



What Might Have Been – Risk Assessment and Management Analysis (RAM) of BP Tapered Production Casing Plan

Gary L. Marsh

1. Summary

BP might (or might not) have enjoyed at least some of the \$7 million to \$10 million savings they assessed would be gained by running an all-in-one string, and still had a safe well afterward had they performed a Risk Assessment and Management (RAM) analysis well in advance of the operation. Such an analysis should have focused far beyond the immediate rig plans to include risks that a second or the same rig might encounter in an eventual reentry and full completion.

2. A RAM Perspective

Knowing full well that the cement job had a low probability of total success, a RAM process focusing on that aspect should have been conducted. Certain mitigating actions could have been planned and put into play before and after the cement job was completed.

The results derived from an assessment of the risks could have been something like the following:

Risk 1

Cement might channel badly with casing not centralized in hole:

- MITIGANT 1a: BP could have planned to run all casing centralizers indicated to be needed by well modeling.
- HARD FACT: Tapered full string could not be reciprocated or rotated for risk of being stuck off of hanger seat at top.

Risk 2

Casing connection transit or stabbing damage to metal-to-metal seal surfaces inside and out might be missed, later causing a casing leak—or even casing connection unzipping and parting:

- MITIGANT 2a: Take the time and labor to clean and inspect each and every metal to metal seal surface before stabbing.
- MITIGANT 2b: Utilize an elastomeric stabbing guide when stabbing each joint.
- MITIGANT 3c: Insure similar care for connections made shore-side before shipping to rig.

Risk 3

Chorography of Nitrogen cement mixing might be off somewhat, cure times long, and cured strength marginal by its nature¹:

- MITIGANT 3a: BP could have demanded, and Halliburton could have tested and provided “Super Spherelite” cement instead of the Nitrogenated mix. Lightweight additives similar to Spherelite, but good for 18,000 psi downhole pressure could have been had in bulk from 3M and obtained on a short lead time

basis.^{2,3} The cement mix would have been more straightforward to mix, stronger when cured, and might well have had a more conventional and reliable set time while still obtaining the desired low slurry density to minimize risks of losing circulation

Risk 4

Well productive zones could flow into annulus or casing bore after cementing:

- MITIGANT 4a: BP/Transocean/MMS (Minerals Management Service) could have planned/approved to monitor the annulus and casing bore for flow on the circulating trip tank after the cement was in place for a reasonable time—at least until the cement took an initial cure. It is important that the full mud column from surface be left applied to make up for minor seepage losses at depth due to filtrate loss or whole mud seepage, i.e., don't set the seal assembly on the casing hanger and keep the riser full.
- MITIGANT/DIAGNOSTIC 4b: If flow was detected, set and test casing seal assembly and retest for flow. If flow apparently stops, flow was into annular space. If not, then it was into the casing bore.
- MITIGANT 4c: If flow was detected in the casing bore, the Blowout Preventer (BOP) could have been closed and sufficient pressure applied to force the well fluids back into the flowing zone and thereby kill the well. Once stable, a bridge plug could be set above the float collar and cement spotted on top of it to prevent any recurrence. Honor protective casing burst limitations during the kill.
- MITIGANT 4d: If flow was detected into the annular space, trip out and get the lock down assembly and install it. Trip out and pick up a work string (pre-made in stands in the “second” derrick/draw works area??), and a Retrievable Test-Treat-Squeeze (RTTS) for 7 in. Run RTTS and set about 16,900 ft deep in the well, be ready and perforate at 16,950 ft, and squeeze cement (downward) to shut off any gas migrating up the annular space. Clear the perforation(s) after the squeeze. Honor protective casing burst limitations during the squeeze.
- MITIGANT 4e: Pull the work string and remove the lock down and seal assembly while monitoring the well for flow. Re-run the work string with a drillable bridge plug and set at 16,950 ft. Establish circulation into the annular space and circulate any residual gas out of the annular space and riser. Circulate a 400 ft cement plug into the 7 in x 9 $\frac{7}{8}$ in drilling liner annulus and pull the stinger out of the bridge plug to hold pressure until the cement sets. Place a 200 ft cement plug atop the bridge plug. WOC (Wait on Cement) and run bond log to confirm annular seal.

Risk 5

Well stable (no flow) full of 14 ppg (pounds per gallon) mud, but bond quality above and below productive zone unknown and might flow if partial displacement with seawater is later done.

