Deposition Testimony of:

Graham Vinson

Date: June 23, 2011

Created by:

inData

www.indatacorp.com

Page 8:01 to 8:05

THE VIDEOGRAPHER: This is the deposition of Graham S. Vinson, III, In Re: The Oil Spill of the Oil Rig DEEPWATER HORIZON in the Gulf of Mexico on April 20, 2010.

Page 8:08 to 8:10

Q. Good morning, Mr. Vinson. My name is Paul Sterbcow. I'm a member of the Plaintiffs' Steering Committee in the case.

Page 8:23 to 10:24

Q. My understanding is that by way of background, you are a petrophysicist; is that correct?
A. That is correct.
Q. What is a petrophysicist?
A. Petrophysicists are responsible for evaluating the formations we actually drill through.
Q. All right. Is that a degreed title? Do you get a degree in petrophysics?
A. You do not.
Q. And how do you come to be a petrophysicist?
A. Actually, I started my career 30 years ago in that white building right behind us, One Shell Square.
Q. All right.
A. You actually have a science or an engineering degree, and then you go into a particular company and you go through a training program.
Q. All right. And you worked for Shell at one time?
A. I did, for seven years.
Q. And when was that, about?
A. January of 1981 to March of 1988.
Q. Where did go from there?
A. BP.
Q. Okay. Have you been with BP regularly since '88?
A. I have.
Q. What job positions other than petrophysicist, if any, have you held with BP?
A. Technical petrophysicist for the first 22 years of my career. Since 2001 I have been the manager of the Gulf of Mexico

DEEPWATER EXPLORATION TIGER team.
Q. And what is the TIGER team?
A. It is a subsurface team, and it is responsible for providing overburden characterization to the wells group for the planning and drilling of wells.
Q. And when you say "Gulf of Mexico," would that include any well drilled by or on behalf of BP in the Gulf?
A. That would, in the exploration group, exploratory wells.
Q. Okay. And Macondo was an exploratory well?
A. Yes, it was.

Page 11:19 to 11:24

Q. Okay. Was Mr. Thorseth your supervisor as of April 20 of 2010, which would have been the date of the catastrophe?
A. He was not.
Q. And who was?
A. Dave Rainey.

Page 13:15 to 14:20

Q. Are deepwater Gulf of Mexico wells high risk, from your -- from your perspective?
A. Define "high risk."
Q. Are they high-temperature, high-pressure wells that involve greater risk than, say, wells that are not in the Gulf of Mexico?
A. Drilling any well into the subsurface involves some element of risk. An exploration well in the Gulf of Mexico, in my view, is no different than risks that are associated with onshore wells.
Q. So the geographic location doesn't make a difference?
A. You still have to drill through the subsurface.
Q. All right. Is the subsurface more difficult in an area like Mississippi Canyon 252 than, say, Brazil or Trinidad?
MR. KEEGAN: Objection; form.
Q. (BY MR. STERBCOW) If you can come to a conclusion like that?
A. Explain further.
Q. Is the subsurface which you're drilling through in an area like Mississippi Canyon 252, does it present more challenges, more issues from your perspective, the TIGER

team's perspective, than, say, a well drilled offshore Brazil or Trinidad?
A. Not necessarily.

Page 15:01 to 15:08

Q. Who was working under you on the Macondo project as part of the team?
A. Marty Albertin, Bobby Bodek and Jonathan Bellow.
Q. And my understanding is Mr. Albertin was the single-point accountability person; is that correct?
A. Yes.

Page 15:10 to 16:02

Q. (BY MR. STERBCOW) And what was Bellow's title?
A. Operations geologist.
Q. And would he have been -- in terms of Mr. Albertin, would Mr. Bellow have been above, below, coequals?
A. Coequals, different job function.
Q. And same answer for Mr. Bodek? Coequals, different job?
A. Right.
Q. And what was his job title?
A. Bobby is also an operations geologist.
Q. As between Bodek and Bellow, was one over the other, or were they coequals?
A. Jonathan has more experience than Bobby. He was his mentor.

Page 17:11 to 17:15

Q. As head of the TIGER team, did you ever participate in any meetings with any Gulf of Mexico drilling and completions managerial personnel on a regular basis where risk management was discussed?

Page 17:17 to 18:10

A. During stage gate reviews.
Q. (BY MR. STERBCOW) And that would be at the beginning, say, of Macondo when you were going through the BTB process?
A. There are multiple stages that we go through in stage gates, and I would interact at those stage gate reviews.

Q. During those stage gate reviews with respect to Macondo, can you recall who that you would meet with?

A. Each stage gate review would have to be signed off by a person from the wells community. So in this case, Ian Little, and it would also be signed off by my supervisor at the time, Jay Thorseth.

Q. All right. Do you recall Mr. Little being the primary person, not your supervisor, Mr. Thorseth, who you would meet with in terms of these stage gate reviews?

Page 18:12 to 18:13

A. They both cosigned the stage gate documents.

Page 18:24 to 19:03

Q. All right. Would he interact with you on a regular basis or any member of the TIGER team as a well like Macondo was being drilled, other than that stage gate process we're talking about?

Page 19:05 to 19:10

A. The interaction was not on a daily basis.

Q. (BY MR. STERBCOW) Did Mr. Little make it a point to monitor the well progress?

A. Yes, he did.

Page 20:11 to 21:15

Q. And we've already deposed Kate Paine. Are you familiar with her?

A. I am.

Q. My understanding is she's not or was not a direct BP employee?

A. Correct. She's a contractor.

Q. What was the role of a contract employee like Ms. Paine in Macondo?

A. Kate has particular expertise in pore pressure detection, and Kate was employed by my team to actually be on the wellsite during drilling to actually update the pressure detection indicators.

Q. So that was a pretty specific role, if you will?

A. It was.

Q. Below you in the hierarchy, was there a particular person on the TIGER team who would be the go-to person for people out on the rig in terms of any questions they had about geology, downhole conditions, that type of thing?
A. The operations geologist.
Q. That would be Mr. Bellow in this case?
A. Bobby Bodek.
Q. Bobby Bodek. All right. Okay.
Mr. Bellow was the ops geologist with more experience, but Bodek was the guy --

Page 21:17 to 21:23

Q. (BY MR. STERBCOW) -- for Macondo?
A. Bobby was the SPA ops geologist for Macondo.
Q. Had Bobby held that position on wells before Macondo, to your knowledge?
A. He had.

Page 22:02 to 23:09

Q. (BY MR. STERBCOW) This document is Tab 1. It has previously been marked as Exhibit 1513, and it's entitled -- well, for the record, it's Bates stamped MDL 01016932 through 01016950, entitled GP 1015 Pore Pressure Prediction.
Is this a document that you're familiar with?
A. Yes.
Q. What role did GP 1015 play within the TIGER team in terms of guiding you on pore pressure prediction?
A. It was our guiding document.
Q. This would be the guiding document?
A. This is the guiding document.
Q. Okay. If you turn to page -- at the bottom it will say Page 1 or 2 of 19 and so forth.
Page 3 of 19 where it talks about description of risk. It says: Prediction of pore and pressure and fracture pressures in the well is considered a zero tolerance activity within BP.
What does that mean?
A. The pore pressure frac gradient plot underpins the basis design of each and

every well that BP operates. We classify -- so since it goes into the basis of design for us, that is zero tolerance activity.

Q. All right. And when they say zero tolerance, what exactly is BP telling folks whose conduct is governed --

Page 23:11 to 23:21

Q. (BY MR. STERBCOW) -- by this document?

A. With respect to this particular document in front of me, it addresses that one must follow -- on Page 2 of 19, one must follow all steps, 1 through 10.

Q. And from BP's perspective that is a mandatory requirement, and if I understand this correctly, they won't tolerate any deviance from that. Is that fair?

Page 23:23 to 24:16

Q. (BY MR. STERBCOW) Or am I oversimplifying this?

A. No. It is a group practice, and the expectation is that you will follow steps 1 through 10.

Q. And as far as you know and you can recall sitting here today, in terms of the Macondo well and pore pressure prediction activity, steps 1 through 10 were indeed followed?

A. Yes, they were.

Q. And would the TIGER team have been the group responsible for following steps 1 through 10 on Page 2?

A. We would.

Q. All right. Was that the sole responsibility of the TIGER team, or are there other BP employees outside of the team who also have to participate in this?

Page 24:18 to 25:16

A. There are -- if you look at line 9 on Page 2 of 19, it requires that a validation review be conducted. I as the manager of the TIGER team cannot validate my own work.

Q. (BY MR. STERBCOW) Right. Okay.

A. So we have outside -- we have a group of global-approved auditors, and we must pull in one of those people from outside of my business.

Q. Got you. And when you say "global-approved," that would be through BP global approved?

A. Through BP.

Q. And they would come in and actually audit the work performed by the TIGER team?

A. They would.

Q. And is this in terms of predrilling pore pressure prediction activity?

A. It is for the pore pressure frac gradient prediction that underpins the basis of design.

Page 25:24 to 26:09

Q. (BY MR. STERBCOW) Anyone outside of the TIGER team overlooking or taking a look periodically at the ongoing pore pressure frac gradient readings being provided through the TIGER team?

A. Not as a requirement. But as experts that we have outside of the team, we do call in on a periodic basis.

Q. And in terms of Macondo, can you remember who that was?

A. Mark Alberty.

Page 26:18 to 26:21

So Alberty, is he employed by a third party or is he a BP employee?

A. At the time of Macondo, he was a BP employee.

Page 27:17 to 28:17

Q. Do you know whether or not the drilling engineering team that's responsible for planning the well, planning the casing and so forth, do they take the work of the TIGER team in terms of pore pressure prediction and use that to then plan how this well is going to be drilled?

A. I would not use the word "take." It is a multidisciplinary integrated project team. So as we are actually developing the forecast, the wells community is actually working with us. It is not a completed project and handoff.

Q. Okay.
A. It's actually working like this during the construction.
Q. So the engineers are actually involved?
A. They're involved.
Q. And in this case would that have been Mr. Morel and Mr. Hafle?
A. It would have been.
Q. Was the wellsite leader -- excuse me -- the well team leader involved, Mr. Guide?
A. Yes, he was.

Page 29:14 to 29:22

00029:14
Q. Were there any other engineers who would have been involved in this initial process besides Mr. Morel and Mr. Hafle that you can remember?
A. During the execution of the well, Brett Cocales.
Q. Would those be the three main -- from the engineering side, three main people?
A. They would.

Page 29:24 to 30:18

00029:24
Q. (BY MR. STERBCOW) In terms of the description of risk on Page 3, do you agree with the statement that: Errors associated with the prediction of pore and frac pressures can lead to harm to people, damage the environment and undermine BP's operational reputation?
A. Not in the way it's phrased.
Q. And why is that?
A. There is inherent uncertainty involved in any subsurface description from actually the location you place the rig, on to any interpretation of the overburden that leads to the basis of design.
So that is what we do is we try to understand that uncertainty, and we plan accordingly for the range of uncertainty that exists.
Q. All right. And that's exactly what you did on this well, I assume?

Page 30:20 to 31:14

00030:20
A. We planned according to the standard.

Q. (BY MR. STERBCOW) Okay. And do you know -- do you have either the knowledge or expertise to say whether or not the engineers involved in the project took your planning and expertise and properly executed the engineering design from their perspective?

A. They took the approved PPFG plot per the guidelines in this document, and they actually developed a casing plan for Macondo based on that document.

Q. All right. And do you have any involvement or any knowledge of whether the casing plan developed on the engineering side required a series of dispensations and management of change forms?

A. I do not. It's outside my area of expertise.

Page 31:23 to 33:16

Q. (BY MR. STERBCOW) All right. Can you recall at any point during the Macondo well being told that the margin -- the drilling margin had dipped below .5 pounds per gallon?

A. I don't recall being told that.

Q. Did you ever see any information in terms of reporting to you that led you to conclude that that in fact occurred?

A. I was not involved in the day-to-day activities of Macondo as the manager. That was Bobby and Jonathan and Marty. So the only inference I would have from that would be if in fact an e-mail was sent to me.

Q. Okay. And as you sit here today, do you have any recollection of being told by any of those gentlemen via e-mail that the Macondo -- that the drilling margin at Macondo fell below 0.5?

A. I don't recall an e-mail to me that talked to that.

Q. All right. Do you have any knowledge as you sit here today that that in fact occurred or did not occur, one way or the other?

A. I have some knowledge that during the drilling of the well we went inside the number you quoted.

Q. Do you know whether or not BP has any internal policy as to what should be done in the event that the drilling margin dips below 0.5 pounds per gallon on a given well?

A. There is a requirement by the MMS BOEM regulations that if such an event does occur, then there is a phone call required for a dispensation to go inside of that.
Q. Phone call from?
A. From BP to the -- of the MMS.
Q. And who, if you can tell me, with Macondo would have been responsible for placing that call?

Page 33:18 to 34:13

A. I don't know specifically in BP who would have made that phone call.
Q. (BY MR. STERBCOW) All right. That's not a TIGER team function?
A. That is not a TIGER team function. That's a wells function.
Q. All right. Do the wells people receive information from the TIGER team from which they can conclude that a -- the drilling margin has dipped below .5?
A. The information they use actually comes from the drilling mud weight in the particular interval. So they don't specifically require input from the TIGER team for that value.
Q. All right. Do you have any personal knowledge as to whether any -- whoever it might have been within BP, anyone contacted MMS to alert them that the drilling margin at Macondo had dropped below .5?
A. I would not.

Page 36:02 to 38:03

Q. (BY MR. STERBCOW) Okay. Once total depth is called in Macondo April 13th, does the TIGER team have any further involvement in any downhole activity on that well?
A. The only followup activity once total depth is called is we actually facilitate the open-hole logging geological operations that go along with that.
Q. All right. So once total depth is called and the logging comes in to gather the data from to open hole, the TIGER team is involved in that effort?
A. We are.
Q. And how? What do you do?
A. We actually work with the petrophysicists, in this case the Macondo

prospect team. And we actually work with Schlumberger to facilitate pallet loading, what tools, because we have that expertise on our team as well. So we actually do that function for the petrophysicists.

Q. All right. Does anybody with the TIGER team actually involve themselves in the logging effort?

A. We are involved through the operational delivery of the logging tools.

Q. In terms of operation of the tools themselves and the gathering of the information?

A. Right.

Q. Was Schlumberger the company that did the well logging in this particular case?

A. They did.

Q. Who with the TIGER team would have been working with them?

A. Bobby Bodek.

Q. All right. Anybody else?

A. Potentially Jonathan Bellow.

Q. And to whom is that logging information -- once the well logging is complete, who receives all of that information, if you know?

A. That information is posted to our well space database, so it is there to be shared with BP and partners.

Q. Okay. And would the engineering team on Macondo, the drilling engineering team, have access to that information?

A. They would have access to that information.

Page 40:01 to 46:02

Q. Got you. Okay. So in terms of what type of casings are run, how to run it, from that point forward TIGER team makes no decisions and has no involvement?

A. We have no decision authority at that point.

Q. And I assume, based on what you just told me, TIGER team has no involvement whatsoever in the cement job on a well like Macondo?

A. We would provide information -- based on the logging tools that were run, we would provide information on temperature.

Q. All right. Do you know -- first of all, was temperature information provided to -- would that be provided to the BP personnel or, in this case, to Halliburton personnel or both?

A. The request for the temperature information would come to our team from the wells community. And from that point forward I don't know where that information flow actually goes.

Q. Okay. And the temperature information itself would come from the logging activity?

A. It would.

Q. Okay. Do you know whether or not temperature information was provided to either BP or Halliburton during the cement pumping operation itself?

A. I would not.

Q. Do you know whether or not temperature information was provided to anyone on the rig just before the negative test was done?

A. I would not.

Q. Would the TIGER team still be on the rig providing any type of well monitoring or logging services once the 7-inch production casing was run and the cement pumping operation began?

A. As a matter of course, we would not.

Q. All right. When would typically the TIGER team representatives leave a rig like the DEEPWATER HORIZON on a well like Macondo?

A. At the completion of open-hole logging run at TD and a couple of days of followup post-well reporting, creating composite logs and the like.

Q. Okay. So having said that, I assume nobody from the TIGER team was actually aboard the vessel on the 20th?

A. They were not.

Q. Would the -- whatever the last logging date was, would that typically mark the last date that anybody from the TIGER team would be aboard the rig?

A. Typically.

Q. Do you know whether or not there was any capability on the DEEPWATER HORIZON to provide downhole temperature readings during and immediately after the cement job?

A. I would not.

Q. Okay. Do you know whether or not downhole temperature was being monitored in any form or fashion, either during the cement job or after leading up to performance of the negative test?

A. I do not.

Q. All right. If that were indeed occurring, do you know who aboard the rig would be qualified to provide downhole temperature readings once the TIGER team was gone?
A. I can't speak to the qualifications of the rig personnel.
Q. Do you have any reason to believe that any errors associated with the prediction of pore pressure and fracture pressure led to this catastrophe?
MR. KEEGAN: Objection; form.
A. I am not aware that the computation of PPFG, as conforms to this document, had anything to do -- the well was -- the well was successfully drilled to TD based on the PPFG prediction and detection without incident.
Q. (BY MR. STERBCOW) Okay. Do you have any information as the TIGER team leader as to what caused the influx of hydrocarbons into the well on April 20th?
A. I do not. Outside my area of expertise.
Q. Totally outside of your area.
And were you involved at all in the post-incident investigation by BP?
A. I was not involved in the investigation.
Q. Were you interviewed by anybody as part of the investigation?
A. I was not.
Q. All right. Do you know if anybody within the TIGER team was interviewed?
A. I do not.
Q. Okay. Have you read any part or all of the -- what we're all calling the Bly report?
A. I have.
Q. Based on your knowledge, do you have any basis, based on education, training or experience, to comment on the conclusions of that report in any manner?
A. I do not.
Q. Okay. I'm assuming you haven't seen the Transocean investigation report because it just came out?
A. I have not.
Q. Okay. If we go to Page 11 of the document that's in front of you. I think we've briefly covered this. At the top it says Accountability. And for the record, we're on MDL 01016942.
It says: BP executives,

managers and supervisors actively participate in and recognize that effective technical management of the zero tolerance activity is critical to our business success.

Would -- is this paragraph describing the process by which the predrilling pore prediction effort is audited?

MR. KEEGAN: Objection --

Q. (BY MR. STERBCOW) Do you know?

MR. KEEGAN: Objection; form.

Q. (BY MR. STERBCOW) Or is this something totally different?

A. I did not write that paragraph.

Q. Okay.

A. But as a manager, I actually do participate in and recognize that getting the pore pressure frac gradient plot, with the uncertainties associated with it described fully based on our technical capability, is an important thing to do to underpin the basis of design of a well.

Q. All right. Are you aware of any BP executives who would have participated in the same manner you did?

Page 46:12 to 46:19

Q. Do you know whether or not in a well like Macondo, once your team is -- has completed its effort and prepared a pore prediction document, is that document trans -- does that document stay within drilling and completions of the Gulf of Mexico, or does it go to someone outside of that specific division, if you know --

Page 46:21 to 48:09

Q. (BY MR. STERBCOW) -- for review?

A. The procedure per this standard is once that document is agreed and the terms of reference of the audit review are signed off on, that particular document is posted on one of our global websites. It is a mandatory part of this requirement. So internal to BP, that document sits on a global wellsite that is accessible.

Q. All right. And do you have any idea who is -- has access to that global website? Excuse me.

A. I do.

Q. And who would that be?

A. It's a group of about 17 people.
Q. All right. Does -- are any or all of those people typically located in London?
A. It is a global distribution list. Some of the people are outside of the United States.
Q. All right. At this time, talking about Macondo, would Mr. Hayward have access to that website?
A. I don't believe he would.
Q. Who -- who within BP who was based in London, if you can tell me, if you know, would have had access to that website and that document?
A. There is one particular gentleman by the name of Stephan Petmecky.
Q. Okay. What was his title?
A. He is actually very similar in capacity to previously mentioned Marty Albertin.
Q. All right.
A. He's a technical pore pressure frac gradient specialist.

Page 48:15 to 54:17

Q. Okay. Do you know whether or not anyone who has access to that document has any responsibility within BP for risk management?
A. The risk management process, as it pertains to a single well, there are -- there are two risk management processes.
The one that I participate in is known as RAT, risk assessment tool. It is part of what is described as the no-drilling-surprises part of beyond the best drilling.
The subsurface team, we have a global list of potential risks. And prior to a well, we do what is called an NDS assessment. In that assessment we identify what risks in this particular tool are -- pertain to the particular well that we're going to drill. We then develop risk mitigation plans for the subsurface on those risks that are identified.
And that document is an input to the combined subsurface and wells risk register --
Q. Okay.
A. -- which is a document that gets signed off on at the selected define gate, and then continues again into define and

execute.
Q. Got you. And was there another document? You said there were two risk management documents?
A. There is a tool called RAT --
Q. Right.
A. -- which is the subsurface tool that captures subsurface-related risks. It is our vehicle to then capture the key ones pertaining in this case to Macondo, which then go into the wells risk management process.
Q. All right. And is -- are you aware of any other risk management tool other than RAT that would apply to Macondo?
A. There is -- from the wells community, there is what we call a risk register.
Q. Okay.
A. And the wells organization manages that risk register with inputs from the subsurface team that have been defined by the RAT tool.
Q. All right. Would you as head of the TIGER team have any input and any role -- or any role in preparing that risk register?
A. I do not.
Q. Okay. And would it be something that you would have seen for any reason or had to review?
A. I -- I actually review it with respect to the subsurface risk of the RAT tool actually populating into that risk register.
Q. Now, in terms of the risk assessment tool, is a document actually filled out, a RAT document, I'll call it?
A. It exists.
Q. It exists?
A. It does.
Q. Okay. And who receives that document?
A. The RAT tool is held on our server in the TIGER team because it is nothing more than a tool that allows us to capture the risks that we see from mud line to the total depth of a particular well. And then we pull the pieces that apply to that well and populate to the wells risk register.
Q. Got you. Okay. Would there be a particular person responsible for completing that risk assessment tool?
A. Which one?
Q. The RAT -- well, I'm envisioning a risk assessment that is documented

someplace on a computer or on a -- on sheets of paper.

A. (Witness nods.)

Q. If that -- who does that? Who inputs that data?

A. In my team, the TIGER team, I actually have a gentleman that is called a "no-drilling-surprises champion" --

Q. Okay.

A. -- as part of a broader global no-drilling-surprises network. And that is the person that has the single-point accountability to capture that information for my team and assure that that information gets moved over to the wells risk register.

Q. All right. And who was that on Macondo?

A. I believe on Macondo that would have been Paul Johnston.

Q. Okay. And I've seen his name on some e-mails. So he would be part of the TIGER team?

A. At the -- in January '09 he was not part of the TIGER team. He transitioned into my team at a later date.

Q. All right. And when would the -- the risk assessment tool, the RAT risk assessment, be done on a well like Macondo?

A. It would be done in what we call the appraise gate.

Q. So that's early on?

A. That's very early.

Q. All right. That process would then be completed, inputted and passed on before actual drilling began?

A. It is a risk assessment predrill.

Q. Okay. Do you know whether or not that risk assessment tool was actually -- or that -- that RAT procedure was actually carried out and that information was inputted into the system in this particular project?

A. We went through a -- we went through the risk assessment exercise on the subsurface. I was not actually a part of the transfer of that into the wells risk register.

Q. All right. As you sit here today, do you know whether or not that information was transferred into the wells risk register?

A. I did not transfer that information into the wells risk register.

Q. Okay. And then -- so having said that, you don't know whether somebody

else did, either, I'm assuming?
A. I do not.
Q. Okay. Do you recall what the subsurface risks were that were identified in this risk assessment tool?
A. The primary risk was -- based on the pore pressure frac gradient plot, was the narrow margin between pore pressure and frac gradient.
Q. Okay. So that primary risk would have been made known to all of the engineers and everybody outside of the TIGER team who was actually responsible for drilling and completing this well before the well began?

