From: Baker, Kate H (UNKNOWN BUSINESS PARTNER)
Sent: Wed Jun 02 01:38:51 2010
To: Willson, Stephen SM
Cc: Hill, Trevor; Grounds, Cheryl A.; Ritchie, Bryan; MC252_Email_Retention
Subject: RE: National Labs and DOE investigation of alternative flow paths
Importance: Normal

Steve, have now spoken with Trevor. There will be a meeting at 10:30 in W4 C303B Wednesday to review data and discuss scenarios. BP people, although we may ask one of the National Labs folk to attend -- likely Sheldon as he seems the most drilling savvy. You are welcome to attend if you think it would be valuable, and to leave if you find out that it's too many pumping guys talking about the details of friction losses in the lines.
He and I are curious about your comment on option (1) that the volume of mud pumped does not seem feasible? Could you not put some significant fraction of 30 kb into the reservoir horizon (M56 sands). Agreed that if we did not get 16.4 ppg fluid quite deep, we would need to see significant pressure at the wellhead; but this is the reason why the flow is seen as down the casing with hydrocarbon flow up the annulus. How a kill works in that case is unclear, as I don't see turning the corner and coming back up the annulus any height above where the mud first fracs into the lowest reservoir sand. And indeed, we didn't achieve a kill, so maybe that's why...
So, no request for further modeling, but you might have a think about what you believe could be going on if flow is not out the 18" shoe, and come prepared to participate in discussions. Kate

---

From: Willson, Stephen SM
Sent: Tuesday, June 01, 2010 5:56 PM
To: Baker, Kate H (UNKNOWN BUSINESS PARTNER); Hill, Trevor
Cc: Ritchie, Bryan; MC252 Email Retention
Subject: RE: National Labs and DOE investigation of alternative flow paths

Kate - I think the scenarios you describe are "possible" and now we need to apply the "plausible" factor too. Maybe Trevor is making headway with his analyses, but my hunch is that if we had got 16.4 ppg mud down as far as the 9-7/8" shoe with no burst disk leaks wouldn't the well have become static provided the mud and oil flow-paths were the same (Option 3)? From my simple (admittedly static) calculation, a reservoir pressure of 13 ppg at 18,000 ft would be balanced by a column of 14,150 ft of 16.4 ppg mud on top of a remaining 3850 ft of 0.482 ppg (0.25 psi/ft) oil. Friction pressures would be acting against this, so I would like to better understand the Option 3 scenario where we get 16.4 ppg mud deep in the well with a common oil/mud flow path.
Option (1) seems feasible, though the volume pumped is not. This would require us to be clear on the leak-path (up the drill-pipe presumably). You would additionally have to get 16.4 ppg fluid quite deep in the section or have a very high injection pressure at the wellhead. Is Trevor calculating this, or is this a request of me? It may be better to have a short meeting to review these possibilities and to work the numbers.
I agree that (2) seems unlikely. Tony Liao has been doing some GAP flow modeling that seems to be promising - at least for possibly explaining Option 4. I believe he is to work this some more and will provide Trevor some preliminary results before distributing them more widely.
I think that for each Option there should be some necessary "distinctive characteristics" that can either be predicted or need to rely on observed evidence - e.g. oil, gas and mud flows, pressures, etc. We should be able to piece together which of these distinctive characteristics can be substantiated and where gaps exist, and perhaps this might help us rank these possibilities?

I'd be happy to meet up to review this, if needed.

Steve

From: Baker, Kate H (UNKNOWN BUSINESS PARTNER)
Sent: Tuesday, June 01, 2010 5:18 PM
To: Willson, Stephen SM; Hill, Trevor

Cc: Ritchie, Bryan; MC252_Email_Retention

Subject: RE: National Labs and DOE investigation of alternative flow paths

OK, Steve. Thanks. What we seem to have now is that the scenario is plausible, even though we can't replicate the details of the response. However, we could also plausibly have fractured around the 7" show with our kill attempts and the 16" burst disks could still be intact, etc.

