# EAST MAMM CREEK PROJECT DRILLING AND CEMENTING STUDY

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**JUNE 20, 2011**

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## List of Acronyms

American Petroleum Institute ...................................................... API
American Standard of Testing and Materials .............................. ASTM
Acoustic Cement Bond Logging ................................................... ACBL or CBL
Barrels ........................................................................................ Bbls
Bearden Consistency Units ......................................................... BC
Colorado Oil and Gas Conservation Commission ......................... COGCC
Crescent Consulting, LLC ............................................................. Crescent
Encana Oil and Gas (USA), Inc. .................................................... Encana
East Mamm Creek Project Area .................................................. EMCPA
Formation Integrity Test ............................................................. FIT
Gamma ray ................................................................................. GR
Lost circulation avoidance ........................................................... LCA
Lost circulation material ............................................................. LCM
NOTICE TO OPERATORS ............................................................... NTO
Photoelectric factor ..................................................................... PEF
Pounds per foot ........................................................................... lbf
Pounds per gallon ........................................................................ ppg
Pound per square inch ................................................................. psi
Segmented Bond Tool .................................................................. SBT
Spontaneous potential ................................................................. SP
Square feet .................................................................................. sqft
Static Gel Analyzer ........................................................................ SGA
Top of cement .............................................................................. TOC
Total depth ................................................................................... TD
UltraSonic Imaging ........................................................................ USI

## Glossary

Gas Fingerprinting – a process by which specific components in a natural gas mixture are identified to track the mixture back to its source

Lenticular – a geological unit that is thick in the middle and thin at the edges, resembling a convex lens in cross-section

Seeps – a place where liquid or gas escape to the earth's surface and atmosphere, normally under low pressure or flow

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**CRESCENT CONSULTING, LLC**

## Executive Summary

The Colorado Oil and Gas Conservation Commission (COGCC) retained a third-party consultant, operating as Crescent Consulting, LLC, to forensically review, assess, and render an opinion regarding drilling[1] and completion[1] practices within the eastern portion of the East Mamm Creek Area, which is located in the Mamm Creek Field, south of Silt, Colorado. The study area for this project, herein referred to as the East Mamm Creek Project Area (EMCPA), is shown on Figure 1 and Figure 2 in Appendix A. The purpose of this study was to evaluate existing data, review past and present drilling and completion practices, and review current COGCC policies and procedures. Wells reviewed during this study are listed in Appendix B. Recommendations are provided for future drilling, completion, monitoring, and where necessary, remedial actions to provide additional safeguards for protection of groundwater and surface water resources from potential impacts related to natural gas exploration and production activities.

The study is limited to drilling activities from 2003 through 2009. Natural gas wells located within the EMCPA were constructed in two phases: Phase I (2003 through 2004) and Phase II (2006 through 2009). A total of 5 wells from Phase I exhibited borehole isolation problems that led to gas migration from natural gas wells. Natural gas was observed in nearby water wells, ground surface gas seeps[2] around natural gas wellheads, and gas seeps in neighboring creeks and ponds.

In an attempt to mitigate further gas migration problems, COGCC and an oil and gas operator, Encana Oil & Gas (USA) Inc. ("Encana") separately prepared and began to implement practices and procedures contained in two documents, which addressed cementing and monitoring efforts in Phase II:

- **NOTICE TO OPERATORS DRILLING MESAVERDE GROUP OR DEEPER WELLS IN THE MAMM CREEK FIELD AREA IN GARFIELD COUNTY, WELL CEMENTING PROCEDURE AND REPORTING REQUIREMENTS ("Cementing NTO")**
- **Encana Cementing Standard Operating Procedure – Casing Running Procedures ("Encana SOP")**

Both documents are attached in Appendix C. The guidance documents established changes to engineering and operations procedures that have remedied many of the wellbore isolation problems that were more common during Phase I.

On July 8, 2010, COGCC established a supplemental guidance document:

[1] Reference Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com) for information on these terms
[2] See Glossary for additional information on these terms

- **NOTICE TO OPERATORS DRILLING WELLS IN THE BUZZARD, MAMM CREEK, AND RULISON FIELDS, GARFIELD COUNTY AND MESA COUNTY, PROCEDURES AND SUBMITTAL REQUIREMENTS FOR COMPLIANCE WITH COGCC ORDER NOS. 1-107, 139-56, 191-22, AND 369-2 ("Bradenhead NTO")**

This document is attached as Appendix D. The Bradenhead NTO was established to ensure that wellbore gas pressure anomalies are recognized early and remediated in a timely manner.

The cumulative effects of improved practices and procedures mandated by the above-referenced guidance documents have resulted in improved cementing[1] performance throughout the EMCPA. The instances of poor cementing performance observed in Phase I wells were dramatically reduced in Phase II wells. None of the Phase 2 wells has exhibited isolation issues significant enough to require remediation. Though the study terminates in 2009, Encana has continued to make efforts to improve cementing performance in the areas surrounding the EMCPA.

Encana's well records for each EMCPA well were reviewed in depth, focusing on the drilling and cementing phases, and to a lesser degree, the completion phase. Remedial cementing activities were reviewed when these efforts were required. Recaps of Crescent's observations appear in the Pad/Well Recap section of this report, and individual well summaries are grouped by drill pad.

Interviews were conducted with Encana personnel familiar with past operations as well as current processes and procedures. The departments interviewed included: Reservoir, Geology, Drilling, Completion, Production, in-house Service Provider Engineering staff, and an independent consultant with gas fingerprinting[2] expertise.

## 1.0 Introduction

The East Mamm Creek Project Area (EMCPA) has been studied for several years in an effort to determine the nature of natural gas observed in water wells and other seeps located at ground surface, in creeks, and in ponds. There have been various studies[3], performed by subject matter experts, focused on gas composition, area geologic trends and characteristics, and a variety of other projects in an effort to determine the cause, source, effects and remedies of these releases of gas. There have also been studies related to cementing and drilling practices, which have been conducted by both governmental agencies and operators. All of these studies were conducted for educational, operational, and process improvement opportunity identification, but none were ever intended or made available for publication.

In part, this study involves a historical review of past drilling and completion activities to provide interested parties with a new perspective of events. This review was performed to supplement previously mentioned studies.  During fall 2010, the Colorado Oil and Gas Conservation Commission (COGCC) selected a third-party professional consulting consortium to embark upon an independent study into the drilling and cementing practices in the EMCPA. Reed Energy Consulting, LLC of Highlands Ranch, Colorado and ROGE, LLC of Loveland, Colorado, operating under Crescent Consulting, LLC ("Crescent") of Oklahoma City, Oklahoma, were engaged to undertake the study. The study entails an in-depth examination of Encana Oil & Gas (USA) Inc.'s ("Encana's") well construction data on 31 producing gas wells and two (2) associated water wells, investigation into the causes of nonconformities, where present, in the construction of these wells, and recommendations for future COGCC regulatory oversight and operator practices and procedures.

## 2.0 Scope of Work

This report was prepared to supplement COGCC's on-going studies related to drilling and cementing activities in the EMCPA. Crescent was hired as a third-party, independent consultant to provide the following:

1) Evaluate drilling practices, primary and remedial cementing practices and stimulation practices, through 2009, through a review of Encana's internal well files as they relate to zonal[1] isolation of water and gas-bearing zones in the EMCPA.

2) Review, evaluate and offer recommendations to improve current State rules and other regulations (Notices to Operators) related to drilling, cementing, and completions in the EMCPA.

[3] Refer to Section 11 for a list of studies applicable to this issue

3) Research and summarize current industry best practices related to cementing and current technology related to Cement Sheath Evaluation.

4) Review, evaluate and offer recommendations to improve practices and procedures contained in Encana's Standard Operating Procedure Document for running and cementing of casing strings[1].

## 3.0 Key Findings

- COGCC's **NOTICE TO OPERATORS DRILLING MESAVERDE GROUP OR DEEPER WELLS IN THE MAMM CREEK FIELD AREA IN GARFIELD COUNTY, WELL CEMENTING PROCEDURE AND REPORTING REQUIREMENTS ("Cementing NTO")** has been effective in mitigating natural gas migration into surface water and groundwater resources.

- **Encana's Cementing Standard Operating Procedure – Casing Running Procedures ("Encana SOP")** has been effective in mitigating natural gas migration into surface water and groundwater resources.

- COGCC's **NOTICE TO OPERATORS DRILLING WELLS IN THE BUZZARD, MAMM CREEK, AND RULISON FIELDS, GARFIELD COUNTY AND MESA COUNTY, PROCEDURES AND SUBMITTAL REQUIREMENTS FOR COMPLIANCE WITH COGCC ORDER NOS. 1-107, 139-56, 191-22, AND 369-2 ("Bradenhead NTO")** has been effective in promoting recognition of potential gas flow scenarios and timely remedial action.

- An empirical overview of well data to identify root causes of known gas migration problems was ineffective in the EMCPA. Crescent concludes that each well must be engineered as an individual entity (there were no "one size fits all" solutions identified).

- Squeeze cementing[1] efforts can be an effective remediation method, and opportunities for improvement in remedial cementing procedures exist.

- Surface casing deviation[1] in the well plan requires rigorous engineering design on the surface section of the wellbore.

- Shallow gas zones exist in the surface hole, and they must be properly identified and isolated.

- The lenticular[2] nature of potentially productive gas-bearing sands is conducive to drilling fluid[1] losses and flows, as the unpredictable pressures of individual lenses are distinct and separate from each other.

- Differences between reservoir fluid pressure gradient[1] and fracture pressure[1] gradient within an openhole section of the wellbore are often minimal. Naturally occurring fractures may also contribute to lost circulation events.

- Drilling fluid losses, whole cement losses and gas flow events are unpredictable.

- Bradenhead pressure may not be reflective of poor cementing practices or performance over the productive interval. As used in this report, the "Bradenhead" is the annular space between the surface casing and the next smaller casing string (the intermediate casing, if installed, or more commonly, the production casing).

- Monitoring Bradenhead pressure changes over time, along with pressure response tests and gas fingerprinting, is an effective method to evaluate the necessity for cement remediation. Remediation may or may not be advised when Bradenhead pressure is observed.

## 4.0 Significant Opportunities for Improvement

- Potential gas source identification in the Surface hole by running open hole logs[1] on the initial well on each pad

- Engineering focus on the surface casing, conditioning, centralization, and slurry design, as is the case with production casing cementing

- Examination of water well construction practices, overseen by the Division of Water Resources

- Recognition and definition of "top of gas" by regulatory authorities for top of cement[1] designs on intermediate and production casing strings[4]

- Additional well planning consideration could positively affect remediation when it becomes necessary

[4] Refer to discussion in section 6.2 for additional description of "top of gas" interpretation

## 5.0 Encana Well File Data Review

Thirty-one (31) natural gas wells were selected by COGCC staff, as shown in Appendix B, and are within a geographic area of known gas seeps and gas identified within potable water wells. The natural gas wells are located on four well pads within the EMCPA. The Encana-designated pad names are: 02E, M1E, F11E and P3. The well files were reviewed for processes and procedures used when drilling, cementing and completing the wells.

Natural gas wells located within the EMCPA were constructed in two phases: Phase I (2003 through 2004) and Phase II (2006 through 2009). Phase I wells were constructed prior to implementation of the Cementing NTO and the Encana SOP. Well drilling and completion processes and procedures generally became more uniform in Phase II compared to wells drilled in Phase I. Statistical observations were attempted early in the review process and were considered of minimal value because of the variability in data when comparing the well to well results, and the relatively small sample size.

### 5.1 Statistical Observations

All wells in the EMCPA experienced some level of lost circulation, and/or gas flow events while drilling. Most of these events were controlled using standard industry drilling practices without incident. Gas flow scenarios are expected, as the general drilling practice is to attempt to drill the entire production portion of the well in a balanced or slightly underbalanced condition, using a method referred to as “lost circulation avoidance” (LCA). LCA minimizes the occurrence of mud losses into openhole strata, including objective hydrocarbon producing zones. Approximately 15% of the wells experienced significant losses in excess of 300 barrels [Bbls] of mud. An equal number had measurable gas flows. There was a period of drilling with “underbalanced” mud systems in 2004. By design, these wells experienced gas flows during drilling operations, as a result, mud losses were eliminated by drilling with underbalanced systems.

Crescent reviewed well records for 31 natural gas production wells and two (2) water wells. Of the 31 production wells, there were a total of 5 wells that had intermediate casing strings installed. In three of the five wells, intermediate casing was installed because of stuck pipe or lost circulation, which led to poor or incomplete isolation of the surface casing string. The other two wells failed a Formation Integrity Test (FIT)[5] at the surface casing shoe[1] or in the horizons adjacent to the casing shoe, and intermediate casing was installed, as required by the Cementing NTO. Details related to installation of intermediate casing strings can be found in the Pad/Well Recap section of this report. Of the 31 wells reviewed, 20 wells exhibited more than 10 degrees deviation at the surface casing shoe. As a result of “pad drilling“ procedures and the deviation of the well path in the upper portion of the hole, 4 of the 5 wells with intermediate casings had surface casing deviations of 20 degrees of more.

[5] Refer to Section 5.3 for definition and discussion on FIT

Of the 31 wells reviewed, 7 had remedial cement squeeze jobs performed because of high Bradenhead pressure or problems encountered during the drilling phase that could have compromised the isolation of the surface stratum. Of those, some of the remedial jobs were performed immediately upon recognition of pressure. These wells may have been “remediated” as a precautionary measure, without documented gas migration impacts prior to remediation. Remediation efforts reduced or eliminated Bradenhead pressures in every case.

## 5.2 Statistical Conclusions

There are two distinct groupings within the study, Phase I wells and Phase II wells. The P3 Pad wells were drilled in Phase I (without Cementing NTO or Encana SOP practices or procedures in place). There were single wells drilled on the O2E Pad and the F11E Pad under the same rules and policies. All other wells in the EMCPA were drilled in Phase II.

The wells within the EMCPA were generally drilled and cemented with similar processes and procedures. Most surface holes were drilled using a 12-1/4 inch open hole to depths ranging from 700 feet to 1,200 feet, and surface casing consisted of 9-5/8 inch casing, except for wells on the P3 Pad, which incorporated 8-5/8 inch surface casing. The production holes were generally drilled using a 7-7/8 inch open hole, with 4-1/2 inch casing used for production strings. This standard design changed when intermediate strings were installed, in which case the production hole size was reduced to 6-1/4 inches. Cement tops varied widely depending on the timeframe in which the well was drilled. The variations encountered from well to well while drilling included lost circulation zones (losses ranged from 20-300+ Bbls) and gas flow zones (gas concentrations ranged from 1,000 gas units to 8,100 gas units[2]). These variable conditions demonstrate that each well was unique. Mud losses, gas and water flows or other difficulties rarely occurred at similar depths in adjacent wellbores, so few problems had common root characteristics. Multiple examples of variations in wellbore conditions can be found in the Pad/Well Recap section of this report.

## 5.3 Pad/Well Recaps

After reviewing 31 wells individually, a review of findings was prepared with wells grouped by drill pad. This report presentation format provides an opportunity to better identify the changes to operations and resulting efficiency improvements in a chronologic fashion. The pads were reviewed from oldest to newest, and the wells on each pad were similarly reviewed chronologically.

Common concepts discussed throughout the drilling and completion summaries within this report are lost circulation and reservoir fluid flow. Lost circulation is a phenomenon whereby the drilling fluid density and its related column weight overcomes the strength of a particular geologic stratum to support that column weight. When the mud density is too heavy, a drilling-induced fracture is created, and drilling fluid is "lost" into the stratum.

The concept of reservoir fluid flow is a related phenomenon. Fluid flow (gas or water) occurs when the drilling fluid density and its related column weight is not sufficient to balance or overbalance the reservoir pressure in a formation encountered during the drilling process. When the system becomes underbalanced, reservoir fluids have the potential to enter the borehole. In this report, the term "gas units" describes the relative amount and deliverability of natural gas in the geologic system. Gas units are related directly to the instantaneous mud weight at the time when the gas unit measurement is made; common practice is to calibrate surface gas detection equipment so that 50 gas units is equal to 1% methane in air. It should be noted that most gas well drilling operations exhibit some level of background gas[1] in the mud system. Background gas is distinct from both trip gas[1] and connection gas[1], which typically occur at higher levels within the wellbore. These are common, yet critical concepts used in both drilling and cementing operations that must be understood in order to achieve an adequate understanding of the reviews presented below.

Formation integrity tests (FIT) are pressure tests performed on the stratum directly below the shoe of a casing string. Each well segment has an estimated mud density to complete the drilling operation, based on anticipated formation pressures. The required pressure containment at the shoe is calculated by multiplying the depth at the shoe (in vertical feet from surface) times the anticipated mud density at total depth (TD) in ppg times 0.052 (conversion constant). A small safety factor (100-200 psi) is commonly added resulting in a calculated pressure at the casing shoe to complete drilling operations. A FIT is performed upon drilling out the shoe, exposing the formation adjacent to the casing shoe. The drilling fluid density exerts a pressure on the formation; additional pump pressure is added to the column by closing in the annulus. The two pressures are additive and are related back to an equivalent mud density calculated to complete the drilling operations. Installation of an intermediate casing string occurs if the formation is unable to hold the required pressure.

#### 5.3.1 P3 Pad – Drilling and Cementing

The P3 pad consists of five (5) wells. The first well was drilled and completed in April 2003. The remaining four (4) wells were drilled, remediated and completed beginning in January 2004. This pad review is slightly different than the others in that commentary on drilling and cementing operations is followed by remediation commentary where applicable. The wells on this pad utilized 8-5/8 inch or 9-5/8 inch surface casing and 4-1/2 inch production casing.

**Arbaney 3-16C**

The Arbaney 3-16C well was drilled in May 2003. The 9-5/8 inch surface casing was set at 915 feet. Circulation was lost late in the surface casing cement job and a cement "top out" job was performed. A FIT was performed to at an equivalent mud weight of 13.9 ppg.

Manageable gas flows and lost circulation were noted in the well records throughout the drilling process. The well was drilled using LCA mud weight methodology. There were notable drilling breaks (changes of penetration rate), coupled with gas influxes measuring 3,000 gas units at 4,032 feet and 4,145 gas units at 5,135 feet. The production casing was run and cemented without incident. Production casing cement was circulated to surface. A cement bond log[1] (CBL) was run, with “good” apparent bonding below the top of cement (TOC). In this report, “good” apparent bond is based on a qualitative evaluation which concludes that gas migration along the cement sheath is unlikely. A good TOC was reported at 2,420 feet, and cement bonding quality transitioned to “poor” bonding up hole from the TOC. Completion efforts commenced in June 2003, and the well was turned to sales. In January 2004, the well was temporarily abandoned to allow for drilling of additional wells on the pad. After finishing drilling and completion efforts on the P3 Pad, Bradenhead pressure was observed on the Arbaney 3-16C well. It is not clear in the well records as to when the Bradenhead pressure was discovered or its magnitude.

Cement remediation efforts commenced in October 2004 and continued through December 2004. To assist with designing the remedial cement job, Encana attempted to identify gas flows behind the production casing using temperature surveys, noise logs and reservoir saturation logs. Based on the logging results, cement was squeezed behind the production casing at 2,600 feet, 1,720 feet, and 1,000 feet. Two squeezes were performed at each depth listed above, because the initial squeezes did not hold adequate pressure during subsequent pressure tests. The post-remediation Bradenhead pressure was reduced to 70 pounds per square inch (psi), and all squeeze holes were tested to at least 1,500 psi after the final squeezes. Bradenhead pressure has slowly increased since December 2004, and the well is currently venting from the Bradenhead to mitigate buildup of high pressure.

**Magic 10-1**

The Magic 10-1 well was drilled in late January 2004. Drilling of the surface hole and the surface casing cement job were uneventful, with surface casing set at a depth of 860 feet. A FIT was performed to an equivalent mud weight of 11.5 ppg. After drilling out of the surface casing, a number of substantial gas flows were observed, starting at 3,742 feet and continuing throughout the well. This well also utilized the LCA mud methodology, and a 10 foot to15 foot gas flare was reported during the drilling process (flaring is used as a surface safety control procedure during a gas flow). This indicates a slightly underbalanced condition (condition in which mud weight is less than formation pressure). The mud weight used to finish the hole was 13.3 ppg. The production string was run and cemented to surface without incident; however, the cement weights were 13.3 ppg on the lead and 13.4 ppg on the tail. Industry best practices promote a cement density of +/- 1 ppg greater than the final mud weight.

In the EMCPA, it is not unusual to use a cement density of 1/2 ppg to 3/4 ppg greater than the final mud weight, to avoid lost circulation. The resulting potential for gas flow increases as the density of the cement approaches the density of the drilling mud. A CBL was run and showed very poor to no bond in the upper 1/3 of the hole. It was not standard practice at the time to monitor Bradenhead pressure, and therefore, it is unknown if Bradenhead pressure was present immediately after the cementing process. It is unclear as to when Bradenhead pressure was first noted. However, the well was remediated in October 2004 to mitigate high Bradenhead pressures. The remediation process was similar to the other P3 Pad wells, in that logs were run to locate gas flows and optimize depths for squeeze cementing. Multiple cement squeeze jobs were performed at 2,250 feet, 1,590 feet and 840 feet, ultimately resulting in isolation of gas-bearing zones and elimination of Bradenhead pressure. A 3-1/2 inch full-string production liner was installed in May 2004 and cemented back to surface prior to commencing stimulation operations.

**Magic 10-1A**

The Magic 10-1A well was drilled in mid February 2004. There were no significant events during the drilling or cementing of the surface section of the hole. There was a change in the design depth of the surface casing compared to previous wells on the pad, as surface was set at 1,235 feet. A FIT was performed to an equivalent mud weight of 13.0 ppg. This well was the first well on the pad to be drilled “underbalanced” by design. This methodology is not unusual in that rates of penetration are usually enhanced. Other operators in the area used the same methodology and claimed better production performance because of less skin damage to the formation and less whole mud invasion in natural fracture systems, resulting in fewer lost circulation events. The production hole was drilled with mud weights ranging from 8.8 ppg to 9.0 ppg, with a constant flare, that at times was reported to 25 feet. This is expected well behavior when drilling underbalanced. The mud system was weighted up to 11.8 ppg to allow for logging and running of the production casing. The cementing process was uneventful, returning 30 Bbls to surface. A CBL was run, and a good TOC was present at a depth of 1,600 feet. Good bonding was apparent below the TOC, and good bonding transitioned to poor bonding above the TOC. As with the Magic 10-1 well, no Bradenhead monitoring was in place at this time. From the onset of the monitoring program (later in the life of this well), this well has shown no Bradenhead pressure.

**Magic 10-2**

The Magic 10-2 was drilled in early March 2004. The surface casing drilling and cementing operations were uneventful. A FIT was performed at the surface shoe of 1,212 feet, but the data was not found in the well records. The well was drilled in an “underbalanced” mode. On March 8, 2004, the rig noted elevated gas levels in the drilling mud returns at approximately 3,300 feet. Mud returns, which had been flowing to the pit, were switched to the return lines through the gas buster[1]. This operation is normal practice when gas is observed in the mud system. However, a risk with this procedure is the potential for drill cuttings to plug the return lines, flow lines and chokes. Apparently, on March 9, 2004 some of the drill cuttings plugged the flow lines and choke system, resulting in an unanticipated pressure buildup in the surface equipment and the borehole. This pressure buildup and subsequent pressure release is hereinafter referred to as the "Arbaney Event". With the flow lines and chokes plugged, there was no place for the gas to be released, so pressure built on the annulus between the drill pipe and surface casing, as well as the open hole section below, for a period of not more than four (4) hours.

Based on Crescent's review of the well records, it is not totally clear what transpired during the pressure buildup, but it appears that the rig crew was unfamiliar with this "plugging" phenomenon and/or proper procedures to clear the blockage in the surface equipment and relieve the contained pressure. The crew called their direct supervision for assistance, as well as the owners of the plugged equipment. It appears that response time was reasonable and that the help arrived and resolved the problem. The lines and chokes were cleared, using the pressure built up behind them to expel the debris. The flare lines were equipped with a fire bucket to ignite the released gas. The released gas reportedly had at least 300 psi trapped behind the chokes, but word of mouth based on Crescent's interviews indicated there could have been as much as 1,200 psi.

It was reported by local news media that there were two "explosions," and a photo was taken that showed a significant "fire ball" in the pit. Ignition of the gas was by design; it was a monitored and a controlled event, albeit noisy. The "fire ball" was a much better alternative compared to allowing a release of gas that could potentially collect in a low area and ignite. There are normally two chokes built into a manifold system for redundant protection, but in this case, both chokes were plugged. The pressure buildup and subsequent clearing of both chokes in a rapid fashion appears to have caused the Arbaney Event. The clearing and setting of the chokes was reported to the COGCC area engineer. Drilling depth at the time of the Arbaney Event was between 3,900 feet and 3,926 feet.

The remainder of the well was drilled underbalanced without further incident. The production string was run and cemented as planned, however cement was not circulated back to surface. The well had two squeeze jobs performed on the production casing, above the surface casing shoe at depths of 840 feet and 305 feet to mitigate high Bradenhead pressure, which was apparently observed shortly after completion of the primary cement job on the production casing. The cement remediation resulted in a consistent Bradenhead pressure response of less than 20 psi to date. A 3-1/2 inch full-string production liner was installed and cemented back to surface prior to commencing stimulation operations.

