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## Removal of sustained casing pressure utilizing a workover rig

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REMOVAL OF SUSTAINED CASING PRESSURE  
UTILIZING A WORKOVER RIG

A Thesis  
Submitted to the Graduate Faculty of the  
Louisiana State University and  
Agricultural and Mechanical College  
in partial fulfillment of the  
requirements for the degree of  
Master of Science in Petroleum Engineering

in

The Department of Petroleum Engineering

by  
Kevin Soter  
B.S., University of Tulsa, 1993  
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## GLOSSARY

**Annulus** – In a borehole, the space between the drill pipe and the borehole, between tubing and casing, or between casing and formation

**Bbl (barrel)** – Unit of measurement equal to 42 gallons used extensively in oilfield operations

**BHA (Bottomhole Hole Assembly)** – Any set of tools made up to the lower workstring designed to accomplish a task, e.g. drill bit and drill collars, under reamer, etc.

**BOP (Blowout Preventers)** – Large valve or set of valves that may be operated during rig operations to control pressure and fluids, usually in the case of an emergency situation.

**Bottoms up** – Mud and cuttings calculated from pump rate and volume to come from the bottom of the hole since the start of circulation

**CIBP (Cast Iron Bridge Plug)** – Low cost bridge plugs for general oilfield service operations set either hydraulically or mechanically. The packers are built from cast iron, brass, aluminum, and rubber and can be set via electric wireline, slickline, coiled tubing, or workstring.

**Cmt (Cement)** – Various portland mixtures exist to for primary cementing of casing, remedial cement squeezing, or in setting plugs for abandonment or sidetracking. It can be modified to meet numerous applications through the use of retarders, extenders, fluid loss additives and accelerators. The following are two of the API classifications set forth by API STD 10A:

**Class ‘A’** – Intended for use from surface to 6,000-ft, when special properties are not required

**Class ‘H’** – Intended for use as a basic cement from surface to 8,000-ft depth as manufactured or can be used with accelerators and retarders to cover wide range of well depths and temperatures

**CTU (Coiled Tubing Unit)** – Continuous small diameter tubing deployed via drum that is used in stimulation, workover and drilling operations. Used in the place of jointed pipe.

**EZSV (EZ Drill<sup>®</sup>SV)** – Halliburton Energy Services’ High temperature/pressure sliding valve cement retainers used for remedial cementing operations. The packers are built from cast iron, brass, aluminum, and rubber and can be set via electric wireline, slickline, coiled tubing, or workstring. Generically termed ‘**cement retainer**’

**Gal (gallons)** - Unit of measurement equal to 4 quarts used extensively in oilfield operations

**IBP (Inflatable Bridge Plug)** – Type of packer that uses an inflatable bladder to expand the packer element against the casing or wellbore.

**Logs** – Any one of various Measurements taken via electric wireline of one or more physical quantities in or around a well. Wireline logs are taken downhole, transmitted through a wireline to surface and recorded.

**MD (Measured Depth)** – The length of the wellbore as measured along the casing or borehole wall. This measurement differs from TVD in all non-vertical wells.

**MMS (Minerals Management Service)** – The Federal Government’s regulatory agency that manages the natural resources on the nation’s outer continental shelf

**Neat Cement** – Cement that has no additives to modify its setting times or rheological properties.

**SCP (Sustained Casing Pressure)** - With the well flowing at steady state conditions, pressure from all casing strings should bleed to 0 psi and remain at atmospheric conditions. If pressure returns, the casing exhibits SCP.

**Skid** – The act of sliding the rig from one well slot to another on a fixed offshore platform.

**Spud** – The beginning of the drilling process by removing rock with a drill bit, e.g. to ‘spud a well’.

**Sxs (Sacks)** – Unit of measurement typically used in cementing operations. It is equivalent to 94-lbm sack of material unless it is a blend of cement and some other material.

**TD (Total Depth)** – The planned end of the well as measured by the length of pipe necessary to reach bottom

**TLW (Trinity Lite Weight)** – Commercial light weight cement manufactured from Portland cement and calcined shale

**TTBP (Thru-Tubing Bridge Plug)** – Mechanical plug designed to be run through the production tubing. Usually associated to live well situations

**WBM (Water Based Mud)** – Drilling fluid in which water or saltwater is the major liquid phase as well as the wetting phase.

## ABSTRACT

This thesis will analyze the techniques used during the 1989 and 1990 workover programs as well as subsequent operations in 1991/1992. It will also present the techniques and results of the most recent 1999 workover program undertaken to alleviate the most persistent sustained casing pressure (SCP) in a mature Gulf of Mexico field. An extensive literature review is included to better illustrate the complexity of the issues involved and possible SCP mechanisms.

The field was drilled during the 1980's and SCP has been prevalent in some cases previous to initial completion operations. Previous remedial programs resulted in limited success in reducing SCP previous to the most recent workover program beginning in 1999. Critical analysis will be based on a review of the methods used and the results obtained. Knowledge gained from the most recent 1999 workover program will be applied to evaluate the effectiveness of the methods employed.

Programs previous to the most recent 1999 workover program were not successful in eliminating SCP since pressure returned almost immediately to the affected casing in most instances. During the programs, perforating or cutting casing to squeeze cement into affected annuli was not successful at any depth. A review of the workover attempts will rely on internal correspondence and drilling reports. These will be compared to the knowledge and results gained from the 1999 rig operations program.

The objective of the 1999 workover program was to address SCP in the field with a consistent and effective method. Techniques were developed by analyzing the successes and failures of past operations and applying aggressive remediation programs tailored to individual wellbores. Discussion will include improved design guidelines in hole preparation before milling and cementing operations, improved milling procedures, and application of a latex cement slurry. Even though some remedial rig work was required while operations were still ongoing, all indications are that the 1999 workover program was successful.

## CHAPTER I: INTRODUCTION

### Statement of Problem

The Minerals Management Service (MMS) is the Federal Government's regulatory agency that manages the natural resources on the nation's outer continental shelf. The guidelines it imposes act to maximize the recovery of mineral resources from federal lands while preserving the environment. The MMS regulations contained in 30 CFR 250 seek to maintain a safe work environment in offshore oil and gas operations, and adherence to these guidelines spurred the rig workover programs presented in this thesis.

Varying magnitudes of sustained casing pressure (SCP) exist in some of the fields of the Gulf of Mexico. The sources of this pressure vary along with the particular affected casing string in the well. Casing pressure does occur from thermal expansion of annular fluid in some high rate wells. However, once a well is flowing at steady state conditions, the pressure from all casing strings should bleed through a needle valve to and remain at atmospheric conditions. If the casing pressure builds up when the valve is closed, then the casing exhibits SCP. Mathematical models have been developed and validated to quantify the magnitude and source of SCP (Xu and Wojtanowicz, 2001).

According to a study performed by Louisiana State University (LSU) and funded by the MMS, over 8,000 wells exhibit SCP in the outer continental shelf (OCS) (Burgoyne et al., MMS/LSU Study). The study is based on a database provided by the MMS with input from various operators. It verifies the prevalence of SCP in the Gulf of Mexico. Of the casing strings exhibiting SCP, approximately 50% were in the production, 10% in the intermediate, 30% in the surface, and 10% in the conductor casings. Of the wells included in the database, approximately 80% of all affected casing exhibit SCP less than the 20% burst pressure rating of the affected string. It further divides the occurrence of SCP into two categories. The first focuses on pressure occurring only on production casing resulting from mechanical problems with the tubing string or other operationally induced pressure. This thesis will concentrate on the second category that includes SCP occurring on all outer casing strings with the exception of structural and drive pipes which are excluded from regulation under 30 CFR 250.517.

The goal of the 1999 workover project was to address the most persistent cases of SCP in a particular mature Gulf of Mexico (GOM) field. Some of the wells had been previously worked over to eliminate SCP between the years of 1989 and 1992, but the pressure had returned. Future drilling from the platform was planned and taken into consideration while the 1999 workover program was being designed. With continued use of the platform, worker safety became the primary concern because it could be manned for many years. Addressing the SCP directly and safely while still allowing for possible future platform utility became the design driver.

During the preparation of this thesis, the well names were made generic by dropping the platform designation and numerating the wells 1 through 15. This was done to ensure the wells and analysis would remain non-field specific. All wells referred in the previous workover programs are consistent with the numbering system in the most recent 1999 workover program.

## **Government Regulations**

Regulations contained in the MMS 30 CFR 250.517 stipulate that the casing and tubing annuli, excluding drive pipe or structural casing, should be monitored for pressure buildup and the MMS should be notified if SCP is observed. Appendix A contains the MMS policy letter meant to inform lessees in the Gulf of Mexico Outer Continental Shelf (GOM OCS) of current policy contained in 30 CFR 250.517 regarding SCP. The letter is dated January 13, 1994 and note that the referenced 250.87 regulation is now designated 250.517.

According to the policy letter, departures from 30 CFR 250.517 do exist for low risk cases as long as proper monitoring and reporting is in place. An automatic departure is approved as long as the SCP is less than 20% of the minimum internal yield pressure of the affected casing and will bleed down to zero through a ½-in. needle valve in less than 24 hours. If SCP occurs on any one casing in the well, diagnostic testing of all remaining casing strings must be performed.

Affected casings should not be bled down without prior notification of the MMS except as required for testing documentation. The diagnostic tests must be repeated whenever the pressure increases by more 200 psi on the intermediate or production casing and more than 100 psi on the conductor or surface casing.

If the casing pressure exceeds 20% of the minimum internal yield pressure of the affected casing, or if the diagnostic test shows that the casing will not bleed to zero pressure through a ½-in. needle valve in a 24-hour period, then the operator is expected to address the SCP. Departures from 30 CFR 250.517 do exist for low risk cases as long as proper monitoring and reporting is in place.

A denied request for departure from 30 CFR 250.517 will require the operator to respond, within thirty days, with a remedial plan to address the SCP. Any approved departure is invalidated upon commencement of workover operations on the well.

The operator is also required to maintain, and make available for government inspection, all records of all observed SCP. Unsustained casing pressure less than 20% of the affected casing minimum internal yield pressure occurring during daily or workover operations, does not have to be reported. Unsustained casing pressure exceeding 20% of the minimum internal yield pressure must be reported.

## **Objective**

The objective of this thesis will be to analyze the techniques used during the workover and casing squeeze programs occurring between 1989 and 1992. These operations will be compared with the most recent 1999 workover program to alleviate SCP in the mature GOM field. The field was drilled during the 1980's and SCP has been prevalent in some cases previous to initial completion operations.

These remedial programs resulted in limited success in reducing, but not eliminating SCP, previous to the most recent workover program beginning in 1999. Critical analysis will be based on a review of the methods used and the results obtained. Knowledge gained from the most

recent 1999 workover program will be applied to evaluate the effectiveness of the methods employed.

Programs previous to the most recent 1999 workover program were not successful in eliminating SCP since pressure returned almost immediately to the affected casing. During the programs, perforating or cutting casing to squeeze cement into affected annuli was not successful at any depth. A review of the workover attempts will rely on internal correspondence and drilling reports. These will be compared to the knowledge and results gained from the 1999 rig operations program.

The objective of the 1999 workover program was to address SCP in the field with a consistent and effective method. Techniques were developed by analyzing the successes and failures of past operations and applying aggressive remediation programs tailored to individual wellbores. Discussion will include improved design guidelines in hole preparation before milling and cementing operations, improved milling procedures, and application of a latex cement slurry. Even though some remedial rig work was required while operations were still ongoing, all indications are that the 1999 workover program was successful.

## CHAPTER II: SUSTAINED CASING PRESSURE MECHANISMS

### **Possible Causes of SCP**

The main roles of primary cementing are to support casing strings and to prevent fluid movement through the annulus or into exposed permeable formations. The cement slurry must efficiently displace drill cuttings and mud from the annulus and then transition from a liquid phase to a solid phase. The resulting cement sheath should be able to withstand any future stress cycles encountered during the life of the well. Proper cement weight, composition, pre-job hole conditioning, and placement techniques must all be adequately designed in order to obtain a successful primary cement job.

The Petroleum Industry has long recognized that the following three factors can all contribute to a loss in annular pressure seal:

1. Improper mud displacement previous to primary cementing
2. Gas influx as the cement transitions to a solid
3. Cement sheath stress cracking during the life of a well

Together, these three issues constitute both early and late onset mechanisms. The focus of the following literature review will be to understand the issues of gaining and maintaining successful primary cement jobs. If a successful primary cement job is not obtained or excessive stress damages the cement sheath during the wellbore's productive life, a costly remedial workover program may be necessary to address SCP or other safety issues.

Some alternative explanations to the slow pressure buildup in wellbores do exist. Dusseault et al. (Dusseault et al., 2000) propose a hypothesis to explain a long term gas leakage mechanism. To summarize, a circumferential fracture can open when the radial stress is less, usually due to cement shrinkage, than the static porous pressure. Differences between higher lateral stress gradients in the rock and the lower pressure gradients in the fracture provide for vertical fracture growth. Pore blockage due to cement paste penetration and capillary effects limits gas leak off to formations. Gas flow into the fractures is thought to be due to diffusion. As the fracture height grows, the contact area with gas bearing formations increases. Gas diffusion becomes continuous with decreased pressures at or near the surface due to gas leak off.

### **Improper Mud Displacement**

Proper mud displacement is required to avoid mud channeling in the annulus during the primary cement job. Mud channels or pockets can lead to pressure communication between zones or to the surface. The factors affecting mud displacement efficiency have been studied and recognized for years. Displacement efficiency is defined as the percentage of the annular volume filled with cement after pumping the cement slurry (Economides et al., 1998). Maintaining formation integrity must be considered when maximizing the displacement efficiency.

Most (McLean et al., 1967, Martin et al., 1978, Beirute and Flumerfelt, 1977, and Haut and Crook, 1979) agree that:

- Drilling mud conditioning
- Pipe movement and centralization



- Fluid velocity
- Spacer and flush designs (including density differences)

all contribute to proper mud displacement and ultimately to the success or failure of a primary cement job.

**Mud Conditioning.** The goal of mud conditioning is two-fold, to create a uniformly viscous profile in the annulus and to remove any gelled mud. Ideal drilling fluid properties focus on proper yield points, plastic viscosities, fluid loss and gel strengths. Most drilling fluids and cement slurries can be classified as non-Newtonian where the viscosity of the fluid is a function of the shear stress and shear rate. For this reason, the bulk of research into efficient displacement of drilling mud has been in understanding non-Newtonian flow.

Increasing the viscosity ratio between the drilling fluid and cement slurry can increase the displacement efficiency by creating a uniform front and avoiding the fingering of fluids. Fluid loss must also be decreased to create a thinner mud cake. Thick mud cakes may inhibit creation of sufficient cement-to-formation bond. Haut and Crook (Haut and Crook, 1979) investigated the effects of drilling fluid condition, formation permeability, pipe centralization, rheological differences, flowrate, and density differences on mud channeling while neglecting pipe movement. A mud immobility factor was introduced where if the type and volume of solids is assumed constant, then the filtrate loss becomes the dominant factor in the mud and cement displacement process.

Sutton and Ravi (Sutton and Ravi, 1989) developed a method for predicting the real time fluid loss rate for cement on the drilling fluid filter cake. An evaluation number called the slurry response number (SRN) was developed based on fracturing fluid loss rate theory assuming the filter cake is a packed bed.

McLean, Manry and Whitaker (McLean et al., 1967) introduced the concept of critical yield strength based on the drilling fluid yield point and wellbore geometry. Lowering the yield point greatly improved the chances of successfully displacing the wellbore. This property must be measured to determine if the static gel strength will be too rapid; and thus, too difficult to condition and displace. Data from Haut and Crook's (Haut and Crook, 1979) displacement tests also indicate that the maximum gel strength of mud can be approximated from the 10-minute gel strength. Decreasing filtrate loss or the 10-minute gel strength can increase the percentage of displaced mud.

Beirute et al. (Beirute et al., 1991) discuss the impact of mud conditioning on cement operations and practical recommendations including minimizing pump shut downs, use of flushes, and casing movement during cementing operations to improve displacement efficiency. In laminar flow, it was found that the higher the flowrate, the higher the circulatable hole. To ensure the hole is properly conditioned, careful monitoring of surface pressures, flowrate, fluid properties, while taking into account hole geometry and temperature, should be monitored real-time and compared to calculated values to estimate the hole size and circulatable hole. Once the circulatable hole has stabilized, the casing is ready to cement (Ravi et al., 1993 and Griffith and Ravi, 1995).

A successful primary cement design to avoid annular pressure, implemented in a troublesome area in the Gulf of Mexico, included casing reciprocation, conditioning mud to low yield points. Achieving 90% mud volume circulation prior to pumping cement was also felt imperative (Brady et al., 1992).

Deviated wells require higher yield points and gel strengths to avoid the settling of solids on the low side of the hole. A channel can form on the low side during the primary cement job in highly deviated wells where solids have settled. Tests have also shown that excess water can channel on the high side (Keller et al., 1983). Tables 2-1 and 2-2 list some recommended drilling fluid properties to optimize the primary cement job.

**Table 2-1:** Vertical Well Recommended Drilling Fluid Properties

| Property                              | Recommended  | Preferred |
|---------------------------------------|--------------|-----------|
| Yield Point (lb/100-ft <sup>2</sup> ) | <= 10        | 2         |
| Plastic Viscosity                     | <= 20        | 15        |
| Fluid Loss (cc/30 min)                | 15           | 5         |
| Gel Strength (10 sec/10 min)          | Flat Profile |           |

**Source:** 1996 Halliburton Best Practices Series: Highly Deviated/Horizontal Cementing with Emphasis on Liner Applications

**Table 2-2:** Deviated Well Recommended Drilling Fluid Yield Points

| Deviation Angle (°) | Yield Point @ 72°F (lb/100-ft <sup>2</sup> ) |
|---------------------|--|
| 45                  | 15   |
| 60                  | 20   |
| 85                  | 28   |
| 90                  | 30   |

**Source:** 1996 Halliburton Best Practices Series: Highly Deviated/Horizontal Cementing with Emphasis on Liner Applications

**Pipe Movement.** There are two types of pipe movement, rotation and reciprocation, each can significantly improve annular mud displacement (Haut and Crook, 1979 and Crook et al., 1987). Rotation is generally recommended for highly deviated or horizontal wells. Reciprocating pipe in highly deviated holes increases the chance of sticking the casing off bottom and dragging the centralizers through highly deviated hole sections. Rotation can be done before and during the pumping of cement, usually without movement of stabilizers. Table 2-3 illustrates the increase in displacement efficiency provided by pipe movement in a 16-lb/gal mud with a 16.7-lb/gal cement slurry at 4-bbl/min pump rate and 60% standoff.

Tests have also proven the effects of rotation or reciprocation during the gelation period to delay pressure loss in cement. Rotation was continued to static gel strengths of 1,000-lb/ft<sup>2</sup> and did not delay gel strength development (Sutton and Ravi, 1991).

**Table 2-3:** Pipe Movement and Displacement Efficiency

| <b>Pipe Movement (rpm)</b> | <b>Displacement Efficiency (%)</b> |
|----------------------------|------------------------------------|
| None                       | 65                                 |
| 20                         | 97                                 |

**Source:** 1996 Halliburton Best Practices Series: Highly Deviated/Horizontal Cementing with Emphasis on Liner Applications

**Centralization.** Casing centralization creates a uniform flow area for cement to more readily displace the annulus and is essential to obtaining a successful primary cement job. Centralization is of great concern in deviated wells where the inner casing tends to lay or ‘sag’ to the low side of the hole. In a highly eccentric situation, fluid will tend to flow at a higher rate where the resistance is least on the wide side of the hole and bypass mud on the low side. Centralizer design must be tailored to the wellbore geometry, casing size and weight, hole size, and type and strength of centralizer to achieve sufficient standoff (Lee et al., 1986). Lee et al., also report that the industry accepted standard for the standoff ratio is presently 0.67.

Some early work by McLean, Manry and Whitaker (McLean et al., 1967) attempted to describe the displacement mechanics of mud and cement slurries using analytical models and experiments in eccentric annuli and found that casing standoff greater than 25% increased the likelihood of flow.

**Fluid Velocity.** Uniform displacement of drilling fluid increases with fluid velocity; however, the influence of casing eccentricity and fluid properties increase the chances of mud channeling. Turbulent flow is widely believed to be the most efficient means of displacing the wellbore fluids previous to pumping cement; yet, concerns of breaking down exposed formations can limit the flow rates. Table 2-4 demonstrates the increase in displacement efficiency with pump rate assuming a 12-lb/gal drilling mud and a 16.8-lb/gal cement. The higher shear forces tend to break down and circulate out more gelled or partially dehydrated drilling fluids. Ravi et al. (Ravi et al., 1992) recommend designing the circulation rate and spacer so that the shear stress on the narrow side of the annulus is greater than or equal to the wall shear stress.

**Table 2-4:** Fluid Velocity and Displacement Efficiency

| <b>Pump Rate (bbl/min)</b> | <b>Displacement Efficiency (%)</b> |
|----------------------------|------------------------------------|
| 1                          | 48                                 |
| 4                          | 75                                 |
| 7                          | 98                                 |

**Source:** 1996 Halliburton Best Practices Series: Highly Deviated/Horizontal Cementing with Emphasis on Liner Applications

Early work by McLean, Manry, and Whitaker (McLean et al., 1967) found that the presence of turbulent or laminar flow did not in itself suggest good or bad displacement efficiency. Lockyear

et al. (Lockyear et al., 1990) illustrated that turbulent displacements will minimize channeling of fluids. They proposed that a Reynold's number greater than 1,500 will significantly reduce channeling for standoffs greater than 50%.

Frigaard et al. (Frigaard et al., 2001) researched the displacement of visco-plastic fluids that directly influence spacer design and slurry properties for mud removal during primary cementing. An analytical expression has been developed for mud displacement velocities in eccentric annuli with a steady state front predicted under certain combinations of physical properties (Frigaard and Pelipenko, 2003).

Smith (Smith, 1990) created an extensive cementing operations database to study the significance of the displacement factors, annular velocity, conditioning time, and preflush design, on obtaining a successful primary cement job. Regardless of the flow regime, an annular velocity greater than 262.5 ft/min was found to be the most important factor in displacement efficiency.

**Spacers and Flushes.** Spacers and flushes separate incompatible drilling fluids and cement slurries to improve the displacement efficiency of a primary cement job. Spacer and flush design depends on the type of drilling fluid being displaced, water vs. oil based, as well as density differences between the cement and drilling fluid. The presence of water sensitive clays, easily fractured, or highly-permeable formations affect spacer design.

Spacer design centers on the amount of contact time the spacer has with the pipe or formation. For vertical wells being displaced in turbulent flow, pumping a spacer equivalent to 500-ft of annular fill with a minimum of 10 minute contact time is recommended (Brady et al., 1992). This time will increase for highly deviated or horizontal wells. Smith (Smith, 1990) proposed a spacer volume equal to the volume required to fill 980-ft of casing-to-hole annulus. The fluid properties should be such that solids suspension will occur during both static and dynamic situations. Inclination reduces displacement efficiency by reducing the gravitational effects and good spacer design is essential to mud removal (Tehrani et al., 1992).

Flushes are generally un-weighted and will readily go into turbulent flow to increase the displacement efficiency. Flushes in turbulent flow will tend to clean settled solids in deviated wellbores more readily than a viscous flush. Viscous flushes have difficulty picking up already settled solids in the annulus. Couturier et al. (Couturier et al., 1990) presented a method to calculate the critical rate for turbulent displacement as well as a laminar profile criterion to avoid distortion of the displacement profile.

Crook et al. (Crook et al., 1987) used field and full scale experiments to confirm mud displacement in high angle wellbores can result in low side-settling of solids and can be prevented with proper rheological control of the drilling fluid. There appears to be a threshold mud yield point below which solids channeling will occur and this yield point value decreases at lower deviations. The use of low viscosity preflushes improve the displacement of settled solids.

Findings from a full-scale lab experiment by Moran and Lindstrom (Moran and Lindstrom, 1990) led to guidelines to prevent solids settling in weighted spacers during turbulent flow. A

mathematical correlation was developed to predict the flowrate necessary to maintain solids suspension and that the settling of spacer is not a problem at hole angles of 60 degrees or less with annular velocities maintained at 1 ft/sec.

**Density Differential.** To minimize channeling and facilitate a smooth fluid interface, the displacing cement density should be significantly higher than the mud it is displacing. Mclean et al. (McLean et al., 1967) found that gravity forces, or buoyancy, help to break down the gelled mud when the mud is lighter than the displacing fluid. However, when the mud is heavier than the displacing fluid, gravity opposes uniform displacement.

Beirute and Flumerfelt (Beirute and Flumerfelt, 1977) developed a mathematical model based on slot flow to describe miscible displacement of mud by cement slurries in laminar flow. Minimizing yield stress differentials, increasing density differences, low displacement rates, and rheological properties of both the mud and cement all strongly influenced displacement efficiency. Martin et al. (Martin et al., 1978) assumed both fluids were immiscible to develop a math model that indicated successful mud displacements could be obtained by simultaneously obtaining proper casing standoff, low thixotropic mud properties, and high density and viscosity differences.

#### **Gas Migration through Unset Cement**

There are more than forty chemical additives that can be added to API slurries to provide the desired slurry characteristics according to job specifications. Available cement additives can be grouped according to 1) density control, 2) setting time control, 3) lost circulation, 4) filtration control, 5) viscosity control, and 6) special additives for unusual problems (Burgoyne et al., 1986). Cement additives exist or have been tested that can improve cement bonding and aid in combating gas influx (Tinsley et al., 1980, Jones and Carpenter, 1991, and Talabani et al., 1993).

Gas migration through unset cement can occur as the setting cement transitions from the fluid phase through the gel phase and hardens. Annular gas migration through unset cement is a recognized problem with a great deal of work done to identify causes and to provide solutions. Zhou and Wojtanowicz (Zhou and Wojtanowicz, 2001) developed a mathematical model that takes into account gelation, volume reduction, and compressibility mechanisms to describe hydrostatic pressure losses in setting cement columns.

It is commonly believed that gas migration occurs when the overbalance pressure is lost due to the combined effects of static gel strength development and fluid loss (Carter and Slagle, 1972, Garcia and Clark, 1976, Levine et al., 1979 and Cooke et al., 1983). Gelation inhibits pressure transfer down through the setting column to make up for water volume reduction. Volume reduction is explained through water loss to permeable formations or from hydration. Gas can enter the setting cement at this point and percolate to the surface leaving a permanent cement channel. Sabins et al. (Sabins et al., 1980) stated that the beginning and end of the transition period is determined from the static gel strength measurements. Results from their laboratory experiments showed that approximately 20 lb/100 sq-ft is sufficient to restrict gas flow and about 500 lb/100 sq-ft will restrict all gas percolation.

Stewart and Schouten (Stewart and Schouten, 1986) proposed a cement depressurization hypothesis saying that at cement initial set, exothermic hydration begins and converts pore water to hydrates resulting in the pore pressure falling below the water phase gradient. Results of their study indicated a gel strength of approximately 40 lb/100 sq-ft was sufficient to stop small gas bubbles.

Carter and Slaigle (Carter and Slaigle, 1972) recognized that the density of the fluids was the first of four contributors to gas leakage. Gas flow through the fluid cement column did not occur until the gas pressure was greater than the hydrostatic pressure. When the gas pressure was greater than the hydrostatic pressure after initial set, a small channel could form as a pressure conduit. Secondly, early setting of cement uphole due to the circulating warm fluid could block hydrostatic pressure and allow for formation gas influx. Cement dehydration from fluid loss, bridging due to sloughing formation, and gelation of cement uphole are the final two mechanisms recognized as contributing to gas leakage.

In order to combat the rapid reduction in pressure during the transition phase, Tinsley et al. (Tinsley et al., 1980) proposed gas entrainment within the cement slurry. When the cement gels, the original hydrostatic pressure is trapped in the cement matrix. Any volume decrease, due to hydration or loss to the formation, that follows will reduce the water pore pressure in the matrix. Hydrostatic pressure reduction is attributed to the low compressibility of the water phase. Introduction of a gas phase will increase compressibility and consequently, the pressure maintenance. Watters and Sabins (Watters and Sabins, 1980) presented the results of a fifteen month compressible cement program to address annular gas flow in which an overall success rate of 85.2% was obtained.

Cheung and Beirute (Cheung and Beirute, 1985) offered another explanation of the gas migration mechanism through gas invasion of unset cement slurry permeabilities. They contended that conventional fluid-loss additives that act at the formation face were not effective at stopping gas influx into the cement matrix and proposed using polymeric or bridging materials to reduce cement mobility in pore spaces. Sutton and Ravi (Sutton and Ravi, 1989) used math models to show that mud channels are the combined result of static gel strength development and downhole losses and not due to gas invasion of unset cement slurry permeability. Gas migration through cement permeability has little effect on gas migration as proposed by Cheung and Beirute.

### **Cement Sheath Failure**

Once placed, the primary cement sheath must set and develop sufficient compressive strength to seal annular flow and support the casing previous to continuation of drilling activities. Although no set value exists, achieving 500 psi of compressive strength is felt as sufficient (Burgoyne et al., 1986).