Page 54:19 to 54:19

Q. (BY MR. STERBCOW) -- correct?

Page 54:21 to 55:21

A. The -- as the drilling engineers and my team work together to develop this pore pressure frac gradient plot, they are aware at that point even before we develop a risk register that in fact this well has a potential narrow pore pressure frac gradient window.
Q. (BY MR. STERBCOW) All right. And then what they -- "they" meaning the engineers -- what they do with that information in terms of actual planning of the well, casing design, et cetera, I'm assuming that's something that's their responsibility, and the TIGER team does not get involved in that?
A. The TIGER team knows nothing about casing design.
Q. Okay. Fair enough. Having said what you said, though, can I conclude that there should have been, in terms of the drilling engineering department, Mr. Hafle, Mr. Morel, Mr. Cocales, even Mr. Guide, and everyone involved in the engineering and the operations, there should have been no surprises to them going in that they may be facing a narrow drilling margin well?

Page 55:23 to 56:17

A. The -- as part of the multidisciplinary process that we use to develop the forecast, the drilling engineers, Mr. Cocales, Mr. Hafle and Mr. Morel were part of that team. So they were aware of what the particular pore pressure frac gradient challenges were that were in the well.

Q. (BY MR. STERBCOW) Okay. Do you know what they did, if anything, to take that narrow margin issue into account in their work?

A. The actual casing design of the well predrill was what was taken into account. The actual design of the well is actually based on a pore pressure plot that showed a fairly narrow pore pressure frac gradient window. That's why an 18,000-foot well had either seven or eight casing strings predrilled designed into it.

Page 57:05 to 63:21

Q. (BY MR. STERBCOW) I'll show you what's been previously marked as Exhibit 1514. And this is GP 10-16 Pore Pressure Detection During Well Operations.

Now, if I understand correctly, this is BP's guide as to how -- we're past the planning stage. Now, this is the guide to instruct how pore pressure should be monitored as the well is being drilled?

A. Correct.

Q. All right. Again, on Page 2 you have the introduction, and there is a number of steps.

Would the TIGER team be responsible for carrying out steps 1 through 9?

A. I appoint a single-point accountability, as I do in pore pressure prediction, to actually lead this particular set of items from 1 to 9.

Q. All right. And who was that single point of accountability on the Macondo well?

A. In this case it would have been Marty Albertin.

Q. Okay. On page -- well, let me back up.

As you sit here today, do you know whether Mr. Albertin complied -- and I'm looking at No. 2 -- ensure that all contractors and employees involved in realtime detection of pressure met the minimum requirements set out in the ETP?

A. Specifically on item 2, that

falls under the domain of the actual operations geologist.

Q. Okay. So that would -- in this case, that would have been?

A. That would have been Bobby Bodek.

Q. All right. And do you know whether or not Bobby took any steps to ensure that the contractors involved in realtime detection met the minimum requirements?

A. Bobby does.

Q. Okay. So that -- then as you sit here today, there is no issue in your mind that the third-party contractors involved in realtime detection of pressure met the minimum requirements of BP?

A. I would -- I would say yes, but clarify. But in this case the words "all contractors," for me, specifically applies to Kate Paine and the two wellsite geologists that actually work on our behalf on the rig.

Q. And who was that?

A. I believe Gord Bennett and Stuart Lacy.

Q. And No. 3: Realtime analysis of pressure for a BP well shall be prepared by a qualified individual who has been trained on BP practices, work flows and relevant tools and applications to be used at the wellsite.

Who was that qualified individual for Macondo? Do you know?

A. Kate Paine.

Q. Okay. And then No. 6: Realtime pressure analysis prepared by contractor shall be monitored on a periodic basis using BP-approved software to ensure that the results are consistent with BP methodologies.

Who would be responsible for monitoring the analysis prepared by contractors on a periodic basis?

A. In this case, periodic on Macondo meant daily, every minute and night that we were drilling.

Q. And why is that?

A. Because it's what we do.

Q. Okay. All right. So you'd have -- one person obviously couldn't do that?

A. Difficult to stay awake 24 hours a day.

Q. Is that done on the rig, or is that done -- that monitoring done in Houston?

A. Both places.

Q. Okay. On the rig, would it be -- well, who -- what job title would be

responsible for the monitoring on the rig?
A. Kate Paine is in my -- I actually hired Kate. Kate is a pore pressure -- in my mind, a pore pressure expert.
Q. Right. Okay.
A. And so Kate's job on the rig is to use our BP-approved software, which she did, and she is gathering information related to converting the log-based data we acquire while drilling to pressure. She's also working with the mud loggers to understand the gas data as we drill that comes back. She is also looking at the cutting size and shape. She's also looking at the drilling parameters, the flow in, flow out, weight on bit, de-exponent; the list goes on and on.
Q. Right.
A. She then synthesizes that into a foot-by-foot interpretation of what the pressure is actually doing in the well. That information is brought back to Marty Albertin --
Q. Okay.
A. -- who prepared the predrill pressure predication. And on an -- in a -- on an ongoing foot-by-foot basis, at any time during the drilling of the well, we have her information fed back into our primary database. So we have an assessment as the well drills day in/day out as to what's happening.
Q. And is Albertin on the rig or is he on the beach?
A. He's on the beach.
Q. Okay. And he's in Houston?
A. He's in Houston.
Q. All right. Are you aware of any -- at any point where there was any problem in Ms. Paine transferring the information to the beach so it could be monitored by Mr. Albertin?
A. I'm not aware of any problem there.
Q. Page 10 -- actually, Page 11 -- I'm sorry -- Page 11 of 17. I'm looking at the software section, Section 9.
A. Okay.
Q. Was the Landmark version of Presgraf the software being used on the DEEPWATER HORIZON?
A. It was a software being used by Kate on the rig.
Q. By Kate. Okay.
At any point was there any

problem that you're aware of from the time that HORIZON arrived at Macondo through the date of the incident with the performance of the software?

A. I'm not aware of any.

Q. She didn't report any, at least --

A. She didn't report any to me.

Q. Okay. Do you know whether or not BP is responsible for ensuring that the -- in this case, the Presgraf software is functioning properly?

A. There is a requirement as part of our safety-critical software that the mathematics and equations that exist behind Presgraf -- we actually audit that through Landmark on an every-two-year basis.

Q. Okay. And if something were to go wrong with the software -- the performance of the software on the rig, would that be a BP responsibility to either address it and fix it or change it out if it needed to be changed?

Page 63:24 to 64:06

A. The Presgraf software as we currently have it on our server is actually maintained by Landmark. So any problem with Presgraf would only be an ability to actually have it work over the network.

If that problem did occur, then I would be able to actually just send a license to Kate that she could use.

Page 64:14 to 64:18

Q. If a neck work -- if a network connection issue -- excuse me -- arose, that's something that you would be prepared to deal with?

A. That's --

Page 64:20 to 64:24

A. I would be able to get her a working copy of the software very quickly.

Q. (BY MR. STERBCOW) Got you. Okay. And you don't recall that happening?

A. I don't recall that happening.

Page 66:17 to 67:10

Q. Okay. All right. Then let's go to No. 4 -- Tab 4. This is MDL01918641. This is an e-mail a few months later to Christopher Casler to, again, yourself and Martin Albertin, attaching a PowerPoint slide, asking whether you can confirm that this is a, quote, current pressure plot. And then there's a -- an attachment.

Do you recognize the attachment?

A. I recognize the form of the attachment.

Q. What is that?

A. That is actually an extraction out of our primary Excel spreadsheet that we use to display our pressure information.

Q. Does this attachment tell us what the conclusions were in terms of prediction of pore pressure at a given TD, total depth?

Page 67:12 to 68:11

A. This particular plot would actually represent what was the assessment of pressure at the time on Monday, April 13th.

Q. (BY MR. STERBCOW) Okay. Is this an ongoing effort?

A. The PPFG plot is actually, per our process, required to be constructed before you go from the select to define gate.

If after the select to define gate there is information that comes available -- for example, another operator may drill a well nearby that we get the information from --

Q. Right.

A. -- then we will update this particular plot, and that update will be recorded in our management of change process.

Q. All right. So every time, if I understand you correctly, if you update a prior pressure forecast on a well like Macondo based on new information, ongoing efforts, would a management of change form have to be filled out to create a new graph like the one shown in the attachment to this e-mail?

Page 68:13 to 69:14

A. If information comes available after the signoff of the select to define gate --

Q. (BY MR. STERBCOW) All right.

A. -- that actually requires we adjust the predrill forecast for pressure, then it is a BP requirement to go through a management of change process with the appropriate signatures that are in the MOC process to record that, in fact, we have updated the plot.
Q. Got you. Okay. And with respect to that particular management of change in that situation, would you as the TIGER team leader be one of the people who had to sign off on that?
A. I would have to sign off on that.
Q. Who else, do you recall?
A. It would be a number of people from the wells organization, and I -- and as I recall, it's my -- my particular boss, the exploration manager.
Q. All right. And you told me his name before.
A. That would have been Jay Thorseth.

Page 69:16 to 72:08

What is -- I'm looking at the numbers on the side: FM, depth, Ppressure, O. Burden, effective stress. Just, if you would, give us a brief explanation of what that means.
A. How many hours do you have?
Q. Not much. Well, what's FM? What is FM referring to? Let's do it that way.
A. Okay. I'm trying to see where you're actually looking at FM.
Q. FM, and it says M57, M56.
A. Formation.
Q. Okay.
A. And then depth and then pore pressure, overburden and effective stress.
Q. All right. And these are all predictions?
A. Correct. The overburden is a computation. The pressure is a computation. And then having -- if you know those two numbers, you can compute the effective stress.
Q. All right. How do the -- those two numbers relate to effective stress?
A. Subtraction.
Q. That's what I thought. Okay.
What does overburden mean? What does that term mean?

A. It's the weight of the earth.

Q. All right. And pore pressure means what it means?

A. It means the pressure of the formation you're going to drill through.

Q. Okay. So when you compute that number, when you subtract pore pressure from overburden and get the number that you call effective stress, what is the usefulness of that particular figure?

A. The term "effective stress" is -- in this case, vertical effective stress -- is actually a term that we use to, in the subsurface world, determine exactly what is the potential column height of hydrocarbons that might exist in any reservoir that we drill through.

Q. All right. Okay. So depending on what formation we're talking about, 57, 56 or 55, that gives you a prediction of the column height of gas that you --

A. Column -- it'd be the column height of whatever fluid that you have --

Q. Whatever fluid.

A. -- a most likely prediction of existing in the well.

Q. Okay. Got you. And do you know how that information would be useful to your engineering team, the drilling engineering team?

A. Effective stress is not very useful to the drilling team.

Q. That's what I thought. Well, who uses that number?

A. Primarily, the subsurface community.

Q. Okay. And for what reason?

A. For -- as I explained earlier, it'd be for column height assessment.

Page 72:18 to 73:14

Q. (BY MR. STERBCOW) Okay. Mr. Vinson, I want to show you what has previously been marked in the case as Exhibit 1312.

I'll first ask you: Is this the document -- it's called Predrill Data Package. Would this be the document that the TIGER team put together that contains all of the fruits of your work in terms of predrilling pore pressure predictions?

MR. KEEGAN: Objection; form.

A. This particular document is a compilation of all the information from the subsurface prospect team and the TIGER team --

Q. (BY MR. STERBCOW) Okay.

A. -- in terms of our understanding of the subsurface for the well.

Q. Got you. So this would be the one document we could go to to look at all of that work?

A. Correct.

Page 73:16 to 73:23

Q. (BY MR. STERBCOW) And who is this document distributed to, do you know?

A. The PDDP, as it's referred to, is a -- as I said earlier, primarily a subsurface-generated document. It is loaded up to the well space document. A smaller version of this is distributed to partners. A copy of this actually resides on the rig.

Page 75:01 to 78:02

Q. (BY MR. STERBCOW) Page 3, and it starts at MDL 00351800 and goes to MDL 00351838. And I'm on Page 3 now. This looks like it's called Fast Facts. It looks like it's just a listing of general facts about the Macondo project, deemed an exploration well. And it says -- two categories below Category where it says Exploration, it says Straight Keeper.

Do you have any idea what that means?

A. "Straight keeper" is a language we use for the wellbore will be not deviated. It will be a straight hole. And "keeper" refers to the fact that we will not temporarily abandon the well.

Q. Meaning what? What was going to happen?

A. We were actually going to run production casing in the wellbore.

Q. So the plan was to run production casing in the wellbore as of September 3, '09?

A. As of the date of this document.

Q. As of the date of that document. All right.

And then down at the bottom, the last three categories, Net Reservoir Thickness, Expected Reservoir Temperature and Expected Pressure, would those be figures that came from the work of the TIGER team?

A. The expected pressure would be work that comes from my team. The net reservoir thickness and the expected reservoir temperature would actually come from the subsurface prospect team.

Q. All right. And how would the TIGER team compute or come up with an expected pressure of 13,300 psi?

A. How many hours do you have to want to discuss how we come up with that?

Q. I figured you were going to say that. Well, let me ask this way: Rather than ask you how you did it, when you say expected pressure and you give a number, what exactly does that refer to?

A. The -- as part of the previous document, GP 1015, in that standard we are required to predrill to make an assessment -- from the mud line of the seabed to the total depth of the well, an assessment of the pressure at every inch of formation we are going to drill. And that is what is in our assessment of pore pressure.

This number of thirteen three would have been an extraction from that plot at the depth listed above of 18,120 TBD subsea.

Q. Okay. That makes sense. So you do the whole range of expected pressures, and then back to the 18,120 total depth figure, you come up with an expected pressure of 13,300?

A. Which only applies to the depth above. Any other depth in the well would potentially have a different pressure number.

Q. Different number. And you'd have to reference that -- if you went back and referenced a particular -- if you picked 15,000, you could go back to the work performed and you could correlate what pressure would be expected at that depth?

A. Correct.

Q. Okay. So that information is available from the beginning to anyone if anyone wants to look at it?

A. In that plot.

Page 78:24 to 79:12

Q. Got you. Okay. It then references: The well path will penetrate possible minor hazards in the overburden between the base of the 22-inch casing point (8,000 feet) and the M56 target amplitude. Such hazards include thin gas sands, the level at which pipe stuck in the MC0252 well (8900 feet.)

Is that referring to Rigel, a prior pipe-sticking event?

A. Yeah. There was a shallow field called Rigel that was not far from the Macondo well. So that interval refers to Rigel.

Page 79:22 to 79:25

Q. Would the Rigel event have been a predictor, if you will, of the potential of Macondo or at least the risk at Macondo to have the same type of event?

Page 80:02 to 80:12

A. The two events are unrelated.

Q. (BY MR. STERBCOW) Totally unrelated?

A. Unrelated.

Q. All right. So if they both involved stuck pipe, if they both involved relatively similar total depth, from your standpoint, from a geological petrophysical standpoint, there is no correlation between the two?

A. No.

Page 80:14 to 81:12

Q. (BY MR. STERBCOW) Does this information in terms of what happened at Rigel provide any benefit to the engineers planning the Macondo well?

A. The reason it is documented here is because that particular risk of the thin gas sand at Rigel and also the potential of a depleted sand at Rigel that could intersect into the Macondo well is actually what was captured in the RAT tool as part of the MDS risk assessment.

Q. Okay. I got you.

A. So those risks would have been captured via RAT and pushed into the wells risk register.

Q. All right. And those risks would have been identified, put into the risk register. For those who had access to the register or needed to look at it, that's how they would be informed, if you well?

A. That's right. The wells

organization would have access to what we in the subsurface community define as a no-drilling-surprises risk.

Page 82:07 to 82:16

Q. Would revision -- from initial to revision 1, 2, 3, would each of these revisions require a management of change or no?
A. We use the "rev" designation because it is a way for us to track the versions of pressure based on new information. No management of change process to this is required unless a variation to it is made after the select to define gate.

Page 83:10 to 84:03

Q. (BY MR. STERBCOW) Okay. Would the PP -- pore pressure and FIT/LOT figures on the right side, would those numbers come from work done by the TIGER team?
A. They would.
Q. All right. So does the TIGER team provide those figures to the drilling engineers, who then create the casing design?
A. The TIGER team actually provides an Excel spreadsheet with that digitally that actually goes to the drilling engineer of Macondo so they can actually electronically use the data that we've developed to actually populate for the basis of design.
Q. All right. Very good. And are these numbers, I take it, that are constantly updated on the rig as the casing design is actually put into effect by folks like Ms. Paine, is that why she's there?

Page 84:05 to 84:08

A. These particular numbers that actually exist on this plot -- you'll notice it says Basis of Design. This is actually prior to the well actually spudding.

Page 84:12 to 85:05

well, first, let me ask you: Do you know whether or not the numbers for pore pressure, FIT/LOT, are those numbers updated as well?
A. When the pore pressure frac gradient plot is locked down in the select to

define gate, then the numbers that are shown here on the right come from that plot.
If there is an update to the pore pressure frac gradient plot in the define gate that requires a management of change process, then this document should reflect that update.
Q. Okay. All right. If these numbers, then, the pore pressure frac gradient numbers shown in -- are -- are shown in any subsequent basis of design document, would changes in those numbers necessarily have gone through a management of change process?

Page 85:07 to 85:13

A. If the original basis of design -- in the numbers that are shown here on the right, if there is a subsequent basis of design that shows a different set of numbers, then there should be a management of change that reflects a change to the predrill pore pressure frac gradient plot.

Page 85:16 to 86:05

Once the March 8th kick occurred, they had the stuck-pipe event and then they had to drill around, do a bypass.
A. (Witness nods.)
Q. Would new pore pressure frac gradient figures -- first of all, would new predictions have to be computed at that point?
A. The requirement of GP 10-16 that we looked at earlier actually has a requirement that we maintain an ongoing assessment of pressure every inch of formation that we actually drill. And so the response of the TIGER team is that through our SPA setup, we do that.

Page 86:07 to 86:16

A. And we provide that to the wells community.
Q. All right. Given that there was a bypass that occurred because of the pipe -- this stuck-pipe incident, do you think that a management of change form would have been prepared with respect to new pore pressure frac gradient figures provided to the

engineering team so that they could prepare their new casing design diagram?

Page 86:19 to 88:08

A. There is not a requirement to do a management of change during the pressure detection phase of a well.

Q. All right. So that -- but just because there was a bypass and a new hole, if you will, in a different location doesn't necessarily correlate to there had to be a management of change form?

A. Correct. Because that particular side track that you actually refer to is literally only feet away from the original well.

Q. Okay. Let's go to No. 12. This is Tab 12, and I'll show you it's an e-mail from Ms. Paine to yourself, Mr. Bellow, Mr. Bodek, and I think Mr. Brannen. And it's dated September 8th, 2009, about five days after the drill package. And she makes recommendations to you and, I guess, to Mr. Bellow, Mr. Bodek, Mr. John Brannen to address certain items.

First of all, let me ask you: Do you recall receiving this? I know it's been a while.

A. I'm not so sure my memory is that good, but, yes, I do remember this e-mail.

Q. All right. Do you know whether or not -- first of all, did you consider or -- in discussion with any of the other recipients of the e-mail, did you determine that any or all of Ms. Paine's concerns were valid?

A. As manager of the TIGER team and knowing Kate the way I do, I filter some of Kate's recommendations.

Q. Okay. Understood. Were any of the concerns and recommendations expressed in this e-mail, to your knowledge, actually deemed to be appropriate and addressed?

Page 88:10 to 88:12

A. There are a couple in here. The -- the one of interest to us is actually agreeing on the best practice for LOT.

Page 88:14 to 89:10

A. Something that we spend a lot of time working on. Then also, access to the data, down in the bottom paragraph, about the monitors on the rig.

Q. All right. And what was -- was there anything done in response to the access to realtime data concern?

A. There was.

Q. And what was that?

A. It was just making the folks on the rig aware that the subsurface team -- actually, per the requirements of GP 10-16, we need to have actual access to that information, and we need displays on the rig to be able to view it.

Q. All right. Did -- were displays provided on the DEEPWATER HORIZON for viewing?

A. Yes.

Q. Was that -- and that was specifically in response to a request from the TIGER team?

Page 89:12 to 90:23

A. The DEEPWATER HORIZON rig as delivered to BP, I believe, in 2001 came with all that capability.

Q. (BY MR. STERBCOW) All right. Do you know the basis of her last statement? She says: I know these are mostly issues which are resolved by exploration owning the well instead of production. However, these were data quality weaknesses I observed which are accepted as normal operating practices.

Did she ever discuss that?

A. She did.

Q. What did she tell you?

A. The MARIANAS rig for BP had never drilled an exploration well. And so the typical wells that the MARIANAS well would actually drill are drilling in producing fields that have much more information available to them than any rank exploration well that we would drill with no offset control. And so you don't require the same amount of foot-by-foot interpretation of the pore and frac window in a well.

And so the MARIANAS did not actually have that capability that was felt to be up to the standards that we in the TIGER team, for what we require for an exploration well, needed.

Q. Okay. Was that concern then

passed on to anyone at BP?
A. That concern would have been passed on to the rig guy, George Gray.
Q. All right. And do you know if Mr. Gray acted on that concern in any manner?
A. Initially, he did not. But after some convincing that it was important, he did.

Page 91:06 to 91:09

Q. Do you know whether or not the DEEPWATER HORIZON, like the MARIANAS, had little or no experience in drilling this type of well?

Page 91:11 to 91:24

A. Two wells prior to Macondo, the DEEPWATER HORIZON had drilled the deepest oil and gas well ever in the history of this planet, to beyond 35,000 feet.
Q. (BY MR. STERBCOW) Was it a well drilled like this to completion? Production casing was set?
A. It was not a keeper. It was just a straight exploration well.
Q. All right. Would that make a difference whether or not it would be a keeper well or -- or in the case of Macondo, where it was actually -- production casing was actually going to be set --

Page 92:01 to 92:03

Q. (BY MR. STERBCOW) -- in terms of the experience of the MARIANAS or the Macondo, from the TIGER team's perspective?

Page 92:05 to 92:10

A. I'm somewhat confused.
Q. (BY MR. STERBCOW) In other words, the concerns that Kate Paine expresses here that you elaborated on, would those concerns have translated to the DEEPWATER HORIZON also --

Page 92:12 to 93:15

Q. (BY MR. STERBCOW) -- if you know?

A. The way in which the DEEPWATER HORIZON rig was actually set up to acquire data and then beam that data back to the beach, state of the art. So there was no concerns on my part with the ability of the HORIZON to capture and distribute the data we needed for the well.

Q. All right. So in that sense it was better equipped than MARIANAS?

A. It was a fifth gen rig as compared to a fourth gen rig.

Q. Okay. And was that data transmitted back to Houston?

A. Which --

Q. The data that we're talking about here -- or Ms. Paine is talking about here?

A. All information gathered on the HORIZON during Macondo is actually captured. Every member on the TIGER team views it on their computer on an ongoing basis. It's actual captured in digital form and distributed to our well space database.

Q. All right. Would it also be sent to the realtime operating center at West Lake?

A. It would.

Page 93:17 to 95:07

Q. (BY MR. STERBCOW) And do you know how that was being monitored by BP with respect to the DEEPWATER HORIZON activity on Macondo?

A. You refer to realtime operating center. For Macondo the realtime operating center was a conference room with many monitors on the second floor of the floor I sit on that has controlled access to the Macondo team.

So the very -- that information sits inside that room, but again, that very same information can be seen by any member of the Macondo team sitting at their desk on their computer monitor.

Q. All right. And was there a separate realtime operating center at West Lake on the tenth floor at that time?

A. I am aware of the tenth floor realtime operating center. I have never actually participated in a well that used the tenth floor realtime operating center.

Q. Do you know what the difference was between the second floor and the tenth floor?

A. I do not.

Q. Do you know why they had two separate -- "they" meaning BP -- would have two separate operating centers in that manner?

A. I do. The realtime operating center concept is employed by many major oil companies. And there was a desire in BP to modernize the concept, to actually eventually go to a place where that data is actually gathered inside a room that's actually potentially manned 24/7 in the BP office.

Q. Okay. Was the second floor monitoring center where Macondo was being monitored being monitored 24 hours a day, seven days a week?

Page 95:09 to 95:20

A. The data that was being acquired from the rig was available to be monitored 24/7 by any member of the wells team. That data is monitored 24/7 at the rig.

Q. (BY MR. STERBCOW) At the rig?

A. At the rig.

Q. Was there any procedure that you're aware of in place in Houston at West Lake where a person or people were specifically charged with the responsibility of 24-hour-a-day, seven-days-a-week monitoring of Macondo?

