From: Pattillo, Phillip D
Sent: Sat Jul 03 18:40:44 2010
To: Tooms, Paul J
Cc: Hill, Trevor; Miller, Richard A; Pattillo, David; Zanghi, Mike; Willson, Stephen SM; Mason, Mike C; Mazzella, Mark; Baker, Kate H (Swift)
Subject: Release of Report - Flow Scenarios
Importance: Normal
Attachments: Macondo_Flow.ZIP
Attachments: Macondo_Flow.ZIP

Paul,

Per your request, please find a report that discusses varios hydrocarbon flow scenarios for MD 252 No. 1 from the limited perspective of well design calculations. As a reviewer of the report, Trevor is familiar with its contents. Further, Steve Willson has also reviewed the portions of the report related to calculations he and I made together. Let me know if any of the report is unclear or if you have further questions.

Thanks,

Phil

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Mississippi Canyon 252 No. 1 (Macondo)

Post-Event Flow Scenarios

Report No. 10-812-9509-02		
Prepared by	P. D. Pattillo, BP America	June 16, 2010
Reviewed by	R. A. Miller, BP America	June 17, 2010
Reviewed by	Trevor Hill, BP Exploration	June 18, 2010
Approved by	David Pattillo, BP America	June 25, 2010
Authorized by	Mike Zanghi, BP America	July 2, 2010
Issued to	Paul J. Tooms, EPT - Ops HSSE & Eng	July 3, 2010
Revision	1.0	July 3, 2010

1 Executive Summary

1.1 Conclusions

1. The internal flow (only) scenario provides a justifiable path of reservoir hydrocarbons, simultaneously predicting lift-off and a nearly neutral sustained lift-off condition.

2. The external flow (only) scenario provides plausible explanations for a variety of pressure behaviors following the blow-out event. The scenario, however, is more difficult to envision, with lift-off possible, but sustained lift-off difficult unless a sizeable pressure drop is occurring across the production casing hanger.

3. The combined internal and external flow scenario exploits the advantages of both its progenitors, allowing it to explain practically any observation. Its weakness is that it requires complete breakdown of the the cementing process, leaving both the shoe track and annular sheath open conduits to hydrocarbon flow.

2 Introduction

This report summarizes the current state of knowledge on the status of the Mississippi Canyon 252 No. 1 well using known performance properties of the well system components (see Figure 1 and Table 1). The narrative is built around a conceptual fault tree and lists possible reservoir fluid flow paths, both their genesis and their consequences. Initiating events, however, are treated as assumptions from which consequences develop—this report is intended to address wellbore response to, and not the cause of, the blow-out.

As each flow path and its consequences are discussed, both the favorable and unfavorable evidence for that conduit are enumerated. It will become clear that no path(s) is without its issues[1]. The exercise, however, may serve as a useful means of eliminating certain options through engineering analysis.

3 Fault Tree

Figure 2 presents an overview of the potential paths considered in this discussion. Starting from the lower-left of the figure, one possible path for reservoir fluid to the surface begins at the reamer shoe at the lower end of the 7 in. section of production casing and assumes (a) the shoe track between the reamer shoe and the float collar is not filled with cement and (b) the float collar is open (*i.e.*, not converted). Flow then proceeds up the inside of the casing, with eventual lift-off of the casing hanger (see Figure 3) due to fluid imbalance caused by replacing the 14 ppg drilling fluid inside the casing with lighter reservoir hydrocarbons flowing unabated to atmospheric pressure at the surface.

Now considering the lower-right of the figure, a second possible path for reservoir fluid to the surface begins external to the production casing and traverses a channeled cement sheath to the production casing annulus. Flow then proceeds outside the casing, with eventual lift-off of the casing hanger due to fluid imbalance caused by a combination of (a) seawater in the riser and casing to a depth of 8,367 ft and (b) migrated gas pressure in the production casing annulus.

A third, combined scenario starts again with the left portion of the figure and proceeds as previously described through lift-off of the production casing hanger. At this point, however, the annulus of the production casing unloads—again, perhaps, due to channeled cement—and flow paths[2] are created both interior and exterior to the production casing.

[1] At the time the technical note is being written, neither definitive pressure nor flow path evidence is available below the level of the BOP.

[2] The flow paths may not necessarily be of equal volumetric rate. The fluid may, for example, show a preference for the less convoluted path up the inside of the casing.

