BP Incident Investigation Team – Notes of Interview with John Guide
July 1, 2010 at BP Westlake 1 at 10:30am CDT.

Participants in Interview:

John Guide, BP Wells Team Leader – Deepwater Horizon
David Stetler, Attorney and Personal Counsel to John Guide
Corey Rubenstein, Attorney and Personal Counsel to John Guide
Kent Corser, BP Incident Investigation Team
Steve Robinson, BP Incident Investigation Team
James Lucari, BP Legal/Counsel to BP Incident Investigation Team

Ground rules: BP Attorney Lucari explained that this was a non-privileged, business led factual investigation of the causes of the April 20, 2010 Transocean Deepwater Horizon Rig incident. Mr. Guide and his attorneys acknowledged that no legal privilege would attach to any of the discussions during the interview and that there was no joint defense or other privilege between the Company and Mr. Guide. Mr. Guide and his lawyers further acknowledged that the BP Incident Investigation Team expected to prepare a report of its work and that it would rely, among other things, on statements and information provided by Mr. Guide in the context of the interview, which could be cited in the report. Furthermore, given the non-privileged nature of the Company's investigation, the Company could not provide any assurance that the Team's notes of the interview could be protected and that the Team's work papers would likely be subject to subpoena or other legal process. Finally, Attorney Lucari told Mr. Guide and his counsel that Mr. Guide was free to consult with his personal attorneys at any time during the course of the interview and that the BP Incident Investigation team would allow him to do so privately if he wanted to do so. Mr. Guide and his attorneys indicated that Mr. Guide intended to cooperate fully with BP's investigation and the interview commenced at approximately10:35 am. [Except as otherwise noted, Mr. Corser led the interview.]

<u>Centralizers</u>

Kent Corser asked Mr. Guide to describe his involvement in any discussions concerning decisions taken relating to the use of centralizers on the Macondo well. John explained that he first became aware of the issue on April 16, after he received an email from Greg Walz (which was sent at 1am that morning.) John explained that the Engineering team (consisting of Greg Walz, Brett Cocales, Mark Hafle and Brian Morel) were involved in evaluating the use of centralizers on the well. He indicated that he knew that the Engineering team had been running OptiCem models and had concluded that running additional centralizers would be beneficial given the modeling results.

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John further explained that Greg Walz, who had previously worked on Thunderhorse, believed that a type of centralizer, which was a one-piece device, would be appropriate to use on the final casing string for the Macondo well. (John said that he was not aware of the Thunderhorse centralizer study.) John recalled that there was a discussion in the 7:30 am daily call on April 16 concerning the logistics of delivering additional centralizers to the DWH rig. John said that he advised the team that even if the rig crew needed to wait, he would support that, if the Engineering team felt it (i.e. the additional centralizers) was important.

Following the call, Brian Morel sent John Guide an email with a picture of the available centralizers which were multiple piece types, that were different than the one piece type the team had discussed on the call. John forwarded this e-mail to Greg Walz advising that the centralizers were different than what had been discussed. John noted that he was concerned because he was aware on April 3-5 that BP had problems with multi-piece (stop collar) type centralizers used on the DDIII. He thought the problem was that they had fallen off and gotten stuck in the hole. He later spoke with Greg Walz about the centralizers. John said Walz agreed with his concerns. Kent asked if John could elaborate on his knowledge of the problem. John explained that the drill crew on DDIII had run into the hole with standard (i.e. multi-piece) centralizers and that the crew had problems with the stop collars coming apart in the well. John said he was concerned that if that happened on Macondo, it could cause the casing to become stuck in the hole.

John said that he assumed that the spring loaded centralizers that were depicted in the Morel email were the type that had two stop collars and a sleeve, or three pieces per centralizer x 15 = 45 pieces in total. In his discussions with Greg Walz, John recalled that Greg said that Thunderhorse had special (i.e. one piece centralizers) that had been tested. He explained that these were the type of centralizers that the team had discussed adding to the Macondo well casing, and were different than the centralizers described in the email. John said that whenever he talked with the team about centralizers, he understood them to be the one-piece type. Instead, the available centralizers appeared to be the multi-piece, standard bow-spring type of centralizers. He told Kent that he was not involved in any discussion of using an "injection slurry" process.

