Chapter 3 – Description of the Accident

Introduction

Horizon coming onto this well, coming in after the Marianas, and its job was to complete the well. They'd be successful in drilling the well down to TD, and total depth of the well was 18,360 feet. They just logged the well and they were just about to evaluate it and they were actually going to run the log strength which was part of the design.

Personnel

BP had six personnel on the rig. Bob Colusa had just arrived over from Thunder Horse and was filling in for Ronny Sepulveda. Don Bedron, who had been on the rig for six months, was working nights including days. So there are two company men, two wellsite leaders out there. Colusa was standing in, Bedron was six months on the rig and then you had other BP personnel.

Drilling Crew Experience

I think, you know, for this team Macondo was a little bit different because this rig and this team normally drilled and evaluated exploration wells, and in the past they have run, you know, these production casing strings, which a production casing string is a string of casing that you run prior to running your production tubing. So they have run them in the past but not all the time.

Macondo

tight operation. They had evaluated the well. There was very little effective stress between the pore pressure in the well and the fracture gradient and, as such, getting the 9 and 7/8ths seven-inch liner down was going to be a careful job to ensure that they didn't incur losses because fundamentally losses at this stage, one, with a liner in the hole would have given them a complex and challenging well control environment if they lost volume in the hole and they couldn't get that loss stopped, you could have gas hydrocarbons coming in from the exposed reservoir section that they just drilled and two is to secure every chance of getting cement up the backside and maintaining effective zonal isolation they needed a stable bottom to the hole. So they were being very cautious to ensure that they didn't put any surge pressures or loads on the bottom of the well whilst they were running the casing or through designed cement job to compromise the integrity of the open hole section.

EXHIBIT # 96
WIT:

Plan for the Well

So what was different here was they were running a production casing string. And, also, you know, once they run the string, once they got it cemented in place, they had set the pack off in the wellhead and they had set their cement plug and pressure tested it. Then they were actually going to suspend this well. And the suspension process, once they've done this, completed the suspension process, then really it was really just going to be a matter of hours before it was pull the riser and store the riser on the rig and then move to the next location. So if you're looking at a context piece, we were at the end of the well, we were securing the well and we were starting anticipation for our rig move and starting to think ahead to what other things are going to go on when we get to the next location and start the next project.

Drilling Program

So that with the slightly different string design that came with a certain number of limited centralizers, those were the kind of focus areas for the engineers when they were actually trying to put this program together.

Casing

I think there's probably a couple of things that made this a little bit different, and so I'm just going to talk about -- rather than get the outline, I'm just going to talk about it. So I think, you know, from a design perspective, you know, we were running a 7-inch, 9 and 7/8ths tapered casing string, and that was not part of the original design, although the principle of running a single long string was in the original design. It was originally designed to be 9 and 7/8ths, not 7 inch and 9 and 7/8ths. The reason that we had to go to the tapered string was that because of the pore pressure fell on the well it required us to set the two contingency strings, and one of those contingency strings was the casing string that we were going to have as our production casing. So we had to commit that earlier in the well.

Casing Liners

And so that necessitated us to find 7-inch equipment. And so that was a bit of -- I know the team got after that. Once they knew they had to procure this equipment, they went out to the market and started looking around for this equipment. But, you know, it's not easy to get this equipment just off the -- the market is in high demand. They did secure 7-inch liners, sufficient grade and weight and quality for BP, but with that they actually got a limited number.

Centralizers

I think they got six centralizers that came with that. They got a similar float collar to what BP would normally run, and they got a reamer shoe which is the bottom section of casing. So they were able to procure from Nexen the majority of the equipment. But in addition to just procuring the right equipment -- and, to be honest, six centralizers, you know, if they had come with 20 centralizers it would have taken 20. It just happened to come with six and that was what Nexen needed for their job and that's all they had given to us. That became an issue later on.

ECD

But the other issue for us was, you know, this equivalent circulating density, once you get the casing on the bottom and you ran it very carefully, when you got it on the bottom then you needed to break circulation to

Circulate

circulate the mud up from the bottom of the well to -- for two purposes.

One was to get any gas that had just kind of -- through osmosis had just kind of crept into that well. You want to circulate that out before the cement job.

But also, too, is you leave the mud down there for a while and the gel set up and it gets viscous, so you want to break the gel and pump the mud. They did that successfully. They didn't pump the volumes that they said they were going to pump in the drilling program, but I suspect the reason they didn't do that is really just because they were worried about inducing losses. They did break circulation. They had good circulation. They didn't actually get any losses, but I think there was a little bit of we just got to hedge our bets a little bit here. The mud looks in good shape. We don't see any back line gas. Let's go ahead and get the cement down there before we lose the bottom of the hole. They were just concerned about that.

Cement Selection

And in terms of the cement that they had to select, that was a challenge because they were finely balanced here on pore pressure, 14.2, and fracture gradient, so, you know, they needed a cement slurry that they could get down there to get the more reasonable isolation across the hydrocarbon zones and also ensure that they didn't fracture the well.

So they actually -- Halliburton, a cement provider, worked up a slurry design for us which was in comparison to previous wells it was a relatively high percentage of nitrogen. The reason we needed the high percentage of nitrogen was to give it that lightness so it would be light downhole.

Base Oil Spacer

They also used a base oil spacer again which it is used but on rare occasions because it is so light. But this slurry itself was, you know, they were really focused on reducing the weight of the slurry because so that the equivalent circulating density would be within the narrow window of opportunity that they had. So a lot of focus was put on that.