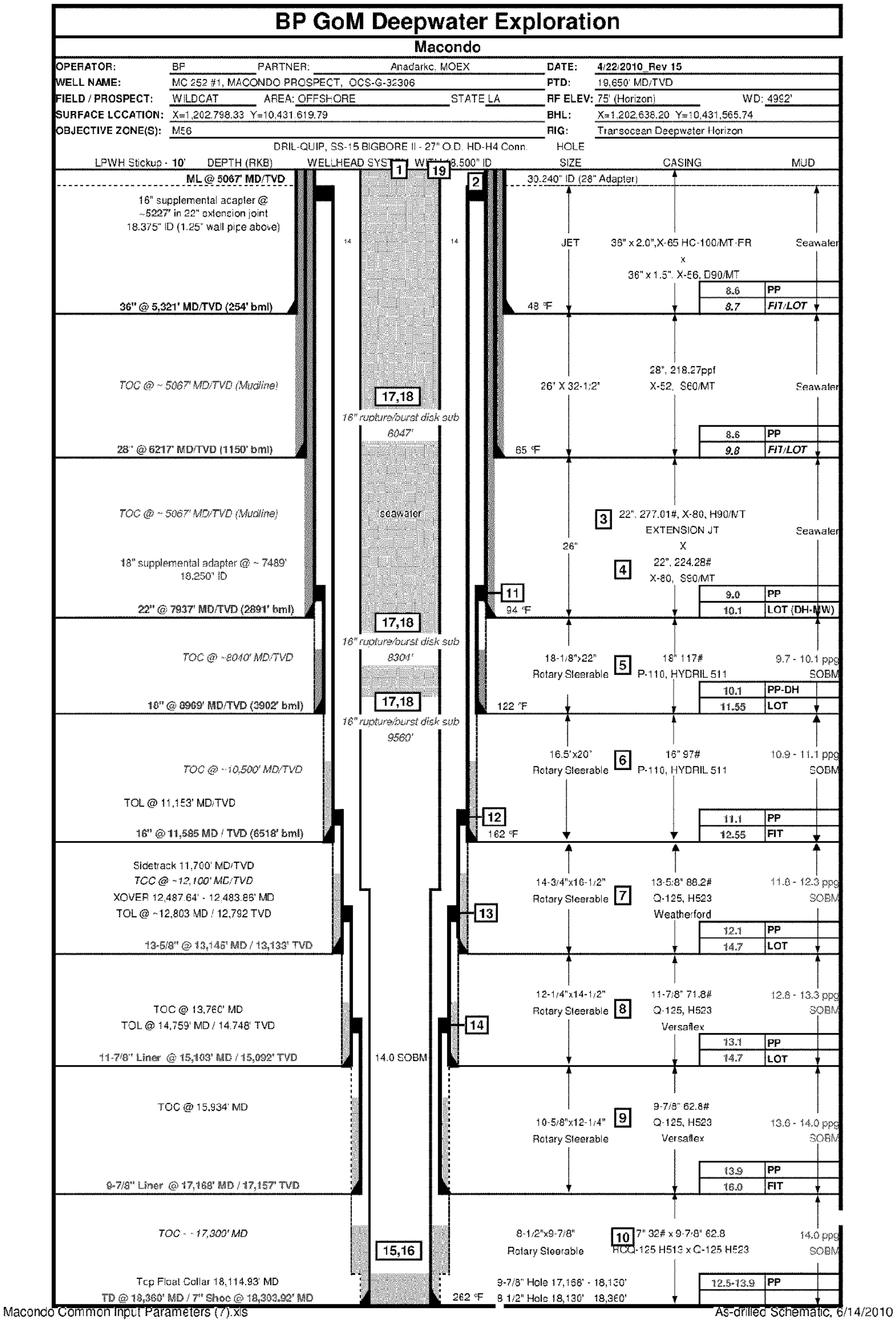

Figure 1. Schematic of Mississippi Canyon 252 No. 1 at Time of Event

Table 1. Selected Ratings and Values in Figure 1

Label	Quantity	Value	Source	Notes
1	Mudline shut-in pressure	8,900 psi	Yun Wang	Best estimate of shut-in pressure calculated at geostatic temperatures.
2	16 in. supplemental adapter seal[a]	6,500 psi	Jay Leonard	From top.
		5,000 psi		From bottom.
3	22 in., 277 ppf, X80 casing	7,950 psi	ISO 10400	MIYP[b]
		8,380 psi		Rupture[c]
4	22 in., 224.28 ppf, X80 casing	6,360 psi	ISO 10400	MIYP[b]
		6,640 psi		Rupture[c]
5	18 in., 117 ppf, P110 casing	6,680 psi	ISO 10400	MIYP[b]
		7,560 psi		Rupture[c]
6	16 in., 97 ppf, P110 casing	6,920 psi	ISO 10400	MIYP[b]
		7,830 psi		Rupture[c]
7	13-5/8 in., 88.2 ppf, Q125 casing	10,030 psi	ISO 10400	MIYP[b]
		10,970 psi		Rupture[c]
8	11-7/8 in., 71.8 ppf, Q125 casing	10,720 psi	ISO 10400	MIYP[b]
		11,760 psi		Rupture[c]
9	9-7/8 in., 62.8 ppf, Q125 casing	13,840 psi	ISO 10400	MIYP[b]
		15,370 psi		Rupture[c]
10	7 in., 32 ppf, Q125 casing	14,160 psi	ISO 10400	MIYP[b]
		15,740 psi		Rupture[c]
11	18 in. liner hanger seal[d]	3,500 psi	S. Sigurdson	From top.
		1,500 psi		From bottom.
12	13-5/8 in. liner hanger seal[d]	6,000 psi	S. Sigurdson	From top.
		6,000 psi		From bottom.
13	11-7/8 in. liner hanger seal[d]	8,200 psi	S. Sigurdson	From top.
		7,950 psi		From bottom.
14	9-7/8 in. liner hanger seal[d]	7,751 psi	S. Sigurdson	From top.
		7,501 psi		From bottom.
15	Bottom-hole pressure	11,850 psi	Yun Wang	At 18,000 ft TVD reservoir depth.
16	Bottom-hole temperature	243 °F	Yun Wang	At 18,000 ft TVD reservoir depth.
17	Burst disk rupture pressure[e]	7,125 psi	Rich Miller	Internal pressure differential to open burst disk at 200°F.
18	Collapse disk rupture pressure	1,600 psi	Rich Miller	External pressure differential to open collapse disk.
	Collapse disk back-pressure	>7,000 psi[g]		Minimum back-pressure (*i.e.*, internal pressure differential) sustainable across the collapse disk at 150°F.
19	9-7/8 in. casing hanger seal[f]	15,000 psi	S. Sigurdson	From top.
		10,000 psi		From bottom.

[a] Differential pressure of seal assembly rating on 16 in. supplemental adapter.

[b] Minimum internal pressure differential to initiate yield on inner surface at room temperature.

[c] Minimum internal pressure differential to rupture casing at room temperature.

[d] Differential pressure of seal assembly rating on 18 in. liner hanger.

[e] Reflects low side of ±5% manufacturing tolerance.

[f] Differential pressure of seal assembly rating on 9-7/8 in. casing hanger.

[g] See David Pattillo, "Backpressure Testing of Macondo Collapse Disks," Revision A, May 15, 2010.