Kent next asked if there was any discussion of the risks of running the casing without the additional 15 centralizers. John said, "yes, there was a discussion." He explained that due to a perceived "inaccuracy" with the [OptiCem] model, he was concerned about running unfamiliar centralizers based on the output from the model. He said the team had reached a consensus that there would not be a significant risk in running fewer centralizers (i.e. less than the 21) because the available centralizers could be spread out across the hydrocarbon bearing zone and provide adequate centralization in this key area of the formation. He further indicated that the team felt that the chances of getting "good cement coverage" were good because the cement job was occurring at the bottom of the hole and they expected to get good cement lift [up the annulus]. He stated that most of the risk discussion was about "getting good returns" as a sign that the cement job was adequate. He said there was no discussion, that he was aware of, about the length of time it would take to "glue on" centralizers. John said he had not informed Halliburton about the decision not to run the additional centralizers and he didn't know whether Halliburton was informed by someone else [on the Engineering team]. He said that he had left David Sims a voicemail on April 16 notifying him of the decision not to run the additional multi-piece centralizers, to which he did not receive a response.

Design Plan for Well

Kent then asked John a series of questions addressing changes to the design plan for the well to address conditions encountered in the formation. John said there were a series of discussions throughout development of the well about managing fracture gradient and losses, which occurred in the context of regular Well Site Leader (WSL) meetings

John noted that at 18,260 feet, the under reamer appeared to quit drilling; the rig crew circulated the hole clean to make a trip and this was right in the middle of the pay zone. There was a loss of complete returns; the team figured out through examination of pressure while drilling (PWD) data that it was a 14.7 ppg EMW that caused the loss (i.e. exceeded the frac gradient point.) It took 2-3 days to seal the formation. John further noted that there was a Geotap pressure measurement of 12.6 ppg in the main pay. While the rig crew was dealing with the well, the Engineering team took the available data to work out a plan to complete the drilling of the well. John stated that it took some "additional footage" to get a rat hole; the mud weight at that time was 14 ppg equivalent, and the crew finished the well and ran a Schlumberger wire line.

Liner vs. Long string option

John said his role in this decision was limited. He was mostly consulted about issues; his primary role was to get the rig ready to run either the long string or the liner, depending on the final decision. He noted this "wasn't a huge deal because they would need to run 7 inch casing, either way." John explained that the original basis of design had them running 9-7/8" casing, but they had run a 9-7/8" liner before they got to the total depth. At the time, John said he was focused on securing the right cement head and darts, and the like.

[Kent then showed Guide a copy of the TD Forward Plan Peer Review ppt.]

John said that there were discussions about the two options at a WSL meeting on April 14, attended by John Guide, Jon Sprague, Terry Miglicco, David Sims, and joined by members of the Engineering team by conference call, including Greg Walz, Brett Cocales and Brian Morel. The discussion addressed the possibility that there might be issues with getting a good cement job and the Engineers were still analyzing the situation. John noted that the document identified the long string as the primary option. He also pointed out that he thought the frac gradient showed up on the chart as a bold white line on the chart at 14.7, but after Kent pointed out a hashed line on the chart, he concluded he was mistaken and the correct frac gradient was 14.5.

John said that the first models run, which were "wrong," produced a static mud weight of 14.5 ppg; John attributed this error in the model to compressibility of the mud at total depth. John stated that the pore pressure was 14.1; which was very close to the mud weight of 14.17. John said that the engineers continued to tweak the cement program model and that he had not seen all of the different model runs.

Kent asked whether he had recognized that the model results showed that the cement program design would exceed the fracture gradient in the formation. John said that during the team discussions he participated in, it was agreed that the team "would do everything we could to stay below the frac gradient." John said he deferred to the Engineers expertise on the model issues, but he understood there was a tight tolerance level to achieve an effective cement job.

Kent asked who, in John's opinion, was the decision maker regarding the long string versus liner option. John said that the Engineers would make a recommendation to Jon Sprague and David Sims. Kent asked whether John Guide had accepted the recommendation. He said again that he deferred to the Engineers on the design of the cement program, and on that basis, he signed off on the MOC package.