Contaminant Mixing

So the significance of the base oil spacer is when you pump cement and you've got a pseudo oil base mud, you don't want to have the mud and the cement mix together because what that will do is it contaminates the cement, and that means the cement either may get contaminated to the extent that it won't go off and never set because it's just too high a percentage of contaminants or it will actually be contaminated that it may -- you may want it to set in 72 hours but it won't set for 105 hours. So it makes it very unreliable in terms of that.

Base Oil Spacer

So to negate that you pump a spacer in between your mud and your cement. Now, normally what you do is you pump, you know, mud, a viscous mud or something, some sort of mud, but because they wanted to reduce the hydrostatic they used a base oil which is very light. Now, the issue is if you can imagine pumping a 14.1 pseudo oil based mud and coming behind it and pushing it up with kind of, I don't know, 10 pounds, 8 pounds light oil, it's quite easy that that oil is just going to go straight up through or it's going to go behind because you've got 16.1 cement behind it so it's going to go through much heavier and much denser. So in terms of effect of spacer, I'd argue it's probably not a very effective spacer, and it's not a practice that's widely used in the oil field or seems to be a good practice. It may have been a necessity in this case, but it added another degree of risk into the overall not just the formula of nitrified cement but the overall fluid.

Do we know why they chose
the base oil?
Just really because it was
lighter than anything else. If you remember, you pump that in casing, you pump up the annulus. The annulus is very small.
So you're looking at six
barrels of space. I don't know how much that would come to, but that's quite a hydrostatic head. So that's why they pumped it, to reduce the hydrostatic head and offset the weight of the cement.

Nitrified Cement

used the spacer because you need to use the hydrostatic head to compensate for the weight of the cement. And if you kind of sat back and looked at it, could you have looked at a simpler cement slurry to achieve the same outcome. You know, we kind of very much went to nitrified cement. You know, our set of understanding is the percentage of nitrogen we needed to retain in this was at the very high end of its normal end point. We needed to put base oil in there. You had cap cement and tail cement which were different densities. So you've got, you know, four different fluid compositions to get this hydrostatic balance to add cap and tail below this nitrogen trapped in this cement. And, you know, in hindsight could you have just used one slurry formulation, a light slurry, the people have and is available and just kept your job really simple. That would be a debate not just necessarily the spacer but did you need that for not overly complex but more sophisticated cement slurries to achieve the same. Could you have chosen something else.

Concerns

In any event, looking back, you know, we focused a lot on circulating density, we focused a lot on the setting time of cement because you need to understand how long do you have before this cement is going to go off and set. We focused a lot of time on the compressive strength of this cement, so how hard is it going to be at any time.

Stability Testing – Not extensive

And when you look back and look at the tasks we've done, there was very little kind of work seems to be done to test the stability of the nitrified cement job with these percentages of nitrogen. There doesn't seem to be any extensive testing done. And at the extreme end of the envelope we asked why weren't we doing a lot of tests to prove stability because if it's not stable then it actually will fall out of the cement as it pumps that hole and you don't have a good cement job and there's the risk that the nitrogen itself will contaminate the rest of the slurry and, in effect, you'll have a really bad mess. You'll have contaminated cement downhole that won't give you, in effect, zonal isolation. And so when we look at the results that aspect is the rheology of the cement was very low. You know, I think it was on -- the parameters I'm not sure. I can't tell you exactly. But we did a measurement of two, and we were supposed to have in excess of nine. It's something that would have drawn your attention in an extreme way, and it didn't seem to draw attention.

Fluid Loss Agent

There were characteristics of the slurry that you would have expected to see such as, you know, fluid loss agent. It sort of goes from a liquid to a solid. The fluid loss is to kind of retain hydrostatic fluid as it transitions, and there was no fluid loss additive in the slurry at all which was amazing. We think that was one of the characteristics that we looked at. So then we got -- a defoamer was blended into the dry mix of the cement itself. We're trying to foam a cement slurry and we've got a defoamer in there.

Halliburton Concerns

So these are, you know, issues that if one had done some analysis one would have expected the cement provider, Halliburton, to have brought those to the attention of At the end of the day the only concerns

that Halliburton raised with BP are Jesse Galliano said he was really concerned about adequacy of centralization because the Optichem set program had advised that we really need special centralizers and that there was a chance of gas break-out because of the limited number of centralizers we were running. And we very much accept that. The team who were doing the job, you know, that was brought to their attention, and they did consider that.

Additional Centralizers

And on the back of that Greg Walls, who is the engineering wells team leader, mobilized an additional 15 centralizers to the rig. You know, he mobilized them to the rig. They got out to the rig in sufficient time. I think there's testimony from the company man and others on the rig at the time that says they remember them coming in the helicopter.

Centralizer Decision

Unfortunately when they got to the rig and they were described back to the time as both centralizers, both personnel on the rig and the personnel at the time thought they were centralizers that were similar to the design in those that had been recently used on the Atlantis project and that had failed when running in hole and had come apart in hole and they caused a lot of well problems by coming apart. There was some genuine concerns over the integrity of these centralizers, and, as such, when the team thought those were the centralizers that they got on board, they made the decision that even with the evidence and information they had from Halliburton that they weren't going to run them because they felt there's a greater threat that they could get hung up on the hole and have casing potentially across the BOPs (phonetic). And so they made a decision not to run these additional centralizers.

Risk Assessment and Mitigation

And their intent was that they had actually evaluated the quality of the cement job at the end, and if it was poor they would perforate the casing and squeeze and achieve zonal isolation in a remedial sense. So they were aware of the risk. They thought they had the wrong equipment out there, and, as such, they made the decision.