Page 95:22 to 99:06

A. The specific charge of 24/7 sits with the folks that actually reside on the DEEPWATER HORIZON. The office team is an extension of that team. And my guys monitor during the day and my operations geologist monitors until they have to actually get some sleep.

Q. (BY MR. STERBCOW) Right.

A. At that point it then shifts to my wellsite geologist, which is actually on the rig.

Q. On the rig. Okay.

Were any other wells, if you know -- and let me know if I'm getting outside of your area -- were any other deepwater wells in the Gulf of Mexico monitored in Houston differently than the Macondo well was monitored?

A. All exploration wells drilled by the DEEPWATER HORIZON were monitored in the

way I just described.
Q. All right.
A. Exploration wells.
Q. When your folks -- and I'm talking -- I'm not talking about the rig now because I understand they're there 24/7, obviously.
When your folks completed their monitoring duties, had to go home, had to get
00097:01 some sleep, did BP have any procedure in place where someone or more than one person would be assigned the responsibility to take over that monitoring job?
MR. KEEGAN: Objection; form.
A. The primary accountability of monitoring drill parameters and any indications of pressure sits at the rig. It's purposely designed to be that way. They're closest to the action, so to speak.
What we do in the office side is we provide support to them from the technical side. We have more in-depth technical knowledge as to how those forecasts were generated.
But the primary accountability for all data being acquired at the rig sits at the rig.
Q. (BY MR. STERBCOW) Okay. And who on the rig has the primary responsibility to monitor that?
A. The toolpusher, the driller, the assistant driller, the mud logger, our wellsite geologist, and our pore pressure frac gradient expert.
00098:01 Q. All right. And between all of those people, there is a system in place on the DEEPWATER HORIZON that this data is monitored constantly?
A. I understand how the mud logging data is monitored, and I understand how the wellsite geologist and the pore pressure frac gradient expert monitor the data.
I can't speak as to how the Transocean driller, toolpusher, in respect to Transocean parties, actually monitor their data.
Q. Okay. Is the data monitored all through the same system? Are they all on the same computer system?
A. It's my understanding it is.
Q. All right. So it's not a separate Transocean monitoring system or a separate Sperry system or a separate BP system on the rig?
A. The data tie-ins are based on

the design of the rig as delivered to BP, and then the various vendors plug in to that particular auxiliary box to display the data around the rig.
Q. Got you. Okay. Was there a time period during the day or during the week or on weekends where in the West Lake facility there was no one actually physically monitoring -- assigned to and actually physically monitoring the Macondo data?

Page 99:08 to 99:11

Q. (BY MR. STERBCOW) Would there be a specific time, weekends, nights, whatever, you know, when your folks had to go home, get some sleep or whatever?

Page 99:13 to 100:19

A. During the drilling operation of the well, regardless of whether it's night, holidays or weekends, my single-point accountabilities are actually monitoring the rig from the bank as well as the wellsite geologist and the pore pressure expert upon the rig; and then, of course, as well as the driller toolpusher and mud logger as well.
Q. (BY MR. STERBCOW) Okay. So who in Houston would be monitoring this data?
A. My operations geologist and my SPA for PPFG will monitor the data as needed to monitor; again, the primary accountability being at the rig. That's why we have experts actually sitting at the rig to do that.
Q. Right.
A. And then we have a communications protocol set up such that if those guys need to check in or need advice, then they make the appropriate phone call.
And then those folks will either engage via telecon from home, or wherever they are, or they -- if they have a need, they will convene in the office to address a potential issue.
Q. All right. Do you know whether or not that system has changed in terms of realtime monitoring in Houston since the DEEPWATER HORIZON accident?
A. We have not operated a well since the Macondo incident, so I can't address that.

Page 100:21 to 101:08

Has the realtime monitoring procedure in West Lake, changes to that procedure, been discussed with you at all?

A. They have.

Q. And what are the -- what are the substance of those discussions?

A. The particular substance is -- is that we would like to potentially go to a manned 24/7 center in the Houston office.

Q. Would it all be located in one central location rather than that second floor or tenth floor or whatever it might be, if you know?

Page 101:10 to 101:11

A. The plan would be to have that actually sit in one location.

Page 102:03 to 102:03

Exhibit 2199. Okay. That's for purposes of

Page 102:06 to 102:06

(Exhibit 2999 was marked.)

Page 102:09 to 103:25

work our way forward. And I -- you did not get a copy of this e-mail string until the very end, but it looks like it started from somebody at Kongsberg, and Paul Johnston did receive it.

And they're talking about synchronizing the Macondo well data from Halliburton's INSITE server into the Kongsberg SiteCom utility server here at BP.

First of all, let me ask you: Do you know what that means?

A. I do.

Q. What does that mean?

A. The -- I mentioned that we monitor -- my team and the wells team have the ability to monitor, from either the office or home, the data coming from the rig. That was actually provided by a system called INSITE, which is owned by Halliburton, Sperry-Sun mud logging.

BP, because of the technology coming forward and the amount of data that is actually starting to come to us, felt like that we needed to get to a place where we needed to go to a more sophisticated system of actually acquiring data from the well such that we could actually interpret more quickly and respond to questions from offshore.

Q. Got you.

A. That's what the Kongsberg system does for us.

Q. Okay. And is the Kongsberg system a system that's actually on the HORIZON -- the DEEPWATER HORIZON?

A. There is a Kongsberg server that actually sits on the rig, and then it replicates into a server in the Houston office.

Q. Okay. And that's BP's equipment, I'll call it, rather than Sperry-Sun?

A. Right.

Page 104:19 to 104:25

Q. Information transfer protocol. Okay. All right. And -- okay.

And then if I understand correctly, at the end of the day, what would be the reason from BP's standpoint to want to synchronize Halliburton's INSITE with the Kongsberg SiteCom utility?

Page 105:02 to 105:13

A. The -- it was our view in the many, many years that we had used the INSITE system that the ability to do the types of data computations and manipulations that we needed to be able to do, that INSITE was starting to not be able to deliver that.

And there had been a decision made at a fairly high level in BP that Kongsberg would be the system of choice.

Q. (BY MR. STERBCOW) Got you.

A. We had not yet converted HORIZON to the Kongsberg system.

Page 106:22 to 107:01

Q. Was there ever any concern with you or Mr. Bellow among the TIGER team that the -- first, that the Sperry INSITE system was not appropriately transmitting required data from the rig to Houston?

Page 107:03 to 107:13

A. There was no concern on our part. We had been using the system for eight or nine years. This was nothing more than a recognition that a better technology was actually available.

Q. (BY MR. STERBCOW) All right. And so --

A. No concerns with the Sperry INSITE system at that time.

Q. So this is a -- is this part of, I guess, the effort to update the system?

Page 107:16 to 107:25

A. It's like any new technology. We saw the potential in this new technology to actually allow us to assimilate the growing amount of data that's actually acquired in the BHAs and drill strings.

Q. Okay. Was the INSITE system capable of handling the increased amount of data that technology allowed BP to collect, downhole data, and transmit it in an appropriate manner?

Page 108:02 to 108:05

A. It was capable of actually acquiring and displaying the information that we needed at the time to drill the wells we were drilling.

Page 109:10 to 110:01

Q. All right. Are you aware of any problems that arose at any point, but particularly from March 26 forward to April 20, with realtime data transmission from the rig to the beach?

A. I'm not aware of any.

Q. Are you aware of any problems or concerns that anyone at BP had that BP was not receiving, both in terms of quality and time, the realtime data that it wanted to receive from the DEEPWATER HORIZON?

A. The SPAs that I assigned to their particular parts of the well never discussed with me if they had any concerns --

Q. All right.

A. -- around the data that was being acquired.

Page 110:15 to 111:17

Q. All right. Fair enough. Let me ask you while I'm thinking about this. You were designated as BP's representative on two areas of what's called a Rule 30(b)(6) deposition notice to speak for the company.
A. Uh-huh.
Q. And I'm looking at the pleading, the notice, and Area No. 21 says: Any estimates, predictions and/or analysis of anticipated pressures, both static pressure and/or dynamic pressure, within the formations of the Macondo prospect and/or the Macondo well, including but not limited to information provided to Transocean and the manner in which such information was utilized in selection of or approval of the BOP assembly used by the DEEPWATER HORIZON for the Macondo well.
That clearly has to be broken down. Okay.
In your position as the BP-designated representative for purposes of this issue only, would the estimates, predictions and/or analyses of anticipated pressures, both static and/or dynamic, be contained in that report we looked at earlier -- I don't remember what tab it was now -- the predrilling data package?

Page 111:19 to 112:05

A. The information contained in the predrill data package addresses that statement up to the point of the word "static."
Q. (BY MR. STERBCOW) Okay. And explain that for me.
A. Dynamic pressure analysis is a very broad term. My understanding or my connotation of when I read dynamic pressure analysis is that actually involves the interpretation of pressure transient analysis after you've actually flowed a well.

Page 112:07 to 112:09

A. I have no expertise in doing Horner analysis or any analysis using programs such as OLGA --

Page 112:11 to 112:19

A. -- and other things that do dynamic simulation flow.
Q. All right. Does BP, to your knowledge -- and it's -- clearly it would be outside of the TIGER team -- but does anyone with BP employ any dynamic pressure analysis using OLGA or some such system as part of planning the well?
A. Not to my knowledge.

Page 112:21 to 112:23

A. Let me clarify. Not to my knowledge as it pertains to an exploration well.

Page 114:15 to 115:03

Q. And those are the numbers. Okay.
What information on static pressure, if any, would be provided to Transocean prior to the drilling beginning?
A. As part of the APD submittal, there is a whole series of computations in the back under a section called MASP, of which Transocean has access to those.
And I also -- I also believe it's actually part of the Transocean MMS checklist that they actually verify these calculations as they relate to the components of the BOP.

Page 115:15 to 115:21

Q. Okay. Who would -- who would be able to answer the question of whether BP takes the MASP information, the pressure information, if anyone, and determines whether or not a particular blowout preventer is appropriate on a given well, given these figures?

Page 116:05 to 116:09

Q. Do you know whether or not anybody with BP would undertake that effort?
A. I do not know if that -- if that effort is actually done, it would be in the wells organization.

Page 116:13 to 118:13

Q. Okay. Who actually computes the MASP numbers?
A. My team actually will compute MASP numbers predrill.
Q. All right. And how is that done?
A. Again, two or three hours?
Q. I keep doing that to myself.
A. The simplest -- I mean, the simplest form of MASP is -- again, going back to GP 10-15, there is an approved and verified PPFG plot with uncertainties expressed predrill. It's signed off in the select to define gate. So at any point along the curve on that plot, you have a running assessment of what the pressure is at any depth.
All one needs to do at that point, then, is to take that mud weight, convert it to a pressure, and at any particular interval, then one needs to actually understand what is the expected fluid density of the fluid in the pore space of the rock you're going to drill.
Q. Right. Okay.
A. And then you do a simple mathematical extrapolation back to the mud line, and then one can compare that number up against the various ratings of BOP elements.
Q. All right. Were you ever told by anyone, your superiors at BP or anyone else, that BP considered the blowout preventer to be the failsafe last line of defense in a well control situation?
A. Are you asking me, have I actually heard that term used?
Q. Right.
A. I had only first heard that term used after the incident in the various reports that came out.
Q. Okay. Prior to April 20, 2010, did you have any understanding as to whether the blowout preventer at Macondo was indeed considered a failsafe device? Did you even think about that?
A. Speaking personally for me, I have a mindset of, when it's called a blowout preventer, exactly what a blowout preventer is.
Q. Okay.
A. It prevents blowouts.

Page 119:04 to 119:11

Q. Okay. As of the time that the DEEPWATER HORIZON arrived and spudded down at Macondo, did you -- or, if you know, anybody on the TIGER team -- know whether or not the DEEPWATER HORIZON's blowout preventer was mechanically capable of controlling the potential pressures and flow that it would encounter in a well control loss situation?

Page 119:13 to 119:19

A. In the TIGER team, it is made up of geologists and geophysicists.
Q. (BY MR. STERBCOW) Right.
A. I'm actually the only engineer. We have no technical understanding whatsoever of a BOP; only that they're normally red and really big.

Page 120:03 to 120:09

Q. Right. Okay. Do you agree with me that -- and we can pull the documents out, but my review of documents indicates that the BP method -- prescribed method of computing maximum anticipated surface pressure is taking into account a gas column to surface for exploration wells; is that accurate?

Page 120:11 to 120:22

A. The -- I believe as you state that statement, that is actually part of the DWOP.
Q. (BY MR. STERBCOW) Right. And we can go through it if you want, but it sounds like you know what I'm talking about?
A. Yeah.
Q. Is it accurate in the DWOP, though, to say that the maximum allowable wellhead pressure shall take into account a gas column to surface for exploration and appraisal wells?

Page 120:24 to 121:09

A. As defined in DWOP, it is a first-level screening tool.
Q. (BY MR. STERBCOW) Okay.
A. If the particular well that you are actually designing based on that criteria

actually exceeds the rating, then there is a particular process in BP whereby one can actually obtain a deviation.

Q. All right. And did that occur with respect to Macondo and maximum anticipated surface pressures at this well?

Page 121:11 to 121:16

A. There was no requirement to do that on Macondo because the actual reservoir pressure for the deepest target was actually below the rating.

Q. (BY MR. STERBCOW) And how did you know that?

Page 121:18 to 122:18

A. Because it is my understanding that one of the -- one of the components of the BOP was rated to 15K. And the reservoir pressure in a previous document that we did -- you showed, we had the pressure at depth being 13,300 psi.

So even if we put a .1-psi-per-foot gas gradient on that, that pressure just decreases to the mud line. It does not increase.

Q. (BY MR. STERBCOW) Okay.

A. So it would be below the rating.

Q. What part of the BOP, if you know, was rated at 15,000?

A. My understanding is the blind shear.

Q. And would that rating be valid for any size drill pipe? And again, if I'm getting outside of your area, let me know.

A. You are.

Q. That may be placed in the BOP? You don't --

A. I don't.

Q. All right. That's not something --

A. No.

Page 123:09 to 123:12

Q. All right. Do you know whether or not BP, as a policy matter, instructs potential users of the BOP in a well control incident to operate the lower annular first?

Page 123:14 to 123:21

A. Again --

Q. (BY MR. STERBCOW) Outside of your area?

A. Outside of my area of expertise.

Q. And do you have any knowledge as to what rating, in terms of pressure, the lower annular on the BOP on the HORIZON had?

A. Did not.

Page 125:04 to 126:02

Q. Okay. Was there any requirement -- BP requirement with respect to Macondo that the maximum anticipated surface pressure be computed only with surface -- as they put it, gas column to surface rather than a mixture of gas and mud or gas and another substance?

A. Our first screening tool will be with .1-psi-per-foot gas gradient. Our second screening tool will then be to run a mass calculation to be based on our most likely prediction of the reservoir fluid. In the case of Macondo, that was an oil.

Q. Okay.

A. So we would have used an oil gradient to actually run a second level of screenings.

Q. All right. Let me -- I'm going to have you explain that for me. Let's go to 73. And what I'm about to hand you is a -- well, it's an e-mail from Scherie Douglas dated Tuesday, May 26, 2009, MDL00237054 to 00237083, current Exhibit No. 3061. And what I believe this to be

Page 126:14 to 126:20

Q. Okay. And as a matter -- just a practice in BP, would you typically not review an application for permit to drill a new well, whether it was Macondo or any other?

A. I've never reviewed an APD for submittal.

Page 127:02 to 128:06

Q. (BY MR. STERBCOW) Well, it's the MMS APD worksheet. If you just keep flipping, you'll go past the APD schematic and then past -- I don't know what that is -- Sheet 202, and then there's a page that starts: Gulf of Mexico MMS APD worksheet.

MR. KEEGAN: 22 casing, Page 1 in the upper right?

MR. STERBCOW: That's it. Very good.

Q. (BY MR. STERBCOW) Would this be the page in the APD that reflects calculation of maximum anticipated surface pressure at -- I think it's -- it's divided out by the casing shoe, one for 22-inch and there is one for 18-inch, et cetera, et cetera?

A. Correct.

Q. Okay. Is it within BP policy and procedure to compute, say, under mass bottom hole pressure, it says: A column of 70 percent gas and 30 percent liquid back to the surface gives a certain amount, 70 percent gas, 30 percent liquid from ML to surface.

Mud line pressure is a given pressure. And then mass at surface, that gives the worst case.

But the first two, is it within BP policy and procedure to utilize 70 percent gas, 30 percent liquid, rather than 100 percent gas in those calculations?

Page 128:08 to 129:14

A. I can speak to how the mass number in terms of psi is actually computed. That is the end of my responsibility as far as computing MASP. I don't actually get myself involved in what are the BOE MMS regulatory requirements. This particular sheet you're actually looking at here was not filled out by me.

Q. (BY MR. STERBCOW) I was just going to ask you that.

A. I did not fill this out. It was filled out by the wells group. Obviously the PPFG plot that we have looked at previously was the seed point for most of these calculations. Any regulatory mixtures of fluid that go into this actually comes from the wells organization.

Q. All right.

A. And those would be the -- the ladies and gentlemen that would actually know the policy way better than I do.

Q. So I make sure I understand, when you say the wells organization, if you can't give me names, what job positions would be the ones who put this information together?

A. I believe that would be the

drilling engineer for the well.

Q. Okay. So in this case would Mr. Hafle and Mr. Morel be the ones, to your knowledge?

A. To my knowledge, Mark and --

Page 129:16 to 130:15

A. To my knowledge, Mark and Brian would be capable of making this computation.

Q. (BY MR. STERBCOW) All right. 70 percent gas versus 30 percent liquid, why they use those figures and whether that comports to either BP or MMS requirements or both is something that's outside of your area of expertise?

A. Correct.

Q. All right. Do they consult with you at all in computing these MSAP figures, or is it just something they do on their own?

A. The consultation with us is through the multidisciplinary action of constructing that PPG plot. And then the particular gradient of the hydrocarbon phase that they would use, they would consult with us on that number.

Q. Okay. And I assume, having said that, for this one page with the 22-inch casing shoe, Mr. Morel and Mr. Hafle would also be responsible for any subsequent APD worksheet, regardless of the level, the 18-inch line or the 13- and 5-inch as we go down, they did all of those calculations?

Page 130:17 to 131:17

A. The TIGER team is not involved in any part of the process for preparing the APD work sheet for MASP.

Q. (BY MR. STERBCOW) Got you. And in terms of whether or not these final numbers are then viewed by BP or Transocean with an eye toward whether or not the BOP is appropriate, that's not something the TIGER team does, either?

A. We do not.

Q. And I think you said before, within BP, if that effort is undertaken, you're not sure who would do it?

A. The TIGER team is not involved.

Q. Right.

A. I do -- my expectation would be that this particular calculation sits in the domain of the drilling engineer of the project.

Q. All right. Got you. Are you aware of any effort at Macondo to compare MASP figures throughout the course of the project to the capabilities and ratings of the BOP to determine whether the blowout preventer could handle these pressures?

A. I'm not.

Page 132:03 to 133:12

Q. (BY MR. STERBCOW) Okay. Let me revisit briefly, Mr. Vinson -- we may have covered this, but I want to make sure.

Going back to the deposition notice in that area 21. So now you're putting your BP hat back on.

A. Okay.

Q. Okay. It says, in part, talks about: Estimates, predictions, analyses of anticipated pressure, including but not limited to the information provided to Transocean.

Do you have any specific information on if and how any estimates, predictions, analyses of anticipated static pressure is provided to Transocean before the well begins?

A. My understanding -- I specifically in my job do not provide that information to Transocean.

Q. Okay.

A. My understanding is, as to the document that is in front of me, it's detailed in the APD, of which Transocean would have a copy.

I also believe that as part of a checklist that Transocean works through, that task of comparing MASP to BOP components is assigned to the toolpusher.

And I also believe that there are some sections in their own well control handbook that actually talk to the MASP calculation and verifying the actual numbers relative to the components of the BOP for the particular rig.

Page 133:22 to 135:15

Q. The other area you were designated in is No. 35, which is the existence, nature, scope and contents of any BP guidelines, policies or practices relating to locating and determining pay zones or

potential pay zones in a well.
What can you tell me about that?
A. I spent 22 years doing that for a living.
Q. Okay.
A. So my experience in my total of 30 years --
Q. Right.
A. -- two-thirds of it was related to doing that.
Q. All right. What specific BP guideline, policy or practice, written, relates to locating and determining pay zones or potential pay zones?
A. There is a document maintained by the director of petrophysics, Mike Webster, and there is a guideline called "Static" -- I believe the title is "Static Petrophysics Guidelines," and is a document that actually just logically steps through what are the different ways in which one can actual determine hydrocarbon-bearing zones from well logs.
Q. Got you. Okay. Would you have been involved in any effort to determine hydrocarbon-bearing zones from well logs at the Macondo well?
A. I was not. That was actually done by Galine Skripnikova.
Q. Okay. I've seen that name. And what's her job?
A. She was fully the petrophysicist for the Macondo well.
Q. Got you. So any questions regarding the effort -- BP's effort with respect to Macondo specifically relating to locating and determining pay zones or potential pay zones should be directed to her?

Page 135:17 to 137:08

A. I can speak to the general methods and procedures and practices that one would use on a well like Macondo to actually describe where are the hydrocarbon-bearing zones.
Q. (BY MR. STERBCOW) That's what -- would you -- actually, I need that description. What would be the general practices that would be employed?
A. The -- we mentioned earlier Schlumberger in running the well logs. In those multiple passes of tools that we run, we made many different types of measurements

of rocks.

For example, we measure the conductivity of rocks. We determine a property called porosity, which is the void space in the rock in which the water in the oil or gas exists.

We actually do something very similar to what humans do when they go for a brain scan in the hospital. We actually measure the magnetic resonance image of rocks. We actually run a tool that actually takes fluid samples from the rocks.

And so we take all of that information, and we have quite a bit of mathematics and computations, both BP-derived and industry publications, and we take all of that information and come up with an interpretation of, first off, where is the sand versus the shale. That's the first discriminator we try to figure out.

And then what we do is where we identify the sands, we then determine what is the porosity of that formation. We make an estimate of what is the permeability of that formation.

Ultimately from that, we compute what is the water saturation in there. 1 minus the water saturation is the volume of hydrocarbon that will exist in that rock.

Page 137:17 to 137:25

Q. Do you know of any effort undertaken by BP prior to commencing drilling on Macondo to determine the location of pay zones or potential pay zones based on offset wells?

A. The -- yes. The primary offset well that -- that we used in looking at that for Macondo was a previous well that BP had drilled called Isabela.

Page 138:07 to 139:07

Q. Well, what is accurate in using an offset well? I mean, I know it's an inexact science, I would imagine.

A. Well, it's a science that has uncertainty associated with it.

Q. Right.

A. The Isabela well -- which actually had targeted during the drilling phase an interval that was very similar in geologic gauge to what Macondo was targeting, the M56.

And so we evaluated -- by the process I just described, we evaluated that for Isabela post-well, and we utilized properties from that to actually make a computation for Macondo of exactly what was it we were drilling through.

Q. Okay. Was there any effort to estimate the volume of hydrocarbons in the Macondo well?

A. For every exploration that we drill, we make an assessment of what is the resource base of that particular formation we're going to drill through.

Q. Resource base is the --

A. How much oil is in place, OOIP.

Page 139:25 to 140:18

Q. (BY MR. STERBCOW) Do you have any idea what the prediction was in terms of --

A. I know what the range was.

Q. And what was that?

A. It was approximately 50- to 70 million barrels.

Q. All right. Do you have experience in the Gulf of Mexico sufficient for you to label 50- to 70 million barrels as -- in terms of size, small, medium, large, or is that something that would be outside of your area of expertise?

A. Only in how it relates to the way in which BP describes the sizes of fields. I can't speak for how another oil company would describe that.

Q. All right. And how would BP deem that --

Page 140:20 to 140:25

A. Macondo was actually what we called an infrastructure-led exploration well. The acronym for that is ILX. And the reason it is described as that is it was a volume of resource that was near a BP infrastructure, a platform that we could

Page 141:11 to 141:18

Q. Okay. So in terms of BP's nomenclature, 50 million to 70 million barrels would be considered what size?

A. Small.
Q. Small. All right.
A. Or actually, let me rephrase. It would not be what we would consider in our terminology a super giant.

