BEDROCK ENGINEERING

WELL CONTROL INCIDENT ANALYSIS

EOG Resources Inc.

Punxautawney Hunting Club 36H

Clearfield County, Pennsylvania

Prepared By: John G. Vittitow Sr. **July 2010**

Table of Contents

Addendums

Executive Summary

On June 3, 2010 at approximately 6:40pm, EOG Resources (EOG) experienced an unscheduled release of gas, frac fluid and brine on their Punxautawney Hunting Club 36H (PHC 36H) well located in Clearfield County, Pennsylvania. EOG, through its contractor CC Forbes, was in the process drilling out a string of composite bridge-plugs utilized in the fracing operation between multiple sets of perforations when a Beaumont Iron Works (BIW) stripping head rubber and subsequently, a 7-1/16" – 5,000 psi working pressure (WP) 2-3/8" pipe ram failed. These two failures allowed the surface wellhead pressure to escape to the atmosphere unchecked. After attempts to control the flow of gas, frac fluid and brine failed, the CC Forbes workover unit was shut down and the location was evacuated until well control experts could be consulted and mobilized to location. Clearfield County 911 was notified by EOG at approximately 10:47 pm on June 3, 2010 of a well control issue on the well. Boots & Coots, a well control specialty company, were the first well control responders but were replaced on the morning of June 4, 2010 by Wild Well Control, Inc. After checking the location for combustible gases and determining none were present, the workover unit was re-started at 12:00pm and the pipe rams were opened which allowed the 2-3/8" tubing to fall down the hole. The 5-1/8" – 10,000psi WP full opening frac valve was closed shutting off the flow of gas, frac fluid and brine and the well was secured. An estimated 35,000 gallons of frac fluid and brine were expelled onto the PHC 36H location due to the well control incident. The location clean-up was started immediately with Pennsylvania Department of Environmental Protection personnel on location.

I interviewed the CC Forbes rig personnel and manager of the CC Forbes Pennsylvania yard on Saturday, June 12, 2010 at the Department of Environmental Protection office in Philipsburg. Interviews of the EOG wellsite supervisors, completion engineer and EOG Vice President and General Manager in charge of Marcellus operations were conducted on Monday, June 14, 2010 at the Department of Environmental Protection office in Philipsburg. All parties interviewed were cooperative and open during the interviews.

The sworn testimony, daily reports, written statements and operational experience were utilized in determining the root cause of this incident as well as factors that contributed to overall failure of the frac cleanout operation on the EOG PHC 36H well. The primary cause was determined to be the failure of EOG to maintain an adequate number of pressure barriers between the producing formation and the atmosphere as well as failing to protect the primary barrier that was in place. The combination of pressure control equipment that was utilized by EOG, namely the single pipe ram and stripper rubber, should never be considered adequate barriers by themselves for drilling out plugs under pressure or used in the application which they were being used.

Additionally, several factors contributed to the failure of EOG to prevent and control the release of gas and fluids once it occurred. Among these are:

1. Failure of EOG to properly test the Blow-Out Preventers (BOPs) prior to use and to conduct the BOP test in a proper manner.

2. Failure of EOG to have EOG or CC Forbes personnel on location with current industry accepted Well Control Certification.

EOG personnel also failed to follow the proper spill notification procedure as outlined in the EOG Prevention Preparedness and Contingency plan. While this did not contribute to the cause of the incident, it did delay the response of the Department's spill team and possibly delaying emergency responders if the situation had worsened.

The well control incident on the EOG PHC 36H well could have been avoided if proper barrier procedures and practices had been in place and properly trained and experienced wellsite and office personnel had recognized the potentially dangerous situation they had put themselves into. Hopefully by fully analyzing this incident, future potentially more serious accidents can be avoided.

Operational Summary

The EOG Resources Punxsutawney Hunting Club 36H was drilled as a horizontal Marcellus Shale development well to a depth of 7,162’ True Vertical Depth (TVD) / 12, 660’ Measured Depth (MD). 5-1/2” production casing was set to total depth. BJ Services performed a 16 stage frac program in the horizontal productive interval with a total of 15 composite bridge plugs set between the stages. The final frac stage was pumped on May 27, 2010. The well was left with a 5-1/8” – 10,000 psi full opening frac valve on top of the wellhead with a 5-1/8” – 10,000 psi flow cross with dual flow wings on top of the frac valve.