John said he did not recall any discussion that the circulating pressure (ECD) would be above the frac gradient. He said that it was the team's view that there were problems with the model. John stated that there was a geotap pressure sample (up the hole) which read 14.17.

Kent asked whether there was any discussion about hydrostatic pressure. John answered, yes. He said they subsequently went into the hole with an MDT tool, and they couldn't get a pressure reading at that level. He said they could replicate pressure at 12.6, but not 14.1.

Based on these results, John thought that the geo tap might have been inaccurate because he thinks it was tested with pipe that would be difficult to locate across this two foot zone, as compared with wire line data which is more accurate.

Follow-up Questions about Centralizers

John was asked about the decision to go forward without the additional centralizers. He said that he asked Greg Walz about whether the team needed to wait until the right type (i.e. single piece) centralizers were delivered. John stated that no one suggested that they needed to suspend the well until the proper centralizers were located. He noted that there were risks in waiting due to the fact that the rig had an open hole into the HC zone. In any event, John said he was not involved in the discussion among the Engineering team (Walz, Morel & Cocales) about the decision to run with less than 21 centralizers. John was asked who signs off on the well plan for the Deepwater Horizon rig. He said that the well plan was signed by Greg Walz, John Guide and David Sims.

Cement Job

Kent asked John Guide for his assessment of the cement program at the time he signed off on the well plan. John said that he reviewed the cement job and recalls discussions about the risk and complexity associated with it. John said that at the time he believed and voiced concerns that the cement job was too complex (overly complicated). He said that he voiced those concerns with Greg Walz, Brian Morel, Brett Cocales and David Sims. He said that his main concern was the program called for using 6 barrels of base oil to get the model "to spit out a number below the fracture gradient." John believed that the base oil contributed nothing – it was too low of a volume to make a difference due to mixing with the mud.

Kent asked what did he do about his concerns; how were they addressed. John said he was told that the cement program was vetted with Halliburton and Erick Cunningham and that the cement experts believed it would work. John said that he respected their expertise and relied on it and signed off on the plan. John further stated that he wasn't disappointed in the cement itself – he thought that the 6 barrels of base oil was insufficient given the total volumes that needed to be pumped.

Kent asked whether nitrogen break-out was discussed as a risk. John said that Halliburton advised that this was not a concern – that nitrogen break-out would not occur. John noted that Halliburton had aggressively marketed the use of nitrified cement in deepwater wells. John said that his experience did not suggest any problems, as nitrified cement had been used in other wells (e.g. King South – which he noted was a long string casing) without any problems.

Compliance with MMS and BP DWOP requirements

John said he was on "peripheral ends" of conversations about compliance with MMS regs. and DWOP. He said he made sure that the subsurface staff clearly identified the top of the HC zone so that the plan would ensure good cement coverage up to 500 feet above the pay zone; he noted that there were e-mails describing this verification effort.

Kent pointed out that the well plan decision tree has a contingency around losses and no-losses which has implications for conformance with DWOP and ETPs. He asked John whether he was familiar with BP's zonal isolation requirements. John said that he could not recite DWOP zonal isolation guidance by heart.

Kent noted that the MOC written by Hafle covered DWOP and MMS compliance and asked John who was accountable to assure compliance. John stated that "on the rig, I am accountable for safe and reliable operations."

Cement Bond Log (CBL)

John said that Jon Sprague and David Sims were involved in the discussions about whether to run the CBL. John noted that Sprague, as the Engineering Authority for GoM, needed to approve any dispensation from DWOP.

John explained that the Engineers reviewed scenarios and developed the decision tree options -- if we didn't get good returns, we would run the CBL; if we didn't lose returns, CBL was not required. John noted that both Sims and Sprague had signed-off on the Decision Tree.

John said he didn't know if the Decision Tree complied with DWOP; he acknowledged that he thought everyone should know if our plans were compliant with DWOP. John said that at the time [the team was working on the Macondo well], he had not reviewed the new DWOP/ETP for zonal isolation that had been finalized in December 2009. He acknowledged it had been "rolled-out" in February 2010. John noted that he had provided copies of the new DWOP to Transocean. He said that the team had not sought a dispensation from the zonal isolation requirements of DWOP.