Excessive temperature changes and casing pressures, including casing test pressures, during the life of the well can both contribute to cement sheath failure and the resulting annular pressure. Some testing has (Goodwin and Crook, 1992 and Bosma et al., 1999) investigated the causes and limits of cement sheath failure conditions. It has been found that internal casing pressure resulting in casing expansion after the cement has obtained high compressive strength can cause radial stress cracks. These stress cracks can cause a loss of pressure seal generally in the lower

¼ to ⅓ of the wellbore. Excessive temperature stress cracking tends to occur in the upper ⅓ to ½ of the wellbore. Low compressive strength cements, between 500 and 1,000 psi, are more ductile and can better handle stress cycling.

Microannular flow occurs when the cement sheath is excessively stressed before sufficient compressive strength is developed. Many times this can occur when the casing shoe is drilled out or by pressure testing the casing previous to drilling out the shoe. Proper cement cure time, based on accurate bottomhole temperature data, must be allowed before continuing operations. Documented primary cement jobs prove that rapid gelation and sufficient compressive strength development at the time of drill out is essential for gas control (Coker et al., 1992).

Jackson and Murphy (Jackson and Murphy, 1993) used lab equipment to demonstrate the casing-cement-formation loading effects during pressure cycling on 5-in. casing cemented inside 7-in. casing. Gas flow occurred through channels created during pressure cycles greater than 5,000 psi. Pressurizing the 5-in. casing to 8,000 psi increased its radius by up to 0.003-in. causing a permanent plastic deformation to the cement sheath. Gas was able to flow once the pressure was released.

Bosma et al. (Bosma et al., 1999) used finite element analysis to better understand the failure mechanisms in various cements associated with excessive temperatures and pressures. It was found that the compressive strength of the cement is not the sole design factor for proper zonal isolation. Young's modulus, Poisson's ratio, tensile, shear, and bonding strengths are also required. Ravi et al. (Ravi et al., 2002) presented a design procedure to estimate the risk of cement failure as a function of cement sheath, formation characteristics, and well loading. To avoid debonding, cracking or plastic deformation failures, the cement design should be compensated for hydration volume reduction and rendered less stiff under downhole conditions.

Long term gas migration can occur due to mud channeling caused by plastic-state shrinkage during the initial pumping and setting process. Cement can be pumped and set without any gas migration but shrinkage during the setting phase can cause a weakening of the cement-to-filter cake bond necessary to isolate reservoir pressure. A small fracture in the cement can develop that provides a gas migration conduit which can worsen as the fracture widens due to further dehydration of the mud filter cake.

Expansive cement additives can also help prevent mud channeling problems during the post-set period. Some work has been done to investigate the use of cement additives to optimize the contraction-expansion mechanism during cement setting to avoid micro-fractures (Talabani et al., 1993).

Although not exhaustive, an attempt has been made to illustrate the vast amount of research, debate, and complexity surrounding the sources of SCP. The occurrence of SCP is widespread and not localized to any area. Each development or area will offer unique challenges and the following chapters analyze multiple attempts by an operator at alleviating SCP in one particular field. Presently, no one solution exists that can universally address SCP.

## **Remediation Efforts**

Numerous SCP remediation techniques have been employed with varying success. Some wells may only require a tubing replacement or mechanical barrier set in the tubing or casing. The more difficult methods of annular squeeze cementing, casing removal, or lubricating heavy brines into the annulus tend to be less desirable options due to the difficulty in accessing and addressing the SCP and the high costs associated with such operations.

The results of lab studies and post well reviews of remedial casing squeeze attempts in the Celtic Field abandonment project indicate four possible causes of casing vent flows (CVF) encountered in the field abandonment project (Watson et al., 2002). Development of thaumasite in setting cement, leaking isolation tools, incomplete long term seal of source zones, and incorrect source detection or squeeze interval were noted as potential causes. Some of the original cement did not set properly due to contamination before and during mixing, fluid influx after placement, and cooler than expected wellbore temperatures. Thaumasite is a hydration mineral that develops in the presence of sulfate and carbon dioxide in the cement slurry and its development prevents the cement crystals from growing together.

Improved solutions to address the CVF's in the Celtic Field abandonments included pumping chemical washes ahead of the treatment, use of a permeability-sealing fluid ahead of the expansive cement slurry, and mechanical isolation barriers. Improvements in abandonment design resulted in a 70% success, when compared to a rate of 55% from a previous program, in obtaining successful squeezes in twenty wells with CVF. Of the twenty wells abandoned, eleven had CVF. The improved abandonment techniques resulted in an immediate relief of CVF on seven wells with the remaining four wells indicating flow dissipation.

An alternative solution to addressing SCP has been proposed by Carpenter et al. (Carpenter et al., 2001) through the use of placing palletized alloy metal into the affected annulus. The metal would be heated and expand to seal the annulus. Both small and large-scale physical models have proven the concept. Further testing will be necessary to establish limits of the technology.



## CHAPTER III: PAST OPERATIONS 1983-92

### Objective

The objective of this chapter is to analyze the techniques used previous to the 1999 workover program. Review of operations to alleviate SCP during the 1989 workover program, the 1990 casing squeeze program, and further operations undertaken through 1992 will be made. The field was drilled during the 1980's and SCP has been prevalent in some cases previous to initial completion operations.

These remedial programs resulted in limited success in reducing SCP previous to the most recent workover program beginning in 1999. Critical analysis will be based on a review of the methods used and the results obtained.

None of the 1989, 1990 or 1990-1992 workover programs were successful in eliminating SCP since pressure returned almost immediately to the affected casing. During the programs, perforating or cutting casing to squeeze cement into affected annuli was not successful at any depth.

In 1989, Wells 3, 13, 5, and 10 were all worked over in an attempt to relieve SCP. By 1990, all four wells had significant amounts of SCP returning on the 10 3/4-in protective casing. The 1990 workover program concentrated on squeezing cement into the affected casing annuli. This program included work on Wells 1, 14, 11, and 15. Operations between 1990 and 1992 concentrated on two additional wells and reworked 5 of the previously worked over wells.

### Background Information

The incentive for alleviating the high annular pressures stemmed from both the operator's safety standards and adherence to MMS guidelines. At the time, MMS guidelines required no SCP in excess of 20% of the API burst rating of the pipe. The rig workover programs focused around three temporary abandonments in 1989 and again in 1990 during a four well program. These programs resulted in limited success in reducing but not eliminating annular pressure previous to the most recent workover program beginning in 1999.

At the time of the 1989 and 1990 workover programs, no definitive source of the annular pressure was known. Efforts to define shallow source had not been successful. Log data indicated both possible shallow and deep flow sources. The common thinking at the time of the workover tended toward non-isolated deep gas sands as the major source of pressure with some smaller shallow stringer contributing to outer casing string pressure buildups. Some limited laboratory analysis indicated that two samples from differing annuli on Well 14 had identical composition and were of a shallower bacterial source rather than a condensate flash gas.

Upon completion of the 1990 casing squeeze program, recommendations, for both the producing and temporarily abandoned wells, stemming from the 1989 and 1990 programs was presented. Selectively squeezing, minimizing perforation length, and localizing pressure testing were all recommended for addressing casing pressure on producing wells. These operations should only be performed if there are sufficient reserves to justify the risks.

In 1989, four wells were worked over in an attempt to relieve SCP. All four wells had significant casing pressure returning on the 10 ¾-in protective casing. Perforate casing to squeeze and cut casing to circulate operations were not successful due to inability to establish circulation with the annulus. Casing pressures declined but soon built back up.

The 1990 workover program attempted to apply the latest technology and concentrated on squeezing cement into the affected casing annuli of four different wells. Initially, deep cement squeezes were attempted where logs indicated poor bond. Annular pressures were not successfully reduced until large cement volumes were squeezed at intermediate shoes. The 1990 workover program succeeded in reducing annular pressures but did not bring them to zero.

## **1989 Workover Program Wells**

### **Well 3**

**Original Drill.** The well was spudded in December, 1984. The 20-in. was run to 1,304 ft and cemented with 1,000 sxs TLW and 500 sxs 'H' with no returns while cementing. The 16-in. was run to 2,305 ft and cemented with 700 sxs TLW and 500 sxs 'H'. A 10 bbl freshwater spacer was used and the plug was bumped with 1,500 psi with full returns. No centralizers are listed as being run.

The 10 ¾-in. was run to 4,502 ft. The well was drilled to 10,938 ft with the 7-in. production casing being run and cemented to TD. Eighty 'Latch-On' Trico centralizers were run every 30-ft. from the bottom. A 50 bbl dual spacer was pumped ahead of the 850/2,000 sxs 17.2/17.5 ppg Class 'H' cement slurry with the plug being bumped with 2,000 psi and held for 30 minutes. The 7-in. casing got stuck while reciprocating but had 100% returns while pumping. A dry hole tree was nipped up and tested before skidding the rig.

**Initial Completion.** The rig was skidded back over the well in November, 1985 to complete the well. The 10 ¾-in. casing had 1,150 psi. The well was perforated, sand control run, and the rig was skidded. Within a year, a total of 3 bbl mud and gas was bled from the 10 ¾-in. casing. Eight barrels of 16.3 ppg mud was pumped into the 10 ¾-in. casing that brought the pressure down to 1,110 psi.

**May 1989 CTU Washout.** A coiled tubing unit was rigged up to wash sand from 1,750 to 10,164 ft and could not get deeper.

**June 1989 Workover.** The well had been off production since sanding up in March 1988. A CBL indicated poor bonding except across the producing zone. Approximately 2,000 psi had built up on the 7 x 10 ¾-in. annulus and builds up quickly after bleeding off. Communication between the tubing and 7-in. annulus was established both previous to pulling the tubing hanger and once stinging out of the gravel pack packer. The well began flowing on the 7-in. annulus.

An EZSV was set above the gravel pack packer at 9,650 ft but was unable to establish an injection rate. The workstring was stung out and 25-bbl cement was spotted on top. The 10 ¾-in.

casing was bled down from 2,250 psi. A noise/temperature survey was run with noise stations taken from the 10 ¾-in. casing shoe and up to the 16-in. shoe.

The 7-in. casing was perforated above the 10 ¾-in. shoe at 4,404-ft with charges designed to penetrate the 7-in. but not the 10 ¾-in. casing. An unsuccessful attempt to circulate the 7 x 10 ¾-in. was made when the drillpipe pressured to 3,000 psi with no leak off. The 10 ¾-in. casing was bled down from 580 psi and cut at 3,500 ft. Circulation could not be established and the casing was perforated at 3,000 and 2,900 ft.

The 10 ¾-in. casing was bled down from 250 psi with gas in the returns. The casing was cut at 4,368 ft but was unable to circulate through the cut. A 7 ½ bbl 16.2 ppg cement plug was spotted at 4,500 ft.

Still unable to circulate between cut at 3,500 ft and the perforations at 3,000 ft. Cement was tagged at 4,410 ft and drilled out. The casing was perforated at 8,900 ft and an EZSV was set at 8,800 ft. A tight spot was noticed at 8,300 ft while running the EZSV in the hole. Twenty barrels of cement were squeezed below and spotted 5 bbl on top of EZSV.

Squeeze perforations were made at 4,550 ft and squeezed 45 bbl below EZSV set at 4,300 ft. and spotted 5-bbl of cement on top. A 25 bbl cement plug was then spotted from 3,500 to 2,800 ft before skidding the rig. The 7 x 10 ¾-in. annular pressure was reduced and remained at approximately 200 psi for around 18 months but then began drastically rising to values in excess of 1,500 psi.

**October 1991 Workover.** A rig was skidded over the well and bled 550 psi from the 7-in. casing and got ½ bbl of mud in the returns. Approximately 1,200 psi was bled from the 10 ¾-in. casing with 2 bbl mud in the returns. The 7 x 10 ¾-in. annular pressure had been climbing at a rate of approximately 50 psi per week. No bleed-down/buildup tests had been performed to allow the pressure to stabilize and to prevent possible pressure communication.

A 40 psi gas kick was taken while drilling up cement on top of an EZSV and then again after drilling up the EZSV. The wellbore was cleaned out and a 37 ft window was milled in the 7-in. casing from 4,440 to 4,477 ft. No injection could be established through the 25 ft overlap into the open hole. A 20 bbl 16.2 ppg cement plug was spotted from 4,477 to 4,227 ft. and WOC for 12 hours.

The 7-in. casing was cut and recovered to 845 ft with a total of 8 cuts made including one at 850 ft. An EZSV was set at 845 ft and cement was pumped with 6 bbl remaining on top before skidding the rig.

### **Well 13**

**Original Drill.** This well was spudded in February 1985. A 13 ½-in. bit and 26 in. under reamer was used to drill to 1,235 ft. The 20-in. casing was run to 1,228 ft, a 25 bbl seawater spacer was pumped, and then 950 sxs 11.5 ppg TLW followed by 500 sxs 16.2 ppg 'H' was pumped with full returns while pumping. The casing was tested to 205 psi for 30 minutes. No

centralizers were run and the casing was not rotated nor reciprocated while pumping the cement slurry.

A 13 ½-in. bit and 20-in. under reamer were used drill to 2,885 ft. The 16-in. casing was run to 2,885 ft and cemented with 1,100 sxs 11.5 ppg TLW followed by 500 sxs of 16.2 ppg 'H'. A 25 bbl Superflush K spacer was pumped ahead of the cement slurry. During the pumping of the slurry, the P-tank line plugged from wet cement pumped from boat and had to be cleared for 1 hour before cementing operations could resume. No centralizers were run and the casing was reciprocated with 10 ft strokes. The plug was bumped with 2,100 psi and held for 30 minutes. Full returns occurred while pumping the slurry and the casing was tested to 1,840 psi for 30 minutes.

A 13 ½-in. bit was used to drill to 6,425 ft while having to gas cut mud at 4,534, 5,173 and 5,540 ft. The 10 ¾-in. was run to 6,425 ft and cemented with 2,500 sxs of 14.5 ppg 'H'/TLW followed by 500 sxs of 16.2 ppg 'H' after pumping a 50 bbl dual spacer. The plug was bumped with 1,500 psi with full returns and the casing was not rotated or reciprocated. Trico KK-5 centralizers were run but quantity and spacing was not listed.

A 9 ⅞-in. bit was used to drill to 11,100 ft with gas cut mud occurring at 8,805, 8,921, and 10,656 ft. Twelve hours were spent at 10,656 ft circulating out a gas kick. The 7-in. casing was run to 11,100 ft and had to circulate out 2,000 units of gas that cut the mud weight from 15.3 to 14.1 ppg. An 850 sxs 17.2 ppg 'H' tailed by 2,000 sxs 17.5 ppg 'H' was pumped after a 50 bbl dual spacer. The plug was bumped with 1,500 psi and had full returns during while pumping. Eighty-five Latch-On Trico centralizers were run every 40 ft. The casing was reciprocated with 15 ft strokes while circulating but stuck during the pumping of the cement slurry. The rig was skidded after nipping up a dry hole tree.

**Initial Completion.** The rig was skidded back over the well in March, 1986 for completion operations. A cement bond log was run and indicated no bonding through the completion interval and a water sand 30 ft above the zone of interest. Squeeze perforations below the zone of interest were made and four 16.2 ppg 'H' Neat cement squeezes totaling 293 sxs of cement were made. The perforations broke down with ±1,700 to 2,200 psi test pressure. A cement bond log indicated that the bottom of the zone of interest was sufficiently isolated.

Squeeze perforations were then made above the zone of interest and two 100 sxs 16.2 ppg 'H' cement squeezes were made. A cement bond log was then run and indicated no improvement in bond. A third cement squeeze was made with 125 sxs 16.2 ppg 'H' and low water loss cement. A cement bond log again indicated no improvement in bond.

The squeeze perforations were isolated and a third set was made above them. A total of four cement squeezes were made before running a cement bond log. The log indicated 60 to 75% bond above the zone. Sand control was pumped and the well was completed previous to skidding the rig.

Twelve cement squeezes totaling 1,200 sxs of cement were pumped but none were successful. The well was gravel packed and placed on production but only produced sand, mud and cement before sanding up.

**June 1989 Workover.** Initially, pump in lines were rigged up on the 10 3/4 and 16-in. casing strings to monitor casing pressure. Tables 3-1 and 3-2 summarize the initial bleed down and build up data and Tables 3-3 thru 3-5 summarize the pressure buildup 30 days into the operation. A snubbing unit was rigged up and used a 1 1/4-in. workstring to wash until the hole was clean.

**Table 3-1 – (Well 13) 10 3/4-in. Bleed Off/Buildup Data: 06-01-89**

| <b>Well 13: 10 3/4-in. Casing (06-01-89)</b> |                             |                               |                                      |
|--|-----------------------------|-------------------------------|--------------------------------------|
| <b>Initial Pressure (psi)</b>                | <b>Final Pressure (psi)</b> | <b>Bleed Down Time (min.)</b> | <b>Remarks</b>                       |
| 2,350  | 0                           |                               | Gas w/0.25 bbl SW Returns            |
| 2,000  | 1,150                       | 3                             | Pump 1 bbl SW                        |
| 2,000  | 1,500                       | 5                             | Pump 0.25 bbl SW                     |
| 1,500  | 0                           |                               | 0.25 bbl SW Returns                  |
| 2,000  | 0                           |                               | Pump 0.25 bbl SW<br>0.25 bbl Returns |

**Table 3-2 – (Well 13) 16-in. Bleed Off/Buildup Data: 06-01-89**

| <b>Well 13: 16 in. Casing (06-01-89)</b> |                             |                               |   |
|--|-----------------------------|-------------------------------|---|
| <b>Initial Pressure (psi)</b>            | <b>Final Pressure (psi)</b> | <b>Bleed Down Time (min.)</b> | <b>Remarks</b>                          |
| 1,080                                    | 0                           |                               | Muddy SW Returns                        |
| 800                                      | 0                           |                               | Pump 3.75 bbl SW<br>3.75 bbl SW Returns |

**Table 3-3 – (Well 13) 10 3/4-in. Bleed Off/Buildup Data: 06-30-89**

| <b>Well 13: 10 3/4-in. Casing (06-30-89)</b> |                             |                            |                    |
|--|-----------------------------|----------------------------|--------------------|
| <b>Initial Pressure (psi)</b>                | <b>Final Pressure (psi)</b> | <b>Buildup Time (min.)</b> | <b>Remarks</b>     |
| 2,475  | 0                           |                            |                    |
| 0  | 200                         | 10                         |                    |
| 200  | 0                           |                            | 0.5 bbl SW returns |
| 0  | 680                         | 60                         |                    |

**Table 3-4 – (Well 13) 16-in. Bleed Off/Buildup Data: 06-30-89**

| <b>Well 13: 16-in. Casing (06-30-89)</b> |                             |                            |                |
|--|-----------------------------|----------------------------|----------------|
| <b>Initial Pressure (psi)</b>            | <b>Final Pressure (psi)</b> | <b>Buildup Time (min.)</b> | <b>Remarks</b> |
| 1,040                                    | 800                         |                            | Mud returns    |

**Table 3-5 – (Well 13) 20-in. Bleed Off/Buildup Data: 06-30-89**

| <b>Well 13: 20-in. Casing (06-30-89)</b> |                             |                            |                |
|--|-----------------------------|----------------------------|----------------|
| <b>Initial Pressure (psi)</b>            | <b>Final Pressure (psi)</b> | <b>Buildup Time (min.)</b> | <b>Remarks</b> |
| 80                                       | 0                           |                            |                |

A rig was then skidded over to pull the production tubing and squeeze the production perforations with 25-bbl 16.2 ppg of cement below an EZSV. Squeeze perforations were made at 9,232 ft and squeezed below an EZSV. A temperature survey was then run but did not find any anomalies.

Squeeze perforations were made below the 10 ¾-in. casing shoe at 6,500 ft and squeezed with 22.5 bbl of cement below an EZSV. The 7 x 10 ¾-in. annulus was bled down to zero psi and built up to 320 psi in 30 minutes, 560 in 1 hr, and 1,760 psi in 2 hr.

The casing was cut at 6,090 ft and at 6,209 ft but was unable to establish injection. Squeeze perforations were then made at 6,100 ft and squeezed with 45 bbl of 16.2 ppg cement. While WOC, the 7-in. casing was bled from 200 to 0 psi, 10 ¾-in. from 850 to 0 psi, and the 16-in. from 600 to 0 psi. After 6 hr, the 20, 16, and 7-in. casing strings all remained at zero but the 10 ¾-in. had built back up to 490 psi. After 9 ½ hr, the 7-in. remained at zero and the 10 ¾-in. increased to 700 psi and the 16-in. to 50 psi. The 16-in. was bled to zero. After 18 hr, the 7-in. remained at zero and the 10 ¾-in. had built to 1,120 psi.

A 6-in. window was cut below the 16-in. shoe and recovered shavings with a trace of gas in the returns. Injection could not be established with the 7 x 10 ¾-in. annulus. An EZSV was set at above the window but could not establish injection. A 5-bbl cement plug was spotted before skidding the rig.

Testing indicated that the casing communication had been eliminated after the June, 1989 workover operation. However, the 10 ¾-in. casing pressure climbed to over 2,000 psi within a year. Diagnostic bleed-down operations in August, 1990 bled the pressure to 1,250 psi but aborted after mud and abrasive material plugged the choke.

**April 1991 Workover.** The rig was skidded over the well to mill windows in the 7 and 10 3/4-in. casings below the 16-in. shoe and set an inflatable packer. The 10 3/4, 16, and 20 in. casing strings were bled down and monitored. The bleed-down and buildup results are listed in Tables 3-6 and 3-7.

**Table 3-6 – (Well 13) 10 3/4-in. Bleed Off/Buildup Data: 03-27-91**

| <b>Well 13: 10 3/4-in. Casing (03-27-91)</b> |                             |                          |  |
|--|-----------------------------|--------------------------|--|
| <b>Initial Pressure (psi)</b>                | <b>Final Pressure (psi)</b> | <b>Bleed Time (min.)</b> | <b>Remarks</b>                                 |
| 1,500  | 0                           | 3                        | No fluid. Continuous blow for 1 hr observation |
| 0  | 550                         | 120                      | No fluid when bled to zero. Continuous blow    |

**Table 3-7 – (Well 13) 16 & 20-in. Bleed Off/Buildup Data: 03-27-91**

| <b>Well 13: 16 and 20-in. Casing (03-27-91)</b> |                               |                             |                          |                |
|---|-------------------------------|-----------------------------|--------------------------|----------------|
| <b>Casing OD (in.)</b>                          | <b>Initial Pressure (psi)</b> | <b>Final Pressure (psi)</b> | <b>Bleed Time (min.)</b> | <b>Remarks</b> |
| 16  | 108                           | 0                           | 2                        | No fluid       |
| 20  | 75                            | 0                           |                          | No fluid       |

The wellbore was cleaned out and no communication was noted between casing strings. The previous 6-in. window cut during the June 1989 workover was located with a mechanical cutter and extended to 30 ft before the hole started taking 12.5 ppg BHC (Borehole Control) mud. BHC mud is a fluid system that develops gel structure for solids suspension but exhibits low viscosity flow characteristics. The mud weight was cut to 11.0 ppg while multiple lost circulation pills including walnut and mica were pumped. Plans were changed to attempt a recovery of the 7-in. casing to the depth of the 16-in. casing shoe. A temperature log was run from below the 16-in. shoe and up that indicated fluid movement at the 7-in. casing window and up to 60-ft. above the window. An EZSV was set and 25-bbl 16.2 ppg ‘H’ was squeezed below with a final squeeze pressure of 2,000 psi.

The 10 3/4-in. casing was bled from 1,000 psi to zero in one minute. The 16 and 20-in. strings were bled from 40 psi. Squeeze perforations were made adjacent to the 16-in. casing shoe. An EZSV was set and two 25-bbl squeezes were pumped. Multiple cuts in the 7-in. casing were made but no circulation was established. The 10 3/4-in. casing increased to 380 psi.

To ensure that no channeling was occurring up the 7 x 10 3/4-in. annulus, a 50 ft. window was milled and de-scaled in the 7-in. casing immediately above the 16-in. casing shoe. Pressure on the 7 x 10 3/4-in. annulus was monitored until it had successfully dissipated. Two unsuccessful attempts were made to latch and pull the 7-in. casing before cutting and recovering it at 101 ft. A 9 1/2-in. rotary shoe and 9-in. washpipe was used to wash hard, dehydrated mud in highly eccentric casing before cutting and recovering 54 ft of 7-in. casing. The 7-in. casing was washed over and cut and recovered 19 ft. The 7-in. casing was then cut two more times and recovered to

and the 10 3/4-in. was de-scaled from. A 9 7/8-in. bit was tripped in the hole but could not work through damaged 10 3/4-in. casing at 155 ft. Circulation was established up the 16-in. casing through the tubing placed at 2,500 ft. A 9 3/4-in. impression block sat down at 155 ft and was “slightly shaved 180 degrees apart”.

A 9 7/8-in. watermelon mill was worked through the damaged area and broke through the tight spot. The 7-in. casing was mechanically cut over 50 times and recovered in 4 to 15 ft increments at an average of 33-ft per day over a twenty day interval. The damaged 10 3/4-in. casing was tagged again at 155 ft and a 9 1/2-in. and 9 7/8-in. tandem string mills were worked down to the top of the 7-in. casing stub. Junk was tagged with a muleshoe at 900 ft and washed to 2,220 ft.

A 6-in. bit and string mill tagged the bottom of the 7-in. window at 2,554 ft and reamed to 2,680 ft. A Tri-State Lockomatic descaler for 10 3/4-in. casing was run the length of the window from 2,503 to 2,555 ft. A cement bond log was then run from 2,100 to 817 ft inside the 7-in. The centralizers were changed out for the 10 3/4-in. and logged from the 7-in. casing stub to surface.

An inflatable packer was set at 2,508 ft but unable to fully inflate with 5 bbl cement. Attempts to push the packer downhole were unsuccessful and the packer hung up at 1,708 ft on the way out of the hole. A 5 7/8-in. burning shoe milled over the packer from 1,708 to 1,750 ft before the packer was pushed downhole to 2,695 ft.

A ‘Payzone Packer’ was set at 2,516 ft and inflated with 1 bbl of 16.2 ppg cement and 5 bbl pumped into the casing with the TOC was tagged at 2,456 ft. A 10 3/4-in EZSV was set at the top of the 7-in. stub and 4 ft of squeeze perforations were made in the 10 3/4-in. casing. Circulation was established between the 10 3/4 and 16-in. casing. A 10-bbl of 16.2 ppg ‘H’ cement was spotted in both the 10 3/4 and 16-in. casing. Cement was subsequently tagged at 769 ft and tested to 1,000 psi.

The BOP stack was nipped down to pull the 10 3/4-in. casing spool. The top 107 ft of 10 3/4-in. casing had parted and came out with the spool. The 10 3/4-in. casing was then cut and recovered to 757 ft. A 14 3/4-in. flat bottom mill and string mill reamed the 16-in. casing from 657 to 756 ft. A 16-in EZSV was set at 755 ft with 11 bbl of 16.2 ppg cement spotted on top. The cement plug and 16-in. casing was tested to 1,000 psi for 30 minutes. A dry hole tree was nipped up and the rig skidded. Pressure in the 16-in. remained at zero psi and the 20-in. at approximately 75 psi. A departure was filed with the MMS for the 20-in. casing.

## **Well 10**

**Original Drill.** This well was spudded in March 1984. A 13 1/2-in. bit was used to drill to 1,390 ft and underreamed to 26-in. Due to tight hole, the 20-in. was cemented at 1,348-ft with 775 sxs 11.5 ppg TLW followed by 350 sxs 16.2 ppg ‘H’ with full returns throughout the job.

A 13 1/2-in. bit was used to drill to 2,580 ft and underreamed to 20-in. One casing capacity was circulated before cementing the 16-in. casing at 2,556 ft with 450 sxs TLW followed by 500 sxs ‘H’. The plug was bumped with 1,500 psi and had full returns while cementing.



A 13 ½-in. bit was used to drill to 5,200 ft. The 10 ¾-in. casing was cemented at 5,210 ft with 1,500 sxs 'H'/TLW followed by 500 sxs 'H'. A 25 bbl spacer was pumped ahead of the slurry, the plug was bumped with 1,500 psi and had full returns while cementing.

A 9 ⅞-in. bit was used to drill the well to a TD of 10,370 ft. Gas cut mud was circulated out at 8,620 and 9,900 ft. The 7-in. casing was cemented at 10,175 ft with 2,200 sxs of 17.2 ppg 'H' and the plug was bumped with 1,500 psi. A 35 bbl dual purpose spacer was pumped ahead of the slurry.

**Initial Completion.** The rig was skidded back in February, 1986 to run CBL, perforate and place sand control. The rig was released March 6, 1986.

**July 1989 Workover.** Rig was skidded over the well and bled down 10 ¾-in. casing from 1,640 psi and recovered 5 bbl clabbered mud. An EZSV was set at 9,250 ft but was unable to establish injection into the formation.

Squeeze perforations were made at 9,138 ft and cemented with 25 bbl of 16.2 ppg cement through an EZSV set at 9,000 ft. A temperature survey was then run from 8,700 ft to surface that found no anomalies.

