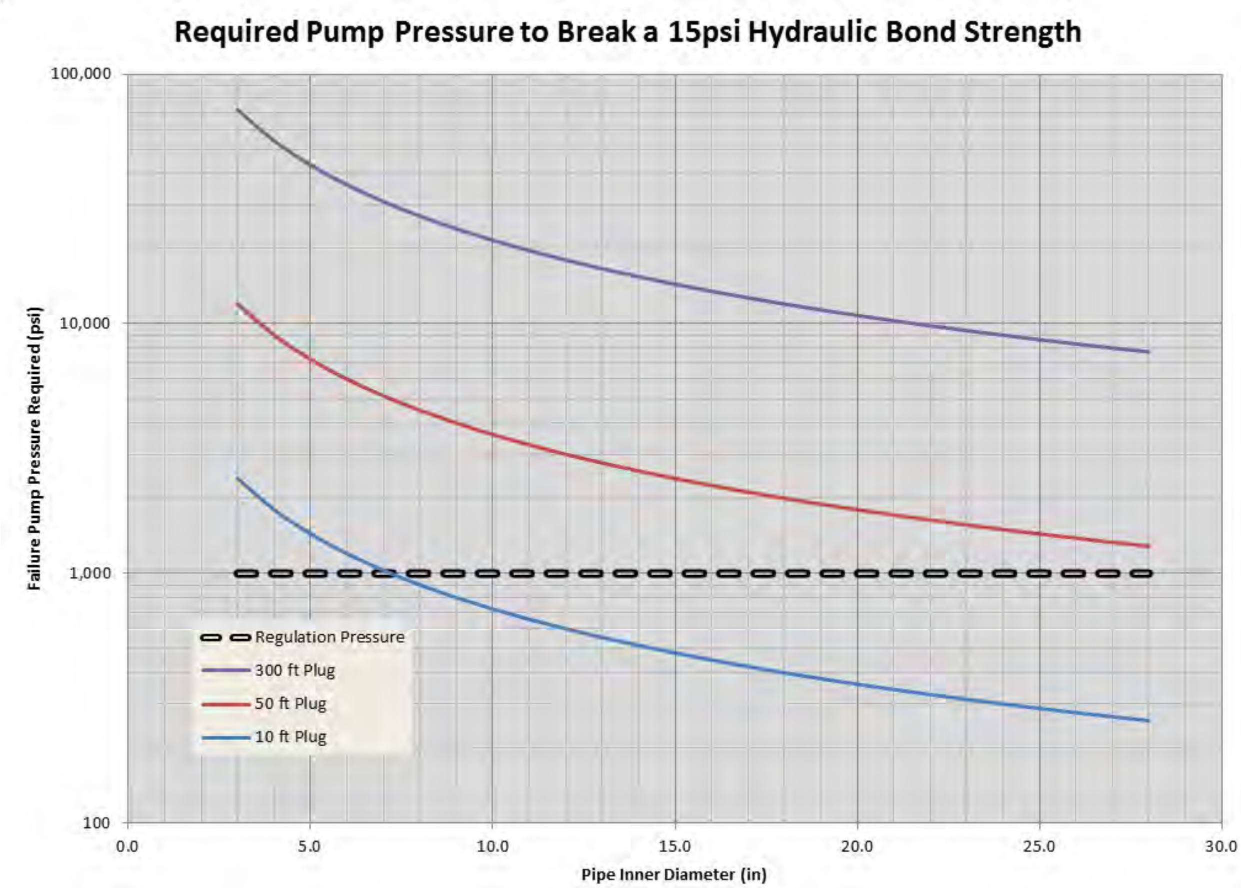

Figure 40: Required Pump Pressure to Break a 15 psi Hydraulic Bond Strength

It was noticed that higher pressures are required to break cement plugs with longer effective cement lengths. The black dotted line shows the current regulation pressure test. From this, one can see that plugs with effective lengths of 10' will fail the pressure test when place in casing larger than 7 inch. The same calculation and graphical representation was performed for the weight test. Figure 41 shows the required tag weight to break a 15 psi shear bond strength of a 10 foot, 50 foot, and 300 foot cement plug for varying plug diameters.

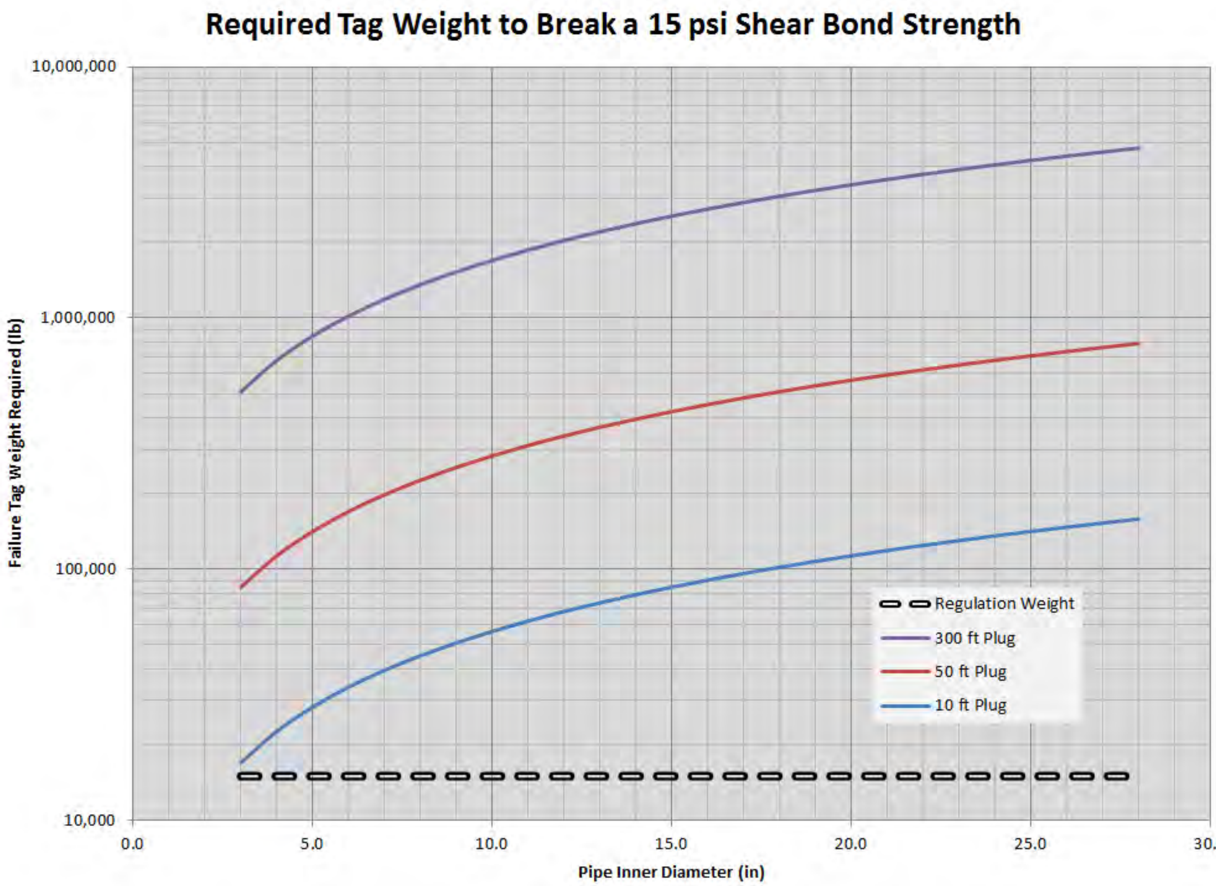

Figure 41: Required Drill Pipe Tag Weight to break a 15 psi Bond Strength

It should be noticed from this figure that a very large amount of force is required to break cement plugs using the weight test method. Longer effective length plugs require even higher forces. It was also found from laboratory testing that because of different failure modes between hydraulic testing and shear testing, that shear bond strengths are higher than hydraulic bond strength. Laboratory data concluded that shear bond strengths are generally ten times higher than hydraulic bond strengths. From this analysis, the pump pressure test is a much more severe test method when compared to the tag weight test.

Current Plug Testing Assessment

Use of the current methods allows a very large variance of cement plug required bond strengths depending on the general plug geometry. The current integrity verification methods also do not validate plug stability in certain downhole configurations.

The geometry of the cement plugs being placed plays a huge role on allowable bond strength development as well as the required bond strength to satisfy seal integrity verification. From an engineering standpoint, plugs placed in small diameter holes currently do not require as much force (mechanical or hydraulic) as plugs placed in large diameter holes to uphold seal verification methods. Hydraulic force is the surface pump pressure multiplied by the cross-sectional area of the cement plug.

Current integrity verification methods do not test for plug stability and overlook plug location after placement. In balanced plug situations, cement is pumped into the production tubing and balanced within multiple annular spaces simultaneously. When cement is placed in these balanced plug situations, generally the wellbore fluids inside the hole are not designed to support the cement which leads to fluid swapping. The heavier density cement ends up falling down the casing and not covering the expected zones. Set cement density variance also happens as a result of this fluid swapping which can be detrimental to compressive strength development within the plug. The surface pump pressure test will indicate if there is insufficient cement coverage at the perforations, but will not indicate the overall integrity of the entire cement plug. The drill pipe weight tag test will reveal top of cement, but does not thoroughly define the plugs stability or whether there is any communication between casing strings. The strengths and weaknesses of both the pressure test and weight test are discussed below.

Surface Pump Pressure Test

Strengths

The surface pump pressure test method has several strengths, one of which is its better verification of seal integrity in relation to gas migration as opposed to the weight test. One other advantage is the applicability in certain situations where the weight test would be virtually impossible such as very small casing/tubing diameters or plugs near the mud line in shallow water situations. These situations happen very often in shallow water zones. Plugs in these zones are generally tested only with the surface pump pressure test to reduce costs incurred, especially in rig-less abandonment operations.

Weaknesses

One of the main weaknesses regarding the surface pump pressure test method, which is also a weakness for the weight test, is the variability of required bond strength depending on plug geometry. Cement plugs placed in large diameter holes require much higher bond strengths to satisfy the surface pump pressure test than plugs set in smaller diameter holes. The surface pump pressure test is also unable to confirm plug location after placement. Top of cement can only be confirmed by tagging the cement plug after placement. One other weakness is that the pressure test only verifies that there are no casing leaks above the plug and not the seal integrity of the plug itself. Once good seal is obtained on the first plug placed in the well, where the pressure test holds, any additional plugs placed in the well should essentially pass with no problem as long as no damage to the casing occurred during plugging operations.

Drill Pipe Weight Test

Strengths

The main strength regarding the drill pipe weight test method is that plug location and top of cement are confirmed as in addition to performing the test. One other strength of the weight test is confirmation that there isn't any "green" cement, especially when testing secondary plugs at shallower depths.

Weaknesses

One of the main weaknesses, as explained earlier regarding the surface pump test method, is the variability of required bond strength depending on plug geometry. Cement plugs placed in small diameter holes require much higher bond strengths to satisfy the drill pipe weight test than plugs set in larger diameter holes, which is a resultant of contact surface area. Another main weakness of the drill pipe weight test is its feasibility when testing plugs at shallow depths or in rig-less abandonment operations. In either of these situations, drill collars must be made up to account for the weight necessary to perform the test. Making up the required weight can be a safety risk, especially in rig-less operations because special tools must be used such as a "Baash Ross" Safety Clamp for connections.

Recommendations for Plug Testing

Although the use of the surface pump pressure test method has its inherent cons, it currently is the preferred method. After speaking with service companies currently performing offshore operations, additional recommendations were posed. It is recommended to still pressure test the cement plug to verify there are no leaks in casing above the plug, but first to run slick-line into the hole to verify cement placement by "tagging." After an acceptable positive pressure test has been performed, a negative gas bubble observation should then be performed to verify the absence of gas migration within the well-bore. The gas bubble observation is performed by attaching a surgical tube to the well-bore by use of a reducing adaptor. Once all potential flow paths are directed through the tube, the end of the tube is placed in a vessel full of water (generally a 5 gallon bucket) and the flow of gas bubbles from the well (if any) are observed. The gas bubble observation is currently a qualitative procedure which can be interpreted differently depending on who is performing observing meaning that further testing and field observation would be necessary to standardize the gas bubble observation procedure. One additional procedure which operators could do to quantify unwanted gas flow would be to attach a digital gas flow meter to the tubing with data capture ability. Historical data of gas flow after abandonment would help other operators and service companies gauge future abandonment operations on seal effectiveness. It is still recommended to tag every cement plug placed in a wellbore such that there is qualitative data that every cement plug that is placed does in fact exist and is covering the correct zones or areas downhole.

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2. Tettero F, Barclay I; Petroleum Development Oman, Staal T; Schlumberger Oilfield Services: "Optimizing Integrated Rigless Plug and Abandonment – A 60 Well Case Study" paper SPE 89636, presented at the SPE/ICoTA Coiled Tubing Conference and Exhibition, Houston, Texas, USA, March 23-24, 2004.

Appendix A: Literature Summaries

SPE Papers

SPE 25181 Surfactants: Additives to Improve the Performance Properties of Cements

Cowan et al. (1993) describes the use of surface acting agents (surfactants) to modify the properties of Portland cements for well cementing operations. He explains the properties of surfactant cement blends saying that they: have improved interfacial sealing between cement and pipe, less shrinkage of the cement during setting/hardening, and generally improved cement properties at lower costs. He comments that additional steps are required in the design process when a fluid loss control additive is used in conjunction with a surfactant. Several field applications were commented on which all had successful results. He recommends the use of surfactants in most cementing operations and particularly where good interfacial sealing is critical including: cementing operations in wells drilled with oil muds, tail cements, cement operations in casing-casing annuli, and abandonment plugs.

SPE 23110 A Platform Abandonment Program in the North Sea Using Coiled Tubing

Hoyer et al. (1991) describes the cost effective method of using coiled tubing to set plugs in the North Sea. He describes how one platform (28 wells) was abandoned by the use of coiled tubing with great success. He describes several design factors and best practices that have to be addressed when placing plugs with CT, these are: surface batch mixing cement, monitoring mixing energy, and reduced circulation volumes causing higher downhole temperatures. The cement mix itself has to have very good fluid characteristics including: low rheological values, non-existent gel strengths, very low fluid loss, and controllable thickening times which must be tested on a non-API test schedule which better represents downhole conditions.