How would we go about ranking these scenarios (?):

1. Mud flows down center, oil goes up annulus. Well initially full of 14.0 SOBM below 8367 MD, 16.4 WBM above that to the mudline, where the pressure is 6000 psi. Would we fracture the 7" show and then pump mud away into the lowermost reservoir sands in the M56?
2. Mud goes down casing to 8367 MDRKB and immediately back up the drillpipe -- we know this isn't the whole story, as we can't pump more than 25-30 BPM through the DP without exceeding the observed pressures, so at least some mud has to go somewhere else. Maybe the rest goes through the BOP body-DP annulus and very little downhole. But this is hard to believe as there seems to be little evidence for erosion.
3. Mud flows down the 16" x (9-7/8 x 7") annulus with the burst disks still intact. Mud goes out into the formation at the 9-7/8 " shoe at 17,168, or if there is no sand there, into a sand below the 9-7/8" liner and the TOC for the 7", estimated to be at about 17,300 ft and out. Is this plausible with 16.4 ppg mud, given friction losses in the annulus that must approach 3000 psi? Looking at the PPFG curves, this seems plausible to me. We have not much sand between 17,300 feet and 17,168, so would be on a shale frac gradient.
4. Mud flows down the annulus, out the burst disk "ports" and out the 18" shoe. This is the case you've been working on.

I think we need to take a BP view on this. Apart from observing that case 2 seems rather unlikely among the options, I don't have an opinion about the relative probabiliites of the others.

Kate

From: Willson, Stephen SM

Sent: Tuesday, June 01, 2010 2:26 PM

To: Baker, Kate H (UNKNOWN BUSINESS PARTNER); Hill, Trevor

Cc: Ritchie, Bryan

Subject: RE: National Labs and DOE investigation of alternative flow paths

Kate / Trevor:

I'm having a really hard time to generate any "humps" in an injection profile using STIMPLAN, as I am pushing the code past its design limitations. It simply fails to converge with problems like these. I will continue looking at this later today. The "humps" and the overall pressure trace does look like a fracture growing in height and being arrested by sand layers before breaking through these as the sand gets plugged by the solids in the mud. However, if we want to model this, then it may be necessary to go to an outside vendor such as MI-SWACO to run the analysis using their fracturing code that has been tailored for simulating drill cuttings injection. STIMPLAN is geared to hydraulic fracture stimulation and not so well for cuttings injection, so I feel that I am struggling here rather.

I'll press on some more before replying with a more definitive verdict.

Steve

From: Baker, Kate H (UNKNOWN BUSINESS PARTNER)

Sent: Tuesday, June 01, 2010 10:59 AM

To: Ritchie, Bryan; Willson, Stephen SM; Hill, Trevor

Cc: Yeilding, Cindy; Carragher, Peter D; Thorseth, Jay C; Tooms, Paul J; Edwards, Michael L; McDonald, W Leith; MC252_Email_Retention

Subject: National Labs and DOE investigation of alternative flow paths

Trevor, Steve, Bryan: The DOE is investigating alternative flow paths in order to understand MC252 shut in risks. They would like to discuss various scenarios with you, and also get your opinion as to the plausibilty of alternatives they have investigated. I have assured them that if we had a 16.4 ppg gradient established to the 7-inch shoe and we

believed we had pressure communication down the 9-7/8 x 7" to the reservoir, there would be no problem losing returns into the reservoir. By when might the two of you have had a chance to put your heads together re geology, frac gradients, and observed presssures during the 3rd top-kill attempt to have agreed a BP view of what might have happened? They would like a presentation by one or all of you on this today or tomorrow -- Trevor, I believe you were already scheduled to come advise on latest views **at 2 p.m. today.** However, the work Steve is doing just now is relevant to the discussion -- modeling a potential fracture so as to take a view on the humps in the pressure-time plot at 220 and 250 minutes. It would be good to incorporate that, even if that has to be done in a spearate discusison later today or tomorrow. As there have been questions from the Science Team about the geology, we need a geologist with understanding of the implications of the geology for leakoff.
It would be helpful to the Science Team if they had the post-drill PPFG plot, so I will separately request to Kent Wells for release of Fig 9 from the Technical Memo: **Post-Well Subsurface Description of Macondo well (MC 252).** You may find it useful, too. Kate
<< File: Post-drill PPFG Plot aka Figure 9.ZIP >>