A second set of squeeze perforations were made below the 10 ¾-in. shoe at 5,260 ft. The perforations were then cemented with 17-bbl of 16.2-ppg cement through an EZSV set at 5,300 ft. The 7-in. casing was cut at 4,900 ft but was unable to establish circulation at 2,500 psi with the 10 ¾-in. casing. An EZSV was then set at 4,900 ft and 5-bbl cement was dumped on top before skidding the rig.

**March 1991 Workover.** The rig was skidded over the well to re-enter the TA'd wellbore and eliminate casing pressure. The 7-in. was bled down from 30 psi, the 10 ¾-in. from 1,500 psi, the 16-in. from 8 psi, and the 20-in. from 20 psi to zero. After 12 hours the 10 ¾-in. casing had built back up to 500 psi.

A 120-ft window was milled in the 7-in. casing from 4,560 to 4,680 ft. Junk was tagged and worked through at 4,610 ft. A de-scaler tool was run from the top of the window but could not get deeper than 4,619 ft. A 6-in. mill tagged up at 4,622 ft and milled to 4,684 ft.

Junk was tagged at approximately 4,610 ft and probably occurred during the milling of the 7-in. casing as the cutter blade OD became worn down. This tended to leave a sliver of 7-in. casing on one side. This was verified by crescent-shaped slivers in the returns. The de-scaler tool tagged up at 4,619 ft and only able to make it to 4,622 ft. A 6-in. flat-bottomed mill was used to push the trash downhole but was not completely effective inside of the 10 ¾-in. casing ID.

A muleshoe was picked up on workstring and tagged up at 4,691 ft. Six barrels of 16.4 ppg Class 'H' was pumped and WOC for 12 hr. A successful cement test was not obtained.

An inflatable packer was set with its bottom at 4,610 ft and cement was spotted and tagged at 4,572 ft. Began pumping past the inflatable packer at ½ bpm and 1,000 psi but unable to obtain

communication with the 10 ¾-in. casing. A successful pressure test on the inflatable packer was not obtained.

A possible leak in the 10 ¾-in. casing was diagnosed at 4,567 ft. A 15.5 ppg mud weight could not be supported and had to be cut back to 12.5 ppg after milling 7 ft of window. After the inflatable packer was set, 5 bbl of cement was spotted on top and 1.5 bbl was able to be squeezed away. A 1,500 psi test was obtained over 12.5 ppg mud. Pressures on the 7-in., 10 ¾-in., and 16-in. were zero psi two weeks after the end of operations.

A 5-bbl cement plug was spotted and 1.5 bbl were squeezed away. The plug was tested to 1,500 psi, a dry hole tree was nipped up and the rig was skidded. All casing pressures were at zero psi when the rig was skidded as well as two weeks later. Within three weeks, pressure was again seen on the 10 ¾ and 7-in. casings and gradually built after a few months in excess of 1,000 psi and 800 psi respectively.

## **1990 Casing Squeeze Program Wells**

### **Well 1**

**Original Drill.** This well was spudded in April of 1983 with 8.7 ppg gelled seawater and drilled without incident to 1,305 feet in 13 ½ hours. Upon underreaming the hole to 26 in., the 20 in. casing was cemented with 900 sacks of Class ‘H’/2% Econolite followed by 350 sxs of Class ‘H’ with partial returns. The bit and workstring was picked up and tripped in the hole until cement was tagged at 1,238 ft. Twenty-eight feet of cement was drilled out to a depth of 1,266 ft and the casing failed a 203 psi test due to a leaking casing head. The casing head was subsequently repaired and the casing tested to 203 psi.

The intermediate hole was drilled to 2,298 ft in 6 ½ hours with 9 ½-ppg gelled seawater. The hole was tight and swabbed as the workstring was being pulled. The 16-in. casing was run but could not get past 1,844 ft. The casing was pulled and the workstring run to 2,292 ft. A bottoms up was circulated with no gas in the returns. Two trips with a 20-in. under reamer and a 17 ½-in. bit were made before running the 16 in. casing to 2,324 ft. The 16-in. was cemented with 700 sxs of Class ‘H’/2% Econolite followed by 500 sxs Class ‘H’. The plug was bumped with 1,508 psi with full returns. The casing was set with 150,000 lb. of tension and tested to 1,508 psi for thirty minutes. The shoe and forty-three feet of formation was then drilled with 10 ppg gypsum seawater mud and tested to an equivalent of 13.5 ppg.

The well was drilled to 3,612 ft while circulating out up to 1,200 units of gas that cut the mud weight from 10.5 to 9.2 ppg. The mud weight was raised to 11 ppg to drill to 4,005 feet. Up to 800 units of gas were circulated out with the mud being cut from 11 to 10.3 ppg. The mud was weighted up to 12.9 ppg to drill to 4,500 ft but was gas cut to 11.3 ppg with up to 1,400 units of gas being circulated out. The mud weight was raised to 13.1 ppg.

A hole opener was run and a wiper trip was made before circulating bottoms up with 500 units of gas. The 10 ¾-in. casing was run to 4,507 ft. A cement slurry of 1,150 sxs of Class H/TLW followed by 500 sxs of Class ‘H’ was pumped with full returns without bumping the plug and the

casing was set with 225,000-lb tension. Cement was tagged at 3,660 ft after 9 hours of waiting on cement. The cement was drilled out to the float collar and the casing tested to 1,508 psi. The cement was then drilled out to the shoe and 10 ft of formation was then tested to a 16.5 ppg equivalent.

While drilling to 5,085 ft, the mud was cut from 13.9 to 12.5 ppg while circulating out up to 100 units of gas. A trip was made for a new BHA and three hours were spent circulating out up to 2,300 units of gas. The mud was cut from 14.1 to 11 ppg before shutting in the well and circulating through the choke to bring the mud weight up to 14.3 ppg.

At 6,259 ft, the mud was cut from 14.3 to 7.6 ppg upon circulating bottoms up. The mud weight was raised to 14.7 ppg to drill to 10,808 ft with the mud being gas cut many times. The mud weight was increased to 15.2 ppg to drill to the total depth of 12,243 ft. Upon running openhole logs and obtaining sidewall cores, the 7-in. production casing was run to 12,266 ft., a 25 bbl 'SD' spacer was pumped, and cemented with 1,600 sacks of Class 'H'. The plug was bumped with 1,000 psi. The casing was run to TD and circulated one complete circulation before the casing got stuck and could not reciprocate the pipe. The casing was tested to 1,910 psi for 15 minutes before nipping down the blowout preventers and skidding the rig.

**Initial Completion.** The rig was skidded back on July 8, 1983 to test the 7-in. casing to 2,100 psi, displace to completion fluid and complete the well. The 20, 10  $\frac{3}{4}$ , and 7- in. casings already exhibited SCP.

**September 1983 Workover.** A snubbing unit was rigged up to pull and replace a velocity valve utilizing a 1  $\frac{1}{4}$  workstring. The 20, 10  $\frac{3}{4}$ , and 7-in casings still exhibited SCP.

**April 1990 TA Operation.** A rig was skidded over Well 1 to address a tubing leak. The tubing failed a pressure test and oil began to flow from the 10  $\frac{3}{4}$ -in. casing while attempting to bleed it down from 1,500 psi. Operations now began to focus on casing repair. A prior noise/temperature survey indicated possible gas flow behind the pipe at 7,200 ft and virtually no cement bond from the 10  $\frac{3}{4}$ -in. casing shoe at 4,507 ft to 8,300 ft. Logs also indicated some permeability and a possible source at 7,150 ft.

The 10  $\frac{3}{4}$ -in. casing was squeezed at 7,140 ft above the possible shallow source at 7,200 ft. with 50 bbl of Halliburton's Microbond cement. Injection pressures were established into the perforations at one and two barrels per minute at 1,200 and 1,400 psi respectively. Final squeeze pressure on the 16.4 ppg cement slurry was 2,400 psi. After a five day waiting period for expansion of cement, excessive casing pressure still existed.

Another 50 bbl Microbond cement squeeze was attempted below the 10  $\frac{3}{4}$ -in. casing shoe at 4,550 ft with a final squeeze pressure of 300 psi. Upon waiting for proper cement expansion, the perforations were drilled out and tested to 1,000 psi

Squeeze perforations at 10,600 ft were made above the abandoned production sand and squeezed with 12 bbl of 16.2 ppg Microbond cement. These squeeze perforations were then successfully

tested to 1,500 psi. Upon drill out and testing of the three squeezes, each set of squeeze perfs held once and then failed a second pressure test.

Injection was established into the previously squeezed perforations at 7,140 ft. A 25-bbl 16.2 ppg cement squeeze was pumped with a final pressure of 2,000 psi. These perforations were successfully tested to 1,500 psi for 15 minutes.

A 25 bbl Microbond remedial squeeze on the perforations at 4,550 ft was then performed with a final pump pressure of 2,000 psi. Following five cement squeezes, the annular pressure was brought under control with the 10 ¾ in. casing pressure building to 350 psi after 15 days and bleeding to zero. A kill string was run in the hole before skidding the rig.

#### **Well 14**

**Original Drill.** This well was spudded in February, 1982. The conductor hole was drilled with a 17 ½-in. bit and underreamed. The 20-in. casing was set and cemented at 1,116-ft. with 750 sxs TLW and 350 sxs 'H' with returns lost during the last 100-bbl. The casing was pressure tested to 203 psi on an unknown mud weight.

The surface hole was drilled with a 12 ½-in. bit and underreamed to 20-in. The 16-in. casing was run and cemented to 3,586-ft. with 1,600 sxs TLW and 800 sxs 'H' with full returns throughout job. The casing was tested to 500 psi on 10 ppg mud.

Upon drilling out the 16-in. casing shoe, gas was encountered at 3,793 ft. to 4,484 ft. The 11 ¾-in. casing was run and cemented to 5,850 ft and cemented with 16.2 ppg Class 'H'. Had full returns while pumping but did not bump the plug. No centralizers were run and the pipe was neither rotated nor reciprocated. The mud was circulated for 30 minutes while the casing was on bottom. The cement cured for over 60 hours while installing the wellhead, testing BOP's and performing rig maintenance. The 11 ¾-in. casing was then tested to 1,520 psi with 13.2 ppg mud.

A 9 ⅞ in. bit and 12 ¼-in under reamer was used to drill this section. Gas was encountered from 6,929 ft. to the 9 ⅞-in. casing point at 9,682 ft with the mud weight being eventually raised to 16.5 ppg. A 9 ⅞-in. liner was run from 5,417 ft to 9,682 ft and cemented with 2,000 sxs Class 'H' cement. A tight spot was encountered at 800-ft with a mill being worked from 676 ft to 902 ft. The 9 ⅞ in. liner top was squeezed with 500 sxs Class 'H' neat with the liner top being tested to 2,100 psi for 30 minutes.

The hole was deepened and evaluated to 12,440 ft. Gas cut mud and lost circulation hampered the operation until the well was plugged back.

**Liner Tieback and Complete.** In August, 1986 the 9 ⅞-in. liner was tied back and the well was completed. Difficulty was experienced while cleaning out the wellbore and could not sting the tieback into the liner. Hard barite was drilled out from 4,497 ft until tagging up at 9,503 ft. A tandem tie-back mill encountered tight spots at 5,379 ft and 5,410 ft.

The tieback was displaced and cemented with 110 sxs of 17.2 ppg cement but the plug did not bump. Very little cement was placed between the tieback and intermediate casing and most was found at the liner top. A total of 9 ½ days transpired previous to drilling out the cement due to wellhead and BOP problems. Very hard cement was then tagged at 5,101 ft and drilled to 5,428 ft. The liner was then tested 2 ½ days later with 2,500 psi for 30 minutes on 17.5 ppg mud. It was also underbalance tested to 2,350 psi for one hour.

The cement bond log indicated no bond through the completion sand requiring two sets of squeeze perforations. One squeeze below the pay zone placed 7 bbl 16.2 ppg Class 'H' Neat into the casing at 800 psi and tested to 500 psi. The second set of squeeze perforations above the pay zone were squeezed three times without success with a total of 220 sxs Class 'H'. A fourth squeeze of 100 sxs Class 'H' was pumped at 1 bpm and 1,000 psi and slowed to ¼ bpm at 1,500 psi. This squeeze was tested to 2,200 psi and broke back to 400 psi in 5 minutes. A fifth squeeze of 100 sxs Class 'H' was pumped at 1 bpm and 1,500 psi but did not test.

A cement bond log was run and indicated sufficient cement bond above the proposed production perforations. The decision was made to commence completion operations.

**May 1989 Workover.** The original objective of a workover in May, 1989 was to address a tubing leak; however, casing damage was found and isolated. A noise and temperature survey indicated damage in the 9 ⅝-in. casing across from the 'B' Sand as well as a temperature anomaly at 3,000-ft. A leak was finally located at 7,720-ft and isolated behind a packer.

**August 1989 Workover.** An attempt was made to replace the gravel pack in August of 1989 but operations were ended after two unsuccessful attempts at getting the gravel pack assembly past the casing damage at 7,720-ft. Two cement plugs were spotted, an EZSV was set and a 2 ⅞-in. kill string was run.

**April 1990 Workover.** First, a cement squeeze at the 11 ¾-in. shoe was performed with 30 bbl Class 'H' and a final pressure of 2,500 psi. Secondly, a total of 6 50-bbl squeezes were performed at the 16-in. shoe into the 11 ¾-in. x 9 ⅝-in. annulus. Various cement formulations were used with both 16.2 ppg and 15.3 ppg slurries pumped at up to 3 bpm and 1,800 psi.

During the subsequent cleanout operations, a tight spot was found at 7,749 ft and ultimately diagnosed as parted casing. Consequently, a 7-in. scab liner was run to 8,562 ft. Estimated TOC in the 9 ⅝-in. x 7-in. was calculated at 6,410 ft after 1,285 sxs 16.0 ppg cement without bumping the plug. The 7-in. liner was tested to 3,550 psi with 14-ppg mud after 45 hours WOC. A bradenhead squeeze was then performed with 90 bbl of Class 'H' on the 7 in. liner. Upon monitoring the casing, it was decided that the casing pressure was successfully reduced and sand control was pumped to put the well on production.

**May 1991 Workover.** In May of 1991, a workover to eliminate casing pressure was performed. Operations involved perforating and squeezing the 7-in. and 9 ⅝-in. casing strings with Magne-set cement immediately above the producing sand. The first squeeze was attempted with 100-sxs at 1.5-bpm and 1,500 psi. Injection gradually slowed to 0.25-bpm at 1,300 psi and over displaced. The first squeeze failed a 1,000 psi test. A second 100-sk. Magne-set squeeze was

pumped at 2,100 psi and 1 bpm and into the squeeze perforations at 2,000 psi. A successful pressure test to 1,500 psi for 30 minutes was obtained. Finally, a 2 7/8-in. kill string was run previous to rigging down the equipment.

A cement bond log run during this workover indicated cement from 950-ft. to 3,582-ft in the 9 5/8-in. x 7-in. annulus from the April, 1990 bradenhead squeeze. Bleed-down and build-up diagnostics were implemented to evaluate the squeeze operation. The squeeze resulted in a 9% decrease in the 16-in. x 11 3/4-in. annulus and a noticeable 85% decrease in the 11 3/4-in. x 9 5/8-in. annulus. However, the 9 5/8-in. x 7-in. annular pressure increased after the job.

**September 1991 Workover.** This workover intended to address a temperature anomaly above the 16 in. shoe that may indicate an annular pressure source. The work consisted of perforating the 7-in., 9 5/8-in., and 16-in. casing strings and pumping acid through the perforations to enhance communication previous to squeezing cement.

During the operations, an injection rate could not be achieved upon perforating, requiring a second perforating run. A 12%-3% HCl-HF acid blend was pumped ahead of the first 37 bbl Magne-set cement slurry. No running squeeze was obtained so a second 37 bbl Magne-set slurry was pumped. Due to mechanical problems, only 22 bbl was pumped and achieving a final squeeze pressure of 1,500 psi.

A post-workover bleed down/build up performed on the 16-in. resulted in 10-gal mud with the pressure dropping from 845 psi to 90 psi in 40 minutes. The pressure built back to 183 psi in one hour and up to 336 in 24 hr. Within three months, the 16-in. was 1,100 psi, 7-in. at 34 psi, 9 5/8-in. at 135 psi, 11 3/4-in. at 485 psi, and the 20-in. remained at 0 psi.

**February 1992 P&A Operation.** Upon cleaning out the wellbore, a 60-ft. window was milled in the 7-in. casing from 6,016 to 6,076 ft. and a 30-ft. section was milled in the 9 5/8-in. from 6,026 to 6,056 ft. The mill used to mill the outer string consisted of a milling tool with modified arms and under reamer that opened to the ID of the outer string for stability. Three sets of cutter arms were needed to mill 20-ft of window in the 9 5/8-in. casing.

A 30-bbl S-Mix cement slurry was pumped and tested to 1,000 psi to isolate this window. S-Mix is a Shell-patented cement slurry that essentially converts mud into cement through the addition of soda ash and caustic activators immediately before pumping the slurry. Large amounts of gas cut the mud and needed to be circulated out previous to cementing.

An 80-ft. window was then milled in the 7-in. casing from 2,847 to 2,927-ft. A 60-ft. window in the 9 5/8-in. was then attempted but difficulties in making the cutout resulted in a 4-ft. window being milled and a further 32-ft. being milled under-gauge leaving a sheath behind. One more run through this section was necessary with cutter arms that opened to the ID of the 11 3/4-in. casing. The window was extended to a total of 50-ft. from 2,856 to 2,906 ft.

A cut out was attempted in the 11 3/4-in. casing at 2,861 ft but failed due to cutter arm damage. Another cut was made 5 ft below but it appeared that the 5 ft section had fallen. Circulation was achieved in the 11 3/4 x 16 in. and 9 5/8 x 11 3/4 in annulus. Forty barrels of S-Mix was pumped

into the 11 3/4 x 16 in. and 23 bbl was pumped into the 9 5/8 x 11 3/4 in. annulus. The casing pressure was then monitored. The pressure on the 16 in. continued to rise.

A cement plug was set at 2,500 ft and the 7 in. casing was recovered to 950 ft. An EZSV was set at 947 ft with 50 ft of cement on top. The 9 5/8 in. casing was recovered to 880 ft with an EZSV set at 878 ft with 50 ft of cement on top. A 42 ft section was then milled in the 11 3/4 in. from 780 to 822 ft. Two 15 bbl barite plugs and Class 'A' cement was set in the window. The 11 3/4 in. was then recovered to 780 ft and an EZSV was set at 774 ft with 50 ft of cement on top.

## **Well 11**

**Original Drill.** This well was spudded in December, 1984. The 20 in. casing was run to 1,305 ft and cemented with 700 sxs 11.5 ppg TLW followed by 500 sxs 16.2 ppg 'H' while being reciprocated with 10 ft strokes. Partial returns were obtained during cementing and no centralizers were run. The casing was tested to 203 psi with 9.5 ppg gelled seawater.

The 16-in. casing was run to 2,302 ft with 5 latch-on Trico centralizers every 60 ft and cemented after pumping a 25 bbl Superflush spacer with 700 sxs 11.5 ppg TLW followed by 500 sxs 16.2 ppg 'H' with partial returns. The casing was reciprocated with 10 ft strokes while losing mud to formation and packing off. The plug was bumped with 2,000 psi and held for 30 minutes. The casing was tested to 1,840 psi and the formation was tested to a 14.0 ppg equivalent.

While drilling to 4,305 ft, 2,035 units of gas was circulated out with the mud weight cut from 13.3 to 9.2 ppg. The mud was weighted up to 13.5 ppg but the well still flowed. Up to 2,168 units of gas was circulated out while weighting back up to 13.4 ppg. The 10 3/4-in. casing was run to 4,305 ft with an unknown amount of Trico KK-5 centralizers and cemented with 1,450 sxs 14.5 ppg 'H'/TLW followed by 500 sxs of 16.2 ppg 'H' with no returns. The plug was bumped with 1,508 psi and held for 30 minutes. The formation was tested to a 17 ppg equivalent before drilling out.

While drilling at 6,971 ft, the mud weight was cut from 15.8 to 13.5 ppg with 1,500 units of gas. At 8,158 ft, the mud was cut from 16 to 11.5 ppg with 1,200 units of gas and again to 12.9 ppg at 8,573 with 1,600 units of gas. While drilling from 9,054 to the 7-in. casing point, the mud weight was cut multiple times from gas influx. The 7-in. casing was circulated and reciprocated while obtaining 180 units of gas in the returns. Trico KK-5 centralizers were run one per joint for the first 80 joints. A 50 bbl dual purpose spacer was pumped ahead of 850 sxs 17.2 ppg 'H'/1,800 sxs 17.5 ppg 'H' cement was pumped and the plug was bumped with 2,000 psi and held for 30 minutes before nipping up the dry hole tree and skidding the rig.

**Initial Completion.** In November, 1985, a rig was skidded over the well to complete it. The 10 3/4-in. casing was bled from 1,350 psi while the 20, 16, and 7-in. casing were all at zero psi. A tight spot was found at ±8,000 ft. A CBL was run indicating good bond around the zone of interest. Sand control was placed and the rig was skidded.

**October 1986 Workover.** A rig was skidded to pull the completion and replace the gravel pack. While burning over the gravel pack assembly, an obstruction was tagged at 8,946 ft. The casing

was milled to 8,977 ft until pieces of casing were recovered. Bad casing was diagnosed from 8,935 ft and down with a window cut from 8,949 to 8,961 ft. A cement retainer was set at 8,910 ft and 13 bbl of 16.2 ppg Class 'H' Neat cement squeezed below. 15.2 ppg zinc bromide kill weight fluid was left in the hole with a kill string hung-off.

**December 1986 Sidetrack.** In early December, a rig was skidded to location and the well was sidetracked. The first sidetrack was abandoned due to stuck drill collars. A 5-in. liner was run and cemented with 100 sxs of 17-ppg Class 'H' after pumping a 20 bbl dual purpose spacer. The plug was bumped with 1,900 psi. The well was perforated and sand control was placed previous to skidding the rig.

**March 1990 Workover.** This workover was intended to relieve 7 x 10 3/4-in. annulus casing pressure of 2,180 psi and return the well to production. The well had been producing on a reduced choke size due to sand production.

The 10 3/4-in. casing was bled down from 2,200 psi while the 7, 16, and 20-in. casing remained at zero psi. Squeeze perforations in the 7-in. casing at 6,836 ft were made and 20 bbl of Microbond cement were pumped with a final pressure of 500 psi. No squeeze was obtained and the rig was skidded. In less than a month, the rig was skidded back and 1,050 psi was measured on the 10 3/4-in. casing.

Squeeze perforations were made at 4,350 ft, the base of the 10 3/4-in casing shoe, and 100-bbl Flo-Check cement was pumped. No squeeze was obtained with the final pump pressure of 1,600 psi. Some reduction in surface pressure was obtained. The 10 3/4-in. was pressured to 1,100 psi, 1,600 psi maintained on the drillpipe, and 1,200 psi on the 2 7/8 x 7-in. annulus for 12 hours. The cement was drilled out and the squeeze failed a 500 psi pressure test.

A second 100 bbl Flo-Check cement squeeze was pumped and succeeded in obtaining a squeeze at 2,500 psi. The drillpipe was pressured to 2,500 psi, the 10 3/4-in. maintained to 1,100 psi, and the 2 7/8 x 7-in. annulus to 1,500 psi for 12 hours. The surface pressure was reduced to 700 psi and was adequate for MMS departure approval. The pressure was bled off, the cement was cleaned out of the wellbore, and a kill string was hung off previous to skidding the rig off.

The rig was skidded back and the squeeze perforations at 4,350 psi failed a pressure test to 1,500 psi. An EZSV was drilled up at 6,696 ft before hanging off a kill string and skidding the rig.

Further downhole operations were deemed too dangerous and economics did not justify further remedial work. In order to comply with MMS regulations, operations centered on adequately plugging the perforations at the 10 3/4-in. casing shoe.

About one month after moving off, the rig was skidded back and injection was established into the perforations at 4,350 ft before locking up with 4,000 psi. Sixteen barrels of mud acid was then pumped into the perforations and the well started flowing on the drillpipe and 7-in. casing. Both 25 bbl of 13 ppg and 7 bbl of 14.7-ppg Magne-set cement were mixed and pumped at 2 bpm and 2,300 psi while not obtaining a squeeze. Two hesitation squeezes were then performed



with a final pump pressure of 1,650 psi. Pressure was held on the squeeze while WOC for 12 hours.

The pressure was released and WOC for a further 12 hours before drilling out the cement. By pumping in at 1 bpm and 800 psi, an attempt to test the squeeze failed. Three 20-bbl Neat cement squeezes were pumped without obtaining a squeeze. Attempted to test squeezes but was able to pump at 2,000 and 2,150 psi at 1 bpm.

Two further 20 bbl Magne-set squeezes were pumped. On the final squeeze, 8-bbl of cement was left in the casing. A total of 6 hr WOC before a successful test on the cement to 2,300 psi for 15 minutes was made. The kill string was hung off before skidding the rig.

Within months, the 10 ¾-in. casing pressure began building. A bleed down/build performed in April of 1991 bled gas as the pressure decreased from 982 psi to 0. Pressure continued to increase to values in excess of 1,000 psi.

**March 1992 Workover.** The rig was skidded over the well in March of 1992 to re-enter the wellbore and eliminate casing pressure. The 7-in. casing had 16 psi, the 10 ¾-in. had 1,370 psi, and the 16-in. casing had 720 psi. The 7-in. casing was tested to 3,000 psi before pulling the kill string.

The objective of this workover was to attempt a 'suicide' squeeze in the 7 x 10 ¾-in. casing annulus by milling windows with a #5 Lockomatic with 7 ¼-in. blades. A 2-ft window was milled in the 7-in. casing at 4,308 ft MD immediately above the 10 ¾-in. shoe. An unsuccessful attempt to circulate was made before milling a second 2-ft window at 4,008 ft. A second unsuccessful attempt to circulate was made before extending the window to 4,023 ft for a total of 15-ft.

The casing was de-scaled with a 9.7-in. Tri-State descaler and 6 ½ bbl of experimental poly plastic (polyacetalate) resin was spotted in the window. The resin plug was tested to 1,500 psi and held this pressure for 12 hrs. The kill string was hung off before skidding the rig.

Results of the March 1992 resin job were limited. The pressure previous to the workover was rising at a rate of 75 psi/week and was at 1,450 psi immediately before commencement of operations. After the resin job, one bleed down was performed with the pressure stabilizing at approximately 675 psi. It was theorized that further bleed-downs were necessary since the trapped pressure was not completely bled down. The resin is also recommended to be squeezed in a clear fluid system rather than spotted in a mud system.

## **Well 15**

**Original Drill.** This well was spudded in November, 1984. A 13 ½-in. hole was drilled with 8.7 ppg gelled water to 1,467 ft. It was underreamed to 26-in. before running 20-in. casing to 1,466 ft. The casing had to be circulated and washed down from 695 to 736 ft. The 20-in. was cemented with 950 sxs TLW/500 sxs 'H' with full returns. A 203 psi test was made after 9 hrs WOC.

A 13 ½-in. bit was again used to drill to 2,823 ft and the hole was underreamed to 20-in. The 16-in. casing was run and cemented to 2,823 ft with 900 sxs TLW/500 sxs 'H'. The plug was bumped with 1,840 psi and had full returns while cementing. The casing was reciprocated while pumping cement and latch-on centralizers were run 1 per joint for the first 6 joints.

A 13 ½-in. bit was used to drill to 5,534 ft before running and cementing the 10 ¾-in. casing to TD with 2,000 sxs TLW/H followed by 500 sxs 'H'. Two bottoms up were circulated prior to pumping cement. A total of 10 Latch-on centralizers were run at 1 per joint for the first 8 joints and then two at the shoe between the 10 ¾ and 16-in. casing strings. The casing was stuck after tagging bottom and was unable to reciprocate. The plug was bumped with 1,508 psi and received 35 bbls of cement at surface. The spacer was damaged beyond use due to weather and was unable to receive a replacement spacer in time for the cement job.

Upon testing the shoe and formation to a 17 ppg equivalent, a 9 ⅞-in. bit was used to drill to a TD of 11,737 ft while encountering gas cut mud from 9,464 ft. Open hole logs were run and sidewall cores were recovered before running the 7-in. casing to 11,564 ft. Over 300 units of gas was recovered upon circulating the first of two bottoms up and the mud weight was cut back from 15.8 ppg to 14 ppg. Eighty Latch-on Trico centralizers were run every 30 ft. The cement slurry pumped consisted of 850 sxs 'H'/19.2 ppg Hi-Dense followed by 2,200 sxs 17.2 ppg 'H' with Gas Check additive. The plug was bumped with 2,000 psi and held for 30 minutes. The rig was skidded.

**Initial Completion.** In March of 1986 the rig was skidded back to clean out and complete the well. A bit and scraper tagged up ±50 ft high from the float collar. The casing was tested to 3,000 psi with 15.5 ppg mud and again to 4,500 psi with 8.6 ppg seawater. A cement bond tool was run and indicated 'very good' cement above, thru, and below the zone of interest. The well was perforated, sand control pumped, and tubing run before the rig was skidded.