*In the opinion of this author the rig crew did exactly as they should have during the Arbaney Event, this was a potentially deadly situation and to have acted in any other fashion might have resulted in injury, death, or significant equipment damage. There were problems with lack of adequate training and/or equipment issues, and therein lies opportunity for improvement. Potential downhole impacts resulting from the pressure buildup are not known absolutely. There were noted gas-bearing zones present in the interval from 3,377 feet to 3,790 feet. If the gas pressure exceeded the pore pressure in weaker strata, then a cross flow into the weaker strata is a likely possibility. Gas pressure may have also overcome formation pressure in an open, natural fracture, resulting in gas flow into the natural fracture system.*

*Both scenarios are possibilities as a result of the Arbaney Event. During the course of the Arbaney Event, the annulus, including the open hole section below the surface casing shoe, was exposed to gas pressure. After the blockage was removed from the flow lines, the built-up pressure could be safely relieved from the system and managed from that point forward. The event itself may have opened and enhanced shallow naturally-occurring fractures during the 3 hour to 5 hour duration of the pressure buildup, allowing gas into these systems. The gas may have eventually migrated to nearby water wells and surface seeps, related to the surrounding geologic trends. A definitive answer as to where the pressured gas went is only supposition, as we have few control points: reservoir pressures and fracture gradients of the shallow strata are unknown.*

**Arbaney 3-15C**

The Arbaney 3-15C well was drilled in March and April of 2004. The surface drilling and cementing operations were uneventful. The cement job went as planned, with cement circulated to surface and a surface casing shoe depth of 1,092 feet. A FIT was performed at an equivalent mud weight of 13.0 ppg. The production hole was marred by a driller “crowning” the blocks with the bit positioned in the potential gas zones at a depth of 4,175 feet. The damage to the rig forced a temporary abandonment procedure which included setting a drillable bridge plug at 1,032 feet. Upon resumption of drilling operations five (5) days later, the mud weight was raised to 12.5 ppg and there was no report of well control difficulties when the temporary plug was drilled out. Upon reaching TD, the well had a number of bridges (sloughed formation) to drill out prior to logging. The production casing was run and cemented without difficulty, returning 30 Bbls of cement to surface.

Though there is no conclusive evidence, the drilling delay may have contributed to pressure events downhole that have contributed to the gas releases experienced on this pad.

The well exhibited 450 psi Bradenhead pressure within a few days after the production casing cementing operation, and subsequently, gas bubbling was observed in the soil at the surface near this well. Upon further investigation, all of the wells on the pad, with the notable exception of the Magic 10-2, have exhibited elevated Bradenhead pressures, and both Arbaney wells have gas bubbling in the soil outside the surface casing. Additionally, two water wells in the immediate vicinity of the P3 Pad have been impacted with methane gas. The Arbaney 3-15C well was remediated with cement squeeze jobs performed at 1,240 feet and 811 feet. A full-string 3-1/2 inch liner was installed and cemented to surface prior to commencing stimulation operations. This well continues to have Bradenhead pressures trending slowly higher when shut-in. However, the well is currently being vented to mitigate Bradenhead pressure buildup.

**P3 Pad Stimulation Comments**

The acid and fracture stimulation processes were reviewed in each well on the pad. There were no indications on any of the jobs that would indicate communication of stimulation pressures to the annulus above the TOC.

**P3 Pad Remediation Comments**

Cement remediation efforts involved locating the entry and exit points (sources and sinks of gas flows) in the wellbore and sealing them off. CBLs, ultrasonic logs, noise logs, reservoir saturation logs and temperature surveys were used to identify the perforation intervals for squeeze operations. The cement squeeze jobs themselves were well-conceived and executed, and the slurries were well-designed. Monitoring of post remediation pressures is ongoing under the guidance of the Bradenhead NTO. The ground bubbles were reduced post-remediation, though not eliminated. Methane gas is still observed in nearby water wells, and experimentation with pressure buildup in gas wells on the P3 Pad has been recently performed to identify which wells are connected and to what extent. All wells on the P3 Pad are being vented to mitigate potential Bradenhead pressure buildup. There have been previous studies presented to the COGCC, and this review of day-by-day operations and thought processes found that there was little else to report from a cementing and well construction standpoint. Wellbore schematics may be reviewed in a presentation made by Encana to the COGCC entitled Moon Property Presentation – July 2010 which is attached in Appendix E.

The issues of shallow gas are illustrated by Figure 3 and Figure 4 in Appendix A, showing an example section of RST log and a Triple Combo log section. These logs indicate the occurrence of possible shallow gas zones starting at approximately 60 feet below the surface.

**P3 Pad Key Points**

- **Drilling**
    - **Extended shut-in conditions during an underbalanced drilling attempt may have led to a subsurface pressure buildup (the Arbaney Event)**
    - **Temporary abandonment may have led to a subsurface pressure buildup event**
    - **Proper training and adherence to standard procedures may reduce the potential for recurrence of similar events**

- **Primary Cementing**
    - **Slurry density should be at least 1/2 ppg higher than the mud density to reduce the potential for gas flows during cementing**
    - **Gas flows are likely when cement slurry and mud density are balanced, which may result in cement channeling**
    - **Gas flow potential should be carefully monitored when bringing long columns of cement back to surface**

- **Remedial Cement Design – Gas Flow Identification Tools**
    - **Temperature surveys – fluid movement behind casing**
    - **Noise logs – fluid movement behind casing**
    - **Ultrasonic cement bond tools – identify materials behind casing in a 360 degree representation**
    - **Acoustic cement bond tools – provide insight as to materials behind pipe and consistency**
    - **Reservoir saturation tools – identify possible gas-bearing zones**

- **Remedial Cement Squeeze Processes**
    - **Can be effective at stopping gas flows**
    - **May not be permanent seals because of pressure and temperature cycling on squeeze perforations[1] while the well is actively being produced**
    - **May inhibit effective stimulation and production of the resource**
    - **Always requires an individual, well-engineered approach to be successful**
    - **Continued post-remediation Bradenhead pressure monitoring is recommended, as required by the Bradenhead NTO**

### 5.3.2 O2E Pad – Drilling and Cementing

This pad consists of six (6) wells, all of which exhibited various degrees of lost circulation during the drilling phase. After all well construction was finished, four (4) wells exhibited good isolation of gas-bearing zones. Several significant events occurred with three (3) wells on the O2E Pad. Recaps of these events are presented below by well.

**Schwartz 2-15B**

The Schwartz 2-15B well was drilled in January 2004 and completed without significant deviation from the drilling plan. Surface casing was set at a depth of 706 feet. Manageable gas flow events were noted at 1,529 feet, 1,635 feet, 3,947 feet, and 4,375 feet. The production casing was run and the production casing cement job was performed without difficulties. However, the CBL showed a TOC of 4,050 feet, indicating significant fall back of the cement top from the initial TOC after the plug[1] was bumped ("bumping the plug" signals the end of circulation during the cement job). The results of the CBL analysis indicate that two gas bearing zones with significant deliverability were left exposed. The cement fallback is not an unusual occurrence, but the loss of 4,050 feet of cement column is notable and indicative of an unusually weak zone. Coupling a weak zone with zones that exhibited high propensity for gas flow is a formula for the outcome observed in this case. Up until the time when the cement fell back, there was no indication noted in the well records of a weak zone.

Well stimulation operations commenced in March 2004 and progressed without any indication of difficulty. In the well records, Bradenhead pressure was noted only in the detail of the 5th hydraulic fracture stage. However, inspection of the job data yields no indication of Bradenhead pressure that was directly attributed to the fracturing process (the pressure remained relatively stable during completion operations through Stage #5). Encana personnel confirmed that Bradenhead pressure existed prior to commencement of completion operations. After the final completion stage, the productive gas-bearing zones were isolated.

After the Stage #5 stimulation, Bradenhead pressure was measured at 661 psi, and as a result, cement remediation efforts were implemented to mitigate the high bradenhead pressure. The well was perforated, and cement was squeezed at 3,800 feet on April 5, 2004. After this squeeze, the Bradenhead pressure was bled down to 86 psi and equalized at 80 psi. A CBL and a temperature survey were run on September 24, 2004. These logs suggested an anomaly (potential gas movement behind the production casing) at a depth of 2,700 feet. Cement was squeezed behind the production casing from 2,246 feet to 2,251 feet. Following the squeeze, a CBL was run, and apparent bonding on the CBL indicated an improvement in isolation. Post-remediation Bradenhead pressure has been monitored monthly and has exhibited pressures consistently below 95 psi. Figure 5 in Appendix A gives an illustrative section of CBL run before a squeeze job, and Figure 6 gives a side-by-side comparison of the same section logged after the squeeze job.

The pressure responses of the hydraulic fracture jobs were analyzed for any anomalies that might have suggested communication into zones up hole. All pressure responses were normal and did not indicate any such anomaly. It is likely that the source zone was the zone encountered while drilling at 3,947 feet, which was above the TOC following the primary cement job.

Two additional wells, Schwartz 2-14A and Schwartz 2-14D, experienced events that caused alteration of drilling plans. These wells were the fourth and fifth wells drilled on the pad. The Schwartz 2-14A well was drilled in November 2007, and the Schwartz 2-14D well was drilled in March 2008.

**Schwartz 2-14A**

While running the surface casing, the hole sloughed in on the surface casing at 1,100 feet. Efforts to reach the designed surface hole depth were unsuccessful. While working the pipe to get to depth, circulation was lost at 1,138 feet. A tail cement system was pumped through the casing and around the casing shoe. When circulation was not reestablished, the casing was perforated at 638 feet and a lead cement system was pumped in an attempt to circulate cement and provide a seal from 638 feet to surface. This procedure is sometimes referred to as the "tack and seal method". Concerns about the surface casing's ability to contain pressure prompted the decision to run a 7 inch intermediate casing, to provide an additional protective casing string to the wellbore. This also was consistent with COGCC rules and policies. The cement placement on the intermediate casing was according to plan and without incident.

During drilling of the production string, there were intervals of lost circulation that were healed. Running and cementing the production casing went well with no pressure on the Bradenhead at the end of well construction. However, Bradenhead pressure has subsequently developed on the Schwartz 2-14A well, and it is currently venting to mitigate Bradenhead pressure buildup (the Bradenhead pressure will build to 155 psi when it is shut-in).

**Schwartz 2-14D**

The surface drilling and cementing process went well without any deviations in plan. The surface casing was set at a depth of 1,186 feet. After drilling out of the surface casing, the FIT at the surface casing shoe would not hold satisfactory pressure to allow the production hole to be completed as designed. This led to the installation of a 7 inch intermediate casing, which was installed as designed without incident. This installation was consistent with COGCC rules and policies.

A significant loss of circulation was encountered between 5,947 to 5,964 feet. The zone was healed with the use of particulate lost circulation material (LCM). The production casing and cement were placed per plan. To date this well has zero psi on the Bradenhead, however, cement squeezes were performed on the production casing in September 2010 to remediate high production casing-intermediate casing annulus pressures, which declined to zero psi after remediation.

> *Wells on the O2E Pad wells, with the exception of the Schwartz 2-15B well, were drilled under the conditions of the Cementing NTO and the Encana SOP. Encana staff members indicated that there were errors made in the recognition of the Bradenhead pressure response on the Schwartz 2-15B. It is unlikely that earlier recognition would have had a great effect regarding the migration of gas away from the wellbore. It might have reduced the ultimate volume, but the pressure on the hole above the TOC initiated the gas flow path very early in the event. The Cementing NTO required installation of intermediate casing on the Schwartz 2-14D because of the FIT failure.*

**O2E Pad Stimulation Comments**

The acid and fracture stimulation processes were reviewed in each well on the pad. There were no pressure events during or after the jobs that would indicate communication of stimulation pressures to the annulus above the TOC.

### 5.3.3 M1E Pad – Drilling and Cementing

Drilling commenced on the M1E Pad in August 2006. Four (4) wells were drilled and completed in 2006. Six (6) additional wells were drilled and completed in 2008. Notable comments for the 2006 wells are summarized below.

**Juniper 1-13A**

The Juniper 1-13A well was the first well drilled on the M1E Pad in August 2006. The surface hole was logged using a “triple combo” open-hole log suite, which included neutron porosity and formation density logs. When plotted together, these logs give an indication of gas-bearing zones in the borehole. The surface casing was installed and cemented as planned, with a surface casing setting depth of 1,513 feet. However, shortly after the cement job was finished, gas was observed, bubbling in the surface casing - conductor pipe annulus. The conductor pipe, with a 20 inch diameter, is larger than the surface casing, and it was installed prior to the surface casing at a depth of 40 feet. Further investigation of the triple combo log indicated three (3) gas bearing zones present in the first 100 feet of hole. A CBL and ultrasonic imaging tool were run, and these logs indicated poor bond behind the surface casing from approximately 300 feet to surface. Physical inspection indicated cement at surface in the surface casing - conductor casing annulus. The gas was tested, and it reportedly contained 20% combustibles. No action was taken on this situation and though it is not shown in the well records, the gas flow likely diminished as pressure in the shallow gas zone was depleted.

The surface casing shoe was drilled out without incident and the FIT at the casing shoe met the required equivalent mud weight of 13.0 ppg. Another FIT was performed at a depth of 2,780 feet and also passed. This test was performed 50 feet into the Ohio Creek Formation in the upper Mesa Verde Group. The second FIT was not required by COGCC, but Encana performed the FIT to gather information from the Ohio Creek Formation. The equivalent mud density derived from the test was 13.0 ppg. While drilling the production hole, lost circulation was encountered at depths of 4,712 feet and below.

While addressing the loss of circulation issues, a preliminary decision was made to run 7 inch intermediate casing, presumably to mitigate additional losses. Running a 7 inch string required the hole diameter to be increased, as the original production hole diameter was 7-7/8 inches. A “hole opener” reaming assembly was run in the hole to increase the hole diameter to 8-3/4 inches to accommodate the 7 inch casing. Additional drill time losses were associated with a “fish” being lost in the hole, related to the use of the “hole opener” assembly. Ultimately, the 7 inch casing was not run, because the lost circulation zones were healed during the reaming operation. However, production hole drilling operations were continued with an 8-3/4 inch bit to TD.

The 4-1/2 inch production casing was placed with no lost circulation or other significant problems recorded while running and cementing the casing. Within 24 hours of the cement job, Bradenhead pressure was observed. The highest reported Bradenhead pressure was 475 psi. The well was vented and monitored while drilling the remaining wells on the pad. A CBL showed good bond below a depth of 5,400 feet. Cement bond transitioned from good to poor above a depth of 5,400 feet, with a reported TOC of 3,560 feet. The well shows characteristics of possible gas migration and inadequate centralization in the interval from 5,400 feet to 3,560 feet. The well has not been remediated to date, and the Bradenhead is being continuously vented. Bradenhead pressure will build to 150 psi to 160 psi after being shut-in for a period of 10 to 20 days.

**Juniper 1-13**

The Juniper 1-13 well was drilled in September 2006, with manageable gas flows and lost circulation events documented in the well records. The surface casing was set and cemented according to design at 1,523 feet. The production casing TOC was 300 feet short of COGCC’s requirement. After stimulating the well, there was 150 psi on the Bradenhead, and venting dropped the pressure to 15 psi. After additional venting in late 2008 and early 2009, the Juniper 1-13 well had zero Bradenhead pressure.

A Sundry Notice (notice of intent to remediate and raise the TOC) was approved by COGCC staff in November 2008. The job was completed in November of 2008, with no specific remediation details or references available in the well records. Examination of the resulting CBL indicates improved cement bond from 3,900 feet to 2,582 feet. The Bradenhead currently builds to 90 psi, although the well has not been vented, post remediation.

**Juniper 2-16**

Significant lost circulation was encountered while drilling the surface hole on the Juniper 2-16 well in October 2006. Lost circulation zones took 85 Bbls of drilling mud at a depth of 520 feet, and 210 Bbls at a depth of 1,160 feet. The surface casing was set at 1,529 feet, and cement was pumped with no returns. Encana ran a temperature log to identify the TOC, which was located at 1,140 feet. The casing was perforated at 850 feet and squeezed in an effort to raise the TOC. After the cement squeeze job, another temperature log was run, which identified the TOC at 775 feet. A "top out" cement job was performed to bring cement to surface. The subsequent casing pressure test failed and another cement squeeze was pumped at 848 feet. The casing passed a pressure test after this final cement squeeze. Two additional pressure tests were performed; one at the perforations and one at the surface casing shoe. Both pressure tests passed. Encana opted to incorporate a 7 inch intermediate casing, because of the multiple cement squeezes on the surface casing, and concerns regarding long-term integrity of the squeezed perforations.

The 7 inch intermediate casing was placed and cemented as planned. Drilling continued to TD, encountering a loss of circulation at 5,090 feet that was successfully mitigated. The 4-1/2 inch production casing was run to TD and cemented without incident. This well builds to 5 psi on the Bradenhead, and it has not been vented to date.

**Juniper 2-16A**

The Juniper 2-16A well was the final well on the pad in the 2006 drilling program. The well was drilled and cased according to plan, with notations of manageable gas flow and lost circulation. The well builds to 39 psi on the Bradenhead and has not been vented to date.

The 2008 program featured six (6) wells drilled from June through August 2008. These wells were drilled with no significant deviations to the drilling plans. There were some reports of manageable seepage and/or losses of drilling fluid. These situations were addressed and overcome with no apparent detriment to construction of the wells. Of these wells, four exhibited no Bradenhead pressure. The Juniper 1-12A well builds to 75 psi, while the Juniper 12-4A well builds to 34 psi Bradenhead pressure when shut-in. These wells have not been vented to date.

The entire pad was drilled under the requirements of the Cementing NTO. The 2006 wells were drilled prior to implementation of the Encana SOP, but the 2008 wells were drilled using practices and procedures in the Encana SOP. These enhancements to practices and procedures, such as attention to circulation and pipe running practices, mud conditioning, centralization, slurry design and pipe movement appear to have positively impacted the outcome of the drilling and cementing operations.

**M1E Pad Stimulation Comments**

The acid and fracture stimulation processes were reviewed in each well on the pad. There were no pressure events during or after the jobs that would indicate communication of stimulation pressures to the annulus above the TOC.

### 5.3.4 Pad F11E – Drilling and Cementing

The initial well on the F11E Pad was drilled in January 2004. The Brown 11-2C well was drilled and completed with the only variation from the drilling plan being a "top out" job on the surface casing and a significant gas kick at 3,700 feet. The Brown 11-2C well has not exhibited any Bradenhead pressure.

> *In Crescent's opinion, a "top out" process is not an optimum procedure to finish off a full column of cement on the surface casing, however, the author prefers this methodology to perforating and circulating when the fall back is less than 250 feet, and the cement top can be reached by "spaghetti tubing" via the annulus. Displacement is difficult in this environment, so the use of cement slurries significantly heavier than the mud system is strongly recommended. When cement has been circulated prior to the fall back event the void will be filled with air, in which case any competent slurry should successfully fill the void*.

There were nine (9) additional wells drilled on the F11E Pad from September 2008 through January 2009. These wells shared several common characteristics, including the surface casing size: they were all equipped with 9-5/8 inch surface casing strings, which is now common practice. This larger casing size provides additional clearance to set an intermediate casing string, if necessary.

**Encana 11-3B2**

The Encana 11-3B2 well was the first well drilled in the 2008 drilling program. This well experienced notable gas flows in the Ohio Creek Formation at depths of 2,308 feet and 2,345 feet. The TOC on the production string was 2,500 feet. Bradenhead pressure was observed at 140 psi after the production casing cement job. With the TOC below the Ohio Creek Formation gas shows, Bradenhead gas may originate from the Ohio Creek Formation, the overlying Wasatch Formation, or some combination of the two. This well is currently being vented to mitigate buildup of high Bradenhead pressure.

**Encana 11-4D**

The Encana 11-4D well was drilled in September 2008. While all operations were routine, and no anomalous shallow gas zones were identified, a pressure of 25 psi has been observed on the Bradenhead.

The following wells were drilled in order: Encana 11-4C, Encana 11-5, Encana 11-12A, Encana 11-3D, and Encana 11-6A. None have shown Bradenhead pressure to date, except the Encana 11-3D well with 5 psi. All of these wells saw gas shows between 3,500 feet and 4,100 feet while drilling, though none of the shows appeared to have significant magnitudes, based on Crescent's review of the open-hole logs and well records. Bradenhead pressures were monitored on previously drilled wells as the drilling program proceeded. The last two (2) wells on the pad encountered significant difficulties, as described below.

**Encana 11-6**

The surface casing in the Encana 11-6 well got stuck at 1,012 feet, short of the intended setting depth, and then circulation was lost. The surface casing was "tacked" at the shoe, then perforated and cement was circulated to surface. A 7 inch intermediate string was installed at 3,416 feet and cement was circulated back into the surface casing shoe. This was in accordance with COGCC's Cementing NTO policy. The remainder of the well was drilled without major incident. Pressure has not been observed on the Bradenhead.

**Encana Federal 11-11A**

The Encana Federal 11-11A experienced similar difficulties, with the surface casing sticking at 972 feet and subsequent lost circulation. Two cement block squeeze attempts secured the string in place. An intermediate casing string was installed at 3,521 feet. A water flow was observed in the intermediate casing – surface casing annulus, and a cement squeeze procedure was successfully performed at the surface casing shoe to kill the water flow. The remainder of the well was drilled without incident prior to running production casing.

The production string was set and cemented. However, within 10 minutes of bumping the plug during the cement job, the well kicked (the maximum noted pressure on the annulus was 1,500 psi). The slimhole annulus (4-1/2 inch casing by 6-1/4 inch hole) environment caused by setting the intermediate string may have contributed to this event. Slimhole environments display higher Gas Flow Potential (GFP) tendencies, particularly in deviated wellbores. Deviation, coupled with a slimhole environment requires adequate centralization, fluid loss control and general cementing practices to control gas migration tendencies.

The gas kick appears to have been initiated from an intermediate depth source, below the intermediate casing shoe and above the production casing TOC, considering that the bottom portion of the cement job appears to be isolated on the bond logs. The upper portion of the hole was protected from the pressure event by the intermediate string. A gas influx was observed and subsequently squeezed at 3,727 feet (at the apparent "flow zone", based on drilling data) and again at 1,330 feet, though the reason for the upper squeeze is not clear in the well records. The well shows 2 psi Bradenhead pressure. The remediation squeezes were initiated immediately, and they were pumped prior to commencement of completion operations.

With the exception of the Brown 11-2C, all of the F11E Pad wells were drilled under the Cementing NTO and the Encana SOP. These enhancements to practices and procedures, such as attention to circulation and pipe running practices, mud conditioning, centralization, slurry design and pipe movement appears to have positively impacted the outcome of drilling and cementing operations.

**F11E Pad Stimulation Comments**

The acid and fracture stimulation processes were reviewed in each well on the pad. There were no pressure events during or after the jobs that would indicate communication of stimulation pressures to the annulus above the TOC.

## 6.0 Encana Interview Recaps

Crescent interviewed members of Encana's current staff. Encana is organized by geologic basins and discipline teams. The Leaders of the Development Group and the Production and Completions Group have been part of the South Piceance team since the program began. The other team members have been added at various times during the development of the area. Some discussions resulted from direct questions; others were more spontaneous. Encana personnel appeared to be forthcoming during our discussions. The following subsections recap and highlight discussions with each group.

### 6.1 Development Group

The Development Group consisted of a Group Lead Development, Geologists, Reservoir Engineers, and a number of other planners. Encana's geologists provided a geologic overview of the area, which led to specific discussions regarding the Molina (lower) member of the Wasatch Formation, its characteristics, and its reservoir potential for gas as is seen down dip to the west. Figure 7 in Appendix A provides a stratigraphic column of the Grand Junction area, showing the relative location of the Molina member and the Wasatch Formation. The concept of non-commercial gas zones was discussed; there are several zones in the shallow horizons (deep Wasatch Formation and shallow Mesa Verde Group) within the EMCPA that produce non-commercial amounts of gas under certain circumstances.

We reviewed an open-hole log from the Schwartz 11-2A well, which exhibited three (3) potential gas bearing zones from surface to a TD of 1,130 feet. A number of cased-hole reservoir saturation logs were reviewed, which indicated the possibility of shallow gas sands scattered throughout the surface casing section of the hole. We discussed options for identification of potential gas zones in the surface hole, so that precautions could be taken to insure isolation during surface casing cementing operations. Encana has taken proactive steps on a number of pads outside of the EMCPA area by running open-hole logs in surface holes.

We discussed the term "Top of Gas," which is term found in the Cementing NTO. Without a specific definition in COGCC's rules or the Cementing NTO, Top of Gas could be interpreted to imply "Top of Commercial Gas." Commercial gas has adequate gas content and an operator-designated acceptable water saturation threshold for economic recovery.

### 6.2 Drilling Group

The Drilling Group consists of a Group Lead Drilling, a Field Drilling Superintendent, two well site supervisors for each rig, four drilling engineers, and an operations technician. The Field Drilling Superintendent resides on the Western Slope and has been involved in the field for the majority of the development time, so conversations were held via telephone. According to the Field Drilling Superintendent, during placement of the surface casing strings, few major difficulties have been seen operationally. Though there are occasional occurrences of lost circulation, gas and water flows, and hole instability, these problems are intermittent while drilling the surface section of the wellbores in the EMCPA.