Page 142:06 to 144:03

Q. Got you. Okay. Let's see. Looking back on the history of Macondo, the kicks and the number and volume of lost return events, do you have any opinion as to whether, first of all, the -- the field team, the TIGER field team, was adequately providing pore pressure frac gradient figures during the drilling operation?
A. To answer that, it actually -- it requires discussing uncertainty and what is the relative amount of accuracy that we're trying to achieve.
When you actually look at the details of a couple of the well control events during the drilling of the well, the actual difference between what was the pressure determined based on pressures gathered during that event versus what we were actually predicting at the time was -- was tense. And tense at that depth as a percentage of the absolute pressure is in the single digits.
Q. Right.
A. So it is -- so it is very difficult sometimes to say -- it's easy to say you took a kick. You obviously didn't know what the pressure was.
No, that's not true, is -- is that if you -- if the pore -- if the mud weight hydrostatic is 1 psi less than the formation, you will take a kick.
Q. Right.
A. And when you start to look at the level of certainty/uncertainty associated with it -- so long-winded answer to say that what Kate was doing at the wellsite, to the best of her ability with the information we had, was a good assessment of the pressure at the time within the ranges of uncertainty.
Q. Right. Do the ranges of uncertainty become more and more important in terms of well control as the margin decreases?
In other words, if you have this built-in range of uncertainty because that's just the way it is, does the risk increase as the margin of -- the drilling margin becomes

less, .8, .7, .6, goes down?

Page 144:05 to 144:16

A. Your ability to manage the mud weight you need to balance the pressure of the formation, while at the same time taking into account what is a single-point estimate of the rock strength at the previous casing shoe's leak-off test, it becomes more challenging.
Q. (BY MR. STERBCOW) Right. Do you have any opinion as to whether the drilling side did not appropriately use the information that was being provided by your team?

Page 144:18 to 145:04

A. I'm not aware on Macondo of any instance where the particular information that we were gathering at the wellsite corroborating in the office, that the wells team was not using that information --
Q. (BY MR. STERBCOW) Okay.
A. -- in the continued drilling of well.
Q. Was there ever any concern on your part or any member of your team that you're aware of that drilling was going too fast?

Page 145:06 to 147:19

A. I am aware of a particular e-mail that suggests that we were drilling, quote, as you say, fast.
Q. (BY MR. STERBCOW) Was that ever a concern of yours during the project?
A. I am not concerned by the term fast. What you want to do in a well is not get to a place where you out-drill the indicators that you actually have to determine what the pressure is foot by foot.
Q. Okay.
A. So to me, fast is not a relevant term. You either are drilling and the indicators are telling you what you need to know. But you also have to be able to recognize if you are in a section where, as you said earlier, the margin is narrowing, then I want to know if I'm actually out-drilling my indicators.

And that is -- that is not a black-and-white science. That has many -- many avenues of input from many different people as to what that would look like.

Q. All right. Do you think or are you aware of any instance in the life of the well, the drilling of the well, where they were out-drilling the indicators that you were able to provide?

A. I'm not personally aware of any instance where we were actually out-drilling the indicators.

One needs to understand what the number of indicators are because probably -- you have leading indicators. You have lagging indicators. The leading indicators are the domain of the rig. The driller has got his hand on the brake. They measure flow in, flow out, wait on bit, torque, standpipe pressure. Those are the only leading indicators -- pit volume. Those are the only leading indicators of pressure that we have.

Any of the pressure detection work that my team, the TIGER, does, those are what are called lagging indicators. If it's gas, we had to drill it and wait for it to be circulated up. If it's cuttings, we have to wait. The logging tools, they sit 85 to 130 feet behind the bit. Again, lagging indicators.

So your first line of defense in terms of whether you're drilling, as you said, too fast actually is the domain of the rig crew. They have those indicators right there in front.

When we come in after the fact, as in the lagging indicators, we process those to say, yes, we either agree or disagree with what the actual leading indicators are.

Q. Okay. Was the number of lost return events and the volume of lost returns for Macondo higher than you would have expected?

A. No.

Page 147:21 to 150:24

Q. (BY MR. STERBCOW) Why is that?

A. In my career of being affiliated with 30 exploration wells for BP, losses, we call it a nonproductive time event, NPT. Losses are not uncommon.

Q. The -- would the -- did the volume of the losses ever come up in discussions with the TIGER team?

A. We did. I mean, it was a -- the event you're referring to, it was a large sum of fluid.

Q. Right.

A. But at the time something like that occurs, one still doesn't yet know what was actually the root cause of the lost event. There are many types of geologic features that can lend themselves to loss events, and it's sometimes very difficult to determine exactly which mechanism of loss you just had.

Q. Right. Okay. Has the TIGER team or anyone, to your knowledge, gone back and looked at the history of the loss returns of Macondo to try to learn anything from those events?

A. Absolutely.

Q. And has anything been learned?

A. Yes.

Q. What is that?

A. Something that is not uncommon. The major loss event in Macondo was associated with a 250-foot interval of moril [phonetic], which in technical terms has a less rock strength than the leak-off test that was measured at the previous casing shoe.

And so as the ECD of that well, as we completed that whole section to run pipe, that extra one-tenth of mud weight that was used to have the well be prepared for running casing was actually just enough pressure to actually exceed that rock strength.

Q. Okay. And which -- do you recall which loss circulation event that was?

A. I believe that was below the 16-inch. It was the one that actually created the side track event of the well.

Q. Okay. That was when the pipe was stuck?

A. Right.

Q. All right. Did any procedures on the rig change in terms of well condition monitoring after that March 8th kick?

MR. KEEGAN: Object to the form.

A. I don't recall the exact dates. I do recall that there had been a number of nonproductive time events in Macondo.

And so what I instructed Bobby Bodek to do -- actually, first, I actually send an e-mail to David Sims saying we're going to take a hard look at the lessons

learned that we've gathered during the
drilling of the previous hole sections in
this well.
And then we're going to go back
to the rig and reengage the subsurface team
in terms of lessons learned and engage them
as well as the mud loggers to say, okay, our
intent from this point forward in this well
is to TD this well without anymore
nonproductive time events, which is actually
what happened.
Q. (BY MR. STERBCOW) Okay. And
that was -- if I recall correctly, that was
the impetus of you suggesting that Bobby
actually go out to the rig?
A. That was the reason I sent Bobby
to the rig.

Page 151:04 to 151:17

Q. From the point where he arrived
on the rig forward to when he called total
depth, were there any other nonproductive
time downhole incidents?
A. There was a minor loss event
that occurred when we actually had drilled to
just beneath the formation to actually create
a rat hole, as we call it, to be able to get
our logging tools through the interval to
evaluate.
Q. Okay. But beyond that
everything went smoothly, I'll say?
MR. KEEGAN: Objection; form.
A. It went according to plan.

Page 151:20 to 156:03

Let me -- Tab 33. What I'm
going to show you is -- and this will be
marked as Exhibit 3062, and it's MDL00852514.
(Exhibit 3062 was marked.)
Q. (BY MR. STERBCOW) And what I
believe this probably is is the e-mail from
yourself to Mr. Sims dated March 10th where
you lay out the beginnings of the process you
just described.
First, let me ask: What was it
specifically about the performance of the
TIGER team in support of D&C that had
disappointed you up to that date?
A. The -- back when the -- I need
to give a little context prior to this
e-mail.
Back when I actually formed the

TIGER team in 2001, one of my objectives as the manager was, we will render subsurface nonproductive time a thing of the past. It will be zero, realizing that I'm not aware of any well drilled in the Gulf of Mexico or any other part of this planet that has ever drilled a well with no nonproductive time.

Q. Right.

A. Prior to Macondo, the last ten exploration wells that we had actually drilled, seven of those ten had nonproductive time values where the subsurface component was less than 5 percent of the total well. So we were well on our way to achieving that vision.

When we got to Macondo, after we had a couple of well control events and the side track due to the stuck pipe, it was -- as I always do, it's always about continuous improvement.

So it was nothing more than rallying the troops, having, as I say there, some gloves-off time. Let's take a good, hard look in the mirror. Let's look at what we've learned from this well, and let's don't forget our lessons learned, and let's just reaffirm what those are, and let's make sure that we finish this well to TD and log it with no more nonproductive time.

So that was actually the content of that e-mail.

Q. Okay. Very good. Do you recall -- specifically, you mentioned -- I'll call it the second paragraph. It's really -- where you start: We have identified a few key areas that we have simply forgotten in terms of lessons learned.

A. Uh-huh.

Q. Do you remember what those key areas were specifically?

A. I do. The -- one of the things that we observed during the well is -- is that it's important to -- and I mentioned it earlier -- it's important to understand the leading indicators versus the lagging indicators.

And there had been, particularly on one of the well control events, in my opinion there had been some really early leading indicators that in fact this well was having a well control event, and it was not diagnosed to my satisfaction.

And I felt like that even though that remit sits pretty heavily with the mud loggers, I wanted to make sure my wellsite

geologist and my subsurface pore pressure expert, in this case Kate, were actually making sure that they engaged with the mud loggers so that we could actually get the leading and the lagging and bring that information closer to bear.
Q. Okay.
A. And that's exactly what we did.
Q. All right. Did you ever have any concern as leader of the TIGER team that the Sperry-Sun mud loggers were not competent to do their jobs?
A. I did not. I've had a relationship with the Sperry-Sun mud loggers for almost 17 years.
Q. Did you know either -- did you know Joe Keith personally? Do you know who he is?
A. I used to actually sit on rigs with Mr. Keith.
Q. All right. Are you aware of the fact that he was on duty at the time that the final well control event began?
A. I am.
Q. All right. Have you looked at what he did and did not do? Do you have any knowledge of the facts surrounding his performance that night?
A. Only as I have heard from his previous testimony.
Q. All right. Prior to -- and I take it from what you said, prior to April 20, you had not had any specific problem or you can't think of an example where Mr. Keith did not perform his mud logging duties to your satisfaction?
A. I have --

Page 156:05 to 156:07

A. I have no evidence that he did not perform as he was -- as he had in the past.

Page 157:13 to 157:22

Q. All right. And what was -- was there a specific reason why you would have sent the March 10 e-mail to Mr. Sims?
A. Only because David -- David and I have a personal relationship that dates back four or five wells. I had a similar hallway conversation with John Guide. So this very same conversation that sits here in

e-mail was also had with John Guide. I said: John, we're going to tune this up.

Page 158:04 to 158:08

Q. Do you know whether or not Mr. Guide had any similar meeting that you had with the folks that he was supervising to talk about whether or not their performance was up to standard?

Page 158:10 to 158:22

A. I do not. The interaction between -- the formal interaction between my team and the wells team happens at the 7:30 a.m. operations meeting. That is our one time a day where we formally gather.

During the rest of the times of the day, it's an informal relationship that if there is a need, based on parameters being gathered during the well, that they need some confirmation or just some geologic discussion, that a conversation happens first at the rig, and then it will happen subsequently in the office.

Page 161:01 to 161:10

Q. (BY MR. STERBCOW) It was a Friday, March 12th -- yeah. Let's see. We'll go to Tab 37. And this was previously marked as Exhibit 1071. It's a March 12 e-mail from Mr. Bellow to a number of folks, Lacy, Bennett, Brannen, Kate Paine, DEEPWATER HORIZON, Sperry-Sun, John Guide, Hafle, Morel, Bondurant -- oh, and you are CC'ed, actually. I see that at the bottom now.

A. Okay.

Page 162:07 to 163:17

Q. All right. Did he ever have a personal conversation with you about these concerns?

A. He did.

Q. What was the result of that conversation?

A. As we chatted earlier, in his mentor relationship with Bobby --

Q. Uh-huh.

A. -- Mr. Bellow has done 15 exploration wells for me, so he's very experienced.

The tone -- the context of this e-mail was -- is that most of the exploration wells that we and BP have drilled in the past four or five years were actually wells that are drilled through thick salt sections, 20- to 25,000 feet of salt.

Q. Right.

A. What that does is it replaces the pressured layers of the earth that we were actually going to drill through at Macondo.

So what he was referring to here, similar to what I mentioned earlier about lessons learned, is let's not forget the few -- what we call non-subsalt wells that we actually drill now -- let's not forget our historical lessons learned as to how we do pressure detection in those wells.

And in fact, there isn't a section of 20- to 25,000 feet where we don't have to worry about impermeable formation that will not flow. Every inch of formation that we drill at Macondo, we need to evaluate.

Page 163:20 to 164:10

Q. All right. Was there any process in place in drilling and completions in the Gulf of Mexico where risks that were unique to a Macondo-type well versus risks that did not exist in a salt -- I'll call it a salt well -- were assessed and discussed?

MR. KEEGAN: Objection to form.

A. The risks that were in Macondo as a part of the outcome of our no-drilling-surprises assessment, those risks were not dissimilar to other risks in previous exploration wells that the HORIZON had drilled.

The one main difference with respect to Macondo is, it did not have a thick salt section in it.

Page 164:12 to 164:21

A. But if you don't have salt, any layer of earth that you drill carries an uncertainty with respect to what pressure do you, predrill, think is going to be there, and what pressure do you actually find when you actually drill it.

Q. Got you. Okay. Does that then

mean that a well like Macondo is a riskier well to drill and control while drilling than a well that's predominated with salt?

Page 164:25 to 165:07

A. No, not in my opinion. The -- that is why the basis of design -- for instance, Macondo had, I believe, seven casing strings in the basis of design. Those casing strings were actually placed in the positions they were placed in order to mitigate any potential risks that might exist for pressures in the formation below.

Page 166:07 to 169:18

previously marked as Exhibit 1072, and this is a response from Stuart Lacy to Mr. Bellow. It says he agrees with pretty much everything he says. We're a bit complacent, having been drilling subsalt wells.

Same thing we just talked about.

This is a different kettle of fish. One thought is that we always used to flow check sands in exploration wells, but the drive for increased performance has seen this abandoned.

Do you know what he's talking about there?

A. I can't speak to the accuracy of his statement that this performance has been abandoned. I'm not aware that it's been abandoned.

Q. Okay.

A. We still do if the need exists during the pressure detection of the phase, if we feel like, based on the response of the leading indicators and lagging indicators, that we are at a place in our mud weight in the well that it may be encroaching upon the regulatory range relative to the previous shoe leak-off test. Then if we actually drill a sand, we will actually do a flow check on it.

Q. All right.

A. That's a standard procedure. It is a discretion of a call on the rig. It doesn't require the office to do that.

Q. Okay. And so as far as you know, whatever Lacy was talking about that flow check sand in exploration wells being abandoned is just incorrect?

A. It is his opinion that we may

have abandoned it. I don't share the same opinion.
Q. All right. Do you know what he's referencing when he talks about the drive for increased performance?
A. Not the actual context. That's a very generic -- a very generic term.
We do have what are called KPIs inside of BP, performance metrics. They are both safety, they're financial; they're a host of things. So he could be in this case potentially referring to a metric called days per 10K.
Q. All right. And what would be the -- you said they're both -- involve both safety and performance?
A. Correct.
Q. What's the safety component?
A. No accidents, no harm to people, no damage to the environment.
Q. All right. And what's the performance component?
A. One of the components is days per 10K.
Q. What does that mean?
A. That's a -- that's how many days per 10,000 feet of hole does it take you to actually drill that section.
Q. Drill a hole. Okay.
A. That is not just a BP metric. It's an industry metric.
Q. Is there a monetary reward associated with that?
A. I'm not aware there is.
Q. All right. Are you aware of any cost-cutting that occurred in the drilling and completions section in the Gulf of Mexico in 2008, 2009 and 2010 leading up to this incident?
A. I'm not aware of any specific cost-cutting measures.
Q. Are you aware of any pressure being placed on rig personnel to get the Macondo well to total depth as quickly as possible?
A. As manager of the TIGER team, I have personally never felt any monetary pressure to do only what I do. I can't speak to any pressures that the rig crew may have felt.

Page 170:25 to 171:06

Q. All right. Again, looking back on this, if you've done so, do you see any evidence that the drilling in this PP narrow-window well was unwise and compromised the TIGER team's ability to provide the information it needed to provide in a timely manner?

Page 171:08 to 171:11

A. If that had occurred, I would have intervened.
Q. (BY MR. STERBCOW) Okay.
A. And I did not intervene.

Page 171:17 to 172:12

go to 40. This has been previously marked as 1079, MDL0025882 through 25884. This is Kate Paine's response to Mr. Bellow's e-mail. And she goes through different observations she has, and at the very end she concludes by saying: I'm sorry to push back on the lessons learned. I know you've got to get something out there to make it look like we won't do this again. But without obvious indicators and with the real push to make the hole and skip the contingency liner, I don't see us really learning. The best bet is to hedge the most likely to have some centroid built into the plan, initially.
Again, now, this is the second person, Mr. Lacy and now her. She references: The real push to make the hole and skip the contingency liner.
Ms. Paine never came to you with this same concern that things were just going too fast?

Page 172:14 to 172:25

A. I never had a personal conversation with Kate concerning this nor why -- nor during the particular skip the contingency liner. I was not involved in any conversation where we had anything related to skipping a contingency liner.
Q. (BY MR. STERBCOW) Okay. Do you know if any of the -- either Lacy's response or Kate Paine's response were either forwarded by Mr. Bellow to others above him or utilized to make any changes in the way that the well was being handled?

Page 173:02 to 173:25

00173:02 A. I'm -- I don't have personal knowledge that Mr. Bellow sent that.
What I do know is relative to the time in which this was being discussed -- go back to a previous answer -- is after the stuck pipe and loss event, we successfully drilled the well to TD --
Q. (BY MR. STERBCOW) Right.
A. -- without any NPT or major NPT event, which suggests to me, one, we were not drilling like a bat out of hell, and two, we did not skip the contingency liner.
Q. Okay.
A. So it's very difficult for me to say what was making Kate and Stuart on the rig feel like that we were doing that. I didn't have any evidence that we were doing that.
Q. Let's go to 57. This has previously been marked as 1241, and this is MBI 00126338 and 00126339. It's the first page that I'm really looking at. This is the -- Mr. Bodek's April 13 e-mail to Michael Bernie when he calls total depth.

Page 174:08 to 174:12

00174:08 Q. (BY MR. STERBCOW) Okay. When were you informed that total depth -- that Mr. Bodek had concluded that they had run out of drilling margin, and TD was called at 18,360?

Page 174:14 to 174:22

00174:14 A. Mr. Bodek did not call total depth. Bobby does not have the decision-making authority within BP to alone call the total depth of a well.
Q. (BY MR. STERBCOW) Who did that?
A. Ultimately that decision would be taken in the wells group, and that decision would have to go through the wells team leader, which is John Guide.

Page 175:02 to 177:01

00175:02 Q. If you know, would Mr. Guide be authorized to call total depth?
A. Mr. Guide, based on the parameters set out in the statement of requirements, which lists the objectives of the well, if there are any concerns from an

HSSE perspective related to extending a casing point or extending the total depth of a well, then the wells organization has full decision-making authority to do that.

If there is not a safety hazard at the time, then that decision also has to go through the vice president of exploration.

Q. All right. Does it appear -- can you tell from the e-mail that Mr. Bodek concluded that because of running out of drilling margin, that this had in fact become a safety issue?

A. I don't have any recollection that Bobby felt it was a safety issue. What he's addressing here in the e-mail is that there were three sand intervals exposed in that open-hole interval, and those three sand intervals had measured pressures that were very different. And in order from shallow to deep, they were decreasing.

So what that meant to Bobby is that the main reservoir sand had a pressure that was lower than a sand 4- to 500 feet up above it.

So the potential effect of that is that you're having to keep a high mud weight in the well to balance that upper sand, but now I've got a pressure down here that's lower.

What that means is that the rock strength of this lower sand is now less, so you have a potentially reduced drilling margin because of these differences in pressure.

Q. Got you.

A. So that's what Bobby is alluding to in this e-mail. He has concerns that if we were to encounter another sand, and it was on the same trend and potentially even lower pressure, then we could have a loss event.

Q. In the typical well, if there is such a thing, would you expect the pressures in the sand layers as you go down to increase rather than decrease?

Page 177:03 to 177:16

A. This particular pressure expresses itself as a regression in mud weight space but not as a regression in absolute pressure space.

There is two types of pressure. There is pressure that we convert to mud weight for the drillers on the rig to physically put mud weight in the hole. We may express a regression in terms of mud weight, which again, if we had a few more days or hours, actually just means that the pressure build rate of the subsurface is decreasing relative to what it was doing shallower.

Page 177:20 to 178:03

Q. I got you. I think -- in terms of the mud weight, if I understand you correctly, the driller knows he's got to put in a mud weight of X to make sure he's handling the pressure at this -- at a level higher.

But if he uses that same mud weight, and that mud weight gets to the lower sand level, it may be too heavy?

Page 178:05 to 179:19

Q. (BY MR. STERBCOW) Is that a simplified way of saying it?
A. If I have a high-pressure sand shallower and a lower pressure sand below, per our GP 10-16 we not only assess pore pressure, but we have to assess what is the fracture strength of the rock.
Q. Right.
A. So the issue that Bobby is referring to is that we had a 14.1, a 13, a 12.6. I still have to keep mud weight in the hole shallower to balance the 14.1.
Q. Right.
A. The difficulty is that that mud weight or the equivalent circulating density of that mud weight at the TD depth of the well where the 12.6 pressure was measured is actually encroaching upon the computed frac gradient of that bottom sand at a 12.6 mud weight.
Q. Okay.
A. And so that is -- that is a common occurrence in many wells that we drill. We have to monitor for that. It doesn't mean that it is a potential safety issue.

It just means that if we are going to extend beyond where we are, then we as a group need to have a conversation around what do we actually expect the formation pressures to actually be below us.
Q. Got you. Okay. Do you know what he -- at the very end of his e-mail, he

says: We had simply run out of drilling margin. At this point it became a well integrity and safety issue.
First of all, well integrity, does he mean what you just said, that if we keep going, we run the risk of damaging the formation?

Page 179:21 to 179:22

Q. (BY MR. STERBCOW) Or having another lost return event?

Page 179:24 to 182:14

Q. (BY MR. STERBCOW) If you know.
A. I don't know the context that Bobby would use there for "well integrity." Based on the information that's in the previous four or five sentences, it's -- as I had explained earlier, his concern is that you have a higher mud weight across a sand interval that potentially you're -- that mud weight is getting close to the physical rock strength of that formation.
Q. Okay.
A. His worry would be for lost returns.
Q. Lost returns -- and what would the -- and it says: And safety issue.
Do you have any idea what he'd be referring to?
A. I do. If you actually have a lost return event, then, as we had experienced previous in the well, that could also result in stuck pipe. And stuck pipe in my mind generally can be a safety issue.
Q. Okay. Could that be indicative of a kick occurring?
A. Well, in this particular case with respect to this event, it wasn't going to be a kick because the formation pressure and mud weight at depth was lower --
Q. Right.
A. -- than the pressure that we were actually balancing above.
However, if you did actually take lost returns to a significant degree in that bottom section, then the potential would exist to set up a cross-flow situation where you're actually pressuring up the deeper sand by the shallower sand that's higher pressure.
Q. Okay. Got you. And that could potentially be a safety issue?

A. In general terms --
Q. Right.
A. -- that is something that you would be concerned about.
Q. I'm with you. Okay. Is there any way -- looking at this e-mail, when he says run out of drilling margin, is there any way by looking at the figures in that e-mail to determine what exactly the drilling margin was at 18,360 feet, or do you not have enough information there?
A. What I would need to see is the actual pore pressure detection plot showing
00182:01 the ECD and the ESD, and then what was actually the leak-off test at the previous casing shoe.
Q. Okay. And would that be something that had been performed already by the TIGER team?
A. It would have been performed by Kate offshore in terms of her assessment, and then integrated into our office-based plot by Marty Albertin.
Q. All right. And given this date, April 13, is there any way for us to know or track the date on which that data would have been obtained?