SPE 86941 Abandonment of a Former Steamflood Reservoir

Slater et al. (2004) explains the method of establishing communication with the top of a steam flood reservoir by the use of an abrasive jetting tool with nitrogen to cut slots into the casing string for abandonment in the Lloydminster field. Initially, the cement blends were designed for high temperature applications and did not set correctly downhole requiring multiple remedial operations. Once the cement was re-designed for lower temperatures, they had great success abandoning the wells. The use of Bradenhead squeezes for multiple downhole conditions were adopted along with very slow pump rates such that the cement would set up during pumping operations to effectively seal perforated zones and satisfy a regulatory pressure test of 1000psi for 30 minutes. The main cement blend used for these operations was a class G cement with 40% silica and a generic fluid loss additive.

SPE 116698 Best Practices in Designing HP/HT Cement-Plug Systems

Syed (2008) begins by explaining several well schematic factors that will affect the plugging ability of cements. He describes how proper evaluation of temperature is very important for plugging operations especially in HT (180-240F) applications. He explains that additives must be able to perform in HT applications if used in HT wells. He strongly recommends the use of spacers/pre-flushes to remove mud filter cake and water wet annular surfaces before cementing. He then explains 3 case studies; case one was 14 wells on the east coast of India using the balanced plug method in where 4 of the wells had plug failures in the deviated sections. Case 2 was three wells being plugged where sponge wiper balls were used in the deviated sections for successful plugs. Case 3 were plugging the same wells but using a plug catcher during placement for successful plugs. The general plug test procedure used for these plugs was to either drill the plug out to test it, or hydrostatic pressure test plugs. They did not describe pressures used for test.

SPE 24802 Case Histories of New Low-Cost Fluid Isolation Technology

Littlefield et al. (1992) explains the use of resin plugs to cover water producing zones in a steam flood well. 5 of the 7 wells plugged were successful. The two that weren't successful were because the operators didn't know where the water was producing from. The use of resin was much more cost effective than normal Portland cement in this case. Resin was placed using a dump bailer method.

SPE 46589 Sidki Well Abandonment and Platform Removal Case History in the Gulf of Suez

El Laithy et al. (1998) describes a production platform which was hit by a cargo ship offshore of Egypt. There were several producing wells which had to be abandoned. The wells were horse collar plugged in multiple sections with cement. There was very little other detail relating to cement or abandonment techniques as the paper focused more on platform removal.

SPE 100771 Permanent Plug and Abandonment Solution for the North Sea

Liversidge et al. (2006) explains the case study of three wells that were abandoned in the North Sea. He first explains several regulatory requirements that operators have to adhere to when plugging in the North Sea which include but are not limited to: borehole plugs must be tested with 100KN pressure min 5MPa inflow test, plugs are recommended to be at least 30.48m of uninterrupted cement to form barrier, tagging plug, pressure test greater than 500psi, and all plugs must be tested for proof of the plug's existence and its length. Through laboratory testing, he found that flexible and expanding cement is a fit for purpose system for abandonment. The three wells in this case study had multiple plugs successfully set using flexible expanding cement. One of the plugs was tagged twice with 9072kg to test its shear strength but all other plugs weren't tested since there was no requirement to tag or pressure test said plugs. Abandonment was successful for all three wells.

SPE/IADC 102039 Cementing Under Pressure in Well Kill Operations: A Case Study From the Eastern Mediterranean Sea

Johnstone et al. (2006) mostly describes the planning procedure of killing a wild cat well and briefly goes into detail of the cementing operations. The cement was placed using a tailpipe disconnect device since the well was still under pressure during placement. Very little information was conveyed relating to cement composition. The job was a success.

SPE 102534 Drillable Tailpipe Disconnect: Used Successfully in More Than 120 Wells Worldwide

Rogers et al. (2006) explains several case histories of using a device called a Tubing Release Tool (TRT). The TRT is an apparatus and method which allows setting a balanced plug without pulling the tubing out of the cement. the balanced plug is set, then a ball is dropped into the tubing and pressured up which disengages the upper tubing string from the lower portion that is left in the cement. tubing is generally made of fiberglass for ease of later drilling operations.

SPE 1569 Abandonment and Salvage of Deep Water Wells and Structures

Jeffus et al. (1966) presents the method used to restore production following extensive damage to production platforms in West Delta Block 117 caused by Hurricane Betsy. Platform A: All well connections were submerged and a high pressure neoprene hose as used to connect the cementing unit on the barge and the tubing safety valve installed on each tubing string. Sea water was pumped into the tubing string to breakdown the perforations and was followed by 150 sacks of Class D cement. The cement was displaced in the tubing strings to 1,500' above the top packer with 12.01 lb/gal mud placing cement into the perforated interval leaving a long plug in the tubing. The tubing safety valve was then closed and the hose disconnected. Seven of the 11 completions were cemented in this manner and tested to 1,500 psi for 15 minutes. A formation breakdown could not be established in four of the completions with 5,000 psi pressure and the perforated interval could not be squeezed. The tubing strings …were perforated at 2,376'…The casing and tubing strings were flushed out with sea water and a cement plug was equalized in the tubing and tubing casing annulus from 2,376' to 500'. Each of these cement plugs placed in the tubing and casing strings were pressure tested at 1,500 psi for 15 minutes. Platform B: The other seven wells on this platform were plugged using the same methods stated above. Most of the wells were found to have pressure on the tubing and it was necessary to kill them. Nine of the 12 completions were plugged by pumping cement to the formation. One tubing string was filled with cement…The 10 ¾" X 7" annulus at four of the eight wells was cemented by breaking down the formation and displacing a 500" cement plug to 100" below the mud line. A formation breakdown in the annulus was not obtained with 2,500 psi at three wells, and cement could not be displaced into the annulus. As a result a 1" tube was placed in the annulus so that cement could be circulated and placed. Plugs could not be placed in the surface casing annulus of some wells. Surface plugs were placed in the production casing by cutting the tubing strings 350' below the mud line and placing the cement plug through the tubing. Surface cement plugs were set in five of the eight wells and also done in other wells after cutting the wells down to the mud line.

SPE 27235 Decommissioning and Abandonment: The Safety and Environmental Issues

Shaw (1994) outlines the safety and environmental issues of decommissioning a major North Sea Installation and proposes a structured method for the identification of risks and hazards facing the operator. The abandonment of production wells will include…plugging with cement and mechanical bridge plugs. The exact methods and procedures will have to be approved by the government regulatory authority.

SPE 30514 Plug Cementing: Horizontal to Vertical Conditions

Calvert et al. (1995) presents an in-depth study of cement plug placement that was conducted with large-scale models for the improvement of plug cementing practices and plug integrity. The cumulative effects of density, rheology, and hole angle are major factors that affect plug success. The Boycott effect and an extrusion effect are predominant in inclined wellbores. A spiraling or "roping" effect controls slurry movement in vertical wellbores. Model Description and Fluids Testing was carried out using an 18' and 30' plexiglass model whose diameters ranged from 4.5", to 6.0", and 8.5". The Tailpipe OD's used were 2.34" and 1.564" maintaining lengths of 7' for the 18' models and 11' for the 30' models. All tests were conducted at atmospheric temperature and pressure. Most of the testing was performed with a 16.4 lb/gal cement slurry, while some were conducted with a 12.4 lb/gal prehydrated bentonite slurry. Successful plugs in this study are defined as those whose cement does not progress the full length of the model. Test Results – Horizontal Wellbore Testing Setting plugs under horizontal conditions proved the least challenging, regardless of hole diameter. For the 4.5" and 6.0" models, a YP of 30 $lb_f/100ft^2$ for an 8.7 lb/gal mud prevented severe slumping and subsequent mud channeling across a 16.4 lb/gal plug. In the 8.5" model, a YP closer to 40 $lb_f/100ft^2$ proved better. It can be concluded that the smaller the differential between mud and cement densities the lower the YP of the mud can be. Test Results – Deviated Wellbore Testing For tests conducted at 45° to 75°, the best chances of cement plug stability are obtained by:

- Reducing the density difference between the drilling fluid and cement.
- Increasing the YP of the drilling fluid below the intended cement plug.
- Placing a reactive spacer between cement and mud.

The 76 lbf/100ft2 YP is considered the minimum to support cement plugs in larger wellbores. Test Results – Vertical Wellbore Testing Flow observed in these tests showed the cement slurry to unwind or rope from the bottom of the plug in a clockwise circular pattern until the slurry reached the bottom of the model. Results showed the longer the rathole, the shorter the competent plug and smaller cement volumes yielded little or no competent cement plugs. A 14.2 lb/gal mud having a YP of 50 $lb_f/100ft^2$ resulted in a stable plug. An 11.8 lb/gal mud having a YP of 140 $lb_f/100ft^2$ was of marginal success.

SPE 81182 Challenging the Limits: Settling Long Cement Plugs

Sankar et al. (2003) advocates the development of a procedure that facilitates extending the length of cement plugs beyond current best practices, justifying that extending the length of cement plugs to 1,800' is the best solution for isolating long openhole sections based on economics, efficiency, and risk. The success setting balanced plugs for abandoning zones are based on operational execution, the ability to clear the placement string out of the cement plug, the top of the cement plug, and the ability of the plug to support a stipulated weight. Interzonal communication and unexplained pressure variation associated with charging or leakage are possible indicators of a failed plug. Abandonment can be achieved by: Conventional Cement Plugs (300'-900') Some of the best practices adopted to ensure successful cement plugs in small and large holes, wells deviated from 0°-50° in oil or water base muds are: Use of the balance plug technique Optimization of Mud Properties prior to setting plug Stable Well-bore Condition Use of a Diverter Tool and small diameter tail pipe Pipe Movement Washing the entire plug interval and circulating at optimum annular velocity for mud removal (240-270 ft/min) Stable Base (viscous pill) Adequate spacer and cement volumes Slow pulled out of cement (at 30-50 ft/min) Waiting on cement (WOC) time of 24 hours or the time to attain 2,500-3,000psi Use of Sacrificial String with a release mechanism and an optional packer Entails RIH with a sacrificial string, an openhole packer, a release sub and the retrievable workstring. Cement is placed both inside and adjacent to the sacrificial string. The openhole packer is then set prior to releasing from the workstring and pulling out the hole. Four 1,800' and one 1,400' cement plugs were successfully set to abandon the Amherstia A-11B01 wellbore. The plugs were set one on top of the other an eliminated any WOC time. Extending the length of cement plugs provides for the most economic and efficient manner of abandoning long openhole sections

SPE/IADC 97347 Laboratory and Field Validation of a Sealant System for Critical Plug and Abandon Situations

Nagelhout et al. (2005) presents case histories and discusses the laboratory validation of a sealant system for plug-and-abandon (P&A) operations in critical gas wells close to habitations. Two cement systems were designated as candidates for plugging operations. One system with high flexibility and expansion met the specifications and did not leak until a differential pressure of more than four times specification was applied. The application and effectiveness of a silicone material incorporated into a conventional cement system was analyzed however the material combination is not available commercially. A cement plug was set in a large cell and the flow of gas across the cement plug was measured at different differential pressures to test the gas-sealing ability of the two flexible systems. The nonshrinking System A showed an immediate gas leak at a differential pressure of <0.1 MPa at an absolute pressure of 15MPa. The leak rate could not be controlled indicating a significant flow path had formed proving that a nonshrinking cement is insufficient to ensure a gas tight seal under test conditions. The expanding System B did not show a gas leak; the system was then overpressurized above specifications and once the cement-casing seal was broken it did not reseal. The intervention and the flexible and expanding cement plug placement were executed without any problems in the field and over the course of a year no pressure has been measured on any of the annuli indicating successful plugging operation. This has been confirmed on four additional wells. Large-scale tests are a much more severe test of plugging ability than small-scale tests

SPE 130159 Efficiency in Cement Jobs for Fresh Water Formations Isolation During Plug and Abandonment in Canadon Seco Field, South Argentina

Graterol (2010) presents the whole procedure for achieving the isolation of fresh water formations from once productive formations and also includes details in each phase of testing/design and execution. Due to shallowness of the Patagoniano formation, the unconsolidated (and extremely high permeability) sands show a high level of fluid loss. This problem has been confronted without proven success in the past through use of sodium metasilicate (Na_2SiO_3) pads, glass fiber, two stages cementing squeeze jobs, among others. 13 out of the 14 wells were successful in just one squeeze job; the 1 required a second squeeze job. Implementation of the new methodology / slurry has allowed a cost reduction of 41% and operational days were also reduced. Displacement rate should be kept as low as possible in order not to promote fluid loss into the formation

SPE 49151 A Coupled Model to Predict Interformation Flow Through an Abandoned Well

Striz and Wiggins (1998) Present a new model to predict interformation flow in an abandoned well. They expand on previous models by determining true pressure losses in the abandoned wellbore taking into account turbulent or laminar pipe flow, plugs, and casing perforations. Their model also predicts fluid flow behind pipe through an open or plugged annulus, or a fractured annular plug. Their scenarios involved fluid flow into the upper formation of an abandoned well in response to a neighboring injection well in a lower formation. The abandoned well was initially assumed to be open to both the top and bottom formation, which allowed it to act as a conduit between the two formations which were otherwise separated. In this scenario the properties that most affected flow in the abandoned well were the distance between the wells, the formation rock properties, fluid properties, and the flow rate at the injection well. Later scenarios proved that more important than the aforementioned properties are the condition of the abandoned well. They proved that an abandoned well with a just 100 feet of plug in the wellbore or annulus reduced the flow to the extent it was considered negligible. Another scenario assumed a 0.01 inch fracture in the plug and while the flow rate increased it was still low enough to be considered negligible.