[The next portion of the interview was led by Steve Robinson]

Steve asked John to explain how he knew if Halliburton was abiding by its policies if BP did not have a copy of its operating manual. John said that Halliburton was responsible for complying with its own design policies. He also stated that Erick Cunningham was the BP person accountable for ensuring that cement programs complied with BP's ETP.

Steve then asked John about the training program for DWOP/ETPs. John explained that the training was being rolled out during the first quarter 2010 by Jake Skelton, while the DWH team was on the Macondo well. John said that he was scheduled to take the training but that his training had been scheduled for sometime after the Macondo well incident occurred.

John explained that he looked at DWOP from an operational standpoint, not from an engineering perspective. He assumed that the Engineers were covering the engineering aspects. He couldn't recall any specifics [of DWOP] that he had reviewed from an operational standpoint.

Steve asked if the Well Site Leaders had received any training on the new DWOP. John noted that there was an initial roll-out of the DWOP at the WSL meetings on April 14-15 and that he was in attendance. He noted that he had distributed the new DWOP books to Transocean's OIM and Senior Toolpusher.

GoM Lines of Authority

John stated that the Engineering team was the group responsible for proposing changes to the well plan; they would write plan proposals for approval by the Engineering supervisor, after which it would in turn be reviewed and approved by Guide and Sims. John believed that Jon Sprague would have been consulted only where there were dispensations from DWOP (e.g. loss of returns/ECDs)

After the functional reorganization took effect (i.e. April 1, 2010), John stated that the Wells Operations manager was only accountable for Operations. If there was a disagreement between Jon Sprague and David Sims, it would need to be elevated to Pat O'Bryan for resolution, as that was the first organizational level where the two groups came together. Before April 1, once the well was in an operational phase, the Engineers were seconded to the Wells team leader; after April 1, all engineers worked for Greg and John Guide had no accountability for engineering issues. Under this structure, Operations had to make a request to Engineering for support.

John felt that the new organizational structure had created some confusion in authorities. John said that he was used to a seamless team (Ops/Eng) working together. After the reorganization, John's view was that the Operations and

Engineering teams were not working smoothly yet. He said that the new structure introduced a new mix of people. Nonetheless, John felt that accountabilities were clear between he and Greg Walz – Greg was accountable for engineering issues and operations were John Guide's accountability.

In John's opinion, it was not a good idea to have a structure where Ops and Engineering only came together at the VP level. He said that he had "no issues" with Greg Walz, but the structure made the decision-making flow more difficult, as it took decision-making authority away from a smaller, focused team with both operations and engineering capabilities. If there was an engineering issue that surfaced through Operations during well development, unless safety related, it would go to Brian Morel with Mark Hafle as his back-up.

John then described the two organizational groups following the reorganization:

Engineering	Operations
Drilling Engineer	Wells Site Leader
Drilling Engineer Team Leader (Walz)	Wells Team Leader (Guide)
Drilling Engineering Mgr. (Sprague)	Wells Operations Manager (Sims)
N/A	Wells Director (David Rich)
Vice President (O'Bryan)	

Kent Corser asked how much involvement David Sims had in John's work. John stated that he was "intimately involved in all aspects."

<u>Management of Change Process</u> [Kent Corser resumed lead of interview]

Kent asked John to describe the circumstances under which an MOC needs to be completed and whether an MOC was required for changes to the negative test procedure. John described a number of on board changes to the plan that had been established for the Macondo well.

The initial plan called for "base oil to the well head." The plan was changed to allow for seawater to the wellhead. The original well plan also called for a lock down sleeve assembly for the well head to allow for completion as a production well. This was a decision under the purview of the subsurface team. In order to accomplish the setting of the well head lock down sleeve assembly, the rig crew needed to hang approximately 100,000 lbs [of drill pipe] below the well head. There was a concern about running pipe through the seal assembly because this was a sealing surface (which could be damaged in the process). Accordingly, the team needed to set the plug deeper in the hole [to accommodate the additional drill pipe] approximately 3,000 feet below the mudline. This was a change from the original well plan. This resulted in the displacement to seawater to a depth of 8,367 feet. The team developed some revised T&A steps that needed to be submitted to MMS for approval and the MMS approved the proposal to set the plug deeper.