**July 1990 P&A Operation.** Well 15 was to be abandoned by first attempting to reduce the annular press with a deep squeeze at the shallowest hydrocarbon source. If pressure remained, operations would continue by milling and under-reaming below the 10 ¾-in. shoe. An openhole packer would then be set and the openhole section would be cemented. After milling the first 26 ft of 7-in. casing, the mill could not re-enter the lower 7-in. casing stub. It was theorized that this casing misalignment indicated massive hole washout in the vicinity.

The rig was skidded over the well for abandonment operations. The 20-in. casing was bled from 440 psi and then filled with 8 bbl of seawater. The 16-in. was bled from 180 psi and filled with less than 1 bbl seawater. The 10 ¾-in. was bled from 550 psi to 200 psi before getting fluid in the returns. No communication was observed between casing strings. Within 24 hours, pressure had built up on the 20-in. to 440 psi, 360 psi on the 16-in. and the 10 ¾-in. was back up to 1,287 psi.

An EZSV was set at 9,450 ft. A temperature and noise log was run from 9,350 ft and 9,260 ft respectively. Excessive drag was noticed at 9,100 ft while TIH with 4 ½-in. guns. After making a bit and scraper run to the EZSV, squeeze perforations were made at 9,350 ft. Fifty barrels of

16.2 ppg ‘H’ cement was mixed and pumped with 45 bbl squeezed below an EZSV set at 9,300 ft and 5 bbl spotted on top.

Bleed off tests were performed on the 10 ¾-in., 16-in. and 20-in. casing. See Tables 3-8, 3-9, and 3-10 for a summary of the results. Casing pressures were bled to zero and shut-in for build up. The 20-in. casing would not bleed off and began to flow at 0 psi.

**Table 3-8** – (Well 15) 10 Hour Buildup Data from July 1990 Workover

| <b>Well 15: 10 Hour Buildup</b> |                               |                             |
|---------------------------------|-------------------------------|-----------------------------|
| <b>Casing OD (in.)</b>          | <b>Initial Pressure (psi)</b> | <b>Final Pressure (psi)</b> |
| 10 ¾                            | 250                           | 25                          |
| 16                              | 160                           | 12                          |
| 20                              | 146                           | 110                         |

**Table 3-9** – (Well 15) 24 Hour Buildup Data from July 1990 Workover

| <b>Well 15: 24 Hour Buildup</b> |                               |                             |
|---------------------------------|-------------------------------|-----------------------------|
| <b>Casing OD (in.)</b>          | <b>Initial Pressure (psi)</b> | <b>Final Pressure (psi)</b> |
| 10 ¾                            | 25                            | 20                          |
| 16                              | 12                            | 0                           |
| 20                              | 110                           | 225                         |

**Table 3-10** – (Well 15) 9 Hour Buildup Data from July 1990 Workover

| <b>Well 15: 9 Hour Buildup</b> |                               |                             |
|--------------------------------|-------------------------------|-----------------------------|
| <b>Casing OD (in.)</b>         | <b>Initial Pressure (psi)</b> | <b>Final Pressure (psi)</b> |
| 10 ¾                           | 20                            | 72                          |
| 16                             | 0                             | 12                          |
| 20                             | 225                           | 315                         |

A window was cut in the 7-in. casing from 5,535 to 5,552 ft. The window was then underreamed. The hole started taking fluid while cutting the window so the mud weight was cut back from 15.7 to 14.7 ppg and ultimately down to 13.9 ppg mud while underreaming. The window was extended down to 5,561 before losing contact with the 7-in. casing. Plans to fish the 7-in. casing were abandoned and a bridge plug was set at 4,000 ft with 5 bbl 16.2 ppg ‘H’ cement placed on top.

A Tri-State cutter made a cut in the 7-in. casing at 2,900 ft but was unable to neither establish circulation nor pull the casing free. Another cut was made at 1,031 ft and was able to latch and pull the 7-in. casing free after circulating on casing volume. Two joints of casing were then

backed off and a cut was made at 2,965 and 2,198 ft after running a free-point tool. Three joints of casing were backed off and another cut and recovery was made at 1,754 ft. A cut was made at 2,272 ft and 1,976 ft. The 7-in. casing was recovered to 1,976 ft and washed over to 2,031 ft.

Progress was too slow so perforations were made at the 16-in. shoe at 2,825 ft but was unable to establish injection. A second set of perforations was made at 2,870 ft and an injection rate of 3 bpm was made at 500 psi. An EZSV was set at 1,970 ft and 85 bbl of 16.2-ppg 'H' cement was squeezed below, leaving 5 bbl on top. The 10 3/4-in. was tested to 1,500 psi.

The 20-in. was bled down from 100 psi and in 1 hour had built up to 10 psi. Squeeze perforations were made at the 20-in. shoe at 1,500 ft and 2 bpm at 1,000 psi injection was made. An EZSV was set at 1,400 ft with 45 bbl 16.2 ppg 'H' squeezed below and 5 bbl left on top. The casing was tested to 1,500 psi before skidding the rig.

### **1989 to 1982 Findings**

The following summarizes the learnings from operations between 1989 and 1982; however, Chapter 5 will study the findings in more detail. Analysis of these operations led to the improvements described in Chapter 4 during the 1999 workover program.

In summary, the four wells worked over in the 1989 workover program were exhibiting SCP within one year of the workover. This program centered on perforating, cutting, and squeezing operations with Class 'H' cement. Generally, it was not successful in eliminating SCP between the production and protective casing strings due to a failure to establish circulation with the annulus. The greatest success in addressing SCP appears to have been within the most easily accessible 7-in. casing.

During the beginning of the four well 1990 casing squeeze program, Halliburton's Microbond cement was used and focused on possible deep source gas sands. Following the Microbond squeezes, a Flo-Chek cement slurry was applied but had little to no success in reducing casing pressures. Various Class 'H' and accelerated CaCl<sub>2</sub> cement squeezes were attempted with limited success. Magne-Set cement was also used but the pressure continued to rise one year after the squeezes.

During the 1990 squeeze program, two methods were considered when addressing SCP in wells to be abandoned. The first was to mill windows in casing at strategic points and fill the void with cement. The second method was to perforate and squeeze at affected casing shoes.

Milling and underreaming operations at the intermediate casing shoe were abandoned in mid-1990 when trouble was encountered while milling and the lower stub fell away. It could not be re-entered. Damage to outer casing strings during milling operations was suspected; as a result, section milling operations were re-evaluated with blades sized to mill both the larger collars as well as the thinner tube.

Some of the learnings from the 1989/1990 program were incorporated into operations between 1990 and 1992. It concentrated on removing affected casings when possible and applying improved squeeze techniques or different cement recipes.

## CHAPTER IV: DESCRIPTION OF 1999 RIG METHOD

### Summary

To comply with MMS regulations, the operator put a workover rig on location in 1999 to address SCP. Several scenarios were considered in an attempt to alleviate the SCP from numerous annuli of multiple wells on the platform. In particular, proper application of various cementing designs and other pressure isolation methods were studied. Any opportunities to use large OD coiled tubing were also reviewed. Because some casing recovery was expected, the use of coiled tubing was not cost-effective.

This chapter highlights the rig remediation techniques developed for use on twelve wells during the 1999 workover program. The affected casing strings vary from the 7-in. production casing to the 16-in. surface pipe or 20-in. conductors. Some wells presented opportunities for different approaches or varying combinations. The preferred approach was to attempt pressure isolation at the greatest depth possible. Then, according to MMS guidelines for plugging and abandonments, most wellbores were prepared for abandonment to the point of, but not including, blowing conductors and other surface pipes before platform removal.

Each well presented its own unique operational difficulties. However, a general strategy was developed based on depth considerations and the particular casing annulus exhibiting SCP. Intervening as deeply as possible was the preferred method. This allowed for future remedial work if the present operations did not succeed as well as maximizing the hydrostatic pressure available to killing any pressure. Casing shoe integrity and casing burst characteristics were the limiting factors considered when fluid weights and test pressures were chosen during the operation.

The first thing to consider was the number of casing strings with sustained pressure and all associated cuts and plugs to properly abandon the well in accordance to MMS guidelines. This included depth consideration for cement plugs to isolate terminated stubs, milled windows and associated cement plugs, as well as any surface cement plugs in preparation for permanent abandonment. This minimum depth was compared to the 10 3/4-in. casing shoes or other maximum accessible depth.

Initial cuts in the 7-in. production casing were made at approximately 2,000-ft. MD, which was between the 10 3/4-in. intermediate and 16-in. casing shoes. No cuts below the 10 3/4-in. casing shoe were attempted during this operation. Deep cuts were attempted so that kill weight fluid could be circulated into the annulus through the cuts before pulling. Even if circulation was not established, it was hoped that if communication were opened with the annulus, the kill weight fluid would aid in suppressing pressure.

An initial deeper cut using a mechanical cutter was made first and then on the same trip, a shallower cut 40 to 100-ft. was made below the hanger. So that the first section of casing could be cut and pulled, a second shallow cut was necessary immediately below the casing hanger. The shallow cut released tension on the hanger to facilitate its removal. Many times the hanger would have to be jarred out of the bowl when the tension was released. Once the shallow cut was made and the hanger was removed, an attempt was made to pull the section of casing. Many

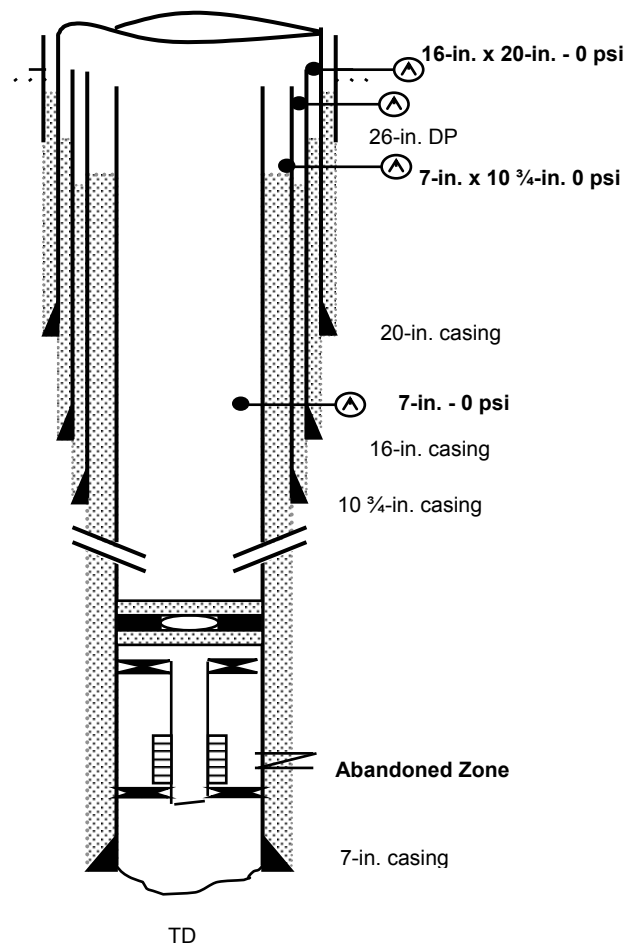
times the casing would not pull free, so casing stretch was then calculated and cuts were made accordingly. At times, it was necessary to pull the sections 20 to 40-ft. at a time.

Initially, a cement bond log was to be run to estimate the top of cement in the annulus of the 7-in. casing. The casing was then to be cut above this log-estimated top of cement. However, during the course of the program, a reliance on calculated pipe stretch became the preferred method. It was found that even though the cement bond log indicated little cement bond, there was still enough cement and/or dehydrated mud to hinder any pull attempts with the rig. Ultimately, a rough estimate of the top of cement was made from the reported volumes of cement pumped during initial cementing operations, whether or not returns were lost during pumping, and if cement returns occurred at surface, as well as any available cement bond log tops. From this, a crude calculated top of cement was assumed, taking into account annular volumes and openhole washout.

Past workover attempts were studied, and some improvements were made to the procedures. Two main approaches to accessing and alleviating SCP were adopted during the 1999 workover program.

The first method involved terminating the affected casing string as deeply as possible inside the outer casing without extending below the 10 3/4-in. casing shoe. Terminating the casing as deeply as possible, maximized the room available for possible future intervention and provided the hydrostatic advantage of the longer fluid column.

The second method involved milling a 120-ft. foot window and isolating both the lower stub and upper stub with cement plugs. This method was attempted in cases where the inner casing string could not be economically or feasibly removed to a necessary minimum depth to address annular pressure. For instance, if drilling reports indicated the inner casing was cemented in place with cement to surface, or if a cement bond log indicated too shallow of a top of cement, a window milling procedure was planned.



**Figure 4-1:** Example wellbore

Discussion of preferred fluid systems and weights, as well as a brief description of the cement slurry properties, will be presented after both methods of pressure isolation.

### **First Method: Termination of Inner Casing**

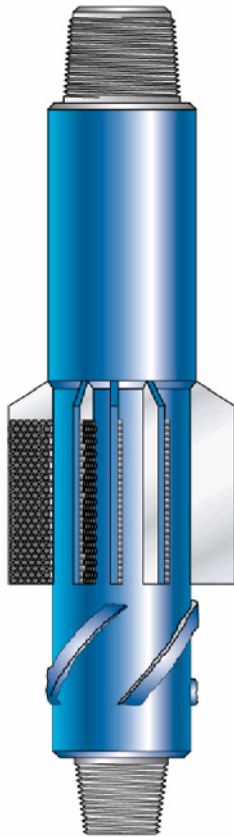
The following example is of a typical ‘cut and pull’ or ‘termination of inner casing’ operation in 7-in. 29-lb/ft casing inside 10 ¾-in. 45.5-lb/ft casing. Refer to Appendix C for well schematics that illustrate the following sequence of events.

This is the preferred method when the affected casing annulus is not cemented or removal is not otherwise restricted. Fig. 4-1 illustrates a typical wellbore before this workover program.

### **Cut and Pull Casing**

Upon gaining access to the wellbore, the mud was circulated out to kill weight fluid. A trip in the hole with the workstring and a mechanical cutter was then made to cut the 7-in. casing in an attempt to circulate kill weight fluid down the casing and into the annulus if possible. When the deep cut was made, the well was verified to be dead before the cut immediately below the hanger was made. When a successful shallow cut was made, the pumps were rigged down and the workstring was pulled out of the hole. The shallow cut released tension on the hanger allowing it to be removed along with the first 40 to 50-ft. of casing down to the shallow cut.

A spear and grapple set to catch 7-in. 29-lb/ft casing was then picked up on workstring and tripped into the hole to spear into the 7-in. casing. An attempt to establish circulation was not made until there was casing movement in order to avoid packing mud or sediment in the annulus. Once the pipe was moving, it was reciprocated while mud was circulated in the hole. The casing was picked up and pulled out of the hole to recover the casing to the deeper cut.

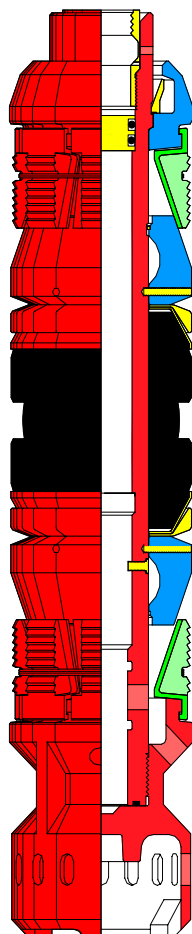


**Figure 4-2:** Typical Metal Muncher Pilot Mill

If the affected casing could not be cut and pulled, contingent stretch calculations were performed to make a cut as deeply as possible. A spear and grapple set to catch the affected casing was picked up and speared into the stub to provide casing movement. Mechanical cuts were then made at depths calculated from stretch to not be restricted behind pipe.

Sometimes it was necessary to pilot mill immediately below the casing hanger or from the deepest successful casing cut and recovery. The pilot mill similar to the one illustrated in Fig. 4-2 contained carbide inserts to increase penetration rates and mill life. This ‘Metal Muncher’ pilot mill is specifically designed to mill various pipes including casing and liners. The blade design creates small cuttings for ease in removal and is run in conjunction with a shock sub and drill collars to provide weight. The weight on mill and rotating speed are determined by penetration rate, torque, and hole cleaning.

Initially, some balling of metal cuttings occurred at or around the bell nipple but a combination of mud conditioning and the use of a mud trough, built in conjunction with the rig contractor, minimized any delays from milled cuttings. The open-top trough was introduced after the third well in the program encountered approximately 40 hours of trouble time cleaning the mud flowlines of metal cuttings. Few problems from plugged return lines were encountered upon switching to the open-top mud troughs and removing all sharp bends or obstructions.



**Figure 4-3:** Example CIBP used during 1999 Workover Program

#### **Casing Cleanout: Preparation for Pressure Isolation of Inner Casing Stub and Annulus**

Once the casing was cut and pulled, a trip in the hole to the 7-in. casing stub with a bit and scraper sized for the outer 10 3/4-in. 45.5 lb/ft casing was made. The bit and scraper was worked from the casing stub up through the top of the proposed plug location. A minimum of one bottoms up was circulated out to clean the hole before pulling out of the hole with the bit and scraper.

Whenever possible, a bottom was set to avoid cement contamination from gas or other fluids migrating through the setting cement. A cast iron bridge plug (CIBP), similar to the one shown in Fig. 4-3, was the preferred method. It had both slips and sealing elements rated to 5,000 psi differential and up to 300°F and was usually set on the workstring inside the proposed casing stub before milling or pulling operations. The CIBP was then pressure tested, resulting in a pressure loss of no more than 10% during a 15-minute time period, which verified proper setting.

When cementing in a water-based mud environment, a diverter sub, similar in design to the one pictured in Fig. 4-4, was then picked up on workstring and tripped in the hole to the planned top of cement and rotated into the hole throughout the plug interval. The tool has an axial flow pattern for efficient removal of mud cake or trash from the casing. Upon switching from a water-based mud system to gelled brine in October of 2001, the diverter sub run was removed from the program.

#### **Pressure Isolation of Inner Casing Stub and Annulus**

Upon proper casing preparation, the workstring was tripped into the hole down fifty feet inside the 7-in. casing stub. The annulus was closed and injection rates were established before cement was mixed. A spacer was pumped ahead of the latex cement.

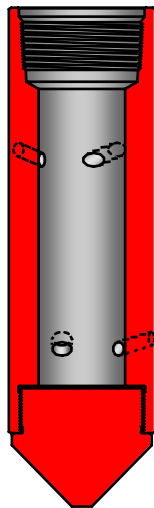
The latex cement was mixed, pumped, and then displaced to balance the cement plug inside and outside of the workstring.



|   |                   |
|---|-------------------|
| <b>Example calculation</b> (7-in. 29 lb/ft stub x 10 3/4-in. 45.5 lb/ft): |                   |
| 7-in. 29-lb/ft Capacity: 50 ft * 0.0371 bbl/ft                            | = <b>1.86 bbl</b> |
| 10 3/4-in. 45.5 lb/ft Capacity: 50 ft*0.0961 bbl/ft                       | = <b>4.81 bbl</b> |
| <b>Total Volume</b>   | = <b>6.67 bbl</b> |

**Cement volume calculated to leave 50-ft. cement in 7-in. casing stub and 50-ft. cement in 10 3/4-in. casing:**  
 $[(1.86 + 4.81) \text{ bbl} * 5.615 \text{ ft}^3/\text{bbl}] / 1.20 \text{ ft}^3/\text{sk} \sim \mathbf{32 \text{ sacks}}$

The workstring was then slowly picked up, 30 to 50 ft. per minute, four stands out of the cement plug. The workstring annulus was closed and pressure applied to attempt to squeeze a maximum of 2-bbl of cement around the 7-in. x 10 3/4-in. casing annulus. This left a minimum of 20 ft. of cement in the 10 3/4-in. casing. Before the squeeze pressure was released, a final squeeze pressure was established and recorded.



**Figure 4-4:** Diverter Sub for Setting of Balanced Cement Plugs

Either one and one half tubing volumes was then reverse circulated, or until no cement was in the returns, without exceeding a pump pressure that could possibly break down any exposed casing shoes. The casing was then pressured to the final squeeze pressure determined earlier. The final squeeze pressure was held while waiting on the cement to cure for a minimum of twelve hours before the workstring was pulled out of the hole.

Next, a bit and scraper for 10 3/4-in. 45.5-lb/ft casing was run to the top of the cement plug. If the top of cement was above a minimum depth necessary to place all subsequent isolation plugs, the top of cement was dressed off to that minimum depth. The scraper was worked and a bottoms up was circulated before pulling out of the hole with the bit and scraper.

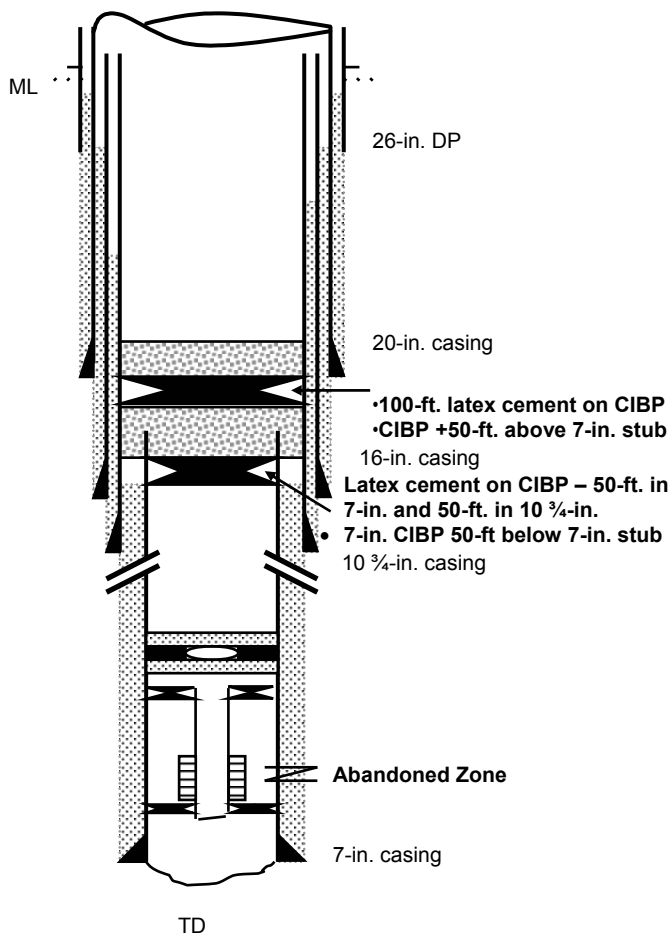
A 10 3/4-in. CIBP was then picked up and tripped in the hole on workstring and set after tagging the cement plug and picking up around ten feet. Once the CIBP was set and tested, 100-ft. of cement was then spotted on top. Fig. 4-5 is an example ‘cut and pull’ operation illustrating the cement and mechanical isolation of the terminated casing stub.

### **Second Method: Window Milling Operation**

One primary concern when milling concentric strings of pipe is breaching the outer barrier with the mechanical cutters. Great care was taken to avoid compromising the next larger casing both when cutting to recover a casing string as well as during any window milling operation. This is a very difficult proposition when invariably a cut is made at a point where the inner casing is eccentric in relation to the outer tube.

To help minimize this effect, cutters were optimized to the outer diameter they were cutting. Previous milling operations may only have one size cutter large enough to mill up the tube and collar in one run. This minimized tripping time but compromised casing integrity. During this operation, two cutter sizes were used on every casing when a window ‘cut-out’ was made: one specifically sized to cut the tube, and a larger cutter for the casing collars. The chances of cutting into the next larger casing were minimized to the length of each collar, which can be considered a significant improvement from previous operations.

Another precaution was the alteration of the cutters to have cutting material only on the lower end of the blades. This was done to avoid unnecessary wear on the outer casing string.



**Figure 4-5:** Example 1999 WO Program Casing Stub Isolation

### **Window Milling**

The following is a summary of a typical 120-ft. window milling operation in 10 3/4-in. 45.5 lb/ft casing in which three sizes of cutters were used. Refer to Appendix D for well schematics that illustrate the following sequence of events. The wellbore schematic in Fig. 4-6 illustrates the window milling procedure and can also be used as a reference.

Whenever possible, a bottom was set to avoid cement contamination from gas migrating through the setting cement or if the wellbore fluid and cement had a 2-lb/gal or greater density difference. The preferred method was setting a CIBP between 100 and 200-ft. deeper than the proposed top of inner casing stub. The bridge plug was then pressure tested to a nominal pressure, depending on the burst capabilities of the surrounding casing, to verify proper setting.

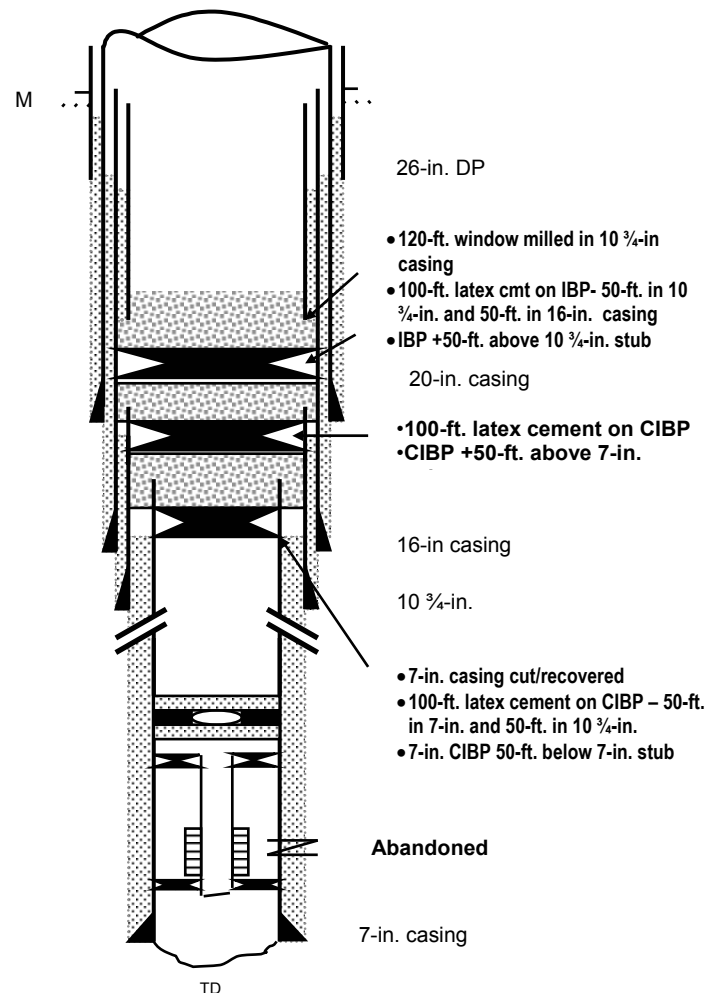
The use of the CIBP was not meant to act as a long-term pressure seal when not used in conjunction with a cement plug; rather, it was used to aid in obtaining a suitable cement job. It is felt that long-term degradation could occur to the CIBP rubber elements from constant exposure to the wellbore environment (mainly temperature). If the wellbore fluid and cement density was greater than 2-lb/gal, contamination of the cement by mixing with the drilling mud could occur and jeopardize the cement integrity. The bottom was also set far enough into the stub to allow debris to fall out of the way from any milling operation.

The following 10 3/4-in. 'cutout' section mill bottomhole assembly (BHA) was used to cut a window in the tube of the 10 3/4-in. 45.5 lb/ft casing immediately below a casing coupling. Other milling assembly sizes for the various casing sizes encountered during the project are listed in Table 4-1.

- 9 3/4-in. stabilizer
- Section mill with maximum expansion of 11 1/2-in.
- 9 5/8-in. OD string mill
- 7 1/4-in. OD cushion sub
- Drill collars

An example Lockomatic section mill is illustrated in Fig. 4-7. The arms of the Lockomatic section mill lock into the open position to ensure full gauge milling. It can be run with a standard drilling BHA and can be dressed with various cutting knives.

A minimum of four ditch magnets for cleaning the mud system were used in the surface return lines. Attempts were made to remove any restrictions, obstructions, or sharp bends where applicable in the flow lines before milling operations.



**Figure 4-6:** Example 1999 WO Program Section Mill Operation

**Table 4-1:** 1999 WO Program Milling Assembly Dimensions

| <b>Casing Size (in.)</b> | <b>Cut-Out Mill (in.)</b> | <b>Section Mill (in.)</b> | <b>Coupling Cut Mill (in.)</b> |
|--------------------------|---------------------------|---------------------------|--------------------------------|
| 7                        | 7 ½                       | 7.38                      | 7.63                           |
| 10 ¾                     | 11 ½                      | 11 ¼                      | 12                             |
| 16                       | 16 ¾                      | 16 ½                      | 17 ¼                           |

The tools were made up and tested at the rotary before tripping in the hole. The tools were passed through the entire length of the proposed window milling section to verify no obstructions were present. The assembly was picked up to top of the proposed section while the depths of all collars in the proposed window were noted. The collars were noted from blade resistance as they dragged past a collar at low pump rates through the tool. The low pump rates allowed for the blades to extend without beginning a cut.