Page 182:16 to 184:12

00182:16 A. That information would be part of the well space database that we keep the information. So we could date it by the actual pore pressure report that was sent in.
Q. (BY MR. STERBCOW) All right. And the pore pressure reports -- I've seen some documents called PPFG reports?
A. Correct.
Q. Is that what we're talking about?
00183:01 A. Correct.
Q. All right. Would that report -- given this date, could that report have been prepared and sent in on April 5th, or would that be too early? If you can answer the question.
A. The requirement on Kate is that by, I believe it's 6:00 a.m., that she has posted the daily PPFG report to the well space database. So for any part of the well that we were actually drilling at that time, Kate would have posted the report.
Q. Got you. Okay. He doesn't say exactly when they drilled that approximately 100 more feet. But assuming that that

occurred, would there be a PPFG report for the date that the team drilled the hundred more feet?
MR. KEEGAN: Object to the form.
A. If there were -- if at the time they were drilling an extra hundred feet, realize two things happen. One, the actual logs that are in the BHA because of the spacing probably do not see that 100 feet. They may see 10 feet of it.
Q. (BY MR. STERBCOW) Right.
A. So there is -- so there won't be an updated report that talks to the conversion of logs to pressure.
What would exist is something that comes from the mud logging and any cuttings or gas data that was actually brought to surface.
Q. Okay. And I'm assuming you would have had no reason and have not in fact had any conversations with John Guide or any engineering personnel about this decision --

Page 184:14 to 184:15

Q. (BY MR. STERBCOW) -- to call TD at 18,360?

Page 184:17 to 185:11

A. I was a part of the final discussion in terms of the hundred feet of rat hole for logging and the conversations around, do we have the proper amount of drilling margin to be able to do that.
Q. (BY MR. STERBCOW) To do that. Okay.
And obviously it was decided that you did?
A. We did.
Q. All right. What was the drilling margin at the time that the hundred extra feet was drilled? Do you remember?
A. I don't remember. I'd have to actually see the post-12 plot and see all the data contained on it.
Q. All right. So do you have a recollection as to whether it was less than .5?
A. I don't know.

Page 185:22 to 186:08

(Exhibit 3063 was marked.)
Q. (BY MR. STERBCOW) It's from a gentleman by the name of Walt Bozeman, I think he pronounces that. Who is Walt Bozeman?
A. Walt was -- at the time of Macondo he was the reservoir engineering team lead.
Q. All right. And it's sent to Mr. Rainey, a number of folks, including yourself?
A. Right.

Page 189:19 to 190:19

Q. Got you. Okay. Do you have any idea where Mr. Bozeman got the 100,000-barrel-of-oil-per-day flow rate reflected in this e-mail?
A. It goes back to some earlier conversations in the testimony. As part of his job predrill, we are required as part of our exploration permit to send a -- to calculate worst-case discharge. It is in fact a government regulation that we do so. So we supply that predrill.
Given this event, then what Walt was doing here was taking information that we had actually gathered during the logging phase -- we now knew some more information about the reservoir than we had in the past -- and he was utilizing some software, of which I don't know what he actually uses, to make an ideal -- what I call an idealistic computation of worst-case discharge.
Q. All right. Was this computation of 100,000 barrels of oil per day based on some method that BP or Mr. Bozeman felt was going to provide as accurate a flow rate as you could possibly come up with as of April 21st?

Page 190:21 to 191:04

A. This calculation was based on standard reservoir engineering calculations. To my knowledge, nowhere in this calculation did he attempt to address any constrictions through the BOP, any constrictions related to a kinked riser, any of the -- what I call the jewelry that was left during the incident. This calculation would not have taken that into account.

Page 192:20 to 193:25

Do you still hold the job of TIGER team leader today?
A. I do.
Q. Has there been any change in your job duties or responsibilities since the HORIZON?
A. There have.
Q. What are those?
A. The name "TIGER team" no longer exists.
Q. Okay.
A. I am known as the Gulf of Mexico deepwater exploration new wells delivery manager.
Q. Okay.
A. I am also the SETA globally for pore pressure frac gradient.
Q. All right. And I've heard that term before. Explain to us what the SETA is.
A. SETA stands for Segment Engineering Technical Authority. GP 10-15 and 10-16 that you entered in previously, I actually control those two documents.
Q. Okay.
A. And I make sure that we are in compliance globally with those two documents.
Q. All right. Who had that responsibility in March and April of 2010?
A. Mark Alberty.
Q. And where is he now?
A. He's left BP.

Page 195:12 to 195:18

Q. Prior to and leading up to April 20, did you report in any fashion to Barbara Yilmaz?
A. I did not. She was the TVP of the wells organization.
Q. TVP is?
A. Technology vice president.

Page 196:04 to 196:19

Q. All right. In your former job of TIGER team leader, now the new wells delivery director, have you ever been involved in any meetings discussing the implementation of the operating management system in Gulf of Mexico drilling and completions?

A. The operating management system is a global system that not only applies to wells; it also applies to the exploration business as well.

Q. Right. Was that system in effect in early 2010 in drilling and completions in the Gulf?

A. OMS was a system in the Gulf of Mexico in that time frame.

Page 197:11 to 197:15

Q. (BY MR. STERBCOW) Do you know whether or not since April 20, 2010, OMS has been implemented specifically within the drilling and completions section of the Gulf of Mexico?

Page 197:17 to 198:03

A. OMS is an all-encompassing process safety management system. Because of the scale and complexity of the BP Gulf of Mexico business, the intent was to have a phased approach because the organization has the ability -- has to have the ability to not only absorb the standard, but to also embed it and sustain it. That is a process that doesn't happen overnight.

Q. (BY MR. STERBCOW) Okay. Well, has it happened now in drilling and completions as of today?

Page 198:05 to 198:06

A. My understanding is that the wells organization is implementing OMS fully.

Page 198:24 to 199:10

Q. (BY MR. STERBCOW) Okay. Have you ever heard or used the term "every dollar matters"?

A. I'm familiar with the term.

Q. And what does that mean?

A. To me personally, what every dollar means is that you manage your business much the way that each of us in this room manages their personal finances in their household. You are efficient. You use your money as it should be spent. You're not wasteful with what you do with your dollars.

Page 200:15 to 200:17

Q. Good afternoon, Mr. Vinson. My name is Stephen Flynn, and I work for the Department of Justice. I have a few

Page 200:19 to 201:10

Just so I understand the TIGER team as it existed at the time of the incident, there was -- you were the team leader, and Martin Albertin was the geophysicist that worked for you?
A. He is a geophysicist by degree.
Q. Okay. What is his title with the team?
A. He is the TIGER team geophysicist.
Q. Okay. And he was also the SPA, or single point of accountability, for decisions involving pore pressure analysis?
A. He was the single point of accountability for the construction of the pore pressure frac gradient plot for the well.

Page 201:12 to 201:13

we get confused with Mark Alberty? Was he on your team?

Page 201:16 to 202:01

A. Mark is -- Mark was actually an employee in the wells organization as part of our exploration and production technology group.
Q. (BY MR. FLYNN) Do you know what Mr. Alberty's duties were there?
A. He was SETA for pore pressure frac gradient.
Q. Okay. And SETA was the...
A. SETA was the custodian of GP 10-15 and GP 10-16.

Page 202:05 to 202:12

A. Mark, as I recall, was actually one of the reviewers that actually audited the pore pressure frac gradient plot for Macondo.
Q. That would have been before any

drilling started?
A. That would have been before the drilling.

Page 202:15 to 202:17

Q. (BY MR. FLYNN) What was his -- what were his duties, if any, once Macondo had begun drilling?

Page 202:19 to 203:25

A. Mark had specific expertise in a number -- in a number of different technical areas. So if there was a need by either the TIGER team or the wells team, it would be on a consulting basis. We would bring Mark in as an expert as we needed Mark to be involved.
Q. (BY MR. FLYNN) Okay. Do you recall ever doing that during the drilling of Macondo?
A. We actually involved Mark a couple of times in the interpretation of leak-off tests at particular casing shoes.
Q. Can you -- do you recall any of those events?
A. I don't recall specifically which leak-off test we brought him in. I just remember he was -- he was brought in by the wells organization to help with the interpretation of leak-off tests.
Q. Now, what is his expertise with regards to leak-off tests?
A. Mark is actually -- at the time was recognized MVP as one of our experts in the interpretation of leak-off tests.
Q. All right. And we've also talked about Gordon Bennett and Stuart Lacy, both wellsite geologists; is that correct?
A. They are.
Q. Okay. And they are not technically employed by BP?
A. They are not.

Page 204:02 to 204:07

Q. (BY MR. FLYNN) And Charles Bondurant, what was his role again?
A. Charles was the geologist -- BP geologist for Macondo.
Q. Okay. Did he supervise Mr. Lacy and Mr. Bennett?

Page 204:09 to 205:04

A. Chuck Bondurant did not.
Q. Who did supervise Mr. Lacy and Mr. Bennett?
A. They are supervised by the operations geologist of the well, so in the case of the Macondo that would have been Bobby Bodek.
Q. What was Chuck Bondurant's role in Macondo?
A. He was the actual prospect geologist that actually developed the prospect concept and brought it to the exploration forum for approval to drill.
Q. What would his role have been if any after-drilling began?
A. If during the drilling of the well we needed additional prospect expertise as to what targets we were drilling through and what the correlation of those targets were to the seismic data, then Chuck would be the person we would bring in for that.

Page 206:01 to 206:01

Q. How about Binh Van Nguyen?

Page 206:09 to 206:14

Q. And what was his role?
A. Binh is a seismic rock properties specialist, and so Binh provides particular expertise to the mapping of particular intervals. He actually assisted with some of the mapping of Macondo.

Page 207:13 to 207:17

know that Ms. Paine produced the pore pressure frac gradient reports during drilling of Macondo. Is that your recollection?
A. It is.

Page 207:24 to 208:01

Q. Oh, okay. So at the time of Macondo being drilled, Kate Paine was the only pore pressure analyst onboard the rig?

Page 208:03 to 208:09

A. We normally employed one pore pressure frac gradient specialist during the drilling section of a well.
Q. (BY MR. FLYNN) So the answer is yes?
A. She was the only one on location.

Page 208:18 to 209:09

poor choice. Who supervised Ms. Paine, if anybody?
A. Kate was hired by me, so ultimately me. But in the way in which I designed my team to handle daily operations, the operations geologist is accountable for our subsurface personnel on the rig, which would be Kate and for either Stuart Lacy or Gord Bennett, whoever was on the rig at the time.
Q. And I also have some other names I'm going to ask you -- well, maybe I can simplify it. Was there any other person that I haven't mentioned -- and obviously in a few cases I was erroneous -- who was, you consider, on the TIGER team at the time of Macondo?

Page 209:11 to 209:16

A. There are a group of biostratigraphers that supported the execution of the well.
Q. (BY MR. FLYNN) Was that Ms. Skripnikova?
A. She was the petrophysicist.

Page 211:25 to 212:08

Q. One thing I wanted to go over generally is the flow of information through the TIGER team. So I understand that there -- almost every day while the drilling occurs, there are two forms of information that come from the well in formal document form. The pore pressure fracture gradient report, is that one?
A. That is one.

Page 212:10 to 212:11

Q. (BY MR. FLYNN) And then a daily geological report; is that --

Page 212:13 to 213:12

Q. (BY MR. FLYNN) Is that correct?
A. There is a daily geological operations report that is produced during the drilling phase of the well.
Q. And we're going to talk about those a lot more. But why are there two such sources? I mean, they seem to overlap quite a bit.
A. They -- in particular, we break them apart primarily because the pore pressure frac gradient part of that is a very specialist topic.
And so the wellsite geologist may or may not have as part of their skill set expertise in pore pressure frac gradient, so that is why we actually have a separate expert on the rig for that.
So what we request is a expert report for that one topic. And then the geological operations report contains much more broad and general information of the past 24 hours of the well.
Q. And Ms. Paine, of course, prepared the -- what is the pore pressure analyst for the rig?

Page 213:14 to 213:15

A. She was the pore pressure frac gradient consultant on the rig.

Page 213:18 to 213:18

previously marked as Exhibit 1314. That's

Page 213:20 to 213:25

You've seen it earlier today. And this was the September e-mail from -- 2009 e-mail from Kate Paine to yourself, and she's talking about certain practices that you've already mentioned. One I'd like to ask you a little further about is the LOT.

Page 214:08 to 215:23

A. There are -- there are multiple

ways and types of techniques to actually pump a leak-off test.

Q. (BY MR. FLYNN) Okay.

A. So there is not a single procedure for doing that.

Q. Okay. This is where you're going to probably lose me, but go ahead. The next line, it says: The Herschel heartburn came from reporting to the MMS a calculated value which exceeded the highest value the PWD tool recorded.

Did I read that correctly?

A. That is correct.

Q. Tell me what that meant to you when you saw this e-mail.

A. There are -- there are -- it's about comparing apples to apples. What is reported to the MMS is a surface mud weight and an additive pressure to compute a leak-off test. So you're comparing a surface mud weight with a surface LOT.

When you actually pump the leak-off test, that same information can also be converted to downhole numbers. Again, it is a comparison of apples to apples.

So in terms of managing the margin in the well that you drill, you either need to manage the surface -- mud weight surface LOT or downhole mud weight downhole LOT. And that's what she appears to be referring to there.

Q. Explain the difference between the downhole LOC and the surface LOC.

A. Compressibility of the mud column. So at any given depth in the well, you have got a certain amount of footage in the mud that is compressible. So the actual value that you measure downhole will actually account for that compressibility in the system.

Page 216:04 to 216:21

Q. (BY MR. FLYNN) Or is it the other way around?

A. There is no simple way to actually do that conversion because it's a function of what the mud properties are. There is a tool in the bottomhole assembly that actually records that leak-off test. And we are able to actually pump that information to the surface and actually look at what that value was that was recorded downhole.

Q. And how do you record the

surface leak-off test? In other words, what is -- what do you read that information from?
A. That's just a physical pressure read at the cementing unit if they were lined up on the cementing unit to pump the leak-off test.

Page 216:25 to 217:12

Q. Okay. And then how do you convert that to a ppg for a fracture gradient?
A. You just take the mud weight that's actually in the hole surface, convert that to pressure, add the amount of pressure, depending on the interpretation of the leak-off test, convert it back to mud weight.
Q. All right. So Ms. Paine is telling you basically that if the Herschel heartburn -- I take it there was a well called Herschel during which there were some issues about this discussion?

Page 217:14 to 218:03

A. The Herschel well was prior to Macondo and was not an exploration well. So I have absolutely zero knowledge as to what transpired on the Herschel well.
Q. (BY MR. FLYNN) What does the next sentence mean to you, or did at the time: Given that FG should be calibrated to minimum stress, a/k/a closure, and not to the highest value, this caused a lot of stress between the working parties.
Presumably FG is fracture gradient. And what is she saying: Fracture gradient should be calibrated to minimum stress, a/k/a closure?
What does that mean?

Page 218:05 to 218:08

A. The determination of, quote, closure pressure or minimum stress, can only be achieved if you actually pump what is called an extended leak-off test.

Page 218:14 to 218:19

A. See if I can do it simply. The only real way to understand closure pressure is that from a physical thing that you would read on the rig, you have to actually see a pressure decrease occur for an increase in volume pumped on the cementing unit.

Page 218:23 to 219:07

A. That would get you to closure pressure. Leak-off is a very generic term that has many connotations, depending on the person you actually talk to who is actually interpreting the leak-off test.

Q. (BY MR. FLYNN) But what is Kate talking about here when she says: Fracture gradient should be calibrated to minimum stress, a/k/a closure?

What does she mean by that?

Page 219:09 to 220:03

A. Her point there is technically correct, is that since we are required to estimate fracture gradient from the pressure, we would love to be able to calibrate it to minimum stress.

The reality is we very rarely ever have true minimum stress measurements in any well. One of the few ways to even get at that number is if you actually complete a well and administer a treatment called a frac pack. You have to actually go in and fracture the rock and then actually measure the closure pressure.

So she's technically correct in stating that we would love to be able to calibrate to minimum effective stress. Most leak-off tests that are actually pumped do not achieve that technical definition.

Q. In other words, they actually end up with a higher reading than that?

Page 220:05 to 220:07

A. You don't end up with a higher reading. There is a point on the curve that is interpretive.

Page 220:14 to 220:16

Exhibit 1021. All right. If you look -- actually, it's the attachment to that, just past that blue page.

Page 220:20 to 220:24

Q. Okay. And in fact isn't that a document prepared by Mr. Bodek?
A. I believe it is.
Q. As a lessons learned and path forward following the March 8th kick?

Page 221:01 to 221:05

A. It is a -- it was a document produced by Bobby to make sure that all members of the team actually understood the technical details of the interpretation of a leak-off test.

Page 221:14 to 221:24

His first sentence: When interpreting graphical leak-off test results, understanding the significance of the leak-off fracture propagation and fracture pressures is imperative.
So he's drawing a distinction between those three points?
A. He is.
Q. He says: The value that is reported to the MMS is the surface fracture pressure.

Page 222:03 to 223:11

A. He's just -- he's saying -- that says we -- the surface means surface is relative to surface mud weight, and it is an interpretation of, quote, the fracture pressure.
Q. (BY MR. FLYNN) Okay. If -- if we look at his graph lower down on the page, where is that point on the curve, the surface fracture point? Is there such a point?
A. It's going to require a little explanation.
Q. Okay.
A. The point that is marked leak-off is the point at which fluids first leak to the rock. No fracture has been created at that point. That is what's technically referred to as the leak-off point.
However, you will notice that by the shape of the curve, for -- there is still an increase in pressure occurring for a

volume pumped. So we haven't actually extended fractures into what we call the near wellbore yet, so everything's fine there.

The point at maximum where he refers to as massive fracture -- poor choice of words. All that actually means is that you have now started to initiate fractures in the near wellbore which might actually break through that field and go into what we call the far-field stress.

I disagree with the term "massive fracture." I do not use that term myself.

Page 223:15 to 223:18

Q. (BY MR. FLYNN) I'm sorry. Do you have a term you prefer?
A. It's fracture initiation pressure.

Page 223:22 to 224:05

Q. Is -- and in fact he uses that term later down, so we'll keep going here.

His next sentence: It is at this downhole equivalent pressure that a large fracture has or have been formed.

Do you see that sentence?
A. I do.
Q. Okay. What is he telling us there?

Page 224:07 to 224:15

A. Again, disagree with that statement as written. When you have reached the fracture initiation pressure, all that has happened is a series of small fractures have been initiated in the near wellbore, but may or may not extend past that region into the far-field.
Q. (BY MR. FLYNN) But this is past the leak-off test?

Page 224:17 to 224:22

A. There have been openings in the rock that have been created as part of that leak-off test, going past the leak-off value.
Q. (BY MR. FLYNN) Okay. So the answer is, yes, it is past the leak-off value?

Page 224:24 to 225:04

00224:24 A. It is past leak-off.
25 Q. (BY MR. FLYNN) Okay. The next
00225:01 sentence: ECD values should be maintained
02 between the fracture initiation pressure
03 (leak-off) and fracture propagation pressure.
04 What does he mean there?

Page 225:06 to 225:20

00225:06 A. What he's describing is that if
07 you increase the mud weight ECD that actually
08 goes past the propagation pressure, then for
09 whatever distance the fractures that were
10 initiated extend, you will open them back up
11 and you will propagate them even further away
12 from the near wellbore.
13 Q. (BY MR. FLYNN) Okay. Now, he
14 uses the term in that sentence "fracture
15 initiation pressure," but then afterwards he
16 has in parens leak-off. It doesn't sound
17 like that's how you would use those terms as
18 equivalent. Is that correct?
19 A. I've been doing it for 30 years.
20 Bobby's been doing it for five.

Page 225:22 to 225:24

00225:22 A. I would choose words a little
23 differently than Bobby chose in this
24 document.

Page 226:04 to 226:13

00226:04 Explain the difference between
05 the fracture initiation pressure and the
06 fracture propagation pressure.
07 A. The fracture propagation
08 pressure is the pressure at which, if the mud
09 weight exceeds it, the fracture will actually
10 continue to propagate in a lateral distance
11 lengthwise away from the wellbore.
12 Q. So it's higher than the fracture
13 initiation pressure?

Page 226:15 to 226:15

00226:15 A. It's actually lower.

Page 226:23 to 227:12

Q. (BY MR. FLYNN) And the reasoning is that once you've broken the rock, it takes less force to propagate the fracture than it did to create it initially?
A. Very good.
Q. Thanks. And then lastly, what's the closure pressure that he has labeled on the same graph?
A. That is the pressure at which the fracture actually completely closes.
Q. Okay. So presumably the mud weight has lessened or the force of the mud had lessened, and it has in essence been squeezed out of the crack back into the wellbore?

Page 227:14 to 227:23

A. The fracture has actually closed. And any fluid that is contained within that fracture, if there is no permeability associated with the matrix, some of that fluid will come back.
Q. (BY MR. FLYNN) Okay. Now, back to my original question: Of those four values that we've now discussed, is the surface fracture pressure the same as the fracture initiation pressure?

Page 227:25 to 228:22

A. In this context on this graph, it would be.
Q. (BY MR. FLYNN) But you're saying in other contexts it may not? You can confuse me further if you want to.
A. No. The -- when you look at the value that's labeled "leak-off," there are some in industry that would refer to that as the leak-off test value. And they would say that I'm not going to take my ECD past that number.
You will notice on that graph -- and if you have a truly impermeable shale -- that that leak-off point is roughly equal to the break in the closure pressure.
So there are some experts that would say that if you actually can define the break point as leak-off, you have in fact for certain lithologies defined the closure pressure.
Not all folks in the industry

share that point of view. There's many ESSPE papers that are written on this topic.

Page 229:07 to 229:15

Q. (BY MR. FLYNN) Is there a prescribed BP method of conducting a leak-off test?

A. There was a recommendation as documented by Mark Alberty, our company expert on the subject at the time. Depending on what type of well you are drilling, he would suggest what type of leak-off test you should actually pump.

Page 230:18 to 231:09

Q. And do you recall what the content of that updated version was? In other words, what was Mr. Alberty recommending?

A. He was just detailing the technical practices of recommended strategies for actually administering leak-off tests. He was describing the technical differences in the different types of leak-off tests.

He was also describing in their recommendations going forward on the -- on the continued use of a standardized spreadsheet to be captured -- for the information of the rig to be captured.

And he had suggestions as well in there as to how leak-off tests would be interpreted.

Page 231:17 to 232:19

Q. (BY MR. FLYNN) All right. At the time of these events in 2010, were you aware of any BP guidelines, whether by Mr. Alberty or anyone else or the company, as to how a leak-off test should be done?

A. I was aware of general guidelines in terms of how a leak-off test should be administered.

Q. Okay. And where are those found?

A. Actually, a set of those documents actually sit in a course that I teach.

Q. What course is that?

A. 21st Century Pore Pressure Frac Gradient.

Q. That's catchy. And who do you
teach that for?
A. That is actually a requirement
of our pore pressure frac gradient ETP
GP 10-15, so that class is taught by my team
twice a year.
Q. Okay. And that's taught to just
BP employees or other people?
A. BP employees and, since it
contains confidential information, select
contractors that we feel need to actually see
that material.

Page 232:21 to 233:01

these -- what is the specific document that
you were referring to about leak-off tests as
part of those materials?
A. It's a couple of PowerPoint
slides in Section 7 of that class under frac
gradient.

Page 233:05 to 233:06

These were previously marked as Exhibit 555,
and it's a whole raft of PPFG reports. But I

Page 234:08 to 234:12

So at the -- the pore pressure
summary that's on the middle of the page, I
take it that's the main point of this
document, this information that Ms. Paine
provides?

Page 234:14 to 234:24

A. The primary point of this
document is to be able to correlate, based on
her experience and the information she's
gathered at the wellsite, the current pore
pressure for the depth listed such that we
can actually compare that back against our
predrill prediction to understand
similarities or differences.
Q. (BY MR. FLYNN) Let's look at
the -- just the top left box. It says: Max
PP open hole, and it says 10.2 ppg.

Page 235:05 to 235:09

Can you tell us what that

information is.
A. I'm actually not familiar with why there is a max pore pressure box sitting in that particular spot.

Page 235:11 to 235:18

A. I mean, the only assessment Kate is making at the wellsite, based on her given authorities, is to estimate at the time we were drilling what is the pore pressure in that wellbore to the best of your knowledge. She is not tasked with making any measurements around the potential uncertainties, high or low.

Page 235:22 to 236:06

Q. (BY MR. FLYNN) It just says -- when it says "max PP," do you assume that means maximum pore pressure?
A. That would only be there for someone wanting to make some interpretation as to -- based on the indicators that I think the pressure is X, but it could be as high as an additional X.
Q. Okay. And when it says "open hole," is -- what does that refer to?