Because of these changes to the plan, the original negative test protocol which called for running base oil to the surface would no longer work; therefore the protocol was changed to conduct the negative test in sea water. John noted that the team liked to set surface plugs in sea water because there was a better likelihood of getting a good plug in sea water as compared with mud.

John stated that the decision to prepare an MOC in this situation was left to his discretion as the Wells Team Leader. John said he did not view this change of procedure as a significant one because the rig team routinely conducts negative tests every time they remove the [BOP] stack and the rig team knows how to run them.

Kent asked John to explain the procedures that were established for testing the well. John said that the plan called for the rig crew to test the casing to 2500 psi below the blind sheer ram (i.e. positive test). John acknowledged that this put pressure on the casing. He said that there is a chart that is signed off by everyone evidencing that the test held low and high pressure for 30 minutes.

John then described the protocol for conducting the negative test. He said that the negative test involved displacing seawater to a depth of 8,367 feet. He indicated that the intent is to put a negative pressure test on the casing, but that the details are left to the rig crew – the tool pusher and driller, in consultation with the WSL, to decide how to line the test up properly and determine if they have a good test. When asked to elaborate on this point, John said a successful test needed to be run for 30 minutes with no flow from the well. He stated that the DWH rig crew had a certain method for conducting the test, with potential adjustments particular to individual well requirements. John said he thought that the parameters for the test were adequately defined for the rig crew.

John was asked specifically whether he thought the test [that the DWH rig crew conducted on April 20] was a good one. He stated that, in hindsight, looking at the test data, he believes that the test did not pass. He confirmed that he did not receive any calls from the rig during the negative test. He further stated that he believed that Hafle received a call from the rig later that evening (after the negative test was complete) from Don Vidrine (he learned this after the incident in a conversation that he had with Mark Hafle).

John's regular practice is to speak to the rig crew three times a day (and as necessary at other times) – he speaks to the night WSL in the morning at around 5:30am when he gets to work and just before shift change. He then again has a call at 7:30am after shift change to discuss the work for the day with the entire rig crew, and a call again, usually at 5:30pm, at the time of the evening shift change.

He recalls that on the day of the incident, he discussed with the rig crew the preparations for performing the negative test, including displacement of seawater to an appropriate depth, and lining up the test down the drill pipe and kill line to form a U tube. He said this discussion of the negative pressure test occurred with Bob Kaluza, and the TO OIM, Senior Toolpusher and Driller, which was the regular complement of participants.

Kent asked John Guide whether he had any insights about an "argument" concerning the negative pressure test (described in the MBI testimony of TO employees Douglas Brown and Mike Williams) – he said he had no knowledge of any such argument, including whether it occurred.

Kent then asked why a lock-down ring wasn't run when the rig crew set the well head assembly. John said he wasn't an expert and further stated that he didn't know if you can run a lock down sleeve and seal assembly together at the same time. He said he had no personal experience ever doing it that way.

<u>Risk Register</u>

John stated that he was not personally involved in creating the Risk Register for the Macondo well; he said that that register was completed by the team running the Marianas rig before John got involved with the well on February 1, when the DWH crew came over from the Freedom well (MC 727) to complete the drilling.

John said that at the start of the DWH team's involvement, he had a meeting with David Sims to discuss the plan going forward and any issues of concern – he does not recall completing a form documenting those discussions.

Kent asked John to describe the risks that he identified. John said the biggest risk they had identified was the tight pore pressure/frac gradient ratio. John said that the team conducted a hole section (section by section) review, before drilling, to identify mitigations for any issues of concern. He said they also worked to define acceptable "leak off" tests; what trips would be needed if they experienced LWD failure; loss of circulation, etc. He said the discussions include geology, engineering, risks and the Tiger team's input.