Recent adjustments to surface hole drilling programs include use of "mud systems," which optimize penetration rates, cuttings removal, and combat lost circulation instead of "spud mud" (simple water system mixed with bentonite and drill solids during drilling), resulting in better surface hole quality. This change was driven by the pad drilling mechanics, in which all of the surface holes are drilled, cased and cemented in a batch process, followed by production hole drilling, casing and cementing in a subsequent batch process. It is routine to circulate 30-50 Bbls of cement back to surface when pumping 80% excess over gauge hole volume. During cementing of the surface casing, CBL's are rarely run, so the volumes of cement to be pumped have been empirically derived. Cement volumes are fine-tuned through a trial-and-error methodology using visual returned volumes to calculate any necessary changes to excess cement requirements on subsequent wells.

In the production hole, the mud is designed for many requirements, including: using LCA drilling methodology, mud weight, rheology, gel strength development, water loss, and pH. Using standard well control procedures, gas flows are managed when encountered, while lost circulation zones can be more challenging, occasionally resulting in extended drilling delays to deploy LCM in the mud system.

Pason and Canrig (instrumentation vendors) rig data is routinely captured. This includes, but is not limited to pump pressures, fluid rates, weight on the bit, drill pipe rotations per minute, return flow rates, mud density and gas detection. During Phase II drilling, the current Drilling Group Leader recognized an absence of information sharing and general communication with the rig supervisors and implemented measures to improve coordination. The efforts have improved knowledge transfer regarding solutions to common problems, and they have resulted in a number of significant efficiencies within the organization.

Gas detection equipment is routine and use of the gas detection measurements is common in determination of designed cement tops. Internally, Encana has changed the use of the term "Top of Gas" to "Top of First Gas Show," rather than interpreting this phrase as top of commercial gas. This change was as a result of finding gas shows in areas that would not have been covered under normal operating regulations using top of commercial gas as a criterion. Gas shows are directly driven by the relationship between mud weight and reservoir pressure, coupled with deliverability of the specific zones encountered.

Further, because Encana operates in both State and Federal lands, they routinely design to meet or exceed the most stringent regulatory requirements, to avoid potential confusion or miscommunication between well designs. The Federal government requires TOC 200 feet above the Top of the Mesa Verde or Ohio Creek Sands (when present). Encana typically designs for an additional 500 feet of cement fill-up above the Federal requirement, as a "safety factor", resulting in 700 feet of cement fill-up above the Mesa Verde Sands. There is an ongoing monitoring program related to cement tops, throughout Encana's Piceance Basin operations. Based on that data (which has been reviewed in the study area, since inception of the monitoring), it appears that cement tops meet or exceed regulatory requirements. Meeting Encana's internal standards for the designed TOC is substantially more challenging.

Centralization designs are standard on all production casing strings, with a goal of +/-50% minimum "standoff" (separation of the casing from the wellbore prior to and during cementing). The Federal standard downhole conditions of approval requires a "triple combo" log suite be run from surface casing

TD to surface (unless the surface string is to be set at 1,000 feet total vertical depth or deeper, and approval from Federal authorities is granted) on the first well drilled off of every pad. Additionally, a "triple combo" is required from the production hole TD to surface string shoe. Significant improvements in record keeping, training and communication have been achieved over the past few years. Use of the Encana SOP for running casing and cementing is also in place (for production strings).

### 6.3 Completion Group

Team members are Team Lead Completions and Production, Completions Engineer, and Completions Supervisor. The Completions Supervisor was interviewed via conference call from the Western Slope. This discussion indicated that the processes and procedures were within industry standards and per Encana's policies. The general perforating design (all sands that appear in an interval are perforated), acidizing design, and stimulation design were reviewed, both present and historically.

Some microseismic fracture mapping processes have been conducted in the general area, but they are not preformed on a routine basis. When microseismic data is generated, offset wellbores or monitor wells are equipped with highly sensitive listening devices called "geophones." Geophones "hear" events caused by rock failure during the stimulation process and thereby can be interpreted to provide information related to rock fractures as microseisms propagate through the zones of interest. EMCPA microseismic data indicates that a limited fracture height growth of 200 feet is typical for hydraulic fracture jobs. Lateral fracture growth may extend several hundred feet from the well. To date, Encana has not used investigatory tracers in EMCPA wells for verification of stimulation fluid placement in perforated intervals.

Though there are few charts to verify, none of the reviewed records indicated an instance where a hydraulic fracture treatment had unusual pressure response that would indicate deterioration of cement integrity. Also, none of the interviewed staff indicated a wellbore integrity issue during a stimulation procedure. If there were Bradenhead pressures, the pressure appeared shortly after initial cementing operations and prior to completion operations.

### 6.4 Production Group

Team Members are Team Lead Completions and Production, and two Production Engineers. This group handles the Bradenhead monitoring program, in addition to their normal production engineering duties. This monitoring program creates a great deal of focus and continues to be a priority. . Administration of the Bradenhead monitoring program is a component of the Production Engineering Staff duties. Discussions included the venting process and use of Bradenhead gas in powering surface facilities where appropriate. Sampling frequency for Encana Bradenhead gas was set at one month intervals until 2010, when the program was adjusted to vent Bradenhead gas that exceeded threshold criteria defined in the Bradenhead NTO and perform one 7-day buildup test each year. This practice has been approved by the COGCC and is consistent with other operators in the area. The installation of automation to provide continuous data is ongoing at present. This group reiterated that the onset of Bradenhead pressure is consistently monitored prior to, during and after fracture stimulation operations, as required by COGCC rules.

### 6.5 Independent Consultant – Dr. Tony Gorody, PhD

Tony Gorody is the President of Universal Geoscience Consulting, Inc. Dr. Gorody outlined the process of gas fingerprinting and the identification characteristics of thermogenic versus biogenic gases. He explained a presentation given to COGCC staff in July 2010 (see Appendix E). We had a discussion about the realities of remediation through squeeze cementing and some of the pros and cons of this approach to seal off annular gas flows. Dr. Gorody's opinions regarding cement remediation were consistent with Crescent's recommendations, as characterized in other sections of this report.

### 6.6 In-house, Cement and Logging Resources

Cementing Specialist, Schlumberger Well Services: This Cementing Specialist provides Encana with internal consultation on cement properties and procedures. There were several discussions geared towards understanding Encana's cement program. Cement systems and chemistries were discussed at length, as well as the design processes and simulation results. Conversations focused on issues ranging from pipe centralization and movement, mud removal, slurry property optimization, static gel strength, lab testing, gas migration issues and prevention, gas flow potential, job simulation and execution.

US Wireline Champion, Schlumberger: Crescent conducted discussions related to CBL results and ultrasonic imaging jobs specific to the project, available options, principles of operation, evaluation methods, and strengths and weaknesses of cement sheath evaluation tools.

Schlumberger, Halliburton and Baker Atlas: These service companies provided information regarding operation and evaluation of results from various downhole logs utilized in this study. This information is included in Appendix F.

## 7.0 Recommendations and Observations

A compilation of industry cementing best practices can be found in Appendix G. Crescent's specific observations and recommendations are presented below.

### 7.1 Surface Casing – Slurry Composition and Characteristics

Surface casing cementing practices in the EMCPA have historically included minimal use of centralizers. As a result, it appears that there have been sections of surface casing with little to no standoff in deviated wellbores. Until recently, minimal mud conditioning has occurred while drilling surface holes. Spacer usage has been fairly uniform at 10 Bbls of fresh water. Pipe movement in the form of reciprocation was a normal practice. There was no evidence in the well records of rate design or centralization calculations in the surface sections of the hole. The cement slurry compositions were typical of surface slurries in the area.

About half of the EMCPA wells utilized “lead” slurries on the surface. The lead slurries typically consisted of American Petroleum Institute (API) Class G Portland cement blended with pozzalan (fly ash) and bentonite (gel). This is a common cement blend for oil and gas wells. Calcium chloride was generally added to cement slurries to accelerate the onset of compressive strength and shorten thickening time. Cellophane flakes were used for lost circulation control. This blend provides light-weight slurry, usually mixed at densities between 12.5 and 13.5 ppg. The cellophane flakes are used to provide a low-cost, low-level lost circulation prevention material.

Gypsum was also used in several lead slurry cement jobs to reduce slurry density, provide free water control, and most importantly, provide thixotropy to the slurry. Lighter slurry density was desirable to control lost circulation, which was observed on several wells in the surface section. A lower density reduces the hydrostatic pressure, subsequently reducing the tendency for losses to occur. Slurry that gels or thickens very quickly upon moving to a static condition is said to be thixotropic. The viscosity can then be reversed by adding energy to the system, which overcomes the yield point. Thixotropy is an important property in lost circulation environments because the rapid gellation of cement from a static condition, in combination with LCM, assists in healing lost circulation zones.

The remaining half of wells in the EMCPA utilized “tail” slurry on the surface casing. Tail slurries also contained API class G Portland cement, but some of the additives used with lead slurries were not used, resulting in heavier slurry. The typical blend included calcium chloride and cellophane flakes and was mixed at 15.8 ppg.

Encana’s cement service provider utilizes an antifoaming agent in all slurries at low concentration. The material prevents air from being entrained in the slurry. The engineering properties of the cement slurry or the solidified cement are not affected by this material.

### 7.2 Surface Casing – General Practices

Wells within the EMCPA were generally designed for 9-5/8 inch surface casing set in a 12-1/4 inch hole. The casing string is cemented with an appropriate volume of cement returning back to surface to insure no mud contamination of the cement slurry in the annulus. The key functions of surface casing are as follows:

1. Prevent sloughing or collapse of the wellbore below the conductor pipe,
2. Achieve zonal isolation of shallow fluid-bearing formations,
3. Provide a foundation upon which to build the remainder of the well casing strings, and
4. Function as an integral component of the well control system by supporting the well control equipment

Engineered cement systems are required to accomplish these goals, particularly the goal of zonal isolation. The cementing process, when properly designed and executed, seals the annular space from pressure and prevents cross flow of fluids from deeper strata into relatively weaker zones in the surface hole. This specifically includes groundwater aquifers that are used for potable drinking water.

The oil and gas industry and related entities tend to adequately engineer a well from the surface casing shoe down to the production casing TD. The Encana SOP is used to assure that the production casing is placed per the engineered design. Encana does not use a similar document for construction of the surface casing, but in Crescent's opinion, standard surface casing cementing practices and procedures should be developed.

The wells within the EMCPA are drilled from multiple-well pads. This type of pad drilling requires that wells be directionally drilled to adequately drain the gas reservoir. When performing directional drilling the well must be diverted from a vertical trajectory to attain the necessary angle to guide the drill bit along the designed wellbore path to the target bottom hole location. In many areas, directionally-drilled wells are "kicked off" (first deviation from a vertical trajectory) below the surface casing shoe. However, to achieve the desired well design in the EMCPA, Encana kicks off their wells at a shallow depth in the surface casing section. This technique places the surface casing in a deviated position, with a tendency for the casing to lie on the low side of the open hole. A condition of eccentricity makes mud and cuttings removal more difficult compared to vertical drilling, and replacement of these materials with cement to provide a 360 degree seal is also challenging. This deviated situation potentially leads to various conditions that may result in incomplete zonal isolation of the surface casing, potentially forming a conductive path for fluids to cross-flow from one stratum into another along the surface casing cement sheath.

With rigorous engineering design, the surface casing portion of the well should be modeled and configured with the proper number and placement of centralizers to center the casing and provide adequate standoff for a more effective cementing process. Use of a slightly modified casing running procedure tailored for surface casing will minimize the potential for gas or water migration along the surface casing cement sheath.

This study yielded a limited number of situations in which casing could not be run to the desired depth. In most cases, these situations occur because of borehole instability. The exposed strata may have internal forces that are not adequately supported by the mud system, or there may be chemical interaction between the mud system and the geologic materials in a particular zone, leading to formation of solids that collapse into the hole. These barriers may prevent successful running of the casing. This can also occur as a result of inefficient hole cleaning during the drilling phase, especially in deviated holes. The majority of the wellbore surface sections were drilled with similar mud systems, both chemically and from a density perspective. Attention to the cuttings can be a tip off for potential issues. Cuttings characteristics were not recorded in Encana's well records, so it is difficult to determine if these conditions were encountered while drilling surface holes in the EMCPA when stuck casing problems occurred.

### 7.3 Surface Casing – Recommendations

Because of surface hole deviation in the majority of the wells in the EMCPA, Crescent recommends that operators perform centralization calculations prior to all surface casing cementing efforts. Displacing the cement jobs at 8 barrels per minute (bpm) appeared to be typical according to review of the well records. This flow rate generates an adequate flow regime for mud removal during circulation of the cement. Though best practices recommend thinning of mud systems prior to cementing operations, care must be taken in situations where significant amounts of LCM are being employed. Thinning mud systems may destabilize the distribution of LCM and lead to bridging in the annulus. However, inadequate thinning may leave immobile mud in washouts and/or lead to channeling of the cement slurry, resulting in poor isolation.

Although top out remedial cement jobs were not common on the pads reviewed in this study, Crescent recommends using a lead slurry system in all EMCPA surface casing cement jobs to minimize cement fallback. In areas where mud losses are observed during drilling, thixotropic, reduced density slurry is advised. The reduced density and comparative viscosities of lead slurries versus tail slurries promotes mud removal, and consequently, lead slurries provide a better opportunity for zonal isolation in the annulus. In lieu of using API "G" based tail slurry, reduced density on tail slurries is also available through the use of ASTM Type III cement. Type III cement offers high early strength, sulfate resistance, and a mix density of 14.2 ppg.

Good cement engineering practice requires attention to the wellbore conditions from spud (commencement of drilling) to TD. All geologic strata will affect the eventual outcome of a cementing process. There are a number of lost circulation materials that would be considered upgrades to the cellophane flake material that is typically used in the EMCPA. In situations where significant losses are observed during the drilling process, materials such as nylon fibers, nut hulls or laminate flakes would potentially provide superior performance. These materials can be effective in pills (slugs of material pumped down the hole) ahead of the cement or as a component of the slurry mixture. In situations where shallow gas zones are encountered or noticed in well logs or offset wells, best practices described above could help mitigate gas migration.

### 7.4 Intermediate and Production Casing – Slurry Composition and Characteristics

The slurries utilized in intermediate casing jobs in the EMCPA were generally similar to the production casing cement slurries with the singular exception of the retarders required to customize thickening times. For this reason the intermediate and production casing cement slurries will be discussed together in this section of the report.

Cementing practices in the EMCPA have changed markedly when comparing pre-2005 (Phase I) efforts with current Phase II efforts. Mud conditioning was not optimized in Phase I wells. As stated in Section 7.3, Surface Casing - Recommendations, care must be taken in thinning mud systems when LCM is present. Casing centralizers were used during Phase I, but their spacing was not optimized. In both Phase I and Phase II, reciprocation was used to accomplish pipe movement during cementing.

Based on Crescent's review of simulation results and empirical data, it appears that slurry weights ranging from 12.5 ppg to 13.5 ppg were preferred while drilling Phase I wells. To provide a comparison with other common industry cement slurries, Class G mixed with minimum water requirements weighs 15.8 ppg, and 50/50/2 slurry (shorthand notation representing percent pozzalan/percent Class G cement/percent gel) with minimum water requirements weighs 14.2 ppg. It appears that the lighter slurry weights used in the EMCPA were designed to be less dense to provide an appropriate solution for lost circulation zones and formation pressures observed while drilling the wells. The Phase I slurry designs utilized API Class G blends with pozzalan, extenders, dispersants, retarders, LCM, free water control additives and fluid loss additives. The systems were basic performers that worked well in most areas of the Piceance Basin. Though there were few Phase I test results available, the slurries would have met a criteria of less than 250 cc/30 minutes fluid loss control, adequate thickening time, and minimal to no free water or settling.

Early results indicated that gas migration problems existed. As a result, attention focused on transition time reduction. The mechanics of transition time reduction can be more difficult to accomplish with light weight or "extended" cement slurries. Extenders are materials that have a high water requirement. Use of these materials replaces heavy cement particles with lighter materials and water to yield lower density slurries. The use of materials like sodium metasilicate and bentonite, two very common extenders, is not conducive to shortening transition time. Other materials can be used to adjust the transition times in conjunction with these materials, but they were not employed in Phase I wells. Densified spacer systems were used from the outset of the drilling projects in the EMCPA.

Most of the documented gas migration impacts in the EMCPA arose from Phase I wells. New materials were used and new methods were implemented to combat gas migration in Phase II wells, which were drilled from 2006 to present. Though it was not a new to the industry in 2006, TXI Liteweight cement was offered as a potential solution by a cement service provider. This material is proprietary pre-blended cement that has a common mixing density range of 12.0 ppg to 14.2 ppg. The material features a finer grind size (6,900 square cm/gram) than API cements (2,500 to 4,500 square cm/gram). This increase in surface area increases the water requirement, resulting in a reduced density. To meet slurry weight requirements, extender use has been greatly reduced, leading to more advantageous transition time performance. The mixing density of the product was ideal for the area operations and was "imported", as it is not commonly available in the Rockies.

With the adoption of the Cementing NTO and the Encana SOP in Phase II, there was an immediate and significant upgrade in cementing performance in the EMCPA. Cement slurries were modified by using the TXI product. Fluid loss additive usage was customized to provide for fluid loss performance of less than 50 cc/30 minutes. Thickening times were shortened to minimize retarder influences on transition time. Mud conditioning was encouraged and performed in a prudent manner relative to the volumes and rates of LCM used in the mud. Centralization and mud removal calculations were performed on all production and intermediate casing designs.

There have been attempts to redesign the tops of cement. Among these attempts have been efforts to bring cement to surface, many of which have been successful. One downside of these efforts is that as the cement column height increases, hydrostatic pressure is lost during the transition phase, which increases the potential for gas migration into the cement. There have been multiple instances that indicate gas migration as a continuing issue, particularly for Phase I wells. Examples of gas migration issues include both Arbaney wells, including the 3-16C and 3-15C, and both Schwartz wells, 2-15B and 2-14D. Many of the wells with cement returned to surface exhibit characteristics of gas migration in the upper portions of the wellbore. Appendix H contains a paper written by James Heathman which illustrates the concepts of gas flow potential and some of the remedies for control of gas migration.

### 7.5 Intermediate Casing – General Practices

If an intermediate casing string is "planned" the intermediate section of the hole should be drilled with an 8-1/2 inch or 8-3/4" bit to the setting depth. However, planned intermediate casing strings were not standard in the EMCPA. The need to install an intermediate string is generally related to some sort of difficulty encountered while installing the surface casing. Difficulties include sticking of the pipe short of the target depth resulting in a failed FIT, lost circulation resulting in concern about the ability of the cement job or pipe to provide proper pressure containment, perforating the surface casing to allow for circulation to surface, or surface casing squeeze cementing.

As with any casing string, good cementing practices are required while installing and cementing the intermediate casing. Proper centralization into the surface casing shoe is necessary in deviated holes. Pipe movement, mud conditioning, use of spacers for mud removal, and proper slurry design are critical when there are concerns about the surface casing's isolation properties. If the intermediate casing is "unplanned", reaming the hole to 8-1/2 inches is highly desirable, as it allows ample annular space for an adequate cement job, and it allows additional clearance for placement of a 7 inch intermediate casing. Current Encana standard practices exceed these recommendations, although it may not have been the case with all EMCPA wells.

If drilling conditions preclude reaming, then a 5 ½ inch intermediate casing is an alternative, followed by a 3 ½ inch production string. However, this smaller diameter casing configuration may compromise the effectiveness of stimulation operations and the ultimate productivity of the well. Intermediate casing strings result in a "slimhole" environment for the production string, and the operator must pay close attention to centralization and cement design for both the intermediate casing and the production casing to provide a successful outcome.

### 7.6 Production Casing – General Practices

On the EMCPA wells, the production hole section was typically drilled with a 7-7/8 inch bit, and a 4-1/2 inch casing is run to the TD of the well. As discussed in the Intermediate Casing Section above, a deviation from this plan within the EMCPA was necessary if an intermediate casing needed to be used. Intermediate casing requires drilling the open hole with a smaller bit size below the intermediate casing shoe. Typically, open holes sizes were reduced to allow the drilling equipment to be run through the 7 inch intermediate casing. The hole size is reduced to 6-1/8 inches or 6-1/4 inches depending on the weight and resulting wall thickness of the 7 inch casing, with 4-1/2 inch casing placed in the open hole upon reaching TD. In slimhole environments, attention to centralization, pump rate and slurry design are critical to successful isolation. Cement sheath thickness is reduced and therefore mud removal and subsequent replacement by cement in the borehole are required for satisfactory performance.

The current Encana SOP has provided a guide for good zonal isolation when cementing the production casing. However, despite implementation of the Encana SOP, gas migration continues to be intermittently problematic. In wellbores successfully cemented to surface, there is a recurring theme of poor bonding performance in the shallow portions of the well. Crescent believes that gas migration problems are symptomatic of long cement columns returned to surface and the need for added attention to transition time characteristics of the slurries. In order to mitigate gas migration problems, casing and cement designs must be customized for each pad and each well based on drilling conditions and geology observed in each well.

Encana typically uses Federal requirements to calculate specific cement volumes for each production casing job. The Federal TOC requirement is 200 feet above the Mesa Verde Formation or the Ohio Creek Formation (if present). The Federal requirement is used for cement calculations because it is a standard that also meets State TOC requirements. Data over the past few years, for wells drilled in the EMCPA area and surrounding areas, indicate that State and Federal requirements for cement tops are rarely missed. However, Encana's internal standard, which exceeds both Federal and State requirements by several hundred feet, is often missed on the low side. This data is presented in Figure 8 and Figure 9 in Appendix A, which show charts generated from Schlumberger data of Top of Cement vs. APD Objective.

### 7.7 Intermediate and Production Casing – Recommendations

Encana's SOP's, their current casing and cementing designs and their quality assurance efforts exceed Federal, State, and normal industry standards. In Crescent's opinion, attempts to bring intermediate and/or production casing cement to surface are not the optimum solution to prevent gas migration. Effectively isolating the potentially productive gas zones is a greater concern, as well as preventing encountered gas zones from damaging the cement sheath, thereby limiting the zonal isolation capacity. Encana is currently designing their cement jobs to cover all shallow gas zones with additional excess cement added as a safety factor. This design is intended to cover zones that have significant deliverability of gas flow in commercial quantities, as well as non-commercial gas zones in the upper Mesa Verde Group, the Ohio Creek Formation, and the lower Wasatch Formation.

Crescent recommends centralization of intermediate casing (when used) and production casing at a minimum 50% standoff from TD, up into the surface casing shoe. This is to facilitate more effective remediation, should it be necessary. Squeeze cementing processes require the same centralization as primary cement jobs to effectively provide 360 degree isolation. If cement to surface is the final goal, there are a number of techniques that should be employed in order to minimize the potential for gas migration: stage cementing (currently being performed by Encana outside the EMCPA); use of stabilized gas generating materials, which provide energized elastic properties to cement systems; foam cement processes; and transition time manipulation of multiple slurries to achieve maximum hydrostatic pressure application to known gas bearing strata.

### 7.8 Cement Remediation

Throughout the EMCPA, remediation efforts have varied from cement squeezes to setting intermediate casing. Differences in individual remediation techniques resulted from challenges that were unique to each specific well. More recently, implementation of the Encana SOP has reduced the need for remedial efforts on intermediate casing and production casing. Crescent recommends development and implementation of a similar document for surface casing to reduce the need for surface casing remedial work. Despite implementation of standard operating procedures, there will be cases of unforeseen situations that require remediation. Corrective action options should be flexible to address unique situations that are likely to occur for each well that requires remediation.

In cases of development of low-magnitude Bradenhead pressures, Crescent believes that monitoring and venting is a viable option. Attempting to remediate low pressure gas leakage leads to removal or masking the ability to monitor pressure buildup and pressure relief. For the purposes of this discussion, Crescent defines low pressure as Bradenhead pressures less than 250 psi. When the 250 psi threshold is reached, acoustic fluid level testing should be initiated to identify the actual pressure on the annulus and to further investigate the need for remediation.

## 7.9 Stimulation

Stimulation (hydraulic fracture treatment) processes do not appear to have an impact on the cement sheath performance in the EMCPA. Cyclical failure is a concern when cemented casing is subjected to repetitive pressure and temperature cycles, as debonding of the pipe from the cement sheath (development of a micro-annulus) is generally the result. This phenomenon is likely occurring, but the resulting micro-annuli are either not conductive to fluids or they are not connected to the perforations. Based on Crescent's review in the EMCPA, occurrence of Bradenhead pressure has occurred prior to pressures exerted on production casing during the stimulation process. COGCC rules require monitoring and recording of the Bradenhead annulus pressures during stimulation operations, and post-completion monitoring is required by the Bradenhead NTO in the EMCPA.