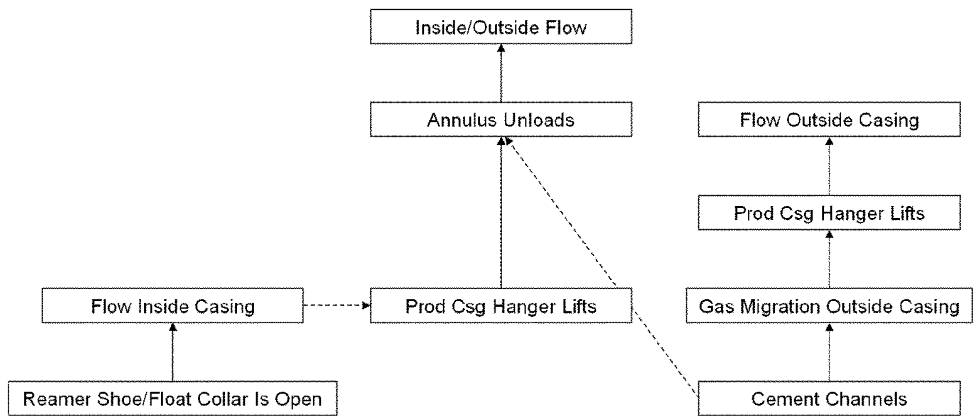

Figure 2. Fault Tree Overview of Mississippi Canyon 252 No. 1 Flow Paths

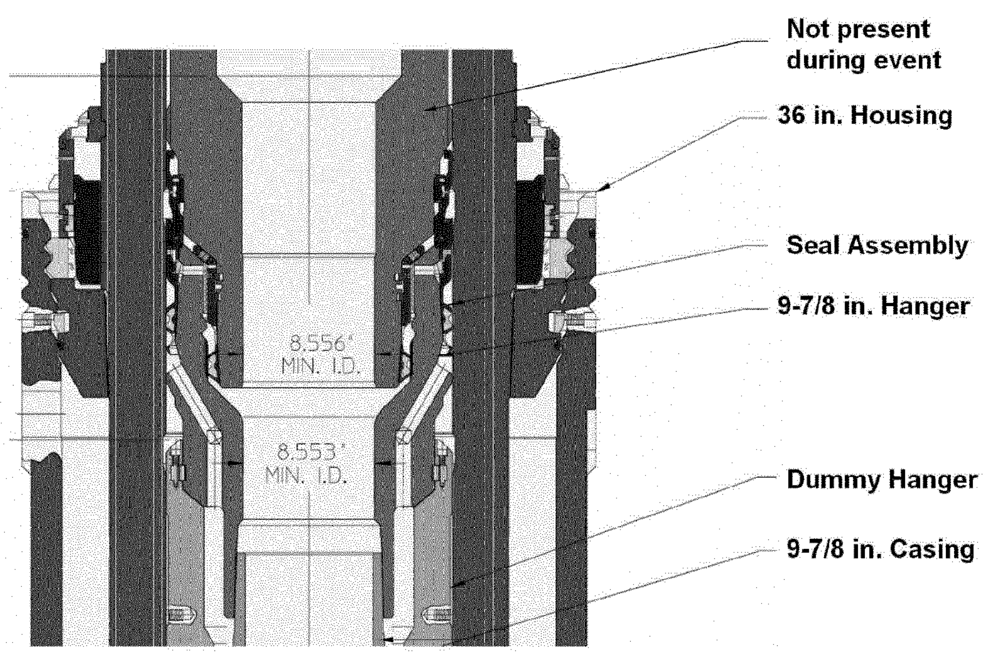

Figure 3. Schematic of 18-3/4 in. Wellhead with 9-7/8 in. Hanger and Seal Assembly

At several points the fault tree addresses lift-off of the production casing from its hanger. For future reference, the results of these calculations, briefly outlined in Section 4, are presented below in Table 2.

Table 2. Summary of Production Casing Hanger Lift-Off Calculations

State	ΔL_{XO}	ΔL_{bal}	ΔL_T	ΔF_{hgr}	F^a_{hgr}	ΔL_{LO}
Initial Condition	0.00	0.00	0.00	0.00	514[c]	N/A
Internal Flow Lift-Off	3.29	4.46	0.00	-533	-331	10.5
Sustaining Internal Flow Lift-Off	1.55	1.82	9.11	-46	7	N/A[d]
External Flow Lift-Off	1.23	1.77	0.00	-313	39	N/A[e]
Sustaining External Flow Lift-Off	-2.46	-3.22	9.11	-45	293[f]	N/A

Length changes are in feet; forces and force changes are in klb.

[a] $F_{hgr} = F^i_{hgr} + \Delta F_{hgr}$.

[b] Six inches (0.5 ft) of upward movement are required to unseat the metal-to-metal seal.

[c] $F^i_{hgr} = 514$, the initial hanger load following waiting-on-cement.

[d] A differential (below to above) pressure of 27 psi across the hanger is required to sustain lift-off; an additional 64 psi will sustain lift-off with $\Delta L_{LO} = 0.5$ ft.

[e] A differential (below to above) pressure of 158 psi across the hanger is required to initiate lift-off; an additional 64 psi will initiate lift-off with $\Delta L_{LO} =$ 0.5 ft.

[f] A differential (below to above) pressure of 1,186 psi across the hanger is required to sustain lift-off; an additional 64 psi will sustain lift-off with $\Delta L_{LO} =$ 0.5 ft.

3.1 Internal Flow

The main supporting evidence for flow of reservoir hydrocarbons up the inside of the production casing is the continuing jet of gas at the top of the LMRP[3] throughout both unabated flow and the top-kill effort, as evidenced by the ROV film. Presumably the flow is aided by an unrestricted flow path near the surface, and especially through the BOP, through drill pipe suspended in the BOP (see Figure 4).

Although internal flow in the production casing is easy to verify visually, actual prediction of flow, that is pressure and flow rate, is less straightforward. Given current knowledge of the flow potential of the main reservoir, there is significant evidence that the flow is being choked by a restriction relatively deep in the wellbore. If the fault tree is accurate, this restriction could be in the shoe track below the cementing float collar.

Given flow inside the casing and subsequent loss of well control, the reservoir hydrocarbons would flow to the surface unabated. Taking the reservoir fluid density to be 4.37 ppg or 0.227 psi/ft, and calculating downward from an atmospheric surface pressure, lift-off of the production casing at its hanger is predicted under the following assumptions:

- The fluid pressure calculation is purely hydrostatic, ignoring friction losses and tortuosity of the flow path.
- The contact between the production casing hanger metal-to-metal seal and the bore of the wellhead is frictionless.

[3] Lower marine riser package.

Figure 4. Upstream View of Riser Cut at "Kink" Showing Trapped Drill Pipe Joints

- Full reservoir temperature is conveyed to the mudline by the flowing hydrocarbons and is available for sustaining lift-off.

lift-off of the production casing at its hanger is predicted. Once lift-off occurs the production casing annulus is open to the surface which may (see Section 3.3) or may not (this section) result in an additional conduit from the reservoir.