May 29, 2010

An Integrated Production Services (IPS) 2” coil tubing unit was rigged up and by utilizing a downhole motor and 4-1/2” mill, drilled out 6 of the 15 composite plugs. The coil tubing was pulled from the well to change out the downhole motor and mill.

May 30, 2010

The coil with new downhole motor and mill was run in the hole. An additional 4 more composite plugs were drilled to a depth of 10,430’ MD. Unable to drill further, the coil tubing was pulled from the well for a new downhole motor and mill.

May 31, 2010

The coil tubing was run back in the hole and 1 additional plug was drilled. At 10,975’ MD, the coil tubing became friction locked and was unable to go any deeper. This is common for long horizontal laterals as the friction on the 2” coil tubing from the bottom of the cased horizontal hole approaches the tension safety factor of the coil tubing. The coil was pulled from the well and the IPS unit was rigged down and moved off location.

June 1, 2010

A CC Forbes workover/completion rig was moved in and rigged up on the well as was a pump and tank. The tank and pump are required to circulate brine down the 2-3/8” tubing while drilling out the remaining composite plugs. A 7-1/16” – 5000 psi dual ram BOP consisting of one blind ram and one 2-3/8” pipe ram was installed on top of the flow cross with the required cross-over flange. A blind ram is designed to close across the open casing and the pipe rams are designed to close around 2-3/8” tubing. The BOPS were connected to hydraulic valves which are an integral part of CC Forbes rig. A remote separate accumulator unit (a self contained set of operating valves with its own power unit) should have been utilized so that the BOP operations were not dependent on the rig power. **The BOPs were not tested at this time.** Appropriate BOP testing practices are discussed in the Operational Issues section of this report. An attempt to kill the well with 10.0 pound per gallon (ppg) brine was unsuccessful due to the amount of gas in the well as well as the stored energy in the well from the fracing operations. This attempt was made to try and overcome the well pressure with a hydrostatic column of the 10.0 ppg brine to allow the 2-3/8" tubing to be run in the hole without surface pressure. The decision was made to set a composite plug above the open perforations to isolate the formation. A Titan wireline unit was rigged up and the composite plug was set at 7,047'. Pressure in the casing above the plug at 7,047' was bled off to 0 psi.

June 2, 2010

A 4-1/2" roller cone bit with an internal float was run in the hole on the 2-3/8" tubing string to the composite plug at 7,047' MD. The hole was circulated with brine and the top composite plug was drilled. The bit and tubing was run in the hole to 9,193' MD where the stripping rubber was changed. **The BOP body and 2-3/8" pipe ram were reported to be tested to 2500 psi after drilling up the kill plug and with pressure on the well.** There is some doubt that this test was actually performed as this operation was not mentioned on one EOG daily report for this date but a second report for the same day reported a BOP test. More details on the BOP test will be discussed in the Operational Issues Section.

June 3, 2010

The rig resumed running the bit and tubing in the hole under pressure until it tagged the first composite plug left in the hole at 11,302'. The rig was rotating and circulating down the 2-3/8" tubing while tripping in the hole. The pressure at the surface choke was +- 1600 psi. The four remaining composite plugs were drilled and four additional joints of tubing were run in the hole after drilling the last composite plug at 12,350'. At the depth of +- 12, 470', the bit could not go deeper and two joints were pulled from the well. The reason for not being able to go deeper is not reported but it would be common for pieces of the drilled composite plugs to become lodged beside the 2-3/8" tubing and not allowing it to move in one direction or the other. The stripper rubber started leaking and the pipe rams were closed. No leaks were observed at that time. At approximately 6:35pm, orders were given by the EOG wellsite supervisor, Barry Rodkey, to pull the 2-3/8" tubing thru the pipe rams to position the collar on the 2-3/8" tubing to the proper position to change the stripper rubber. This decision caused EOG to lose control of the well. As described in greater detail below, no further action should have occurred at the PHC 36H until additional pressure barriers were added.