When the proposed cutting zone was verified to be clear of obstructions, the pumps were idled while slacking off. When the weight indicated a collar near the desired window depth, the assembly was slacked off 2 to 3 ft. below the collar so that the window could be cut out.

To begin milling the cutout window, the mill was rotated while increasing the circulation rate. The tool was rotated several minutes before slacking off and then slacked off in ¼-in. increments for the first 12 to 18 in. Cutout times varied depending on tool pressure, but adequate time was taken in cutting out the window to ensure a smooth cutout. Circulation rates for proper tool function depended on the mud weight being used.



**Figure 4-7:** Lockomatic Section Mill used during 1999 Workover Program

When the cutout window was complete, the BHA was pulled out of the hole and the 11 ½-in. section mill was laid down. A section mill BHA with ‘mill-down’ blades (maximum expansion of 11 ¼-in.) was then picked up. The BHA was as follows:

- 9 ¾-in. stabilizer
- Section mill with maximum expansion of 11 ¼-in.
- 9 ⅝-in. OD string mill
- 7 ¼-in. OD cushion sub
- Drill collars

A minimum of four ditch magnets were again used for cleaning the mud system, and the tools were made up and tested at the rotary before tripping in hole. The window was located from the previous window ‘cutout’ run, and section milling of the tube began. Milling was stopped at 1 to 2 ft. above the next deeper coupling.

Higher weights and rotary speeds were sometimes needed to achieve the best milling results. The string mill and section mill were worked to the upper stub to help prevent cutting buildup at that point, and to assist in hole cleaning. The recommended milling fluid parameters were sufficient to clean the hole; however, the actual rate of penetration varied due to hole cleaning and the hardness of cement behind the casing.

Upon reaching the next deeper coupling, the 11 ¼-in. section mill BHA was pulled out of the hole. The 11 ¼-in. mill-down blades were changed out to a set of ‘coupling cutout’ blades with a maximum expansion of 12-in. and the tool was tripped back in the hole to the bottom of the window.

This milling procedure with the 11 ¼-in. and 12-in. mill-down blades was repeated until a 120-ft. section was completed. The milling assembly was then pulled out of the hole and laid down in preparation for cementing operations.

### **Casing Cleanout: Preparation for Pressure Isolation of Lower Casing Stub**

The first step in preparation for pressure isolation of the lower casing stub was to trip in the hole with a bit and scraper sized for the milled casing along with a Lockomatic under reamer dressed with blades for the next larger casing. This trip was used to clean the greater portion of the cement and dehydrated mud from the casing wall. The outer casing was cleaned throughout the milled region, and a minimum of one bottoms up was circulated to clean the outer casing before a cement plug was pumped. The bit, scraper, and Lockomatic under reamer tool was then pulled out of the hole.

The Lockomatic under reamer tool was laid down, and a Multi-String Cutter (MSC) tool, pictured in Fig. 4-8, for the next larger casing was picked up and run in the hole with a bit and scraper sized for the inner casing. This tool was used to polish off the casing throughout the milled area of the casing to increase the bonding characteristics of the cement to casing. A minimum of one bottoms up was circulated to clean the outer casing before the cement plug was pumped. The bit, scraper, and MSC tool were then pulled out of the hole.

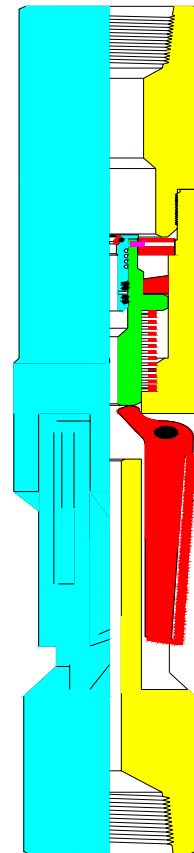
Initially, the MSC tool run in tandem with a bit and scraper for the 10 3/4-in. 45.5-lb/ft casing was the second outer casing cleanout trip. This run was removed from the program in favor of a single cleanout run with Lockomatic underreamer tool. This was done for two reasons: first, the Lockomatic underreamer was found to provide sufficient cleaning of the casing walls without the need for the MSC run, and second, the outer casing was being exposed to unnecessary wear.

**Pressure Isolation of Lower Casing Stub**

During a window milling operation, the next trip in the hole with the workstring was to the previously placed artificial bottom set inside the inner casing stub. A heavy mud was spotted to help minimize any cement contamination from the swapping of light and heavy fluids in the wellbore. The mud was generally a 15.7-lb/gal mud which put the fluid to cement weight differential (15.6-lb/gal latex cement) well within the recommended 2-lb/gal. This plug was spotted to the bottom of the expected cement plug in the inner 10 3/4-in. casing stub.

Upon spotting heavy fluid, the workstring was placed at the proposed cement plug bottom. The annulus was closed and injection rates were established before the cement was mixed. Typically a 25-bbl spacer was then pumped ahead of the latex cement slurry, but in casing strings greater than 10 3/4-in., a 50-bbl spacer was pumped to verify proper displacement.

Necessary cement volumes were calculated to leave 50 ft. of cement in the inner casing stub and 40 ft. in the stub annulus. The cement plug was displaced and balanced inside and outside the workstring.



**Figure 4-8:** Multi-String Cutter used during 1999 Workover Program

**Example calculation** (10 3/4-in 45.5 lb/ft stub x 16-in 84 lb/ft):  
 16-in. 84 lb/ft Capacity: 40 ft\*0.2188 bbl/ft = **8.75 bbl**  
 10 3/4-in. 45.5 lb/ft Capacity: 50 ft \* 0.0961 bbl/ft = **4.80 bbl**  
**Total Volume =13.55 bbl**

**Cement volume calculated to leave 40-ft. cement in 16-in. casing and 50-ft cement in 10 3/4-in. casing stub:** [(8.75 + 4.80) bbl\* 5.615 ft<sup>3</sup>/bbl]/1.20 ft<sup>3</sup>/sk ~ **65 sacks**

When the cement plug was spotted, the workstring was slowly picked up four stands at 30 to 50-ft. per minute. The annulus between the workstring and inner casing annulus was closed and pressured in an attempt to squeeze a maximum of 4-bbl of cement into the 10 ¾-in. x 16-in. casing annulus. Squeeze pressure varied based on burst characteristics of the casing. A final squeeze pressure was established, and then released.

One and a half tubing volumes was then reverse circulated or until there was no cement in the returns, without exceeding 80% of final squeeze pressure.

**Sample workstring volume calculation:** 4 ½-in. 16.60-lb/ft S-135  
XH at 2,100-ft: 1 ½ tubing volume =  $1.5 * (0.0139 \text{ bbl/ft}) * (2,100\text{-ft})$   
= **±44 bbl**

After the hole was circulated clean, the casing was re-pressured to the final squeeze pressure determined earlier. The final squeeze pressure was held while waiting on the cement to cure for a minimum of 12 hours. The pressure was then released before pulling out of the hole.

### **Casing Cleanout: Preparation for Pressure Isolation of Upper Casing Stub**

The next trip in the hole was with a bit and scraper for the 10 ¾-in. 45.5-lb/ft casing run in tandem with an MSC tool for 16-in. 84 lb/ft casing. The MSC tool's arms locked out; the same tool was used in milling the inner casing, but the blades were changed out to protect the outer casing. The 16-in. casing was cleaned from the top of the 120-ft. window down to the top of cement. The top of cement was tagged for depth control. The MSC tool was worked through the window and a bottoms up was circulated to clean the 16-in. casing before the annulus was isolated around the upper 10 ¾-in. stub.

### **Pressure Isolation of Upper Casing Stub**

An inflatable bridge plug was run in on workstring and set 10 ft. above the top of cement for use as an artificial bottom. This bottom was again used to help prevent gas migration and to minimize any mud contamination of the cement slurry. An inflatable bridge plug was needed to pass through the smaller 10 ¾-in. 45.5-lb/ft casing and set in the larger 16-in. 84-lb/ft casing. The inflatable bridge plug was tested with a resulting pressure loss of no more than 10% during a 15-minute time period to verify proper setting.

When water-based drilling mud was being employed, a diverter sub was picked up and tripped in the hole to the planned top of cement at ±100 ft. above the inflatable bridge plug. The plug interval was cleaned by washing and rotating into the hole. The casing was then displaced with 8.6-lb/gal filtered seawater, and the well was monitored for flow to serve as an underbalance test.

A 25-bbl spacer was pumped before the latex cement was mixed and pumped to place 100 ft. of cement in 16-in. casing. Fluid was pumped behind to balance cement plug inside and outside the workstring. The workstring was again slowly picked up four stands at 30 to 50-ft. per minute. One and one-half tubing volumes was reverse circulated or until there was no cement in the returns. Pressure was held on the cement while waiting a minimum of 12 hours for the cement to cure.

### Clear Fluid vs. Drilling Mud

Initially, a water based drilling mud was used under the assumption that it was a cheaper alternative to clear fluids and would have superior cuttings lifting capabilities. Table 4-2 is a comparison between the initial costs per barrel of mud and equivalent weight clear brine.

**Table 4-2: WBM to Brine Cost Comparison**

| Density<br>(lb/gal) | Estimated Fluid Cost<br>(\$/bbl) |       |
|---------------------|----------------------------------|-------|
|                     | WBM                              | Brine |
| 10.0                | 25 to 30                         | 5     |
| 11.6                | 25 to 30                         | 12    |
| 14.0                | 25 to 30                         | 115   |

During both milling and casing cutting operations, a significant amount of fluid conditioning time was required to maintain proper mud properties. While milling, not only were considerable amounts of metal being lifted, but also large amounts of annular material like cement and dehydrated mud from the initial cementing operation on the respective casing string. These cuttings adversely affected the desired mud characteristics.

One further source of mud contamination resulted from the water based drilling mud coming into contact with zinc bromide. Various amounts of zinc bromide were being pumped down the annuli of the wells with SCP in the field to avoid rig intervention. It was hoped that increasing the hydrostatic head of those annuli with SCP, would reduce the pressure to an acceptable level or eliminate it outright. Increased mud conditioning time to rid the system of clabbered mud and added rig costs was common early in the program.

As a direct result of excessive mud conditioning time, the preferred fluid system was changed from a water-based drilling mud to gelled brine during the second half of the program in 2001. A brine system does not have the zinc bromide compatibility issues of the water-based mud and can be sufficiently weighted up or down to suit the pressure requirements in the program. It was found that sufficient hole cleaning of both metal cuttings, as well as cement and dehydrated mud, was obtained by the gelling of the brine with HEC and a xanthan gum viscosifier blend.

If used as a carrying agent, the brine would be required to economically carry large amounts of iron, cement, and dehydrated mud to the surface. A 40-yield point gelled brine was decided upon. An HEC-blended system was implemented and was very effective in obtaining the necessary rheology to lift heavy cuttings and clean the hole.

A breakdown of the mud conditioning costs due to zinc bromide and cement contamination incurred on four wells is included in Table 4-3. Total rig time spent conditioning the clabbered and contaminated mud approached 6 days and \$385,000 before the switch to a gelled brine system occurred in October of 2001. This cost estimation does not include the charges incurred for replacing hundreds of barrels of contaminated water-based mud systems.



**Table 4-3: Mud Conditioning Time Due to Contamination**

| Well   | Mud Condition Time |        | Average Day Rate (\$/day) | Rig Cost for Conditioning (\$) |
|--------|--------------------|--------|---------------------------|--------------------------------|
|        | (hours)            | (days) |                           |                                |
| 12     | 30.00              | 1.25   | 49,951                    | 62,439                         |
| 9      | 58.00              | 2.42   | 60,442                    | 146,270                        |
| 4      | 9.00               | 0.38   | 64,888                    | 24,657                         |
| 6*     | 44.50              | 1.85   | 81,727                    | 151,195                        |
| Totals |                    | 5.90   |                           | 384,561                        |

\*Switched from WBM to brine fluid system

### Determination of Fluid Weights

In order to determine the proper density of workover fluid, the frac gradient of the outermost exposed casing shoe was considered the upper available weight limit. The equivalent fluid weight at the true vertical depth of the casing shoe with both proposed fluid weights and expected applied pressures were considered. Because most of the wells had similar casing programs for the 7-in., 10 3/4-in., 16-in., and 20-in. casing strings, similar proposed fluid weights could be standardized for each equivalent casing size.

The workover fluid weight was designed to fall between the pore pressure and fracture gradient determined from a field-wide pore pressure plot developed during the initial drilling program as in Table 4-4.

**Table 4-4: Workover Fluid Design Table**

| *Depth of Concern |            | Pore Pressure |          |          | Workover Fluid |          |          | Fracture Gradient |          |          |
|-------------------|------------|---------------|----------|----------|----------------|----------|----------|-------------------|----------|----------|
| MD/TVD            | Shoe       | (psi)         | (psi/ft) | (lb/gal) | Type           | (lb/gal) | OB (psi) | psi               | (psi/ft) | (lb/gal) |
| 1,472/1,341       | 20-in.     | 635           | 0.4732   | 9.1      | WBM            | 10.0     | 697      | 781               | 0.5824   | 11.2     |
| 2,741/2,350       | 16-in.     | 1,308         | 0.5564   | 10.7     | WBM            | 11.6     | 1,418    | 1,772             | 0.7540   | 14.5     |
| 5,363/4,318       | 10-3/4-in. | 2,852         | 0.6604   | 12.7     | WBM            | 14.0     | 3,144    | 3,862             | 0.8944   | 17.2     |

\*Depth of concern is exposing the 10 3/4-in., 16-in., and 20-in. shoes to fracture gradient mud weights or pressures.

Attempts were made to stay closer to the pore pressure than frac gradient when possible. All fluid weights were sufficient to kill encountered SCP upon proper circulation and treatment of casing or annular area.

### Cement Slurry

The cement slurry was treated with a latex additive as shown in Fig. 4-9 to increase both the initial and long term bonding characteristics with the casing. It was intended to perform during pressure buildup, either constant or cyclical. Foamed cement was considered for its ability to maintain bond and avoid microannuli during pressure cycles. However, it was discarded because of the operational and economic issues of nitrifying small batches of cement.

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.

It has been shown that a low shrinkage and highly elastic cement formulation is successful in providing successful pressure isolation (Parcevaux and Sault, 1984). The damage resulting from thermal cycling can be detrimental to the cement/casing bond. The resilient and ductile properties of various latex cements are proven to mitigate these detrimental effects (Carpenter et al., 1991). Typical Portland cements tend to fail from tensile cracking as casing pressure is applied (Onan et al., 1993 and Bosma et al., 1999). It was hoped that the increased cement plug elasticity, inherent with the latex cement slurry, would aid in continued casing bond during any potential pressure buildup. If pressure were to return from below the plugs, the casing may balloon and risk damaging the cement to casing bond resulting in SCP buildup. The latex cement is intended to 'flex' with the pipe but still maintain sufficient cement to pipe bonding characteristics.

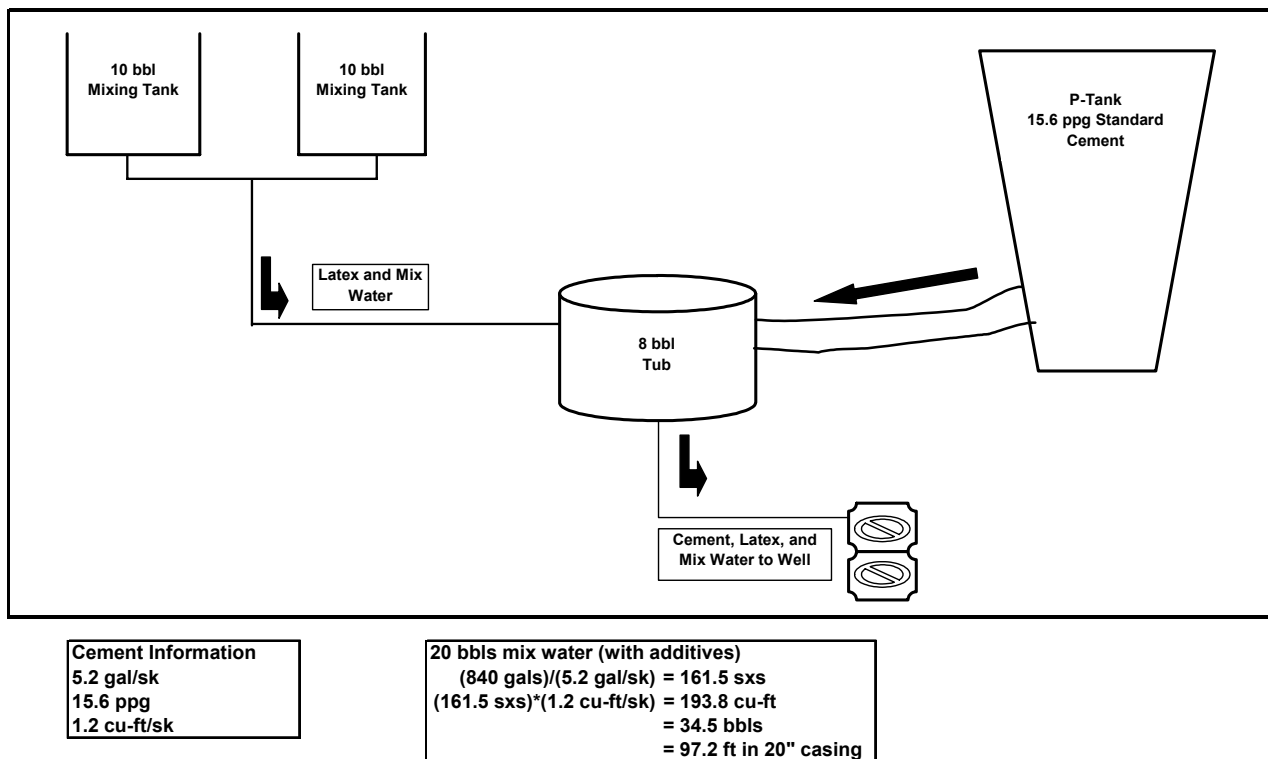
### **1999 Summary of Findings**

The following are bulleted findings and conclusions from the 1999 workover program. A more in depth analysis is contained in the following two chapters.

- Initially, some balling of metal cuttings occurred in the mud return flowline. The use of an open-top surface trough, and eliminating unnecessary sharp bends, restrictions, or obstructions in the return lines minimized any delays due to balled cuttings.
- To help minimize the concern of breaching the outer barrier when milling concentric strings of pipe, cutter sizes were optimized to the outer diameter they were cutting. During this operation, two cutter sizes were used on every casing when a window 'cutout' was made: one specifically sized to cut the tube and a larger cutter for the casing collars.
- HEC and xanthan gum blended/gelled brine with a 40-yield point was able to economically carry large amounts of iron, cement, and dehydrated mud to the surface. It did not have the zinc bromide compatibility issues of a water-based mud.
- The proper density of workover fluid was determined by considering the frac gradient of the outermost exposed casing shoe and expected applied pressures as the upper available weight limit. When possible, attempts were made to stay closer to the pore pressure than frac gradient to avoid breaking down the formation at the casing shoe.
- Before any cementing operation in a water-based mud environment, proper hole preparation is imperative and can be done by rotating a diverter sub into the hole throughout the plug interval and the pumping of properly sized spacers. The diverter tool efficiently removed mud cake or trash to increase the bonding characteristics of the cement to casing.
- The cement slurry was treated with a latex additive to help increase both the initial and long-term bonding characteristics with the casing. It was intended to perform during pressure buildup, either constant or cyclical. Improvements in cementing technology should be considered when designing future programs.
- Isolation of windows or casing stubs was augmented by squeezing cement into the annulus and holding pressure. The final squeeze pressure varied based on burst characteristics of casing and the established pressure previous to reversing out the workstring.

- Whenever possible, a ‘bottom’ was set to avoid cement contamination from gas migrating through the setting cement or if the wellbore fluid and cement had a 2-lb/gal or greater density difference.
- CIBP was the preferred ‘bottom’ and is not meant to act as a long term pressure seal when not used in conjunction with a cement plug. Long-term degradation could occur to the rubbers from constant exposure to the wellbore environment.
- Although the casing was pressure tested upon completion of remedial operations, future recommendations might include running of a caliper log or equivalent after milling operations to aid in verifying that the outer casing did not sustain excessive damage that could compromise pressure integrity.

**P&A Program  
Cementing Unit Hookup**



**Figure 4-9:** 1999 Workover Program Cementing Unit Hookup

## CHAPTER V: ANALYSIS

### 1989/1990 Workover Summary and Conclusions

The 1990 workover program addressed casing pressure problems on the protective casing in Wells 11, 1, and 14 wells. Well 14 had casing pressure on the surface casing that tended to flow when bled down. Four wells from the 1989 workover program were exhibiting SCP within one year of the workover as evidenced in Table 5-1. Extensive perforating, cutting, and squeezing operations with Class 'H' cement was not successful in eliminating SCP between the production and protective casing strings.

**Table 5-1:** One Year 1989 Workover Results

| <b>One Year 1989<br/>Workover Results on<br/>Protective Casing</b> |                           |
|--|---------------------------|
| <b>Well<br/>Number</b>   | <b>Pressure<br/>(psi)</b> |
| 13   | 2,100                     |
| 10   | 1,642                     |
| 5  | 957                       |
| 3  | 120                       |

Table 5-2 summarizes the results of the 1989/1990 workover program. It indicates only marginal success in reducing or eliminating SCP. The data was pulled from correspondence and drilling reports and may be lacking some details. For instance, pressure was only monitored for 14 hours after operations on Well 15 in July 1990. It indicates that the casing pressure was removed but no data was found to verify long term success. The greatest success appears to be within the most easily accessible 7-in. casing in which pressure is indicated to have been removed in 2 of 3 wellbores exhibiting SCP. Post job 7-in. casing pressures could not be located for a fourth well but over 1,000 psi returned within two years. None of the first 3 wells exhibiting 7-in. SCP in 1989 had pressure returning within the same two years (100% success).

Of 7 wells exhibiting SCP on intermediate casing in 1989, only 2 wells showed noticeable initial improvement. However, both drastically rose to pre-1989 levels within months (0% success). Well 13 did have success in eliminating communication between the intermediate and production casings. The gravel pack was replaced on Well 14 and returned to production without addressing the SCP.

Pressure existed on the surface casing in 3 wells before 1989/1990 operations only 1 showed success (33%). Well 13 appears to be the only well that the surface casing pressure was successfully removed. Post job correspondence did not indicate whether the pressure was successfully addressed for Well 15 and Well 14 casing pressures were never remediated during this program.

**Table 5-2: 1989/1990 Workover Program Results**

| Well | Casing Pressures (psi) |                 |                 |           |        |  |           |        |        | Remarks  |
|------|------------------------|-----------------|-----------------|-----------|--------|--|-----------|--------|--------|--|
|      | Program                | Before Workover |                 |           |        | Post Workover  |           |        |        |  |
|      |                        | 7-in.           | 10 ¾-in.        | 16-in.    | 20-in. | 7-in.  | 10 ¾-in.  | 16-in. | 20-in. |  |
| 3    | June 1989 WO           | 0               | >500            | 0         | 0      | 0  | +/- 200   | 0      | 0      | Press. remained at 200 psi for 18 mos. but then drastically rose   |
| 13   | June 1989 WO           | >100            | >2,000          | +/- 1,000 | 0      | 0  | +/- 2,000 | 0      | 0      | Communication eliminated. Aborted B/D after mud & debris returns   |
| 10   | July 1989 WO           | 0               | >1,500          | 0         | >0     | 0  | +/- 250   | 0      | 0      | Clabbered mud from 10 ¾-in. Temp surveys found no anomalies.   |
| 1    | April 1990 TA          | >500            | +/- 1,000       | 0         | 0      | 0  | +/- 1,500 | 0      | 0      | 7, 10 ¾, & 20-in. all had SCP within 1 yr. of initial drill. Temp log indicated possible gas flow below 10 ¾-in. shoe. |
| 14*  | May 1989 WO            | ??              | 0 (11-3/4)      | <1,000    | >0     | No remedial work done to address SCP.                        |           |        |        | Temp/noise log indicated deep damage in 9 ⅝-in. & anomaly above 10 ¾-in. shoe  |
|      | Aug. 1989 WO           | >100 (9-5/8)    | >100 (11-3/4)   | >900      | 0      | Attempted to replace gravel pack. Aborted due to csg damage. |           |        |        | Csg damage @ deep zone   |
|      | April 1990 WO          | 0 (9-5/8)       | +/-300 (11-3/4) | +/- 1,000 | >0     | Ran 7" csg & gravel pack. No remedial work to address SCP.   |           |        |        |  |
| 11   | March 1990 WO          | 0               | >2,000          | 0         | 0      | 0  | >1,000    | 0      | 0      | Pressure increased after a few months.   |
| 15   | July 1990 P&A          | 0               | +/- 2,000       | <400      | 0      | NA   | 0         | 0      | 0      | 7-in. cut/recovered to 1,978'. Pressure monitored for 14 hrs after operation.  |

\*Casing Program includes 7-in. x 9 ⅝-in. x 11 ¾-in. x 16-in. x 20-in.

**Design Concept**

During the 1990 squeeze program, two methods were considered when addressing SCP in wells to be abandoned. The first was to mill windows in casing at strategic points and fill the void with cement. The second method was to perforate and squeeze at affected casing shoes. The former operation is considered very expensive with a high probability of success while the latter option is cheaper with a low probability of success.

The design concept centered on addressing either a deep source well below the intermediate casing shoe or a shallow source just below the intermediate casing shoe. Perforate to squeeze or milling and underreaming options were then considered based on available data or symptoms. Initial operational decisions were based on the above while factoring the probability of success.

For example, a recommended plan of action would be to abandon the production zone and then perforate to squeeze a suspected deep source. If annular pressure still existed, operations would then focus on the intermediate or protective casing shoes for milling and underreaming operations. The underlying philosophy was to address SCP as deeply in the wellbore as possible without removing casing strings. Casing removal would occur during future platform abandonment.

### **Milling Operations**

Milling and underreaming operations at the intermediate casing shoe were abandoned as a result of the Well 15 workover in July, 1990. While milling the 7-in. production casing, the lower stub fell away and could not be re-entered. The thought was that an extreme washout existed below the intermediate casing existed.

Section milling operations were re-evaluated based on damage incurred while milling windows with blades sized to mill both the larger collars as well as the thinner tube. Table 5-3 summarizes the known blade sizing pulled from drilling reports and procedures. Damage to outer casing strings during milling operations was suspected on Wells 10 and 13 wells. This is attributed to blade OD's sized to the collar OD. Furthermore, the blades only had cutting surfaces on the bottom and smooth on the OD.

**Table 5-3: Post 1989/1990 Casing Cutter Sizing**

| Well | Workover Date | Casing Size (in.) | Cut-Out Mill (in.) | Section Mill (in.) | Coupling Cut Mill (in.) | Underreamer OD (in.) |
|------|---------------|-------------------|--------------------|--------------------|-------------------------|----------------------|
| 15   | July 1990     | 7                 | NA                 | 8.275              | NA                      | NA                   |
| 10   | March 1991    | 7                 | Unknown            |                    |                         | NA                   |
|      |               | 10 ¾              | NA                 | NA                 | NA                      | Unknown              |
| 13   | April 1991    | 7                 | 8                  | NA                 | NA                      | NA                   |
|      |               | 10 ¾              | Mechanical Cutter  |                    |                         | Unknown              |
|      |               | 16                | NA                 | NA                 | NA                      | Unknown              |
| 3    | October 1991  | 7                 | 7 ¼                | 7 ½                | 7 7/8                   | NA                   |
|      |               | 10 ¾              | NA                 | NA                 | NA                      | Unknown              |
| 14   | February 1992 | 7                 | Unknown            | 7 ½                | 8 1/16                  | NA                   |
|      |               | 9 5/8             | 9 7/8              | 9 7/8, 10          | Unknown                 | 8 ½                  |
|      |               | 11 ¾              | Unknown            | 13 1/16            | 12 ¾                    | 10 3/8, 10 ½         |
|      |               | 16                | NA                 | NA                 | NA                      | 14.936               |
| 11   | March 1992    | 7                 | 7 ¼                | Unknown            | NA                      | NA                   |
|      |               | 10 ¾              | NA                 | NA                 | NA                      | 9.7                  |

### **Perforating-to-Squeeze**

In producing wells, the number of perforations was limited in size and number. A shot density of 4 shots per foot (spf) over 2 feet in producing wells was used extensively in the 1990 squeeze program. Casing pressures were reduced sufficiently to allow for continued production.

Exposure of the wellbore to excessive test pressures of squeeze perforations, or other diagnostic testing, was localized below a retrievable test packer to avoid cement sheath stress cracking.