3.1.1 Supporting Evidence

1. Visual evidence of a continuing gas jet throughout the top-kill attempt.

2. According to the summarized calculations in Table 2, flow interior to the production casing (State = Internal Flow Lift-Off) can lift the casing hanger off its profile with sufficient excess movement (potentially 10.5 ft) to unseat the metal-to-metal seal in the wellhead[4]. Unseating

[4]Whether lift-off of the production casing hanger qualifies as supporting evidence for the case of internal (only)

the seal assembly can occur in the absence of any temperature change (*i.e.*, $\Delta L_T = 0$).

Once the hanger seal is unseated, pressures on either side of the large hanger area[5] will equalize, removing a significant component (533 klb) of the force lifting the hanger. With internal flow, absence of this force is compensated by temperature change. Although Table 2 does not predict sustained lift-off, only a 27 psi pressure drop (from below the hanger to above the hanger) is necessary across the hanger/unseated metal-to-metal seal to realize continued lift-off[6]. Further, the large potential upward movement suggests significant travel by the seal that may make it difficult to regain its seat.

Contra sustained lift-off for the internal flow (only) scenario is the fact that the sustaining pressure drop must come from below. If there is no annular flow, the production casing hanger will attempt to achieve its hang-off position. This below-to-above sustaining force requirement also suggests that, unless significant damage or obstruction occurs during lift-off, it is unlikely that the annulus would present itself as a significant flow path during a top-kill attempt. The tendency of the hanger when subjected to differential pressure from above would be to re-seat.

Sustained lift-off of the seal assembly does not necessarily do damage to elements in the production casing annulus. Originally, when the seal was set, the pressure equivalent of a 14 ppg hydrostatic head was trapped under the seal assembly. With lift-off, this pressure external to the production casing will dissipate until pressure equilibrium is achieved with the interior flowing fluid. This equilibrium, however, requires a pressure decrease, which would lower the load seen by members forming the boundary of the production casing annulus[7]. The disabled seal could complicate the top-kill attempt by permitting an additional path for kill fluids to take as opposed to the path open to the reservoir through the interior of the

flow is debatable. The case of lift-off implied by this scenario does, however, identify it as the originating and, possibly, dominant flow path for the combined flow case discussed in Section 3.3. The early presentation of lift-off in this discussion is meant to introduce the subject where it is most plausible, hopefully paving the way for the later, more difficult lift-off scenario in the context of external (only) flow.

[5]The upper surface of the hanger is bounded by the inside diameter of the casing (8.625 in.) and the seal bore of the wellhead (18.510 in.), and is 211 in^2. The lower surface of the hanger is bounded by the outside diameter of the casing (9.875 in.) and the bore of the wellhead, and is 193 in^2.

[6]A grove exists in the wellhead bore above the hanger and seal such that an upward movement of 6 in. will unseat the metal-to-metal seal. Presumably, if the hanger/seal assembly tries to exit this groove, the decreasing flow area at the point of the seals could easily produce a pressure differential of 27 psi. The unseated hanger/seal is essentially floating in a sustained state of lift-off.

[7]For an alternate view, see Section 3.3 which discusses the possibility of flow channels both interior and exterior to the production casing.

production casing. As noted in the previous paragraph, however, the disabled seal would have to be seriously impaired, as the preferred response of the hanger to a pressure differential from above would be to close.

3.1.2 Detracting Evidence

1. There are no major detractors to this scenario. A frequent question is that, discounting a major flow path opening if the production casing seal assembly is disengaged (Item 2 under Supporting Evidence above), if the inside of the production casing is the only flow path for hydrocarbon fluids from the reservoir, then why did the top-kill fail to arrest flow? On the other hand, OLGA[8] flow simulations suggest that alternate flow paths, coupled with the well flow rate, could have diverted kill fluid to the point of rendering the kill attempt unsuccessful.

3.1.3 Resolution

The internal flow (only) scenario provides a justifiable path of reservoir hydrocarbons, simultaneously predicting lift-off and a nearly neutral sustained lift-off condition.

3.2 External Flow

External flow (only) requires lift-off of the production casing hanger from the outset. Although initial lift-off is relatively easy to contemplate, sustained lift-off requires a more pronounced pressure drop across the hanger. Once lift-off occurs, continuous influx from the formation is required, and, by a slightly tortuous path, this flow could reach the surface[9]. If, by some means, the production casing seal assembly separated from the hanger body on lift-off, a significant area would be available for flow (approximately 40 in^2).

Access to the production casing annulus provides a convenient means of explaining the difficulties encountered during the top-kill, and also endangers at least the inward-acting rupture disks in the outer boundary (16 in. liner) of that annulus. Once a disk ruptures, communication with the weak 18 in. liner shoe is established, providing an alternate path for reservoir fluids to exit wellbore containment.

External flow, whether alone or in combination with internal flow, presumes loss of isolation by the production casing cement sheath.

[8]SPT Group AS, P. O. Box 113, Instituttveien 10, N-2027 Kjeller, Norway, Telephone: +47 63 89 04 00, http://www.sptgroup.com/en/.

[9]The envisioned flow path is up the production casing annulus, down the drill pipe annulus and then up the drill pipe.

3.2.1 Supporting Evidence

1. Flow up the production casing annulus to the surface could have ruptured an inward acting disk, providing not only an alternate path for kill fluids during the top-kill attempt, but also providing a pressure relief that could explain the observed value of flow pressure during unabated flow of reservoir fluids following the blow-out.

   The inward-acting disks rupture at a differential pressure of 1,600 psi. Given unabated flow to the surface, and ignoring friction loss and tortuosity of the flow path, the hydrostatic head of reservoir fluid from the surface to the depth of the middle disk sub is 0.227 psi/ft $\times$ 8,304 ft = 1,885 psi. The pressure external to the disk is 0.051948 psi/(ft ppg) $\times$ [10.2 ppg $\times$ 8,969 ft - 11.1 ppg $\times$ (8,969 - 8,304) ft = 4,369 psi. The differential pressure at the disk is, therefore, 4,369 - 1,885 = 2,484 psi, a pressure sufficient to rupture the disk[10].

