What Were the Causes That Led to the Deepwater Horizon Blowout and Explosion? - and Open Thread

Posted by aeberman on June 19, 2010 - 10:00am
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Tags: bp, deepwater drilling, deepwater horizon oil spill, gulf of mexico [list all tags]

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Author's Note: This is a guest post by William Semple. Mr. Semple is a drilling engineer and independent drilling consultant with 37 years of experience in the oil and gas industry. He worked for 16 years with a major oil company and has 24 years of experience as a drilling supervisor.

Mississippi Canyon 252 Macondo Well
24th April 2010 at approximately 21:49 hrs

I have summarized the information to try and keep it to the salient facts. The following information is from reliable sources. Most is public record and the remainder is from confidential reviews carried out by other major oil companies. I have interpreted the reports and made some conclusions with caveats where necessary. As such, these are only opinions and no inference of blame can be inferred as a result of these statements.

More detail will emerge when further investigations take place, especially with regard to the last few hours leading up to the explosion. However, I am confident the fundamentals are identified in this article and, most importantly, the crucial lessons learned so none of us repeat the same mistakes.

Much is being made of the water depth as a factor in this disaster. However, many of the mistakes made would have been equally serious in shallow-water drilling or even on land, and lessons learned apply to almost all drilling operations.

Well Status

Drilling of the Macondo well had reached total depth (TD) at 18,360 feet (ft). The previous casing shoe was at 17,168 ft. Open hole diameter was 8 ½ inches (in). Rotary Kelly Bushing (RKB) to Mud line was 5,067 ft. The open hole had been logged over a four-day period.

7 in by 9 7/8 in casing was run from TD all the way back to the wellhead--a single string.

The casing had been cemented using +/-100 bbls of slurry. There were no losses and the plug was bumped. No back flow was observed after displacement (although “U” tube effect was not significant.) Top of cement is estimated at 16,200 ft.

9 7/8 in casing hanger was landed with no lock ring (Reason not known).

No pack off or secondary seal was run (Reason not known).

11 hrs after cementing, the casing was tested to 2,650 pounds per square inch (psi) with the blind shear rams closed.

Drilling string was run to 8,367 ft.

Sequence of events

16.5 hrs after bumping the cement plug, the draw down or negative test was carried out to establish well integrity prior to displacing 14.3 pound per gallon (ppg) oil-based mud out of the well from a depth of 8,367 ft.

This test was carried out part-way through the displacement of the well to seawater including a complex spacer pill, with the well shut in and the kill line open & full of seawater. Kill line pressure was zero but there was 1400 psi on the drill pipe.

The inflow/draw down test was probably flawed. It would not equate to what the well would see after the riser was displaced to seawater. There is also witness statement information that the observation of return flow from the kill line to the cement unit was 15 bbls during the inflow test. As can been seen in the BP report, there was quite a lot going on during this process, and the data seems rather confusing. However, the test was deemed to be satisfactory.

The annular was opened up and the process of displacing the well to seawater continued at 25 to 31 barrels per minute. During this time, oil-based mud was being transferred to the supply boat, so total fluid in and out volumes could not be monitored. However, flow in and out was being monitored.

20:58-21:08 hrs there was an indication of increased flow from the riser returns. This coincided with a slowdown in pump rates and then stopping of pumps to carry out a sheen test in preparation to dump “clean” fluid returns to the sea (fluid spacer). During this period the drill pipe pressure increased (+/- 200 psi increase over five minutes).

21:15 hrs pumping restarted and returns were dumped overboard. The diverter was closed for this operation so there was no longer flow-out measurement.

21:31 pumps off. The pump pressure just prior to this had been increasing but then showed, a drop off which could have been a sign of the gas coming up to surface. Records show 4 telephone calls between the rig floor and the Toolpusher (drilling manager responsible for all operations) during this time.

21:31 – 21:47 erratic drill pipe pressure probably due to unloading of riser because of gas expansion.

21:49 Drill pipe pressure had risen rapidly to 5,800 psi. It is thought that the annular preventer may have been closed at this time. But since the drill pipe valve (Kelly cock/stab in valve) was not closed, the pressure would have reached the pumps where the relief valve pressure could have been exceeded and tripped gas would have flooded the pump room (this is speculation but quite likely).

21:49 All data transmission from the rig were lost presumably due to the explosions & fire.

21:56 hrs The EDS (emergency disconnect system which closes all valves & rams & blind shear rams on the BOP --blowout preventer--and disconnects the riser) was pressed from a remote location but it did not appear to work.

After loss of hydraulics and communication from the well the AMF (automatic mode failure system) on the BOP should have functioned. This would have closed all BOP rams but not the disconnect. This did not appear to work.

Post-explosion ROV (remotely operated vehicle) interventions were conducted to attempt to activate the blind shear rams, variable rams and other BOP functions.

Leaks were found in the system that were previously noted in the rig log.

Hydraulic system errors such that test rams (lower pipe rams) were activated instead of the lower variable rams.

Subsequent NDT (non-destructive testing) examination of the BOP indicated that the blind shear rams & variable rams did move and may be in the locked position, but final status will not be possible until the BOP is recovered.

Conclusions

Well Planning

- The hanger was run without a lock ring. Pressures from gas leaking up from the producing formation could have provided sufficient pressure to move the hanger and affect seal integrity. There was no lock ring or secondary seal (pack off) to prevent this.
- Hanger was only a single barrier—the cement was and could not be tested.
- Gas from the annulus getting past the hanger seal was the most likely source of the kick and subsequent blowout.

Policy & Procedure

- The method of conducting the inflow or draw-down test in conjunction with displacement of the well from weighted mud to seawater is suspect at best, and possibly fundamentally flawed.

Basic Rig Practices

- The inflow/draw down test did not appear to offer satisfactory results, and also took place over a relatively short period of time.
- During the displacement of the well to seawater, volume, flow show and pressure anomalies were evident but did not result in the well being shut in in a timely manner.
- Even after there were some indications that all was not well, pumping operations continued. Returns were dumped and the return flow meter was bypassed,so the rig was effectively blind until things started to get quite serious.
- When the well was shut in, the drill pipe safety valve or IBOP was not closed in time to stop rapid rise in pressure getting back to the pumps and probably blowing the pressure relief valves.

What lessons can we learn from this tragedy?

1. The practice of running a long string instead of a liner to seal off a reservoir means any failure in the cement job cannot be monitored. It is well known that, in certain circumstances, some of the hydrostatic pressure of the cement column can be lost during the cement-curing process. Running a liner means the cement job can be monitored or tested, or that a liner-top packer can be used to act as an additional barrier.
2. The industry should embrace existing techniques to prevent or compensate for potential loss of hydrostatic pressure during the cement-curing process.
3. Hanger assemblies can and should offer dual barriers.
4. Hangers should always include a locking mechanism. This should not be left out for the sake of convenience.
5. Cement should not be considered as a barrier unless it can be properly tested in the direction of flow.
6. Barrier policy should require dual barriers tested in the direction of flow.
7. Inflow/draw down testing and displacing wells to lighter fluids is not part of the IWCF syllabus. It should be.
8. Displacing wells to under-balance hydrostatics should require monitoring of volumes pumped and returned. The process should stop while volume is pumped to a boat.
9. Flow checks during such displacements to lighter fluids should be mandatory and thorough.
10. Basic well control training teaches us that, when there are indications of a kick, the well should be shut in.
11. Basic well control training teaches us that before closing in a well, the drill pipe should be shut in first.
12. Drillers must be empowered to have the confidence and authority to close the well in if they have any suspicions that a well might be flowing. Close the well in first – ask questions later.