For wells with no future utility, post squeeze pressure testing was not of primary concern. Solely addressing the SCP became the primary driver. Increasing the chances of communicating with a behind-pipe channel was enhanced by using a small-phased perforating gun with 12 spf over 4 feet. The shot density and phasing is relative to the casing size and should be adjusted to greater than 40% of the circumferential area. A case study by Hart and Wilson (Hart and Wilson, 1990) of 37 wells in the East Texas and Texas Gulf Coast indicated a success rate of 89% when greater than 40% of the circumferential area was perforated. Furthermore, a success rate of 70% was achieved by placing perforations across an impermeable zone. Cleaning of perforations and increasing communication was obtained by pumping various acids ahead of the cement slurry.

Post 1990 perforate-to-squeeze operations included the squeezing or spotting of mud acid to enhance behind pipe communication. Pressure will be held for longer periods to improve cement injectivity.

**Microbond Cement Squeezes.** During the beginning of the 1990 casing squeeze program, Halliburton’s Microbond cement was used and focused on possible deep source gas sands. It was thought that its expansive nature would seal any cracks or fissures in the cement sheath being used as a pressure conduit. A five-day curing time was recommended to allow for sufficient time for the cement to expand and seal.

Deep source Microbond squeezes failed in four applications where either no surface effect was noticed or little pressure reduction was realized. The program then focused around isolating the shallow protective casing shoe. These shallower squeezes reduced casing pressures but the squeeze perforations were not able to handle the pressure tests. Table 5-4 summarizes the results of Microbond squeezes.

**Table 5-4: 1990 Microbond Squeeze Results**

| <b>1990 Microbond Squeeze Results</b> |                         |   |
|---------------------------------------|-------------------------|---|
| <b>Well</b>                           | <b>Squeeze Location</b> | <b>Results</b>                                  |
| 11                                    | Deep source sand        | No surface effect                               |
| 1                                     | Deep source sand        | Surface flowed. Tested & failed                 |
| 14                                    | 11 ¾-in. shoe           | No surface effect & 11 ¾ x 16-in. communication |
| 1                                     | 10 ¾-in. shoe           | Reduced pressure. Tested & failed               |

**Flo-Chek Cement Squeezes.** Following the Microbond squeezes, a Flo-Chek cement slurry was applied but had little to no success in reducing casing pressures. Flo-Chek is a cement slurry additive often used in the first stage of a cement squeeze to minimize downhole fluid loss. Flo-Chek gels on contact with any fluid containing calcium or magnesium to divert the slurry from the lost circulation zone (Halliburton, 1999). Table 5-5 summarizes the results of the Flo-Chek squeezes. The first squeeze with Flo-Chek on Well 11 was preceded by five mud stages to reduce gas migration into the unset cement. The annular pressure was reduced slightly. The second Flo-Chek application was a 30 minute hesitation squeeze that resulted in significant pressure reduction. Neither set of perforations could hold the test pressures.

**Table 5-5: 1990 Flo-Chek Squeeze Results**

| <b>1990 FLO-CHEK Squeeze Results</b> |   |  |
|--------------------------------------|---|--|
| <b>Well</b>                          | <b>Squeeze Location</b>                       | <b>Results</b>                                 |
| 11                                   | Five mud stages + Flo-Chek @ 10 ¾-in. shoe    | Inadequate surface effect                      |
| 11                                   | Flo-Chek + 30 min. hesitation @ 10 ¾-in. shoe | Reduced surface pressure. Would not hold test. |

**Class ‘H’ Cement Squeezes.** Well 14 had a five stage accelerated CaCl<sub>2</sub> Class ‘H’ + Econolite cement squeeze pumped at the 16-in. shoe with four hour cure time in between stages. This cure time was to allow for cement diversion. The success of this 1,600 bbl squeeze is unknown since a scab liner was run and cemented without extensive testing of the squeeze. A second 5 stage Class ‘H’ cement squeeze was performed on the 10 ¾-in. shoe. Results of this squeeze are unknown since the perforations were never drilled out.

**Magne-Set Cement Squeeze.** BJ’s Magne-Set cement was used in Well 11 to isolate the production perforations. Magne-set is tolerant to contamination, sets rapidly, and has a slightly expansive character. Multiple operational problems including inadequate horsepower, blender problems and crew unfamiliarity with the product may have led to a failed squeeze. The pressure slowly began to build after the squeezes. A bleed down/buildup within a year bled all gas and the pressure bled from +/-1,000 psi to 0. The pressure continued to rise one year after the Magne-Set squeezes

Five cement types, Microbond, Flow-CK, ‘H’, CaCl<sub>2</sub> accelerated and Magne-Set, were used during the 1990 squeeze program with six different techniques including mud pre-pump stages, annular back pressure, staging with inter-stage cure time, high rate pre-flushes, high/low rate squeezes, and hesitation squeezes. Each squeeze resulted in very poor results for various reasons but large cement volumes staged near the intermediate shoe seemed to be the most effective in reducing, but not eliminating, annular pressures. The downhole environment is very hostile and a weak point is created any time the pipe integrity is compromised. This weak point can lead to a future pressure conduit.

**Post 1989/1990 Workover Program Summary and Conclusions**

Five of the wells that were previously worked over to address SCP were again worked over in 1991 and 1992 and summarized in Table 5-6. Some of the learnings from the 1989/1990 program were incorporated into these workovers. It concentrated on removing affected casings when possible and applying improved squeeze techniques.

Well 3 exhibited SCP in the 7-in. production casing where it had previously indicated none. The 7-in. casing was removed during operations in October of 1991. Well 14 was off production and unsuccessful attempts were made at reducing the 7 ⅝-in. production casing pressure but the casing was finally removed during a February 1992 operation.

The intermediate casings again exhibited the most recurring SCP problems. All 5 wells exhibited pressures in excess of 1,000 psi. Operations only succeeded in reducing pressure on



one well but the pressure increased to pre-workover levels within 8 months. In two of the wells the intermediate casing was removed. The long term success rate can be considered (0%) when excluding the two wells in which the casings were removed.

Two of the wells exhibited 16-in. surface casing pressure previous to work and only Well 13 indicated removal for a 50% success rate. Both the 7 and 10 3/4-in. casings were removed in this operation. The 16-in. casing pressure was reduced to 0 on Well 14 but was soon rising after cutting and recovering the 7, 9 5/8, and 11 3/4-in. casings.

**Table 5-6: Post 1989/1990 Workover Results**

| Well | Casing Pressures (psi) |                 |                 |           |        |                |                 |           |        | Remarks   |
|------|------------------------|-----------------|-----------------|-----------|--------|----------------|-----------------|-----------|--------|---|
|      | Program                | Before Workover |                 |           |        | Post Workover  |                 |           |        |   |
|      |                        | 7-in.           | 10 3/4-in.      | 16-in.    | 20-in. | 7-in.          | 10 3/4-in.      | 16-in.    | 20-in. |   |
| 3    | Oct. 1991 WO           | +/- 500         | +/- 1,500       | 0         | 0      | N/A            | 200             | 0         | 0      | 10 3/4-in. flowed mud while B/D. Press. > to +/- 1,000 in 8 mos.                              |
| 13   | April 1991 WO          | 0               | +/- 1,500       | >100      | <100   | N/A            | N/A             | 0         | <100   | 7 & 10 3/4-in. casings removed  |
| 10   | March 1991 WO          | 0               | >1,000          | 0         | 0      | +/- 800        | >1,000          | 0         | 0      | Press. = 0 two weeks after WO. After 3 wks, press. returned.                                  |
| 14*  | May 1991 WO            | >1,000 (7-5/8)  | >1,000 (11-3/4) | >100      | 0      | >1,500 (7-5/8) | >1,000 (11-3/4) | <1,500    | 0      | B/D & B/U diagnostics to evaluate.  |
|      | Sept. 1991 WO          | >500 (9-5/8)    | +/-100 (11-3/4) | +/- 1,000 | 0      | >100 (7-5/8")  | <500 (11-3/4")  | +/- 1,000 | 0      | Bled gas & 10 gal. mud from 16-in. Press. from 845 to 90 psi in 40 min.                       |
|      | Feb. 1992 P&A          | +/-200 (9-5/8)  | <500 (11-3/4)   | +/- 1,000 | 0      | N/A (7-5/8")   | N/A (11-3/4")   | >0 Rising | 0      | 7-in.> 0 psi before WO. 7, 9 5/8, & 11 3/4-in. casings cut/recovered. Press. rising on 16-in. |
| 11   | March 1992 WO          | 0               | >1,000          | 0         | 0      | 0              | +/- 600         | 0         | 0      | Press. reduced - not stabilized. > at lower rate than before WO                               |

**Squeeze Operations**

Well 14 was squeezed in September, 1991 to address a temperature anomaly above the 16 in. shoe indicating a possible annular pressure source. The work consisted of perforating the 7-in., 9 5/8-in., and 16-in. casing strings and pumping acid through the perforations to enhance communication previous to squeezing cement. A 12%-3% HCl-HF acid blend was pumped ahead of the first 37 bbl Magne-set cement slurry. No running squeeze was obtained so a second

37 bbl Magne-set slurry was pumped. A bleed down/buildup of the 16-in. performed after this workover resulted in bleeding gas and 10 gal of mud. The pressure decreased from 845 to 90 psi in 40 minutes. The pressure built back to 183 psi after one hour and 336 psi within 24 hours.

Forty barrels of S-Mix was pumped into the 11 3/4 x 16 in. and 23 bbl was pumped into the 9 5/8 x 11 3/4 in. annulus during the February, 1992 Well 14 P&A operation. S-Mix is a Shell-patented cement slurry that essentially converts mud into cement through the addition of soda ash and caustic activators immediately before pumping the slurry. The casing pressure was then monitored. The pressure on the 16 in. continued to rise.

Results of the March 1992 experimental poly plastic (polyactalate) resin job pumped on Well 11 were limited. The pressure previous to the workover was rising at a rate of 75 psi/week and was at 1,450 psi immediately before commencement of operations. After the resin job, a bleed down resulted in the pressure stabilizing at approximately 675 psi. It was proposed that further bleed-downs were necessary since the trapped pressure was not completely bled down. The resin is also recommended to be squeezed in a clear fluid system rather than spotted in a mud system.

In addition to remedial work on Wells 3, 10, 11, 13, and 14 after the 1989/1990 programs, SCP removal operations on two additional wells were performed but have not been reviewed for the purposes of this thesis.

### 1999 Workover Program Summary and Conclusions

The 1999 workover program appears to have been effective as evidenced by the removal of SCP from affected casings. All affected casing annuli, with the exception of one well, remain at zero psi. Table 5-7 lists casing pressures both before the 1999 workover program as well as of April 30, 2003.

**Table 5-7: 1999 Workover Program Results**

| Well | Casing Pressures (psi) |                         |            |        |        |                          |                       |                       |        |
|------|------------------------|-------------------------|------------|--------|--------|--------------------------|-----------------------|-----------------------|--------|
|      | Rig M/O Date           | Before Workover Program |            |        |        | Present (April 30, 2003) |                       |                       |        |
|      |                        | 7-in.                   | 10 3/4-in. | 16-in. | 20-in. | 7-in.                    | 10 3/4-in.            | 16-in.                | 20-in. |
| 1    | 2-7-00                 | 0                       | 1,269      | 0      | 0      | NA                       | NA                    | 0                     | 0      |
| 2    | 5-14-00                | NA                      | 0          | 54     | 0      | NA                       | 0                     | 0                     | 0      |
| 3    | 9-25-00                | NA                      | 795        | 1,300  | 0      | NA                       | 125                   | 0                     | 0      |
| 4**  | 7-29-01                | 520                     | 505        | NA     | 0      | 0 <sup>(7-5/8)</sup>     | 0 <sup>(13-3/8)</sup> | NA                    | 0      |
| 5    | 9-24-01                | 100                     | 250        | 0      | 0      | NA                       | 0                     | 0                     | 0      |
| 6*** | 10-5-01                | NA                      | 32         | 0      | 0      | NA                       | 0 <sup>(9-5/8)</sup>  | 0 <sup>(13-3/8)</sup> | 0      |
| 7    | 10-19-01               | 0                       | 1,030      | 0      | 0      | NA                       | 0                     | 0                     | 0      |
| 8    | 11-11-01               | 720                     | 1,300      | 168    | 0      | NA                       | 0                     | 0                     | 0      |
| 9*   | 12-7-01                | 0                       | 1,713      | 155    | 0      | NA                       | NA                    | 0                     | 0      |
| 10*  | 12-9-01                | 898                     | 836        | 89     | 10     | NA                       | NA                    | NA                    | 0      |
| 11   | 1-2-02                 | 489                     | 176        | 0      | 0      | 0                        | 0                     | 0                     | 0      |
| 12*  | 1-20-02                | 83                      | 125        | 86     | 10     | NA                       | NA                    | NA                    | 0      |

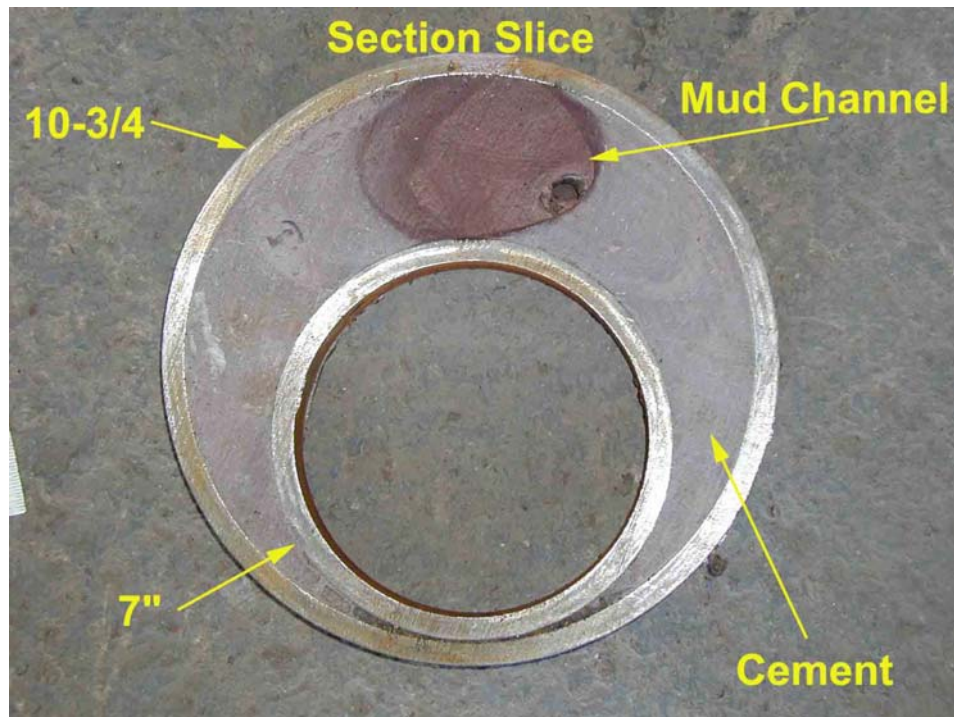
\*Indicates rig skidded back for remedial work during program

\*\*Casing program includes 7 5/8-in. x 13 3/8-in. x 20-in.

\*\*\*Casing program includes 7-in. x 9 5/8-in. x 13 3/8-in. x 20-in.

Fig. 5-1 is a powerful picture. It is a slab cut from a section of 10 3/4-in. x 7-in. casing cut and pulled simultaneously in Well 11 during the latter half of the 1999 workover program. It indicates possible conduits of the SCP and may provide some clues as to why previous workover attempts failed to address the problem. Placing a sufficient amount of squeeze perforations and cement to isolate the mud channel on the high side of the hole may be feasible. However, the 7-in. casing is lying on the 10 3/4-in. casing on the low side of the hole. This situation indicates a nearly impossible feat of injecting sufficient volumes of cement to create a pressure barrier. Furthermore, the extreme eccentricity of the inner 7-in. string highlights the need for the precise milling procedures employed during the 1999 workover program.

It appears that mud channeling occurred during the initial cementing of this 7-in. casing string and could have contributed to SCP. If mud is not properly displaced during the primary cement job, channels or pockets of mud can be strung out in the cemented annulus to help provide an avenue for pressure to reach the surface. Improper displacement can be a result of any one of the long-recognized factors of improper mud conditioning, pipe movement, centralization, fluid velocities, or spacers and flushes.

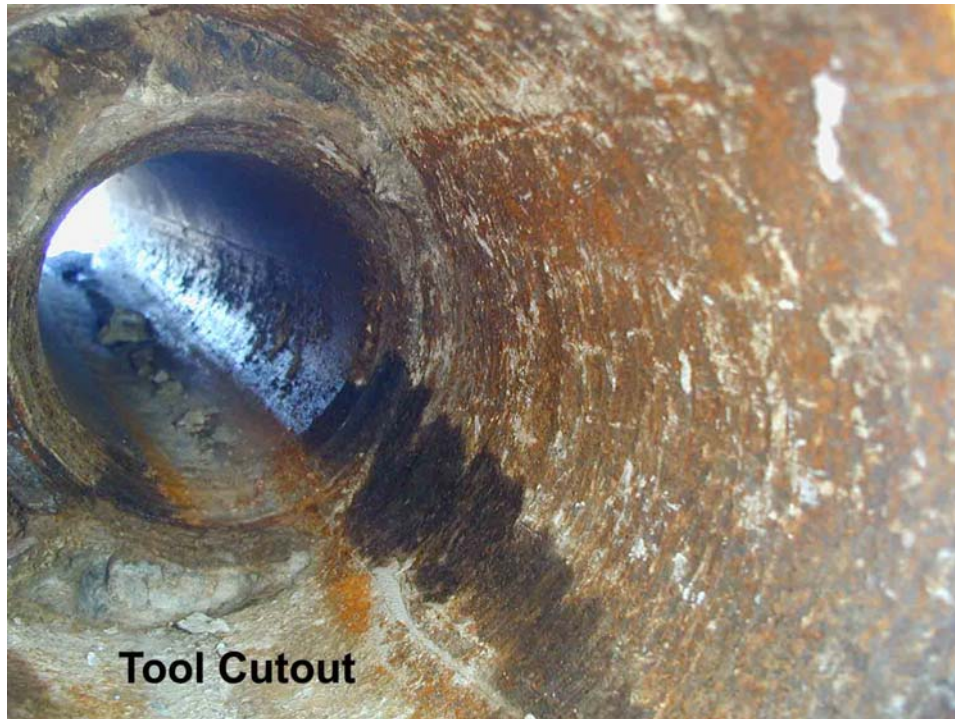


**Figure 5-1:** Concentric Casing Slice Illustrating Mud Channel

Another potential medium for SCP could be the extreme eccentricity of the pipe and the inability to place cement between the strings of pipe on the low side of the hole. The lack of cement can prevent a suitable pressure seal from downhole pressure sources. This only stresses the need for proper centralization during the initial cementing operation.

Figs. 5-2 and 5-3 demonstrate the minimal scarring incurred on the outer 10 3/4-in. casing during a section milling operation. This section of 7-in. casing was milled out previous to cutting the 10 3/4-in. casing and pulling both strings simultaneously. As can be seen in the picture, the 7-in.

casing is lying against the 10 3/4-in. casing on the low side and was not breached during the section mill run. Fig. 5-3 is a cut-away view showing the nicks on the ID of the 10 3/4-in. wall. No indication of excessive wear was seen throughout the milled section. This attests to the advantages gained in tailoring the cutter size both to the collar and tube ODs during the 1999 workover program.



**Figure 5-2:** Casing Section Mill Results - Minimal Scarring of 10 3/4-in. casing



**Figure 5-3:** Slight Scarring of 10 3/4-in. Casing from Milling Operation



**Figure 5-4:** 7 and 10  $\frac{3}{4}$ -in. Casing on the Rack after being Cut and Pulled



**Figure 5-5:** Close up of 7 and 10  $\frac{3}{4}$ -in. Casing on the Rack

The following conclusions and learnings can be made from the 1999 workover program. Each of the following items contributed to the program's operational effectiveness:

Improvements to the milling operations were made through a combination of research into the past operations and current best practices. It was felt that breaching of outer casing during milling operations was the cause of SCP in some previously unaffected casing. To help minimize the concern of breaching the outer barrier when milling concentric strings of pipe, cutter sizes were optimized to the outer diameter they were cutting. During this operation, two cutter sizes were used on every casing when a window 'cutout' was made: one specifically sized to cut the tube and a larger cutter for the casing collars.

The proper density of workover fluid was determined by considering the frac gradient of the outermost exposed casing shoe and expected applied pressures as the upper available weight limit. When possible, attempts were made to stay closer to the pore pressure than frac gradient to avoid breaking down the formation at the casing shoe. Initially, a water based mud system was used on the basis that this system would have superior hole cleaning characteristics. In reality, too much rig time was spent circulating and conditioning the mud due to zinc, cement and dehydrated mud contamination. An HEC and xanthan gum blended/gelled brine with a 40-yield point was able to economically to carry large amounts of iron, cement, and dehydrated mud to the surface. It did not have the zinc bromide compatibility issues of a water-based mud.

Before any cementing operation in a water-based mud environment, proper hole preparation is imperative and can be done by rotating a diverter sub into the hole throughout the plug interval and the pumping of properly sized spacers. The diverter tool efficiently removed mud cake or trash to increase the bonding characteristics of the cement to casing. The cement slurry was treated with a latex additive to help increase both the initial and long-term bonding characteristics with the casing. It was intended to perform during pressure buildup, either constant or cyclical. Whenever possible, a 'bottom' was set to avoid cement contamination from gas migrating through the setting cement or if the wellbore fluid and cement had a 2-lb/gal or greater density difference. CIBP was the preferred 'bottom' and is not meant to act as a long term pressure seal when not used in conjunction with a cement plug. Long-term degradation could occur to the rubbers from constant exposure to the wellbore environment.

Isolation of windows or casing stubs was augmented by squeezing cement into the annulus and holding pressure. The final squeeze pressure varied based on burst characteristics of casing and the established pressure previous to reversing out the workstring.

Concern of breaking down the shallower 10 3/4-in. casing shoes due to trapping upwardly migrating pressure, was considered during the design phase of the 1999 workover program. Two conclusions were made, the first is that the pressure seen at surface was considered to be at equilibrium, and the second was that all pressures seen in the 7 x 10 3/4-in. annulus would not exceed the fracture gradient at the 10 3/4-in. shoes.

The recorded pressures had not increased for extended periods of time and were thought to be in equilibrium. If pressure were to continue to build from a source deeper than the 10 3/4-in. shoe, a sand below the casing shoe would tend to break down before the casing shoe would.

Most 10 3/4-in. casing shoes in the field were set between 4,500 ft and 5,000 ft TVD with a corresponding fracture pressure gradient of approximately 17.3 ppg. Regardless of the mud weight displaced by the 7-in. cement job, a present day worst case scenario of dehydrated mud annular gradients can be assumed. For all practical purposes, a saltwater gradient of 8.6 ppg will be sufficient. The highest pressure of 1,700 psi on the 7 x 10 3/4-in. casing annulus was seen in Well 9. At 4,500 ft TVD, the 10 3/4-in. casing shoe exhibits a 4,048 psi [4,500 ft \* (0.052 psi/ft/ppg)\*17.3 ppg] fracture pressure. This is based on fracture pressure gradient of 17.3 ppg from Fig. 5-7. Assuming a saltwater gradient of 8.6 ppg with 1,700 psi on top, this equates to 3,712 psi [1,700 psi + (8.6 ppg\*(0.052 psi/ft/ppg)\*4,500 ft)]. The fracture pressure rating at the 10 3/4-in. shoe [4,048 psi > 3,712 psi] has not been exceeded.

In the instance of Well 3 with 1,300 psi existing on the 10 3/4-in. x 16-in. annulus, the fracture gradient of 14.8 ppg (Fig. 5-7 at a depth of 2,305 ft) at the 16 in. shoe was not exceeded. A window cut in the 10 3/4-in. casing from 681 to 802 ft was used to address SCP in the 16-in. Assume 1,300 psi is trapped at 802 ft. With an 8.6 ppg gradient, an equivalent of 1,972 psi [1,300 psi + (2,305 ft – 802 ft)\*(0.052 psi/ft/ppg)\*8.6 ppg] would be exerted on the 16-in. casing shoe. This value only slightly exceeds the fracture pressure of 1,774 psi [1,972 psi > 1,774 psi] calculated at the 16-in. shoe.

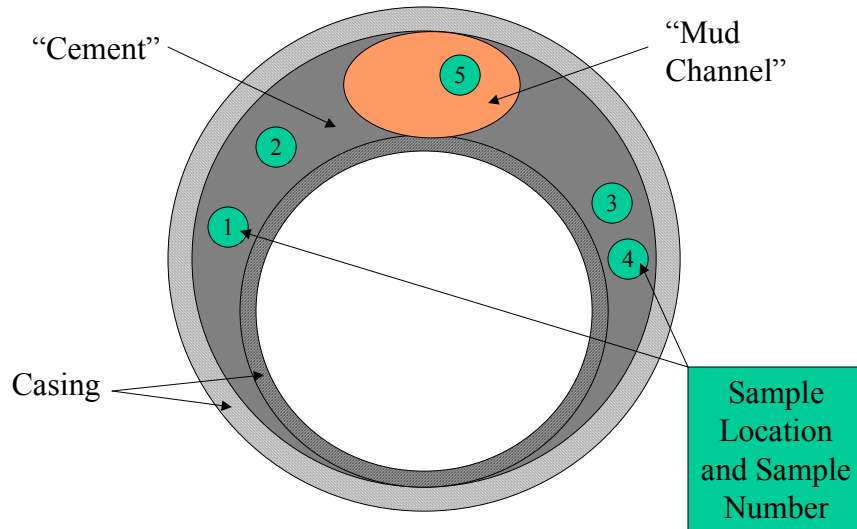
### **Casing Slab Evaluation**

The following is summary of chemical analysis from an annular cross section of casing cut and retrieved from Well 11, late in the 1999 workover program. Figs. 5-4 and 5-5 are pictures of the casing upon retrieval. A chemical analysis was performed on one casing slab in which five samples were taken from a two-inch thick ring of a non-centralized cemented 7 x 10 3/4-in. casing annulus.

An obvious characteristic of the slabs is a large channel present on the thick side of the annulus on all samples. A total of five samples were taken and analyzed as Fig. 5-6 indicates. The following analysis is pulled from information contained in e-mail correspondence from Mr. Mike Cowan to Mr. Felix Medine dated April 11, 2002.

Results of chemical analysis indicated that samples 1 through 4 included both cement and mud while sample 5 contained only mud. The percentage of cement present in Samples 1 through 4 could not be determined since a representative cement sample was not available. Based upon the amount of barite in each sample it appears that approximately 25 to 40 percent cement is present. Based on the mineralogy from x-ray analysis, an average of 1/3 cement per sample seems to be a representative amount. The results of the x-ray analysis are listed in Table 5-8.

Each sample contains a substantial amount of hematite, a.k.a. iron oxide. It was theorized that the source of the hematite could be from rusting steel or possibly a component of the cement or mud system. If neither the mud nor cement fluid systems contained hematite, rusting steel is the most likely source for hematite.



**Figure 5-6:** Cartoon of Casing Slice Sample Location

Calcite is present in the cement slurry or it could originate from a calcium carbonate lost circulation material mixed in the mud. The amount of calcite is highest in Sample 5 which also shows no quartz (silica/sand). This is consistent with Sample 5 being primarily mud since quartz and other silicates are common to cement mineralogy. If the cement contained silica to prevent strength retrogression, the common amount would be 30 to 35% by weight in cement.

The cement and drilling fluid compositions were not available for analysis. This data could have been used to further refine the cement content in Samples 1 through 4.

**Table 5-8:** XRD Analysis of Five Casing Slab Samples

| X-Ray Diffraction Analysis Results |          |          |          |          |          |
|------------------------------------|----------|----------|----------|----------|----------|
| Mineral                            | Sample 1 | Sample 2 | Sample 3 | Sample 4 | Sample 5 |
| Barite                             | 49%      | 58%      | 71%      | 64%      | 64%      |
| Hematite                           | 33%      | 27%      | 7%       | 22%      | 23%      |
| Calcite                            | 9%       | 6%       | 4%       | 4%       | 13%      |
| Quartz                             | 9%       | 10%      | 17%      | 10%      | 0%       |
| Clays                              | 0%       | 0%       | 0%       | 0%       | 0%       |

The mud channel shown in Figure 5-6 could be the result of either improperly displaced wellbore fluids or from gas channeling through unset cement. While circulating and reciprocating the 7-in. casing previous to the primary cement job, gas was present in the returns. Although centralizers were run for the first 80 joints, none were present this shallow in the wellbore and this could explain the extreme eccentricity and inefficient mud displacement.



### **Possible SCP Causes – Well 11**

An attempt at highlighting the possible causes of SCP in this field has been made and applies only to casing that has been cemented concentrically inside a larger casing and the pressure source lies below the outer casing shoe and behind the cement. Bringing the cement on the production casing up into the intermediate casing shoe was a common practice during the initial completions in this field; therefore, this analysis is relevant. However, this analysis does not hold when the inner casing cement job has not been brought up into the larger casing string. In this case, the SCP mechanism could simply be the migration of gas from a small stringer up the uncemented casing annulus to the surface.