Incorrect Information

Now, the fact is that the centralizers that had been sent to the rig were not the Atlantis centralizers. The investigation follow-up shows that these were, in fact, centralizers that had been run on the Thunder Horse project, and they had been proven to have the mechanical integrity required for the Macondo well and had been tested and proven they would have been adequate for the Macondo well. But, unfortunately, that information didn't get through to the personnel on the rig and didn't get through to the personnel in time, particularly the wells team leader who was making the decision, and, as such, the decision made unfortunately was poorly informed.

Run Casing

But, with that, they ran the casing in the ground, and it went well. As I said, they did limited circulating bottoms up. I think they limited the bottoms up. Normally they done a full casing volume, but I think they limited it just because they were worried about pushing the bottom out of the well.

Set Float Collars

when they were trying to set the float collars and they run the casing and they have these internal valves in the casing, and the reason they run the casing with the valves open is so that they allow fluid to naturally come into the casing as they run it. And what that does is it minimizes the surge pressure. Again, this is a pretty common practice for Gulf of Mexico for the environment we were in. But when you get the case in the bottom, you want to actually set these one-way flapper valves so that after you do your cement job these flapper valves will shut, and the imbalance between the greater hydrostatic in the annulus and the hydrostatic in the casing would normally see a U-tube effect and these valves would actually shut and stop that U-tube from occurring so that they hold the back pressure of the annulus so that the cement can set rather than U-tubing back into the casing.

Break Circ

So the activity to -- once they got to the bottom, they tried to break circulation. They couldn't break circulation. And I think it took them -- I saw a document that it took them nine attempts, and I think they went from, you know, 500 psi up to 3100 psi before eventually it appears that we cleared whatever blockage there was in the casing and then allowed us to circulate. The reason I say it cleared the blockage in the casing is because we don't know at this time whether the blockage was in the float collar which was at the top end of the shoe track with the valves in it or whether the blockage was actually at the reamer shoe at the bottom of the casing. We just don't know. But whatever way, it was blocked. And when we actually cleared the blockage, the blockage could have been we ran the hole and we ran into some solid cuttings and they just blocked the ports at the bottom of the reamer shoe or blocked the circulating sleeve for the float collar. So any of those things could have occurred.

Cleared Blockage

But, anyway, when we actually pumped through it and we got the blockage cleared through that process they were in communication with Weatherford to ensure that if they had seen any problems through consultation back at the time they were satisfied that they were in compliance with the standards and design material. So that was good. But, in effect, the investigation as we looked back it was not clear to us that we actually created the correct differential pressure across the float collar subsequent to clearing the blockage that would have pushed out the setting sleeve and allowed these flapper valves to close. That may have been the case, but we're concerned that we didn't have flow rates in excess of 7 barrels per minute which is the required flow rate. There's no recording of us having 7 barrels per minute but actually, you know, when you actually had that surge through the system when the blockage cleared you could have exceeded 7 barrels per minute instantaneously so that could have been enough to shift the sleeve.

Cement Job

But, either way, got that blockage cleared, started the circulation. I think they curtailed the circulation because they were worried about losses in the well, and they subsequently then went ahead with the cement job, mixed the cement on the surface. You know, they pretty much pumped everything as they expected. They pumped the cement to the bottom. We don't see any variation in pump rate, so, you know, it was continuous pumping rate. They pumped the cement to the bottom. Through the course of the cement job, it doesn't appear that we had any losses, but the investigation team monitored the active pits. There was a lot of change in between the Halliburton unit displacing, the rig floor displacing, the rig pumps, a lot of movement back and forth, but we've checked the pit site. We can't see any major indications of losses through the cement job. So the conclusion of the team offshore made was they had no losses during the job. It's a reasonable assumption to make.

100 psi Lift Pressure

So they got the cement around. And actually when they got the cement around they drew the conclusion that they had 100 psi of lift pressure and, as such, deemed that they had sufficient lift pressure to justify submitting the annulus and they called the job a good one. Again, with the benefit of looking at this job, we don't believe the method that they used to

determine that kind of cement was particularly accurate.
It was a very low number.

Didn't Slow Pumps (Better Method)

You know, our recommendation was that you would slow the pumps down just before the cement got to the bottom of the casing and subsequently record your pressures. And subsequently when the cement was just about all the way through the casing and about to finish going around the annulus, slow down again to something in the order of a quarter of a barrel per minute to then again see if you can get an accurate determination of that lift pressure. We don't have any evidence to suggest that's what we did, just to pump it at a quarter barrel per minute. So, as such, the conclusion that we had lift pressure, that lift pressure indicated a positive cement behind the casing, it just feels there's no -- there's just been no case of great confidence in that method of determination given the small volume of cement and small pressures involved.

what you're trying to do by slowing the pumps down is you're trying to minimize your friction loss associated with pumping. So if you slow down your pumps, you get the lowest possible. Now, you do it at the beginning so you just push that hydrostatic head of mud up the annulus. Then the second time you do it is you do it again to kind of see what's the difference. So you have the same very slow pump rate and you seem to have very low friction losses so then you have -- you see the difference between the two and the result in hydrostatic. You'll still have some element of friction loss in there because the viscosity of the mud is going to be different from the viscosity of the cement, so it won't be absolutely accurate but a reasonable indication.

but what you get from that information is an estimate of the height of the cement?
Yeah, because the differential pressure is going to be the difference between the hydrostatic cement -- hydrostatic height of cement versus the equivalent hydrostatic height of mud. So when you get that you can determine how much cement you have.