## 7.10 Plugging and Abandonment

In the Piceance Basin, including the EMCPA, the practice of covering all gas bearing zones is not practical during plugging and abandonment, particularly for shallow non-commercial gas bearing zones in the Wasatch Formation. Setting a plug above the producing formation is a reasonable procedure to prevent unwanted fluid migration. Crescent recommends that COGCC modify its internal policy for surface casing shoe plugs to require 100 feet of cement in and 100 feet of cement out of the surface casing (COGCC's current state-wide policy requires 50 feet of cement in and 50 feet of cement out of the surface casing). Recovery of production pipe is not common in the Piceance Basin, but slotting, cutting or perforating can accomplish access to the annular space below the surface casing shoe to facilitate circulation of cement past the shoe. COGCC rules provide general guidance for plugging and abandonment. However, in order to account for the unique wellbore configurations in each well, COGCC rules are necessarily flexible to allow for individual well plugging designs, and well-specific plugging orders are approved by COGCC staff for all wells.

## 7.11 Water Wells

For many older water wells in the EMCPA, there is limited information available from the Colorado Division of Water Resources regarding water wells and their construction details. For water wells with detailed records, Crescent's review found that there is limited attention paid to water well isolation strategies for aquifers and surrounding formations, particularly in older water wells. The "surface pipe" protection is designed to prevent hole collapse, and it functions more like a conductor pipe in a gas well. The water well surface pipe normally consists of 40 feet of steel pipe which is grouted with neat "ready mix” slurry. In Crescent’s opinion, the water well surface pipe provides minimal control to prevent fluid migration. The “water production” string is generally, 4 inch or 5 inch PVC pipe which is “pre perforated”. This string is often not cemented to provide stability or isolation of water (or shallow gas) bearing zones above or below the perforated well screen. On some occasions, the water production string will have gravel or sand dropped behind it through a tremie pipe to promote water flow into the well and prevent collapse of the wellbore, but there is generally no form of isolation above the gravel or sand pack.

### 7.12 Well Logging – Cement Sheath Evaluation

There were several cases when CBLs were run on wells, indicating adequate coverage, only to have Bradenhead pressures develop, requiring remediation of the wellbore. In some of these situations, the Bradenhead pressures may have resulted from shallow gas-bearing strata above the TOC supplying the source for the pressure. CBL analysis, open-hole log analysis, and some cased hole log analysis, when coupled with the Bradenhead NTO monitoring program, should provide adequate indication of isolation. If this data is inconclusive, then the need for higher-level evaluation tools should be considered. Ultrasonic isolation logs are available from a number of service providers and should be employed when Bradenhead pressure, CBL analysis or both lead to questions regarding cement performance. Appendix F contains information regarding the uses and features of ultrasonic isolation logs. The information was supplied by vendors of the various technologies. A description of the triple and quad combo open-hole logging suites that are used for identification of porous media and fluid identification is also included in Appendix F.

## 8.0 Document Reviews

### 8.1 COGCC 300 Series Rules – Effective May 1, 2009

The current COGCC Rules for Drilling and Cementing are captured in the 300 Series. There were few changes in specific drilling and cementing rules compared to a previous set of rules that was effective in 1998. The majority of the changes were verbiage for clarification. The current 300 Series rules are suitably general and flexible to allow COGCC staff and operators to react in a timely manner to the unique drilling and cementing conditions encountered in various parts of the State. The 300 Series rules also are adequate and clear regarding reporting responsibilities. A significant new section within the rules outlines the use of pitless drilling systems, berms and spill reporting and response plans for drilling pads located within Rule 317B buffer areas. These additions keep pace with current technology and environmental responsibility. A new Rule 341 also requires Bradenhead pressure monitoring during stimulation operations. There are no changes or clarifications recommended in the 300 Series Rules section, with the following exception.

Current plugging regulations are contained in section 319. Crescent recommends that COGCC modify its internal policy for surface casing shoe plugs to require 100 feet of cement in and 100 feet of cement out of the surface casing (COGCC's current state-wide policy requires 50 feet of cement in and 50 feet of cement out of the surface casing).Crescent recommends "100 in/ 100 out" plug methodology, because of the variability of the plug mud or water systems. The risk of cement contamination is relatively high in this environment as is the potential for gravity segregation. These items lead to concerns regarding cement plug integrity. The COGCC offers additional guidance documents and personal assistance to operators in both design and execution of plugging procedures.

### 8.2 Cementing NTO

**NOTICE TO OPERATORS DRILLING MESAVERDE GROUP**
**OR DEEPER WELLS IN THE MAMM CREEK FIELD AREA**
**IN GARFIELD COUNTY**
**WELL CEMENTING PROCEDURE AND REPORTING REQUIREMENTS**
**July 23, 2004**
**Revised February 9, 2007**

This document is a supplement to the COGCC's 300 Series cementing rules, with specific requirements for the EMCPA and surrounding areas. The Cementing NTO outlines requirements for FIT's, well control situations, cementing, evaluation of cement sheath, and follow up to insure sheath competency via reporting of Bradenhead pressure monitoring. The policy is written clearly and without ambiguity. Crescent recommends modifying the policy to require minimum centralization efforts (50% or better standoff) on all deviated strings. This is critical to insure long-term isolation and channel prevention via mud removal. Crescent also recommends updating the contact information on the document.

Implementation of the Cementing NTO has had positive effect in the EMCPA with zonal isolation of casing through proper design and execution of cement jobs. Gas migration problems have been effectively eliminated in Phase II wells, which were drilled under requirements of the Cementing NTO.

### 8.3 Bradenhead NTO

**NOTICE TO OPERATORS DRILLING WELLS IN THE**
**BUZZARD, MAMM CREEK, AND RULISON FIELDS,**
**GARFIELD COUNTY AND MESA COUNTY**
**PROCEDURES AND SUBMITTAL REQUIREMENTS**
**FOR COMPLIANCE WITH COGCC ORDER NOS.**
**1-107, 139-56, 191-22, AND 369-2**
**July 8, 2010**

The Bradenhead NTO was published on July 8, 2010 for Buzzard, Mamm Creek and Rulison Field operations in Mesa and Garfield Counties. The NTO outlines equipment, testing and reporting requirements. It also generally outlines mitigation and remedy requirements when Bradenhead pressures are observed above a 150 psi threshold. The mitigation and remediation section is left purposely flexible to allow for engineering judgment, instead of a “cookie cutter” approach to remedial operations. All of the listed requirements are reasonable and clearly stated. Based on Crescent’s review of well records in the EMCPA, it appears that the required monitoring leads to appropriate action when high Bradenhead pressure is recognized. Encana’s EMCPA wells are currently being equipped with automation to make the testing and recording simple.

Crescent recommends venting whenever possible within accepted pressure limitations, as remediation can potentially force gas into surrounding strata and might be detrimental to these zones. Although it is not mentioned in the Bradenhead NTO, COGCC currently allows operators to utilize the gas for powering surface equipment if the option exists. The Bradenhead NTO encourages the use of combustors when feasible. Both measures prevent air quality impacts; use of gas on the lease for powering equipment also promotes good stewardship of the natural gas resource.

Cement remediation should be designed on a case by case basis, with a specific result in mind. This Bradenhead NTO program has been effective. Monitoring of the Bradenhead is a first step in recognizing potential downhole pressure issues. By vigilant monitoring, a number of specific incidents have been recognized and addressed in a timely fashion. The use of automated monitoring systems is a substantial voluntary improvement by Encana.

## 8.4 Encana SOP

### Cementing Standard Operating Procedure and Casing Running Procedures

The Encana SOP is currently specific to the Production string, and it incorporates many currently-recognized industry practices and procedures. In Crescent’s opinion, the lone deficiency is that the specific attention is placed on the production casing, but not other casing strings in the well. The procedure should be expanded to include all casing strings placed in a well, with specific attention focused on the surface casing.

Isolation of shallow gas zones behind the surface casing is a concern when kicking off from vertical to a directional wellbore within the surface casing section. Attention to casing centralization for adequate mud removal and cement placement would provide the necessary casing standoff for adequate isolation of gas-bearing zones. Currently, centralizer spacing is not sufficient to provide at least 50% standoff between the surface casing and the borehole. Without adequate centralization, the casing tends to settle against the low side of open hole, creating an area adjacent to the casing in which the cement cannot completely surround the casing. This situation can create irregularities in the cement sheath that could potentially lead to cross-flow of fluids from one zone to another.

In Crescent's opinion, amendments to the Encana SOP should include provisions for surface and intermediate string cementing, similar to the specifications for production strings. The entire production string should be centralized, with performance goals of 70% standoff from TD up through the primary cementing interval and 50% standoff form the top of the primary cementing interval, up into the surface casing shoe). If the TOC falls back to a lower depth after the primary cement job, then the proper standoff will increase the potential for adequate isolation using remedial cement.

The Encana SOP is a "living" document. It should be updated regularly as new technology, materials and procedures offer value by providing improved results.

## 9.0 Conclusions and Recommendations

Review of Encana's well records and various interviews with persons associated with operation, regulation and study of the EMCPA wells has provided the background for the following conclusions and recommendations. Details and commentary on these items can be found throughout the body of this report. Conclusions and observations are followed directly by related recommendations.

### 9.1 COGCC Conclusions and Recommendations

- COGCC's Cementing NTO has been effective in improving cementing performance.
  - Require minimum standoff of 50% for all casing strings.
  - Update document contact information.

- COGCC's Bradenhead NTO has been effective in providing timely recognition and mitigation of potential gas flow scenarios.

- Remediation evaluation should be triggered when Bradenhead pressure reaches a pressure 250 psi at the surface. Overall pressure gradients exceeding 0.6 psi/ft require further evaluation. COGCC's current threshold for reporting and mitigation (venting or remediation, depending on the nature of the flow) is 150 psi. Continue to vent or utilize Bradenhead gas whenever possible.

- In surface casing cement applications where fallback occurs, "top out " procedures are preferred to perforating casing and circulating cement when the annular cement top is less than 250 feet in depth.

## 9.2 Encana Conclusions and Recommendations

- Encana's SOP has been effective in improving production casing cementing performance.
  - Further improvements may be available in terms of controlling gas migration, especially when cement is returned to surface on production casing jobs.
  - The existing document should be expanded or a similar document should be developed specifically for establishing standards for surface and intermediate casing installation and cementing.
- Slimhole environments resulting from intermediate casing installation may result in higher GFP tendencies, particularly in deviated cases.
  - Deviation, coupled with a slimhole environment requires adequate centralization, fluid loss control and general cementing best practices to control gas migration tendencies. Adherence to rigorous engineering design is critical in these environments.
- Use of more advanced LCM in cement slurries may provide superior performance and limit cement fallback. Materials include but are not limited to fibers, laminates, and nut hulls. Experiments should be performed in all casing string applications to identify optimum LCM for the EMCPA.
- Surface casing deviation in the well plan requires rigorous engineering design on the surface section of the wellbore.
  - Develop and implement an expanded Encana SOP or a specific SOP to account for surface casing installation and cementing to minimize the potential for fluid migration along the surface casing cement sheath.

- In areas with lost circulation in the surface casing section, utilize lightweight lead slurries, and evaluate the potential for Type III or TXI Lightweight tail slurries to reduce density.
- More rigorous casing and cementing design may improve cement remediation results when remediation is necessary.
  - Provide proper casing centralization in sections above the primary TOC.

## 9.3 Joint Conclusions and Recommendations

- Shallow gas zones exist in the surface hole, and they must be properly identified and isolated
  - Perform open hole logging of the initial well on each pad to identify shallow gas-bearing zones in the surface hole

- Drilling fluid losses and whole cement losses and gas flow events are unpredictable.

- The lenticular nature of potentially productive gas-bearing sands is conducive to drilling fluid losses and flows, as the unpredictable pressures of individual lenses are distinct and separate from each other.

- Differences between reservoir fluid pressure gradient and fracture pressure gradient are often minimal.

- Recognition and definition of the “top of gas” is critical for TOC designs on intermediate and production casing strings.
    - Considering that gas flows in the EMCPA are more prevalent in the Wasatch Formation and productive intervals of the Williams Fork Formation, Crescent recommends that the first show of gas in mud logs, in either of these sections, be used as the “top of gas“ for design purposes. In other areas outside of the EMCPA, this definition may not be appropriate. Area geology and characteristics of gas-bearing zones must dictate the definition of “top of gas” and the resulting requirement for TOC.

- To protect gas resources, stimulate wells prior to remediation processes whenever possible.
    - Squeeze holes limit mechanical integrity and reduce pressure ratings thereby reducing the rate available to stimulate each perforated interval.
    - Reduced diameter when using 3-1/2 inch liners also inhibits rate, impacting stimulation efficiency. The reduced diameter also limits the tools available to isolate fracturing stages.

- There is no evidence that “hydraulic fracture” stimulation operations have had an effect on cement sheath integrity, and they have not contributed to Bradenhead pressures on the annulus in any wellbore evaluated during this study.

- Bradenhead pressure alone is not reflective of poor cementing practice or performance.

- Monitoring Bradenhead pressure changes over time is an effective method to evaluate the necessity of cement remediation, which may or may not be advised when Bradenhead pressure is observed.

- Squeeze cementing efforts can be an effective remediation. Post-remediation monitoring is recommended as the squeeze cement can deteriorate over time with pressure and temperature cycling.

- Remediation efforts reduced or eliminated Bradenhead pressures in every case. These may or may not be permanent solutions to gas movement, as cement squeezes are susceptible to degradation through pressure and temperature cycling.

- Remediation success and efficiency is subject to technology advances in problem identification, and plan execution. Each situation is unique and should be treated as such.

- Statistical overview of well data to isolate root causes of known problems was ineffective in the EMCPA. Crescent concludes that each well must be engineered as an individual entity (there are no “one size fits all” solutions).

- Water well construction practices could be improved. Historic and current construction practices are not optimized for zonal isolation of shallow gas-bearing zones that may be encountered while drilling water wells.

## 10.0 Recommended Areas for Further Study

The following are observations and opportunities for process improvement as a follow-up to this EMCPA study.

### 10.1 COGCC

- Initiate a discussion with Colorado Division of Water Resources on water well construction specific to the EMCPA and surrounding areas regarding potential changes to water well isolation requirements.

  Identify and evaluate potential improvements to statewide plugging and abandonment requirements

### 10.2 Encana

- Model the Surface pipe to assure adequate centralization. It is important to eliminate the low side potential for isolation problems to prevent the flow of fluids along the cement sheath.

- Considering that production casing is rarely recovered during the plugging process, centralize the complete length of the production casing.
  - Proper centralization will improve cement zonal isolation on the primary cement jobs.
  - Proper centralization will allow for more efficient remediation should that become necessary.

- Run one open-hole triple combo log per pad within the Surface casing section of the open hole.
  - This log would be used to identify shallow gas-bearing zones on the pad that may be present in the surface hole on the remaining wells on the pad.
  - Logging results may lead to a more advanced centralization strategy.
  - Logging results may lead to a proactive change in slurry design.

- Review current cement systems for:
  - Cement system density or hydrostatic review
  - Fluid loss
  - Transition time
  - Static gel strength where gas is likely to be encountered
  - Cement flexibility

- Review alternative methods to isolate the open hole interval between the current TOC and the Surface Casing shoe. Opportunities include the following:
  - Evaluate the potential for extending the depth of the surface casing
  - Raise the top of the production string cement from the TD to the surface through the use of multi-stage cement jobs, with particular attention to gas migration prevention
  - Set intermediate casing strings as well conditions dictate during drilling
  - A combination of several of the above
  - Incorporate the latest cement evaluation tools to assess the cement performance and integrity

## 11.0 References

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## Appendix A – Figures

# EXHIBIT "A-1"

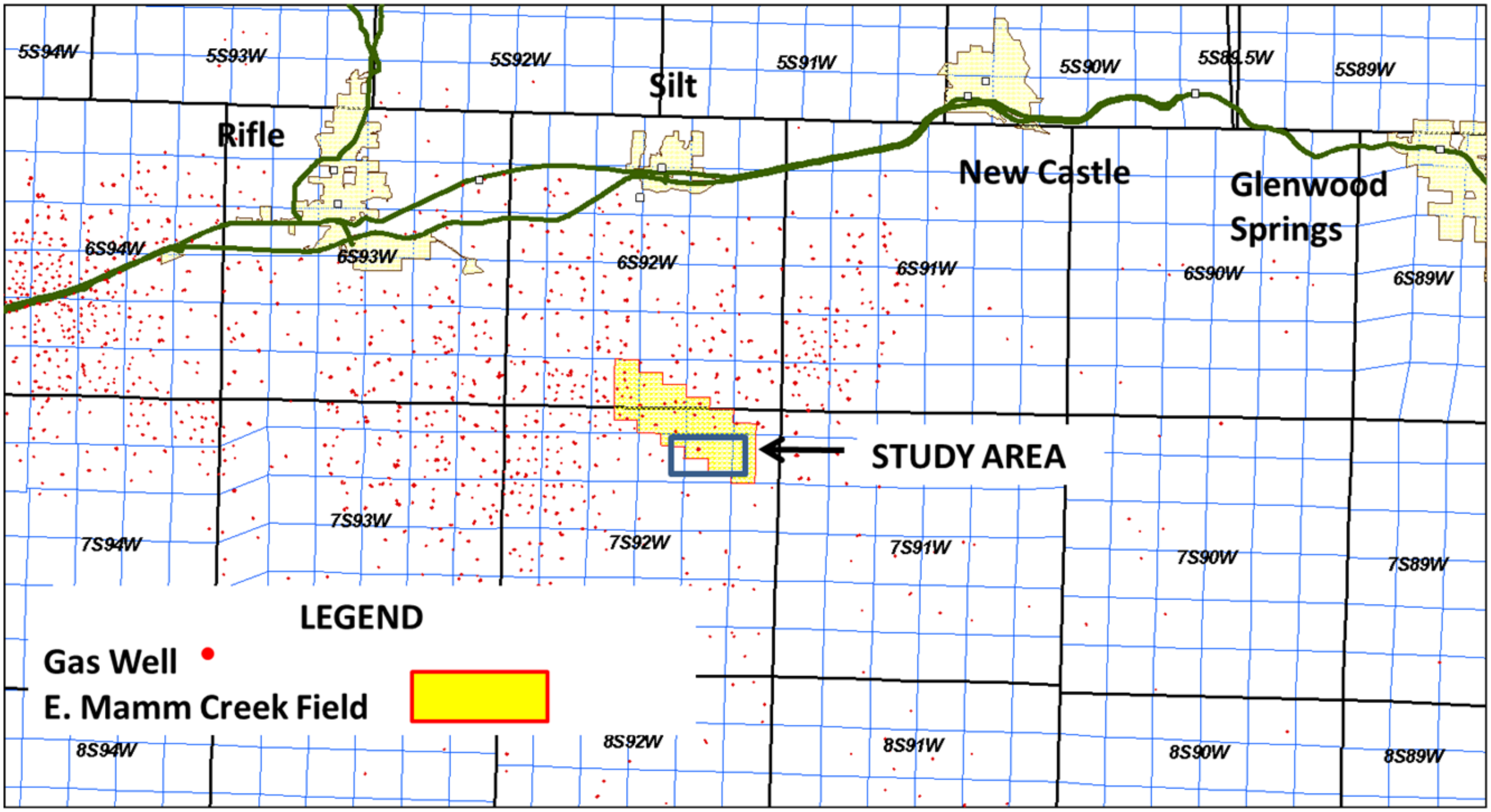



**Figure 1 –** Exhibit "A-1": East Mamm Creek mapped location and well locations.

EXHIBIT "B-1"

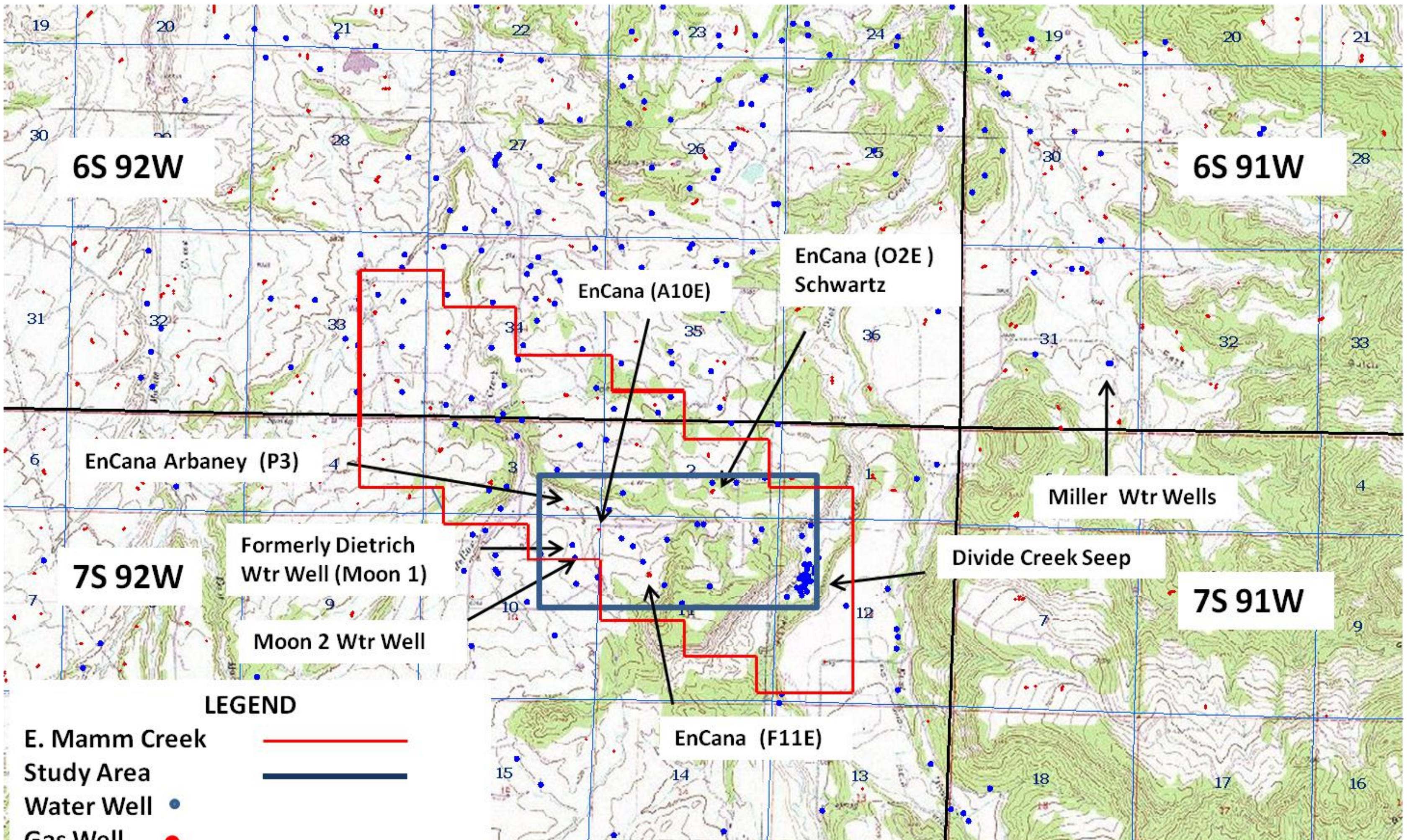



**Figure 2 –** Exhibit "B-1": East Mamm Creek Project Area (EMCPA) mapped location and included wells

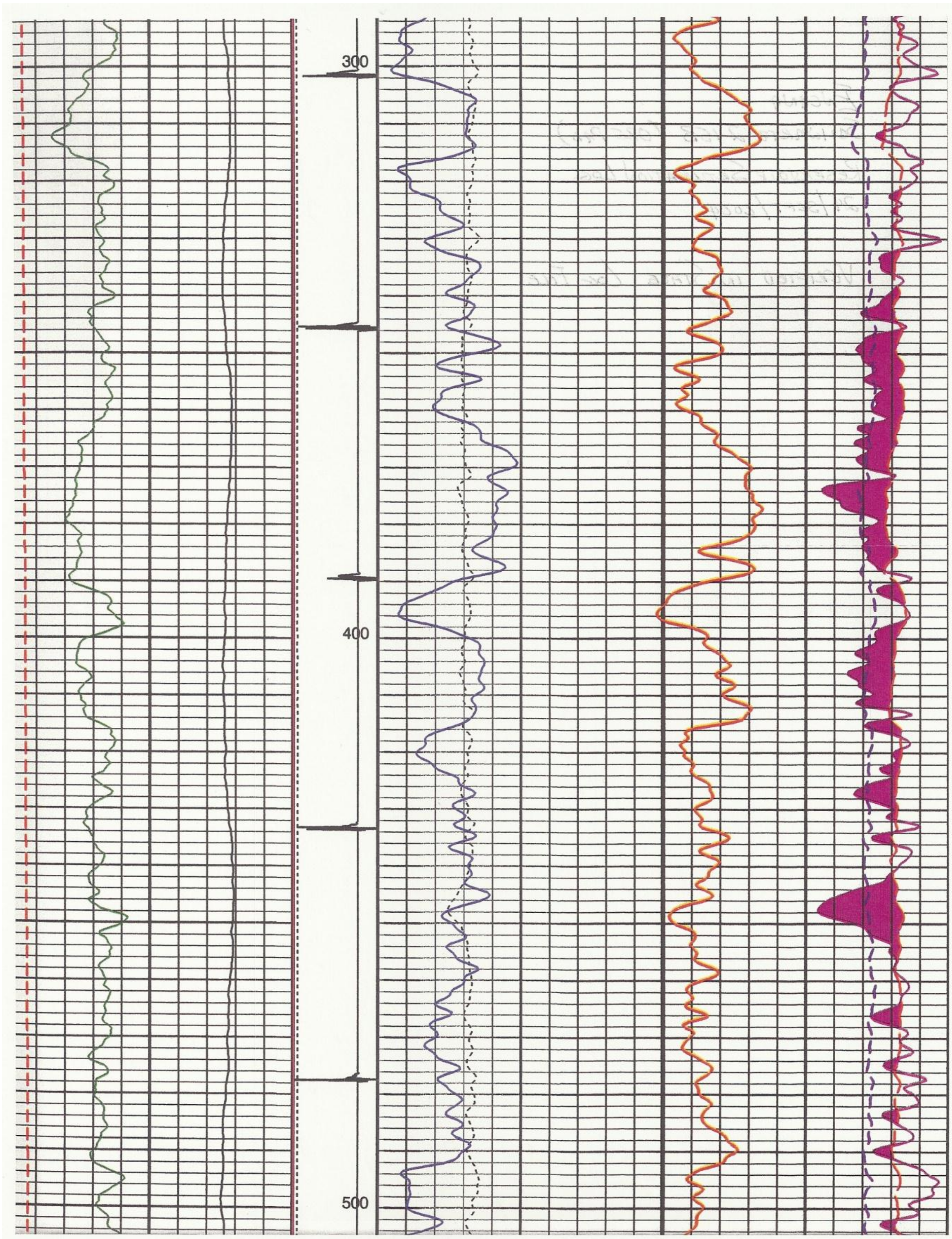



**Figure 3 –** Example section of RST log showing potential presence of hydrocarbon (shaded intervals) in the second track at shallow depth

