Exploration & Production **Technology**

Technical Memo

Title: **Impact of well shut-in and flow out of the 18" shoe**

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Draft for Comment

Items Addressed in this Memo

This note discusses the potential impact of a 16" casing leak path existing for hydrocarbons to enter the 18" x 16" annulus and the consequences of potential fracturing of the exposed formation below the 18" casing shoe.

Principal Conclusions

1. For the three shut-in scenarios considered - a short-term shut-in of less than 1 week; (ii) a medium-term hurricane evacuation lasting up to two weeks; and (iii) a long-term shut-in of up to two months - there is little associated negative downside risk. The potential positives - principally that of confirming the integrity of the 16" casing - present a compelling case for considering a shut-in.
2. Three injection and fracturing scenarios are possible, depending upon the capacity of the formation to dissipate the injected hydrocarbons in to sands that might be present at depths shallower than the 18-inch casing shoe. In the case that 16-inch casing integrity is compromised, wellhead injection pressure responses will not be diagnostic to determine which fracturing injection scenario applies. Broaching to surface can only be confirmed by visual ROV survey inspections.
3. If no broaching occurs after a short- and medium-duration shut-in (for well integrity assessment of hurricane evacuation) the option exists to prolong the shut-in. If broaching has occurred, then the situation is no worse than continued wellhead flow, and the resumption of wellhead flow will divert the flow of hydrocarbons from the fracture which will be expected to slowly heal over time.
4. Should the well be shut-in at the time of the relief well intercept kill, it is recommended that wellhead flow be resumed for the kill operations as it will be important to visually monitor changes in flow rate and fluid composition as the kill proceeds.

Context & Issues of Concern

Previous technical memos have assessed the potential for a broach to seabed by a hydraulic fracture propagating from the 18" shoe[1,2]. This current note summarizes the findings of these previous studies and comments further in a wider context upon the impact of sub-surface injection at the 18" shoe at a depth of 3902 feet below mudline. This discussion is pertinent as in the near-term it may become possible to shut-in the flowing Macondo MC252-1 well with a blow-out preventer that has supplemented capability that allows this to occur. Were the well to be shut-in, three shut-in scenarios are possible - (i) a short-term shut-in (of less than 1 week duration) with the objective of assessing the pressure integrity of the well; (ii) a hurricane evacuation shut-in (potentially lasting up to two weeks); and (iii) a longer-term shut-in period where the well is

1 "Potential for a broach at the 18-inch casing shoe in the Macondo well during top-kill operations", EPT Drilling Specialist Technical Support Team Memo, Version 2, 14th May 2010.

2 "Updated analyses simulating a broach at the 18-inch casing shoe in the Macondo well during possible shut-in operations", EPT Drilling Specialist Technical Support Team Memo, Version 0, 29th June 2010

shut-in awaiting the successful intersection by the relief wells. (Here several weeks - 1 to 2 months - of shut-in time might be conceivable).

When the well is shut-in, in the absence of leak paths in the 16-inch casing, it is expected that wellhead pressures will increase above 7000 psi depending upon the amount of reservoir depletion that has occurred in the M56 reservoir sands (7260 psi - 8600 psi range likely[3]). These pressures are insufficient to rupture an outward-facing burst disk during the shut-in period (in excess of 10,000 psi pressure is needed[4]). It is assumed here that were a shut-in build-up to occur to these required pressures then the 16-inch casing would be assumed to be pressure containing and leak-free.

However, during the blow-out event prior to the Deepwater Horizon sinking, a condition could have arisen in the case of annular flow between the 16-inch and 7-inch × $9\frac{7}{8}$-inch casings that rupture of an inward-facing collapse disk (or disks) could have occurred[4]. This would permit flow across the 16-inch casing into the 18-inch × 16-inch casing annulus. As an estimated ca. 1600-feet of uncemented open-hole interval exists below the 18-inch shoe, it is possible that a build-up of wellhead pressure can transmit sufficient pressure to below the 18-inch shoe to cause the formation to breach (fracture), so propagating a fracture away from the well.

Previous work has established that a wellhead pressure of 4221 psia (for oil) or 4681 psia (for gas) would generate a pressure that is equivalent to the fracture closure pressure of 5,235 psia at the 18-inch shoe[5]. (This work assumes negligible friction losses across the ruptured disks). There is a possibility that the inability to build significant wellhead pressure during the top-kill attempt may have been exacerbated by leakage from below the 18-inch shoe - see Figure 1. (It should be noted that excessive leakage from the wellhead and drill-pipe are additional scenarios to explain the inability to build pressure during the top-kill).