Page 236:08 to 236:09

A. The section that's being drilled that's not cased off.

Page 236:16 to 236:21

Q. Okay. And by bottomhole, again, you believe it's the pore pressure below the last casing string?
A. It's the actual pore pressure that should correlate with the depth boxes that are listed up above.

Page 237:08 to 238:13

Q. And progress in the last 24 hours is 120 feet. Is that the amount of hole that's been drilled?
A. That's the amount of hole that would have been drilled subsequent to the last report that was issued.
Q. And the hole size, 18 by 22,

what is that measurement? How is that measurement taken?
A. That's the actual size of the bit versus how -- versus the under-reamer that's being run. So that's the pilot hole versus the underreamed hole size.
Q. Okay. The next line, "Sensored Distances," what do those tell us?
A. Those are the distances of the -- for each particular tool, what depth that sensor sits relative to the bit.
00238:
Q. So these are higher than the bit?
A. These are part of what I described earlier today, the lagging indicators. These sit behind the hit.
Q. All right. Coming back down to the pore pressure summary. The next box on the left that I want to talk about, it says: Surf MW 10.1 ppg.
What does that represent?
A. Surface mud weight.
Q. And that would be measured at the surface presumably by the mud loggers?

Page 238:16 to 239:15

00238:
A. That would be actually measured by the mud engineer. That's the mud weight that sits in the pits.
Q. (BY MR. FLYNN) The next box says ECD, which I believe is the equivalent circulating density, which I think you've explained. And it says: 10.32 ppg.
And would that be a calculated number or would that be measured downhole?
A. It's measured downhole.
00239:
Q. And then the -- there is two boxes to the right. The top box says: Last LOT 7952 feet TVD.
Then it reads: 10.46 ppg.
And what does that information tell us?
A. That is an interpretation of the previous casing shoes leak-off test.
Q. Now, of the discussion that we just had a few minutes ago, is Ms. Paine relating the leak-off test as you described it, or is she relating something that happened when the pressure increased and the wellbore either initially fractured or propagated?

Page 239:17 to 240:07

A. This should relate to the leak-off test value that was actually submitted as part of the regulatory paperwork.

Q. (BY MR. FLYNN) Okay. Can you explain that.

A. The -- we have to actually report our leak-off tests to the MMS or the OEM. And so that is actually reported by the wells organization, not by the TIGER team.

Q. Right. I understand that.

A. So Kate would have that there.

Q. And -- but is that figure the actual leak-off test, or is it, as Mr. Bodek said in his e-mail, the surface fracture pressure?

Page 240:09 to 240:12

A. I would have to actually look at the leak-off test curve for that shoe to determine whether that 10.46 is actually the leak-off value or the max pressure.

Page 240:20 to 240:22

Q. (BY MR. FLYNN) So I guess my understanding is, so this would be the value that should be provided to MMS?

Page 240:24 to 241:20

A. This value in this box would have been submitted to the MMS prior to actually drilling out of that casing shoe that's annotated as 7952 TVD.

Q. (BY MR. FLYNN) If we look at the box below it: ESD min/ESD max 8898 MD.

We have two values: 10.24/10.31 ppg.

Can you tell us what those represent.

A. The pressure while drilling, known as PWD, tool that sits in the BHA actually continuously is measuring the static mud weight when we are actually not circulating. So that stands for equivalent static density, and it pulses up the minimum value it records, and then it also pulses up the maximum value that it records.

Q. Okay. So that's the mud weight at the bottom of the hole when it's not circulating?

A. Correct.

Page 242:07 to 242:11

Geological Reports for the dates 10/23/2009, 10/24/2009, 10/25/2009, 10/26/2009, 10/27/2009, 10/28/2009, 10/29/2009, 10/30/2009 and 10/31/2009.
And those will be Exhibit 3064.

Page 243:24 to 244:03

All right. Now, what additional information does this document provide? Obviously, I see some description here of the actual stone composition.
A. There is a detailed --

Page 244:05 to 244:13

A. There is a detailed summary of the stratigraphy being drilled.
Q. (BY MR. FLYNN) Again, that's the type of stone?
A. So that's sample descriptions that covers through the interval. There is an annotation of the particular gas that was actually seen both in terms of total gas and its carbon breakout components. And --

Page 245:02 to 245:18

could help me -- the difference between connection gas and background gas?
A. Background gas is the gas that's liberated from the volume of cuttings that are actually drilled and circulated up to the surface continuously during drilling.
Connection gas is a measure of once you've actually cut the pumps off and the well has gone static in terms of circulating, when you actually kick the pumps back on and drill ahead, that connection will actually come back to the surface, and it's another measure of gas.
Q. And what is the significance of the connection gas? Does that potentially tell you whether you have a flow of gas into the wellbore?

Page 245:20 to 247:03

A. For me personally, connection gas -- I actually use connection gas ratio to the level of background gas to give me an indicator of whether the pore pressure of the formation is actually approaching the mud weight that's actually in the hole.
Q. (BY MR. FLYNN) And how does it do that?
A. It does it based on interpretation.
Q. Okay. So what is -- what are you looking for when that -- when you're making that analysis?
A. In my personal experience in having done this, what I look for is a trend. If I see at two to three connections where the ratio of connections background is decreasing, that's an indicator to me that we need to stop and actually take a look and understand what the other both leading and lagging indicators actually tell me about the pressure in the well. It is an indicator. It is not the only indicator.
Q. No, I understand.
The next section is entitled Mud Properties.
What is the information contained there?
A. Essentially, the depth at which we had a measure of static density and circulating density, the type of mud, what the mud weight surface is, and then an estimate of what the range of pore pressure could be.

Page 247:20 to 248:10

Is some of this doc -- information that was seen in the last two exhibits, is that transmitted electronically to your office?
A. It is posted to our well space server.
Q. Does the well space server keep a history of this information, meaning the -- like, the lot and the pore pressure, or is it constantly upgraded with the -- the actual penetration?
MR. KEEGAN: Objection to form.
A. The documents that are uploaded to well space are time and date stamped based on the point in time in which they were uploaded.

Page 248:12 to 248:12

A. They're all retained.

Page 248:14 to 248:21

in. I want to talk about some of the electronic information that is not in these two documents.

And I'm going to ask you about -- can you think of any -- or simply list the ones that you know that would not be contained in here that would be obtainable if you looked at the well space?

Page 248:23 to 249:10

A. What is -- what is not included here is the actual physical mud log that is recorded.

Q. (BY MR. FLYNN) And that is information from Sperry?

A. That is provided by Sperry-Sun. The LWD data, the sensors that are in the drilling BHA, in terms of the resistivity, gamma ray, sonic and PWD logs, those composite logs are also posted to the well space.

Q. In the mud log from Sperry, what information is contained in that?

Page 249:12 to 250:03

A. It contains a summary of the previous information I mentioned. It has the logs on it, resistivity, gamma ray and sonic logs. It will have the lithologic description, not only the -- not the one that is provided to us in this document, but actually is provided by the mud logger.

So there is a second lithologic interpretation that is provided on that log, and it will also carry some annotations and comments made by the observations of the mud logger on that log.

Q. (BY MR. FLYNN) Okay. And now, we -- and that -- have we described the total information that is actually coming in on a -- in a sense, a day-by-day basis about the drilling of Macondo?

Page 250:05 to 251:13

A. What we have not described is the vast amount of drilling information --

Q. (BY MR. FLYNN) Okay.

A. -- which is everything from weight on bit to torque to standpipe pressure to shock and vibration to -- the list goes on and on. There's a whole host --

Q. How does --

A. -- of drilling measurements.

Q. Excuse me. How does that latter information, the drilling information, play a role in the TIGER team's analysis?

A. We use pieces of that information to combine with the other measurements that I mentioned in the interpretation of the ongoing assessment of pressure in the well.

Q. Can you give me an example of that.

A. One example would be, for instance, flow in/flow out parameters. We actually look at connection gas, background gas. We look at the conversion of our logs to pressure.

And then we -- if we see a trend developing, we then look to see, is there any change in the trend of flow in versus flow out. And then we also then take a look and see if there is any change in the pit volume.

Q. And I understand that, as you explained before, Mr. Bodek would be the -- well, I'll ask you: Who interprets this data for the TIGER team to provide to the drilling engineers?

Page 251:15 to 251:23

Q. (BY MR. FLYNN) Now, you said that was the next step, that this -- basically, you look at the -- all this information, and that you try to refine the prediction for the pore pressure and the fracture gradient on the next section of hole that's going to be drilled, and you provide your best estimate to the drilling engineering team; is that correct?

Page 251:25 to 252:01

Q. (BY MR. FLYNN) Mr. Morel and Mr. Hafle?

Page 252:03 to 253:05

A. We are tasked -- we interpret on all the different parameters that are gathered during the drilling of the well to make an ongoing assessment of pore pressure frac gradient in that well.

We then use that information to inform the wells team as to whether we think the pressure is increasing or decreasing or we're on plan.

Q. (BY MR. FLYNN) How do you do that? In other words, how -- and that's not a good question.

But in what form does that information go to Mr. Hafle and Mr. Morel?

A. There is a 7:30 a.m. operations call --

Q. Okay.

A. -- with the rig each and every day, regardless of whether we're drilling or running casing. That happens every day, including weekends. That information is transmitted into that room at that point in time and then followed up with the required documentation of it.

Q. Okay. Let's -- we only have a few minutes left on this tape. Let's discuss a little bit. We can take the meeting itself first. Who attends the meeting?

Page 253:07 to 254:20

A. That meeting has a number of attendees. It will have the wells team leader. It will have the drilling personnel that report to the wells team leader. It will have my operations geologist for the well.

Q. (BY MR. FLYNN) Mr. Bodek?

A. Mr. Bodek in this case. Jonathan Bellow would also attend. It would also include the geology, geophysics and petrophysics personnel from the subsurface team.

Q. And do you know who that would have been for the Macondo well?

A. Galina Skripnikova and Chuck Bondurant would be in attendance.

Q. Not Mr. Albertin?

A. Marty would attend as needed, and select contractors.

Q. Would you attend?

A. I do attend on occasion.

Q. For example, after the incident on March 8th where they took a kick and stuck the pipe, did you attend any of the meetings after that?

A. I actually knew about the kick event very shortly after it happened. I actually have, as part of my requirements for my team, any subsurface NPT-related event, I get a phone call. So I was aware of this within minutes of it actually occurring.

Q. Okay. Who do you get that phone call from? Is it the same person usually or the same role?

A. It would be Bobby Bodek making the phone call to me. If it's during business hours, I sit right next to him. So it would be a face-to-face communication with the details of the event.

Page 254:22 to 254:23

meeting, who presents the -- the data? Mr. Bodek? To the group, I mean.

Page 254:25 to 255:25

A. If -- when Marty Albertin attends, he would actually do it. But Bobby is more than capable of providing the summary of that information into the meeting.

Q. (BY MR. FLYNN) Okay. But assuming Mr. Albertin wasn't there, then typically it would be Mr. Bodek?

A. It would be Bobby Bodek.

Q. Okay. And then how is it -- you said it was also followed up in documentary form. How is that done?

A. Well, they have the two documents we've discussed, the geologic operations report and the pore pressure frac gradient report.

We also take the information that is being gathered by Kate, and Marty Albertin actually assimilates that into our predrill spreadsheet where we keep the running tally, foot by foot, of how the predrill pressure prediction compares with what is actually being interpreted for detection.

Q. Is -- and how would be the people at the morning meeting view that latter information?

Page 256:02 to 257:04

A. Computer screen up on the wall.

Q. (BY MR. FLYNN) Okay. Is that a part of the well space database?

A. This would be just on our actual laptops projecting onto a screen in the room.

Q. Is -- and what do you call that document, if you will?

A. That's our -- that's our as-working pressure prediction worksheet. It doesn't have a fancy title.

Q. But the people at the morning meeting would also be seeing the two doc -- two types of documents that we discussed today, the daily pore pressure fracture gradient report and the daily geological report?

A. Those documents are available to anyone in that room that wants to actually view them.

Q. But are they actually distributed to the engineering team?

A. Every person on the Macondo wells team has a password to be able to go into well space and view those documents.

Q. But you don't know if they do or not?

A. I don't know how often they go in or if they don't view those documents.

Page 257:13 to 258:24

Exhibit 555. And I want to look at a particular date on the daily PPFG report. This is March 19th, 2009.

If you would, what is the last FIT that's recorded on that document?

A. This document, 12.55.

Q. And when we say FIT, how is that different than a LOT?

A. FIT is a generic terminology. FIT may or may not be different than the LOT. It goes back to interpreting the shape of that curve we discussed earlier.

Q. And how might it be different?

A. FIT stands for formation integrity test. That is not generic -- not dissimilar to the phrase leak-off test. They are used one and the same.

Q. Have you also heard the term PIT, pressure integrity test?

A. Those -- both of those would be in a -- that explanation would be a pressure integrity test.

Q. Is there a difference in your mind between an FIT and an LOT?

A. Go back to the answer given when we previously explained the shapes of those curves. And in my definition, leak-off test is the point at which fluid first leaks to the formation. The FIT tends to be a value that is higher on that curve.
Q. Is the -- okay. All right. If -- what is the -- again, there is two values given here, 12.55 for the FIT ppg, and it says: Surf.
I assume that means surface.
And then: 12.67 ppg (DH).
A. DH is --

Page 259:01 to 259:14

00259:
A. DH refers to downhole, so that would be the value that is pulsed up from the TWD's tool in the BHA. The surface value quoted there is just taking the surface pressure, adding it to the mud weight, convert it to pressure, and then convert it back to mud weight.
Q. (BY MR. FLYNN) And then that gives you your surface FIT reading?
A. That gives you your surface pressure reading for that leak-off test.
Q. Now, if we compare that to the surface mud weight that's listed there, what is that number?

Page 259:16 to 260:08

00259:
A. Surface mud weight on this document is 12.3.
Q. (BY MR. FLYNN) Okay. Now, you were saying at one point that if you had a difference between the FIT or the LOT and the mud weight that was greater than .5 ppg, I think you told Mr. Sterbcow that you needed a waiver from MMS. Is that your understanding?
MR. KEEGAN: Objection to form.
A. It is my experience that during
00260:
the drilling portion of the well, if the surface mud weight relative to the previous use surface LOT actually becomes less than .5 ppg, then there is a requirement to contact the MMS for a waiver to .3.
Q. (BY MR. FLYNN) So if those -- based on this document for March 19th, 2009, there would be a requirement for a waiver?

Page 260:12 to 260:15

A. If there was drilling activity occurring in that whole section.
Q. (BY MR. FLYNN) In other words, to drill ahead?

Page 260:17 to 260:20

Q. (BY MR. FLYNN) They would require a waiver?
A. To drill ahead based on the value reported there, yes.

Page 261:02 to 261:05

Exhibit 1241. And this is the same e-mail you saw earlier from Mr. Bodek to Michael Beirne dated April 13, 2010, in which he's describing the last part of the drilling.

Page 261:07 to 261:15

Q. (BY MR. FLYNN) Now, if I understand it, what he's describing -- and tell me -- and I'm going ask you if I'm incorrect -- is that he's telling Mr. Beirne that they had to make a decision, and not necessarily Mr. Bodek alone, but that a decision had to be made to call the total depth of the well before the original planned depth; is that correct?

Page 261:17 to 261:22

A. That's my understanding from reading this document.
Q. (BY MR. FLYNN) Okay. And he's saying that one of the reasons was that there was a continuing problem with fluid loss at the base of this formation.

Page 261:25 to 262:04

A. I don't know that I read in here that there was a continuing problem.
Q. Okay. Fair enough. But that there was some problem with a fluid loss at the bottom of the formation; is that correct?

Page 262:06 to 262:12

A. There were losses experienced at

the very bottom of the well.

Q. (BY MR. FLYNN) And that there was a decision made that -- to drill ahead approximately a hundred more feet to allow certainty that they had drilled through the entire reservoir package?

Page 262:14 to 263:01

Q. (BY MR. FLYNN) Is that correct?

MR. KEEGAN: Object to the form.

A. The primary reason to drill further, as Bobby notes in this e-mail, was twofold. One was to actually be able to get the length of the logging tool sufficiently through the reservoir so we could actually evaluate the full sand thickness, and the other one was to be able to run the completion casing string as planned.

Q. (BY MR. FLYNN) Okay. But he had a problem for that last hundred feet, didn't he?

Page 263:06 to 263:19

A. I don't know that Bobby had a problem. He was just describing the technical details, the merits and the decision and the information that needed to be used in the decision of how we could do that.

Q. (BY MR. FLYNN) Well, as I understand it -- and I'll -- we'll take it piece by piece. He's saying we -- and I'm quoting from his sentence about ten lines from the end. He said: We had already experienced static losses with a 14.5 ppg ESD!

What does he mean by that?

Page 263:21 to 264:03

A. He's referring to the static density mud weight at the time that those losses were experienced.

Q. (BY MR. FLYNN) Okay. So what he's describing is the fluid loss that I spoke of occurred with a mud weight of 14.15 ppg without circulating; is that correct?

Page 264:05 to 264:08

A. Downhole static density of 14.5.

Q. (BY MR. FLYNN) Now, essentially that becomes your fracture gradient, doesn't it?

Page 264:10 to 264:10

A. Not necessarily.

Page 264:23 to 265:05

Is that correct? Did I read that right?

A. That's a personal interpretation by Bobby.

Q. Okay. Would you disagree with that based on the information in the preceding sentence?

A. The --

Page 265:07 to 265:16

A. The 14.5 static density only refers to the mud weight for wherever in that particular wellbore that static loss was actually -- that loss was actually occurring.

That doesn't speak at all to the ability to be able to use lost circulation material and stress cage material to actually strengthen that, and then to safely deliver the well the extra hundred feet to create the opportunity to evaluate the well.

Page 266:08 to 266:14

Q. (BY MR. FLYNN) Okay. Well, assuming these -- this information that Mr. Bodek is relating to Mr. Beirne is correct, isn't it true that he has in fact -- or isn't it true that there was not a sufficient margin between the mud weight and the fracture gradient of .5 ppg?

Page 266:16 to 266:25

A. The MMS regulations as they relate to drilling margin are specific to the surface mud weight of an interval relative back to the surface leak-off test of that casing shoe.

My recollection is that the leak-off test value of the previous casing shoe was 5/10ths of a pound per gallon greater than the surface mud weight equivalent to 14.5 static density downhole.

Page 267:03 to 267:07

But the fact that it is experiencing these losses at 14.5 ppg ESD, doesn't that indicate that the previous LOT was no longer the weakest part of the formation?

Page 267:09 to 267:21

A. The leak-off test at the previous casing shoe is only a valid estimate of the leak-off of that 10 feet of formation that was drilled to actually run that test.

Q. (BY MR. FLYNN) Okay. I think I understand what you're saying. But -- and that is different than what he's experiencing now in this last hundred feet.

In other words, he's losing fluid at 14.5 ppg, and what he's telling Mr. Beirne was, he doesn't have -- excuse me: It appeared as if we had minimal, if any, drilling margin?

Page 267:23 to 268:11

A. I don't agree or I -- personally I wouldn't agree with that wording. When I read this, what it refers to is that we know we had a series of sands where the highest pressure that was GeoTap'd was 14.15.

So all he's trying to highlight for the drilling group is that the 14.5 static, we know we have losses at that event. So all it's suggesting to us is that we need to manage the mud weight in that hole section at a lower value to create the ability to safely extend the hundred feet of that well and not experience losses, which is exactly what we did.

Page 268:23 to 269:01

Q. (BY MR. FLYNN) Now, are there ever times when you were performing an LOT and determined that the value it gives you is too high, that it can't be relied upon?

Page 269:03 to 269:19

00269:03 A. The measure at any depth of LOT is just a place in the geologic column where we equate a value to it. It does not necessarily infer that the rock strength from that point forward is equal to, greater or less than that value.
Q. (BY MR. FLYNN) If we'd turn to Tab 10. And this is previously marked as Exhibit 1343. We have an e-mail from Mr. Albertin on which you were copied, and dated April 2nd, 2010.
A. (Witness nods.)
Q. Have you seen this e-mail before?
A. I have.
Q. And what was Mr. Albertin concerned with?

Page 269:21 to 271:14

00269:21 A. Marty's first concern is that the leak-off test value was actually greater than the computed overburden gradient at that depth.
Q. (BY MR. FLYNN) And is that
00270:01 reason to make one skeptical of the LOT?
MR. KEEGAN: Object to the form.
A. There was no indications that the actual shape of the curve was not valid. It was just the fact that the actual number was greater than what we actually predicted predrill.
Q. (BY MR. FLYNN) Can you take a look at -- this is Tab 15 again, Exhibit 555, on March 23rd, 2009 -- actually, excuse me. That was a mistake -- April 5th, 2010. I'm sorry. The daily PPFG report.
MR. KEEGAN: The last couple of pages.
Q. (BY MR. FLYNN) Now, do you see the FIT that is recorded there by Ms. Paine?
A. I do.
Q. And it's given as 15.98 surface ppg?
A. Correct.
Q. Is this the FIT that Mr. Albertin is commenting upon on April 2nd, 2010, in an e-mail, Exhibit 1343?
A. I believe that would be true.
Q. And so the explanation that -- or excuse me -- Mr. Albertin is indicating
00271:01 that this FIT is not indicative, if I'm -- and I'm quoting him -- is not indicative of the true fracture strength of the average

shale that we are about to drill - which I suspect is much lower than this FIT suggests.

A. That is -- that was Marty's interpretation.

Q. And do you agree with that?

A. I do.

Q. You were copied on this, as you recall?

A. (Witness nods.)

Q. Okay. And what was your explanation for that unusually high FIT?

Page 271:16 to 272:09

A. There were a number of explanations of that particular value. One does not expect to see a -- a FIT greater than overburden and a passively relaxed extensional basin like Macondo sits in.

One would see a FIT test like that if one were working in a tectonically compressive regime where you've actually got additive forces to the minimum horizontal stress component. We had no reason to believe, based on the seismic interpretation, that any of that existed at Macondo.

Q. (BY MR. FLYNN) So by this e-mail, Mr. Albertin is informing Brian Morel, the -- one of the drilling engineers, that he should not rely upon -- or the drilling engineers collectively should not rely upon that FIT in planning the drilling of the next section --

Page 272:11 to 272:11

Q. (BY MR. FLYNN) -- is that true?

Page 272:13 to 273:03

A. He is educating Brian that it is the TIGER team's interpretation that that value only represents a potentially small piece of rock, which was measured in that 10 feet of open hole where the leak-off test was taken.

But it would not be the TIGER team's interpretation that you could rely on that level of rock strength as being the lowest value in that interval, and it would increase with depth.

Q. (BY MR. FLYNN) And so what he's effectively cautioning the engineers about is that if they do rely upon it, they may fracture the formation with the fluid further down the hole?

Page 273:05 to 273:22

A. He's only bringing that to the attention in that for each hole section that we drill, we have a managed mud weight schedule that forms the basis of our plan.

And it was his interpretation that the actual leak-off of the rest of the formation in that interval beyond that 10 feet of new hole was going to be a value that was potentially significantly less than that number.

Q. (BY MR. FLYNN) Right. So if we discussed before that the drilling margin should be -- or could be as much as -- as high as .5 ppg below the fracture gradient, what Mr. Albertin is telling Mr. Morel in the e-mail is that, don't allow your mud weight to go up to 15.5 ppg for this next hole section --

Page 273:24 to 273:25

Q. (BY MR. FLYNN) -- is that what -- is that true?

Page 274:02 to 274:10

A. There was no expectation based on the predrill work that was done that the pressure in that next hole section would come close to that particular value.

Q. (BY MR. FLYNN) Okay. So the effect is that it's the TIGER team's recommendation that the 15.98 figure ppg surface should not be used to calculate the drilling margin?

Page 274:12 to 274:20

A. It was us informing and educating our -- our wells team that we did not believe that that 15.98 surface was reflective of any rock other than the 10 feet of open hole that had been drilled to run that leak-off test.

Q. (BY MR. FLYNN) Or it could have been an erroneous test. Isn't that what he also says in here?

Page 274:22 to 275:03

A. I believe the curves were looked at by a number of individuals, and we did not determine that it was an erroneous test.
Q. (BY MR. FLYNN) And how would -- what do you see when you see an erroneous test? In other words, what -- what would you expect to see in the curves?