MR. WETHERBEE: And this method is already -- this is more of a question -- already has a higher degree of difficulty because the cement is light?

when you kind of do kind of a static balance the difference is 100 psi, something of that order of magnitude. But because you've got that low window of effective stress between a fracture pressure and pore pressure, you're trying to stay above -- you're trying to stay at 14.2 but not go below -- yeah, so you're trying to stay at 14.2 but you don't want to exceed 14.5. So you got 0.3 pounds per gallon to play with. So there's not a lot of difference in what was in the annulus and what was in the casing, so you've got a very low difference in hydrostatic pressure. So it's not that reliable means of determining the quality of the cement behind your indication.

MR. WETHERBEE: What's the difference between that and another job that would be easier to do if you'd have different cement?

Small Volume

MR. BROCK: I think that doing another job, one, so you're pumping 50 barrels of cement, more or less, around here, so it's a small volume. And actually 50 barrels at 9 and 7/8ths casing that's tapered over to 7-inch casing, you know, it's a small volume to go down this size of casing and then around the backside. So you've got contamination. A little bit of contamination can go a long way. So you're worried about that first and foremost. And two is most cement jobs you're pumping hundreds of barrels of cement, you know, so your differential pressure is hundreds of psi, not 21 or 80 or 100. You know, you have much bigger numbers to work with. And also, too, is when you finish your cement job your hydrostatic differential is much greater than your pressure losses. So because you've got higher volumes and greater height of cement, you've got bigger numbers to work with and it gives you a higher degree of confidence. In this case you have very small numbers to work with.

MR. WETHERBEE: But why -- so I understand, the volume of the annulus is less here, but the height I guess is what matters. And why was this height so lower?

PP/FG – weight of Cement

PP: > 14.2 (need heavier mud to prevent kick)

FG: < 14.5 (take losses, fracture formation)

MR. BROCK: Right. Because you're working -- because you knew you were going to have losses at 14.5, and you knew you had to maintain 14.2 which was the equivalent pressure, right. So you have 0.3 PPG is the one you had to work at. Now, if you thought you were in a different regime, so say you were in a 14.5 fracture gradient but your reservoir pressure was just 11.6 pounds per gallon, then you've got between 11.6 and 14.5 is the weight of your cement. So you can weight up your cement. You've got a lot of space here. You can weight up your cement and really get a good, heavy dense cement down there without worrying about fracturing, but it would be way in excess of what the mud weight would be inside your casing. So you'd have -- even for the same volume of cement you'd have a much higher weighted cement and it would give you a bigger differential pressure. one that was more reliable.

It's just the height relative to the weight --

The height of the cement here was 500 feet above the shallowest hydrocarbon zone, and that was to meet the international requirements. So the H is there. So density is height times weight. So it's PPG. So if you've got, you know, the differential PPG is .3 or if it's, you know, kind of 2, you can see the difference here of -- you got a thousand foot. This can be a lot denser where you -- and this frac pressure is 14.5, you're going to lose mud at 14, 14.2, you're going to kick. So you've just got a really low window gate to push mud between. The height is going to be the same either way. It's just going to be much lighter in this case than it will in this case.

Harder because --
what you start to do is the numbers are going to be much smaller, and then you actually have -- much smaller and then just to think about the accuracy of the gauges and machines you're using to measure those heights. And also, too, is when you've got a much bigger differential, the differential pressure is much greater than the friction loss. In this case the friction loss is much higher than differential.

So pump the cement. And then we decided not to do the CBL?

CBL

Long String

but I think the long string design is robust.

It was compliant with BP
design standards. I mean, there were a couple of dispensations, you know, where it didn't exactly meet the casing design policy, but that's not unreasonable in this environment, you know, but in principle it kind of met BP design policy and where it didn't the right dispensations were put in place with the right people. So the design was robust admitting this when they got to the bottom, this was a

Particularly Challenging Cement Job

So when you kind of look at it, you kind of look at high percentage and some concerns raised through just the composition of the slurry and it's rheology and its properties, you know, it's kind of last minute job here, a lot of things are being run last minute optisim. We are still waiting on the final slurry run because we asked to extend the time setting time so we asked for more retardant to be added. I still haven't seen that from Halliburton. So, you know, kind of the edge of the
envelope slurry, a small slurry, big casing low volume, didn't run all the centralizers we would like to because we thought we had the wrong ones out there.

Decision Tree

And then
when we got to the bottom, we didn't have losses and the guys built a pretty good decision tree, although his decision tree was based on meeting MNS requirements and when you look at it and you compare it with BP's ETP for zonal isolation, you know, you'd ask two questions.

One, you're accepting 500-foot above hydrocarbons. I understand that is an MMS requirement. That in itself, you know,

BP's requirement is that if you're not going
to use a proven method to determine top of cement that you should pump 1,000-foot of cement above the perimeter zones and you should also centralize the casing 100-foot above the perimeter zones as well. And that's just make sure you minimize channel and you get good zonal isolation. We didn't do this and we didn't pump 1,000-foot. Now I understand why we didn't pump 1,000-foot because they were worried if they didn't pump a 1,000 foot they'd get cement into the next casing shoe. And we've had a lot of issues in the Gulf of Mexico for production casing annulus pressure build up. And that's really where in the production mode thermal expansion of gases actually can cause collapse loads in the annulus of production casing. And that's a pretty well known phenomena. And they were trying to design this string for that in mind, so

they were trying to
leave the shoe of the last casing shoe 9 and 7/8ths they were trying to leave that shoe free to formation so if they got an annulus pressure build up, then they would have leak off that shoe and they maintain integrity for the longer term life of the well.