SPE 56959 Cement Plugs: Stability and Failure by Buoyancy-Driven Mechanism

Crawshaw and Frigaard (1999) looked at buoyancy to determine fluid rheologies required to prevent failures of cement plugs placed above the bottom of the well. These plugs have a high rate of failure due to the unset cement mixing with the mud below it before it sets. Along with density difference between fluids, key factors are hole size and angle. The smaller diameter vertical holes are the most resistant to fluid mixing. As hole size and angle increase the fluids have a greater tendency to mix. Through mathematical modeling they determined that Bingham fluids with yield stress will resist flow the best.

SPE/IADC 62752 Viscous-Pill Methodology Leads to Increased Cement Plug Success Rates; Application and Case Studies from Southern Algeria

Fosso et al. (2000) developed a software program based on the modeling work done by Crawshaw and Frigard (1999) that increased the off-bottom cement plug success rate from 25% to almost 100% in southern Algeria. This program takes into account hole conditions, as well as the properties of both the cement and mud and then determines the necessary rheology of a viscous pill to be placed between the two.

SPE 66496 New Abandonment Technology New Materials and Placement Techniques

Englehardt et al. (2001) experimented with sodium bentonite as an alternative plugging material in abandoned wells. They experimented with compressed sodium bentonite plugs, which were compressed, round nodules of the material with a SG>2. Once placed and hydrated, these plugs form an impermeable plug in seawater, saturated salt water, and even oil. They also seal flow paths formed in a hot steam environments. In the presence of hydrogen sulfide their swelling ability was reduced by 30%. These plugs are easily bypassed with a soft formation drilling assembly if the well needs to be reentered.

SPE 134843 Cost Effective Field Applications Utilizing Coiled Tubing Inflatable Packer System in South Mexico

Robles et al. (2010) plugged an open hole section in a newly completed well by pumping a squeeze slurry using an inflatable packer system through coiled tubing. This allowed them to keep the production tubing in place and eliminated the need for a workover rig, which would have taken 7 to 10 days instead of the 28 hours it took using the packer and coiled tubing.

SPE 10957 – Successful Deep Openhole Cement Plugs for the Anadarko Basin

Dees et al. (1982) deals with how to successfully complete deep openhole plugs for horizontal well kickoff purposes. It thoroughly describes the properties needed in the mud used for drilling, as well as the potential risks that some of the chemicals in the mud have with regards to cement slurry contamination. It then goes through several ways to place a plug involving types of muds, spacers, and cements as well as placement techniques and good cementing practices. Most importantly for our purposes, the cement plug must be given ample time to reach full strength before work can begin.

SPE 27709 – In Conflict: Marginal Reserves vs. Regulator-Enforced Abandonment

Haynes (1994) raises the concern that we might be plugging wells for abandonment too quickly…meaning that they could potentially be produced again. There is nothing about plug testing or plug placement.

SPE 83443 – Well Abandonment in the Los Angeles Basin: A Primer

Evans et al. (2003) explains how old oil fields which have been abandoned can be sold as real estate and the problems that current abandonment techniques can present in order for that to occur. It describes several things that need to happen in order for abandoned wells to be able to have buildings and other structures built on or around them. There is very little mention of cement plug placement techniques or testing. They only mention the requirements of the state at the location they are at.

SPE 89622 – Utilizing Innovative Flexible Sealant Technology in Rigless Plug and Abandonment

Barclay et al. (2004) introduces a new expansion additive to be placed in cement for use in plugging and abandonment of wells. They state that due to well conditions and other factors, even good plugs can fracture over time and start to allow the well to leak. If the flexible expanding technique they propose is used, not only will micro annuli be closed but should fracturing occur, the sealant would close the gap. They also describe in depth a series of lab tests that should be performed in order to determine the effectiveness of a cement plug. First, they say that the thickening time test should be performed at BHST conditions and that extra shear should be given to the slurry at the beginning to simulate batch mixing and plug placement. Compressive strength testing should also be performed, as well as specialty testing. These tests include non API testing such as BP slurry stability, non API Thickening Times and non-API shear times. They also test their expansion additive in expansion molds to ensure that the cement will adequately expand.

SPE 104443 Technology of Plugging Long-Interval High-Pressure Channeling Wells by Cement with Overburden Pressure During Curing

Wang Yan, Wang Demin, Luo Jiangtao, Zhong Ping, Dong Zengyou & Liu Yingzhi (2006) present a new method to plug long interval high pressure channeling wells by cement curing with an overburden pressure. They try to repair channeling in cement created when the cement is developing gel strength and microannulus caused by cement shrinkage. To prevent these two conditions an overburden pressure higher than the formation static pressure and below the frac pressure was applied and held on the setting cement. The authors then discuss how to use cement to remedially repair channeling in previous cement jobs. The cement slurry design discussion is very standard and basic. Field results are documented and concluded.

SPE 64-033 New Technique for Improving Cement Bond

Georges Evans & Greg Carter (1964) present a unique and novel idea for improving the bond between cement and steel casing. Their method involves applying a resin-sand coating to the pipe. The cement-steel bond is improved because of the rough surface and because the resin has certain chemical properties that increase the shear bond. The resin has to be resilient, strong, able to resist shattering, withstand temperature and pressure changes, unreactive to wellbore fluids and adhere to steel and sand. The sand grain size and resin coating thickness must be tailored to the meet bond requirements. Laboratory and field testing results are presented for resin chemical resistance, sand grain size effects, and bond strength improvement. These tests showed a huge improvement in shear, hydraulic, and gas bond strengths for resin-sand coated casing even in the presence of a mud film. The surface of the casing must be chemically or mechanically cleaned before applying the resin and sand to remove the varnish that is applied to the casing surface at the steel mill. Lab tests show that a resilient resin-sand coating can withstand perforating shots without debonding. Acoustic bond logs on field tests show a marked improvement in the cement bond. This method has been used in oil, gas, and injection wells in Texas, New Mexico, Oklahoma, Kansas, Pennsylvania, and the Gulf Coast. All of the testing appears to have tested the resin-sand coating applied on the OD of the casing.

SPE 11415 Improved Method of Setting Successful Cement Plugs

Smith, Beirute & Holman (1984) discuss the causes of failure of cement plugs placed by the balanced plug method. Using a simulated casing and open ended drill pipe in the laboratory testing, it was determined that heavy cement (which can be 6-7 ppg heavier than the mud) will start to fall and the lighter mud below will channel up through the cement. It proved the actual conditions and results in the well are not ideal and established there is a great potential that the cement will not completely seal the pipe. It was also established that cement/mud interface stability affects the fluid density swap. The presence of a stable interface is not enough for good cement placement as it can be easily disturbed by certain events such as drill pipe movement, percolating gas and even the turbulence of the cement during placement. Since pumping of the cement into place caused a problem, the author tried placing a viscous bentonite pill ahead of the cement to create a support "table." This only produced fair plug quality with cement slurries under 11.8 ppg when using extremely slow, careful, and uniform placement of the pill. All of the slurries above 11.8 ppg channeled to the bottom of the test cylinder. A second approach using a diverter tool attached to the end of the drill pipe to spot the pill and then the cement. This resulted in good 15.8 ppg cement plugs and fair 17.5 ppg cement plugs when placed in 9 ppg mud. A third approach used the diverter tool without a pill. This resulted in good cement plugs with slurries up to 13.8 ppg. The 14.8 ppg and above slurries all channeled through the mud to settle at the bottom. The diverter tool works by forcing the fluids into the face of the wellbore. It proved to improve plug quality. The authors disapprove of plug slurries with dispersants because they are thinner and have unstable cement/mud interfaces that promote density swap and channeling. Cement/mud compatibility that tends to gel on contact can help plug stability in field applications. Thixotropic cements can also help by creating gel strength. Field cases are presented that document success of using a diverter tool and viscous pill together.

SPE 27864 Cost-Effective Solutions to Well Plugging and Abandonment

M.V. Smith & J.M. Pitura (1994) discuss new one-trip cement retainer and cement slurry placement tools and methods that do not use conventional mechanical (rotation, high tension, or high compression) and wireline setting methods. The first new method uses a standard wireline set-type cement retainer, a special hydraulic setting tool, and an optional circulation sub. The setting tool works by hydraulic pressure only and can be pumped through. It functions by being run to depth on a work string, dropping a setting ball, pressure up to set the retainer, increasing the pressure to shear the release tool, pulling up to close the retainer valve and pump cement above the retainer. No rotation is needed to set the retainer. The second method consists of a modified setting tool with a bridge plug attached to the end of the work string. An appropriate volume of retarded cement is mixed and poured into the tubing and then a rotational equalizing joint is installed above the cement filled tubing. Then it is run to depth and the retainer is set by rotating and pulling 25k lbs and then slacking off 25k lbs. The mechanical setting tool is then released by 2-3 right hand turns and the cement falls out of the tubing as it is pulled up. Pouring the cement in the tubing before running it in the hole removes the need for pumping equipment. Successful lab cases and case histories for this method are also briefly discussed.

SPE 89636 Optimizing Integrated Rigless Plug and Abandonment – A 60 Well Case Study

Frans Tettero, ian Barclay & Timo Staal (2004) present the results from a 60 well case study on the results of rigless P&A operations. Environmental and economic goals were reached through technology and continuing improvements. The key elements required for successful rigless P&A operations are discussed. The 5 key elements are super mobility of equipment, self-supporting site contractors, dry location concept, one-stop job to eliminate returns to the site, and minimum mileage. The goal of plugging a well is to permanently isolate all the subsurface formations intersected by the well. This requires quality long lasting primary cementing jobs to prevent leaks up the backside. Flexible and expanding cement systems are recommended to maintain long-term isolation. This paper then goes through the typical process they used to abandon the wells in the case study and satisfy the 5 key elements. One important aspect of the operations was properly cleaning and preparing of the wellbore to ensure a good bond between the cement and the casing. Residue left on the pipe can move over time and cause problems with the cement seal. They cleaned the wells with chemical washes, jetting tools, and a combination of the two. Correct tubing perforation schedules and execution is very important. Operational lessons from the case study such as logistics and equipment requirements are discussed.

SPE 84556 Improved Techniques to Alleviate Sustained Casing Pressure in a Mature Gulf of Mexico Field

Kevin Soter, Felix Medine & A.K. Wojtanowicz (2003) talk about remedial work to relieve sustained casing pressure (SCP). A group of wells suffered from SCP and had three attempts at remedial work to correct the problem. They discuss the operational aspects of the remedial work such as the "cut and pull" method of removing the upper uncemented portions of inner casings that have SCP in the outer annulus. The casing is pulled then cleaned with bits and scrapers. If possible, a CIBP is installed and a cement plug is placed on top. A latex cement was used and pumped through a diverter sub on the end of the workstring. The cement was then squeezed into the annulus around the top of the cut casing. The other method they used was a window milling operation. It is similar to the cut and pull method but instead of pulling the inner casing, a long window is milled into it to open the annulus. The main lessons learned for the cementing portion of the work are: it is important to prepare the hole by washing with a diverter tool and using effective spacer designs; use a latex additive in the cement to improve bonding and long term durability; and if possible, create a bottom for the cement to prevent mud contamination by using a CIBP.

SPE 66497 – Streamlining Abandonments for Cost Reduction

Fred Woody (2001) details the development of a database created in conjunction with Chevron that allows for a more efficient abandonment process. The database stores well design parameters and location equipment inventories. The database also stores general regulatory requirements for abandonment based on well conditions, and the program could generate abandonment packages ready for submission to regulatory agencies. These packages only require modification in special cases. The program also generated packages to be given to field personnel including procedures, materials requirements, wellsite inspections, work clearances and biological reviews. The field personnel can enter details after abandonment is complete, allowing projects to be tracked easily at a higher level.

SPE 100435 – The Eureka Canyon Oil Field: A Case History

B.H. Hesson (2006) discusses the process of securing, identifying, and abandoning 23 orphaned wells in the Eureka Canyon and Smith Canyon fields in California. The paper begins with a history of the Eureka Canyon field. These were discovered after a wildfire burned down much of the forest in the Eureka and Smith Canyons, making visible many of the previously hidden orphaned wells. Wellheads were installed on the ten wells found open to the atmosphere. One well was found leaking oil to surface with no surface casing in place. A 5 ½" casing was cemented in place to a depth of 40' with an inflatable donut around the casing shoe to prevent cement from falling deeper into the wellbore, and a wellhead was installed on this casing. As there were essentially no records for the orphaned wells, the wells were to be cleaned out as deep as possible and cement circulated to surface. The first well was abandoned by cleaning out with coiled tubing to a depth of 725 feet. Cement was circulated to surface in stages. A set of perforations was shot at 300 feet and squeezed off with cement to shut off oil and gas flow outside of the casing. The remainder of the orphaned wells had tubing pulled (if any was left in the well), were cleaned out and filled with cement.

SPE/IADC 79799 – Abandonment of the Hutton TLP Wells

Plumb et al. (2003) details the methods of abandoning 32 wells from the Hutton Tension Leg Platform in the East Shetland Basin of the North Sea. In each well, two zones were to be isolated, the overpressured HC-bearing Brent Reservoir and the normally pressured water-bearing Nordland/Hordaland Reservoir. Two plugs were required to isolate the Brent reservoir. The first was a 16.0 ppg Class G with 35% silica, with retarder and fluid loss additives. This cement was bullheaded below the production packer and tested three ways. TOC was determined by tagging with slickline, then a positive pressure test to 500 psi above initial injection pressure, and a negative pressure test by filling the well with seawater and relieving all of the tubing pressure. For the two wells with too low of an injection rate (<1 bpm at 4000 psi) to bullhead cement, a mechanical plug was set with a cement plug placed on top. Two wells failed their initial pressure test after the first plug. One well still had a high enough injection rate to bullhead another plug, and the other had a marginal injection rate, so a mechanical barrier was placed and cement was spotted on top. The second plug was a 2000 ft. plug that filled the tubing and the tubing-casing annulus. Slickline was used to perforate the tubing 50 ft above the first plug and cement was circulated down the tubing into the tubing-casing annulus. This plug was pressure tested 500 psi over initial injection pressure from the first plug. Production tubing was cut and removed above this plug. The third plug to seal off the water bearing formation was placed in three stages. The annulus between the 9 5/8" production casing and the 13 3/8" intermediate casing was perforated above the production tubing and just below the wellhead. This annulus was checked for injection, then for circulation. If circulation was established, then 150 ft of cement was circulated into the annulus, and if there was any injection, then cement was squeezed into the annulus to seal it off. This plug was tested to 500 psi over the injection pressure or to 80% of the burst rating of the 13 3/8" casing (whichever was lower). The same process was repeated for the 13 3/8" intermediate to 20" surface casing annulus. The third stage was to set a balanced plug inside of the 9 5/8" production casing above the upper sets of perforations to completely seal the well. The cement used for the plugs to seal off the water formation were neat class

G with 2% calcium chloride. The annular plugs had difficulty testing due to faulty seals in the wellhead. All of the plugs set inside of the 9 5/8" casing successfully tested by pressure testing or tagging with a bit.