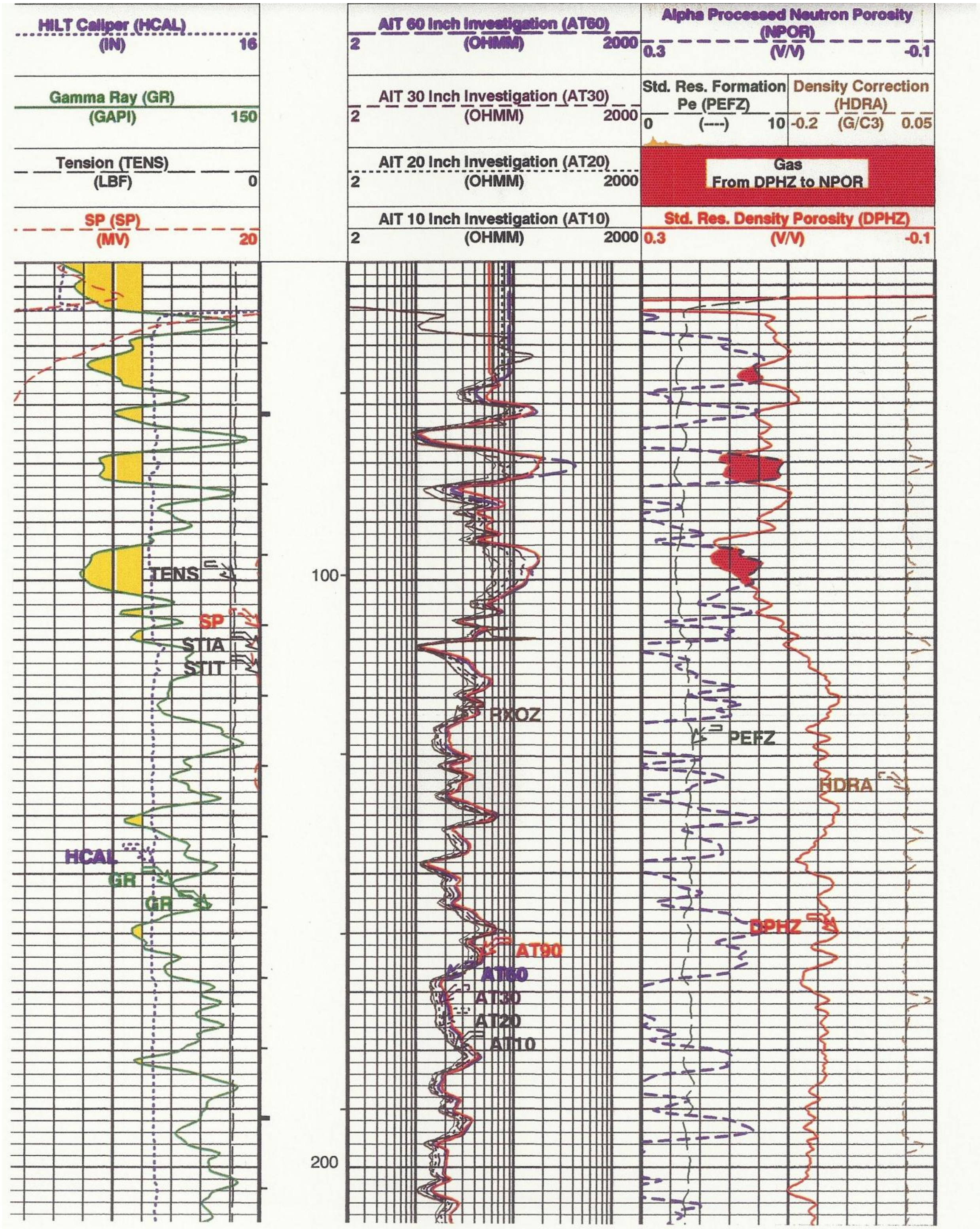



**Figure 4 –** Example triple combo log section indicating potential shallow gas zones (shaded intervals)

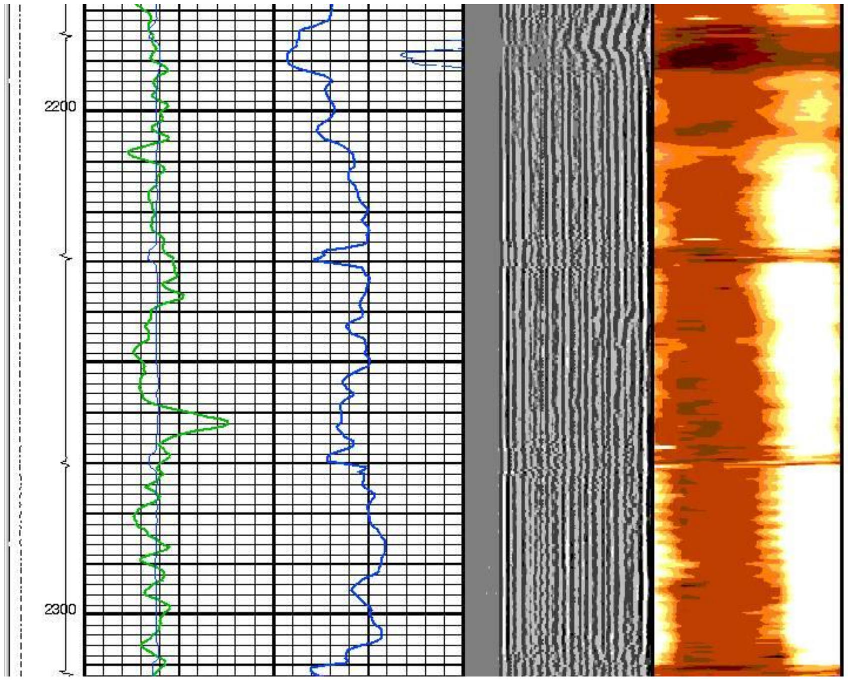



**Figure 5 –** Example log section of Cement Bond Log (CBL) before cement squeeze job

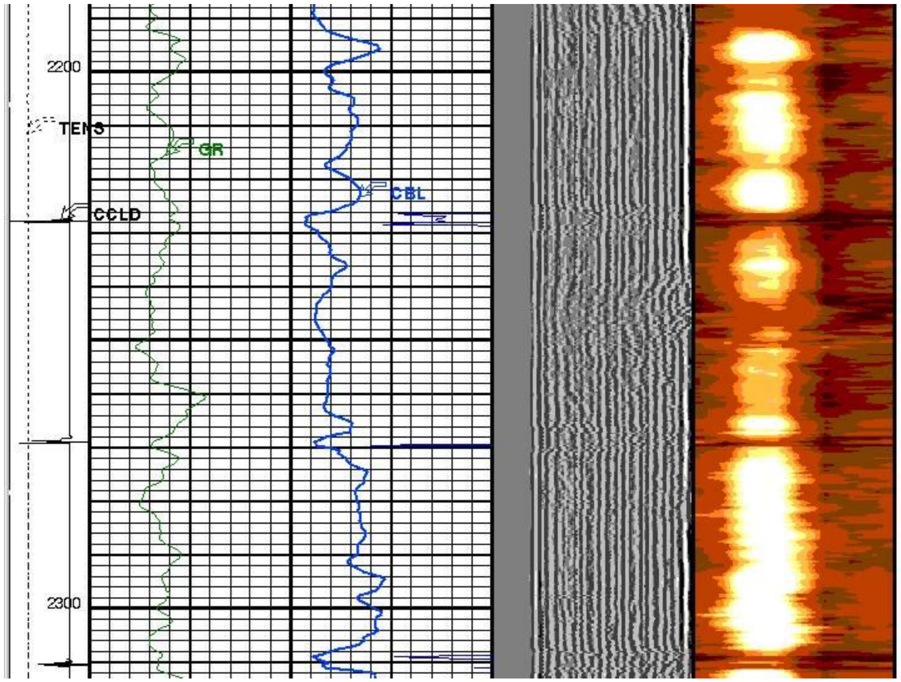
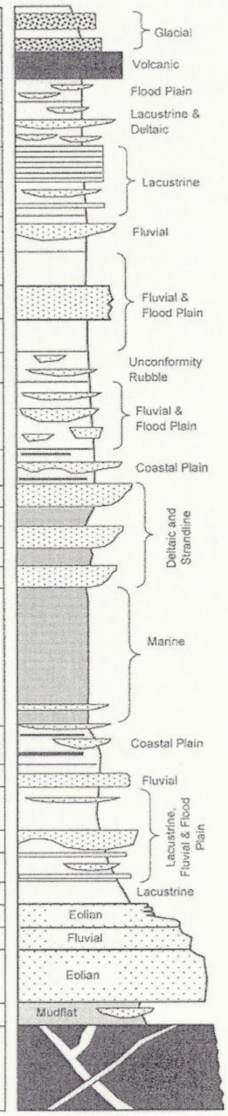



**Figure 6 –** Example log section of CBL after cement squeeze job

*Stratigraphic Architecture and Reservoir Characteristics of the Mesaverde Group, Southern Piceance Basin, Colorado*

| AGE | FORMATION | MEMBER | THICKNESS (ft) | DOMINANT ROCK TYPES |
|---|---|---|---|---|
| Quaternary | *Grand Mesa* | | < 100 | Gravel and Till |
| | *Lands End* | | < 100 | Gravel and Till |
| Miocene | *Basalt* | | 170-680 | Basalt |
| Miocene | *Unnamed* | | 0-100 | Sandst. & Mudrock |
| Eocene | *Uinta* | | 400+ | Sandst. & Mudrock |
| | *Green River* | Parachute Creek | 300-1,100 | Oil Shale and Marlstone |
| | | Garden Gulch | 300-700 | Mudrock, Limest. & Sandst. |
| | | Douglas Creek | 100-300 | SS and Shale |
| | *Wasatch* | Shire | 600-4,000 | Mudrock |
| Paleocene | | Molina | 50-500 | Sandstone |
| | | Atwell Gulch | 700-1,800 | Mudrock |
| Upper Cretaceous | *Mesaverde Group* – *Williams Fork (Hunter Cyn.)* | Ohio Creek | 0-100 | Sandst. & Conglom. |
| | | Undifferentiated | 1,500-2,000 | Sandst. & Mudrock |
| | | Bowie Shale | 300-450 | Mudrock, Sandst. & Coal |
| | *Iles (Mt. Garfield)* | Rollins | 100-150 | Sandstone |
| | | Mancos tongue | 80-120 | Mudrock |
| | | Cozzette | 100-150 | Sandstone |
| | | Mancos tongue | 40-80 | Mudrock |
| | | Corcoran | 30-60 | Sandstone |
| | *Mancos* | Juana Lopez Mbr. | 4,000-4,500 | Mudrock and Silty Sandstone |
| | *Dakota* | | 80-120 | Mudrock, Sandst. & Coal |
| L. Cretaceous | *Burro Canyon* | | 100-200 | Sandst. & Mudrock |
| Jurassic | *Morrison* | Brushy Basin | 200-300 | Sandst. & Mudrock |
| | | Saltwash | 100-150 | Sandst. & Mudrock |
| | | Tidwell | 50-120 | Sandst., Mudrock & Limestone |
| | *Wanakah* | | 20-40 | Mudrock |
| | *Entrada* | | 100-150 | Sandstone |
| | *Kayenta* | | 50-80 | Sandst. & Mudrock |
| | *Wingate* | | 250-320 | Sandstone |
| Triassic | *Chinle* | | 80-120 | Mudrock & Sandst. |
| Proterozoic (1.7-1.4 Ga) | *BLACK CANYON COMPLEX* | *GREAT UNCONFORMITY* | Feet | Schist, gneiss, pegmatite, granite, monzonite, and diorite. |




RDC/10/2003

NOT DRAWN TO SCALE

**Figure 7 –** General stratigraphic column for the Grand Junction area. Data sources: Young and Young (1968), Hintze (1988), and Scott and others (2001). Piceance Basin Guidebook, Rocky Mountain Association of Geologists

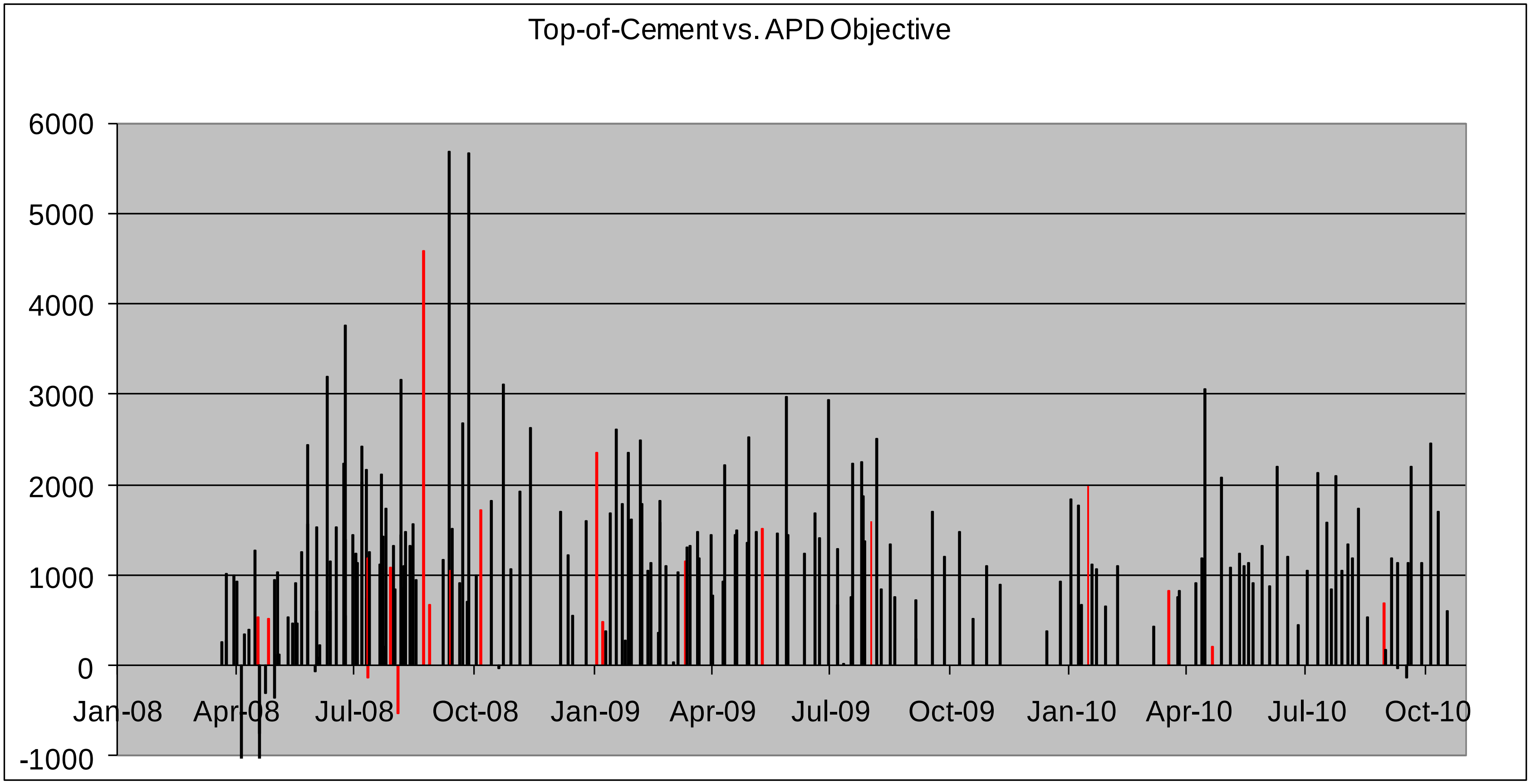



**Figure 8 –** Schlumberger chart showing the progression of top of cement compared to APD values from 2008 through 2010 for all EnCana wells in Piceance Basin. The y-axis represents the height of cement above the State-required TOC in feet.

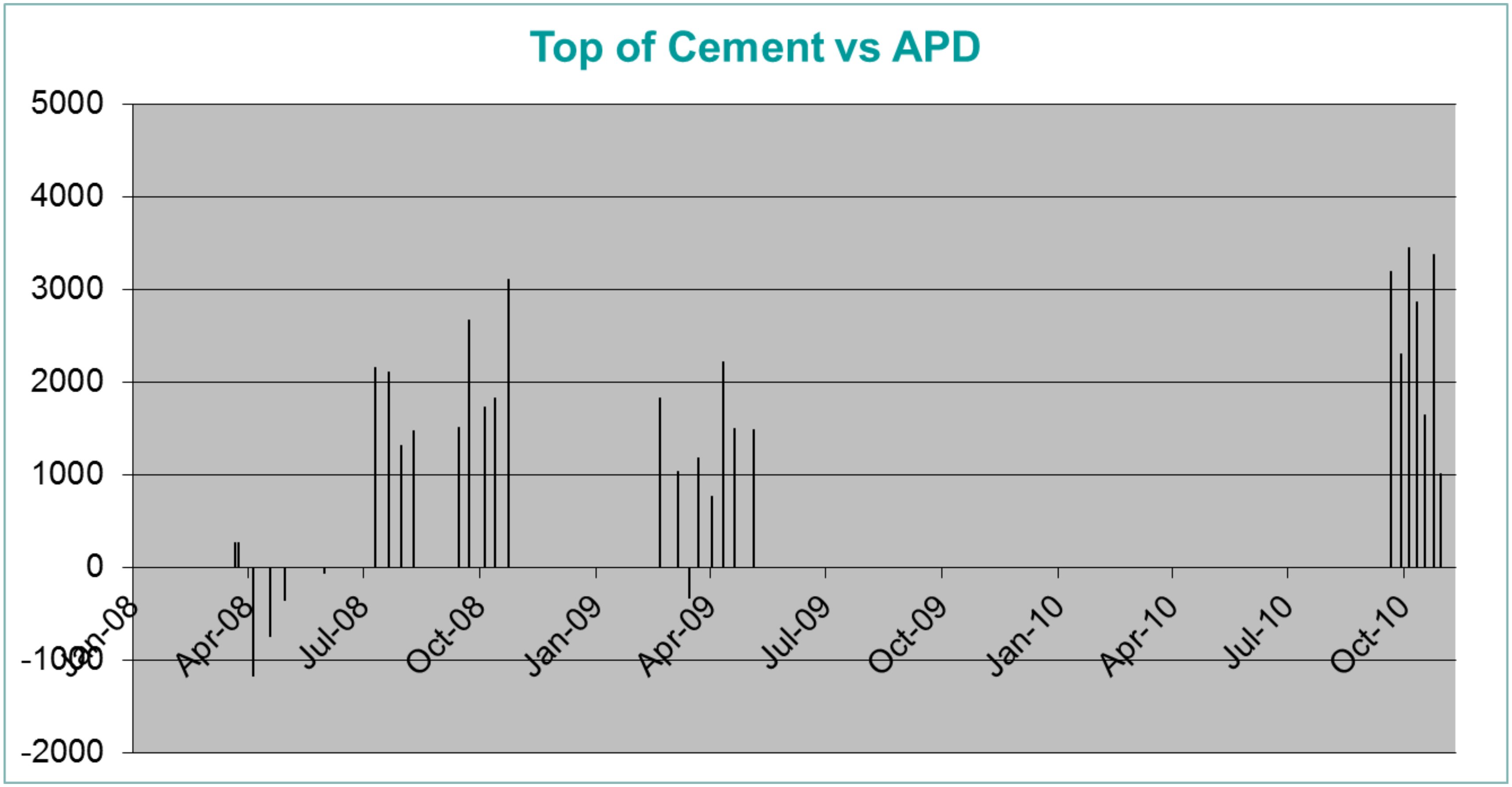



**Figure 9 –** Schlumberger chart showing the progression of top of cement compared to APD values from 2008 to 2010 on study area wells only. The y-axis represents the height of cement above the State-required TOC in feet.

## Appendix B – EMCPA Wells

| Well Name (Pad) | Section | T/R | API Number | County |
|---|---|---|---|---|
| Schwartz 2-15B (O2) | SWSE 2 | 7S -92W | 05-045-09306 | Garfield |
| Schwartz 2-15A (O2E) | SWSE 2 | 7S -92W | 05-045-14608 | Garfield |
| Schwartz 11-2A (O2E) | SWSE 2 | 7S -92W | 05-045-14609 | Garfield |
| Schwartz 2-14A (O2E) | SWSE 2 | 7S -92W | 05-045-14614 | Garfield |
| Schwartz 11-3B (O2E) | SWSE 2 | 7S -92W | 05-045-14615 | Garfield |
| Schwartz 2-14D (O2E) | SWSE 2 | 7S -92W | 05-045-14726 | Garfield |
| Juniper 1-13A (M1E) | SWSW 1 | 7S -92W | 05-045-12515 | Garfield |
| Juniper 1-13 (M1E) | SWSW 1 | 7S -92W | 05-045-12580 | Garfield |
| Juniper 2-16A (M1E) | SWSW 1 | 7S -92W | 05-045-12581 | Garfield |
| Juniper 2-16 (M1E) | SWSW 1 | 7S -92W | 05-045-12582 | Garfield |
| Juniper 1-12A (M1E) | SWSW 1 | 7S -92W | 05-045-16049 | Garfield |
| Juniper 2-9 (M1E) | SWSW 1 | 7S -92W | 05-045-16050 | Garfield |
| Juniper 1-12 (M1E) | SWSW 1 | 7S -92W | 05-045-16051 | Garfield |
| Juniper 12-4A (M1E) | SWSW 1 | 7S -92W | 05-045-16052 | Garfield |
| Juniper 11-1A (M1E) | SWSW 1 | 7S -92W | 05-045-16053 | Garfield |
| Juniper 2-9A (M1E) | SWSW 1 | 7S -92W | 05-045-16088 | Garfield |
| Brown 11-2C (F11E) | SENW 11 | 7S -92W | 05-045-09787 | Garfield |
| Encana 11-3B2 (F11E) | SENW 11 | 7S -92W | 05-045-14999 | Garfield |
| Encana 11-5 (F11E) | SENW 11 | 7S -92W | 05-045-15578 | Garfield |
| Encana 11-4C (F11E) | SENW 11 | 7S -92W | 05-045-15579 | Garfield |
| Encana 11-12A (F11E) | SENW 11 | 7S -92W | 05-045-15580 | Garfield |
| Encana 11-4D (F11E) | SENW 11 | 7S -92W | 05-045-15581 | Garfield |
| Encana 11-11A (F11E) | SENW 11 | 7S -92W | 05-045-17627 | Garfield |
| Encana 11-6 (F11E) | SENW 11 | 7S -92W | 05-045-17698 | Garfield |
| Encana 11-6A (F11E) | SENW 11 | 7S -92W | 05-045-17699 | Garfield |
| Encana 11-3D (F11E) | SENW 11 | 7S -92W | 05-045-17700 | Garfield |
| Arbaney 3-16C (P3) | SESE 3 | 7S -92W | 05-045-09118 | Garfield |
| Magic 10-1A (P3) | SESE 3 | 7S -92W | 05-045-09461 | Garfield |
| Magic 10-1 (P3) | SESE 3 | 7S -92W | 05-045-09462 | Garfield |
| Magic 10-2 (P3) | SESE 3 | 7S -92W | 05-045-09463 | Garfield |
| Arbaney 3-15C (P3) | SESE 3 | 7S -92W | 05-045-09465 | Garfield |

## Appendix C – COGCC Cementing NTO and Encana SOP

**NOTICE TO OPERATORS DRILLING MESAVERDE GROUP OR DEEPER WELLS IN THE MAMM CREEK FIELD AREA IN GARFIELD COUNTY**
**WELL CEMENTING PROCEDURE AND REPORTING REQUIREMENTS**
**July 23, 2004**
**Revised February 9, 2007**

This Notice to Operators was developed considering information that was included in the March 10, 2006 report on the Phase I Hydrogeologic Characterization of the Mamm Creek Field Area in Garfield County as well as other pertinent information regarding the prudent drilling of oil and gas wells in the Mamm Creek Field Area.