They also put
designed in burst disks at a 16th inch casing as a similar mitigation. And then there's an argument that you could have

pumped more cement and even with that you would have exceeded the fracture gradiant and as such you may have wanted to pump more cement but you would have more losses. So a difficult situation, but neither centralization required to meet the BP requirement nor the methodology of determining a successful top of cement met the ETP as written. Now the ETP is a little ambiguous, it's not particularly well written to define identification and testing of barriers prior to suspension of wells in the annulus, but I think the intent is that we have two proven barriers one way or the other, and the question here is we didn't have the means of effectively proving the cement and do an assessment. And it's not evident that we did a rigorous risk assessment just looking at the information we had. Either after setting the cement or actually after the negative test when we would normally had sat down and do we know enough about this to allow us to suspend the well here in a few hours.

Cementing Tools

So after the cement test was done, our cement was put on bottom. The next operation was to go back with the cementing tools. They did that. They ran back in the hole.

Positive Test

Prior to running the hole, they closed the blind shear rams. And we did a good test on the casing. We did a pressure test on the casing 500 and 525-psi. That was a good test. The test itself, se tested the shoe. We tested the casing, tested the seal assembly. We actually set the seal assembly first then we went in and did the testing. Setting the seal assembly, set it, got it in place, setting the seal assembly went textbook.

Sequence of Lock ring

The procedure for exploration wells is we set the seal assembly and then subsequently come back in and set the lock ring. And we had set the seal assembly. It had pressure tested very well. There was no abnormalities in that setting procedure whatsoever. And we were planning after we did the negative test to come in and set the lock ring on that seal assembly. It was a place for our lock ring which was pretty standard practice for the drill wellhead system. Although, in our production strings, they normally run integral lock ring with the seal assembly. It's just different configurations that make a difference.

Wiper Plug?

They did the pressure test. That was good. The pressure test was good. They would have tested the seal assembly casing. They would have tested the shoe. Admittedly we had a wiper plug down there. People talk about did we get a good test in the casing. We did get a good test on the casing. But you may have been testing the wiper plug as opposed to the shoe track where you had your kind of class A cement. That's just the wiper plug is good for 5,000-psi so you probably tested that plug as opposed to testing the integrity of the shoe track and such. And after that test the ram hold to I guess 8,000. I can't remember the exact depth, but kind of into the depth.

Negative Test

And then they actually proceeded to line up to do the negative test, which was their procedure. And part of that was to, you know, displace the pseudo oil based mud with seawater, which again is just standard practice, as you get to suspend the well you got to take the pseudo oil based mud out, displace the top of the well and displace the riser to seawater.

Spacer

As an interface between that they had some high visc material in the pits. These were loss circulation pills and they got a recommendation from MI to comingle these pills and then use them as an effective spacer. So you can imagine you are displacing 14.1 pseudo oil based mud with seawater. It would be really ineffective if you tried to pump one after the other because your seawater would cut straight through your seaoil based mud and you would get a lot of contamination. So they pumped this pill, and I guess pill 450 barrels. You know, it doesn't really make a huge difference how big the bill is. It just needs to be big enough to be effective. In terms of pill size you normally pump 200, 250 barrels maybe in that order, maybe a little less. There is no inherent risk of pumping this volume of pill really just as a matter of using what you have available to you after it's being pumped through it's a water based fluid. It was what was contaminated would be disposed of so nonissue.

Spacer procedures

But they displaced this. But the issue is here in the investigation the intent was to pump this viscous pill, displace it with seawater to well above the BOP. And once it was well above the BOP then the idea was to shut the upper annular and then have the well was then displaced to seawater, to kill the choke lines would be displaced to seawater and then we do our negative test. The fact is through the investigation we've reviewed the MI procedures. We've reviewed the stroke contours on the rig that we got back from various mudlogs. It looks like there was mistake. Although, the instructions look very clear from MI, it looks as though there was some confusion by whoever was actually doing the pumping whether it was the AD or the driller on the rig floor they seemed to have gotten the mixed and as such they under-displaced the pill and the determination of the investigation team is that by mistake the pill was inadvertently left across straddled the BOP.

We don't believe that at the time where they were actually closing the annular and conducting the negative tests that the drill crew, nor the BP wellsite leader were aware that the pill was there. I think everybody thought that the pill was 1,000-foot up in the riser. So we're doing the negative tests and if normal practice in this rig was they used to do the negative test which really is a draw down on the well to simulate the well being open to seawater hydrostatic; i.e., the BOP is being removed is to simulate that condition so the positive test is based test that the material integrity of the casing. The negative test is to test that the casing can withstand a lower effective density inside the casing with regards to the back pressure which will be either heavy mud or hydrocarbons from the reservoir. So it was really just to test the integrity of the casing from pressure behind the casing itself with the well pressure inside from disconnected BOP. And we normally do it down the drill pipe or they normally do down the drill pipe in this rig, and as such, the Transocean crew lined up to do it on the drill pipe closed up the annular and prepared to do that test which is, you know, just basically displace the sea water and monitor for flow.

(Annular Leak)

In the course of that initially they bled off 50 barrels. And they weren't quite sure where that 50 barrels came from, but they realized in the process that it was likely that the annular was not sealing. So they upped the regulator pressure on the annular, closing pressure on the annular, got a tight seal on the annular, and they actually filled up the riser again just to offset.
So they were getting lined up on the drilling pipe. They had figured out that the annular was leaking. They upped the pressure. They got a seal.