Table 5-9 is a review of initial drilling operations. It focuses on the SCP mechanisms presented in Chapter 2 with the initial drilling operations documented in Chapter 3 to find a correlation with SCP. This effort was reliant on drilling reports and other documentation and is inconclusive or incomplete where information was lacking.

Using Well 11 as an example, it is felt that a lack of centralization in conjunction with inadequate mud properties and displacement techniques led to a lack of pressure isolation. It is apparent from Fig. 5-2 that two pressure conduits exist, one in the mud channel on the wide side as well as along the 7 x 10 <sup>3</sup>/<sub>4</sub>-in. interface. The casing was cut and recovered from +/-900 ft to surface and all was highly eccentric.

A spacer was pumped ahead of the cement slurry, the plug was bumped and the casing was reciprocated all indicating good displacement techniques. The deviation survey indicates that the well is still vertical through the 10 <sup>3</sup>/<sub>4</sub>-in. casing shoe and then slowly builds to 25 degrees inclination below the 10 <sup>3</sup>/<sub>4</sub>-in. shoe to TD.

Mud properties from a cementing detail indicate the following mud properties previous to pumping cement:

**MW – 16.6 ppg**  
**Plastic Viscosity – 39 cp**  
**Yield Point – 11 lb/100 sq-ft**  
**Gel Strength - 2/10 lb/100 sq-ft**  
**Water Loss – 2.4 cc/30 min**  
**Displacement Rate – 11 bpm**

The following analysis is based on information from Chapter 2 and in particular Table 2-1. The plastic viscosity value of 39 cp is higher than the recommended value of 20 cp and preferred value of 15 cp. Too viscous of a mud can tend toward inefficient displacement or ‘fingering’ of mud through the cement slurry. Furthermore, the yield point of 11 lb/100 sq-ft is around the recommended value of 10 lb/100 sq-ft but significantly higher than the preferred value of 2 lb/100 sq-ft. The measured water loss property of the mud was measured at 2.4 cc/30 min which is well within the recommended 15 and preferred 5 cc/30 min. This low fluid loss value would tend to create a thinner filter cake and sufficient cement to formation bond. The gel strength of 2/10 lb/100 sq-ft is indicative of a thixotropic mud that can be more difficult to displace.

**Table 5-9: Correlation of SCP to Possible Mechanisms**

| Well | Csg OD (in.) | Max SCP | Displacement                  |                     |                                  | Centralizers           | Gas influx             |
|------|--------------|---------|-------------------------------|---------------------|----------------------------------|------------------------|------------------------|
|      |              |         | Returns/<br>Bump Plug         | Spacers             | Pipe Movement                    |                        |                        |
| 3    | 20           | No      | No returns                    | 25 bbl SW           | None                             | ??                     |                        |
|      | 16           | >1,000  | FR/ BP                        | 10 bbl FW           | Reciprocated                     | ??                     |                        |
|      | 10 ¾         | >1,000  | FR/BP                         | None                | None                             | 80 at 1/jt.            |                        |
|      | 7            | ~500    | FR/BP                         | 50 bbl dual         | Stuck while recip                | 80 at 1/jt.            |                        |
| 13** | 20           | <100    | FR                            | 25 bbl SW           | None                             | None                   |                        |
|      | 16*          | ~1,000  | FR/ BP                        | 25 bbl Sup. flush K | Recip w/10 ft strokes            | None                   |                        |
|      | 10 ¾         | >2,000  | FR/ BP                        | 50 bbl dual         | None                             | Yes - quantity?        | Gas while drlg         |
|      | 7            | >100    | FR/ BP                        | 50 bbl dual         | Stuck while recip w/15 ft stroke | 85 at 1/jt.            | Gas w/csg on bottom    |
| 10   | 20           | >0      | FR                            | None                |                                  |                        |                        |
|      | 16           | <100    | FR/ BP                        | None                |                                  |                        |                        |
|      | 10 ¾         | >1,500  | FR/ BP                        | 25 bbl              |                                  |                        |                        |
|      | 7            | ~1,000  | BP                            | 35 bbl dual         |                                  |                        | Gas while drlg         |
| 1    | 20           | No      | PR                            |                     |                                  |                        |                        |
|      | 16           | No      | FR/ BP                        |                     |                                  |                        |                        |
|      | 10 ¾         | ~1,000  | FR/ PNB                       |                     |                                  |                        | Circ out gas on bottom |
|      | 7            | >500    | BP                            | 25 bbl 'SD'         | Csg stuck while reciprocating    |                        |                        |
| 14   | 20           | >0      | Lost rtns last 100 bbl        |                     |                                  |                        |                        |
|      | 16           | ~1,000  | FR                            |                     |                                  |                        |                        |
|      | 11 ¾         | <500    | FR/ PNB                       |                     | None                             | None                   | Gas while drlg         |
|      | 9 ⅝          | >1,000  | BP                            | None                | None                             | None                   | Gas while drlg         |
| 11   | 20           | No      | None/PR                       | 25 bbl SW           | Recip w/10 ft strokes            | None                   |                        |
|      | 16           | No      | PR/ BP                        | 25 bbl Superflush   | Recip w/10 ft strokes            | 5 Total - 1 each 60 ft |                        |
|      | 10 ¾         | >2,000  | NR/ BP                        | 50 bbl dual purpose | ??                               | Yes - quantity?        | Gas while drlg         |
|      | 7            | <500    | BP                            | 50 bbl dual         | Reciprocated                     | 80 at 1/jt.            | Gas w/csg on bottom    |
| 15   | 20           | No      | FR/None                       | 25 bbl SW           | Reciprocated                     | ??                     |                        |
|      | 16           | <400    | FR/ BP                        | 25 bbl S. Flush     | Reciprocated                     | 6 at 1/jt.             |                        |
|      | 10 ¾         | ~2,000  | FR/BP (90bbl cmt. at surface) | No Spacer (damaged) | None - Csg stuck                 | 10 at 1/jt.***         |                        |
|      | 7            | 0       | FR/BP                         | 25 bbl dual         | Reciprocated                     | 80 at 1/jt.            | Gas w/csg on bottom    |

\*P-tank line plugged from boat and had to be cleared for 1 hr before resuming operations

\*\* 12 cement squeezes pumped before putting well on line - Well sanded up

\*\*\* 2 centralizers run at shoe between 10 ¾ and 16-in. shoes

FR = Full Returns PR = Partial Returns NR = No Returns BP = Bump Plug PNB = Plug Not Bumped

As reported by Smith (Smith, 1990), an annular velocity greater than 200 ft/minute is recommended for efficient displacements. For 7-in. inside of 10 3/4-in. 45.5 ppf casing, 11 bpm translates to 226 ft/min (11 bpm \*20.59 ft/bbl). This value is not in itself conclusive but does not indicate serious problems. Over 1,300 psi was bled down from the 10 3/4-in. casing less than a year from the primary cement jobs. Assuming that the mud dehydrated to an equivalent 8.6 ppg gradient of water, the 1,300 psi pressure indicates a pressure source somewhere below the 10 3/4-in. shoe. Information from a field pore pressure (Fig. 5-7) plot indicates a source depth of at least 4,700 ft and a 13.2 ppg pore pressure assuming the 1,300 psi SICP or a depth of 5,500 ft and 14.1 ppg pore pressure using a 2,000 psi SICP.

Operations on 10 wells between 1989 and 1992 resulted in 2 initial successes but required remedial work on 5 wells before the program finished and 5 of these wells were re-worked in 1999. Four wells were considered successful in reducing or eliminating SCP. This results in a 20% initial success rate in reducing or eliminating SCP and a 40% ultimate success rate in reducing or eliminating SCP.

Of the twelve wells worked over in the 1999 program, 3 wells required remedial work while operations were ongoing, and only 1 well exhibited SCP upon completion of the program. This results in a 75% initial success rate and a 92% ultimate success rate in alleviating SCP in the field as of April 30, 2003.

Absolute certainty of SCP causes in this field is not known, but research into operations indicates problems with the primary completion as summarized above. What is known is that the improvements in operations during the 1999 workover program, mainly relying upon removal of sufficient casing to place a satisfactory pressure barrier, properly sized cutters to avoid breaching outer casing, Proper hole preparation previous to cementing operations, and cement placement techniques have led to an improved method of ‘Removal of Sustained Casing Pressure Utilizing a Workover Rig’.

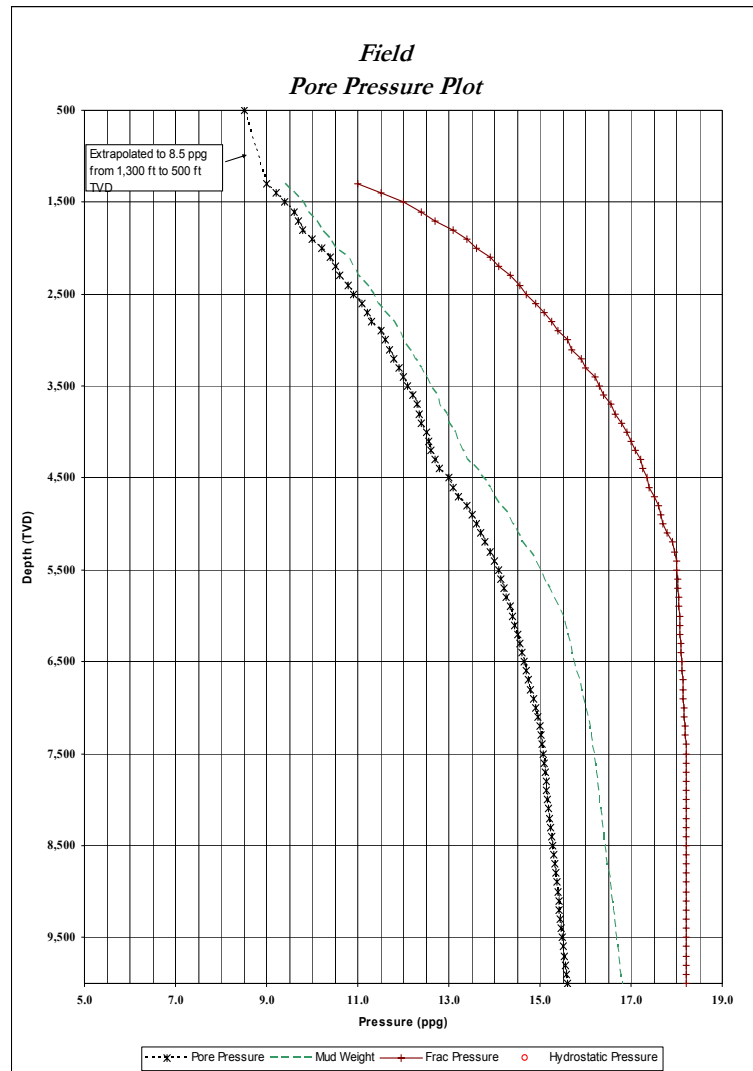


Figure 5-7 – Field Pore Pressure Plot

## CHAPTER VI: 1999 PROGRAM REASONS FOR SUCCESS

The following conclusions can be made from the 1999 workover program. The underlying principle was to address the SCP as deeply as feasible to allow for possible future intervention. Each of the following items contributed to the program's operational effectiveness. The 1999 Workover Program has succeeded where previous operations have failed due to the following four main factors:

### **1. Relying Upon Removal of Sufficient Casing to Place a Satisfactory Pressure Barrier and not Relying Upon Traditional Squeeze Operations**

Many failed perforation or cut to squeeze operations have been documented as evidenced in the last chapter by **Tables 5-2, 5-4, 5-5, and 5-6**. Multiple formulations and procedures were employed in the past with only limited success in reducing but not eliminating the pressure. The 1999 Workover Program relied on addressing the SCP as deeply as possible with multiple, extensive pressure barriers.

**Figures 5-1 and 5-5** are prime examples of difficulties in isolating SCP through perforation or cut to squeeze operations. Although perforations or a cut can access some of the channels, all of the conduits may not be isolated with sufficient volumes of cement. It is highly unlikely that any cement could be placed on the low side of the hole in the highly eccentric situation depicted in **Fig. 5-1**. Previous perforate to squeeze operations may have failed due to the inability to place sufficient pressure barriers in the affected annulus.

### **2. Properly Sized Cutters to Avoid Breaching Outer Casing**

To avoid breaching the outer casing string barrier when milling concentric strings of pipe, cutter sizes were optimized to the outer diameter they were cutting. During this operation, two cutter sizes were used on every casing when a window 'cutout' was made: one specifically sized to cut the tube and a larger cutter for the casing collars. These procedural changes are a continuation of the lessons learned while milling casing during the 1990 workover program.

Initial milling operations resulted in some balling of metal cuttings in the mud return flowline. The use of an open-top surface trough was built in conjunction with the rig contractor to address the downtime due clearing clogged return lines. Eliminating unnecessary sharp bends, restrictions, and obstructions in the open top return lines succeeded in minimizing any delays due to balled cuttings.

### **3. Proper Hole Preparation Previous to Cementing Operations**

Before any cementing operation in a water-based mud environment, proper hole preparation was imperative. A diverter sub was rotated into the hole throughout the plug interval previous to the pumping of properly sized spacers. The diverter tool efficiently removed mud cake or trash to increase the bonding characteristics of the cement to casing.

Preparation for pressure isolation of casing stubs began with a trip in the hole with a bit and scraper sized for the milled casing along with a Lockomatic under reamer dressed with blades for the next larger casing. This trip was used to clean the greater portion of the cement and dehydrated mud from the casing wall. The outer casing was cleaned throughout the milled region, and a minimum of one bottoms up was circulated to clean the outer casing before a cement plug was pumped.

The preferred fluid system was altered midway through the program once it was apparent that excessive conditioning times were necessary to maintain proper rheological properties. The initially chosen water-based mud system clabbered when milling extensive lengths of cement, dehydrated barite and zinc bromide. Various amounts of zinc bromide, from a non-rig program attempting to avoid rig intervention, were present in some of the affected annuli. HEC and xanthan gum blended/gelled brine with a 40-yield point was found to be sufficient to economically carry large amounts of iron, cement, and dehydrated mud to the surface without compromising its rheology.

The proper density of workover fluid was determined by considering the frac gradient of the outermost exposed casing shoe and expected applied pressures as the upper available weight limit. When possible, attempts were made to stay closer to the pore pressure than frac gradient to avoid breaking down the formation at the casing shoe.

#### **4. Cement Placement Techniques**

The cement slurry was treated with a latex additive to help increase both the initial and long-term bonding characteristics with the casing. It was intended to perform during pressure buildup, either constant or cyclical. Improvements in cementing technology should be considered when designing future programs.

Isolation of windows or casing stubs was augmented by squeezing cement into the annulus and holding pressure. The final squeeze pressure varied based on burst characteristics of casing and the established pressure previous to reversing out the workstring. Whenever possible, a mechanical 'bottom' was set to avoid cement contamination from gas migrating through the setting cement or if the wellbore fluid and cement had a 2-lb/gal or greater density difference. A CIBP was the preferred 'bottom' and was not meant to act as a long term pressure seal when not used in conjunction with a cement plug. Long-term degradation could occur to the rubbers from constant exposure to the wellbore environment.

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**APPENDIX A: MMS POLICY LETTER 30 CFR 250.517**



# United States Department of the Interior



## MINERALS MANAGEMENT SERVICE

Gulf of Mexico OCS Region  
1201 Elmwood Park Boulevard  
New Orleans, Louisiana 70123-2394

In Reply Refer To: MS 5221

Gentlemen:

This letter serves to inform lessees operating in the Gulf of Mexico Outer Continental Shelf of the current policy concerning sustained casing pressure according to the provisions of 30 CFR 250.17. The following policy - supersedes our last Letter to Lessees and Operators dated August 5, 1991, and is intended to streamline procedures and reduce burdensome paperwork concerning the reporting of sustained casing pressure conditions and the approval process for those wells that the Minerals Management Service (MMS) will allow to be produced with sustained casing pressure;

1. All casinghead pressures, excluding drive or structural casing, must be immediately reported to the District Supervisor. This notification by the lessee, to the District Supervisor can either be in writing or by telephone, with a record of the notification placed in the record addressed in paragraph 5 below, by the close of business the next working day after the casing pressure is discovered.

2. Wells with sustained casinghead pressure that is less than 20 percent of the minimum internal yield pressure of the affected casing and that bleed to zero pressure through a 1/2-inch needle valve in 24 hours or less may continue producing operations from the present completion with monitoring and evaluation requirements discussed below.

A diagnostic test that includes bleed down through a 1/2-inch needle valve and buildup to record the pressures in et least 1-hour increments must be performed on each casing string in the wellbore found with casing pressure. The evaluation should contain identification of each casing annulus; magnitude of pressure on each casing; time required to bleed down through a 1/2-inch needle valve; type of fluid and volume recovered; current rate of buildup, shown graphically or tabularly in hourly increments; current shut-in and flowing tubing pressure; current production data; and well status. Diagnostic tests conducted on wells that meet the conditions described in paragraph 2 above do not have to be formally submitted for approval.

3. Wells having casings with sustained pressure greater than 20 percent of the minimum internal yield pressure of the affected casing or pressure that does not bleed to zero through a 1/2-inch needle valve, must be submitted to this office for approval. The information submitted for consideration of a sustained casing pressure departure under these conditions should be the same as described in the above paragraph.

4. The casing(s) of wells with sustained casinghead pressure should not be bled down without notifying this office except for required and documented testing. If the casing pressure from the last diagnostic test increases by 200 psig or more in the intermediate or production casing, or 100 psig or more in the conductor or surface casing, then a subsequent diagnostic test must be performed to reevaluate the well. Notification to this office is not necessary if the pressure is less than 20 percent of the minimum internal yield pressure of the affected casing and bleeds to zero pressure through a 1/2-inch needle valve. The recorded results of the subsequent diagnostic test must be kept at the field office. However, the results of this test must be submitted to this office for evaluation if the conditions as described in Paragraph 3 apply.

5. Complete data on each well's casing pressure information need only be retained for a period of 2 years, except that the latest diagnostic information must not be purged from the overall historical record that must be kept. Casing pressure records must be maintained at the lessee's field office nearest the OCS facility for review by



# United States Department of the Interior



## MINERALS MANAGEMENT SERVICE

Gulf of Mexico OCS Region  
1201 Elmwood Park Boulevard  
New Orleans, Louisiana 70123-2394

the District Supervisor's representative(s).

6. The previous approval of a sustained casing pressure departure is invalidated if workover operations, as defined by 30 CFR 250.91, commence on the well. Also, operations such as acid stimulation, shifting of sliding sleeves, and gas-lift valve replacement require diagnostic reevaluation of any production or intermediate casing annulus having sustained pressure.

7. Unsustained casinghead pressure may be the result of thermal expansion or may be deliberately applied for purposes such as gas-lift, backup for packers, or for reducing the pressure differential across a packoff in the tubing string. Unsustained casinghead pressure which is deliberately applied does not need to be submitted to this office. Unsustained casinghead pressure, as the result of thermal expansion, greater than 20 percent of the minimum internal yield pressure of the affected casing or does not bleed to zero through a 1/2-inch needle valve needs to be submitted to this office with either of the following information:

a. The lessee must report the casing(s) pressure decline (without bleeddown) to near zero during a period when the well is shut in, or

b. With thoroughly stabilized pressure and temperature conditions during production operations, the lessee may bleed down the affected casing(s) through a 1/2-inch needle valve approximately 15 - 20 percent, and obtain a 24-hour chart which shows that the pressure at the end of the following 24-hour period is essentially the same as the bleed down pressure at the start of the 24-hour period while production remains at a stabilized rate.

8. Subsea wells with remote monitoring capability must be monitored, analyzed, and reported as described above. If the casing valve(s) must be operated manually the monitoring, analyzing, and reporting frequency is 2 years at a maximum.

9. Should a request for a departure from 30 CFR 2-0.87 result in a denial, the operator of the well will have 30 days to respond to the MMS District Office with a plan to eliminate the sustained casinghead pressure. Based on well conditions, certain denials may specify a shorter time period for corrections.

If there are any questions regarding this matter, please contact Mr. B. J. Kruse at (504) 736-2634.

Sincerely,

(signed)  
D. J. Bourgeois  
Regional Supervisor  
Field Operation

## APPENDIX B: 1999 OPERATIONS SUMMARY

The following is a summary of the rig operations performed during the 1999-2000 workover campaign. A total of twelve wells were worked over but only the following four wells are presented to illustrate representative operations.

### Well 1

This well was drilled and completed in 1983 and was temporarily abandoned from the producing formation with five EZSV's. The shallowest EZSV was immediately above the 10 3/4-in. casing shoe. A workover was planned to replace leaking tubing but during preliminary work, the 10 3/4-in. casing began to flow. Multiple cement squeezes were attempted but none seemed to bring the pressure under control. Hydrocarbon reserves could not justify further work and it was subsequently temporarily abandoned in 1990. The objective of the present operations is to cut and recover the 7-in. and 10 3/4-in. casing as deeply as possible. Set 10 3/4-in. and 16-in. CIBP's and spot cement in accordance to CFR Title 30, Section 250.702 regulations. The following two tables summarize the casing pressures previous to beginning of operations as well as a summary of design considerations:

#### CASING PRESSURES

| CASING       | OD (IN.) | WEIGHT (LB/FT) | GRADE/ CONNECTION | CURRENT PRESSURE (PSI) | INTERNAL YIELD (PSI) | 20% INTERNAL YIELD (PSI) |
|--------------|----------|----------------|-------------------|------------------------|----------------------|--------------------------|
| Drive Pipe   | 26       |                |                   | 0                      |                      |                          |
| Surface      | 20       | 94.0           | X-52              | 0                      | 2,110                | 422                      |
| Intermediate | 16       | 75.0           | X-52              | 0                      | 2,630                | 526                      |
| Intermediate | 10 3/4   | 45.5           | K-55 STC          | 1,269                  | 3,580                | 716                      |
| Production   | 7        | 26.0           | N-80 LTC          | 0                      | 7,240                | 1,448                    |

#### PRESSURE PROFILES

| *DEPTH OF CONCERN |                 | PORE PRESSURE |        |     | WORKOVER FLUID |     |         | FRACTURE GRADIENT |        |     |
|-------------------|-----------------|---------------|--------|-----|----------------|-----|---------|-------------------|--------|-----|
| MD/TVD            | DESCRIPTION     | PSI           | PSI/FT | PPG | TYPE           | PPG | OB(psi) | PSI               | PSI/FT | PPG |
| 4507/4352         | 10 3/4 in. SHOE | 3,047         | 0.676  | 130 | WBM            | 140 | 200     | 4,078             | 0.905  | 174 |

\* Depth of concern during operations is exposing the 10-3/4-in. shoe to fracture gradient mud weights or pressures.

### Operations Summary

The workover rig was moved on and rigged up beginning on January 8<sup>th</sup>, 2000. The 7-in. 26 ppf casing was cut, pulled and laid down from 1,699-ft. Sixty cu-ft of latex cement was squeezed into and around the 7-in. casing stub while holding 250 psi. Pressure was held on the squeeze for twelve hours with the top of cement subsequently being tagged at 1,591-ft.

A CIBP was then set at 1,584-ft and tested to 1,000 psi. An under balance test was performed and a 60 cu-ft latex cement plug was then spotted with 1,000 psi held on it for 12 hours. The top of cement was then tagged at 1,450-ft.

Upon isolating the 7 x 10 3/4-in. annulus, the 10 3/4-in. casing was then cut, pulled, and laid down from 838-ft. Sixty cu-ft of latex cement was then squeezed onto and around the 10 3/4-in. casing stub while holding 500 psi on cement for twelve hours. The top of cement was tagged at 808-ft indicating that some cement was squeezed into the 10 3/4 x 16-in. annulus.

A CIBP was then set in the 16-in. casing at 778-ft and tested to 1,000 psi. A 120 cu-ft latex cement plug was then spotted with 500 psi applied to the cement for twelve hours. The top of cement was then estimated at 678-ft.

Both the 16-in. and 20-in. casing had no pressure on them. The rig was then rigged down and moved to well 10 on February 07, 2000.

## Well 2

The well is presently temporarily abandoned with an EZSV at 6,352-ft. The 10 3/4 x 16-in. annulus has sustained pressure (See table below). The objective of the workover is to relieve sustained casing pressure from the 10 3/4 x 16-in. casing annulus, mill approximately 120-ft of 10 3/4-in. casing and set an inflatable bridge plug in the 16-in. casing with approximately 40 ft of cement below and 100' of cement on top. Next, mill the 10 3/4-in. casing, cut and recover 16-in. casing to 700-ft, set a 20-in. CIBP, and spot 200-ft of cement on top.

### CASING PRESSURES

| CASING       | OD (INCHES) | WEIGHT (LB/FT) | GRADE/ CONNECTION | CURRENT PRESSURE (PSI) | INTERNAL YIELD (PSI) | 20% INTERNAL YIELD (PSI) |
|--------------|-------------|----------------|-------------------|------------------------|----------------------|--------------------------|
| Surface      | 20          | 94.0           | X-52              | 0                      | 2,110                | 422                      |
| Intermediate | 16          | 84.0           | K-55 BTC          | 54                     | 2,980                | 596                      |
| Intermediate | 10 3/4      | 45.5           | NT-80H STC        | 0                      | 5,210                | 1,042                    |
| Production   | N/A         | N/A            | N/A               | N/A                    | N/A                  | N/A                      |

### PRESSURE PROFILES

| *DEPTH OF CONCERN |             | PORE PRESSURE |        |      | WORKOVER FLUID |     |         | FRACTURE GRADIENT |        |     |
|-------------------|-------------|---------------|--------|------|----------------|-----|---------|-------------------|--------|-----|
| MD/TVD            | DESCRIPTION | PSI           | PSI/FT | PPG  | TYPE           | PPG | OB(psi) | PSI               | PSI/FT | PPG |
| 2645/2620         | 16-in.shoe  | 1512          | 0572   | 11.1 | WBM            | 120 | 123     | 2030              | 07748  | 149 |
| 1,305/1,305'      | 20-in.shoe  | 577           | 04420  | 8.5  | WBM            | 100 | 102     | 746               | 0572   | 110 |

\* Depths of concern during operations is exposing the 16 & 20-in. shoes to fracture gradient mud weight or pressure.

## Operations Summary

Work began on March 24, 2000 by nipping down the tree and nipping up the BOP's. An inflatable packer was set to test the BOP's and then recovered. Next, a 10 3/4-in. CIBP was set at 2,600-ft and the 10 3/4-in. casing was section milled from 2,239 to 2,352-ft. A 160 cu-ft latex cement plug was spotted on the CIBP in the 10 3/4-in. casing with 1,000 psi being held on it for 12 hours.

An inflatable packer for 16-in. casing was set at 2,335-ft and tested to 1,000 psi for 15 minutes. 213 cu-ft of latex cement was spotted on top of the inflatable packer to 2,143-ft. A CIBP was set at 900-ft and tested to 1,000 psi for 15 minutes.

The 10 3/4-in. casing was then milled to 800-ft and the 16-in. casing was tested to 1,000 psi for 15 minutes. The 16 3/4-in. 5M BOP's were nipped down and 21 1/4-in. 3M BOP's were nipped up and tested before cutting the 16-in. casing at 750, 125, and 69-ft. The 16-in. casing could not be pulled so a window was section milled in the 16-in. casing from 559 to 750-ft. 191 cu-ft of latex cement was pumped into the 10 3/4, 16, and 20-in. casings from 878 to 716-ft and held 350 psi for 12 hours on the cement.

An inflatable packer for 20-in. casing was set at 700-ft but would not test. The inflatable packer was retrieved and an RTTS test packer was set inside the 16-in. casing. The 16 and 20-in. casings were tested from 540-ft to surface to 500 psi for 15 minutes. The RTTS packer was retrieved and a 359 cu-ft of latex cement was spotted in the 16 and 20-in. casings from 716 to 524-ft. Seven barrels of cement were squeezed away and held 500 psi for 12 hours with the top of cement subsequently tagged at 552-ft. Finally, 70 cu-ft of 15.6-ppg neat cement was mixed and pumped with an estimated TOC at 495-ft. A dry hole tree was nipped up and the rig was skidded to well 12. The 20-in. casing had 0 psi on it.

### Well 10

The well was drilled in the spring of 1984. No future utility was seen for the wellbore and it was subsequently temporarily abandoned during a July, 1989 workover from the producing formation. The well was re-entered in March of 1991 to address SCP in the 7-in. casing, 7 x 10 3/4-in., 10 3/4 x 16-in., and 16 x 20-in. annuli all having sustained pressure (See table below).

The objective of the present operation was to relieve the SCP from the 7-in. casing, 7 x 10 3/4-in., 10 3/4 x 16-in., and 16 x 20-in. casing annuli by cutting and recovering the 7-in., 10 3/4-in., and 16-in. casing as deeply as possible. CIBP's would then be set as mechanical barriers with cement squeezed into each casing stub. Spot surface cement plug and skid the rig.