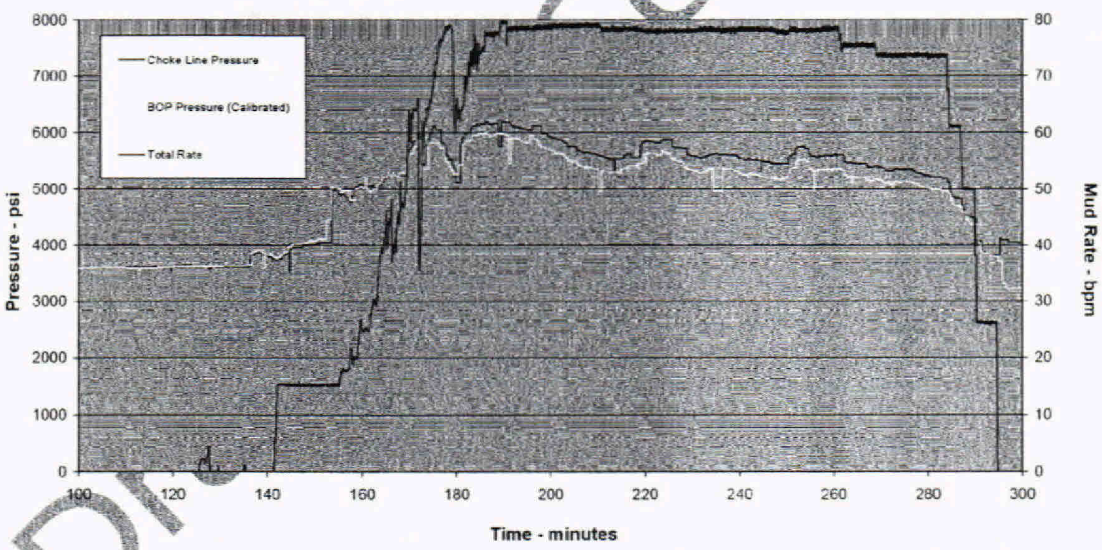

Figure 1. Pressure and injection rate variation with time during the third top-kill pumping attempt

3 "Depletion Rates", technical note written by Bob Merrill, version B-Draft, June 15th 2010.

4 "Mississippi Canyon 252 No. 1 (Macondo) Post-Event Flow Scenarios", Report No. 10-812-9509-02, written by Phil Pattillo, Revision 1.0, June 28, 2010.

5 "Conditions Required to Shut Down a Broach to the Sea Bed", technical memo written by Tony Liao, version A, May 21st 2010.

Injection scenarios at the 18" shoe

Fracturing behavior at the 18-inch shoe is strongly influenced by the distribution of sands within the overburden and their stress state relative to the more abundant shale. Detailed review of the occurrence of sands within the Macondo overburden indicates that a cumulative sand thickness of 474 feet exists above the 18-inch casing shoe[6]. This may be compared with an estimated net pay thickness of 87 feet in the Macondo reservoir. As the less compacted shallow sands will have considerably higher porosity and permeability than the deeper reservoir sands, a significant "storage" capability may be present above the 18-inch shoe to accommodate leaking hydrocarbons, provided the cumulative areal extent of the shallow sands is at least equivalent to that of the deeper reservoir.

Injection scenarios have been investigated to assess possible modes of fracture propagation[2]. End-member scenarios of fracture extent assuming either: (i) mapped permeable sands at lower stress than the overburden shale; or (ii) an impermeable shale-only overburden, are shown in Figure 2. Where permeable sands are present, these provide a containment barrier due to both their permeability - i.e. by allowing fluid to dissipate into the surroundings - and by possessing lower stress. The lower stress is important, as the fluid dissipation provided by sand permeability prevents the build-up of pressure within the formation and fracture (provided it has sufficient areal extent) so that it cannot subsequently break through into the formations above. In the case of limited sand volumes, the pore pressure in the sand would increase over time (as a function of injected volume) until it reaches the stress in the shale above, at which point the fracture would propagate upwards to the next sand layer, where the sand filling and break-through sequence would resume. Thus, there are three principal injection scenarios possible: (i) propagation of a fracture through shale resulting in a broach to surface (with an injected volume of less than 120,000 bbls); (ii) a progressive fracture / sand fill / fracture sequence that accommodates significant injected volumes and migrates to surface over an uncertain time period (but expected to be many days); and (iii) limited fracture growth intersecting sufficient permeable sands such that the dissipation of fluid into the sands matches the injection volume (this is similar to numerous water disposal wells on shore, for example). In this last scenario fracture propagation to seabed will not occur.