MR. BROCK: Yeah, one of the tests they did is they were trying to figure out where did this 50 barrels come from because you are now putting this draw down on the well and your concern should be holy molely I should not be -- when you put the draw down on you should get a couple of barrels back just as the casing relaxes, but you shouldn't be getting 50 barrels back. So what they did is they looked down the rig floor, they looked down into the riser and they saw that the riser had dropped, and that's how they ascertained that the bag was leaking.

So we don't think we had an influx yet.

MR. BROCK: No, we didn't. We were pretty sure that was the mud bypassing the annular. And that's pretty common too because if remember you had actually seawater down one line, but you had this pseudo oil based mud and this pill which is heavier than the other.

So that would be very natural for if the annular wasn't leaking for any pressure seen in the drill pipe would have come from the higher material in the riser, higher weight material in the riser.

MR. BROCK: So they started to do the test on the drill pipe and Bob ca Luccia, the BP wellsite leader came up to the floor. I think either could Luccia or Don vitrein they were just handing over at this period in late afternoon. And you got all of the facts in that.

MR. WETHERBEE: Yep.

Procedures (re MMS Permit)

But one of them ascertained well, this is actually the permit, the MES permit says we should be doing this test on the kill line, and it's neither here nor there whether the kill line or drill line it's the same test. But to be precise to meet the letter of the law in terms of the permit, the drill company had stop the test on the drill pipe and then get our systems switched over so they could get it on the drill line and they did that. And people were upset they were changing halfway through partially completed test and they like to do it a certain way and there was lots of references to different people did it different ways, but in effect it's the same test and they wanted to follow the letter of the requirement for the MNS. Incidentally, the negative test, I believe, is not an MNS requirement, but we put it in our permanent reserve requirement for BP and that's why we did it.

Misinterpretation of Neg Test Results

So the line up and the kill line and they were getting balance back and forth in the kill and trap pressure. But in effect they got the kill line lined up and they felt they were satisfied that it was open and they monitored the kill line for 30 minutes and the kill line stayed at zero pressure for 30 minutes. However, the drill pipe which is the other side of the U tube was recording 1400-psi. And when they discussed the difference between the two, the difference was described by, let's say, personnel on the rig as a bladder effect some phenomena where you get this disbalance, but it was discounted of being of any great significance. The investigation team looked into this, and we believe that one, you know, we don't believe there is any credence arguing that there is a bladder effect or other phenomena. You know, there should have been 1400-psi on the drill pipe there should have been 1400-psi on the drill pipe.

First Influx

And we believe that 1400 psi was an indication that we had gotten integrity and that we were in communication with one of the sands in the open hole section. And why do we not need it on the kill line, it would have been any number of events.

Reasons for No Flow on Kill

1. The valve could have be shut on the kill line. So that they actually inadvertantly had a valve closed and they weren't actually getting any pressure from the well. 2. that the viscous pill that we had inadvertently or had been inadvertently left across the BOP had when we were bleeding down pressures had come inside the kill line and had actually blocked off the kill line itself. 3. And more simply this material was very viscous and the very fact it was in annulus meant that pressure communication between the well and the kill monitor was blocked by this very viscous material, which didn't transmit the pressure. So any one of those three could have led to zero drill on the kill line as opposed to the 1400 on the drill line.

Decision

But with three hours to do this test, a lot of debate on what the particular circumstances were and at the end of the day all parties, you know, <u>Transocean, BP, concluded that the test was good and when, in fact, it wasn't</u>. And as such, they kind of opened up the annular and started to contintue to circulate the seawater into the well, circulate the pill and the pseudo oil based mud to surface.

MR. WETHERBEE: Okay. So now they go into thinking that they've just demonstrated the integrity of the well, they go into do another operations which we

would expect them to do.
MR. BROCK: So I'll talk about that. Let me give you my ten minutes worth first.
So at this stage as we said earlier, you know, the guys were actually, this was the last kind of,

SimOps

the negative test was the last significant operation before setting a cement plug and then testing that cement plug and then set the seal assembly, set up cement plugs, set the seal assembly, disconnect the riser and pull the riser in location. But in that there was a lot of work going on, and all through the day, you know, people were back 1. loading the equipment on to the bankston. the supply vessel. They were 2. transferring mud because they you displace all this mud out of the well, they were displacing the mud back on the pits on the rig and then they were actually, you know, transferring the mud from the pits onto the boat itself. We don't believe at any stage that they were directly going from the well straight to the boat. But we think they were moving pits, they were 3. cleaning pits on the rig. They were cleaning during the negative test, they were 3A. actually cleaning the trip tank which is a small accurate tank on the rig floor, gives the driller a chance to accurately monitor the well. So a lot of work on that, which was sim-ops.

So they were doing, you know, they were cleaning pits. They were preparing materials for back load. You know, they were bleeding riser tensions down. They were stripping mud pumps, doing work on the mud pump systems, don't know exactly, but a lot of care and maintenance work now that we've finished drilling the well. You know, circulating the seawater is a relatively straightforward activity. You expect a drilling or AD to be on the rig floor just monitoring events there, while everybody else was to doing axillary work or getting ready for the next phase of the operation which was do the cement plug and set the seal assembly. So a lot of sim-ops going on or round about on the rig itself. And that kind of, you know, through the course of this, you kind of -- you've got, you know, for us we look back at the data, you know.