   If a collapse disk ruptures, the 18 in. liner shoe is exposed, with the property that prolonged fluid loss with sufficient rate at this shoe will eventually reach the surface[11]. Further, the shoe acts as a pressure regulator under steady flow conditions. As an example, Liao and co-workers[12] have demonstrated that, should a disk rupture, a flow path from the wellhead, external to the production casing, through the disk rupture, to the 18 in. shoe, and regulated by the fracture pressure at the 18 in. shoe (5,235 psi), will result in a flowing wellhead pressure of between 4,221 psi (oil) and 4,681 psi (gas), close to that observed during steady state flow of Mississippi Canyon 252 No. 1.

   Further, a leak path through a ruptured disk to the 18 in. shoe provides one possible explanation for the difficulties experienced during the top-kill operation. Consider Figures 5–7 which depict, respectively, flow before, during and after the top-kill attempt[13]. Prior to the top-kill, and again referencing the work of Liao and co-workers, the production casing annulus, along with at least a portion of the 16 in. annulus is full of reservoir hydrocarbons down to the 18 in.

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[10] The calculation is performed computing back-up pressure from the 18 in. shoe upward. One can also compute back-up from the 16 in. hanger seal downward with similar results. For example, and now considering the uppermost disk, the hydrostatic head of reservoir fluid from the surface to the depth of the uppermost disk sub is 0.227 psi/ft $\times$ 6,047 ft = 1,373 psi. The pressure external to the disk is 0.051948 psi/(ft ppg) $\times$ 11.1 ppg $\times$ 6,047 ft = 3,487 psi. The differential pressure at the disk is, therefore, 3,487 - 1,373 = 2,114 psi, a pressure sufficient to rupture the uppermost disk.

[11] Stephen Willson, "Potential for broach at the 18-inch casing shoe in the Macondo well during top-kill operations," May 14, 2010.

[12] Tony Liao, with contributions by Mark Alberty and Stephen Willson, "Conditions Required to Shut Down a Broach to the Sea Bed," Version A, May 21, 2010.

[13] The figures focus on flow in the annulus. Possible flow inside the casing is ignored, but not necessarily discounted.

shoe (Figure 5). An oil gradient extrapolated to the mudline approximates the observed[14] lower BOP pressure. During the top-kill a portion of the kill mud enters the annulus at a wellhead pressure higher than that needed to fracture the 18 in. shoe (Figure 6). A portion of this mud might have arrested flow of hydrocarbons up the annulus. The easier path for those fluids, however, would be through the ruptured disk and out the 18 in. shoe[15]. Finally, following the top-kill (Figure 7), the reservoir would quickly regain control, flowing both up the production casing annulus to the wellhead and out the ruptured disk replacing mud which entered the 16 in. annulus during the top-kill. With time, the flow would be expected to return to the status depicted in Figure 5.

2. The comments of the previous item conjure the rupture of an inward-acting disk and creation of an additional flow path/exit at the 18 in. shoe. Repeated calculations by various workers have investigated the possibility of rupturing an outward-acting disk—so far without success. As an example, the last recorded drill pipe pressure at the surface on the *Deepwater Horizon* was 5,700 psi. Adding a seawater gradient to this value, at the mudline the pressure inside the drill pipe is 5,700 psi + 0.051948 psi/(ft ppg) $\times$ 8.6 ppg $\times$ 5,067 ft = 7,964 psi. Traversing down the drill pipe, then up the drill pipe annulus back to the mudline adds an additional 0.051948 psi/(ft ppg) $\times$ (8.6 - 4.37) ppg $\times$ (8,367 - 5,067) ft = 725 psi, for a cumulative pressure in the drill pipe annulus at the mudline of 8,689 psi. Finally, adding the hydrostatic pressure of 14 ppg mud from the mudline down to the first disk sub, the internal pressure on the uppermost outward-acting disks is 8,689 psi + 0.051948 psi/(ft ppg) $\times$ 14 ppg $\times$ (6,047 - 5,067) ft = 9,402 psi. The 16 in. annulus pressure at this same depth is 0.051948 psi/(ft ppg) $\times$ [10.2 ppg $\times$ 8,969 ft - 11.1 ppg $\times$ (8,969 - 6,047) ft = 3,068 psi. The differential pressure at the disk is, therefore, 9,402 - 3,068 = 6,334 psi, substantially less than the temperature derated disk rating of approximately 7,100 psi. Of course, the last drill pipe pressure recorded may not be the highest drill pipe pressure experienced, but to date, the search for a scenario by which an outward-acting disk might rupture has been unsuccessful.

   Notwithstanding the inability of current calculations to rupture an outward-acting disk, an alternate "outward" path similar to a burst disk is that provided by the 9-7/8 in. liner shoe. Figure 8, discussed in more detail below, indicates that before an outward-acting disk would rupture one should expect the formation to fracture at the liner shoe. This formation break-

[14] In connection with the top-kill a 966 psi error was discovered in the lower BOP pressure measurement. The values on the figure have been corrected for that error.

[15] There may be a rate issue at this point in the scenario. That is, how many disks rupture to create an increasing flow path for exiting fluids? Six inward-acting disks are available—all designed to rupture at approximately the same annulus pressure environment—so all disks could have ruptured.