Until further notice, the following conditions shall be attached to all approved Permits-to-Drill for all Mesaverde Group or deeper wells in the Mamm Creek Field, Garfield County:

1. The Mamm Creek Field Area is defined as follows:
   Township 6 South, Ranges 91-93 West, 6th P.M.
   Township 7 South, Ranges 91-93 West, 6th P.M.
   Township 8 South, Ranges 91-93 West, 6th P.M.
   Township 9 South, Range 91 West, 6th P.M.
2. Wells shall be required to be cemented to five hundred (500) feet above the top of gas.
   a. The cement coverage shall be verified with a cement bond log.
   b. The cement compressive strength for all cement slurries used to cement the production casing shall be sufficient to meet the requirements of Rule 317. i. and allow the cement to be easily identified with the use of a cement bond log (CBL).

3. A drilling prognosis showing projected top of gas and formation tops shall be required with the Application for Permit-to-Drill Form 2. This information shall be provided in the form of a wellbore diagram showing the top of gas, formation tops, and top of cement for each stage.

**Procedure and Reporting Changes:**

1. Upon completion of the primary cementing operation, the annular fluid level around the production casing shall be monitored for a minimum of 4 hours prior to the installation of the casing slips. This requirement may also be met by setting the casing slips immediately after cementing and maintaining the ability to monitor the annular fluid level and keep the hole full. The amount of mud that is used to keep the hole full shall be recorded. If mud volumes in excess of twenty (20) barrels are

necessary to keep the hole full, the loss of fluid shall be reported to the COGCC immediately. The record of the mud volume needed to keep the hole full shall be included on the Sundry Notice, Form 4 requesting approval to complete the well.

2. The bradenhead pressure shall be measured at intervals of 6, 12, 24, 48 and 72 hours after the production casing is cemented. If bradenhead pressures greater than one hundred fifty (150) psig are observed, such pressures shall be immediately reported to the COGCC and a remediation procedure shall be prepared for COGCC approval.

3. Following the cementing operation, a combination temperature/cement bond log shall be run within 12 to 48 hours to locate the actual cement top. If the cement top does not meet the requirements of this Notice to Operators, the COGCC shall be immediately notified and a remediation procedure shall be prepared for COGCC approval. Running the CBL may be delayed if a temperature survey is conducted within 6 to 48 hours of cementing and if the operator monitors the bradenhead pressure on a daily basis after the initial 72 hour period on all wells on the pad until the CBL is run. If the option of delaying the running of the CBL is chosen, the results of the temperature survey and the bradenhead monitoring shall be reported via e-mail to the COGCC Northwest Area Engineer within 7 days of cementing. If bradenhead pressures greater than one hundred fifty (150) psig are observed during the extended monitoring period it shall be immediately reported to the COGCC and a remediation procedure shall be prepared for COGCC approval. The operator shall maintain the ability to immediately and safely commence remedial cementing operations if needed.

**NOTE:**

The option of deferring the running of the CBL beyond 48 hours is not allowed in the below-defined East Mamm Creek Area. The CBL shall be run within 12 to 48 hours within the East Mamm Creek Area.

4. The East Mamm Creek Area within the Mamm Creek Field is described as follows:

Township 6 South, Range 92 West 6th P.M.
Section 33: E½
Section 34: S½NW¼,S½
Section 35: S½SW¼

Township 7 South, Range 92 West

Section 1: S½SW¼
Section 2 and 3: All
Section 4: N½SE¼, Lots 1 and 2
Section 10: N½NE¼
Section 11: N½, N½NE¼
Section 12: W½

Operators drilling within the East Mamm Creek Area are required to follow the general procedures described above and the special procedures described in 4.a. through g. below:

a. An operator may use only one (1) rig at a time to drill that operator's first five (5) wells within the East Mamm Creek Area. If the first five (5) wells are drilled without incident, then the operator may request approval from the Director to use two (2) rigs at a time. No more than two (2) rigs shall be used by an operator in the East Mamm Creek Area.

b. Surface casing shall be set at a depth equivalent to 15% of the proposed total depth of the well, or five hundred (500) feet below the depth of any water well within a one (1) mile radius, whichever is greater, and shall be cemented to surface.

c. Operators shall perform a Formation Integrity Test (FIT) at least fifty (50) feet below the surface casing shoe. The test shall be performed to an equivalent mud weight of 13.0 pounds per gallon (ppg). A loss of more than 10% of the surface pressure applied to perform the test, in a 15 minute time period, shall constitute failure. Failed FIT's shall be reported to the COGCC staff immediately. COGCC staff shall be notified at least 8 hours in advance of the test to allow them the opportunity to witness it. The results of the test shall be reported on the Form 4 Sundry Notice Request to Complete and noted on the wellbore schematic that accompanies the Form 4. The FIT report shall include the depth of the test, the mud weight, the initial and final surface pressures and the equivalent mud weight.

d. If the well bore does not test to the equivalent of mud weight of 13.0 ppg during the above noted FIT, the operator shall be required to set intermediate casing at a depth at least fifty (50) feet below the top of the Mesaverde Formation. The intermediate casing shall be cemented to a height of at least five hundred (500) feet above the depth of the intermediate casing shoe if no kicks have been encountered in the Wasatch Formation. If kicks have been encountered in the Wasatch Formation the top of cement shall be adjusted to comply with Rule 317.i. and to cover all gas bearing intervals. If intermediate casing is necessary, the requirement to obtain a temperature survey and cement bond log on the production casing within a 12 to 48 hour period following the cementing of the production casing shall not apply. The operator shall obtain COGCC staff approval to complete the well prior to conducting completion operations.

e. All drilling rig employees shall have adequate understanding of and be able to operate the blowout prevention system. Well control training for blowout prevention shall be required for at least one (1) person at the well site during drilling operations.

f. Choke pressures during well control operations shall be restricted to levels that will not cause the maximum wellbore integrity demonstrated by the FIT to be exceeded. As a precautionary measure, if the choke pressure exceeds the surface pressure used to determine wellbore integrity during the FIT, it shall be immediately reported to the COGCC staff and the operator shall submit a report of the well control event on a Sundry Notice, Form 4 within 24 hours. The report shall include the following information:

- date and time of the event,
- total depth of the well at the time of the event,
- surface casing depth, size and cementing data,
- type of kick (gas, water, or oil),
- shut in drill pipe pressure, shut in casing pressure, or any other pressure measurement or information used to determine the mud weight required to control the kick,
- initial mud weight at the time of the event,
- pit gain volume,
- mud weight required to control the kick,
- maximum choke pressure that occurred while circulating out the kick,
- any indication of fluids migrating outside of the surface casing (surface expression, etc.),
- a narrative description of the well control event and current condition of the well.

g. In addition to the bradenhead pressure measurement requirements in the entire Mamm Creek Field Area, in the East Mamm Creek Area the bradenhead pressure of each well on a pad shall be monitored daily until 30 days following the cementing of the production casing of the last well on the pad. Following that, the bradenhead pressures shall be monitored monthly for the following 12 month period. If bradenhead pressures greater than one hundred fifty (150) psig are observed, such pressures shall be immediately reported to the COGCC and a remediation procedure shall be prepared for COGCC approval. These requirements shall also apply to monitoring intermediate casing pressure if intermediate casing is required.

5. Prior to completion of the well, the bradenhead pressure record, cement bond log, temperature survey log, and revised formation tops shall be provided to the COGCC Northwest Area Engineer along with a Sundry Notice, Form 4 requesting approval to complete the well.

6. All information shall be submitted electronically via e-mail to the Northwest Area Engineer. A separate e-mail with the required attachments, provided in the required format, shall be sent for each well.

The attachments shall include the following:

a.) Results of the FIT and the final mud weight.
b.) A CBL with temperature survey in *.pdf or Schlumberger format.
c.) A Sundry Notice, Form 4 requesting approval to complete the well stating the well has been successfully cemented according to the approved plan.
d.) A summary of the bradenhead pressure measurements.
e.) A wellbore diagram with the as-built cement tops, formation tops, top of gas, casing shoes etc.
f.) A temperature survey in a single page format.

7. The COGCC shall review the casing and cementing operations and approval shall be obtained by the operator from the COGCC prior to commencement of completion operations on all wells in the field.

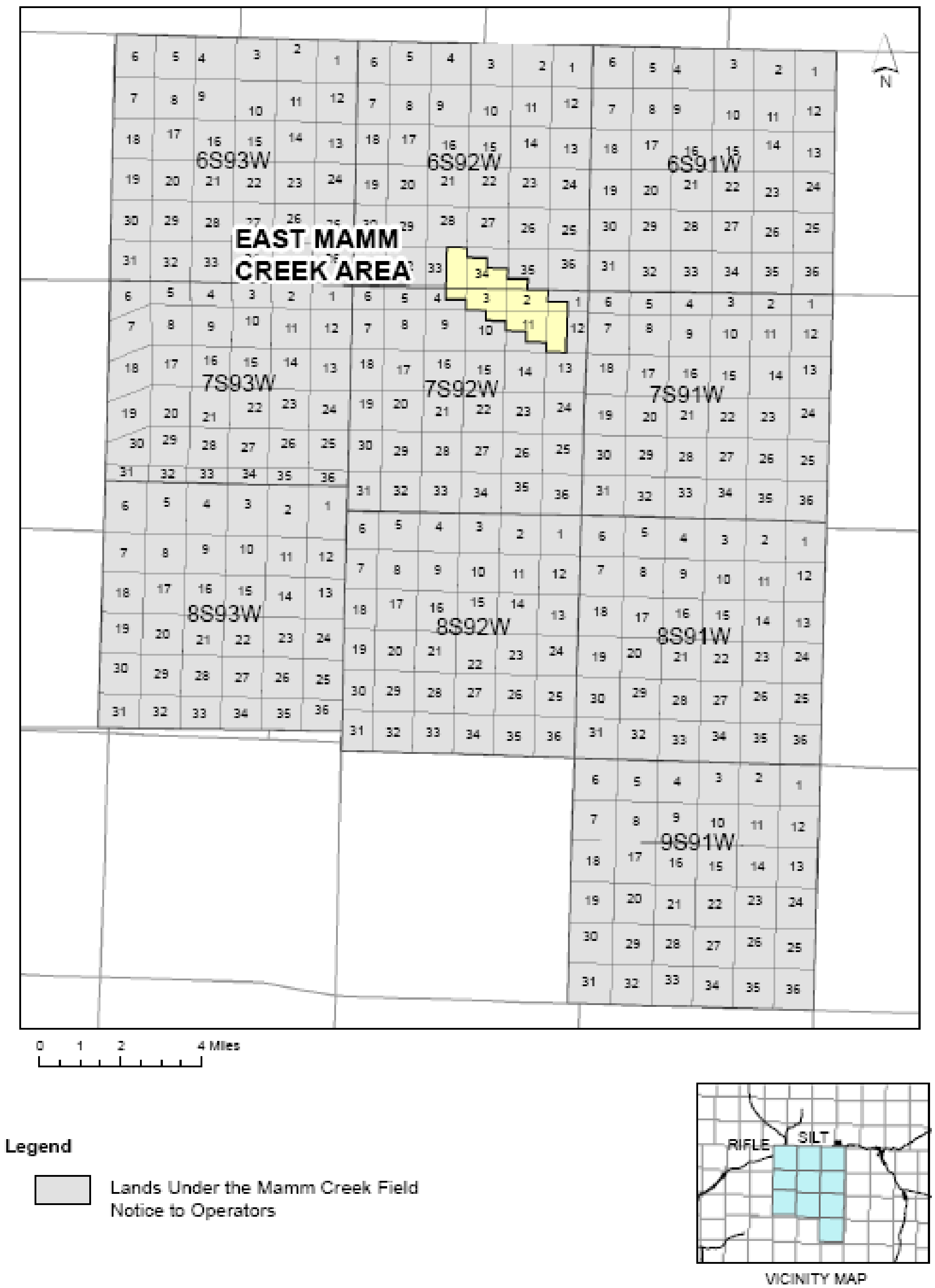
8. The bradenhead pressure shall be monitored and recorded when performing fracturing operations. If intermediate casing is set, then the intermediate casing pressure shall also be monitored and recorded.

The Northwest Colorado Area Engineer is: Jaime Adkins Office (970) 285-9000 Cell (970) 250-2440 e-mail: jaime.adkins@state.co.us

Signed,

Brian J. Macke
Director

See map below:




## NOTICE TO OPERATORS IN MAMM CREEK FIELD AREA
## GARFIELD COUNTY, COLORADO

COGCC, November 22, 2006

**Appendix C – COGCC Cementing NTO and Encana SOP** (continued)

**Encana Cementing Standard Operating Procedure –**
**Casing Running Procedures ("Encana SOP")**

## Production Casing Running Procedure

1. Several days prior to running production casing order necessary casing hardware including at least the following: float shoe, float collar, stop ring, centralizers (appropriate I.D. for casing size and appropriate O.D. for gauge bore hole), latch-in insert w/latch-in plug, thread locking compound, and any special casing hardware for specific well. Request nails for centralizer's that will allow for the ends to be bent locking in place. Order float equipment that is at least the same grade as casing to be run.
2. Upon delivery of casing hardware, visually verify proper type and size of casing hardware ordered is delivered prior to signing a delivery ticket.
3. Strap production casing on pipe racks following delivery to verify proper footage available for specific well. Extra footage ordered based on company man preference.
4. Schedule casing crew to prepare casing for running by removing thread protectors and drifting casing. Any bad casing to be unmistakably marked (painted with fluorescent paint) and pulled from running stock.
5. Thoroughly clean threads on float shoe and float collar.
6. PU first joint of production casing and clean pin. Apply thread lock compound to pin only and screw on float shoe. Make up float shoe to appropriate torque for casing type and size.
7. Install stop ring on the middle of the shoe joint and place first centralizer over stop ring. Make sure nails on centralizer are bent on the end to lock in place.
8. Apply thread lock compound to pin end of float collar only and screw in to top of first joint of casing.
9. Install Latch-in Landing Plate in top of float collar and make sure plate is screwed all the way to the bottom of threads inside float collar.
10. Apply thread lock compound to pin of second joint of casing and make up to optimum torque for casing type and size.
11. PU and run following joints of casing doping threads and making up tool joints to optimum torque for specific casing type and size. Install second centralizer on top of second joint of casing and then specific to the centralizer program that must be provided by service company on all production casing jobs.
12. Run production casing to surface casing shoe and break circulation to verify all float equipment is open and note rate and pressure.
13. Continue running production casing to ¼ TMD and pump bottoms up watching for any loss of returns. Document rate and pressure. If no losses encountered prepare to run additional casing. If losses are encountered take measures to regain full circulation prior to proceeding.
14. Continue running production casing to ½ TMD and pump bottoms up watching for any loss of returns. Document rate and pressure. If no losses encountered prepare to run additional casing. If losses are encountered take measures to regain full circulation prior to proceeding.

15. Continue running production casing to ¾ TMD and pump bottoms up watching for any loss of returns. Document rate and pressure. If no losses encountered prepare to run additional casing. If losses are encountered take measures to regain full circulation prior to proceeding.
16. Continue running production casing to casing landing depth. Wash down casing as necessary and circulate an excess volume prior to picking up next joint of casing. If several joints need to be washed down to landing depth then pump bottoms up and record final rate and pressure.
17. Make up landing joint if used.
18. Install service company cement head in landing joint. Ensure that a tattle tale is attached to the Latch-in Wiper plug loaded in the cement head. RU service company iron or high pressure hose as needed to circulate with rig pump.
19. Start pumping mud with rig pump and slowly increase rate to verify rate and pressure are similar to final landing rate and pressure. Once rate and pressure look good start reciprocating casing with at least 45' strokes to condition mud and bore hole (Rule of thumb would be to thin the mud to ½ the original viscosity as long as there is no chance of solids falling out of mud while circulating). Attempt to circulate at 8-12 bpm depending on casing size and loss circulation concerns.
20. Circulate NLT 1.5 times the complete hole volume prior to turning well over to cementing company.
21. RU cementing company to casing and start cementing operation.

## Production Casing Cementing Procedure

1. Once TD is reached and the bore hole is being conditioned prior to LDDP, the cementing company must be contacted to obtain NLT 1 gallon of drilling mud from the suction side of the mud tanks. This mud will be used to verify mud weight and rheology for use in Cementing Simulator to design pumping schedule. The mud should also be used to verify compatibility with washes and spacers planned for the cementing operation. All of these results must be documented in cementing Design.
2. Once TD is reached the cement volumes must be calculated by EnCana personnel on location and cementing company engineer. Volumes will be determined from a caliper log if open hole logs are run or calculated from gauge hole plus an excess to be agreed upon between EnCana personnel on location and cementing company engineer. The final volumes must be agreed upon before cement company loads out job.
3. The day prior to planned cementing operation the cementing company must obtain NLT 1 gallon of water from tank to be used for mixing cement. This water will be tested by cementing company for pH and ions such as Cl, Ca, $SO_4$ and any other ion concentration that may adversely affect the properties of the cement slurry and be documented for reference. Cementing company to run field blend thickening time test to determine actual working time of cement slurry. Any difference between field blend thickening time and pilot thickening time must be communicated to EnCana personnel once testing is completed. A 1.5 deg/100 ft temperature gradient will be used for all thickening time tests unless otherwise stated by EnCana engineering personnel.
4. Upon arriving on location the cementing company supervisor/engineer must immediately contact the EnCana company representative to review the cementing design in its entirety and

verify that all necessary equipment and materials are available to execute the Cementing Design. All production casing cementing operations should utilize a process controlled mixer or batch mixer to ensure proper cement slurry density. Any deviation from this plan must be discussed with the EnCana Drilling Superintendent and/or Drilling Engineer. All cement slurry density measurements in the field must be verified with the use of a calibrated pressurized mud balance.

5. Once verification is made that all necessary equipment and materials are present on location the cementing company will spot equipment and begin rigging up to the floor as approved by the EnCana company representative.
6. Fresh water volume requirements must be verified by both EnCana representative and cementing company supervisor/engineer prior to mixing any washes or spacers. There must be no question that there is an excess volume of fresh water on location to complete the Execution of the Cementing Design. Provide a water truck with fresh water if necessary.
7. Any chemical wash and/or weighted spacer must be mixed just prior to turning the well over to the cementing company. Verify designed spacer density with use of pressurized mud balance. Continue to circulate and reciprocate while these pre-flushes are being mixed. We don't want any down time other than what's absolutely necessary to switch from circulating the well with the rig pump to starting to pump with the cementing equipment.
8. Hold safety meeting with all personnel on location while circulating with rig pump just prior to turning well over to cementing company.
9. Turn well over to cementing company to rig up treating iron to cement head. Pressure test lines to appropriate pressure which should exceed any anticipated lift pressure during execution.
10. Once all lines and equipment have been observed to have no leaks commence cementing operation.
11. Pump designed wash at designed rate. Begin to reciprocate casing at same stroke rate used while circulating with rig pump. Note rate and pressure to verify bore hole is still in same condition as previously noted. Stop reciprocating pipe and place near landing position once wash reaches float shoe.
12. Pump designed spacer at designed rate.
13. Pump designed lead cement slurry at designed rate.
14. Pump designed tail cement slurry at designed rate.
15. Shut down to wash pump and lines to rig floor. This must take 5 minutes or less to complete.
16. Drop Latch-in wiper plug and adjust valves on cement head to pump plug out of head.
17. Start displacement at 2-4 bpm and make sure plug leaves cement head as evidenced by tattle tale leaving cement head.
18. Once plug is out of cement head increase pump rate to designed rate. EnCana representative and pump truck operator must be on pump truck from start to finish of displacement to verify displacement volume from displacement tanks.
19. Continue pumping displacement at designed rate while adding appropriate chemical to water (typically a KCl substitute).
20. Slow pump rate to 2.5 bpm within 10 bbl of reaching calculated displacement volume as measured from displacement tanks. Set pressure trip on pump truck to no more than 1000 psi over designed final lift pressure.
21. Slow rate to 1.0 bpm to bump plug. Once plug reaches Latch-in plate continue to pressure up to 750 psi over final lift pressure.

22. In the event the plug does not bump at the calculated displacement volume shut down. Quickly verify proper volume was pumped as per displacement tank volume. If you are confident the volume pumped is correct then pump and additional 2 bbl of displacement. If the plug bumps continue to pressure up to 750 psi over final lift pressure. If the plug does not bump shut down.
23. Once the plug has been bumped to 750 psi over final lift pressure and the pump is shut down. Observe pressure for at least one minute to verify the casing is holding pressure and there is no leak off. If pressure holds steady begin to bleed pressure back to displacement tank slowly. When there is 750 psi remaining on the casing open the bleed line quickly to release all pressure. Watch flow to displacement tank and verify flow stops to indicate floats/latch-in plug is holding.
24. Once we verify the floats/latch-in plug is holding leave all surface valves open and RD cementing company iron. Remove cement head as long as there is no flow from casing.
25. In the event the floats/latch-in plug do not seal leave the cement head shut in for at least 4 hours to allow cement to set. After 4 hours open cement head to check for flow. If there is no steady flow from casing leave cement head open until it is removed from casing.

## Appendix D – COGCC Bradenhead NTO

## NOTICE TO OPERATORS DRILLING WELLS IN THE BUZZARD, MAMM CREEK, AND RULISON FIELDS, GARFIELD COUNTY AND MESA COUNTY

## PROCUDURES AND SUBMITTAL REQUIREMENTS FOR COMPLIANCE WITH COGCC ORDER NOS. 1-107, 139-56, 191-22, AND 369-2

**JULY 8, 2010**

This Notice to Operators (NTO) was developed to promote consistency with bradenhead pressure monitoring and reporting procedures for all wells subject to COGCC Order Nos. 1-107, 139-56, 191-22, and 369-2. The orders were approved by the Commission in 2004, and they established a bradenhead monitoring area (BMA) for Townships 6 through 9 South, Ranges 91 through 93 West, 6th P.M.

The folling summariezes the order requirements for all wells within the BMA:

### Equipment Requirements

- Upon completion of any well, and on wells presently completed, the operator shall equip the bradenhead access to the annulus between the production and surface casing, as well as any intermediate casing, to above ground level with approved fittings to allow safe and convenient determination of pressure and fluid flow.

### Testing Requirements

- Operators shall test all wells for pressure and flow on an annual basis.
- Operators shall notify COGCC staff a minimum of ten (10) days prior to monitoring to allow COGCC staff to witness testing on a random basis.
- The test shall be performed by verifying the tubing and casing pressures and flow characteristics of the well. A pressure gauge with a range of one thousand (1000) psig shall be used to measure the bradenhead (surface and intermediate casing) pressure(s).
- If bradenhead pressures greater than one hundred fifty (150) psig are observed or a continuous flow of liquid and any pressure, such conditions and pressures shall be immediately reported to COGCC staff.

### Reporting Requirements

- The results of the annual bradenhead test for pressure and flow for all wells shall be provided to the COGCC staff on a spreadsheet no later than

November 1 of each calendar year. Remedial requirements and additional subsequent monitoring will be determined by COGCC staff based on the results of the annual tests.

- If bradenhead pressures greater than one hundred fifty (150) psig are observed or a continuous flow of liquid is observed at any pressure, then a Bradenhead Test Report, Form 17 shall be submitted electronically to COGCC staff within seven (7) days of the bradenhead test.

All fittings and valves used for annular pressure monitoring shall remain exposed and not buried to allow for COGCC inspection at all times. A rigid housing may be used to protect the fittings and valves, provided that the housing can be easilly opened or removed.

While the Commission orders only specify annual monitoring, additional monitoring should be performed by the operator at a frequency sufficient to identify significant bradenhead pressure changes if the operator has reason to believe that the bradenhead pressure has the potential to exceed 150 psig. If COGCC staff or an operator has reason to believe, based upon site-specific conditions, that a thresshold pressure lower than 150 psig is appropriate, then the operator should use a lower pressure. Such a decision shall be included in the operator's annual bradenhead test report.

To promote consistency between test measurements over time, the operator shall shut in the bradenhead annulus and, if present, the intermediate casing-production casing annulus for a period of seven (7) days prior to performing pressure tests. Operators should not allow bradenhead pressure to build above 150 psig. If bradenhead pressure builds above 150 psig prior to the end of the seven (7) day shut in period, then the operator shall bleed off the bradenhead pressure and record the shut in duration prior to the bleed off.

**Mitigation and Remediation**

Bradenhead pressure mitigation or remediation will be required for all wells with bradenhead pressures that exceed 150 psig. Venting and continued monitoring will typically be required as an initial mitigation step by COGCC staff, unless high pressures, high flow rates, or significant fluid (water or mud) volumes are observed during monitoring. If these considtions are observed, then remediation will be considered. Any liquids that are blown down from the bradenhead are considered exploration and production waste and must be handled in accordance with COGGCC's 900-Series rules.