- MITIGANT 5a: Once the well proved stable with the 14 ppg mud still in place and the cement has cured to some degree, a bit and scraper run would be made to clean out the shoetrack. A CBL (Cement Bond Log) would then be run and evaluated. Based on the interpretation of the CBL (resulting in doubtful

isolation), the work string could be run and the 7 in perforated and squeezed below the productive zone to assure isolation. A bridge plug could be set above the float shoe for the squeeze and left as a second barrier.

- MITIGANT 5b: Then the 7 in overlap with the 9⁷/₈ in drilling liner (if deficient) could be perforated and circulation into and up the annulus established to enable a circulating placement of an annular cement plug with the perforation cleared for subsequent operations.
- MITIGANT 5c: After waiting on cement, the perforation could then be squeezed to establish a cement plug below and across it. After waiting on cement for the squeeze, a pressure test to 2500 psi would be performed.
- MITIGANT 5d: (ANNULAR BARRIER) If the well showed no signs of flow, the work string could then be pulled and the seal assembly run and tested, and the lockdown assembly run and locked down.
- MITIGANT 5e: The work string with 7 in bit and scraper could then be run to clean out to the top of the cement just above the float shoe or bridge plug and the CBL re-run to confirm the cementing work.

If By Outstanding Good Fortune

If the well exhibits no flow after more than 20 hours waiting on cement, the Seal Assembly and lock down are set. A bit and scraper run is made to drill out the shoetrack and then a CBL is run and shows adequate bonding above and below productive zones (i.e., good zonal isolation, and good cement in 7 in overlap with 9⁷/₈ in protective liner). A 7 in bridge plug could be set in the 7 in x 9⁷/₈ in protective liner overlap interval that is well cemented, and a 200 ft cement plug is placed atop it. This provides a deep barrier to both annular flow (via the primary cement) and pipe bore flow (via the bridge plug).

3. Final Tests

Whether good fortune smiled, or much remedial work had to be done, sufficient barriers would now be in place to enable final positive and negative pressure testing.

With the work string at 16,500 ft (just above the 200 ft cement plug in the bore), a 4000 psi positive pressure test could be run. Then the drill pipe could be displaced to 8300 ft with seawater, the BOP closed, and the choke and the kill lines isolated at the BOP (to prevent them from going on vacuum and feeding fluid). Then the pressure would be released on the drill pipe to provide a negative pressure test with careful volume monitoring. After the seawater is bled back from the drill pipe at the conclusion of the test, the drill pipe shoe would be pulled back to 8300 ft and a 400 ft balanced cement plug could then be set from the 8300 ft KB (Kelly Bushing) upward and the work string pulled up and reversed out above it. After waiting on cement and tagging the plug, oil mud could be displaced from the wellbore and riser with careful control of the volumes pumped versus the volumes returned.

4. Probable Final Results

Reentry later by another or the same vessel for the balance of the completion should encounter nothing more than the result of some minor leakage of the deep plugs when drilling out the surface plug. Barriers to flow into bore of production casing include: 1) the cement bond below productive

interval and/or in shoetrack, 2) the bridge plug and cement plug at the ~17,000 ft KB level, and 3) the surface cement plug. Barriers to flow into annular space outside production casing include: 1) the cement bond above productive zones with impermeable formation, 2) the cement bond between production and protective liner, and 3) the production casing hanger seal assembly and lockdown.

Such a RAM analysis might also form a good basis for an analysis of “probable” cost or “probable” savings which could then be compared to results of a similar analysis for running a production liner and tie back rather than the tapered string. The remedial cementing and evaluation work with the all-in-one tapered casing would be very time consuming and therefore, expensive. The bottom line is that the projected \$7-\$10 million savings for the all-in-one casing approach could vaporize rapidly (in the context of rig operations costing in excess of \$500,000 per day) if all risks are evaluated and the planned mitigations are indeed needed to keep all of the risks within tolerable limits.

5. References

1. Transocean, Deepwater Horizon-- Internal Investigation, Investigation Update Interim Report, June 2010, 10.
<http://energycommerce.house.gov/documents/20100614/Transocean.DWH.Internal.Investigation.Update.Interim.Report.June.8.2010.pdf>.
2. 3M™ Glass Bubbles iM30K Hi-Strength Glass Bubbles.
http://multimedia.3m.com/mws/mediawebserver?mwsId=SSSSSu7zK1fslxtUNY_Un8_Uev7qe17zHvTSevTSeSSSSSS-- .
3. Personal communication by phone, Gary Marsh to Rob Hunter with 3M, August 24, 2010.