#### CASING PRESSURES

| CASING       | OD (IN.) | WEIGHT (LB/FT) | GRADE/ CONNECTION | CURRENT PRESSURE (PSI) | INTERNAL YIELD (PSI) | 20% INTERNAL YIELD (PSI) |
|--------------|----------|----------------|-------------------|------------------------|----------------------|--------------------------|
| Drive Pipe   | 26       |                |                   | 0                      |                      |                          |
| Surface      | 20       | 94.0           | X-52              | 10                     | 2,110                | 422                      |
| Intermediate | 16       | 84.0           | K-55 STC          | 89                     | 2,980                | 596                      |
| Intermediate | 10-3/4   | 45.5           | K-55 STC          | 836                    | 3,580                | 716                      |
| Production   | 7        | 29.0           | N-80 AB Mod       | 898                    | 8,160                | 1,632                    |

#### PRESSURE PROFILE

| *DEPTH OF CONCERN |                 | PORE PRESSURE |        |     | WORKOVER FLUID |     |         | FRACTURE GRADIENT |        |     |
|-------------------|-----------------|---------------|--------|-----|----------------|-----|---------|-------------------|--------|-----|
| MD/TVD            | DESCRIPTION     | PSI           | PSI/FT | PPG | TYPE           | PPG | OB(psi) | PSI               | PSI/FT | PPG |
| 52104347          | 10 3/4-in. SHOE | 2871          | 0.6604 | 127 | WBM            | 140 | 294     | 3,888             | 0.8894 | 172 |
| 25562312          | 16-in. SHOE     | 1274          | 0.5512 | 106 | WBM            | 116 | 120     | 1,731             | 0.7488 | 144 |
| 13481284          | 20-in. SHOE     | 601           | 0.4680 | 90  | WBM            | 100 | 67      | 740               | 0.5720 | 110 |

\* Depths of concern during operations is exposing the 10 3/4, 16, and 20-in. shoes to fracture gradient mud weights or pressures.

### Operations Summary

Work began February 07, 2000 by bleeding down the 7-in. and 10 3/4-in. casing strings to 0 psi. Since the 7-in. casing had pressure, a compression plug was set at 1,017-ft to act as a secondary pressure barrier in order to safely nipple down the tree and tubing spool. An adapter spool and riser were then nipped up before setting a retrievable bridge plug at 310-ft. The blowout preventers were then nipped up and tested and the retrievable bridge plug was recovered.

The 7-in. casing was cut and recovered at 2,069-ft with a sixty cu-ft latex cement plug spotted in the 7-in. and some cement was squeezed into the 7 x 10 3/4-in. annulus from 2,068 to 1,985-ft.



A CIBP was set at 1,940-ft to act as a mechanical bottom with a 60 cu-ft latex cement plug spotted on top from 1,940 to 1,829-ft. The plug and 10 ¾-in. casing was then pressure tested to 2,000 psi.

The 10 ¾-in. casing was cut and recovered as deeply as possible at 711-ft. The 10 ¾-in. casing was then milled to 1,051-ft and an 88 cu-ft latex cement plug was spotted from 1,101 to 1,001-ft. An EZSV was set at 987-ft with 15.65-bbl of latex cement squeezed below and the EZSV tested to 500 psi. Final pressure isolation of the 16-in. casing was obtained by setting a 120 cu-ft latex cement plug from 980 to 882-ft.

The 16-in. casing was recovered to 738-ft and a 161 cu-ft latex balanced cement plug was spotted at 791-ft. However, cement was not tagged as expected at 691-ft. An EZSV was then set at 650-ft. The blind rams were closed to pressure up the 20-in. casing to test the EZSV. At 940 psi, the pressure dropped and was able to inject at 1 BPM at 500 psi. No pressure was noted on the drive pipe gauge.

In order to isolated source of leak, an inflatable packer was tripped in the hole to test the casing. The casing tested down to 634-ft; however, a hole was indicated in the 20-in. casing at approximately 650-ft. Although no formal explanation for the casing leak was put forth, this is the approximate depth that the CIBP was set and casing integrity may have been compromised during pressure testing of the EZSV. Subsequently, 32-bbl of standard cement was circulated into the 20 x 26-in. annulus and a 60 cu-ft neat cement plug was left in the 20-in. casing from 650-ft to a tagged top of cement at 554-ft.

Upon verification of zero pressure on all casing strings, the blowout preventers and riser was nipped down; a dry hole tree was nipped up and the rig was moved off on March 24, 2000. Another well was recompleted before returning to plug and abandonment operations on well 12.

## Well 12

This well was temporarily abandoned from the producing sand with a TTBP during a previous workover operation. The 2 ⅞ x 7-in., 7 x 10 ¾-in., 10 ¾ x 16-in. and 16 x 20-in. casing annuli all had sustained pressures of 83, 125, 86, and 10 psi respectively as of January 2000.

The objective of the workover program was to permanently plug and abandon the producing sand perforations. Further steps would be taken to relieve SCP from the 7-in. casing, 7 x 10 ¾-in., 10 ¾ x 16-in. and 16 x 20-in. casing annuli by cutting and recovering the 7-in., 10 ¾-in., and 16-in. casing strings. The well would be abandoned in accordance to CFR Title 30, Section 250.702 regulations.

**CASING PRESSURES**

| CASING       | OD (IN.) | WEIGHT (LB/FT) | GRADE/ CONNECTION | CURRENT PRESSURE (PSI) | INTERNAL YIELD (PSI) | 20% INTERNAL YIELD (PSI) |
|--------------|----------|----------------|-------------------|------------------------|----------------------|--------------------------|
| Surface      | 20       | 94.0           | X-52              | 10                     | 1,993                | 399                      |
| Intermediate | 16       | 109.0          | K-55 STC          | 86                     | 3,950                | 790                      |
| Intermediate | 10-¾     | 45.5           | K-55 STC          | 125                    | 3,580                | 716                      |
| Production   | 7        | 29.0           | N-80 LTC AB M     | 83                     | 8,160                | 1,632                    |

## PRESSURE PROFILE

| *DEPTH OF CONCERN |  | PORE PRESSURE |        |      | WORKOVER FLUID |      |         | FRACTURE GRADIENT |        |      |
|-------------------|--|---------------|--------|------|----------------|------|---------|-------------------|--------|------|
| MD/IVD            | DESCRIPTION                              | PSI           | PSI/FT | PPG  | TYPE           | PPG  | OB(psi) | PSI               | PSI/FT | PPG  |
| 1,472/1,341       | 20-in. SHOE                              | 635           | 0.4732 | 9.1  | WBM            | 100  | 697     | 781               | 0.5824 | 11.2 |
| 2,741/2,350       | 16-in. SHOE                              | 1,308         | 0.5564 | 10.7 | WBM            | 11.6 | 1,418   | 1,772             | 0.7540 | 14.5 |
| 5,363/4,318       | 10 <sup>3</sup> / <sub>4</sub> -in. SHOE | 2,852         | 0.6604 | 12.7 | WBM            | 14.0 | 3,144   | 3,862             | 0.8944 | 17.2 |

\*Depth of concern is exposing the 10<sup>3</sup>/<sub>4</sub>, 16, and 20-in. shoes to fracture gradient mud weights or pressures.

### Operations Summary

Previous to moving the rig to well 12, electric line was rigged up to cut the production tubing. The rig was then skidded over the well on May 14, 2000. Upon nipping down the tree and nipping up the blowout preventers and testing the BOP's, the rig was unable to pull the 2<sup>7</sup>/<sub>8</sub>-in. production tubing. It was necessary for electric line to cut the tubing. Seven-bbl of latex cement was then spotted down the production tubing and into the 7-in. casing at the tubing cut with 1,000 psi held for 12 hours. The production tubing was then pulled out of the hole and laid down.

The workstring was then tripped in the hole and tagged the cement. The 14-ppg mud was then circulated and conditioned before testing the cement plug to 1,000 psi for 15 minutes. A 7-in. CIBP was then set at 8,000-ft to serve as a mechanical bottom and tested to 1,000 psi for 15 minutes. The blowout preventers were then nipped down and the tubing spool removed. The blowout preventers were then nipped up and tested in preparation of cutting the 7-in. casing.

In order to relieve tension on the casing slips, a cut in the 7-in. casing was made 50-ft below slips. A mechanical cut was then made at 3,600-ft and the 7-in. casing was pulled. Forty-eight cu-ft of latex cement was spotted at 3,700-ft. The casing was pressured to 1,000 psi for 12 hours to squeeze cement around the 7-in. casing stub and into the 7 x 10<sup>3</sup>/<sub>4</sub>-in. annulus. The top of cement was tagged at 3,572-ft.

A 10<sup>3</sup>/<sub>4</sub>-in. CIBP was then set at 3,537-ft and tested to 1,000 psi for 15 minutes to act as a mechanical bottom. Ten barrels of latex cement was then spotted on the CIBP and the cement plug was tested to 1,300 psi for twelve hours. The estimated top of cement was at 3,431-ft.

The well was then displaced to 11.6 ppg water based mud. The blowout preventers and 7-in. casing head were nipped down. The blowout preventers were then nipped up and tested. In an attempt to relieve tension on the casing, a cut was made in the 10<sup>3</sup>/<sub>4</sub>-in. casing at 88-ft but was unable to pull the hanger free. Another cut in the 10<sup>3</sup>/<sub>4</sub>-in. casing was made at 44-ft and the casing was recovered to this depth. A 10<sup>3</sup>/<sub>4</sub>-in. CIBP was then set at 1,000-ft to act as a bottom.

The 10<sup>3</sup>/<sub>4</sub>-in. casing was then milled to 776-ft and 7.1 bbls of latex cement was then pumped in the 16-in. casing from 774 to 740-ft. Five hundred psi was then held on the casing and plug for twelve hours to squeeze 6.1 bbls into 10<sup>3</sup>/<sub>4</sub> x 16-in. annulus. The top of cement was subsequently tagged at 769-ft.

A 16-in. CIBP was set at 726-ft to act as a mechanical bottom and tested to 500 psi for 15 minutes. Ten and one half-bbl of latex cement was then spotted on the CIBP with 500 psi being held on it for twelve hours. The top of cement at 674-ft was tested to 500 psi for 15 minutes. The wellbore was then displaced to 10.3 ppg water based mud before nipping down the blowout

preventers. The 10 3/4-in. casing head was also nipped down and blowout preventers were then nipped up and tested.

In order to relieve tension in the 16-in. casing and to verify the hanger would pull free, the 16-in. casing was cut 50-ft below the slips and pulled out of the hole. Unsuccessful attempts to cut and recover the 16-in. casing were made at 665, 342, and 164-ft. Finally, a cut and recovery was made at 122-ft. The next section to 164-ft was speared and recovered. Further cuts in the 16-in. casing were made at 203 and 184-ft. The casing was then recovered to 184-ft.

A pilot mill was then picked up to mill the 16-in. casing from 184-ft to 205-ft. While pilot milling, the well started losing fluid to the 26-in. shoe via a hole in the 20-in. casing at around 204-ft. A cement squeeze was made in the 20-in. casing at 204-ft with 65 bbls of 12 ppg standard cement. After waiting on the cement for 12 hours, the squeeze was tested to 150 psi but bled to 20 psi. Another cement squeeze was made in the 20-in. casing with 45-bbl of 14 ppg standard cement.

After waiting on the cement for 12 hours, the cement was drilled from 203-ft to 205-ft. The squeeze was tested to 300 psi and bled to 250 psi in 20 minutes but was considered satisfactory. The cement was subsequently drilled to 225-ft.

A window was section milled in the 16-in. casing from 548 to 608-ft. Forty-bbl of latex cement was then spotted from 621 to 460-ft with pressure held on the cement for 12 hours. Four and one-half-bbl were squeezed into the 16 x 20-in. annulus with the top of cement being tagged at 485-ft. The plug was successfully tested to 250 psi with pressure bleeding to 225 psi in 15 min.

The wellbore was finally displaced to 8.6 ppg seawater previous to nipping down the blowout preventers and nipping up a dry hole tree. The 20-in. casing had 0 psi before skidding the rig.

**Well 12 – Re-entry**

This well was abandoned earlier during this workover program in June of 2000. The 20-in. and 20 x 26-in. casing annuli have sustained pressure of 168 psi returning as of September, 2000.

The objective of this operation is to re-enter the wellbore by drilling up the cement in the 16-in. casing from 485 to 621-ft. The 16-in. casing would be section milled to approximately 658-ft. An inflatable bridge plug would then be set above the 16-in. casing stub at approximately 650-ft with 200-ft of cement spotted on the inflatable bridge plug to plug and abandon the well in accordance to CFR Title 30, Section 250.702 regulations.

**CASING PRESSURES**

| CASING     | OD (IN.) | WEIGHT (LB/FT) | GRADE/ CONNECTION | CURRENT PRESSURE (PSI) | INTERNAL YIELD (PSI) | 20% INTERNAL YIELD (PSI) |
|------------|----------|----------------|-------------------|------------------------|----------------------|--------------------------|
| Drive Pipe | 26       |                |                   | 168                    |                      |                          |
| Surface    | 20       | 94.0           | X-52              | 168                    | 1,993                | 399                      |

## PRESSURE PROFILES

| *DEPTH OF CONCERN |             | PORE PRESSURE |        |     | WORKOVER FLUID |     |         | FRACTURE GRADIENT |        |      |
|-------------------|-------------|---------------|--------|-----|----------------|-----|---------|-------------------|--------|------|
| MD/TVD            | DESCRIPTION | PSI           | PSI/FT | PPG | TYPE           | PPG | OB(psi) | PSI               | PSI/FT | PPG  |
| 738/706           | 26-in.SHOE  | 312           | 0.442  | 8.5 |                |     |         | 390               | 0.553  | 10.6 |
| 1,472/1,341       | 20-in.SHOE  | 635           | 0.4732 | 9.1 | WBM            | 100 | 697     | 781               | 0.5824 | 11.2 |

\*Depth of concern is exposing the 26 and 20-in. shoes to fracture gradient mud weights or pressures.

### **Operations Summary (Re-Entry)**

The rig was skidded back over well 12 on September 25, 2000. Mud was circulated in and conditioned to 14 ppg. The dry hole tree was nipped down and blowout preventers were nipped up. In order to test the blowout preventers, an inflatable packer was set at 75-ft. The blowout preventers were tested and the inflatable packer was latched and pulled out of the hole.

A 14 5/8-in. cement mill was tripped in the hole and the cement was tagged at 475-ft. The mud was circulated and conditioned down to 10.8 ppg before milling cement from 475 to 586-ft. The 14 5/8-in. cement mill was pulled out of the hole and laid down. A 14 1/2-in. rock bit was picked up to drill cement from 586 to 608-ft. This bit was pulled out of the hole and laid down. A 14 3/8-in. cement mill and 17 1/2-in. under reamer with a 12-in. body were made up to under ream and clean the 20-in. casing from 552 to 604-ft. The under reamer and mill were then laid down.

The next trip in the hole was with a 12 1/4-in. diamond point mill to mill cement to 617-ft. This diamond point bit was laid down and a 14 1/2-in. rock bit was picked up. Attempts were made but unable to get inside 16-in. casing stub at 608-ft. Subsequently, this bit was pulled out of the hole and laid down in favor of a 9 1/2-in. rock bit. This bit tagged cement at 612-ft and drilled to 630-ft. The casing was washed and reamed from 630 to 672-ft and cement was drilled from 672 to 674-ft. The 9 1/2-in. rock bit was pulled out of the hole and laid down.

A section mill was picked up to mill the 16-in. casing from 608 to 621-ft. The mill was changed out and tagged up at 618-ft. Little headway was made and the mill was pulled out of the hole at 619-ft. A 14 1/2-in. bit was picked up and used to washed and reamed from 618 to 655-ft. Cement was then drilled from 655 to 672-ft before pulling out of the hole and laying down the 14 1/2-in. bit. An under reamer and string mill were then used to under ream the 20-in. casing from 548 to 618-ft before pulling out and laying down the under reamer.

The 16-in. casing tube was then section milled from 618 to 631-ft. Upon changing out the section mill, the casing collar was milled from 631 to 636-ft. The blades were again changed back to mill down the 16-in. tube from 634 to 643-ft. The casing was then washed and reamed from 549 to 640-ft with an under reamer. Finally, a descaling bottom hole assembly was then used to clean the 20-in. casing from 555 to 635-ft before laying down the assembly.

An RTTS packer was set at 517-ft to test below the packer to 300 psi. The pressure bled to 260 psi in 15 minutes. It was again tested to 350 psi and bled to 320 psi in 15 minutes. The RTTS was pulled out of the hole and laid down.

The workstring was tripped in the hole to 654-ft and 12-bbl of 15.6 ppg latex cement was pumped into the 16 and 20-in. casing. An RTTS was then tripped in the hole and set at 350-ft to pressure up to 350 psi in an attempt to squeeze the cement into the 16 x 20-in. annulus to isolate

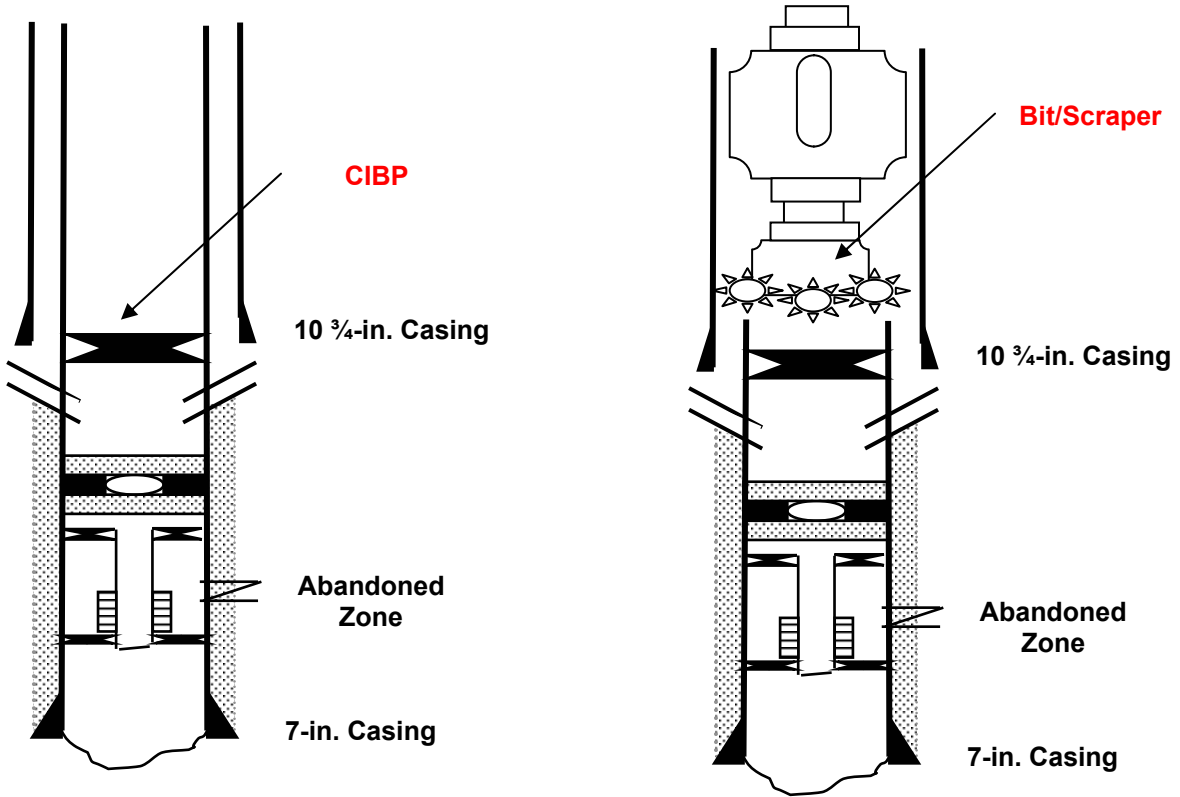
the lower window section. Pressure was trapped while waiting on cement for twelve hours. The pressure bled from 350 to 75 psi. The RTTS was released, pulled out of the hole and laid down.

An 11 <sup>3</sup>/<sub>4</sub>-in. multi-string cutter was tripped in the hole on workstring and tagged the top of cement at 622-ft. The 20-in. casing was then cleaned from 549 to 617-ft. An inflatable bridge plug was then set at 601-ft and tested to 250 psi. The workstring was then tripped in the hole to the inflatable bridge plug at 601-ft and 40-bbl of latex cement was pumped from 601 to 447-ft. An RTTS was then run and set at 345-ft to pressure up to 350 psi in an attempt to squeeze cement into the 16 x 20-in. casing annulus to isolate the upper window section. This pressure was trapped for twelve hours but bled from 350 to 0 psi.

A trip in the hole was then made and tagged the top of cement at 483-ft. The blowout preventers were nipped down and a dry hole tree was nipped up. The 20-in. casing had 0 psi on it. The rig was skidded.

**APPENDIX C: STAGES OF 1999 CUT AND PULL OPERATION**

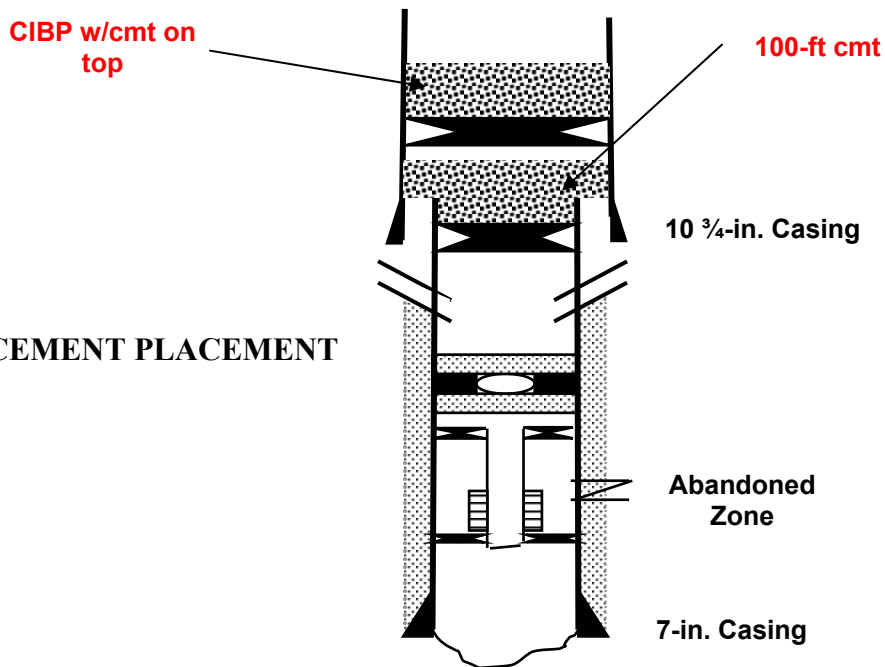
**STEP I AND II: HOLE PREPARATION**



- 7-in. Bit/scrapper Run
- Set Mechanical Bottom (CIBP)

- Remove 7-in. (Cut/pull or Pilot Mill)
- 10 3/4-in. Bit/scrapper Run

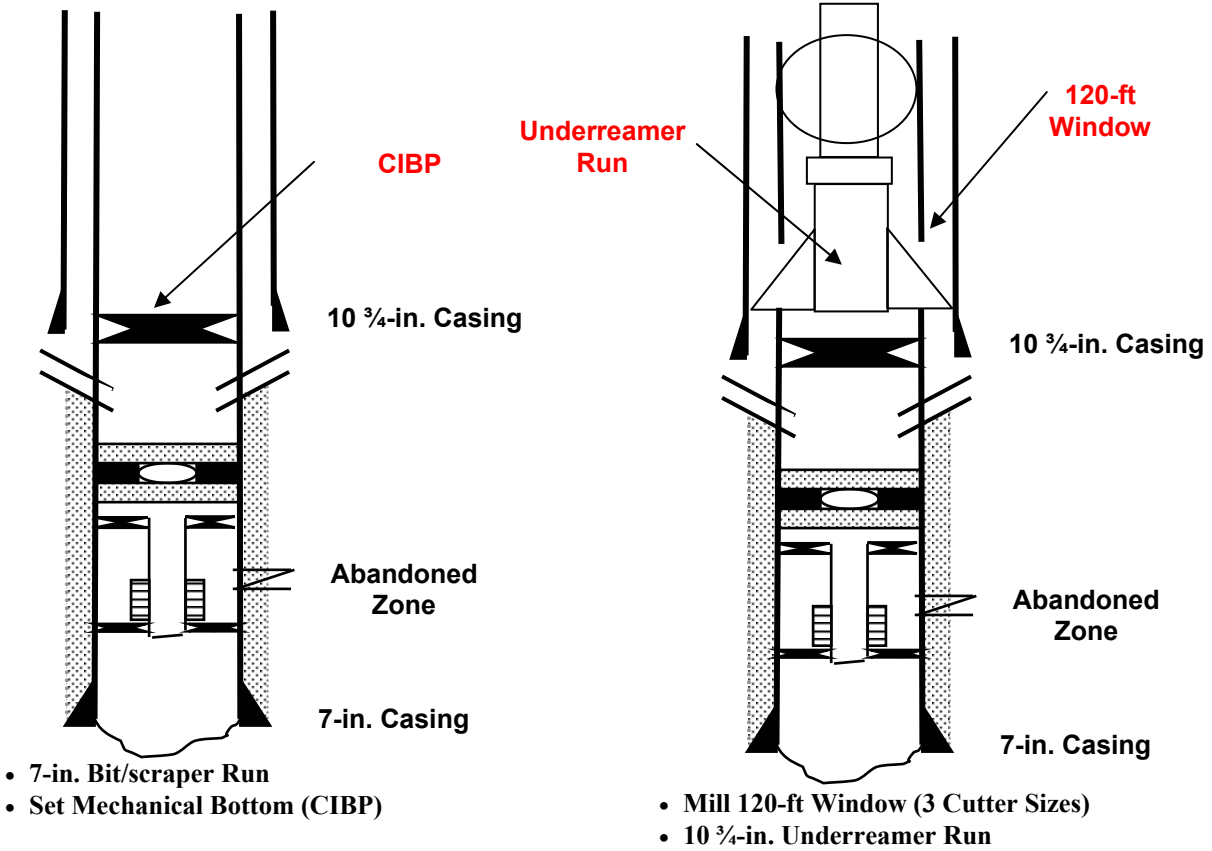
**STEP III: CEMENT PLACEMENT**



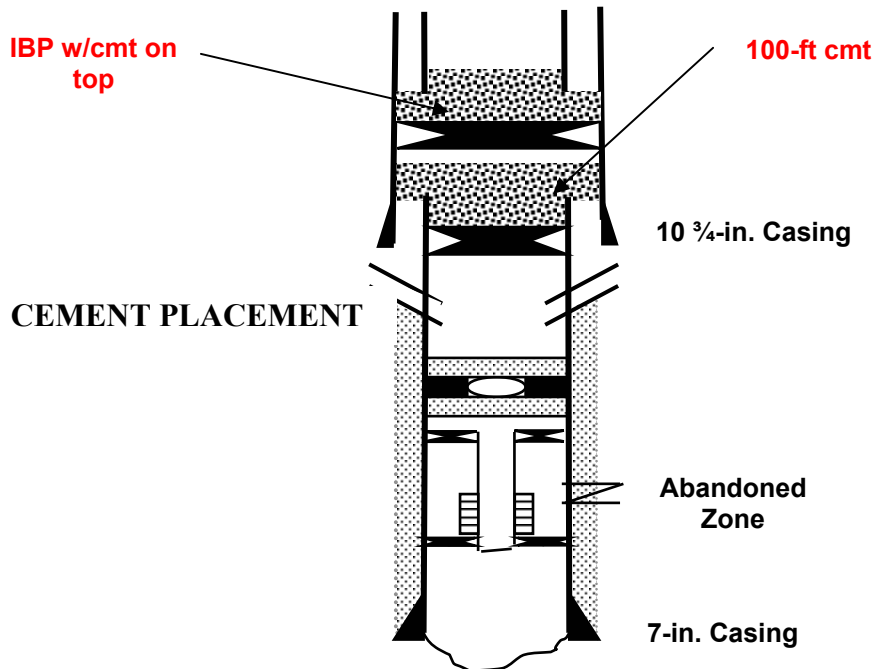
- Spot Cement and Squeeze
- Set CIBP and Spot Cement

**APPENDIX D: STAGES OF 1999 SECTION MILL OPERATION**

**STEP I AND II: HOLE PREPARATION**



**STEP III: CEMENT PLACEMENT**



- Spot Cement and Squeeze
- Underream 10 3/4-in. Csg
- Set IBP and Spot 100-ft. Cement

## VITA

Kevin Soter received a Bachelor of Science in Petroleum Engineering from Tulsa University in 1993. He is a registered Professional Engineer in the State of Louisiana working for Halliburton Energy Services in New Orleans, Louisiana. Previously, he worked as an engineer for Pennzoil Exploration out of Lafayette, Louisiana, for two years and then for Chesapeake Energy Corporation as a Production and Workover Engineer working the Louisiana Austin Chalk Trend. He has been working as a Completions and Workover Engineer for offshore Gulf of Mexico deepwater and shelf fields for five years since joining Halliburton with a brief assignment in Aberdeen, Scotland. Most recently, he has spent the past two years as Halliburton's project leader on Murphy Exploration's Medusa Prospect coordinating completion services and design. He will receive the degree of Master of Science in Petroleum Engineering at the December 2003 commencement.