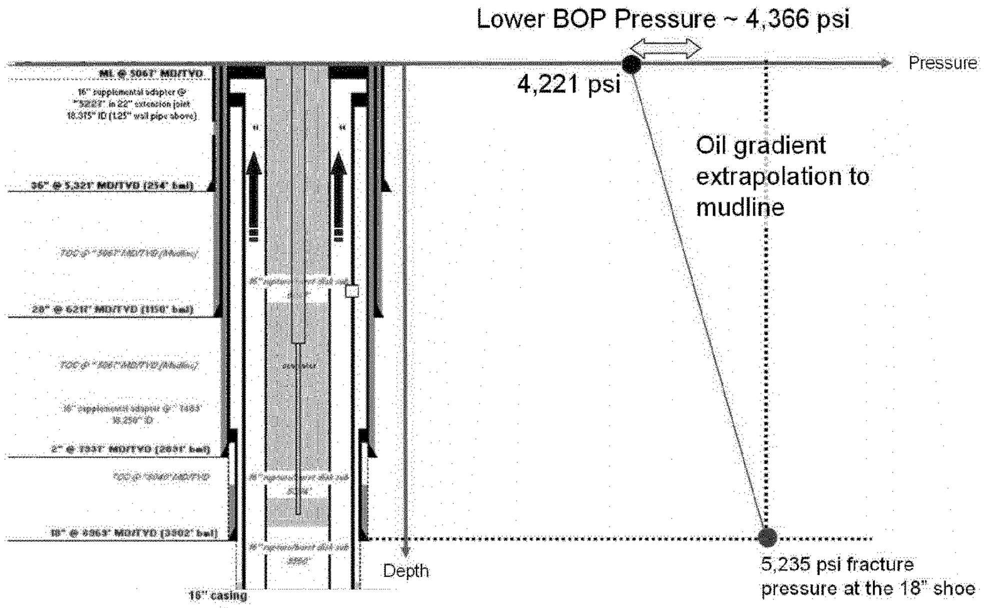

Figure 5. Scenario with Ruptured Collapse Disk—Hydrocarbon Flow Prior to Top-Kill

down could serve the same function as the ruptured inward-acting disk in Figure 6 during the top-kill. Steady-state flow with approximately 4,400 psi at the lower BOP gauge, however, is less easy to reproduce as the fracture pressure at the 9-7/8 in. liner shoe minus a hydrocarbon gradient to the mudline is roughly 11,000 psi which would require a significant pressure drop at the production casing hanger/seal assembly to yield a reasonable value. The case does seem plausible if one assumes a restriction to reservoir flow located below the liner shoe. That is, the 9-7/8 in. liner shoe limits downward (*i.e.*, kill) pressures, but is not the limit point for upward reservoir flow in the production casing annulus.

3.2.2 Detracting Evidence

1. Inasmuch as initial lift-off requires a pressure beneath the production casing hanger slightly greater than that which would be trapped with the setting of the seal assembly, a source of additional pressure is essential to this scenario. Two obvious sources of pressure exist:

   (a) Reservoir hydrocarbons. Gas has been identified either within or just above the reservoir. In either case, and presuming a channel through the production casing cement sheath, this gas could migrate to the surface and provide the additional pressure necessary to

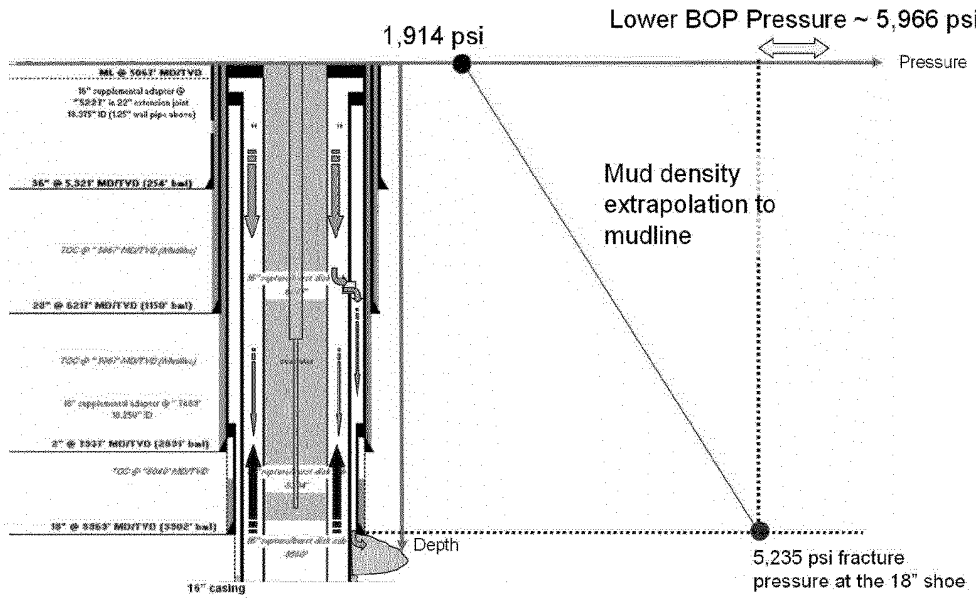

Figure 6. Scenario with Ruptured Collapse Disk—Mud Flow During to Top-Kill

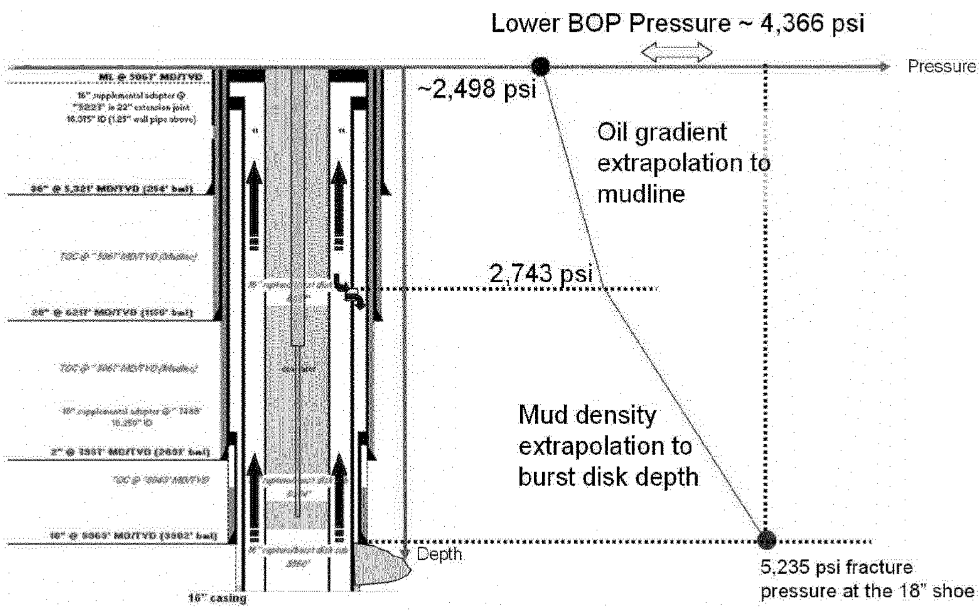

Figure 7. Scenario with Ruptured Collapse Disk—Hydrocarbon Flow Immediately after Top-Kill

lift the production casing hanger. From Table 2 (State = External Flow Lift-Off) an additional pressure differential across the hanger of only 158 psi will initiate lift-off. Further, as indicated in a technical note by R. A. Miller[16], the post cement placement temperature distribution in the production casing annulus is such as to produce a small temperature change from the reservoir to the mudline. Near reservoir pressure would potentially be available at the mudline under the hanger.