Venting requests will be considered by COGCC staff, at the operator's discretion, for wells that have bradenhead pressures less than or equal to 150 psig. Keeping bradenhead valves open "full time" is considered venting by COGCC staff.

Rule 912.b. requires prior approval on a Form 4 (Sundry Notice) to vent bradenhead gas. However, operators should not allow bradenhead pressure to build above 150 psig. COGCCC staff wil grant verbal approval to vent while an operator is preparing the Form 4 if expedited approval is necessary. Only one Form 4 vent request is required per well. Subsequently, venting status should be reqported for all venting wells on the operator's annual spreadsheet reqport. COGCC staff encourages the use of combustors if the vented gas flow rate and thermal content warrant their use without requiring excessive supply gas to keep the combustors lit. The operator is responsible for obtaining any air permits that may be required by the Colorado Department of Public Health and Environment.

When cement remdiation is required, COGCC staff will grant approval to vent as necessary to mitigate pressure buildup until remediation is performed (generally a 30-day period to provide the operator sufficient time to develop and implement a remediation procedure). Remedial cement procedures must be approved on a From 4 prior to performing any remedial work. Remedial cement procedures must be designed to eliminate or significantly decrease bradenhead pressure.

COGCC Contacts

Please see COGCC's "CONTACTS" seciton of our webpage for current contact information. Key contacts for this NTO are David Andrews (West Region Engineering Supervisor) and Shaun Kellerby (Northwest Region Field Inspection Supervisor).

Annual reports, Form 17's, Form 4's, and any other requirests for approval or reports of significant problems should be submitted to the West Region Engineering Supervisor, or his local staff, at the discretion of the supervisor.

Bradenhead montioring test ten (10) day notices should be submitted to the Northwest Region Field Inspection Supervisor, or his local staff, at the discretion of the supervisor.

Signed,

David Neslin
Director

## SURFACE CASING PRESSURES
### OIL/GAS COMPANY NAME

| API# | Well Name | Casing | Date | Initial pressure | Comments | Fluid type | Final Pressure | Casing Depth | Top of Cement | Initial Gradient at Shoe | Action Required |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 045-07898 | BENDO 36-12A | surface | 02/29/2004 | 150 | blew down within 1 minute | gas | 0 | 708 | 0 | 0.21 | no |
| 045-07898 | BENDO 36-12A | intermediate | 02/29/2004 | 500 | would not blow down completely | gas & mud | 150 | 1809 | 0 | 0.28 | no |
| 045-06678 | HERRY 36-13A | surface | 10/10/2004 | 350 | blew down within 5 minutes | gas | 0 | 887 | 2500 | 0.39 | no |
| 045-09989 | ELK HEAD 17-14 | surface | 10/10/2004 | 180 | blew down within 2 minutes | water | 0 | 765 | 1500 | 0.24 | no |
| 045-04567 | SMITH 36-7C | surface | 10/10/2004 | 450 | would not blow down completely | gas | 100 | 809 | 0 | 0.56 | Fms. 4 & 17 |
| 045-01234 | SMITH #2 | surface | 10/10/2004 | 280 | blew down, 150 psi after 8 hrs | gas | 150 | 1211 | 500 | 0.23 | no |
| 077-06777 | FROG 36-6A | surface | 10/10/2004 | 306 | blew down, 200 psi after 8 hrs | gas | 200 | 667 | 780 | 0.45 | no |

01127408

08/25/2004

Example spreadsheet format from COGCC hearing files for Order Nos. 1-107, 139-56, 191-22, and 369-2.

To assist with reporting requirements shown in the Notice to Operators Drilling Wells in the Buzzard, Mamm Creek, and Rulison Fields, Garfield County and Mesa County, COGCC staff recommends adding the following data fields to this spreadsheet:

- Request to Vent approved on Sundry Notice? (Y/N)
- Current venting status

The spreadsheet must be completed annually with information for all wells located within Townships 6 through 9 South, Ranges 91 through 93 West, 6th P.M. The spreadsheet shall be submitted to COGCC Rifle office engineering staff no later than November 1 of each calendar year.

## Appendix E – Encana – Moon Property Presentation to COGCC


### P3 Pad activity 2003 – 2006

- Completions Activity
  - Arbaney 3-16C completed June 2003
  - Arbaney 3-15C, Magic 10-1, Magic 10-1A, Magic 10-2 completed June/July 2006
- Remedial Cementing Activity
  - Procedures approved by COGCC (Jaime Adkins), 2004
  - Arbaney 3-16C, Arbaney 3-15C, Magic 10-1, and Magic 10-2 had elevated bradenhead pressure readings, all remediated Nov/Dec 2004
    - Arbaney 3-15C, Magic 10-1, and Magic 10-2 were remediated prior to completion, and a 3 ½" liner was run to surface and cemented to protect squeeze holes
  - Magic 10-1A, no bradenhead pressure, no remediation required

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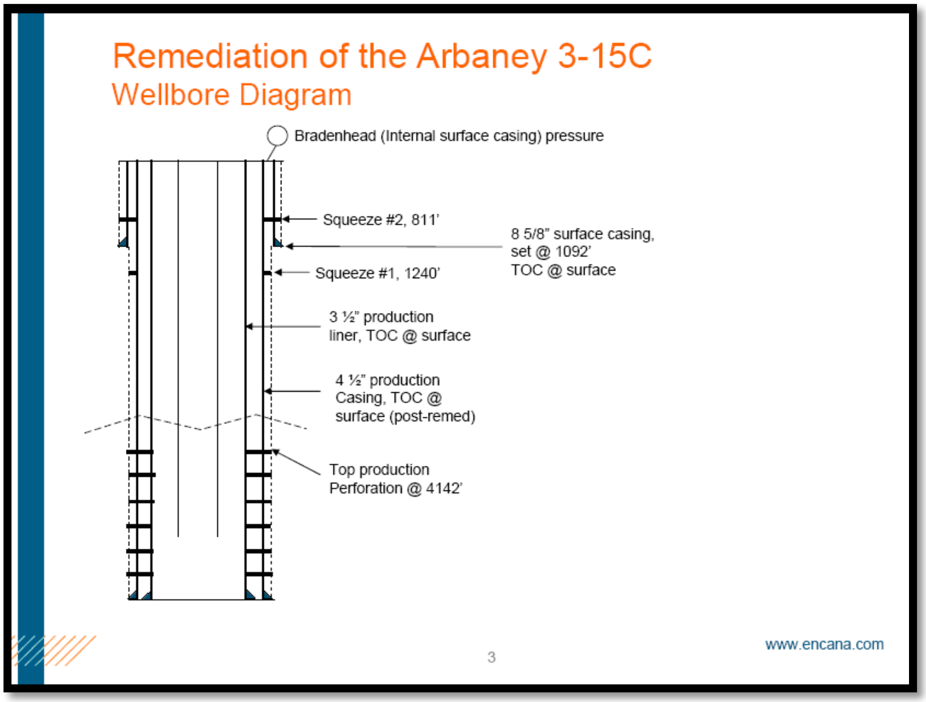
Remediation of the Arbaney 3-15C
Wellbore Diagram
Bradenhead (Internal surface casing) pressure
Squeeze #2, 811'
8 5/8" surface casing, set @ 1092' TOC @ surface
Squeeze #1, 1240'
3 ½" production liner, TOC @ surface
4 ½" production Casing, TOC @ surface (post-remed)
Top production Perforation @ 4142'
3
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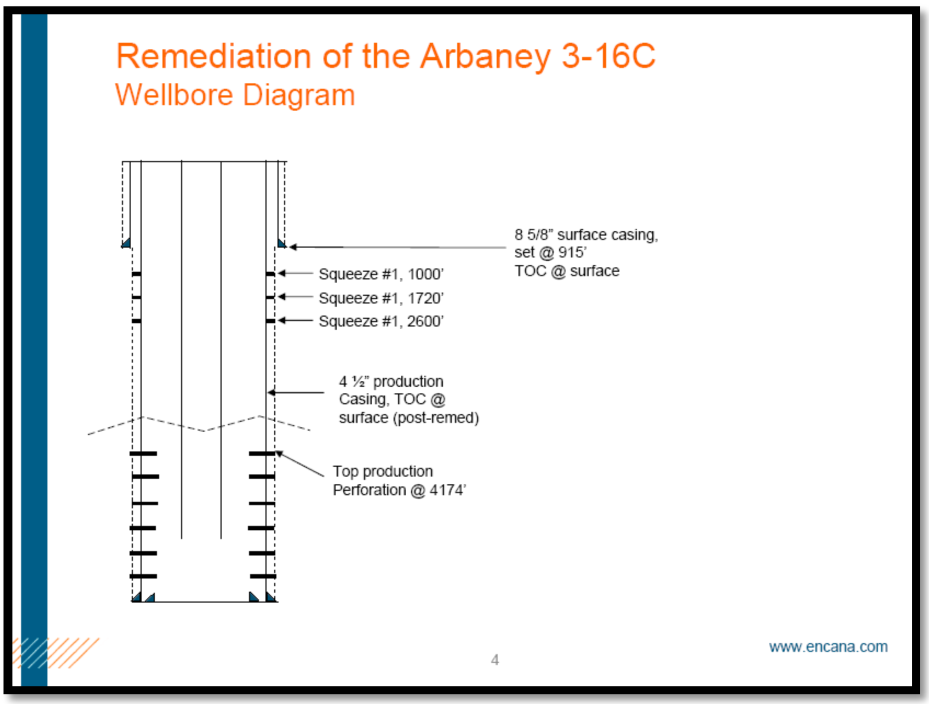
Remediation of the Arbaney 3-16C
Wellbore Diagram
8 5/8" surface casing, set @ 915' TOC @ surface
Squeeze #1, 1000'
Squeeze #1, 1720'
Squeeze #1, 2600'
4 ½" production Casing, TOC @ surface (post-remed)
Top production Perforation @ 4174'
4
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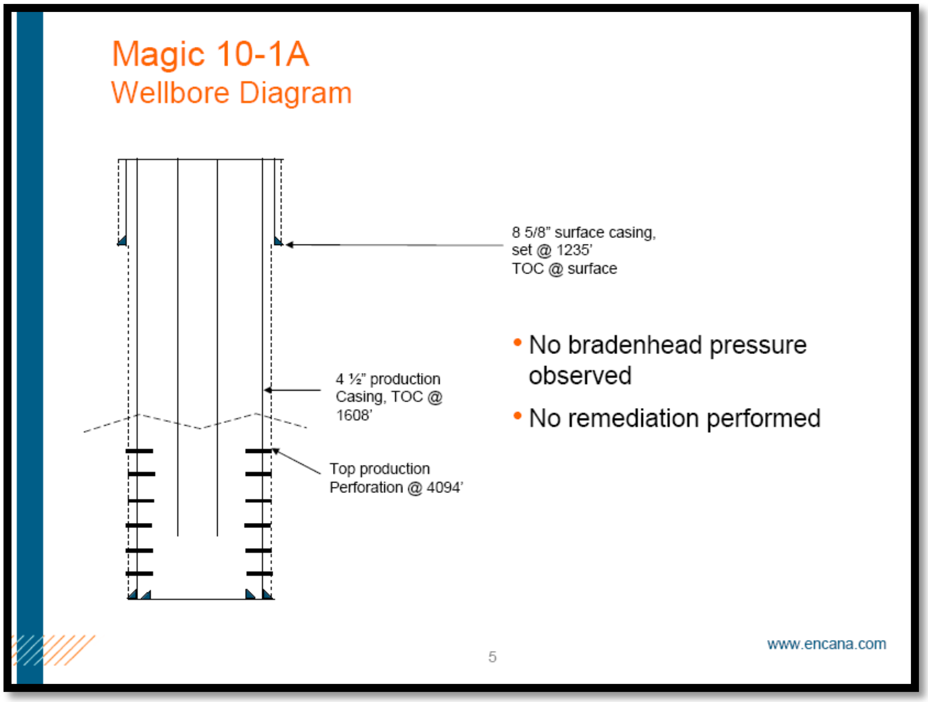
Magic 10-1A
Wellbore Diagram
8 5/8" surface casing, set @ 1235' TOC @ surface
4 ½" production Casing, TOC @ 1608'
Top production Perforation @ 4094'
• No bradenhead pressure observed
• No remediation performed
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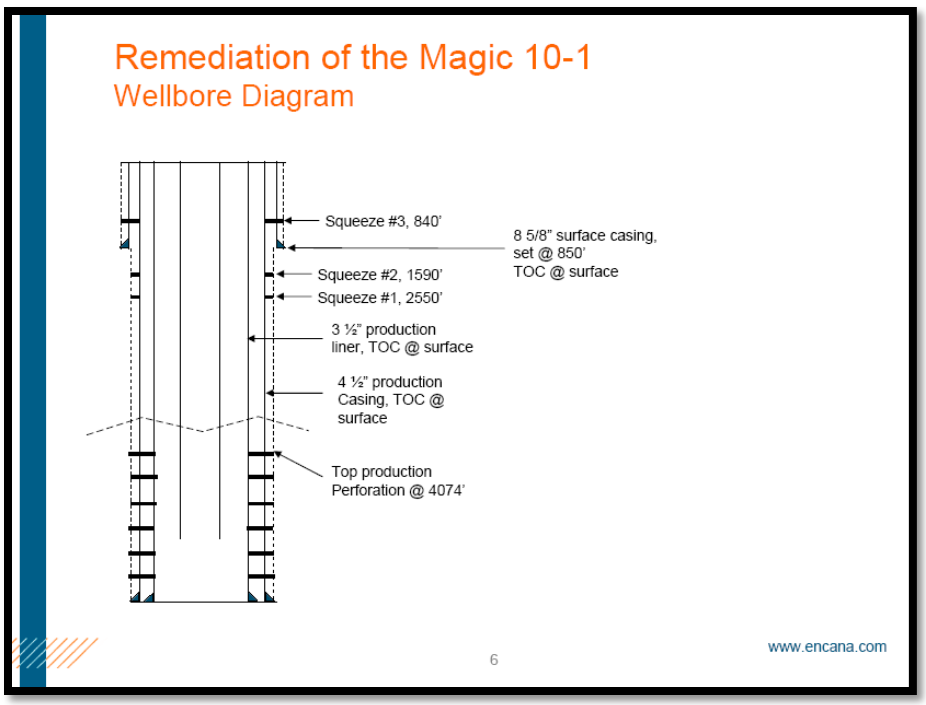
Remediation of the Magic 10-1
Wellbore Diagram
Squeeze #3, 840'
8 5/8" surface casing, set @ 850' TOC @ surface
Squeeze #2, 1590'
Squeeze #1, 2550'
3 ½" production liner, TOC @ surface
4 ½" production Casing, TOC @ surface
Top production Perforation @ 4074'
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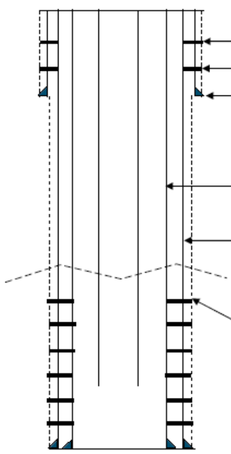
## Remediation of the Magic 10-2

### Wellbore Diagram

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## Remedial Actions from 2004 Event

### Drilling and Completion Moratorium

- The COGCC and Encana staff worked through the moratorium period to address the issues related to this area and developed operational process changes
  - FIT Testing, set intermediate, if needed
  - Primary cement now brought up to 500' above first gas show, not commercial top of gas
  - CBL run immediately after primary cement job
  - Pressure monitoring
- Since that time, there have been no significant issues with new wells
  - Monitoring and process improvements have allowed us to quickly detect and address potential issues

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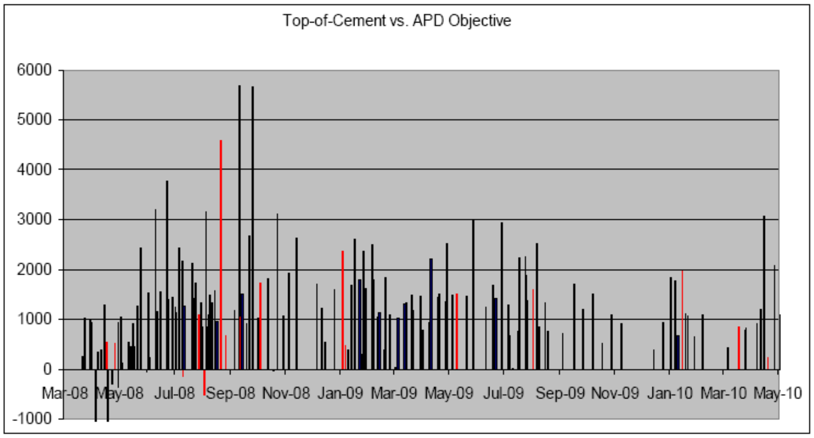
## Top of Cement vs. APD Objective

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## P3 Pad Activity 2007 – 2010

- No major operational activity on pad
  - Workovers on the Arbaney 3-16C, Magic 10-1, Magic 10-1A, and Magic 10-2 in 2008 and 2009
- Bradenhead pressure monitoring
  - Arbaney 3-16C built to 165 psi April 2008, request permission to vent from COGCC (granted 2008, currently on continuous vent)
  - Arbaney 3-15C gradually built from 70 psi Feb 2008 to 120 psi May 2010, requested permission to vent June 2010 (granted)
  - Magic 10- 2 built to 10 psi June 2009
  - Magic 10-1 was 0 psi until it had a 140 psi increase once in Feb 2010, and has dropped back to 0 psi since that time
  - Magic 10-1A has always been 0 psi

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## Bradenhead Pressure Requirements

- COGCC Engineering staff and Industry agreed on reporting of bradenhead levels of 150 psi and greater
  - Selected based on pressure gradient of 0.35psi/ft at an average surface casing shoe plus safety factor of 50% (conservative)
  - All bradenhead pressure above this level must be reported to the COGCC
  - Typically, a low pressure bradenhead will be vented/flared as per best practice guidelines
  - Consistent with other regulatory agencies
- 100% of wells have manual bradenhead pressure readings taken each month
  - All Encana operated wells in Mamm Creek, South Parachute, Rulison, Orchard and Plateau fields
  - An annual report for all wells is submitted to the COGCC
- 70% of wells have automated bradenhead pressure
  - Monitored by lease operators

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## Bradenhead Pressure Remediation Best Practice Guidelines

- Wellhead is tested to insure there is no leak occurring at surface
- Venting/flaring is preferred method for low bradenhead pressures
  - Some agencies do not allow bradenhead pressure to be shut in
  - Some other agencies have requested adding barite (mud weight) to the bradenhead side fluid column, if feasible
- Cement remediation to alleviate bradenhead pressure only if…
  - Pressure is at an unsafe level (has capability of breaking down the surface shoe), or
  - The bradenhead is flowing fluid, or
  - The shallow gas source is obvious and above TOC
- Pitfalls of cement remediation
  - Open holes in casing can become pathways of gas migration
  - Not always permanently effective in eliminating bradenhead pressure
    - Secondary cementing rarely as effective as primary due to diminished ability to remove desiccated mud, etc.
    - If microannuli form over time, they are extremely difficult to remediate

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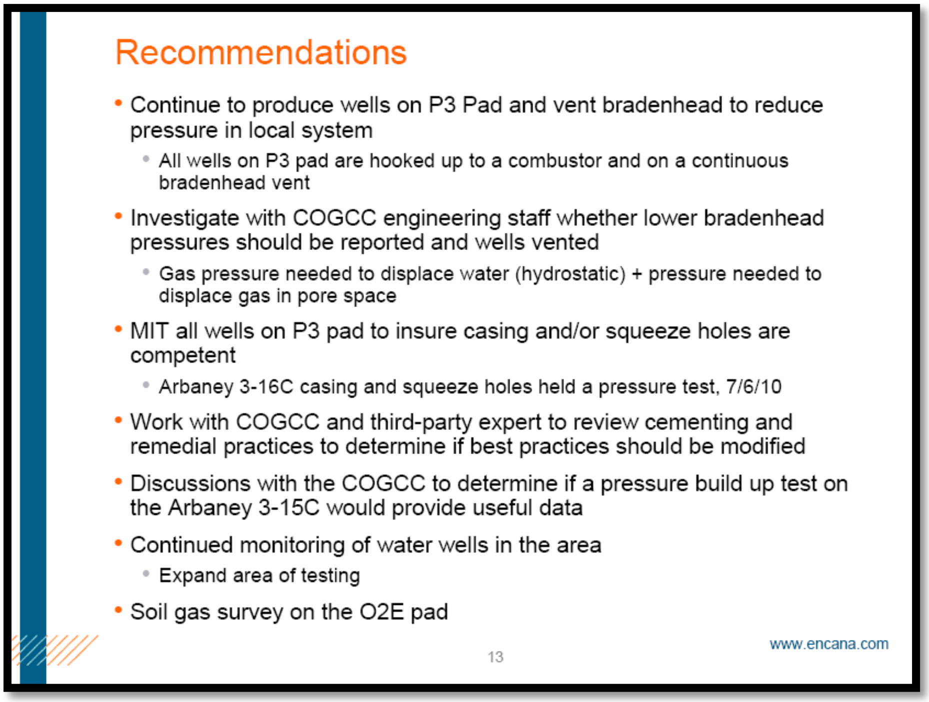
Recommendations
Continue to produce wells on P3 Pad and vent bradenhead to reduce pressure in local system
All wells on P3 pad are hooked up to a combustor and on a continuous bradenhead vent
Investigate with COGCC engineering staff whether lower bradenhead pressures should be reported and wells vented
Gas pressure needed to displace water (hydrostatic) + pressure needed to displace gas in pore space
MIT all wells on P3 pad to insure casing and/or squeeze holes are competent
Arbaney 3-16C casing and squeeze holes held a pressure test, 7/6/10
Work with COGCC and third-party expert to review cementing and remedial practices to determine if best practices should be modified
Discussions with the COGCC to determine if a pressure build up test on the Arbaney 3-15C would provide useful data
Continued monitoring of water wells in the area
Expand area of testing
Soil gas survey on the O2E pad
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# Appendix F – Well Logging Tool Technology

## Evaluatory Tools and Technology

### Acoustic Cement Bond Logging

Multiple companies offer standard Acoustic Cement Bond Logging (ACBL, or "CBL" as used in this report). The basics behind ACBL are quite complex. To simplify the process, a sonic wave is initiated in the wellbore. This wave travels through the wellbore fluid, encounters the casing and the material behind the casing, and is then "heard" by two receivers at different distances from the transmitter. The time of the return and the response of the waveform are different depending on the material behind the casing. ACBL amplitude and waveform responses represent average bonding around the entire circumference of the casing. ACBL technology is not suitable for evaluation of ultralight weight or foam slurries.

Baker Atlas's Segmented Bond Tool (SBT), for example, uses an array of acoustic transmitters and receivers to allow independent views as 60 degree segments of the bore hole. The tool has advantages in deviated holes, as eccentricity does not impact results.

### Ultrasonic Logging

Both Schlumberger and Halliburton offer UltraSonic Circumferential Imaging (USI) tools for sheath evaluation. These are technologies that evolved from fracture identification technology in open hole environments. These tools are sensitive in deviated environments as centralization of the tools is critical. Though the tools are essentially interchangeable, the key differences are in the interpretation and processing of the data. Both of these technologies allow for detailed evaluation of the cement sheath. These tools are better for evaluation of foamed cement and are preferred when evaluating low strength materials. In addition to the USI tool, Schlumberger provides a flexural measurement (Isolation Scanner) used in conjunction with USI data and processing to give amore clear sheath picture. This is the newest of the technology in the sheath evaluation world. Encana has performed a number of these processes in areas outside the EMCPA area.

Ultrasonic technology is the recommended methodology to evaluate ultralight weight or foam cement slurries.

### Triple Combo Definition and Explanation - Supplied by Schlumberger

The triple combo log provides basic evaluation for lithology, petrophysics, fluid identification, and borehole rugosity. The measurements associated with a triple combo log include spontaneous potential, gamma ray, neutron porosity, density porosity, photoelectric factor, resistivity, and caliper. Spontaneous potential (SP) results from electric currents flowing in the borehole fluid and in formations around the borehole. The measurement corresponds to a difference in salinity between the mud filtrate and formation water. SP is used to indicate pay quality (shaliness), formation permeability, and to help calculate formation water saturation.

In sedimentary formations, the gamma ray (GR) log reflects the clay or shale content. Naturally occurring radioactive elements tend to concentrate in clays or shales. Clean formations, such as sandstone or limestone, usually have a very low level of naturally occurring radioactivity corresponding to a low GR value.

To measure neutron porosity - a radioactive source is used to send neutrons into the formation which are detected by near and far detectors on the logging tool a few inches away. The number of neutrons detected is used to interpret the neutron porosity of the formation. When the pore space contains gas, the neutron counts at the detectors are higher (and the measured porosity lower). This is referred to as the gas effect because gas contributes far less hydrogen for the scattering of neutrons than does water or oil. It is important to remember that neutrons will be affected by the hydrogen in both the formation fluids and the formation, even though hydrogen is more commonly found in the fluids. The situation where hydrogen is lacking in the down hole environment (i.e. a gas zone) is seen in many wells, but is truly a special case when compared to all the zones encountered in an entire well.

To measure formation density - a second radioactive source is used which sends gamma rays at a certain energy level into the formation and measures their interactions.