Planning for well work

Kent asked John who was accountable for ensuring an adequate inventory of equipment for well completion. John said that there are clerks on the rigs and the WSLs share the accountability with these support staff; they have contacts with suppliers. For the Macondo well, John said they "went outside" and bought 7" casing, float equipment and centralizers.

John said that it was his understanding that the original plan only called for use of six centralizers; he said that a revised (2nd) well plan on April 15 had the additional 15 centralizers, which was a change to the plan.

BOP Systems

John was asked whether he was aware of any leaks or other problems with the DWH BOP system; John said the only issue he was aware of was a leaking "shuttle valve" on the yellow pod, which was documented in the daily log reports. He believes Murry Sepulvedo was the person who told him. John said that he understood that the valve would leak when it was placed into test mode and, therefore, the yellow pod was put into "block" between tests to prevent it from leaking continuously when it was not being tested.

John said he discussed the risks of this approach with Transocean (the OIM and the Rig manager – Paul Johnson) and the WSLs. John did not think this information had been communicated to the MMS.

John said that he was not aware of any other issues with the BOP or any issue of impaired functionality.

Incentives/Bonus programs

Kent next asked if DWH had an incentive bonus program. John replied that they did not have one for Macondo because the budget was already overspent for the well due to the delays from the Marianas and the hurricane. He said that he and Ian Little made a determination not to put any incentives in place for completion of the well; he indicated that it was also decided not to have a bonus program for the next DWH well – the Nile prospect, which was a P&A well. The next scheduled incentive plan was for the Kaskida well, which was the well scheduled to be drilled by the DWH after Nile.

March 8, 2010 well control event on Macondo well

Steve Robinson asked John how the March 8 well control event was handled; John said that it was a very poor response by the rig crew, which continued to drill for 35-40 minutes while taking a gain before shutting in the well.

John said that he did not initiate a formal incident investigation, but instead had discussions with the WSLs and the TO Rig leaders about the event and the drilling crew's response. He also said there were discussions with the mud loggers (Sperry Sun) about detection of the flow, as well as discussions with the subsurface (Tiger) team (Pinky Vincent and Jonathan Bellow)

Steve asked John to describe the quality of the discussions he had with the rig. John said he reviewed with the WSLs and the TO Rig manager (Paul Johnson) whether there was any lack of clarity in responsibilities. He said that he felt the rig crew understood their responsibilities and admitted to him that they "had screwed up" by "not catching it." John said that the TO driller acknowledged that the driller was the first line of defense in a well control situation. He said he also had phone discussions with the WSL (can't presently recall whom) and the TO OIM immediately after this incident. He said he couldn't recall the exact quote, but the essence of the statement by the OIM was that "... the drill crew needed to do a better job of watching the well." John said he couldn't recall if the same rig crew was on tour on April 20, as was on tour during the March 8 event.

He said that Paul Johnson, the TO rig manager, did not propose any actions in response to the incident. John acknowledged this incident was not recorded in Tr@ction, as this was not the normal process in the Deepwater GoM. He said he did not know that reporting this type of an incident was a requirement of DWOP.

John said that he was "very upset" about this event, noting that one of the primary responsibilities of the WSLs and rig crew is well control. He said he was also upset with the Tiger team (who are accountable for frac. gradient curves and well monitoring); he noted that he threatened to change out personnel due to their perceived failure to warn of the event. In particular, he noted that Kate (a subsurface team member) who was the pore pressure detection expert who works on the DWH rig, had, in his view, become complacent. [John explained the roles of the various members of the team, indicating that the Tiger team members *predict* frac gradients and Kate was on the rig to *detect* changes in pore pressure.]

John said that he was concerned that the team had gotten "too comfortable" with itself because it had a good track record for drilling difficult wells, and missed potential indications of problems in the March 8 event that should have been caught. John explained that his father had died on March 1 and he took some time off; he said the following Monday (March 8) when he returned to work, he read the morning report and noted that during drilling the rig crew "took a kick" and plugged off the well.

[John said he doesn't have a good recollection of the detail around this time because of his father's death.]