The primary detractor from this scenario is the time it would take for reservoir hydrocarbons to migrate to the mudline. Hearsay evidence of calculations made by others suggests this time is on the order of days, much longer than the time between the production casing cementing operation and the blow-out event.

(b) Nitrogen from foam cement. The argument proceeds along lines parallel to those described above. Nitrogen liberated from the tail slurry of the cement column could have risen in the annulus to beneath the hanger and aided lift-off with a pressure approaching that of the nitrogen at reservoir depth. Supporting this possibility is the low solubility of nitrogen in the synthetic mud in the production casing annulus, which would reduce the transit time to about 200 minutes[17]. Contra this possibility is the insight by R. A. Miller, "This would require nitrogen to break out of the cement slurry, migrate through the lead slurry, and rise into the cased hole. Then, the lead slurry would have to cure rapidly prior to the nitrogen migrating through the 14 ppg spacer and mud." That is, migration of the nitrogen to surface requires a slightly convoluted series of processes to occur.

Possibly mitigating against either of the gas sources above is the integrity of the production casing annulus. Figure 8 illustrates the integrity of crucial components in the production casing annulus including the outward-acting rupture disks, the liner top hangers/seals and the formation at the 9-7/8 in. liner shoe. For the various components the rating (plus possible external pressure back-up) of the weakest member[18] is projected to the surface as an indication of the wellhead-vicinity pressure that would be required to fail the component. Of the various mechanical components, the liner hanger seals are the weakest, followed by yield of the 16 in. casing and then the outward-acting rupture disks. The wellhead pressures corresponding to the ratings of these components (*i.e.*, intersection of dashed lines with mudline) are in the

[16] Rich Miller, "Macondo: Integrity of the 9-7/8″ × 7″ Production Casing," Revision A, May 10, 2010.

[17] See Rich Miller, "Macondo: Integrity of the 9-7/8″ × 7″ Production Casing," Revision A, May 10, 2010. The calculation is based on [1].

[18] Exception: The 13-5/8 in. hanger seal is projected to the mudline rather than the 16 in. hanger seal, as the latter is practically at the mudline.

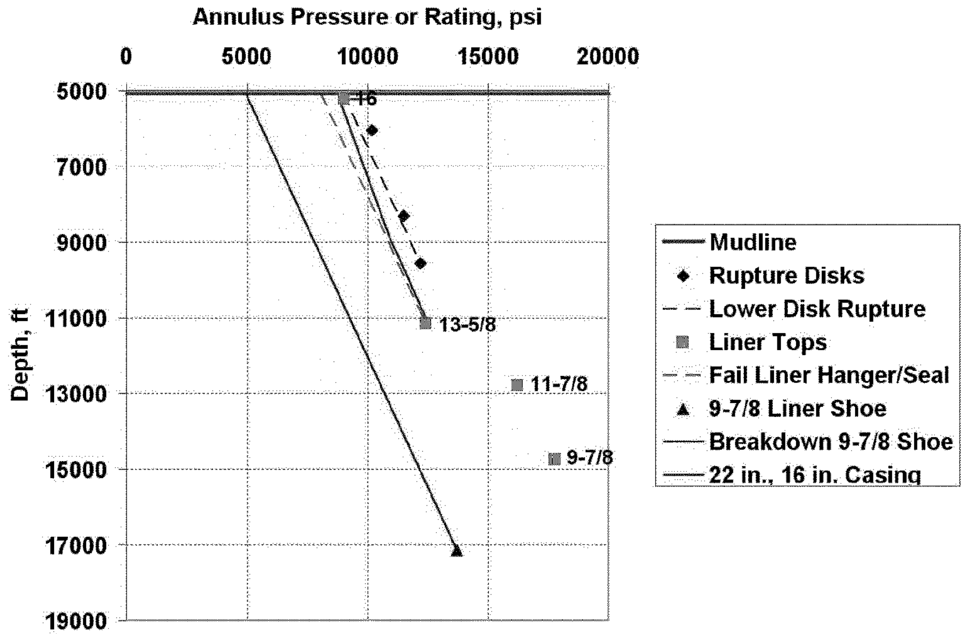

Figure 8. Pressure Limits in Macondo Production Casing Annulus

range 8,000–8,900 psi. Standing out, however, from the relatively clustered ratings of upper hole components is the integrity of the 9-7/8 in. liner shoe, which fractures at a wellhead pressure of approximately 4,900 psi[19]. For the present, simply note that, comparing the calculations summarized in Table 2 with the results of Figure 8, it would be possible to initiate (158 psi) and sustain (1,186 psi) lift-off of the production casing hanger with relief from failure of one of the outer annulus boundary components.

3.2.3 Resolution

The external flow (only) scenario provides plausible explanations for a variety of pressure behaviors following the blow-out event. The scenario, however, is more difficult to envision, with lift-off possible, but sustained lift-off difficult unless a sizeable pressure drop is occurring across the production casing hanger.

[19]Recalling the discussion under Supporting Evidence of this section regarding the role a ruptured disk might play in mitigating the effects of the top-kill attempt, might that same role not be assumed by fracture break-down of the 9-7/8 in. shoe?

3.3 Internal and External Flow

The main support for flow up both the inside and outside of the production casing is that (a) this scenario can be readily explained by first inner flow, then hanger lift-off followed by outer flow, and (b) it can be made to explain almost any of the unabated flow and kill evidence collected.