After pulling the pipe thru the ram for +- 4 inches, the ram started leaking. The EOG engineer in charge of this well, Jeff Leitzell, was notified of the problem. Attempts were made to kill the well with brine being pumped down the tubing at +- 4 bbls per minute without success. The 2-3/8" tubing collar was set down on the pipe ram in an attempt to slow down the leak thru the rams. Attempts were also made to back off the tubing on top of the ram and at the swivel with no success. These actions were attempted to allow the 2-3/8" tubing to fall down the well and allow the blind rams or frac valve to be closed shutting off all flow. Pressure at the surface dropped to 800 psi while pumping brine but flow around the rams increased. The fluid pump failed and it could not be re-started. It is unknown why the pump engine failed and could not be restarted. Pressure started to increase at the wellhead. An attempt was made to close the blind rams and crush the 2-3/8” tubing and cause it to fail allowing it to fall in the hole. This attempt was not successful and had very little chance of success. At +-9:00 pm, all personnel were evacuated from the location and well control experts were alerted and requested on location. The rig engine was killed and the location was secured. Calls were placed and messages left for PADEP Oil & Gas Inspectors Rick Hoover and Travis Walker starting at 10:15pm. Attempts to notify the Clearfield County Sheriff were made at 10:30 pm but were unsuccessful as the number called was out of service. At 10:47 pm, the Clearfield County 911 was notified of the well control problem.

June 4, 2010

The original well control specialist from Boots & Coots arrived at the location at 3:00 am. The situation and location were evaluated for hazards and the decision was made to wait until the primary well control specialists from Wild Well Control arrived on location. The Wild Well Control specialists arrived on location at +- 9:30 am. After evaluating the situation and location, it was determined that no combustible gas was on location. It was also discovered that the 2-3/8” tubing had parted at the collar sitting on top of the pipe rams and that the joint of tubing hanging from the swivel had been ejected from the BOPS and was hanging beside the rig floor. An attempt was made to close the 5-1/8” – 10,000 psi frac valve but without success as the tubing was still in the valve. The BOP controls were set to the open position and the rig was re-started. This allowed the hydraulics to operate and both the pipe and blind rams opened allowing the 2-3/8” tubing to fall down the hole. The frac valve was closed at 12:13 pm on June 4 shutting off all flow at the surface. The well control incident had lasted for 17 hrs 38 min. The BOPs and flow cross were removed from the well. A second 5-1/8” – 10,000 psi frac valve was installed on top of the original frac valve for safety purposes. The workover rig was rigged down and mobilized off the location.

Clean-up operations began with PADEP personnel on location. An estimated 35,000 gallons of frac fluid and brine was released onto the location.

Equipment

5-1/8" – 10,000 psi WP Frac Valve

The lower orange valve is the original 5-1/8" – 10,000 psi WP frac valve which was installed prior to the frac on the wellhead and remained in place during the well control incident. It is a full opening valve and requires 33 rounds to fully open or close the valve. The hand wheel has been removed.

The upper green valve was installed after the removal of the flow cross and BOPS after the well control incident was secured. This was done for safety reasons in the event the lower valve failed.

5-1/8" – 10,000 psi WP Flow Cross

The 5-1/8" – 10,000 psi WP flow cross was installed on top of the frac valve before starting the post-frac cleanout operations. The cross allowed frac fluid and brine to be flowed up the 5-1/2" casing x 2-3/8" tubing annulus.

7-1/16" – 5,000 psi WP Dual Ram BOP

BIW Stripper Head and 2-3/8" Stripper Rubber

The 7-1/16" – 5,000 psi WP Dual ram BOP with Beaumont Iron Works (BIW) stripper head was installed on top of the 5-1/8" – 10,000 psi WP flow cross. A cross – over was required for proper make-up. Blind rams were installed in the lower rams and 2-3/8" pipe rams were installed in the upper rams.

The BIW stripper head has a 7-1/16" – 5,000 psi WP flange so it can bolt up to the BOP. The 2-3/8" stripper rubber is not pressure rated by the manufacturer due to the fact that as soon as it is used it would be downgraded because of wear. Therefore, it cannot be considered a pressure barrier during workover operations.