Underbalance

We left
shortly after the bottoms up that we saw a number of indications that whereby, you know, the well was in an abnormal state and indications where they were taking a kick. You know, we saw pressure build up in the drill string when we slowed down the pumps which was not characteristic to slow down the pumps and especially drill type pressure decrease. We saw an increase. We

saw volumes coming out of the well were greater than volumes going in and subsequently seeing the drill pipe again. I don't have times and dates. We've got all that recorded.

51 minutes before the explosion there were clear indicators that you would expect to be very visible on the drillers panel on the rig floor through the Transocean monitoring system. But additionally you also would have expected to see similar information available in the mud long unit as well and you would have expected just for people that don't notice these to make notifications. As it is, you know, there is an eyewitness account that the

Differential Pressure

chief engineer was on the
rig floor about 21:31. He witnessed the night tool pusher talking to the driller sevet and they were talking about abnormal pressure or conditions in the well and he asked. He went up there to see when they were going to do the cement job. And they said well, it might be a little while because we may have to circulate

bottoms up here. So it appears at 2131 they had recognized some abnormalities. However, looking back at the pressures and the charts recovered from spurry sun mudlogs data that conversation happened at 2131 because there's

No Evidence of Actions

no evidence to us that we took any action to shut the well in until about 10 or 15 minutes later whenever a series of phone calls were made to personnel on the rig notifying them that there was mud flow coming at the rig floor and that they were taking actions to close the annular and to line the return system up to the mud gas separator system. And in fact they were going to use the mud gas separator as a means to controlling flow from the well. And from our analysis, it appears that annular preventer may well have been closing moments before the first explosion and there's sharp pressure spike literally just moments before the explosion that suggests that maybe the annular affected the seal. Or also there's evidence that the upper variable rams may have been closed and that may have given us an effective seal in the annulus itself.

Eyewitness accounts tells us that the closed button for the annular was evident on the control panel on the bridge. There was no indication that the upper doors had been closed, but subsequent ROV inspection and workdays later advised that when they tried to close the upper variable rams that the system needed no fluid suggesting that the upper variable rams were already closed. And as much as this would actually have sealed the annulus, we believe that gas had already broken into the annular or into the riser and graded up the riser and created a massive gas plume out the rig and overwhelmed the mud gas separator system causing gas to vent and leak around the floor and the rig area and in particular it may have find air intakes to the generators. It may have caused the generator systems to go into overdrive and then fail. We don't know. I mean, there was a lot of work on the rig. This gas would have quickly found areas that were known hazardous, safe, and as such we don't know what other conditions they may have found that resulted in at least one if not two explosions. Eyewitness accounts recall a smaller explosion followed by a larger explosion and fire.

MR. WETHERBEE: So, I mean, that was really good. That was like gold. So I decided not to do the outline and just kind of listen because it was really valuable. Thinking about the outline, I would then probably talk about we would then obviously go into the BOP things.

MR. BROCK: Yeah. So let me talk about the BOP because you know what we just talked about there was actions you would expect the driller or the personnel on the rig floor and the driller and toolpusher. The driller and toolpusher they called down. They advised Ed Zelles, toolpusher. They called personnel to different areas of the rig to support response. They called evidence Don or Ed called Don. There was a series of calls went out just notifying people that we had this well control event and they were responding to it. Beyond that, you know, we have no further accounts on the rig floor of what occurred. What we can say though is that individuals mustered, you know, BP visiting VIPs with the subsea engineer and others mustered onto the bridge of the rig and during that muster, they were aware that one light on the panel was on that looks like it was the lower annular was on which indicated it had been shut. There were other accounts of lights were flashing but we can't substantiate what that actually means. But there was a clear direction to fire the emergency disconnect sequence. We believe that Chris pleasant fired that function or tried to activate that function by pressing the control panel on the bridge and there is other accounts that other individuals had subsequently advised to fire and shut fire the EDS. There's also discussions about whether people had the authority to shut the EDS or who would make that decision or do we need to do further decision. There was some decision between the master and OEM about that, and it's well documented in witness statements. But in effect we're pretty sure that the temperature made to fire the emergency disconnect sequence, the EDS, after the second explosion. There's accounts that say that lights came on, they flashed. Accounts came on to say there's no stroke indicators. It's our belief that although they made attempts to fire the EDS system that either after the first or second explosion the communication between the control panel on the bridge and the central computer unit for the BOP, which would subsequently relay the message down to the subsea stack, we believe that that system was damaged and was ineffective. And as such did not communicate the instruction to fire the emergency disconnect sequence. That sequence would have fired off the high pressure blind shear rams to close and it would have subsequently fired off a message to disconnect the low range riser package. And that would have separated the rig from the well itself with the blind shears supposedly sealing in in the well. There's no evidence. We went through the inspection. There is no evidence that the blind shears fired at this time, and there's no evidence that the lower rim riser package had partially or had attempted to disconnect from the well or from the BOP.

Through sequence of events, you know, what happened next, well, it's unclear to us but the next function you would expect to operate would be the auto mode function/dead man system. This system is designed to operate in the event of a catastrophic failure of your riser, where the BOP loses hydrolic communication and electrical communications and communication between the yellow and blue pods for the BOP. If these three conditions are satisfied, then the blue and the yellow pods will then get a signal to fire the high pressure blind shear rams. Again, you know, just through after the explosions or actually when the rig sank, we're pretty sure that these three conditions were satisfied. But, again, on the ROV inspection there is no evidence that the blind shear rams were activated, and that's caused some concern for us and it's an area of inquiry into the investigation, and I'll come back to that in a second.