3.3.1 Supporting Evidence

1. The discussion of Section 3.1 provides the genesis of this scenario. Once internal flow lifts off the production casing hanger, the 14 ppg trapped pressure under the hanger is released (equilibrating with the pressure of internal flow at wellhead depth) and the potential for the reservoir to unload through the production casing annulus is realized (assuming a channeled cement sheath). One now has both internal and external flow, with either or both limited by chokes at the reservoir (both), shoe track (internal) and cement sheath (external). The alternate paths join at the wellhead with annular fluids either flowing down the drill pipe annulus, then up the drill pipe, or flowing external to the drill pipe through the BOP. Multiple paths, coupled with multiple exit points (ruptured inward-acting disk or 9-7/8 in. shoe) mitigate the efforts of the top-kill[20].

3.3.2 Detracting Evidence

1. The primary, but not unbelievable, detractor from this scenario is that it requires a total breakdown in cement placement—both failure of the float collar to convert and incomplete cement insolation by the external sheath.

3.3.3 Resolution

The combined internal and external flow scenario exploits the advantages of both its progenitors, allowing it to explain practically any observation. Its weakness is that it requires complete breakdown of the the cementing process, leaving both the shoe track and annular sheath open conduits to hydrocarbon flow.

[20]Although the 9-7/8 in. shoe appears weak as an *initiator* of flow outside the wellbore, unabated flow at the 9-7/8 in. shoe is unlikely. If, for example, reservoir hydrocarbons enter the production casing annulus due to lift-off of the production casing hanger, complete replacement of the 14 ppg mud in the production casing annulus and sustained hydrocarbon flow through a fracture at the 9-7/8 in. liner shoe would require an equalized hanger pressure of approximately 11,000 psi.

4 Appendix—Lift-Off Calculation

The lift-off calculation performed on the production casing at Mississippi Canyon 252 No. 1 begins with the casing hanging under its own weight (*i.e.*, gravity) and in (a) the fluid environment in place at the time the cementing plugs were bumped[21], and (b) a temperature environment defined by the undisturbed, geostatic temperature gradient[22]. From this initial state, potential movement of the casing and lift-off of the hanger consists of three effects:

1. Change in axial force on the cross-over between the upper (9-7/8 in.) and lower (7 in.) sections of production casing. The length change given by this concentrated force is

$$\Delta L_{XO} = -\frac{L^{-}\left[\Delta p_i\left(A_i^{+} - A_i^{-}\right) + \Delta p_o\left(A_o^{-} - A_o^{+}\right)\right]}{E\left(A_o^{-} - A_i^{-}\right)}. \tag{1}$$

2. Ballooning, that is, the change in axial length with a change in lateral internal and external pressure,

$$\Delta L_{bal} = -\frac{\nu}{E}\frac{2L}{r_o^2 - r_i^2}\left(\overline{\Delta p}_i r_i^2 - \overline{\Delta p}_o r_o^2\right). \tag{2}$$

3. Temperature change,

$$\Delta L_T = \alpha L \overline{\Delta T}. \tag{3}$$

In computing ΔL_{bal} and ΔL_T in Equations 2 and 3, separate length changes over each section of the production casing must be summed. Length change due to possible column buckling is ignored.

Between the initial state and the final state the input quantities Δp_i, Δp_o and ΔT are calculated along the uncemented portion of the production casing and then averaged to obtain $\overline{\Delta p}_i$, $\overline{\Delta p}_o$ and $\overline{\Delta T}$. With the geometry of the tubulars, these quantities are substituted into Equations 1–3 to yield ΔL_{XO}, ΔL_{bal} and ΔL_T. Under the assumption that the (initial) hanging weight of the casing is maintaining contact between the casing and its landing profile in the wellhead (*i.e.*, the casing does not lift off its hanger), the force reduction at the depth of the hanger can be calculated from

[21] The BP default for fluids and pressures in the initial condition consists of the displacement fluid (internal) and drilling fluid, spacer and cement slurry(s) present at the end of cement displacement. The cement is assumed to thicken instantaneously with no change in the hydrostatic head external to the casing during this period.

[22] The BP default for temperature in the initial condition is the undisturbed temperature gradient. Identifying the post cementing temperature with the undisturbed temperature is a common assumption in casing design. It is possible to model the planned cementing operation and waiting time with a thermal simulator such as WellCat. Inasmuch as the actual times associated with a cement job may not correspond to plan, however, for consistency an initial temperature profile associated with the undisturbed temperature is used.

$$\Delta F_{hgr} = -\frac{\Delta L_{XO} + \Delta L_{bal} + \Delta L_T}{\frac{L^-}{EA_p^-} + \frac{L^+}{EA_p^+}} + \Delta p_i A_{hgr}^+ - \Delta p_o A_{hgr}^-, \tag{4}$$

where the last two terms on the RHS of Equation 4 account for changes above and below the hanger, respectively. This decrement will adjust the initial F_{hgr}^i. If the result is positive, the hanger remains seated. If the result is negative, the hanger will lift off by an amount

$$\Delta L_{LO} = -\left(F_{hgr}^i + \Delta F_{hgr}\right)\left(\frac{L^-}{EA_p^-} + \frac{L^+}{EA_p^+}\right). \tag{5}$$

4.1 Symbols

A_{hgr} area of production casing hanger

A_i area of the pipe internal cross section, $A_i = \pi/4d^2$

A_o area of the pipe external cross section, $A_o = \pi/4D^2$

A_p area of the pipe cross section, $A_p = \pi/4(D^2 - d^2)$

D specified pipe outside diameter ($= 2r_o$)

d pipe inside diameter, $d = D - 2t = 2r_i$

E Young's modulus

F_{hgr}^i initial axial force at hanger

F_{hgr} axial force at hanger

L length

ΔL_{bal} length change created from a change in internal pressure, external pressure or fluid density from the initial condition

ΔL_{LO} lift-off length of hanger due to excess loss of initial hanging force

ΔL_T length change created from a change in temperature from the initial condition

ΔL_{XO} length change created from a change in axial force at a crossover from the initial condition

p_i internal pressure

p_o external pressure

r_i internal radius

r_o external radius

T temperature

t specified wall thickness

α_T coefficient of linear thermal expansion

ν Poisson's ratio

$\overline{()}$ average of (), usually over length

$\Delta()$ change in ()

$()^-$ quantity () below the crossover

$()^+$ quantity () above the crossover

References

[1] A. B. Johnson and D. B. White. Gas-rise velocities during kicks. *SPE Drilling Engineering*, 6(4):257–263, December 1991.