The hydrocarbons flowing into the formation have low density and viscosity. This has the consequence of requiring relatively small excess pressure in order to propagate a fracture into the formation. The stress differences between sands and shale are also small (typically less than 200 psi). As such the pressure versus injected volume profiles for all three scenarios are very similar - varying by the amount of stress difference between the sands (i.e. <200 psi). The consequence of this is that wellhead pressure may not be a clear diagnostic of fracturing behavior at the 18-inch shoe[7]. This is especially true in instances where significant upwards height growth occurs. If the leak path through the 16-inch casing has little pressure restriction, then the wellhead pressure will not be diagnostic of the injection response and the wellhead pressure will remain at ca. 4500 psi during the build-up. In the case it will be possible to conclude that the integrity of the 16-inch casing has been compromised. In the case that wellhead pressures rise above 7000 psi, then the integrity of the 16" casing is assured. For intermediate pressures, the possibility of a small leak exists with a large pressure drop occurring across the leak orifice. This too may be considered a positive outcome, as loss of integrity of the 16" casing is likely, but the corresponding risk of broaching to surface is significantly reduced as the injection rate is correspondingly lower. Here, the wellhead pressure response over time may be diagnostic of the rate of erosion (i.e. enlargement) of the orifice opening and the rate of flow across the 16" casing and into the formation.

[6] From spreadsheet "Macondo_sand_table.xls" by Skripnikova, Wydrinski, Wagner, & Albertin

[7] This observation is consistent with other BP reviews of large-scale water and drilling waste injection operations.