SPE 24294 – Successful Remedial Operations Using Ultrafine Cement

Harris et al. (1992) describe the use of ultrafine cement for remedial operations during the life of a well. The focus of the paper is on using microfine cement for applications where conventional cement cannot be used. Three general processes are described: gravel pack squeezes, casing leak squeezes, and water control squeezes. Different slurry designs and operational procedures for each case are given. Two case histories are presented that show the successful use of ultrafine cement in sealing casing leaks. Ultrafine cement is given as a method of plugging and abandoning a gravel pack; however, no information is given specifically regarding this type of operation.

SPE 26087 – Use of Coiled Tubing for Abandoning Shallow Thermal Wells, South Belridge field, Kern County, California

Fram and Eberhard (1993) discuss the use of coiled tubing to spot abandonment plugs in these shallow steam injection and heavy oil production wells. The main focus of the paper is on the reduced cost and increased efficiency that comes with using coiled tubing as opposed to a workover rig to quench the wells and spot the cement plugs. The cement systems used were redesigned for use with coiled tubing. As the tubing used to spot cement on a workover rig had a large ID, a blend of between 2:1 and 4:1 sand to cement with 35% BWOC silica flour was used. The slurry was changed to premium cement with 35% BWOC silica flour. This was found to be very expensive. To reduce costs, the system was changed to a 50:50 Pozzolan cement blend with 5% bentonite and 35% BWOC silica flour.

SPE 35333 – Total Integrated Solutions Reduce Costs in the Gulf of Mexico

Slocum and Baez (1996) discuss the evolving relationship between service companies and operators. Modern service companies offer multiple product lines and have turned their focus to the development of new technologies. The use of 'integrated solutions', i.e., one service company to provide multiple services along with their technical expertise has become beneficial to operators for two reasons. First, service companies are willing to lower prices if an operator agrees to use multiple service lines. Second, the service companies are better able to coordinate their own service lines than an operating company is able to coordinate multiple service companies. Four case studies are presented, none of which include any specific technical or operational details.

SPE 114866 – Design and Operational Factors for the Life of the Well and Abandonment

Tahmourpour et al. (2008) discuss factors that need to be taken into consideration when performing a primary cement job. Use of finite element analysis to simulate stresses that will be put on the primary cement sheath throughout the life of the well is described. He states that a well-designed primary cement sheath can reduce costs of remedial work and abandonment in the future.

SPE 35084 Optimization of Balanced Plug Cementing

Harestad et al. (1997) discuss the development and use of a new tool designed to prevent a cement plug from falling due to density difference in a wellbore. The tool consists of two umbrella-shaped parts made from fiberglass rods and canvas. It is placed inside the same workstring used for placement, reducing the need for an extra trip to set a mechanical barrier. The tool is activated by a ball and once the canvas has expanded to meet the casing or open-hole walls, the container acts as a diverting tool. Pilot-testing and field cases are given showing successful use of the tool.

SPE 26897 – A Unique Experimental Study Reveals How To Prevent Gas Migration in a Cemented Annulus

Talabani et al. (1993) describe a testing apparatus used to determine gas-tightness of a cement system when placed in a simulated annulus. A 2” hole is drilled in a 4” diameter oilfield core. 1.5” casing is placed into this annulus and drilling mud is circulated through the hole for 24 hours. This annulus is then cemented. Gas pressure (nitrogen) is applied to the top of the cement sheath incrementally until it reaches 880 psi. A reading of 0 psi at the bottom of the sheath indicates that the slurry is gas tight. A similar method for testing gas permeability of cement is also described. Paper concludes by describing a Class G system with a synthetic rubber powder additive was determined to be both impermeable and gas tight. 4.8% BWOC of the rubber powder is all that is necessary to seal the micro-fractures caused during gelation.

SPE 80592 – Well Abandonment Using Highly Compressed Sodium Bentonite – An Australian Case Study

Clark and Salsbury (2003) describe a process for abandonment by pouring sodium bentonite nodules into an open well and allowing them to hydrate. While it has been shown that the bentonite will hydrate in brine, oil-cut water, and H_2S laden water, its hydration is most effective in fresh water, so this method is only used in wells that can be controlled by a column of fresh water. The well is circulated clean and a bridge plug is set below the deepest set of perforations. The nodules are poured in stages, only 50 feet of nodules are poured at a time. Between each stage the rig sand line is run in and tags the top of the plug. After a plug of sufficient length is set, the bentonite is left in the well to hydrate for 28 days. After this 28 days, the plug is pressure tested to 500 psi. This plugging method is less costly than setting cement plugs (no rig time for WOC, no contract cement company, cement is more expensive than bentonite). There are also numerous safety and environmental benefits (no pressure pumping until the final pressure test, smaller footprint, less equipment required, spills can easily be picked up by hand).

SPE 97944 – Optimized Abandonment Procedures Improved Success and Results in Central California Heavy Oil Field

Glessner et al. (2005) describe a method of abandoning wells that have been severely damaged by cyclical steam injection. With a workover rig in place, production tubing is pulled up just below the parted casing. Coiled tubing is run inside of the production tubing and a cement plug is placed from TD to just below the part using the pump-and-pull method. This system is a Class G + 35% Silica + 2-3% calcium chloride. This plug is tagged in two hours. A thixotropic slurry is then squeezed into the casing part. This cement is pressure tested to 1,100 psi after two hours. The production casing is then perforated at the surface casing shoe depth. Both annuli are perforated and the same thixotropic slurry is bullheaded down into both annuli leaving the production casing full of cement. General performance details for three other cement systems are given but no design information is given other than density. These cement systems are not used during their abandonment campaign.

SPE 115524 – Plugging Wells with Hydrated Bentonite, Part 2: Bentonite Bars

Towler et al. (2008) describe a testing method to determine the friction factor between a bentonite plug made from compressed bentonite 'bullets' and both steel and plastic pipe. This friction factor is used to determine the amount of formation pressure a bentonite plug can hold. For the first five tests, bentonite 'bullets' are placed in different arrangements at the bottom of a steel pipe and covered with water. Once hydration is complete, air pressure is placed at the bottom of the plug and increased until air bubbles are seen coming through or around the plug. The sixth test is the same as the first five with a plastic pipe in place of a steel pipe. The swelling of the bentonite varied between 85% and 300% (mainly based on arrangement within the pipe). The friction factor of the plugs was determined to be 1.85, compared with a friction factor of 0.8 for non-compressed bentonite pellets. Conclusion is made that compressed bentonite bullets are better suited for abandonment of oil or gas wells than non-compressed bentonite pellets.

SPE 138287 Field/Well Integrity Issues, Well Abandonment Planning and Workover

Diller (2010) shows the complexity of planning re-entry and well abandonment of a well that was previously abandoned but insufficiently. Many contingency plans are put forth in the paper but the actual job and what occurred was not discussed nor are cement slurries.

SPE 89348 Coiled Tubing and Wireline intervention for well abandonment

Kirby et al. (2004) Covers methodology used while BP was abandoning 24 wells on a single platform in the North Sea. Three plugs were typically placed in the well for abandonment purposes. The first was right above the reservoir and was 200-500ft long, the next one up was 1,200-1,500ft and the last one, near the surface, was 700ft in length. All plugs were verified with by tagging or pressure testing. Plugs were placed using either coil tubing, circulation or bull heading. All critical equipment had backup and contingency plans ready ahead of time. The appendices contain several fully explained methodologies with regard to abandonment procedures used.

SPE 88921 Abandonment of Well in Shell Nigeria Operations

Odita et al. (2004) more discusses where plugs had to be placed and length of plugs as well as cutting casing. It doesn't mention anything about slurries or the actual methodology used in placing the cement plugs.

SPE 112715 – Innovative Hydraulic Isolation Material Preserves Well Integrity

Roth et al. (2008) explains about improving zonal isolation in order to improve productivity of wells using self-healing cement. It introduces a new expanding material capable of expansion when it comes into contact with hydrocarbons, thus sealing any microannuli or other cement fractures.

SPE 24574 A Laboratory Study of Cement and Resin Plugs Placed With Thru-Tubing Dump Bailers

W.S. White, Mobil E&P U.S. Inc. and Halliburton (1992) performed laboratory experiments to study the factors that influence the successful placement of cement and resin plugs using thru-tubing dump bailers. Full scale tests were performed including shear bond tests. No description of how the shear bond tests were performed is given. The paper focused on designing a cement slurry with delayed gel strength development for better successful dumping. Visual tests indicate plugs of cement are hard, then semi-hard, then soft and continues this series with each successive dump, so the set plug of cement is not uniform. Gravel pack penetration tests were performed with microfine cement, which failed and resin which penetrated, but did not totally seal the formation. The paper does a good job in presenting the test fixtures in detail.

SPE 23928 Surfactant/Cement Blends Improve Plugging Operations in Oil-Base Muds

Harder et al. (1992) focuses on cementing in southeast OK in the Arkoma Basin. The Geology consists of shales which necessitates the use of OBM as a drilling fluid. Often it takes 3 or 4 KOP attempts before getting an acceptable plug in place. The main cause is believed to be contamination of cement. Typically for a plug, a water wetting spacer would be pumped ahead of the cement plug. This would be placed on top of an extremely viscous plug of contaminated (with water) Oil based mud. They found that when they added a water wetting surfactant to the cement, the OBM contamination of cement didn’t have as drastic of an effect on CS development and they were able to get suitable KOP’s in 30hrs.

SPE 91399 – Microannulus Leaks Repaired with Pressure-Activated Sealant

Rusch et al. (2003) detail the use of a sealant that is activated through a pressure differential to seal channels or cracks that provide pathways for the migration of fluid within wellbores. The sealant is unique in that a pressure drop through a leak site causes the sealant fluid to polymerize into a flexible solid seal only at the leak site. The sealant remains fluid until it is released through a leak site where differential pressure causes the monomers and polymers to cross-link by the polymerizing chemicals, sealing across the leak site, but there is still remaining fluid away from the leak site. Laboratory studies and case histories are presented to validate the technology.

SPE 54472 – Coiled Tubing Milling and Temporary Plug and Abandonment Operations

Sorgard et al. (1999) review a case history in which two temporary cement plugs were placed in 10 ¾” casing through the use of coiled tubing. A novel mechanical plug that could be run though a 2 3/8” hole and be expanded to fit inside the 10 ¾” casing was designed and built for the unique application. The mechanical plug is an excellent base for cement plugs, and represents an improvement in cementing technology. Both cement plugs were tagged and pressure tested after WOC and found to be successful. The case history verified that it is possible to set a gas tight cement plug in large diameter hole with coiled tubing even at low flow rates when the proper design is employed.

SPE 54341 – Plug and Abandonment Technique for Geothermal Wells Reduces Operators' Costs

Courville and Anderson (1999) review four case histories involving the use of a coiled tubing unit to deploy and set bridge plugs for plug and abandonment operations in geothermal wells. Pressure operated setting tools allowed entry into these geothermal wells under flowing conditions and allowed operators to successfully set drillable packer mandrels that have bridge plugs installed. Once the bridge plug is set, cementing operations can begin immediately. The mechanical bridge plugs are not necessary to meet regulatory requirements in the area, but are often used as a safety standard to aid in plugging attempts.

SPE 64481 – Novel Technique for Openhole Abandonment Saves Rig Time – A Case History

Chong et al. (2000) present a method for setting a competent plug over a long section of open hole in deviated wellbores through the use of a sacrificial stinger to be released form the drillpipe after the cement plug is set. This method replaces the need for multiple plugs set on top of each other with one long cement plug. It can also help minimize cement plug failures and inconsistencies through minimal disturbance of the cement, minimal contamination with the wellbore fluid, and reduced rig time and material cost compared to setting multiple plugs. Tests have shown that if cement plugs are highly viscous or have begun to develop gel strength, the plug will become contaminated when the workstring is pulled out. The new method eliminates the need to pull the workstring out of the cement plug, removing this issue. The plug set noted in this case history was successfully pressure tested to 3,000 psi for 10 minutes.

SPE/IADC 62764 A New Plug and Abandon Well Operation to Avoid Discharge

Sola and Daulton (2000) describe a new cementing process that does not rely on conventional mixing techniques. The process involves the use of a storable oilwell cement slurry that can be kept in a liquid state for more than 6 months and made to set when required. The slurry, named Liquid Cement Premix (LCP), consists of a premixed Portland cement containing set retarding and conditioning agents, with water as the carrier fluid. The slurry can potentially be stored time periods from 2 weeks to 6 months. When ready, the LCP is activated to yield a finished slurry with suitable properties for a plugging material. The use of LCP cement simplifies cementing operations, minimizes environmental and safety impact, and reduces waste.

SPE 133446 Permanent Abandonment of a North Sea Well Using Unconsolidated Well Plugging Material

Saasen et al. (2010) present an alternative plug and abandonment method with a Bingham plastic unconsolidated plugging material with high solids concentration named the Well Barrier Element (WBE). The WBE is gas tight and does not set up after placement or shrink. The WDE cannot fracture even when shear forces exceed its strength, rather the materials floats and shear forces are reduced below yield strength causing the plug to reshape. Since this is a purely mechanical process, the transition between solid and fluid phase is repeatedly reversible. The method involves the use of a concentrated sand slurry with a mixture of particles with a wide particle size distribution. As long as the slurry is static and in a particle-particle bond gel state, it will at minimum exert a hydrostatic head equal to water or brine phase. Testing has shown that the material remains gas tight for a differential pressure exceeding the hydrostatic gradient of the slurry. The total pressure control gradient of the plug is the sum of the hydrostatic gradient of the slurry plus a constant. The concentrated sand slurry is made pumpable by carefully designing the particle size distribution making the smaller particles fit into the free space between the larger particles, along optimal packing principles. The sand slurry material has been thoroughly tested and qualified by the service provider in cooperation with research institutions and the industry through laboratory and field or pilot testing.