Page 275:05 to 275:13

A. There are certain diagnostic shapes of curves on leak-off tests that we apply to actually diagnose.
For instance, if there is a potential channel in the cement of the previous casing shoe, if there is air compressibility in the lines, we have a series of curved shapes that we use to determine that.

Page 275:15 to 275:15

there are some attachments to Exhibit 1343.

Page 276:11 to 277:03

Q. (BY MR. FLYNN) Could you just look through those and see if there is a document that reflects the LOT or the FIT that Mr. Albertin is discussing in the e-mail?
A. Only one document that applies to the depth setting of that 9-7/8ths-inch casing.
Q. And which document is that?
A. Actually, the very last document in Tab 10.
Q. And what is that document?
A. That is actually a -- a leak-off test.
Q. And if I'm not mistaken, that leak-off test looks like a straight line, and usually they curve around at the top. Am I wrong?

Page 277:05 to 277:05

A. Not necessarily.

Page 277:07 to 277:18

tell me how you would interpret this particular graph.
A. You were taking a leak-off test of 10 feet of formation that was very strong.
Q. Well, it doesn't -- it doesn't look like it leaked off at all. Am I mistaken?
A. I see no indication that it leaked off.
Q. And why would they have terminated the test if it didn't leak off at all?

Page 277:21 to 277:25

A. -- the value that comes at the point of picking the last point of 1520 psi is actually much greater than the mud weight that was designed to complete the end of that well based on the predrill pore pressure

Page 278:02 to 278:16

Q. (BY MR. FLYNN) I see. So what you're saying is once they hit this point, they figured they could -- they had all the room they needed to drill the next section?
MR. KEEGAN: Objection to form.
A. There is no additional information to be gained in order to be able to deliver the TD section of this wellbore by actually taking the test to any further pressure depth.
Q. (BY MR. FLYNN) What is that horizontal brown -- I think it's a brown line on that right side of that graph?
A. That's just the 10-minute shut-in on the backside of the test.

Page 278:19 to 280:16

A. They actually quit pumping, so they were just monitoring pressure after they quit pumping additional volume.
Q. Now, you were saying before that you could tell from this -- the information provided with this graph -- and maybe I'm overstating it -- that the test was an accurate one. It wasn't an erroneous test, that in fact the shale was as hard as they're -- they're reading?

A. I don't personally see any evidence in this test that, if I were to interpret it, would tell me that this is an erroneous test.

Q. Is -- can I ask what you might look for on this page to suggest, for example, that the number would be different if they were getting a reading off cement, for example?

A. The blue line shown on this particular graph is actually the casing test that was actually performed prior to drilling out the float equipment of the previous casing shoe. So that is the benchmark. So if you are just testing pipe, you will produce the blue line.

Q. Oh, I see. And because it's lower than the blue line, you think it's probably rock?

A. So we know that we exposed 10 feet of formation. The primary reason in this case of why they displace is because we now have a different pressure volume relationship in the wellbore because we now have 10 foot of new hole for whatever the diameter of hole was that we drilled.

Different signatures appear depending on the formation. This, in my opinion, looks like 10 feet of very strong formation.

Q. Okay. Thank you. You were asked a question about the submissions to MMS, the APD and similar submissions, and you explained that the TIGER team did not prepare those applications.

How about the pore pressure fracture gradient graph that is -- or was submitted with many of them --

Page 280:18 to 280:19

Q. (BY MR. FLYNN) -- did the TIGER team prepare the graph?

Page 280:21 to 280:25

A. We did not prepare the actual graph that is part of the APD. The information that is on that graph comes from the plot that we actually provide to the wells group.

Page 281:24 to 282:03

Q. (BY MR. FLYNN) How do you know that was reported to the MMS?

A. All leak-off tests that we conduct are required to be reported to the MMS. The TIGER team does not report to --

Page 282:11 to 282:16

A. It is my understanding there is a regulatory requirement of the MMS that the leak-off test be recorded to them.

Q. (BY MR. FLYNN) How about if multiple leak-off tests are taken on a particular casing shoe?

Page 283:03 to 283:05

A. I don't know what the requirement is if you run multiple leak-off tests.

Page 283:14 to 284:16

Q. Okay. Is there a difference between the RAT and the NDS?

A. There -- it's part of the process. The NDS meeting that is done for each and every well that we drill, the RAT tool comes into that meeting. And we actually look at what are the particular risks that apply to the particular well we're going to drill relative to what's in the RAT tool.

Q. Okay. Is the RAT tool an actual document?

A. It's a spreadsheet.

Q. Okay. And the NDS, the no drilling surprise, is this a meeting document process? How would you describe that?

A. No drilling surprises is part of our BTB process. So it is a requirement that we hold an NDS assessment meeting prior to drilling any well.

Q. Okay. You used one more acronym in there. I just want to make sure I understand. B --

A. BTB.

Q. BTB. What's that stand for?

A. It stands for beyond the best.

Q. Of course. And what does that term mean for a BP employee?

Page 284:18 to 284:20

A. Beyond the best was a branding of a new drilling engagement program that was rolled back in the early 2000s.

Page 284:24 to 285:05

A. It was to implement a standardized process globally across BP by which all wells that are drilled would -- would follow.

Q. (BY MR. FLYNN) And how does that relate to the no-drilling-surprise doctrine?

Page 285:07 to 285:13

A. The beyond the best process is what defined the -- what we call the CVP process in BP, common value process. It ultimately created the stage gate process that we follow. NDS is one of the processes in that document that occurs in the appraise to select stage gate.

Page 285:20 to 286:16

Q. What is CVP?

A. Common value process.

Q. All right. You did say that. What does it mean?

A. It's just a -- it just stands for a -- it's a process that includes the stage gates that -- that we go through.

Q. Okay. And you described some of these stage gates. Tell me what the stage gates are for a -- drilling a new well.

A. You go from appraise to select.

Q. Appraise is the first one?

A. Appraise is the first one.

Q. Second one?

A. Second one is select. Third one is define. Fourth one is execute. Fifth one is operate. And that -- that is the official five that we have.

Q. Okay. Where is this spelled out in? In what document? Is it an OMS document or is it something else?

A. There is actually --

Page 286:18 to 286:18

A. There is a BTB handbook.

Page 286:24 to 289:14

Q. Okay. Now, the -- the NDS, no drilling surprise, is that -- is that simply a -- and I don't mean it's simple -- a philosophy, or is it an actual process, or is it an actual document? What is that?

A. There is a -- a spreadsheet with a series of questions that are asked in that particular spreadsheet. It's called an NDS assessment spreadsheet.

And the intent of that spreadsheet is that based on the answers to the questions in there, there will then be a recommended workflow of subsurface practices that one -- it will suggest things to actually look at.

Q. Okay. Is this NDS assessment spreadsheet prepared before the risk assessment tool spreadsheet?

A. It is because it actually supplies information into the risk assessment spreadsheet.

Q. And then the risk assessment spreadsheet is incorporated, in part, into the risk register?

A. Correct.

Q. And is that process from the NDS assessment to the risk assessment tool to the risk register, is that spelled out in the BTB handbook or elsewhere?

A. The -- the general philosophy of the three steps that you just described are spelled out in the BTB handbook.

Q. But not necessarily in those terms? They --

A. Correct.

Q. Are those terms, NDS assessment, spreadsheet, risk assessment tool spreadsheet, are those spelled out specifically anywhere?

A. NDS is specifically spelled out inside the BTB handbook. The RAT tool is not specifically spelled out.

Q. Which -- now, actually, I think you've already explained that the TIGER team prepares the risk assessment tool spreadsheet?

A. We use the risk assessment spreadsheet to capture the risks that we feel are applicable to the well that we are going to drill such that we can develop work plans to actually mitigate that risk in the planning of the well.

Q. Does the TIGER team have any role in preparing the NDS assessment spreadsheet?

A. We do.

Q. Okay. And what is that role?

A. I actually have an NDS champion in my team, and that person actually facilitates the meeting.

Q. And again, this is a meeting before any drilling takes place?

A. Correct.

Q. Who is that individual?

A. At the time of Macondo it was Paul Johnston.

Page 290:02 to 290:03

Q. My name is Steve Roberts. I represent Transocean. I met you just before

Page 290:20 to 291:20

I want to go back to the 30(b)(6) deposition notice. I think it's before you, No. 21. And I want to ask you in general. I want to go to the section that deals with the BP -- BOP, rather, and determine to what extent BP uses the expected well pressures in the choice of the BOP configuration on drilling vessels. And can you explain that to me.

A. The remit of the TIGER team is to provide a assessment of the pore pressure frac gradient plot for the well to be drilled. At that point any design or understandings of those pressures and how they actually apply to the selection in terms of configurations of BOPs would be handled from the wells team.

Q. Okay. So would I be correct in assuming that the TIGER team, or the former TIGER team that you were in charge of, really has nothing to do with the selection of the drilling rig or the BOP stack configuration of the rig; rather, it simply provides information to others within BOP who take that information and move forward?

A. Yes.

Page 294:03 to 295:01

Q. Okay. Who would you be

reporting to in the highest aspects of your organizational chain?
A. At the time of Macondo?
Q. Let's start with that, yes, sir.
A. At the time of Macondo, initially I reported to the vice president of exploration, which was Dave Rainey.
Q. And to whom did he report?
A. And then David would have reported first through the president of the Gulf of Mexico, which would be Mr. James Dupree. He would have had a dotted line to the exploration president, which would have been Mike Daly at the time.
Q. Now, how is that organizational chain or dotted line or root system or however you want to refer to it?
A. I now report to the vice president of exploration, which is Cindy Yeilding. Cindy Yeilding reports to the Western Hemisphere exploration manager, which is Liz Jolley. Liz Jolley reports to the EVP, Mike Daly.

Page 295:15 to 295:17

Q. Good afternoon, Mr. Vinson. My name is Paul Thibodeaux, and this is my colleague, Mary K. Klinefelter. As

Page 295:25 to 298:17

You mentioned that a PPFG report may not have been prepared upon the day that the final hundred feet of the Macondo well was drilled. And you mentioned that that might have been because the logging tools wouldn't have been able to see into that hundred feet because of the spacing between the BHA and the actual logging tool; is that right?
A. (Witness nods.)
Q. But you said that -- that certain, you know, pore pressure fracture gradient data may have been gathered through mud logging operations, cuttings or gas data. Do I have that right?
A. You do.
Q. If a daily PPFG report was not prepared, would the information that you were referring to about mud logging ops, cuttings and gas data be in the daily geological report?
A. First, I don't know that a PPFG

report on that last hundred feet wasn't constructed.
Q. I want you to assume that it was. We haven't seen one, but just for the purposes of my questions, just assume that it wasn't.
A. Hypothetically if that report had not been generated, then the drilling information, cuttings, gas, that information would have been integrated into the plot that we compare the detection with the prediction by the Marty Albertin.
Even if -- hypothetically if the report had not been generated, Marty would have assimilated that information into the actual plot.
Q. Is that plot reduced to a document?
A. It's a spreadsheet.
Q. It's a spreadsheet.
And is that spreadsheet kept on a realtime basis?
A. It is.
Q. And is that spreadsheet kept in a database at BP?
A. It's actually just an Excel spreadsheet that fits inside our TIGER team folder structure.
Q. Okay. Is it also maintained within well space?
A. I don't know that that plot actually sits in well space.
Q. Okay. And you just mentioned the TIGER team fits in a folder in your TIGER team structure?
A. That's correct.
Q. And what is that folder that you're referring to?
A. On the BP folder system we actually have an amount of disk space that's actually allocated to the TIGER team, 25_ TIGER_team. And underneath there are tabs where we compile all of our work product. So it's the way we actually organize ourselves on a daily basis with respect to digital documents.

Page 299:04 to 300:14

Q. (BY MR. THIBODEAUX) I believe earlier you also referred to the ability to determine the drilling margin for the final hundred feet using a post drill plot. Is that something that we just talked about that would be in the TIGER team folder?

MR. KEEGAN: Objection to form.
A. The post-well PPFG plot for Macondo would exist in that TIGER area that I just referred to.
Q. (BY MR. THIBODEAUX) What is the post-well PPFG report?
A. It is a complete compilation of the pressure indicators gathered during the well, integrated into the predrill prediction for the well. It is the final document that we create at the end of the well which is the beginning for the post-well analysis that we will actually do for each and every well that we drill.
Q. And who prepares that report?
A. The SPA for pore pressure frac gradient prediction for the well.
Q. And who was for the Macondo well?
A. That was Marty Albertin for the Macondo well.
Q. And Marty Albertin did generate a post-well PPFG report for the Macondo well?
A. He did.
Q. And is that maintained as a document or is that maintained as an electronic document?
A. It is maintained primarily as a compilation in that spreadsheet that Marty uses to do that work.

Page 300:19 to 301:11

Q. (BY MR. THIBODEAUX) All right. You talked a little bit today about the 7:30 a.m. daily meetings --
A. Right.
Q. -- as a -- correct me if I'm wrong, but as a primary way for the TIGER team to communicate to the drilling engineers regarding the PPFG data that's being seen as drilling is going forward; is that right?
A. It is the one daily calendared event whereby the entire team can hear all of the information together as a team, both from the office as well as the wellsite leaders on the rig.
Q. Okay. Now, you're aware on April 3rd and 4th there were lost circulation events that occurred on the Macondo well, right?

Page 301:13 to 301:20

A. I am aware there was a lost circulation event.
Q. (BY MR. ROBERTS) Okay. And you're aware that it took them a number of days to get control or to gain circulation in the well before the final hundred feet of the well was drilled on or about April 9; is that right?

Page 301:22 to 301:22

A. I'm aware of that time frame.

Page 302:12 to 302:21

Q. And during that time frame was Mr. Bobby Bodek the ops geologist that was assigned to the Macondo well?
A. He was.
Q. Okay. And he would have been the ops geologist that was in those 7:30 a.m. meetings?
A. He would be in those meetings if he was available, and if not, Jonathan Bellow would be in that meeting.

Page 304:01 to 304:07

Q. (BY MR. THIBODEAUX) All right. You also mentioned that after the 7:30 a.m. daily meetings, it's part of the TIGER team's job to provide the drilling engineers with document support of the information that was provided in those meetings. Do you recall that testimony?

Page 304:09 to 304:16

A. The -- the primary documents reside on well space. The spreadsheet that Marty keeps current with the detection information as it relates to our predrill prediction is available to the wells team when there is a need to actually discuss something pertinent to where that information would actually provide some insight.

Page 305:06 to 306:16

question is: Is -- are all the things that are communicated regarding the PPFG realtime data that's being evaluated communicated to the drilling engineers in the 7:30 a.m. meeting documented as well?

A. The PPFG report and the daily geological operations report, those are discussed between the office and the rig at 7:00 a.m. prior to the general drilling ops meeting at 7:30.

The operations geologist then becomes the spokesperson at that meeting. The 7:30 a.m. call can have up to 35 people in it.

So in order to facilitate a meeting with that many people, my ops geologist then brings in relative to the PPFG as an agenda item on the 7:30 a.m. call, and he brings information in.

It's a consolidation of the wellsite geologist, Kate Paine, the mud logger -- Kate Paine, the PPFG expert, the viewpoints of the Sperry-Sun mud logger, and any viewpoints that Marty Albertin may have for that 24-hour period looking back and the 24-hour period coming forward.

And he brings that into the meeting orally and, if needed, brings it into the meeting in hard copy form.

Q. Okay. And as part of that agenda item for a PPFG reporting during the 7:30 a.m. call, is it the TIGER team's responsibility to communicate to the drilling engineers the pore pressure -- the most recent pore pressures that are being seen in the well?

Page 306:18 to 307:20

A. It is -- it is something that we actually do as part of the agenda item. We update the wells team on what we think has occurred in the past 24 hours and what we think for -- if we're going to drill ahead, what could occur in the drill ahead section.

Q. (BY MR. THIBODEAUX) And that would include pore pressure in the well, correct?

A. That would include pore pressure and --

Q. That would include the frac gradient that you're seeing in the well as you're drilling, correct?

A. You have the predrill frac gradient that is then corroborated against the leak-off test at the previous casing shoe. Any other information relating to frac gradient would be inferred only in the event of a loss circulation event.

Q. But if you have a loss circulation event, and you can identify at what depth -- or you can identify what the mud weight was at the time of that loss circulation event, then you -- the TIGER team communicates that the frac gradient is the pressure at which you were seeing those loss returns, correct?

Page 307:22 to 307:23

Q. (BY MR. THIBODEAUX) Loss circulation. Sorry.

Page 307:25 to 308:10

A. We will communicate based on that loss circulation event what the actual mud densities were as pulsed up.

The other piece of that is that we have to actually know where the loss event occurred such that we can correlate that mud weight to a particular depth in the wellbore.

Q. (BY MR. THIBODEAUX) As Mr. Bodek's supervisor, do you consider him to be a competent operations geologist?

A. I do.

Page 308:16 to 308:20

Q. (BY MR. THIBODEAUX) Okay. Have you -- do you consider Mr. Bodek, though, to be someone that is able to give reliable and accurate information regarding PPFG reporting to the drilling engineers?

Page 308:22 to 309:01

A. I do.

Q. (BY MR. THIBODEAUX) You don't have a problem with his ability to interpret subsurface information and communicate that information to the drilling engineers?

Page 309:03 to 309:05

A. I don't have any -- any questions with Bobby's capability consistent with a person with five years' experience.

Page 309:14 to 310:02

Q. (BY MR. THIBODEAUX) Okay. But my question was: If you weren't comfortable with Mr. Bodek's competency, you would replace him, correct?
A. I don't have any questions as to Bobby's competence. But if I did, he would not be an ops geologist on a well for me.
Q. At any time while Mr. Bodek was working on the Macondo well, did you find that he did not provide accurate information to the drilling engineers regarding pore pressure fracture gradient information encountered in the Macondo production interval?

Page 310:04 to 310:07

A. I never had any communication back to me from the wells organization that Bobby was not actually performing the duties as required of him as an ops geologist.

Page 310:12 to 310:15

I want to talk a little bit about the MMS requirement that a safe drilling margin be maintained. Are you familiar with that concept?

Page 310:17 to 310:21

A. I am -- I am familiar with the term.
Q. (BY MR. THIBODEAUX) And the term is safe drilling margin, correct?
A. Safe drilling margin.

Page 311:03 to 311:21

Q. (BY MR. THIBODEAUX) Okay. All right. What is your understanding of BP's responsibility as an operator to notify the MMS of the safe drilling margin it intends to use in a hole interval?
MR. KEEGAN: Objection to form.
A. In my BP experience, with what we use in terms of drilling margin, we use .5 ppg. So when the surface mud weight -- as long as the surface mud weight is not within .5 ppg relative to the surface leak-off test that is reported to the MMS, then we are

compliant with the term that you just used that's in MMS regs.
My other understanding is that if we need to go inside of that during the drilling phase of a well, then we are allowed an exception to 0.3 ppg during the drilling phase.

Page 312:08 to 312:20

A. I have not read that particular CFR cover to cover. I know the term "safe drilling margin." That's the extent of my knowledge with respect to that CFR.
Q. (BY MR. THIBODEAUX) Okay. It's my understanding that a safe drilling margin can be established by taking an FIT or a leak-off or FIT test, whatever you want to call it, and then providing the MMS with a range of potential mud weights to be used in that interval, and then the MMS may approve or disapprove of that margin as a safe drilling margin. Do you understand that?

Page 312:22 to 313:01

A. I will take your word for it that that's the way the reg is read.
Q. (BY MR. THIBODEAUX) Do you understand that to be a requirement, though, of the MMS?

Page 313:03 to 313:11

A. As I said earlier, I am not -- I am not in the regulatory group. I am a subsurface scientist. I do not get involved in any way, shape or form with any submittals to the MMS. The wells organization has the requirement to be knowledgeable of that and deliver the appropriate paperwork.
Q. (BY MR. THIBODEAUX) Okay. On the Macondo well, who are you referring to?

Page 313:13 to 313:20

A. It would be who actually worked as part of wells team on the wellsite, not subsurface site.
Q. (BY MR. THIBODEAUX) Okay. You're referring to Mr. Morel and Mr. Hafle?
A. I'm referring to the drilling team, which encompassed those two as well

John Guide and Brett Cocales.

Page 314:13 to 315:07

Q. (BY MR. THIBODEAUX) As we've discussed, Exhibit 1343 refers to the final FIT that was performed on the Macondo well, correct?
A. Right.
Q. When was that FIT performed?
A. Oh, I'd have to see the test sheet. I don't recall the exact date. It was at that last casing point.
Q. Okay. It was --
A. April 2.
Q. Okay. The e-mail is from April 2, 2010. Okay. You have it in front of you. And what are you looking at?
A. This is the actual leak-off test for that casing shoe.
Q. Okay. And it sets forth that it was performed on April 2nd, 2010?
A. That's the date listed on the top of this document.

Page 315:17 to 317:05

Q. Who on the BP TIGER team oversees the FIT test as it's being performed?
A. There is not a requirement that anyone from the TIGER team actually oversees the leak-off test. That is a test that is carried out by the crew of the DEEPWATER HORIZON. And the procedures that they actually follow actually come from the wells organization, not the TIGER team.
Q. Okay. So the wells organization or the drilling engineers provide the parameters of the FIT test?
A. It is my understanding that the parameters of the FIT test are actually documented in the well program that actually is sent to the rig prior to drilling the well.
Q. Okay. If we take a look at this e-mail, when Mr. Albertin received the results from the April 2nd FIT test, he informed you that the 16.0 ppg FIT result was not indicative of the true fracture strength of the formation, correct?
A. By "informed," I'm actually CC'ed on that e-mail. I'm not actually in the TO line.

Q. Well, you certainly received the e-mail, correct?
A. I received the e-mail. Whether -- I don't recall if I read that or not. I actually have a personal policy that I don't necessarily respond if I'm CC'ed.
Q. Well, had you read it, then you would see that it says: I think it is safe to say that this test is not indicative of the true fracture strength of the average shale that we're about to drill; is that right?

Page 317:07 to 317:17

A. I agree.
Q. (BY MR. THIBODEAUX) By "fracture strength," that's another way of saying fracture gradient, correct?
A. FIT, LOT, fracture gradient, fracture strength. It's a term that applies equally.
Q. Okay. Earlier I believe you mentioned that you agreed -- or you do agree with Mr. Albertin's assessment in this e-mail of the FIT results, right?

Page 317:19 to 318:04

A. I agree with Marty's interpretation here that that particular FIT was only indicative of the 10 feet of hole that we drilled, new hole to actually perform that FIT, and may or may not be indicative of the foot of rock that we drill in that section.
Q. (BY MR. THIBODEAUX) Well, after you drilled through the whole interval, you knew that the FIT was not indicative of the actual strength of the well, correct?

Page 318:06 to 318:18

A. You had evidence that there was a zone at the very bottom of the well that was actually weaker, and the interpretation in that was that that was actually in sync.
Q. (BY MR. THIBODEAUX) Okay. But my question is: After FIT test results were received, when Mr. Albertin wrote this e-mail, upon subsequent operations on the rig, after two loss circulation events over the course of a couple of days, you then knew

that the fracture strength of the well was no longer -- was in fact not what the FIT indicated, correct?

Page 318:20 to 318:24

A. We experienced losses with a ECD that was less than that value at the previous casing shoe.
Q. (BY MR. THIBODEAUX) So that's a yes?

Page 319:01 to 319:08

A. I'm just saying that we experienced losses at a lower value.
Q. (BY MR. THIBODEAUX) And losses at a lower value indicate that the strength of the formation, because those values were lower than the FIT, were lower -- that the FIT was not an accurate reflection of what the strength of the interval was, correct?

Page 319:10 to 319:20

A. That FIT was an accurate reflection of the 10 feet of hole that was drilled to create it. It was a value that was higher than the strength of the interval at the bottom of the well.
Q. (BY MR. THIBODEAUX) Right. At any point did you notify the MMS that BP did not consider the FIT result in the final production interval to be an accurate indication of the formation fracture gradient?

Page 319:22 to 320:04

A. If there was any reporting done, I wouldn't have been party to it because it would have been done within the wells organization. It's not within the realm of the TIGER team.
Q. (BY MR. THIBODEAUX) So you're not aware of anybody on the TIGER team that would have notified the MMS?