7-1/16" – 5,000 psi WP Rig Assist Snubbing Unit

A snubbing unit is designed to push or pull pipe from a well while under pressure. The units typically consists of a power unit, jack assembly, a 5,000 psi WP annular preventer and either one or two sets of ram type preventers. The rig provides the lifting capacity for the snubbing unit. Most rig assist snubbing units are truck mounted for ease of mob and de-mob.

Operational Issues

During the review of the written testimony of the CC Forbes rig crew, the sworn verbal testimony of the CC Forbes on-site rig operators and the EOG personnel, several operational issues were noted that either had a direct influence on the well control incident on the EOG Resources Punxautawney Hunting Club 36H or could possibly have helped in preventing this incident. These issues are as follows:

> **Pressure Barrier Policy** – During all phases of oil & gas well operations, pressure barriers are required to be placed between the open producing formation and the atmosphere. During the drilling phase, weighted drilling fluids, multiple ram BOPs and annular preventers are often counted on as barriers. During completion / workover operations, weighted completion fluids, downhole plugs, ram BOPs and full opening valves are sometimes used as barriers depending on the operational requirements. Once the well is on production, the tree valves, back pressure valves installed in the wellhead and downhole plugs are often counted on as barriers. But in all phases of the well's operational life, multiple pressure barriers are required for reasons of safety back-up and operational security. Most operating companies have policies in place specifying the number and type barriers required to be in place during specific well operations. During the interviews with the EOG personnel, both field and office, none were aware of EOG having any written pressure barrier policies.
>
> During the post-frac cleanout of the EOG PHC 36H well, only one acceptable barrier was in place once the 2-3/8" tubing was run into the well. The 7-1/16" – 5000 psi WP 2-3/8" pipe rams were the only true barrier between the producing zone and the atmosphere. The BIW stripper head with installed stripper rubber should never be considered a barrier because it has no recognized manufacturer's pressure rating and from the moment of first use, it would be downgraded due to wear. The wear on a stripper rubber is dependent on the condition of the pipe run through it or rotated in it (i.e. – wear is more extensive if the pipe is highly pitted or has a large amount of scale). The other two potential barriers on the well during the cleanout were the blind rams and frac valve which were unusable once the 2-3/8" tubing was run in the hole. This is due to the pipe not allowing the frac valve or blind ram to close.
>
> **Pressure Barrier Maintenance –** Almost as important as the proper number of pressure barriers to a well operation is the maintenance of those barriers. Maintaining the integrity of the pressure barriers is of upmost importance especially when you are down to the last barrier. Once you are to your last barrier, no action should be taken that might jeopardize the integrity of that barrier even to the point of shutting down operations until previous barriers can be repaired or additional barriers added.

On the EOG PHC 36H, the decision to pull the 2-3/8" tubing through the 2-3/8" pipe rams after the stripper rubber (which should not of been considered a barrier) had failed, was flawed and ultimately led to the well control incident. This is especially true with +-1500 psi pressure underneath the pipe rams and 0 psi pressure between the pipe rams and failed stripper rubber.

In the signed written testimony and the interviews with the CC Forbes rig crew, it was claimed that against their recommendation, EOG wellsite supervisor, Barry Rodkey, instructed the crew when changing out worn stripper rubbers to open the pipe rams for a short period of time to allow the well pressure to assist in removing the worn stripper rubber from the stripper head. Mr. Rodkey testified that he never authorized this activity. Regardless of which account is true, this type of activity could have caused potential damage to the pipe ram sealing elements and could have resulted in a premature failure. **This type activity should never be allowed at any time.**

BOP Testing – The testing of BOP components is essential to ensuring that they operate properly and that the sealing elements are in good condition. It is standard operating policy that when BOPS are installed, they are tested before use. This is especially true if pressure is known to be encountered at the surface as in the post-frac cleanout on the EOG PHC 36H. Due to the nature of the operation, it was known that initial pressures between 1500 psi and 2000 psi would be encountered at the surface of this well. Per sworn testimony and EOG morning reports, the BOPs were never tested when installed and were only reported tested after the 2-3/8" tubing was in the hole and the composite top plug was drilled which allowed pressure at the surface.