SPE 28321 - Quality Management Alliance Eliminates Plug Failures

Heathman et al. (1994) describes the results of an industry quality alliance who's goals were to improve the success rate of cement side track plugs in the GOM. He points out that many of the issues related to cement plug failure are attributed to: poor mud removal, unstable cement slurries, insufficient slurry volume, poor communication, and poor job execution. He recommends the use of clay control additives when setting plugs in sensitive formations. He also points out that ignoring the wells potential risk for gas migration is usually detrimental to the success of a plug. He comments on Smith et. Al recommending a maximum density differential of about 2.8lb/gal between cement and supporting drilling fluid while recommending that a static barrier must exist below the cement column to impede plug movement. The study recommends the use of a diverter on the bottom of the tubing which would help with mud removal and assure more accurate cement placement. Using these best practices, Heathman boasts a 100% success rate of 35 sidetrack plugs between 1,500' and 15,000' and at angles as high as 60 degrees in deviated wells.

Other Literature Sources

PETSOC-2006-015 Innovative Cement Plug Setting Process Reduces Risk and Lowers NPT

T. Marriott, H. Rogers, S. Lloyd, C. Quinton & N. Tetrault (2006) discuss a method of setting cement plug in a wellbore to cover lost circulation zones. This type of plug is typically set in the open hole using drill pipe that is run to just above the LC zone. The cement is pumped and the plug is then drilled through leaving the LC zone sealed off during the rest of the drilling. This technique produces poor plug quality due to incomplete coverage and slurry dehydration. To prevent this, they briefly cover slurry design to account for lost circulation. They also discuss placing the end of the drill pipe in the zone, but this risks drilling mud losses and sticking the pipe. To address this issue a tubing release tool (TRT) was devised to run sacrificial fiberglass or aluminum tubing at the end of the drill pipe. It works by running the tubing into the zone and placing the cement across the zone. The fiberglass tubing is released using the TRT and left in the cement. This can later be drilled out. It has been successfully implemented in over 120 wells worldwide. Case histories for single plug, multi-zone P&A, and kick-off plug applications are presented.

OTC 10896 Fine-Grind Cement Aid GOM Plug and Abandonment Operations

Faul et al. (1999) deals with the use of Fine-Grind cement (FGC)(particle size <5mm) to squeeze and plug off wells with a gravel pack. The authors feel that the use of this FGC improves the chance of a successful squeeze to abandon gravel pack. Conventional cements typically consist of particles that are too large to penetrate into the formation or even into the gravel pack. This results in the gravel pack not being sealed off completely. This results in multiple remedial jobs. Case histories cite several examples where a FGC was used in place of a standard cement type. In these cases the gravel packs were sealed successfully after one attempt.

OTC 14283 Developed Wellbore Abandonment Grout with Fly Ash

Cho et al. (2002) deals with the use of Class C flyash as a slurry or part of a slurry in place of standard fly ash. The paper studies the characteristics of the flyash slurries with regard to TTT, CS, FW and other analytical tests. There were no data or case histories where these slurries were used in a well.

USMS 019382 Offshore North Dakota

O'Neil et al. (1989) describes a 40yr history of a well. The well was originally drilled on land at the same time a dam was being built nearby. After completion of the dam, the area where the well was found, was turned into a reservoir. The paper more deals with the planning stages of being able to plug the well, ie how to get to it and what equipment could be used. Only mentions that class G cement was used to set abandonment plugs and a retainer was used as well.

API 62-072 Bonding Studies of Cementing Compositions to Pipe and Formations (Evans and Carter, 1962)

Evans and Carter (1962) examine the shear and hydraulic bonding of oil-well cementing compositions through laboratory testing on cement-pipe and cement-formation interfaces under varying conditions.

Shear bond is defined as the bond which mechanically supports pipe in the hole. Hydraulic bond is defined as the ability of cement to prevent fluid communication. Factors that were found to affect the bond of the cement to casing include curing temperature, condition of the pipe, and variation between cement brands within a given API class.

Hydraulic failure of the bond did not vary with pipe length, but the length of time before failure is observed increases for longer pipe lengths. Pipe diameter was also found to have no apparent effect on hydraulic bond strength. It was found that the pressures at which hydraulic failure occur at the bonded interface depended upon the viscosity of the pressuring fluid, with lower viscosity fluids requiring lower pressure for communications to occur. The surface finish of the inside of the pipe was found to affect bonding strength, with new mill-finished pipe generally exhibiting the lowest bond strength and used rusty pipe having the highest bond strength. Hydraulic bond strength at the cement-pipe interface were governed by surface finish, type of mud wetting, and degree of mud removal. Lack of mud removal was found to be more detrimental to cement-formation bonding than cement-pipe bonding, with the ease of mud removal on the pipe surface considered to be the reason for this. The shear bond values were reduced by a factor of 3 or greater if a water-based mud coating is not removed prior to placing cement.

Hydraulic bond was found to be dependent upon intimate contact of cement to formation, with the maximum reduction in hydraulic bonding caused by a mud layer at the cement-pipe or cement-formation interface. Higher bond strengths were exhibited on more permeable formations since the cement slurry can be better dehydrated against a permeable formation, resulting in higher strength cement. Bonds attained on dry cores approached or exceeded formation strengths.

Correlations were found to exist between compressive strength and shear bond on dry pipe, while no fixed correlation was found between either shear bond or compressive strength and hydraulic bond to pipe. Low hydraulic bond strengths exhibited at the cement-pipe interface were found to be a function of the resiliency of the pipe. Shut in pressure during cement setting was found to reduce bond at the cement-pipe interface after pressure was released. The most effective cement bonds were obtained when effective mud removal practices were utilized.

OTC 7478 Planning for Abandonment

Bartlett et al. (1994) explains how operators can never start too early planning for abandonment; he says that the abandonment plans should be part of the process of planning development of a field. He doesn't really go into any additional detail or case studies.

#530-G <-> A New Retrievable Wire Line Cementing Tool

Caldwell et al. (1955) describes the use of a wire line tool which utilizes gases from the burning of a high energy propellant to expand a rubber packer and shears and aluminum retaining plug from the bottom of the cement container, forcing cement into the desired position. The complete tool with the exception of the small aluminum plug and gun seal is retrieved from the well. He explains though that it is imperative that no fluid or gas, which would agitate the placed cement, enter the well during the operation.

OTC 7479 A Multiple Well Abandonment Program: Methodology and Techniques

Matkowski et al. (1994) discuss the approach they took in abandoning multiple offshore wells. The four techniques of reservoir isolation they evaluated were bullhead cement, rig driven abandonment, a snubbing unit, and coiled tubing. The coiled tubing was determined to be the safest and most cost effective as well the best quality cementing process of the four. First they placed a column of cement across perforated intervals and brought it up to the production packer. Another cement plug was placed above the production packer which provided a second barrier inside the tubing in addition to the annulus.

JCPT 764 – A Study of Cement-Pipe Bonding

Carter et al. (1964) deals with the lab testing of cement-pipe bonding as it relates to oilfield use. They compared different types of pipe with different types of finishes by performing shear and hydraulic bonding testing. In summary, they determined that hydraulic and shear bond increase with pipe surface roughness, the viscosity of the pressuring fluid will increase bond failure pressure as viscosity increases, oil-wet pipe surfaces reduce hydraulic and shear bond strength of cement to pipe, as well as a few other things. This paper mostly deals with primary cementing.

JCPT 80-01-0 – Obtaining Open-Hole Cement Plugs on the First Attempt

Salahub et al. (1980) describes in detail the three main ways to set a plug for any purposes, though it mostly focuses on open-hole plug placement. The three methods described are the balanced method, the dump bailer method, and the two plug method. There really is nothing about testing the plugs to make sure they hold a seal, but they do summarize by stating that by pre-conditioning the drilling fluid, using the two-plug method, preceding the cement with the correct spacer fluid, mixing the cement with minimum water, accurately placing the slurry, using the plug catcher to eliminate the chance of error and allowing sufficient time for the cement to set, the common problems and costly delays associated with setting cement plugs can be avoided.

JCPT 00-05-01 – Drake F-76, In Situ Abandonment of a High Arctic Offshore Completion and Facilities

Duguid et al. (2000) deals with the abandonment of live wells in the artic from a floating ice platform. It gives very detailed descriptions of the entire process. There is nothing about testing the cement plugs and very little about how they placed the cement plugs.

US Patents

US Patent 6802375 B2 Method for Plugging a Well with a Resin

Martin Gerard Rene Bosma, Erik Kerst Cornelissen & Alexander Schwing (2004) patented a method of using resin for primary, remedial, and P&A operations in wells. The resin is cured at a reduced temperature by cooling the well first then allowing it to heat up to BHST. The resin compensates for shrinkage during the curing process and prevents microannulus formation. The patent also covers laboratory methods of chemical and mechanical analysis of the resin. The key advantages of the resin over cement include a better seal because of less shrinkage, ability to penetrate and seal smaller cracks, more chemically stable against wellbore fluids, and improved mechanical properties. Suitable resins must have certain thermal expansion properties during the curing process to be successful. Different resins such as elastomeric thermoset resins and ureum, phenol and melamine formaldehyde resins can be used with this well cooling technique.

US Patent 7607483 B2 – Sealant Compositions Comprising Colloidally Stabilized Latex and Methods of Using the Same

Reddy et al. (2009) describe a latex additive that can be used to prevent lost circulation while drilling and gas migration while cementing. Previous latex additives required the addition of costly stabilizing surfactants to be salt tolerant. The new additive does not require stabilizing surfactants to be salt tolerant like previous latex additives. This additive also improves compressive and tensile strengths of cement (both neat and pozzolan blends), and will create a material capable of curing lost circulation when mixed with drilling mud. Cement slurries made with this additive have acceptable fluid loss (higher than those made with LATEX 2000 from HES).

US Patent 6595289 Method and apparatus for plugging a wellbore

Tumlin et al. (2003) describes an invention dealing with casing perforation and squeezing of cement in a single trip. The device consists of a perforation gun and cement retainer. The entire device is run in. First, the retainer is set. Next the perforating gun is discharged. Finally, casing is cemented through the retainer.

US Patent 5667010 Process and Plug for Well Abandonment

Boyd et al. (1997) discusses a viscous plug that is not cement. The material will remain viscous downhole. As the plug doesn't "set", it can flow to permeable areas and plug these areas.

US Patent 6767398 B2 – Cementitious Compositions and Cementitious Slurries for Permanently Plugging abandoned Wells and Processes and Methods Therefor

Trato (2004) covers the use of cement kiln dust (CKD) as an additive in cement. It will help lower the cost of cement in placing a plug while still providing the properties required by API other regulatory bureaus.

US Patent 3572438 Process of Plugging Perforations in a Well Casing (Rohe, 1971)

Rohe (1971) describes a process for plugging perforation in which a slug of cement is pumped through tubing and forced through existing perforations into the formation. When all of the cement has been pumped through the perforations and the displacing fluid begins to flow into the formation, the pressure in the well decreases. At this point pumping may be stopped and a measure amount of liquid withdrawn from the well to force a portion of the cement back out through the perforations. Before all of the cement is forced out, pressure is held on the well long enough for the cement to set up and the casing is therefore plugged precisely at the point of the old perforations.

US Patent 5330006 Oil Mud Displacement with Blast Furnace Slag/Surfactant

Nahm et al. (1994) invents a cement slurry containing blast furnace slag and a surfactant which is utilized to displace an oil based drilling fluid without causing contamination by the blast furnace slag cement.

US Patent 4043394 Plugging of Abandoned Dry Wells

Campbell (1977) invents a method of checking where the top of cement is in a plugging operation using wire line tools. The cement plug is placed and a selected portion of the cement, treated with a radioactive tracer, is injected to provide a layer of treated cement at the top of the plug with the probe output being recorded graphically to provide a record of the position of the plug top in a dry well.

US Patent 4607694 Well Plug Quality Testing

Sah (1986) invents the method of testing cement plug contamination after plug placement. His method involves lowering a densometer into the well bore and through the cement to measure the variation in plug density prior to the cement setting up downhole.

US Patent 6196316B1 Compositions for Use in Well Construction, Repair and/or Abandonment

Bosma et al. (2001) Invent a method for plugging wells using an addition-curing silicone formulation. This new method creates inherently better gas tight plugs and supplements already placed cement plugs which are leaking gas.

US Patent 3713486 Method of Plugging Back a Well

Meitzen (1973) filed a patent for a method of plugging tubingless wells cased with small diameter pipe. The method involved lowering a tubing stop and flow restrictor by wireline to just above the perforated interval to be plugged, then lowering a squeeze cement slurry followed by a cement wiper plug and displacing until the wiper plug bumps the tubing stop. Pressure is held to allow the cement to set.

US Patent 4462714 Method and Apparatus for Setting a Cement Plug in the Wide-Mouth Shaft of and Earth Cavern

Smith et al. (1984) filed a patent for a method and apparatus of setting a cement plug around an unsupported casing in a wide-mouth cavern. It involved lowering a deflated balloon into the cavern below the bottom of the casing, inflating the balloon, then filling the space above the balloon with cement. The balloon seats against the walls of the cavern and provides support for the set cement.

US Patent 5368103 – Method of Setting a Balanced Cement Plug in a Borehole

Heathman et al. (1994) describes a method to place a cement plug in an open-hole using a balanced placement method. This method involves flushing the mud with spacer and then placing a cement plug in place using a small diameter tubing. Cement is pumped through this tubing until the levels inside and outside the tubing are equal. The pipe is then pulled out slowly while backflushing the pipe. This allows the plug to be put in place with minimum disturbance. The plug will also have less of a chance to become contaminated by chemicals in the mud. The plug will be used for kickoff purposes.