It is known that gamma rays lose energy when they collide with electrons. From this, you can induce that the more electrons there are in the formation, the more likely gamma rays lose energy. After a few interactions, the gamma rays lose enough energy to be absorbed by photoelectric effect. By measuring the number of gamma rays that return to the tool and their corresponding energy levels at a given distance from the gamma ray source, the electron density of the formation can be predicted along with the formation photoelectric factor (PEF). Different materials in the formation have different corresponding PEF values and matrix densities. The density log helps identify sandstones, limestones, dolomites, fresh water, salt water, etc.

Formation resistivity is measured by inducing a current in the formation with electromagnetism and measuring the associated conductivity of the formation. The electromagnetic coils are positioned in the tool to measure resistivity at different depths of investigation (typically 0 to 90 inches) as well as at different vertical resolutions (typically 1, 2, and 4 feet). The corresponding measurements help build an invasion profile and to determine true formation resistivity. Some triple combo tools also include a shallow resistivity measurement called a micro-log which is used determine resistivity in the near-wellbore region where mud cake is typically present.

The caliper log is a continuous measure of the actual borehole diameter used to know the condition of the well where the other tools are being run and to calculate the volume of cement needed behind the casing. A typical triple combo log provides and 2 arm caliper reading in the elongated axis of the borehole.

## Appendix G – Cementing Best Practices

**General Cementing Best Practices:**

Successful cementing processes depend on many variables. The following section outlines actions that can have significant bearing on the outcome. The areas of action and the limits come from a variety of sources including Halliburton Energy Services, Schlumberger Well Services, and BJ Services (now Baker Hughes) documents, the Society of Petroleum Engineers Cementing Monograph, as well as the Oxy Oil and Gas Global Best Practices. There are numerous documents and studies that have ultimately led to better cementing and although the numerical limits might vary slightly, they all point to a similar thought process.

The basic premise of oilfield cementing is built around removal of the mud system from the wellbore and the replacement of that mud with cement. The ideas behind optimization of the mud removal are limited by the realities of the drilled hole and the mud system itself. The key points discussed are mud conditioning, pipe movement, centralization, displacement rate, float equipment and cement slurry design.

**Mud conditioning:**

Mud conditioning is important in that the best mud conditions for cuttings removal are not the same as the best conditions for mud displacement. Mud conditioning parameters prior to cementing include controlling fluid loss to about 10cc / 30minutes. Generally, thinning the viscosity profile of the mud and encouraging a flat gellation profile will help mud stay mobile and encourage advantageous displacement efficiencies. Once the mud is conditioned, circulation of the hole is recommended. A minimum of 1 hole volume is required with many sources recommending up to 2 ½ times the hole volume. The rate of the circulation activities should be matched to the designed rate of the cement placement procedure. In general, maximizing the rate of the circulating and cementing processes, lead to better mud removal and therefore better cementing performance. Breaking circulation periodically while running casing, will help to prevent excess gellation of the mud system. Cementing equipment should be rigged up to minimize the downtime between the end of circulation and the start of the cementing process.

**Centralization:**

Centralization of the casing string in the hole is critical to mud removal. Centralization is measured by a percentage as illustrated in the figure below. Perfectly centralized casing has a standoff of 100%. In this condition there is no path of least resistance and therefore the fluid will tend to displace the entire annular space. When the casing is not centered in the hole the tendency is for the displacing fluid to preferentially flow to the larger side of the hole leaving mud behind. The lack of centralization is magnified in deviated holes. The weight of the casing, mud properties, deviation of the hole and the centralizers selected are the key components to the ultimate centralization of the casing. All major cementing service suppliers have access to centralization software. The various software programs take the dynamic effects of pipe weight and bending, fluid buoyancy, and the restoring force of the centralizers in calculating the centralization of the pipe in the hole.

**Pipe movement:**

Pipe movement is another positive component toward enhancing displacement efficiency. Most studies have found that reciprocation (up and down movement) or rotation (turning) of the pipe is equally effective in improving the displacement efficiency. The two methods are sometimes used in combination though the data indicates there is not a great deal gained in doing so. Reciprocation is operationally much simpler and is therefore employed more often. Most authorities recommend a 20-30 foot stroke over the course of 1 minute. The risk is that the pipe is pulled up and then cannot be lowered back into the hole. This author believes any movement is beneficial (e.g., if 6 foot of movement is the hole loss an operator is willing to risk, then a 6 foot stroke should be used). Rotation is effective, but often requires specialized equipment, in the form of a rotating head, to accomplish the task. There is no risk of lost depth with this methodology. The recommended rate of rotation is 15-30 rpm while cementing. Care should be taken to not exceed the torque ratings of the pipe being rotated.

**Displacement:**

Displacement rates should be determined based on computer simulation. As stated above, higher rates generally lead to better displacement efficiencies. Spacer fluids provide for separation of incompatible fluid systems. Water based mud and cement slurries are incompatible. When mixed these systems “clabber up” leaving a product reminiscent of cottage cheese. The combination is viscous and therefore hard to move and does not build acceptable compressive strength to support casing or provide isolation. Increased annular velocity provides energy to displace the wellbore fluid. Laboratory study has indicated the displacement efficiency increases if “turbulent” flow regime is achieved. Cement slurries normally require high rates to achieve turbulence; spacers however, are usually less viscous and can be moved into turbulence at much lower annular velocities. The spacer can be used to “scour” the wellbore, removing mud filter cake to allow cement to bond directly to the borehole wall. Ideally the spacer should have a density of ½ ppg greater than the mud weight and ½ ppg less than the cement slurry density. Spacer systems must leave pipe and wellbore in a water wet condition. Most best practices documents recommend 10 minutes of annular contact time, though in this authors experience this is rarely attempted because the volumes can be substantial and cost-prohibitive.

Use of a “two plug” methodology is highly recommended. The bottom plug is released ahead of the spacer to wipe the mud off of the casing wall. This provides additional control to prevent mud and cement from mixing, and subsequent contamination of the lead edge of the cement. The top plug is released just prior to pumping displacement. This plug serves three purposes. First it separates the tail slurry from the displacement fluid; secondly it wipes the cement from the casing wall and lastly, provides indication when displacement is complete, when it "lands" at the float collar.

**Float equipment:**

Float equipment should always be used. These valve systems are integral with the casing string. A float shoe provides a one way valve that prevents cement from reentering the casing string when the job is complete. There are a variety of nose configurations, but the intent is to guide the casing into the hole. The float collar usually has a similar valve configuration placed one to three casing joints above the float shoe. The number of joints between the two valves is called the shoe tract or shoe joint(s). These joints can collect contaminated cement that would otherwise be displaced into the annular space at the shoe. Contaminated cement is particularly undesirable when subsequent drilling operations are performed or it is critical to isolate intervals at the very bottom of the hole (surface or intermediate strings). Float equipment comes in a wide variety of designs and should be customized to the particular requirements of individual wellbores. The float equipment can help to "float" heavy casing strings into the wellbore. It is recommended to circulate the hole regularly when running casing. Surge calculations should also be performed to insure the casing is run at a rate to prevent breaking down the hole.

## Cement Slurry Design

**Definitions**

Placement time is the length of time from the start of the mixing of the cement until the cement is placed.

Thickening time is the elapsed time from the point that the cement is mixed until it is to viscous to pump. This is a laboratory derived measurement in which the viscosity is measured in Bearden Consistency Units (BC). Different service organizations use 50-70 BC to identify slurry that is no longer a "pumpable" fluid.

Transition time is the period of time from which the slurry can be pumped until the point which there is sufficient gel strength to prevent gas flow. This can be measured in two ways, dynamically and statically. When using a High Pressure, High Temperature Consistometer the time from 40BC to 100BC readings defines the dynamic transition time. A Static Gel Analyzer (SGA) provides the static data. This apparatus measures the gel properties of slurry in a static condition. Initial gel is noted when the SGA registers 100 lbf/100 sqft, final gel strength of 500 lbf/100 sqft marks the end of the test. The time period between the two events is the transition time. This represents the time in which the cement column is most susceptible to gas influx. Industry scientists have demonstrated that gas will not migrate through materials with 500 lbf/100 sqft gel strength. A common term in the industry regarding this subject is "right angle set". This represents a slurry composition that has a very short transition time.

Compressive Strength is the measure of a material's strength upon reaching a "solid" state. This can be measured destructively by crushing a cube of set cement or non-destructively using an ultrasonic cement analyzer and is measured in force/unit area.

Fluid Loss is the measure of the amount of filtrate that can be "squeezed" out of the slurry across a 325 mesh filter media at 1000 psi differential for 30 minutes. The test is performed with the slurry at bottom hole circulating temperature. This simulates a slurry under pressure across a porous media.

Free water is the amount of clear fluid that separates from a slurry in a static condition due to gravity over 2 hours of observation. This test goes hand in hand with observing settling tendencies. In deviated wells free water and settling can have serious repercussions.

There are a number of additional parameters involved in slurry design but in most cases the items listed above will be the keys to successful slurry performance.

## Appendix H – Gas Flow Potential Paper, Crook & Heathman

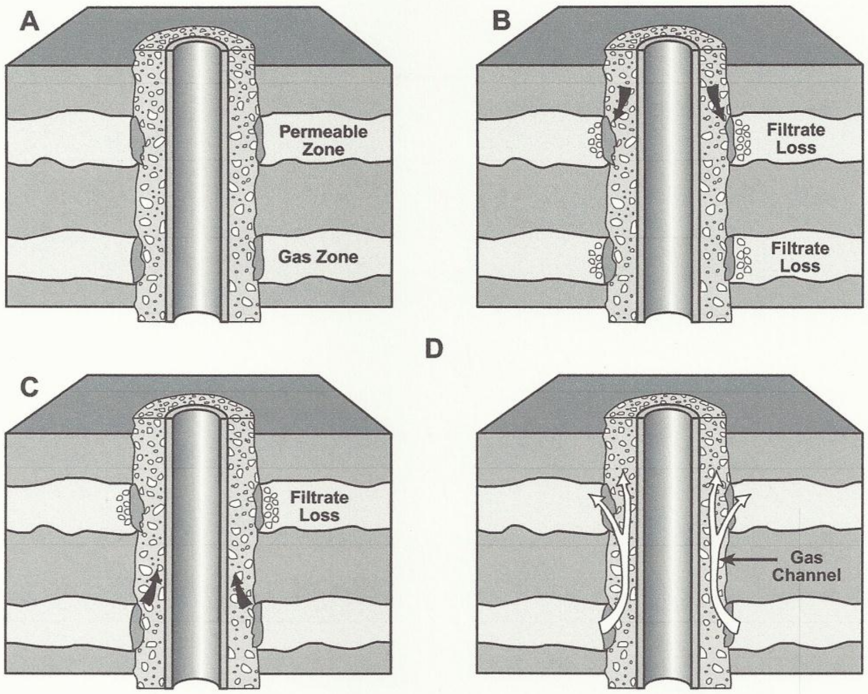


Figure 1: Gas channel migration: Gas migration creates permanent channels in cement columns, decreasing cement strength and contributing to continuing gas-flow problems. The most widely accepted explanation for short-term migration is the cement column's inability to maintain overbalance pressure. This pressure loss depnds on the cement's development of static gel stength, transition time and hydration volume reduction. There are 2 suspected causes of long-term migration: inadequate drilling fluid displacement and cement debonding. Inadequately displaced drilling fluid can prevent good bond formation between the pipe and cement and/or the cement and the formation. Incomplete displacement or excessive filter-cake buildup can create drilling fluid channels in the cement. Over time, gas flow causes the drilling fluid and cake to dehydrate and shrink, resulting in a highly permeable pathway for gas.

# Predicting potential gas-flow rates to help determine the best cementing practices

**Ron Crook and James Heathman, Halliburton Energy Services Inc**

**GAS MIGRATION CREATES** permanent channels in cement columns, decreasing cement strength and contributing to continued gas-flow problems. However, operators can accurately predict the potential of their wells to be troubled by gas flow. Based on the severity of the gas flow problems expected, the operator can avoid remedial squeeze jobs by determining the most effective cementing strategy for the situation.

"Annular gas flow", "gas migration", and "gas leakage" are all terms that refer to formation gas that enters a cemented casing/borehole annulus, creating permanent channels and weakening cement compressive strength. There are two major types of gas migration: short-term and long-term. Short-term gas migration occurs before the cement sets, and long-term gas migration develops after the cement has set. **Sutton, Sabins** and **Faul**[1,2] published definitive work in 1984 presenting (1) annular gas-flow theory and evaluation for annular gas-flow potential, and (2) tracing the evolution of gas-flow theory and preventive practices.

## CAUSES OF SHORT-TERM MIGRATION

The most widely accepted cause of short-term gas migration is the cement column's inability to maintain overbalance pressure. This pressure loss depends on 3 factors: the cement's development of static gel strength (SGS), transition time, and hydration volume reduction.

Static Gel Strength. In a true fluid system, hydrostatic pressure is present. After the cement slurry is placed downhole, it initially acts as a fluid and exerts hydrostatic pressure on the gas-bearing formation. This overbalance pressure helps prevent

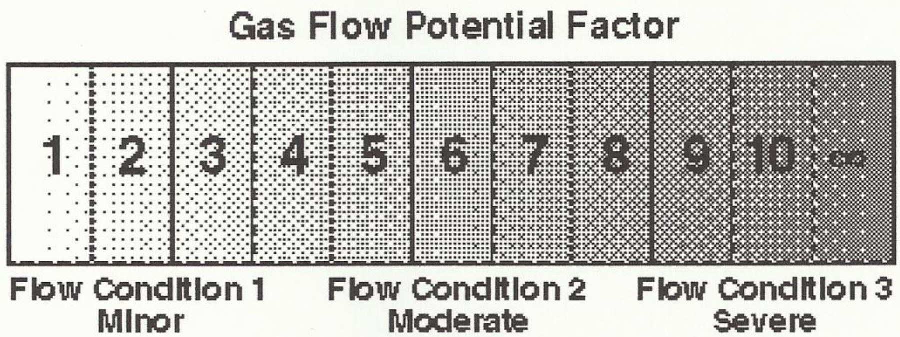


Figure 2: The gas-flow potential factor (GFP) is the estimated amount of gas flow that can be expected from a formation. Operators can use this factor to help determine the most effective cementing system for controlling gas migration. The system should produce effective control at the least expense without producing technological "overkill". The GFP is proportional to the product of the maximum pressure loss and the overbalance pressure.

gas from percolating up through the cement slurry. However, the cement slurry eventually begins to develop static gel strength (SGS) as it sets. Gelation causes the slurry to adhere to the casing and the formation, allowing it to support its own weight. This process reduces the capability of the cement column to transmit hydrostatic pressure and allows gas to enter the annulus and percolate through the gelled cement (Figure 1). Once the gas begins to migrate, it will continue to percolate at a rate proportional to the volume reductions occurring in the slurry until the cement has developed enough gel strength to prevent further percolation. Once a flow channel develops, there is no level of gel strength that can cause the channel to heal; the channel is permanent and can be removed only by remedial (squeeze) cementing.

A cement column's loss of the capability to transmit hydrostatic pressure is directly proportional to its level of static gel strength (SGS) development. The length and diameter of the cement column also affect hydrostatic pressure loss. The relationship between expected maximum pressure restriction and SGS development can be expressed by the following equation:

$$MPR = SGS/300 \times L/D$$

Where
MPR = Theoretical maximum pressure restriction, psi
SGS = Static gel strength, lb/100 sq ft
300 = Conversion factor (to obtain MPR in psi), lb/in.
L = length of the cement column, ft
D = effective diameter of the cement column, in. (hole diameter minus pipe diameter)

In this case, MPR is a change in hydrostatic pressure that results from the development of static gel strength.

The development of static gel strength is not completely detrimental. A certain level of SGS can prevent gas from percolating through the unset cement matrix. The exact SGS level is unknown; however, laboratory and field results show that a 500 lb/100 ft2 SGS can prevent gas from percolating or channeling through unset cement. If the hydrostatic pressure falls below the formation pressure before this SGS develops, gas will usually begin to percolate through the cement matrix, forming a permanent channel.

Transition Time. Transition time is the time interval between the development of the first measurable SGS and the point at which the cement slurry is so rigid that a new gas channel cannot form. Cement slurries undergo a phase transformation from liquid to solid after placement. During this transformation, the cement behaves neither as a solid nor as a fluid, but it retains some of the properties of each. In this stage, the SGS of the cement slurry steadily increases as a result of hydration. The first measurable SGS development occurs as the slurry starts the transition from a true hydraulic fluid, capable of transmitting full hydraulic loads, to a solid having compressive strength. The point at which the slurry loses the capability to fully transmit hydrostatic pressure is referred to as the "start of transition time." Throughout the rest of the transition time, the slurry will continue to gain SGS.

Cement Slurry Volume Reductions. Reduced cement-slurry volume also reduces hydrostatic pressure. Hydrostatic pressure remains constant in a true fluid system where no fluid loss occurs. However, cement slurries do not behave as true fluids; instead, they develop SGS before setting, preventing full transmission of hydrostatic pressure. Any fluid loss from the fluid system during the transitional period causes a corresponding loss in hydrostatic pressure. This pressure loss can be substantial enough to cause complete loss of overbalance pressure. Fluid loss additives limit the rate and volume of fluid loss from the cement slurry, thereby limiting the hydrostatic pressure losses caused by slurry volume reductions.

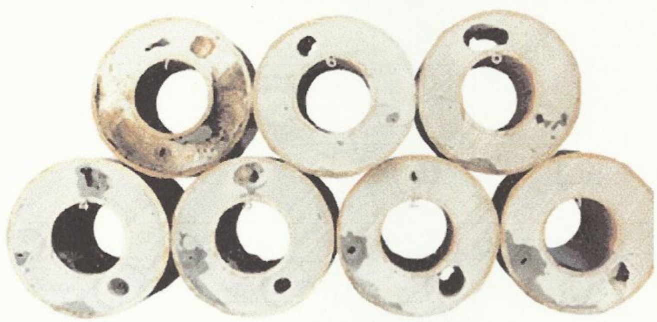

**Figure 3: Test cores of cement subjected to gas flow of 6 liter/min before the slurry achieved adequate gel strength. Controling gas flow depends on the severity of the problem. For small gas-flow potentials, fluid-loss control may be sufficient. For moderate GFPs, exceptional fluid-loss control techniques are called for. In severe cases, especially high-temperature wells, fluid-loss control additives, job modifications and delayed gelling agents alone are not enough. Highly compressible cements are needed in these situations.**

## LONG-TERM GAS MIGRATION

Long-term or "delayed-onset" gas migration occurs some time after the cement job has been performed and is considered successful. As with short-term gas migration, once gas flow channels have set in the cement, they can only be removed by remedial squeeze cementing.

Long–term gas migration is generally indicated by flow at the surface through the annulus. Sometimes this becomes apparent as early as a few weeks after the cement job has been performed. Flow volumes are slight-to-moderate and become more severe over time.

Causes of Long-Term Gas Migration. There are two suspected causes of long-term gas migration: inadequate drilling fluid displacement and cement debonding. Inadequately displaced drilling fluid can prevent a good bond from forming between the pipe and the cement and/or the cement and the formation. Incomplete displacement or excessive filter-cake buildup can create drilling fluid channels in the cement. As time passes, gas flow causes the drilling fluid and cake to dehydrate and shrink, resulting in a highly permeable pathway for gas migration.

Long-term gas migration can also occur when set cement separates from the casing. One reason for this loss of bond is that the casing diameter changes during workovers or stimulation treatments. The resulting long-term gas migration occurs through a discontinuity in the cement sheath, either through micro-flow channels in the drilling fluid or through microannuli between the pipe and the cement or between the formation and the cement.

When gas is flowing through drilling fluid channels and filter cake, the flow volume can usually be expected to increase as the drilling fluid dehydrates and shrinks. Cement also naturally undergoes a minor volume reduction during the setting process. The magnitude of this volume reduction increases further when fluid is lost from the cement slurry. For these reasons, fluid-loss values should be set at low but realistic levels to help prevent excessive volume reductions. Operators should also pay close attention to obtaining the highest drilling fluid displacement efficiency possible.

## GAS-FLOW POTENTIAL

The gas-flow potential factor (GFP) is the estimated amount of gas flow that can be expected from a formation (Figure 2). Operators can use this factor to help determine the most effective cementing system for controlling gas migration. The system should produce effective control at the least expense to the customer without producing technological "overkill." The following equation can be used to determine the gas-flow potential factor:

$$GFP = MPR / OBP$$

Where

GFP = Gas-flow potential factor

MPR = 1.67 LD (maximum pressure loss possible at 500 lb/100 sq ft static gel strength value), psi

OBP = Overbalance pressure (hydrostatic pressure minus the formation pressure), psi

GFP is a dimensionless number indicating the estimated severity or potential for encountering gas migration. This equation uses a static gel strength value of 500 lb/100sq ft because SGS of this magnitude will not permit gas percolation.

GFP Ranges. A gas-flow potential factor of less than 1.0 theoretically signifies no gas leakage problem. Nominal fluid loss control and mud displacement techniques should help prevent any gas leakage problems in such a situation. If the GFP is in the range of 1 to 5, changes in the cement job parameters, including mud densities, cement densities, cement column length, and back pressure can lower the GFP to an acceptable level. When job changes cannot produce a GFP of less than 1.0, operators can increase slurry compressibility or its thixotropic properties to help prevent gas migration. Thixotropic slurries that produce low fluid losses have been used successfully in formations with high GFP values (over 10). For a GFP greater than 5.0, a combination of low fluid loss additives, special thixotropic cement and increased slurry compressibility can result in high success rates. Some 70% of all compressible cement jobs are for well conditions showing GFP values between 1.0 and 9.0; in this range, the success ratio is above 90%. Successful compressible cement applications have even been performed for conditions showing GFP values up to 15.0.

The maximum GFP limit for a specific technique is influenced by gas-zone productivity. Whether due to low permeability or formation damage, a gas source with very low productivity will tolerate a higher GFP without resulting in gas leakage. Although compressible and thixotropic cements owe their effectiveness to changing the slurry compressibility and/or the transition time, these changes do not change GFP or MPR values. Increasing the slurry compressibility and decreasing the transition time decreases initial hydrostatic overbalance (DP) (the maximum pressure loss caused by volume reduction during the transition time). This technique is effective when DP is reduced to a point below MPR.

## GAS MIGRATION CONTROL SYSTEMS

A hands-on, interactive analysis system can model downhole conditions. For any gas flow situation, this program can help evaluate effective gas migration control techniques by using the gas flow potential factor. By employing these simple design factors, it is possible to help reduce gas-flow potentials at little or no added expense.

Minor Gas Flow Potential Conditions. When conditions indicate low gas-flow potential, it is possible to achieve migration control without using any special application additives. Any method that can control extreme conditions would be expected to control lower flow-potential conditions. However, most operators want effective control that is economical and does not produce technological overkill. By using fluid-loss control additives and altering elements of a job design, many minor flow conditions can be controlled. Fluid-loss control in the range of 50 cc/min is recommended.

Moderate Gas-Flow Potential Conditions. If the well has a moderate potential for gas flow, operators should use exceptional fluid-loss control techniques. Although the recommended fluid-loss value decreases as the gas-flow potential increases, a common cement slurry recommendation for high-temperature wells is 25 cc/30 min of fluid-loss control. For added gas-flow prevention, these designs can be supplemented with additives that delay the slurry's SGS development. This delay permits the cement slurry to transmit hydrostatic pressure much longer than with conventional designs. By the time the cement finally begins to gel, the rate of filtrate being lost to the formation drops to a low level. As a result, the pressure drop that occurs during the critical transition period is reduced.

Severe Gas-Flow Potential Conditions. For severe gas-flow conditions in high-temperature wells, fluid loss control additives, job modifications, or delayed gelling agents alone cannot sufficiently reduce flow potential. In these situations, highly compressible cements are necessary. One method is to utilize a cement system that reacts to generate and thoroughly disperse discreet gas bubbles throughout the cement column. A second method of creating a compressible system is to inject an inert gas into the cement system as it is being placed downhole. This action creates a highly compressible cement system that can compensate for volume decreases caused by filtrate loss and hydrate volume reductions. The following equation shows the effect of increasing slurry compressibility:

$$DP = DV/CF$$

Where

DP = Pressure loss from volume reduction
DV = Volume reduction caused by fluid loss and cement hydration
CF = Compressibility factor

The compressibility factor for standard cement slurries is the same as for water. By substituting higher values for the CF, the ratio between volume reduction M and CF can be significantly lowered, resulting in a lower P value. Relatively low gas volumes (2 ½ to 5%) can greatly increase CF and control P. Typically, only 2 ½ to 5% gas by volume is required downhole to produce enough compressibility to help prevent gas entry into the cement column.

## CONCLUSION

Flow channels created by gas migration cannot be "healed." In these cases, operators will usually need to perform remedial squeeze jobs. However, by using analysis systems that help determine a formation's gas-flow potential factor, operators can better determine the most effective cementing practices for preventing gas migration problems.

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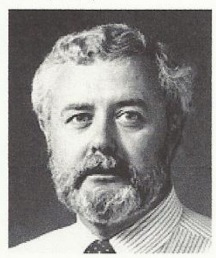
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