John recalled that after the March 8 event, he had problems with Kate's monitoring of the well because she became overly cautious concerning kicks and recommended raising mud weights even when it was not appropriate (that is, when there was no data indicating a need to raise mud weight), which lead to serious over-balanced well conditions, leading to loss of returns on several occasions. John said that he had discussion with Pinky Vincent about Kate's performance issues after the DWH crew lost circulation on the well, sometime after the March 8 incident.

Steve asked John what were his expectations for well bore monitoring. He said it's his view that well bore monitoring needs to be a 24/7 activity until the rig is unlatched from the well. He said he doesn't recall having any specific conversations with Don (Vidrine) or Bob (Kaluza) about this expectation, but thought it was a clearly understood expectation of all well site leaders. When asked why he was confident of this, he said, "because it's a fundamental practice, like putting your seat belt on – it's a fundamental part of what we do." He also noted that monitoring the well was a clear expectation of the third party mud-loggers, whose only role is to monitor the conditions in the well. He noted that while positive and negative tests are crucial and demand the utmost attention, he still expects constant monitoring of the well at all times until detachment. In light of this expectation, John said he did not believe that the rig crew, including the mud loggers, were adequately monitoring the well during the last 51 minutes of the April 20 incident, based on flow data he has seen [subsequent to the event].

John noted that it's ok and consistent with regular practice to move pit volumes during final well work, provided you continue to monitor flow accurately; he said he would not condone moving fluids between pits when the crew are performing significant pressure and flow readings. John noted that the DWH rig had the capability to segregate pits and monitor flows in the pits connected to the well, while other pits were being cleaned. He said that this functionality was necessary to manage fluids and was consistent with regular practice.

John said that he consulted with the subsurface group (Brian Ritchie) about identifying the top of the hydrocarbon zone within the formation; he said that there is email correspondence from the subsurface team confirming his recollection about the top of the HC zone (emails from a team member named Galina with a difficult to pronounce last name).

Temporary Abandonment Option

Kent asked whether the team had seriously considered the T/A option, in light of the risks inherent in drilling this well. John said it was one of the possibilities considered but John personally believed it would have simply resulted in a deferral of the problem. The team felt the well could be completed safely. He said that there was some discussion about whether completion with a 7" casing was enough for a final well completion, but once that issue was resolved affirmatively, that ended the further discussion of the T/A option.

Spacer Pill

John said that he knew that the rig crew intended to use left over lost circulation material (LCM) as a spacer, but he did not know that they were going to combine the "forma-set" and "forma squeeze" products in one pill. He said the team opted to use these materials as a spacer (which, according to John, had been done before on other wells) between the seawater and the drilling mud; he said he thought it would be MI (Swaco)'s responsibility to identify any problems in doing so.

John said it was the Driller's responsibility to ensure that the spacer is placed above the [BOP] stack; he does this by counting strokes on the pump. John said that there had been discussion in the daily morning call [on April 20] about the need to get the spacer above the top annular before conducting the negative test. He said a similar approach (using the procedure of displacing to seawater before conducting the negative test) had been performed successfully on the Freedom well and Tiber well. He recalled that on Tiber, the rig crew had bled back 11 barrels and got a reading of zero on the drill pipe, and on Freedom, the crew bled back 9 barrels and got a reading of zero on the drill pipe. John said he couldn't recall if they had used LCM as a spacer for those wells. Finally, John stated that *if* it happened, he doesn't understand why the Driller would have left the LCM across the stack [during the negative test].

John was then asked whether he had any other information to share or if he had any questions that he thought needed to be resolved.

He said that he would like to find out, if you put the correct pore pressure into the OptiCem model, what would it show; he felt that reservoir pressure would have a big impact on gas flow potential.

He noted that Jesse Gagliano had not run the model with reduced numbers of centralizers as the operative assumption until the final model run [which was 9:30pm on April 18], which showed the higher gas flow potential and that this information had not been available to him. He said that Halliburton did not communicate (flag) for BP and John Guide that there was a significant risk of gas flow potential associated with the revised cement program. He noted that Jesse Gagliano was known for "just in time delivery" of test results and that if Jesse delivers the results later in the evening or overnight, John would not see those until the next morning when he gets to work. He confirmed that there were no objections raised to the cement program by anyone at the 7:30 am calls on April 17-18.