US Patent Applications

US Patent Application 2009/0301720 A1 Remote Plugging Device

Jonathan Paul Edwards & Alexander Jeffrey Burns (2009) patented a remote cement plugging device and method of use. The tool can perforate through tubing and inject cement into the annulus of two casings. The perforating mechanism is powered by hydraulic or pneumatic pressure. This tool provides single trip method for perforating and cement placement. It can be used for a variety of cementing operations including P&A to reduce time and costs.

US Patent Application US 2009/0298724 A1 – Method for Applying Remedial Cement to a Wellbore

Getzlaf et al. (2009) describe a method of placing a cement slurry across a permeable zone. First, an activator (phosphoric acid) is squeezed into the permeable zone followed by an aqueous solution of a microfine silicate material (flyash, silica fume, microfine slag). These two substances mix within the formation and form a rapid setting cement slurry. Neither substance has any cementitious properties by itself. This allows for accurate placement of a cement slurry across a permeable zone while minimizing risk of leaving cement inside tubing or casing.

US Patent Application US 2003/0056953 A1 – Method and Apparatus for Plugging a Wellbore

Tumlin et al. (2003) describe a tool that is run in below a cement retainer that contains perforating charges. The charges are detonated, the retainer is set, and cement is squeezed through the retainer into the perforations. The perforating 'gun' is left inside of the cement plug. This method saves the time and cost associated with tripping in and out of the hole with a wireline perforating gun.

US Patent Application US2010/0258312 A1 Methods of Plugging and Abandoning a Well Using Compositions Comprising Cement Kiln Dust and Pumicite (Brenneis et al, 2010)

Brenneis et al. (2010) describe the use of novel plugging compositions for use in plug and abandonment operations. The plugging composition comprises cement kiln dust in an amount of 5-100% by weight of cementitious components, pumicite in an amount of 5-100% by weight of cementitious components, 0-24% Portland cement by weight of cementitious components, and water, allowing the plugging composition to set and form a plug. Potential advantages of the embodiments presented include reducing the amount of or eliminating higher cost additives such as Portland cement and reducing the carbon footprint of the plug and abandon operation.

US Patent Application #US2004/0256102A1 Cementitious Compositions and Cementitous Slurries for Permanently Plugging Abandoned Wells and Processes and Methods Therefor

Trato (2004) claims invention of blended cement that contains Portland cement and cement kiln dust in specified ratios. The cement blend has higher compressive strengths and generally lower permeability than regular Portland cement giving it better set properties relating to P&A operations.

US Patent Application US 2008/0264637 A1 - Surface Mixing of Encapsulated Plug Components for Well Remediation

Burts et al. (2008) proposes a two part encapsulated cementing system that is mixed at surface and then placed downhole in a method of remediating an active well. This mixture is then allowed to degrade in the well fluid allowing for the formation of a cement plug. Accelerated set times are less than 12 hours but preferably less. The method of placement entails initially placing Component A into the well to be followed by Component B which is then allowed to gravity flow into Component A; both of which may be placed with a dump bailer, coiled, and or jointed tubing. The components need to be placed on a solid base such as a packer, petal basket, or sand plug.

US Patent Application US 2010/0006289 A1 - Method and Apparatus for Sealing Abandoned Oil and Gas Wells

Spencer (2010) proposes an apparatus and method for forming a solid sealing plug of bismuth-tin alloy material within a well casing for sealing oil or gas wells. A solid alloy material is positioned within a heating tool and lowered to a position within the well casing where the seal/plug is to be formed. The heating tool is heated to liquefy the alloy which then runs out of the tool and solidifies on top of a cement plug previously formed within the casing. A cement slurry or other fluid can then be placed on top of the liquefied alloy to enhance the sealing of the plug which forms a barrier that aids in counteracting any pressure acting vertically on the bottom of the plug.

Appendix B: Laboratory Data

Cement Blend Compositions at Different Temperatures

Neat Cement Blends

CSI Technologies

RLS0116C - 1

Laboratory Cement Test Report

Test Date:	January 00, 1900	Depth MD (ft):	200	Job Size / Type	Plug
Project No:	RLS0116C - 1	Depth TVD (ft):	200	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	80	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	80	Test Schedule	Squeeze - 9.26
Operator:	BSEE	Temp. Grad. (°F/100ft):	-	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	940	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): 16.4 Slurry Yield (ft^3/sk): 1.08 Total Mixing Fluid (gal/sk): 4.47

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.470	gal/sk	Lab Stock

Test Results

Measured Density
Cement (lb/gal): 16.4

Desired Thickening Time More than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
80	3:18	4:37	hrs:mins

Desired Fluid Loss 0.00

Static Fluid Loss

Test Temp (°F):	80
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Desired Free Fluid ≤ 1%

Free Fluid

Conditioning Temp. (°F):	80
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Compressive Strength

Test Temperature (°F): 80

50	psi at	4:37	hrs:mins
500	psi at	9:54	hrs:mins
711	psi at	12:00	hrs:mins
1,672	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	92	80	66	60	60	44	22	38	58		
100 %	80	100	92	76	70	60	28	18	43	64	24	24
									cP	lb/100ft²	lb/100ft²	

Comments / Recommendations:

Project Coordinator: Eric Evans

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Neat Cement Blend at 80F

CSI Technologies

RLS0116C - 2

Laboratory Cement Test Report

Test Date:	January 00, 1900	Depth MD (ft):	0	Job Size / Type	Plug
Project No:	RLS0116C - 2	Depth TVD (ft):	3,325	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	120	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	103	Test Schedule	Squeeze - 9.27
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	1,960	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.47**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.470	gal/sk	Lab Stock

Test Results

Desired Thickening Time More than 2hr

Measured Density

Cement (lb/gal): 16.4

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
103	1:43	2:12	hrs:mins

Desired Free Fluid < 1%

Free Fluid

Conditioning Temp. (°F):	103
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss 0.00

Static Fluid Loss

Test Temp (°F):	103
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 120

50	psi at	3:01	hrs:mins
500	psi at	5:12	hrs:mins
1,737	psi at	12:00	hrs:mins
2,733	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	90	74	60	50	32	20	16	58	37		
100 %	103	106	96	76	72	58	26	24	51	62	26	26
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Neat Cement Blend at 120F

CSI Technologies

RLS0116C - 3.2

Laboratory Cement Test Report

Test Date:	January 00, 1900	Depth MD (ft):	9,200	Job Size / Type	Plug
Project No:	RLS0116C - 3.2	Depth TVD (ft):	9,200	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	190	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	162	Test Schedule	Squeeze - 9.30
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	5,200	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.48**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.450	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Retarder	Cement Liq Retarder	0.040	gal/sk	Lab Stock

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time — **More than 2hr**

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
162	3:55	**4:05**	hrs:mins

Desired Free Fluid < 1%

Free Fluid

Conditioning Temp. (°F):	162
Test Angle:	Vertical
Measured Free Fluid (ml):	3.0
Free Fluid (%):	1.2

Desired Fluid Loss 0.00

Static Fluid Loss

Test Temp (°F):	162
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 190

psi		time	
50	psi at	17:24	hrs:mins
500	psi at	20:37	hrs:mins
	psi at	12:00	hrs:mins
1,319	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	65	48	31	26	20	13	10	50	16		
100 %	162	126	112	93	84	64	24	17	63	71	20	24
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Neat Cement Blend at 190F

CSI Technologies

RLS0116C - 4.4

Laboratory Cement Test Report

Test Date:	January 00, 1900	Depth MD (ft):	13,300	Job Size / Type	Plug
Project No:	RLS0116C - 4.4	Depth TVD (ft):	13,300	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	240	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	208	Test Schedule	Squeeze - 9.32
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	7,510	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.42** Total Mixing Fluid (gal/sk): **5.56**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	5.520	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Retarder	Cement Liq Retarder	0.035	gal/sk	Lab Stock
Silica	Silica Flour	35.000	%bwoc (DB)	Lab Stock

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time — More than 2hr

Total Thickening Time - Cement

BHCT (°F):	40 Bc	70 Bc	
208	2:57	3:05	hrs:mins

Desired Free Fluid < 1%

Free Fluid

Conditioning Temp. (°F):	190
Test Angle:	Vertical
Measured Free Fluid (ml):	4.0
Free Fluid (%):	1.6

Desired Fluid Loss 0.00

Stirred Fluid Loss

Test Temp (°F):	208
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 240

50	psi at	2:29	hrs:mins
500	psi at	3:09	hrs:mins
2,787	psi at	12:00	hrs:mins
3,218	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	100	79	70	54	39	22	13	61	43		
100 %	190	64	62	43	39	32	19	12	37	33	7	10
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Neat Cement Blend at 240F

Latex Cement Blends

CSI Technologies

RLS0116C - 15.3

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	200	Job Size / Type	Plug
Project No:	RLS0116C - 15.3	Depth TVD (ft):	200	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	80	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	80	Test Schedule	Squeeze - 9.26
Operator:	BSEE	Temp. Grad. (°F/100ft):	-	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	940	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.46**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	2.950	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Gas Migration	Latex Additive	1.500	gal/sk	C-1746C
Anti Foam	Antifoam Additive	0.010	gal/sk	Lab Stock

Test Results

Measured Density
Cement (lb/gal): 16.4

Desired Thickening Time: More than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
80	2:26	4:16	hrs:mins

Desired Free Fluid: < 1%

Free Fluid

Conditioning Temp. (°F):	80
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss: <50API

Static Fluid Loss

Test Temp (°F):	80
Collected Fluid (ml):	12
Collection Time (min):	30
API Fluid Loss (ml/30min):	24
Calculated API (ml/30min):	

Compressive Strength

Test Temperature (°F): 80

psi		time	
50	psi at	6:08	hrs:mins
500	psi at	15:00	hrs:mins
354	psi at	12:00	hrs:mins
887	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	118	104	88	79	67	27	23	54	71		
100 %	80	164	147	122	111	102	36	27	69	104	34	36
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Latex Cement Blend at 80F

CSI Technologies

RLS0116C - 16.2

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	3,325	Job Size / Type	Plug
Project No:	RLS0116C - 16.2	Depth TVD (ft):	3,325	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	120	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	103	Test Schedule	Squeeze - 9.27
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	1,960	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.47**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	3.460	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Gas Migration	Latex Additive	1.000	gal/sk	C-1746C
Anti Foam	Antifoam Additive	0.010	gal/sk	Lab Stock

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time: More than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
103	1:35	2:23	hrs:mins

Desired Free Fluid: < 1%

Free Fluid

Conditioning Temp. (°F):	103
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss: <50API

Static Fluid Loss

Test Temp (°F):	103
Collected Fluid (ml):	8
Collection Time (min):	30
API Fluid Loss (ml/30min):	16
Calculated API (ml/30min):	

Compressive Strength

Test Temperature (°F): 120

psi		time	
50	psi at	5:00	hrs:mins
500	psi at	8:52	hrs:mins
450	psi at	12:00	hrs:mins
1,199	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	134	114	92	80	68	36	28	71	69		
100 %	103	196	172	142	128	104	32	22	96	111	26	38
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Latex Cement Blend at 120F

CSI Technologies

RLS0116C - 18.3

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	9,200	Job Size / Type	Plug
Project No:	RLS0116C - 18.3	Depth TVD (ft):	9,200	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	190	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	158	Test Schedule	Squeeze - 9.27
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	5,200	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.48**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	2.780	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Gas Migration	Latex Additive	1.500	gal/sk	C-1746C
Anti Foam	Antifoam Additive	0.010	gal/sk	Lab Stock
Retarder	Cement Liquid Retarder	0.040	gal/sk	Lab Stock
.atex Stabilize	Latex Stabilizer	0.100	gal/sk	R-1381
Dispersant	Cement Dispersant	0.050	gal/sk	Lab Stock

Test Results

Desired Thickening Time — **More than 2hr**

Total Thickening Time - Cement

BHCT (°F):	40 Bc	70 Bc	
158	2:14	**2:25**	hrs:mins

Measured Density

Cement (lb/gal): 16.4

Desired Free Fluid ≤ 1%

Free Fluid

Conditioning Temp. (°F):	158
Test Angle:	Vertical
Measured Free Fluid (ml):	1.0
Free Fluid (%):	

Desired Fluid Loss <50API

Static Fluid Loss

Test Temp (°F):	158
Collected Fluid (ml):	9
Collection Time (min):	30
API Fluid Loss (ml/30min):	**18**
Calculated API (ml/30min):	

Compressive Strength

Test Temperature (°F): 190

50	psi at	2:44	hrs:mins
500	psi at	5:54	hrs:mins
1,107	psi at	12:00	hrs:mins
1,743	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	86	58	45	35	27	16	13	62	23		
100 %	158	94	83	67	63	59	45	39	40	59	37	43
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

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Latex Cement Blend at 190F

CSI Technologies

RLS0116C - 19.3

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	13,300	Job Size / Type	Plug
Project No:	RLS0116C - 19.3	Depth TVD (ft):	13,300	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	240	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	208	Test Schedule	Squeeze - 9.27
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	7,510	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.42** Total Mixing Fluid (gal/sk): **5.55**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	3.850	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Gas Migration	Latex Additive	1.500	gal/sk	C-1746C
Anti Foam	Antifoam Additive	0.010	gal/sk	Lab Stock
Retarder	Cement Liquid Retarder	0.040	gal/sk	Lab Stock
Silica	Silica Flour	35.000	%bwoc (DB)	Lab Stock
.atex Stabilize	Latex Stabilizer	0.100	gal/sk	R-1381
Dispersant	Cement Dispersant	0.050	gal/sk	Lab Stock

Test Results

Measured Density
Cement (lb/gal): 16.4

Desired Thickening Time More than 2hr
Total Thickening Time - Cement

BHCT (°F):	40 Bc	70 Bc	
208	2:15	**3:33**	hrs:mins

Desired Free Fluid < 1%
Free Fluid

Conditioning Temp. (°F):	190
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss
Stirred Fluid Loss

Test Temp (°F):	208
Collected Fluid (ml):	34
Collection Time (min):	2
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	**263**