There are several operational issues with this scenario. Mainly, if there are problems with BOP components or the nipple up and they do not test, the BOP will not be able to control the well . The time to discover this is prior to being required to hold well pressure. Once the top composite plug was in place and the pressure in the casing was removed, the opportunity was there to properly test the BOP components and nipple up prior to their use. Proper testing of the BOP components should have been performed at this time. Testing could have been accomplished by the use of a test plug installed in the wellhead below the frac valve. Pressure is applied between the test plug and the blind ram to test the blind ram and with a joint of 2-3/8" tubing screwed into the top of the test plug, pressure can be applied between the test plug and the pipe rams to test the pipe rams. The usual test pressure for ram type BOPs is to the rated pressure. In this case, 5,000 psi. I do not see a need to only test the rams to 2,500 psi. Secondly, by waiting until the 2-3/8" tubing was in the hole and well pressure was at the surface, if the pipe rams had not tested or the flange connections had leaked, there would be no way to correct the problem. A well control incident could have occurred. Also, testing of the blind ram was impossible at this point because the tubing was in the hole and did not allow the blind ram to close..

No proper BOP testing was conducted on this well during the post-frac cleanout operations. While one version of the EOG morning report dated 6/3/2010 indicates the BOPS were tested for 15 minutes between 05:15 am and 05:30 am, the original version does not reflect a BOP test being performed. This discrepancy does not provide any confidence that a BOP test was performed at all, even at an illogical point in the well operation as the second report indicates. It is also not known the condition of the blind rams or if they would have sealed if they were required.

Rig Assist Snubbing Unit – During the post-frac clean-out process on horizontal wells, the common practice is to utilize coil tubing to drill out the composite plugs between frac stages. EOG started the clean-out process with a 2" coil tubing unit and was able to drill up 11 of the 15 composite plugs in the hole. Due to friction between the coil tubing and the casing in the horizontal hole, the coil was not able to drill the remaining 4 plugs. EOG made the decision to use a workover rig, 2-3/8" tubing and a power swivel to drill up the remaining 4 plugs plus the upper composite plug used to seal off the open perforations while going in the hole. Using a rig and power swivel can be acceptable if proper pressure barriers are in place. However, a snubbing unit must be used after drilling out the composite plugs to pull the tubing from the well and to run in the hole with the production tubing. A much safer plan would be to rig up a rig assist snubbing unit once the coil tubing cannot go deeper in the well. This is true especially since a snubbing unit must be used anyway to finish the operation. While there would be a minimal additional cost, it would be a much safer operation as a snubbing unit is designed for the purpose of running and pulling tubing in a well under pressure.

Independent Closing Unit – EOG utilized the CC Forbes 7-1/16" – 5,000 psi WP dual ram BOPS in their post-frac cleanout process. These BOPS were connected to the workover rig's hydraulic system which required the rig to be operating for the BOPs to be operated. Once the rig was shut down then the BOP rams could not be opened or closed. While this was not a major problem during the EOG PHC 36H well control incident, it could have presented a major problem under slightly different circumstances. A remote independent powered accumulator unit located 100' away from the wellbore would be a much safer and should be considered a requirement on every post-frac cleanout location.

Well Control Training – While wellsite personnel properly trained and certified in well control procedures may not have been able to stop the release of gas and fluids once they occurred, it would be hoped that the training might have made them more aware of the situation that was developing with the single pipe ram and stripper rubber and helped them make the decision to stop operations before the well control incident developed. Per the information received, there was not one person with either CC Forbes or EOG on location that held a current industry accepted Well Control Certification. Well Control Certification is usually required for all drilling wellsite supervisors, but emphasis is not put on completion / workover supervisors to be certified as well even though as in this case, they work with guaranteed pressure at the surface. Because pressure at the surface will occur, proper training in well control is even more important.

Notification of Proper Emergency Response Providers – The prompt notification of all required Pennsylvania state agencies, particularly the Department of Environmental Protection who is charged with regulating the oil & gas industry in the State of Pennsylvania, and the county emergency response providers is vital to the protection of the population and environment in the case of an uncontrolled spill of gas and well fluids. In this particular case, The PHC 36H well control incident did not result in any injuries or known serious environmental consequences but it was not known at the time of the incident how serious the incident would become. According to the EOG provided time line, interviews and daily reports, The PADEP hotline was never notified and attempts to contact local PADEP Oil & Gas Inspectors Rick Hoover and Travis Walker were made +- 3 hours after the start of the incident without success. Attempts to contact the Clearfield County Sherriff's office also failed due to incorrect numbers being called. At 10:47 pm June 3, +- 4 hours after the start of the incident, Clearfield County 911 was notified.