Later on with the ROV on the seabed, the team tried to simulate the disconnection of the long range riser package and that would have kicked in an auto shear feature. The auto shear feature again is a mechanical device. It's got no electronic parts. It's just a mechanical device that is tripped whenever the low range riser package disconnects from the BOP. And if the emergency sequence has not been activated, the automatic feature here is that somebody has inadvertently disconnected the LMRP from the BOP so the mechanical device trips the high pressure shear rams and they are activated to shut and seal the BOP.

As part of our inquiry, we got a chance to examine both the recovery of yellow and blue pods. The inquiry we did actually suggested to us that critical solenoids in the yellow pods were defective and as such at the time of the incident we believe that they were defective and as such would have meant that the ability to function the dead man on the yellow pod would have been ineffective. Similarly, we recently covered the blue pod. We carried a full inspection of the blue pod. And in that inspection we identified there are critical batteries in the system that are needed to make the function active were, in fact, dead. We've done some analysis on this and it's highly probable that given the voltage failed in the batteries at this time of inspection that the batteries back on the 20th of April were also quite likely or very probable that they had insufficient charge to have activated the deadman system on the blue pod.

In addition to that, the ROV identified a number of leaks on the BOP, leaks on the upper annular, leaks on the ST locks on the blind shear and two other leaks on the system itself. And we've done a detailed hydraulic modeling analysis. And through that hydraulic modeling and analysis we've concluded that these leaks when the system was connected to the rig and had available hydraulic horsepower from the rig meant in this particular case while they were supported by hydraulic fluid and pressure from surface these leaks were immaterial. However in the mode whereby the system is disconnected from the rig and is wholly dependent upon the subsea accumulator system that in the event of activation of the blind shear systems, the leak on the ST locks would have at the time of activation of the blind shear rams through the subsea accumulator auto function -- sorry. Let me go back one.
The function of the blind shear rams either through the auto shear mechanism, simulation or through the AMF function and is not likely to have been able to cut pipe because the leak rate was sufficient to have bled off pressure that meant suboptimal pressures were available to drive the closure of the blind shear.

And as such it's likely that some attempt to shear would have been made, but it would not have been effective in completely shearing the pipe and sealing the well.

Overall from the analysis of maintenance

records, from analysis of the recovered parts of the BOP, the pods, we don't have an impression that this BOP was particularly well maintained, given that it's a piece of safety critical equipment, we would have expected to see a more consistent rigorous campaign program for this component and that was not evident from the work we've done to date.

Additionally the ROV work identified quite a number of undocumented changes to the hydraulic control systems on the BOP. We believe that a lot of these changes were made without the oversight of the original manufacturer, and as such we don't believe that the MOC process used by Transocean, you know, was adequate in terms of documenting changes in terms of getting third party sign off or completing it essential

acceptance testing for the changes was adequate given the nature of the equipment that these changes were being completed on, these changes were being made to. So we have concerns about that.
I mean, a lot of this work on the BOP, you know, we've done from, you know, inspection as we can do observations from the ROV and from available drawings that we've made, be made available to us either through the drilling operations team at BP or through documents we've got through from Transocean. We don't have a comprehensive set of documents of as-built diagrams. And as such one of the strong recommendations to this is once the BOP is recovered that further inspection is done to really proof out the actual modifications and then complete further analysis on the hydraulic modeling system failures et cetera, that needs to be done once recovered.

In addition to that one of the key things that needs to be preserved are the accumulator bottles themselves where we can ascertain what the available pressures and volumes would have been subsea and so those systems should not be bled down before the BOP is recovered. They should be preserved as an accurate means of determining just what fluids were available subsea.

MR. WETHERBEE: Closing out this section just back to an outline kind of a deal we will also have conclusions and recommendations, long-term, short-term, that kind of thing.

MR. BROCK: So hydrocarbons and surface. So as we said, the driller noticed at 2131 that there was some abnormalities in the well. We believe that, you know, around 15 minutes later, you know, we were seeing mud come back on the rig floor and then actually seeing excessive fluids and gas come up to the rig. And our understanding is from the eyewitness accounts and reports that the driller toolpusher lined up through terms fluids through the mud gas separator system. So they shut the divertor and lined up on the mud gas separator system and as such diverted the flow from the well into the degasser which in itself is not a high capacity vessel nor is it a high pressure rated vessel. And it quickly became overwhelmed and gas was vented out of the vent systems but these vent systems had a series of goosenecks on them. So they vented gas back down on the rig floor areas, areas adjacent directly with the rig floor. And the systems failed themselves, you know, we just had slip joint failed, pressure relief valves are likely to have failed. So the system itself was overwhelmed as a result of diverting through the mud gas separator system.
One of the areas that we're looking into the investigation is the alternative if we had recognized that there was an ongoing well control vent, you would have expected first and foremost, one, the crew to respond much more quickly to the signs that they picked up on the rig floor particularly at 2131. You would have expected rams to be closed a lot quicker and as the influx got to the surface and you started to see kind of gas breakout which resulted in jets of mud releasing from different components. You would have expected to see a system of this high rate, high volume be diverted to the primary diverter system which is two foot an inch over board lines. Our early understanding at this stage if we diverted to these overboardlines, we could have actually safely diverted the majority, if not

all of the fluids overboard and created a broader window for the rig crew to respond to the event and possibly a different way with possibly a different outcome.
MR. WETHERBEE: Very good.

MR. BROCK: That's what I'm thinking is your layout is the intro, your failure model, your causal effects, conclusions, recommendations.