Compressive Strength

Test Temperature (°F): 240

50	psi at	2:04	hrs:mins
500	psi at	3:45	hrs:mins
1,119	psi at	12:00	hrs:mins
1,369	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV (cP)	YP (lb/100ft^2)	Gel Strength 10 sec (lb/100ft^2)	Gel Strength 10 min (lb/100ft^2)
Cement	80	162	128	92	78	66	44	34	106	60		
100 %	190	212	182	148	134	120	66	54	101	120	44	50

Comments / Recommendations:

Project Coordinator: Eric Evans

Latex Cement Blend at 240F

GMA Cement Blends

CSI Technologies

RLS0116C - 5.5

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	200	Job Size / Type	Plug
Project No:	RLS0116C - 5.5	Depth TVD (ft):	200	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	80	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	80	Test Schedule	Squeeze - 9.26
Operator:	BSEE	Temp. Grad. (°F/100ft):	-	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	940	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.50**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.300	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Fluid Loss	Liquid GMA	0.200	gal/sk	R-1290A

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time More than 2hr

Total Thickening Time - Cement

	40 Bc	70 Bc	
BHCT (°F): 80	3:05	3:51	hrs:mins

Desired Free Fluid < 1%

Free Fluid

Conditioning Temp. (°F):	80
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss 0.00

Static Fluid Loss

Test Temp (°F):	80
Collected Fluid (ml):	24
Collection Time (min):	30
API Fluid Loss (ml/30min):	48
Calculated API (ml/30min):	

Compressive Strength

Test Temperature (°F): 80

50	psi at	7:37	hrs:mins
500	psi at	11:56	hrs:mins
508	psi at	12:00	hrs:mins
1,780	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	136	106	68	51	36	22	18	111	30		
100 %	80	138	107	73	55	39	21	16	108	35	14	34
									cP	lb/100ft^2		lb/100ft^2

Comments / Recommendations:

Project Coordinator: Eric Evans

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GMA Cement Blend at 80F

CSI Technologies

RLS0116C - 6.2

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	3,325	Job Size / Type	Plug
Project No:	RLS0116C - 6.2	Depth TVD (ft):	3,325	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	120	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	103	Test Schedule	Squeeze - 9.27
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	1,960	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.50**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.300	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Fluid Loss	Liquid GMA	0.200	gal/sk	R-1290A

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time — **More than 2hr**

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
103	2:01	**2:02**	hrs:mins

Desired Free Fluid < 1%

Free Fluid

Conditioning Temp. (°F):	103
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss 0.00

Static Fluid Loss

Test Temp (°F):	103
Collected Fluid (ml):	17
Collection Time (min):	30
API Fluid Loss (ml/30min):	**34**
Calculated API (ml/30min):	

Compressive Strength

Test Temperature (°F): 120

psi		time	
50	psi at	4:35	hrs:mins
500	psi at	7:05	hrs:mins
1,281	psi at	12:00	hrs:mins
2,178	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	134	100	63	44	27	10	7	117	21		
100 %	103	133	102	71	42	25	9	7	117	22	7	10
									cP	lb/100ft²	lb/100ft²	

Comments / Recommendations:

Project Coordinator: Eric Evans

GMA Cement Blend at 120F

CSI Technologies

RLS0116C - 7.1

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	9,200	Job Size / Type	Plug
Project No:	RLS0116C - 7.1	Depth TVD (ft):	9,200	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	190	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	162	Test Schedule	Squeeze - 9.30
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	5,200	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.51**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.260	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Fluid Loss	Liquid GMA	0.250	gal/sk	R-1290A

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time — More than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
162	4:03	4:10	hrs:mins

Desired Free Fluid ≤ 1%

Free Fluid

Conditioning Temp. (°F):	162
Test Angle:	Vertical
Measured Free Fluid (ml):	6.0
Free Fluid (%):	2.4

Desired Fluid Loss 0.00

Static Fluid Loss

Test Temp (°F):	162
Collected Fluid (ml):	15
Collection Time (min):	30
API Fluid Loss (ml/30min):	30
Calculated API (ml/30min):	

Compressive Strength

Test Temperature (°F): 190

psi		time	
50	psi at	11:28	hrs:mins
500	psi at	15:02	hrs:mins
108	psi at	12:00	hrs:mins
2,129	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	128	96	56	36	20	8	6	119	13		
100 %	162	122	90	52	36	20	6	6	112	13	6	6
									cP	lb/100ft²		lb/100ft²

Comments / Recommendations:

Project Coordinator: Eric Evans

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GMA Cement Blend at 190F

CSI Technologies

RLS0116C - 8.2

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	13,300	Job Size / Type	Plug
Project No:	RLS0116C - 8.2	Depth TVD (ft):	13,300	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	240	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	208	Test Schedule	Squeeze - 9.32
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	7,510	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.43** Total Mixing Fluid (gal/sk): **5.59**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	5.290	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Retarder	Cement Liq Retarder	0.035	gal/sk	Lab Stock
Fluid Loss	Liquid GMA	0.264	gal/sk	R-1290A
Silica	Silica Flour	35.000	%bwoc (DB)	Lab Stock

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time — More than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
208	5:41	**6:12**	hrs:mins

Desired Free Fluid — ≤ 1%

Free Fluid

Conditioning Temp. (°F):	190
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss

Stirred Fluid Loss

Test Temp (°F):	208
Collected Fluid (ml):	71
Collection Time (min):	11
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	**234**

Compressive Strength

Test Temperature (°F): 240

psi		time	
50	psi at	3:05	hrs:mins
500	psi at	4:24	hrs:mins
1,796	psi at	12:00	hrs:mins
2,316	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV (cP)	YP (lb/100ft²)	Gel Strength 10 sec (lb/100ft²)	Gel Strength 10 min (lb/100ft²)
Cement	80	192	138	80	54	34	12	8	175	20		
100 %	190	146	110	70	50	34	16	14	123	27	14	20

Comments / Recommendations:

Project Coordinator: Eric Evans

GMA Cement Blend at 240F

Surfactant Cement Blends

CSI Technologies

RLS0116C - 9

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	200	Job Size / Type	Plug
Project No:	RLS0116C - 9	Depth TVD (ft):	200	Well Fluid Density (lb/gal):	8.5
Company:	NA	BHST (°F):	80	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	80	Test Schedule	Squeeze - 9.26
Operator:	BSEE	Temp. Grad. (°F/100ft):	.	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	940	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.47**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.420	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Surfactant	Cement Surfactant	0.050	gal/sk	C-1746B

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time — **More Than 2hr**

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
80	3:18	4:37	hrs:mins

Desired Free Fluid — **≤ 1%**

Free Fluid

Conditioning Temp. (°F):	80
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss — **NA**

Static Fluid Loss

Test Temp (°F):	80
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 80

psi		time	
50	psi at	4:37	hrs:mins
500	psi at	9:54	hrs:mins
711	psi at	12:00	hrs:mins
1,672	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	90	78	56	50	38	28	18	57	39		
100 %	80	80	66	56	44	38	24	20	45	39	18	18
									cP	lb/100ft²	lb/100ft²	

Comments / Recommendations:

Project Coordinator: Eric Evans

Surfactant Cement Blend at 80F

CSI Technologies

RLS0116C - 9

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	3,325	Job Size / Type	Plug
Project No:	RLS0116C - 9	Depth TVD (ft):	3,325	Well Fluid Density (lb/gal):	8.5
Company:	NA	BHST (°F):	120	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	80	Test Schedule	Squeeze - 9.26
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	940	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.08** Total Mixing Fluid (gal/sk): **4.47**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.420	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Surfactant	Cement Surfactant	0.050	gal/sk	C-1746B

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time	More Than 2hr		
Total Thickening Time - Cement	40 Bc	70 Bc	
BHCT (°F): 80	7:16	7:39	hrs:mins

Desired Free Fluid < 1%

Free Fluid

Conditioning Temp. (°F):	80
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss NA

Static Fluid Loss

Test Temp (°F):	80
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 120

50	psi at	3:14	hrs:mins
500	psi at	6:08	hrs:mins
1,153	psi at	12:00	hrs:mins
1,678	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	86	67	47	38	30	17	11	62	27		
100 %	80	74	59	43	37	30	20	13	48	28	12	13
									cP	lb/100ft²	lb/100ft²	

Comments / Recommendations:

Project Coordinator: Eric Evans

Surfactant Cement Blend at 120F

CSI Technologies

RLS0116C - 10

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	9,200	Job Size / Type	Plug
Project No:	RLS0116C - 10	Depth TVD (ft):	9,200	Well Fluid Density (lb/gal):	8.5
Company:	NA	BHST (°F):	190	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	162	Test Schedule	Squeeze - 9.30
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	5,250	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): 16.4 Slurry Yield (ft^3/sk): 1.08 Total Mixing Fluid (gal/sk): 4.48

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.390	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Surfactant	Cement Surfactant	0.050	gal/sk	C-1746B
Retarder	Cement Liq Retarder	0.040	gal/sk	Lab Stock

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time More Than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
162	7:07	1:16	hrs:mins

Desired Free Fluid < 1%

Free Fluid

Conditioning Temp. (°F):	162
Test Angle:	Vertical
Measured Free Fluid (ml):	0.0
Free Fluid (%):	0.0

Desired Fluid Loss NA

Static Fluid Loss

Test Temp (°F):	162
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 190

50	psi at	23:11	hrs:mins
500	psi at	26:54	hrs:mins
3	psi at	12:00	hrs:mins
72	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	74	58	36	32	24	20	16	56	21		
100 %	162	74	64	58	40	44	30	24	36	42	22	22
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Surfactant Cement Blend at 190F

CSI Technologies

RLS0116C - 17.2

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	13,300	Job Size / Type	Plug
Project No:	RLS0116C - 17.2	Depth TVD (ft):	13,300	Well Fluid Density (lb/gal):	8.5
Company:	NA	BHST (°F):	240	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	208	Test Schedule	Squeeze - 9.26
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	7,580	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.42** Total Mixing Fluid (gal/sk): **5.56**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	5.470	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Surfactant	Cement Surfactant	0.050	gal/sk	C-1746B
Retarder	Cement Liq Retarder	0.035	gal/sk	Lab Stock
Silica	Silica Flour	35.000	%bwoc (DB)	Lab Stock

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time >2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
208	3:43	3:54	hrs:mins

Free Fluid

Conditioning Temp. (°F):	190
Test Angle:	Vertical
Measured Free Fluid (ml):	7.0
Free Fluid (%):	2.8

Stirred Fluid Loss

Test Temp (°F):	208
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 240

50	psi at	3:39	hrs:mins
500	psi at	4:36	hrs:mins
1,389	psi at	12:00	hrs:mins
1,733	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	196	152	104	84	64	26	22	145	57		
100 %	190	162	140	112	96	72	32	9	94	78	26	32
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

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Surfactant Cement Blend at 240F

Expanding Cement Blends

CSI Technologies

RLS0116C - 14

Laboratory Cement Test Report

Test Date:	January 00, 1900	Depth MD (ft):	200	Job Size / Type	Plug
Project No:	RLS0116C - 14	Depth TVD (ft):	200	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	80	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	80	Test Schedule	Squeeze - 9.26
Operator:	BSEE	Temp. Grad. (°F/100ft):	-	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	940	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.13** Total Mixing Fluid (gal/sk): **4.64**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.640	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
elerator/Expan	Gypsum	5.000	%bwoc (PH)	R-1280

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time More than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
80	4:21	5:18	hrs:mins

Desired Free Fluid ≤ 1%

Free Fluid

Conditioning Temp. (°F):	80
Test Angle:	Vertical
Measured Free Fluid (ml):	4.0
Free Fluid (%):	

Desired Fluid Loss 0.00

Static Fluid Loss

Test Temp (°F):	80
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 80

psi		time	
50	psi at	7:10	hrs:mins
500	psi at	14:28	hrs:mins
329	psi at	12:00	hrs:mins
1,092	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	114	100	86	76	67	34	30	50	70		
100 %	80	164	139	108	98	78	39	33	91	80	32	36
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Expanding Cement Blend at 80F

CSI Technologies

RLS0116C - 12

Laboratory Cement Test Report

Test Date:	January 00, 1900	Depth MD (ft):	3,325	Job Size / Type	Plug
Project No:	RLS0116C - 12	Depth TVD (ft):	3,325	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	120	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	103	Test Schedule	Squeeze - 9.27
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	1,960	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.13** Total Mixing Fluid (gal/sk): **4.64**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.640	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
elerator/Expan	Gypsum	5.000	%bwoc (PH)	R-1280

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time: More than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
103	1:42	2:33	hrs:mins

Desired Free Fluid ≤ 1%

Free Fluid

Conditioning Temp. (°F):	103
Test Angle:	Vertical
Measured Free Fluid (ml):	3.0
Free Fluid (%):	1.2

Desired Fluid Loss 0.00

Static Fluid Loss

Test Temp (°F):	103
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 120

psi		time	
50	psi at	2:57	hrs:mins
500	psi at	5:55	hrs:mins
1,166	psi at	12:00	hrs:mins
1,877	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	136	115	93	77	68	41	30	75	68		
100 %	103	187	161	128	109	82	43	38	110	88	38	48
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

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Expanding Cement Blend at 120F

CSI Technologies

RLS0116C - 11

Laboratory Cement Test Report

Test Date:	January 00, 1900	Depth MD (ft):	9,200	Job Size / Type	Plug
Project No:	RLS0116C - 11	Depth TVD (ft):	9,200	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	190	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	162	Test Schedule	Squeeze - 9.30
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	5,200	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.11** Total Mixing Fluid (gal/sk): **4.64**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	4.600	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Retarder	Cement Liq Retarder	0.040	gal/sk	Lab Stock
Bonding Agent	MagOx M	3.000	%bwoc (PH)	R-1279

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time: More than 2hr

Total Thickening Time - Cement

	40 Bc	70 Bc	
BHCT (°F): 162	1:42	1:56	hrs:mins

Desired Free Fluid: < 1%

Free Fluid

Conditioning Temp. (°F):	162
Test Angle:	Vertical
Measured Free Fluid (ml):	2.0
Free Fluid (%):	0.8