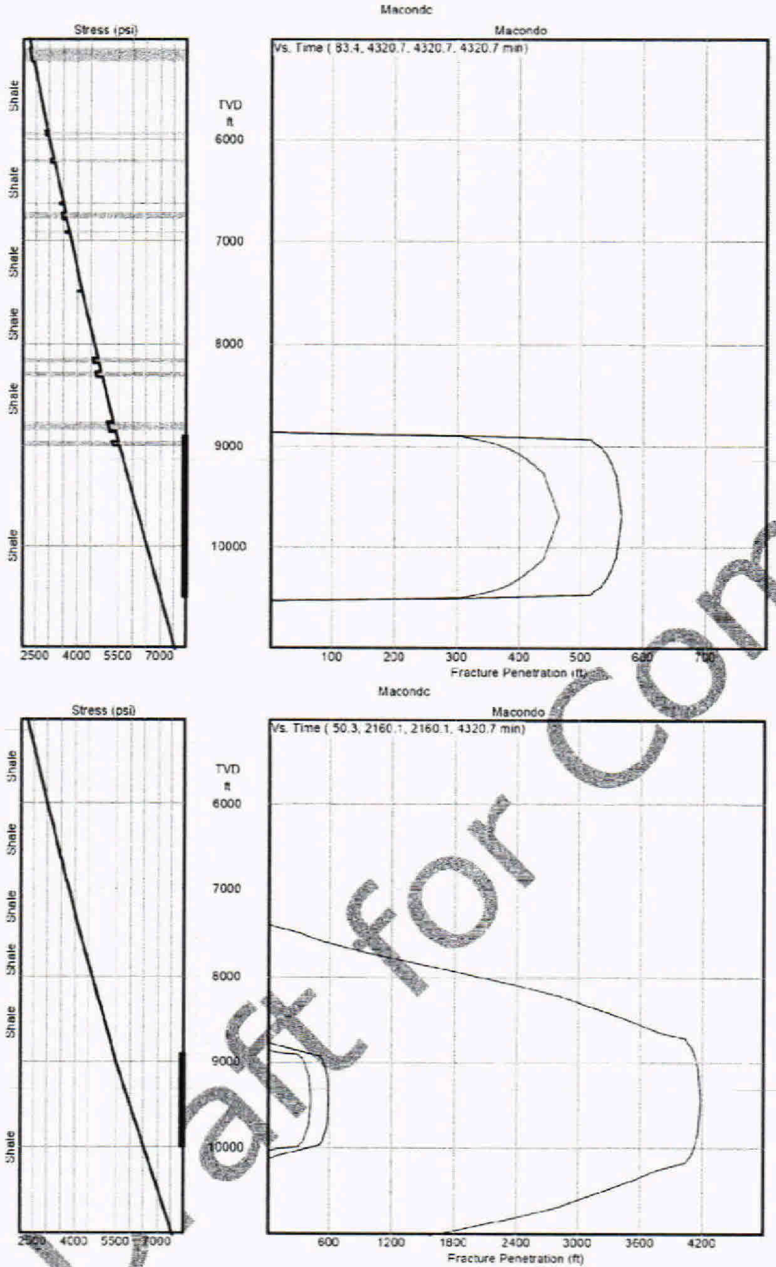

Figure 2. Predicted fracture geometries for 3 days of injection at 30,000 bpd - Top: with permeable sands with expected minimum horizontal stress lower than surrounding shale; and Bottom: impermeable shale overburden with no sands present

Summary of broaching scenarios

It is possible to condense the fracturing and broaching scenarios into a 'map' that assesses the probability of a broach to surface as a function of shut-in scenario and fracture propagation scenario. This is shown in Table 1. Building on these outcomes, a scenario map indicating broach / fracturing consequence is presented in Table 2, and a scenario map indicating additional actions for shut-in relative to continued wellhead flow is presented in Table 3.

The evaluated scenarios indicate a low-level of risk of broaching if conducting a well integrity shut-in of less than 1 week. Here the worst likely "regret exposure" is that a broach to seabed occurs in a relatively short period of time. In this case two positive outcomes are achieved - (i) loss of integrity of the 16-inch casing is confirmed; and (ii) it is confirmed that the Macondo overburden possesses few barriers to vertical fracture height growth. If early-broaching occurs, then the well integrity assessment goals have been met and wellhead flow can be resumed with the oil being collected by the wellhead containment system. In the case that broaching does not occur, the option then exists to extend the shut-in period, as oil leakage to the sea has been stopped. This may only be a temporary respite, depending on the nature of fracture propagation, but it is expected that this would be a preferable scenario to the alternative of continued collection and leakage.

Scenario	Well integrity assessment shut-in (< 1 week)	Hurricane shut-in (<2 weeks)	Wait for relief well shut-in (4 to 8 weeks)
Shale only propagation	Broach possible	Broach likely	Broach expected
Progressive frac / sand fill / frac propagation	Broach very unlikely	Broach unlikely	Broach possible
Containment by sands	No broach	No broach	No broach

TABLE 1. Scenario map indicating broach to surface probability

The same arguments apply to a hurricane shut-in of less than two weeks, though here it may be difficult to assess the time over which the broach to seabed evolved. Regardless, the integrity assessment of the 16-inch would be completed. If, after a hurricane shut-in a broach is seen, then resuming wellhead flow and collection will reduce the flow via the fracture leak-path and the fracture is expected to heal over time.

The one scenario that might warrant further consideration is the longer-term "wait for relief well shut-in". Here if the 16" casing integrity is compromised the desirability of reverting to wellhead flow for the relief well intersection kill needs to be evaluated. It is anticipated that wellhead flow during the kill may be advisable, as the effluent from the wellhead can be visually monitored for reduction in flow rate and change in fluid composition. This cannot be achieved if fluids are leaking off to the formation at depth.

Scenario	Well integrity assessment shut-in (< 1 week)	Hurricane shut-in (<2 weeks)	Wait for relief well shut-in (4 to 8 weeks)
Shale only propagation	Fracture 'drains' with resumed wellhead flow & heals over time	Broach stops upon resuming wellhead flow & fracture heals over time	After broach occurs, resume wellhead flow for intercept kill
Progressive frac / sand fill / frac propagation	Pressures dissipate over time - no permanent effect	Pressures dissipate over time - no permanent effect	If broach occurs, resume wellhead flow for intercept kill
Containment by sands	No action needed	No action needed	No action needed

TABLE 2. Scenario map indicating broach / fracturing consequence

Scenario	Well integrity assessment shut-in (< 1 week)	Hurricane shut-in (<2 weeks)	Wait for relief well shut-in (4 to 8 weeks)
Shale only propagation	If no broach, consider extending shut-in period	Evaluate need to resume wellhead flow if no broach occurs - i.e. continue shut-in	Resume wellhead flow for kill operations to visually inspect outflow
Progressive frac / sand fill / frac propagation	If no broach, consider extending shut-in period	If no broach, consider extending shut-in period	Resume wellhead flow for kill operations to visually inspect outflow
Containment by sands	None	None	Resume wellhead flow for kill operations to visually inspect outflow

TABLE 3. Scenario map indicating additional actions for shut-in relative to continued wellhead flow