The EOG Resources Prevention, Preparedness and Contingency plan provides a detailed list of agencies, both state and federal, to be notified in the event of a spill or emergency. This plan was ignored with the exception of calling Clearfield County 911 4 hours after the start of the incident. The EOG engineer in charge of the PHC 36H well, Jeff Leitzell, during his interview testified he did not have access to the EOG Emergency Response Plan. Even though it is recognized that each operator decides who will activate an Emergency Response Plan, all operational employees should have access to the plan. In the event of a more serious incident, this delay could have proven costly to both human and environmental concerns.

Conclusions

Several conclusions should be made after the analysis of the data available on the well control incident of June 3-4 on the EOG Resources Punxautawney Hunting Club 36H located in Clearfield County, Pennsylvania. They are as follows:

1. The primary cause of the well control incident was the failure of EOG Resources to have proper pressure barriers in place for the post-frac cleanout operations that were in progress at the time of the incident. Only one barrier was in place, the 7-1/16" – 5,000 psi WP 2-3/8" pipe rams and once they were compromised, there was no back-up.

2. EOG wellsite personnel failed to protect or properly maintain the last pressure barrier, the 7-1/16" – 5,000 psi WP 2-3/8" pipe rams which directly led to their failure. All operations should have ceased once that barrier was reached until additional barriers were repaired or in this case, added.

3. The 7-1/16" – 5000 psi WP dual rams were not tested before use and improperly tested once well pressure was applied to them. This puts in question the condition of the blind and pipe rams before the operations started.

4. A rig assist snubbing unit would have been a safer method of running the 2-3/8" tubing in the hole, drilling out the remaining composite plugs and pulling the 2-3/8" tubing out of the hole.

5. A remote independent closing unit for the BOPs should have been in place during the post-frac clean-out on the PHC 36H.

6. The lack of EOG Resources and CC Forbes personnel on location who were current in their Well Control Certification could have possibly helped avoid the well control incident or to a minimal degree, provided trained onsite solutions once the incident occurred.

7. Proper notification of the Pennsylvania Department of Environmental Protection and the local emergency response providers did not occur in a timely manner.

Recommendations

Based on the conclusions reached after the analysis of the well control incident on the EOG Resources Punxautawney Hunting Club 36H well located in Clearfield County, Pennsylvania, The following recommendations should be considered:

1. A minimum of two pressure barriers should be in place during all post-frac cleanout operations. Possible barriers could include the following:

    a. Pipe ram preventer - multiple

    b. Annular preventers

    Stripper heads should not be counted as pressure barriers in any post-frac cleanout operation or any well activity.

2. Recorded test results (chart record) of any BOP equipment utilized in post-frac cleanouts should be on file at the wellsite or with the wellsite supervisor. This test should be performed immediately after the installation of the BOP equipment and before its use.

3. The use of a snubbing unit (stand alone hydraulic or rig assist) to perform post-frac cleanouts if coil tubing is not able to clean out the composite frac plugs and sand to total depth should be highly recommended. A snubbing unit is designed to run and pull tubing in and out of a well under pressure.

4. A remote independently powered BOP accumulator unit (closing unit) located a minimum of 100' from the well should be used on all post-frac cleanout operations.

5. Recorded test results (chart record) of any BOP equipment utilized in post-frac cleanouts should be on file at the wellsite or with the wellsite supervisor. This test should be performed immediately after the installation of the BOP equipment and before its use.

6. A minimum of one wellsite supervisor should be on location during post-frac cleanout operations who has current industry accepted Well Control Certification from a recognized well control school. Their Well Control Certification Certificate should be in their possession at all times.

7. A clear and concise notification process which is agreed upon by all Pennsylvania state agencies should be established which specify maximum reporting times in the event of a well control incident. This process should be documented and forwarded to all oil and gas operators in Pennsylvania along with the required contact numbers.