Desired Fluid Loss: 0.00

Static Fluid Loss

Test Temp (°F):	162
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 190

50	psi at	10:43	hrs:mins
500	psi at	12:59	hrs:mins
239	psi at	12:00	hrs:mins
2,451	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	98	80	56	46	37	20	13	68	34		
100 %	162	182	162	115	101	74	42	33	117	78	34	38
									cP	lb/100ft^2	lb/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Expanding Cement Blend at 190F

CSI Technologies

RLS0116C - 13.2

Laboratory Cement Test Report

Test Date:		Depth MD (ft):	13,300	Job Size / Type	Plug
Project No:	RLS0116C - 13.2	Depth TVD (ft):	13,300	Well Fluid Density (lb/gal):	8.4
Company:	NA	BHST (°F):	240	Well Fluid Type	Sea Water
Requestor:	Eric Evans	BHCT (°F):	208	Test Schedule	Squeeze - 9.32
Operator:	BSEE	Temp. Grad. (°F/100ft):	1.2	Spacer Type:	Fresh Water
Well Name:	NA	Test Pressure (PSI):	7,510	Spacer density (lb/gal):	8.5
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal): **16.4** Slurry Yield (ft^3/sk): **1.46** Total Mixing Fluid (gal/sk): **5.72**

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (Lehigh)	94	100	94.00	R-1266

Mix Water	Concentration	Units	CSI Log #
Sea Water	5.680	gal/sk	Lab Stock

Function	Additive	Concentration	Units	CSI Log #
Retarder	Cement Liq Retarder	0.035	gal/sk	Lab Stock
T Bonding Age	Mag-Ox H	3.000	%bwoc (PH)	R-1278
Silica	Silica Flour	35.000	%bwoc (DB)	Lab Stock

Test Results

Measured Density

Cement (lb/gal): 16.4

Desired Thickening Time: More than 2hr

Total Thickening Time - Cement

BHCT (°F)	40 Bc	70 Bc	
208	2:54	3:20	hrs:mins

Desired Free Fluid ≤ 1%

Free Fluid

Conditioning Temp. (°F):	190
Test Angle:	Vertical
Measured Free Fluid (ml):	6.0
Free Fluid (%):	2.4

Desired Fluid Loss 0.00

Stirred Fluid Loss

Test Temp (°F):	208
Collected Fluid (ml):	0
Collection Time (min):	0
API Fluid Loss (ml/30min):	-
Calculated API (ml/30min):	-

Compressive Strength

Test Temperature (°F): 240

50	psi at	2:57	hrs:mins
500	psi at	3:42	hrs:mins
2,501	psi at	12:00	hrs:mins
3,300	psi at	24:00	hrs:mins

Rheological Properties

Fluid / Mixture	Temp °F	300	200	100	60	30	6	3	PV	YP	Gel Strength 10 sec	Gel Strength 10 min
Cement	80	492	380	268	216	168	104	84	354	152		
100 %	190	552	484	400	325	224	120	88	333	260	24	64
									cP	lb$_f$/100ft^2	lb$_f$/100ft^2	

Comments / Recommendations:

Project Coordinator: Eric Evans

Expanding Cement Blend at 240F

8ft Perm Data

Date	Day	Pressure Applied	1	2	3	4	5
2/9/2011	Day 1	100	0	0	0	0	0
2/10/2011	Day 2	100	0	0	0	0	0
2/11/2011	Day 3	100	0	0	0	0	0
2/12/2011	Day 4	100	0	0	0	0	0
2/13/2011	Day 5	100	0	0	0	0	0
2/14/2011	Day 6	100	0	0	0	0	0
2/15/2011	Day 7	100	0	0	0	0	0
2/16/2011	Day 8	100	0	0	0	0	0
2/17/2011	Day 9	100	0	0	0	0	0
2/18/2011	Day 10	100	0	0	0	0	0
2/19/2011	Day 11	100	0	0	0	0	0
2/20/2011	Day 12	100	0	0	0	0	0
2/21/2011	Day 13	100	0	0	0	0	0
2/22/2011	Day 14	100	0	0	0	0	0
2/23/2011	Day 15	100	0	0	0	0	0
2/24/2011	Day 16	100	0	0	0	0	0
2/25/2011	Day 17	100	0	0	0	0	0
2/26/2011	Day 18	100	0	0	0	0	0
2/27/2011	Day 19	100	0	0	0	0	0
2/28/2011	Day 20	100	0	0	0	0	0
3/1/2011	Day 21	100	0	0	0	0	0
3/2/2011	Day 22	100	0	0	0	0	0
3/3/2011	Day 23	100	0	0	0	0	0
3/4/2011	Day 24	100	0	0	0	0	0
3/5/2011	Day 25	100	0	0	0	0	0
3/6/2011	Day 26	100	0	0	0	0	0
3/7/2011	Day 27	100	0	0	0	0	0
3/8/2011	Day 28	100	0	0	0	0	0
3/9/2011	Day 29	100	0	0	0	0	0
3/10/2011	Day 30	100	0	0	0	0	0
3/11/2011	Day 31	100	0	0	0	0	0
3/12/2011	Day 32	100	0	0	0	0	0
3/13/2011	Day 33	100	0	0	0	0	0
3/14/2011	Day 34	100	0	0	0	0	0
3/15/2011	Day 35	100	0	0	0	0	0
3/16/2011	Day 36	100	0	0	0	0	0
3/17/2011	Day 37	100	0	0	0	0	0
3/18/2011	Day 38	100	0	0	0	0	0
3/19/2011	Day 39	100	0	0	0	0	0
3/20/2011	Day 40	100	0	0	0	0	0
3/21/2011	Day 41	100	0	0	0	0	0
3/22/2011	Day 42	100	0	0	0	0	0

3/23/2011	Day 43	100	0	0	0	0	0
3/24/2011	Day 44	100	0	0	0	0	0
3/25/2011	Day 45	100	0	0	0	0	0
3/26/2011	Day 46	100	0	0	0	0	0
3/27/2011	Day 47	100	0	0	0	0	0
3/28/2011	Day 48	100	0	0	0	0	0
3/29/2011	Day 49	100	0	0	0	0	0
3/30/2011	Day 50	100	0	0	0	0	0
3/31/2011	Day 51	100	0	0	0	0	0
4/1/2011	Day 52	100	0	0	0	0	0
4/2/2011	Day 53	100	0	0	0	0	0
4/3/2011	Day 54	100	0	0	0	0	0
4/4/2011	Day 55	100	0	0	0	0	0
4/5/2011	Day 56	100	0	0	0	0	0
4/6/2011	Day 57	100	0	0	0	0	0
4/7/2011	Day 58	100	0	0	0	0	0
4/8/2011	Day 59	100	0	0	0	0	0
4/9/2011	Day 60	100	0	0	0	0	0
4/10/2011	Day 61	100	0	0	0	0	0
4/11/2011	Day 62	100	0	0	0	0	0
4/12/2011	Day 63	200	0	0	0	0	0
4/13/2011	Day 64	200	0	0	0	0	0
4/14/2011	Day 65	200	0	0	0	0	0
4/15/2011	Day 66	200	0	0	0	0	0
4/16/2011	Day 67	200	0	0	0	0	0
4/17/2011	Day 68	200	0	0	0	0	0
4/18/2011	Day 69	200	0	0	0	0	0
4/19/2011	Day 70	300	0	0	0	0	0
4/20/2011	Day 71	300	0	0	0	0	0
4/21/2011	Day 72	300	0	0	0	0	0
4/22/2011	Day 73	300	0	0	0	0	0
4/23/2011	Day 74	300	0	0	0	0	0
4/24/2011	Day 75	300	0	0	0	0	0
4/25/2011	Day 76	400	0	0	0	0	0
4/26/2011	Day 77	400	0	0	0	0	0
4/27/2011	Day 78	400	0	0	0	0	0
4/28/2011	Day 79	400	0	0	0	0	0
4/29/2011	Day 80	400	0	0	0	0	0
4/30/2011	Day 81	400	0	0	0	0	0
5/1/2011	Day 82	400	0	0	0	0	0
5/2/2011	Day 83	500	0	0	0	0	0
5/3/2011	Day 84	500	0	0	0	0	0
5/4/2011	Day 85	500	0	0	0	0	0
5/5/2011	Day 86	500	0	0	0	0	0
5/6/2011	Day 87	500	0	0	0	0	0
5/7/2011	Day 88	500	0	0	0	0	0

5/8/2011	Day 89	500	0	0	0	0	0
5/9/2011	Day 90	600	0	0	0	0	0
5/10/2011	Day 91	600	0	0	0	0	0
5/11/2011	Day 92	600	0	0	0	0	0
5/12/2011	Day 93	600	0	0	0	0	0
5/13/2011	Day 94	600	0	0	0	0	0
5/14/2011	Day 95	600	0	0	0	0	0
5/15/2011	Day 96	600	0	0	0	0	0
5/16/2011	Day 97	700	0	0	0	0	0
5/17/2011	Day 98	700	0	0	0	0	0
5/18/2011	Day 99	700	0	0	0	0	0
5/19/2011	Day 100	700	0	0	0	0	0
5/20/2011	Day 101	700	0	0	0	0	0
5/21/2011	Day 102	700	0	0	0	0	0
5/22/2011	Day 103	700	0	0	0	0	0
5/23/2011	Day 104	800	0	0	0	0	0
5/24/2011	Day 105	800	0	0	0	0	0
5/25/2011	Day 106	800	0	0	0	0	0
5/26/2011	Day 107	800	0	0	0	0	0
5/27/2011	Day 108	800	0	0	0	0	0
5/28/2011	Day 109	800	0	0	0	0	0
5/29/2011	Day 110	800	0	0	0	0	0
5/30/2011	Day 111	900	0	0	0	0	0
5/31/2011	Day 112	900	0	0	0	0	0
6/1/2011	Day 113	900	0	0	0	0	0
6/2/2011	Day 114	900	0	0	0	0	0
6/3/2011	Day 115	900	0	0	0	0	0
6/4/2011	Day 116	900	0	0	0	0	0
6/5/2011	Day 117	900	0	0	0	0	0
6/6/2011	Day 118	1000	0	0	0	0	0
6/7/2011	Day 119	1000	0	0	0	0	0
6/8/2011	Day 120	1000	0	0	0	0	0
6/9/2011	Day 121	1000	0	0	0	0	0
6/10/2011	Day 122	1000	0	0	0	0	0
6/11/2011	Day 123	1000	0	0	0	0	0
6/12/2011	Day 124	1000	0	0	0	0	0
6/13/2011	Day 125	1000	0	0	0	0	0
6/14/2011	Day 126	1000	0	0	0	0	0
6/15/2011	Day 127	1000	0	0	0	0	0
6/16/2011	Day 128	1000	0	0	0	0	0
6/17/2011	Day 129	1000	0	0	0	0	0
6/18/2011	Day 130	1000	0	0	0	0	0
6/19/2011	Day 131	1000	0	0	0	0	0
6/20/2011	Day 132	1000	0	0	0	0	0
6/21/2011	Day 133	1000	0	0	0	0	0
6/22/2011	Day 134	1000	0	0	0	0	0

6/23/2011	Day 135	1000	0	0	0	0	0
6/24/2011	Day 136	1000	0	0	0	0	0
6/25/2011	Day 137	1000	0	0	0	0	0
6/26/2011	Day 138	1000	0	0	0	0	0
6/27/2011	Day 139	1000	0	0	0	0	0
6/28/2011	Day 140	1000	0	0	0	0	0
6/29/2011	Day 141	1000	0	0	0	0	0
6/30/2011	Day 142	1000	0	0	0	0	0
7/1/2011	Day 143	1000	0	0	0	0	0
7/2/2011	Day 144	1000	0	0	0	0	0
7/3/2011	Day 145	1000	0	0	0	0	0
7/4/2011	Day 146	1000	0	0	0	0	0
7/5/2011	Day 147	1000	0	0	0	0	0
7/6/2011	Day 148	1000	0	0	0	0	0
7/7/2011	Day 149	1000	0	0	0	0	0
7/8/2011	Day 150	1000	0	0	0	0	0
7/9/2011	Day 151	1000	0	0	0	0	0
7/10/2011	Day 152	1000	0	0	0	0	0
7/11/2011	Day 153	1000	0	0	0	0	0
7/12/2011	Day 154	1000	0	0	0	0	0
7/13/2011	Day 155	1000	0	0	0	0	0
7/14/2011	Day 156	1000	0	0	0	0	0
7/15/2011	Day 157	1000	0	0	0	0	0
7/16/2011	Day 158	1000	0	0	0	0	0
7/17/2011	Day 159	1000	0	0	0	0	0
7/18/2011	Day 160	1000	0	0	0	0	0
7/19/2011	Day 161	1000	0	0	0	0	0
7/20/2011	Day 162	1000	0	0	0	0	0
7/21/2011	Day 163	1000	0	0	0	0	0
7/22/2011	Day 164	1000	0	0	0	0	0
7/23/2011	Day 165	1000	0	0	0	0	0
7/24/2011	Day 166	1000	0	0	0	0	0
7/25/2011	Day 167	1000	0	0	0	0	0
7/26/2011	Day 168	1000	0	0	0	0	0
7/27/2011	Day 169	1000	0	0	0	0	0
7/28/2011	Day 170	1000	0	0	0	0	0
7/29/2011	Day 171	1000	0	0	0	0	0
7/30/2011	Day 172	1000	0	0	0	0	0
7/31/2011	Day 173	1000	0	0	0	0	0
8/1/2011	Day 174	1000	0	0	0	0	0
8/2/2011	Day 175	1000	0	0	0	0	0
8/3/2011	Day 176	1000	0	0	0	0	0
8/4/2011	Day 177	1000	0	0	0	0	0
8/5/2011	Day 178	1000	0	0	0	0	0
8/6/2011	Day 179	1000	0	0	0	0	0
8/7/2011	Day 180	1000	0	0	0	0	0

8/8/2011	Day 181	1000	0	0	0	0	0
8/9/2011	Day 182	1000	0	0	0	0	0
8/10/2011	Day 183	1000	0	0	0	0	0
8/11/2011	Day 184	1000	0	0	0	0	0