Page 320:06 to 320:12

A. I'm not aware of anyone on the TIGER team that would have done that. We don't actually have the authority in BP to do that. It has to go through the wells organization.

Q. (BY MR. THIBODEAUX) Did anyone in the wells group notify the MMS?

Page 320:14 to 320:17

A. You would have to speak to someone in the wells group. I wouldn't know.

Q. (BY MR. THIBODEAUX) You didn't see any e-mails regarding that?

Page 320:19 to 320:23

A. Normally I would not.

Q. (BY MR. THIBODEAUX) Did you have any conversations with anybody from the wells group about whether or not such an identification should be made?

Page 320:25 to 321:04

A. I did not.

Q. (BY MR. THIBODEAUX) Are you aware of anybody on the TIGER team having conversations with the wells group about that?

Page 321:06 to 321:10

A. About what, the submittal?

Q. (BY MR. THIBODEAUX) About notifying the MMS that the FIT results were, in Mr. Albertin's language, not indicative of the true fracture strength of the formation?

Page 321:13 to 322:02

Q. (BY MR. THIBODEAUX) Not indicative of the true fracture strength of the average shale that we're about to drill?

A. I am not aware that there is actually a requirement to report to the MMS an interpretation of a leak-off test that may be different with the next foot of rock that we drill.

Q. That's not my question, though. It's not whether there is a requirement. I'm asking if anybody did.

Are you aware of anybody having a conversation on whether that should be --

that information should be given to the MMS?
A. I'm not aware --

Page 322:04 to 322:09

A. I'm not aware of anyone on the TIGER team that did.
Q. (BY MR. THIBODEAUX) And are you aware of anybody in the wells group that had a conversation regarding that?
A. I'm not --

Page 322:11 to 322:13

A. -- aware of anyone.
Q. (BY MR. THIBODEAUX) Or anybody within BP as a whole?

Page 322:15 to 322:22

A. I am not aware in general of any conversations that may or may not have been had with the MMS as it pertains to the leak-off test at that casing shoe.
Q. (BY MR. THIBODEAUX) After receiving this e-mail from Mr. Albertin on April 2nd, did you direct anyone at BP to perform another FIT or leak-off test?

Page 322:24 to 323:06

A. I did not direct anyone to perform another leak-off test.
Q. (BY MR. THIBODEAUX) Are you aware of anybody within BP directing anyone to perform another FIT or leak-off test at Macondo?
A. I'm not personally aware of anyone.

Page 323:24 to 324:06

Q. If you don't mind, turn to Tab 5 in your binder, please. I believe Tab 5 is the April 5, 2010, PPFG report?
A. (Witness nods.)
Q. And I believe that was the same report that you looked at earlier that was a part of Exhibit 555, correct?
A. Yes.

Page 324:15 to 326:06

Q. (BY MR. THIBODEAUX) Okay. If we look on the first page, down in the bottom left-hand corner it says: Pressure Analyst Paine.

Does that indicate to you that Kate Paine prepared this April 5th report?

A. That would indicate that to me, yes.

Q. In the pore pressure summary we have various figures given for max pore pressure, surface mud weight, pore pressure bottom hole, ECD, last FIT, ESD minimum and ESD maximum.

Can you explain to me how or whether all of these figures are given in surface weight or downhole weight?

A. The surface mud weight column specifies surface.

Q. Uh-huh.

A. By definition, ECD is equivalent circulating density, so that should contain a downhole circulating density number. And also, by definition, ESD is an equivalent static density. Those terms are measured and pulsed up by the PWD tool.

Q. Okay. And then the FIT specifies surface in the downhole, correct?

A. It does.

Q. The DH represents downhole?

A. Correct.

Q. The PP Bottom hole indicates bottomhole pressure, correct?

A. The PP Bottom hole box has two values which reflect the range of pressure that was actually measured by tools in that well.

Q. Okay. Which would be a 12.5 ppg to a 14.4 ppg, correct?

A. Correct.

Q. So that 14.4 ppg would indicate the highest pore pressure in that open hole interval, correct?

Page 326:08 to 327:08

A. In this case that would refer to, I believe, the shallowest sand where we actually successfully had a GeoTap pressure and actually measured the pressure of that formation.

Q. (BY MR. THIBODEAUX) And then next to that you have the max pore pressure open hole. Why is the max pore pressure open

hole of 14.2 less than the pore pressure bottomhole max of 14.4?
A. Because there's two types of detection that actually go on with the log-based indicators that Kate actually is converting from a particular log attribute to pressure. That actually is reflecting what is known as a shale pressure that may or may not reflect actually that a sand would exist right adjacent to that shale.
00327:01 So in this case, this max PP is likely referring to a shale pressure. In the PP bottomhole she's reflecting the measured pressures that are actually in the sands.
Q. Okay. When a determination is made as to the mud weight that is needed to cover the max pore pressure in the open hole, are you going to use 14.4 or 14.2?

Page 327:10 to 328:10

00327:10 A. The pressure in the shale has to be honored because you actually do not know if you're actually going to drill and encounter a thin sand that might be a shale pressure. So just because you actually measure a pressure that's less than that particular value does not necessarily indicate that the next foot you drill -- you might drill a thin sand encased in a shale, and it may be at the actual higher value, as indicated from the log conversion to pressure.
Q. (BY MR. THIBODEAUX) So this April 5th PPFG report indicates that the mud weight needs to account for the 14.2 ppg max pore pressure; is that right?
00328:01 A. There was -- as I recall, there was a GeoTap taken that actually measured 14.1 ppg in a sand. So we -- at that point you know that there is a mud weight required in that interval regardless of what happens in the pressure interval below to balance that 14.1 ppg.
Q. So is the 14.2, then, giving you a small factor of safety on top of that 14.1 ppg?

Page 328:12 to 329:23

00328:12 A. The 14.2 ppg is a surface mud weight that is -- with compressibility will actually be greater than the pore pressure of the sand that was measured.

Q. Okay. If we take a look at the ECD value, it's listed as 14.13. You have a surface mud weight value between 14.3 and 14.4. The ECD value has to be a typo, correct?
A. That value does not look consistent with -- related to the value of the surface mud weight.
Q. You would expect the ECD value to be higher than 14.13, correct?
00329:01 A. Uh-huh, under normal conditions.
Q. You would expect it to be higher than the surface mud weight of 14.3 or 14.4, right?
A. I would expect it to be.
Q. You would expect it to be potentially higher than the ESD values that are listed, too, correct?
A. The fact that the ECD is less than the ESD for the conditions, this section would be drilled -- would lead me to believe that that's in fact a typo.
Q. Do you know what the -- is the ECU -- isn't the ECD value here also supposed to be -- is also a reflection of the 17,943 depth that's indicated on the ESD?
A. Not necessarily. Normal -- I mean, as you can see here, when she actually relates to a depth, she actually annotates what that actual depth is. I don't know for a fact, based on just looking at this report, what the actual depth reference to that ECD number is.

Page 331:12 to 331:18

00331:12 Q. What you're saying is you'd expect the ECD value at 17,943 feet to be above the 14.71 ppg ESD value at 17,943 feet; is that right?
A. Under normal circumstances you expect the circulating density to be above the static density.

Page 331:25 to 332:05

00331:25 Q. All right. You would expect the
00332:01 ECD value at 14 -- 17,943 feet to be above the ESD value of 14.71 ppg at 17,943 feet; is that right?
A. Under normal drilling circumstances, I would.

Page 332:07 to 334:21

on April 5th were normal drilling circumstances encountered?

A. I don't see any indications in this report that we did actually -- okay. Down on the bottom, so we continued to circulate and lose returns. That would be an event that potentially would create the instance whereby the ECD could potentially be lower.

Q. While you're having a lost return event, you could have an ECD low -- value that would drop below the ESD value?

A. You're losing density to the -- you're losing fluid to the formation. So you're -- you are having a lightening of the hydrostatic head of the wellbore.

Q. Let's take a look at the additional observation section towards the bottom. Second full sentence says: GeoTap at 18,079 TVD 12.58 ppg, which has a corresponding sand FG of 14.4 ppg.

What is a GeoTap?

A. That is the trademark designation of Sperry-Sun's pressure while drilling tool.

Q. Okay. And what is the point of doing a GeoTap?

A. It's actually a direct pressure measurement of the sand interval that you just drilled.

Q. Okay. So does the sentence I just read indicate that a -- that the GeoTap determined that at 18,079 feet, there was a pore pressure of 12.578 ppg?

A. That is correct.

Q. Okay. Then the final part, which has a corresponding sand FG of 14.4 ppg, does FG stand for fracture gradient?

A. That would be a computed value. That is not measured value.

Q. Of fracture gradient?

A. Of fracture gradient.

Q. And by "computed," you mean that's a conversion from the 12.58 ppg pore pressure?

A. We take the 12.5 pore pressure, and we do convert it mathematically to a computation.

Q. And a measured value would be one that you -- would be a fracture gradient that you determine through an FIT?

A. That is one way to get a

measure.

Q. What's another way to get a measure?

A. If you actually experience a loss event, then at that point in the well you have another point of what a particular rock strength is at the depth if you can identify where the loss occurs.

Q. And you would look at the ECD and ESD pressures at that point to determine what that frac gradient is, depending on if the pumps were run or not, correct?

Page 334:23 to 335:14

A. I would -- if I were doing it, I would look at the PWD time log, and I would interrogate the PWD time log to look at exactly what is happening with the ECD and the subsequent ESD.

And then I would make an interpretation at that point as to what was the mud weight at the time the loss event actually occurred.

And then if I can actually identify at what point in the well that occurs, then I can assign a pore pressure to it and make a computation of frac gradient.

Q. Do you know if anyone within BP notified the MMS on or after April 5th that the frac gradient in the production interval was 14.4 ppg?

Page 335:16 to 335:22

A. The 14.4 number you quote was actually a computation.

Q. (BY MR. THIBODEAUX) That wasn't my question, though.

Are you aware of anybody that notified the MMS that the frac gradient in the production interval was 14.4 ppg?

Page 335:24 to 336:06

A. That was your question. I did not say that the frac gradient was 14.4. The 14.4 is a computation. It's not a measure.

Q. (BY MR. THIBODEAUX) I'm asking you, though: Are you aware of anybody at BP -- if anybody at BP notified MMS that the frac gradient was 14.4 in the production interval?

Page 336:08 to 336:17

A. I don't mean to be hard on this one, but I did not say the frac gradient in the interval was 14.4.
Q. (BY MR. THIBODEAUX) And I -- okay. I'm not arguing with you about that.
I'm asking you: Aside from the document you're looking at, do you know if anyone within BP notified the MMS that the frac gradient in the Macondo production interval was 14.4 ppg?

Page 336:19 to 337:25

A. I don't know if any notifications pertaining to the question you raised were made.
Q. (BY MR. THIBODEAUX) Do you know if anyone within BP considered notifying the MMS that the frac gradient in the production interval was 14.4 ppg?
MR. KEEGAN: Objection to form.
A. I would not know that. That would be done from the wells team.
Q. (BY MR. THIBODEAUX) Okay. Let's set that one aside, please, and look at Tab 6. Tab 6 is -- has a Bates number of BP-HZN-MBI00143259 to 461. I believe it's previously been marked. I just don't know the exhibit number.
MR. KEEGAN: Do you want to remark it just to be safe?
MR. THIBODEAUX: Sure, we can do that. Mark it as Exhibit 3065.
(Exhibit 3065 was marked.)
Q. (BY MR. THIBODEAUX) If you don't mind, stick that on there, please.
MR. THIBODEAUX: Let's go off the record for one minute, please.
THE VIDEOGRAPHER: The time is 4:40 p.m. We're off the record.
(Break.)
THE VIDEOGRAPHER: The time is 4:32 p.m. We're back on the record.
Q. (BY MR. THIBODEAUX) Prior to the break I identified a document, Bates

Page 338:07 to 338:15

(Exhibit 3066 was marked.)
Q. (BY MR. THIBODEAUX) Have you seen Exhibit 3066, Mr. Vinson?

A. I have not.
Q. Prior to today were you aware that on April 14th, BP produced a management of change document which set forth that BP was assuming a frac gradient in the Macondo production interval of 14.5 ppg?

Page 338:17 to 338:22

00338:17 A. I was not. First time I've seen this document.
Q. (BY MR. THIBODEAUX) If you'd take a look at the Risk Mitigation section of the document.
A. Okay.

Page 339:05 to 339:22

00339:05 says: Lost circulation during the cement job?
Q. Right.
A. Okay. I see the paragraph after that.
Q. In that paragraph, in the second line towards the end there is a sentence that begins: Since that second event, we have been using a 14.5 arbitrary frac gradient that we are attempting to abide by based on actual circulating conditions. We have put the wellbore under since having losses in fixing them.
Do you see that?
A. I do.
Q. In April 2010 were you aware that -- that BP was attempting to abide by a 14.5 frac gradient?

Page 339:24 to 339:25

00339:24 A. I was not personally aware of that.

Page 340:16 to 340:16

00340:16 an MOC like Exhibit 3066; is that right?

Page 340:18 to 341:02

00340:18 A. I have never been involved in an MOC subsequent to the predrill PPFG production.
Q. (BY MR. THIBODEAUX) Let's take

a look at Tab 7, please. Tab 7 is an application -- Application for Revised Bypass from April 15th, 2010. It has a Bates No. BP-HZN-2179 MDL 0096724 through 731. I'd like to mark it as Exhibit 3067.

(Exhibit 3067 was marked.)

Page 341:10 to 342:01

Q. Is this the type of document that you referred to earlier that you would expect the wells group and drilling engineers to prepare and submit to the MMS?

A. It is -- it is my personal knowledge that this documentation is handled by the wells group in coordination with our regulatory group.

Q. And who is the regulatory group?

A. We have a broad regulatory group. The person that we use for exploration is Scherie Douglas.

Q. Please turn to Page 8. Do you see in the bottom right-hand corner it says Page 7 of 8, Page 8 of 8 and so on?

MR. KEEGAN: Last page?

MR. THIBODEAUX: Yeah, last page.

Page 344:15 to 344:19

Q. Do you see the mud weight, 14.0 ppg?

A. I do.

Q. That was the final mud weight in the production interval at Macondo, right?

Page 344:21 to 345:24

A. Again, I would actually need to look at the final morning report at the TD of the well to actually determine if that was the mud weight that was. I don't recall the detail, if that was or was not the mud weight.

Q. (BY MR. THIBODEAUX) Well, if the morning report reflects that the mud weight was 14.0, then -- then it would have been -- that would accurately reflect what the final mud weight was in the production interval, correct?

A. If the morning report actually reflects a 14.0 surface mud weight, then yes, that would -- that would reflect that TD mud weight.

Q. Do you see where it says fracture gradient ppg 16.0?
A. Uh-huh.
Q. Based on -- back up for a second.
See where it says in the far right column: Pore pressure 13.9?
A. I do.
Q. Okay. Based on previous documents we looked at, including the April 5th PPFG report, the pore pressure in the production interval was higher than 13.9, correct?

Page 346:01 to 346:09

A. When you say "production interval," can you be more specific.
Q. (BY MR. THIBODEAUX) Sure. The final -- the final hole interval.
A. So all formations contained in the open-hole interval between 9-5/8ths-inch casing point?
Q. Correct, where the 7-inch casing is going to be run.

Page 346:11 to 346:24

A. In the final open-hole interval of the well, there were actually measured pressures in a number of sand units, and they were actually all different.
Q. (BY MR. THIBODEAUX) And as we saw in the April 5th PPFG report, there was a 14.2 ppg pressure, correct?
A. There was a -- my recollection is there was a measured 14.15 rounded up, there was a 13.0, and there was a 12.58 rounded up to 12.6.
Q. Why would this Application for Revised Bypass have 13.9 pore pressure and not have 14.15?

Page 347:01 to 347:08

A. Since I don't actually prepare the document, I can't answer who actually got that number and how that number was actually placed at the APD.
Q. (BY MR. THIBODEAUX) Well, you would expect that the pore pressure that's reported to be the highest pore pressure in that well interval or hole interval, right?

Page 347:10 to 347:19

A. I don't know that because I'm not -- I'm not involved in the preparation of the Application for Revised Bypass.
Q. (BY MR. THIBODEAUX) All right. In the -- in the column to the left, there is fracture gradient ppg 16.0. Do you see that?
A. I do.
Q. The fracture gradient in the final hole interval of Macondo was not 16.0, correct?

Page 347:21 to 348:11

A. The -- there was a value of a leak-off test at the 9-5/8ths-inch casing shoe, so that was a point of reference in the well. And then there was a loss event at TD specific to that event, of which we have a measure of what the mud weight was at the time there were losses that occurred.
Q. (BY MR. THIBODEAUX) And it was less than 16.0?
A. That loss of TD -- that rock was less strong than what existed at the casing shoe at the 9-5/8ths.
Q. So -- but the fracture gradient of an entire hole interval would be the lowest fracture gradient within that interval, right?

Page 348:13 to 348:15

A. Again, the fracture gradient changes inch by inch, foot by foot as we drill.

Page 348:17 to 349:11

A. So I'm only aware of two points of reference in that final hole section, a leak-off test at the 9-5/8ths and then a loss event at TD. Any assessment of frac gradient in between would be a computation based on an assessment of the ongoing pore pressure at the time.
Q. When determining mud weights and whether or not BP is maintaining a .5 ppg drilling margin, the lowest known fracture gradient within that hole interval is what's evaluated, correct?
MR. KEEGAN: Objection to form. There

was a loss event that indicates at the bottom of the well there was a value -- I believe we said it was documented at 14.5. That was less than the leak-off test of the shoe.
Q. (BY MR. THIBODEAUX) So that's the fracture gradient that you would use, correct?

Page 349:14 to 349:17

A. For what purpose?
Q. (BY MR. THIBODEAUX) In setting what the fracture gradient is for that hole interval.

Page 349:19 to 350:07

A. Not necessarily. That -- that fracture gradient just references a point in depth at the well. So it's just a point in reference in a particular depth.
Q. (BY MR. THIBODEAUX) But it's a point of reference that tells you that the -- that at that depth, you have a potential for fracturing the formation?
A. It sets a limit for what mud weight you would want to have in the hole at the time that would not actually open those fractures back up and create losses.
Q. Correct. It controls that mud weight, correct?

Page 350:09 to 350:12

A. It is a control point.
Q. (BY MR. THIBODEAUX) It sets a high bound for what that mud weight can be, correct?

Page 350:14 to 350:19

A. I'll agree with that.
Q. (BY MR. THIBODEAUX) When you have a fracture gradient of 14.5 and a hole interval, a previous FIT result of 16.0 is no longer relevant with respect to setting your mud weight, right?

Page 350:21 to 351:09

A. If I'm drilling the well, if it's a known loss event that sets at 14.5 at any point in that open hole section, then that has now created for me a different reference point in terms of what mud weight I need to use in the well in order to not actually have it go to a point where it once again opens up those fractures and creates losses.

Q. (BY MR. THIBODEAUX) Right. You're going to set your mud weight based on that 14.5 fracture gradient as opposed to any previous fracture gradient of 16.0 you might have seen, right?

Page 351:11 to 351:16

A. If I'm drilling the well, I'm going to choose a mud weight that doesn't create another loss event.

Q. (BY MR. THIBODEAUX) And to do that, you would honor the 14.5 fracture gradient that you are aware of, right?

Page 351:18 to 352:01

A. The 14.5 fracture gradient becomes an upper limit of mud weight such that you don't actually initiate another loss event into that same interval.

Q. Why would BP report on April 15th to the MMS that the fracture gradient is 16.0 when it knew that a fracture gradient -- that there was a lower fracture gradient in the well of 14.5?

Page 352:03 to 352:07

A. You would need to actually question the particular parties of the wells group that actually submitted the information that actually goes into this revised bypass NPD.

Page 352:15 to 352:18

Q. (BY MR. THIBODEAUX) I think you mentioned a little while ago that 16.0 value was the April 2nd FIT result that you agree with Mr. Albertin was erroneous, correct?

Page 352:20 to 353:03

A. I don't -- I'd have to refer

back to that leak-off test. I don't recall if it was exactly 16.0, but it -- it's in the range of what that high value was.
And I don't agree that it was an erroneous value. It was a measure of a rock at a certain depth. I didn't see anything that that test -- that told me it was erroneous.

Page 353:09 to 353:20

A. I do not agree -- if the word "erroneous" was used in that e-mail, I do not agree that it was an erroneous value.
Q. Okay. Well, what do you think the value was?
A. It was a -- it was a very high leak-off test taken in an interval of rock that appears to be abnormally strong for that depth.
Q. And it's not indicative of the fracture gradient in the remaining parts of that interval, right?

Page 353:22 to 354:18

A. It was our interpretation at the time that the next footage that we actually drilled in that well, that in fact we would interpret that the particular rock strength would be less than that value.
Q. And that was proven to be true when you ran into loss circulation events fracture gradients that were less than 16.0, right?
A. If you go through the mathematics of computing frac gradient in sands versus shales, you will always compute a frac of sand that is less than a shale. The leak-off test that was performed at the 9-5/8ths-inch casing shoe was measured in a shale.
So there would be no surprise that if you encounter a series of sands in the next hundred feet from the casing shoe, they would in fact have a fracture gradient that was calculated to be less than the leak-off test.

Page 355:04 to 355:17

My question is: After you had loss circulation events, you could then see that you had frac gradient -- you had a fracture gradient within the well that was lower than the 16.0 FIT result, correct?

A. You had one sand at TD of the well that was apparently weaker than the high-value leak-off test alluded to by Marty Albertin in his e-mail.

Q. Which confirmed what Mr. Albertin said in his e-mail, which was that the 16.0 ppg FIT was not indicative of the fracture strength of the hole interval, right?

Page 355:23 to 357:12

A. I wouldn't agree with the exact wording. Marty's words in that e-mail were not pertaining to a frac gradient relative to any sands that exist in the well. We know sand frac gradient is less than shale frac gradient.

There is a simple Poisson's ratio explanation for that. He was referring to the fact that the shale frac gradient as measured was abnormally high. And his expectation was that any subsequent shale frac gradient in that wellbore was going to be less than that actual leak-off test value that was measured.

He was -- I don't interpret in his e-mail that he was even addressing the issue related to sands. We know that to be the case.

Q. (BY MR. THIBODEAUX) With respect to Exhibit 3067, the Application for Revised Bypass, with the information that's contained in the column that we were just looking at, general information, including the hole size, mud weight, fracture gradient of 16.0, is that all information that you would expect to be provided to the MMS by the drilling engineers on Macondo?

A. It is -- it's my understanding that this form that is actually submitted to the MMS by definition requires BP input.

Q. And you would expect the drilling engineers to provide that input as it relates to the fracture gradient pore pressure mud weight, correct?

A. Since my team is not -- I'm not aware that my team was consulted to actually populate this particular Application for Revised Bypass, then I would expect that this was provided by the -- by the drilling engineers in the wells team for Macondo.

Page 358:08 to 358:12

Q. (BY MR. THIBODEAUX) Well, stated differently, if BP cannot maintain a safe drilling margin as it's drilling forward, then it must suspend operations, correct?

Page 358:14 to 358:18

A. If you get to a point in the well where you interpret that relative to your known frac gradient in the mud weight you need, then essentially you are at another decision for a casing point.

Page 359:02 to 359:24

Q. Well, earlier today you testified and made a distinction, I think, between reporting requirements regarding the .5 ppg in saying that it's relative to the FIT test. In this case, for example -- is that right?
MR. KEEGAN: Objection to form.
A. Within BP, the numbers that I work to is that we start with .5 ppg as our drilling -- as our drilling margin. And we then have the ability to get a dispensation from the MMS. If it -- if we feel like we have to go in the drilling phase, go inside .5 ppg, then we can take that to .3 ppg.
If at that point there is a requirement in terms of maintaining the wellbore inside of that for drilling purposes, then that is a casing point in the well. We cannot actually drill any further.
Q. (BY MR. THIBODEAUX) So it's BP's policy to suspend drilling if you're going to go within .3 ppg of the frac gradient --

Page 360:01 to 360:02

Q. (BY MR. THIBODEAUX) -- relative to the mud weight?

Page 360:04 to 360:07

A. If the -- if the actual mud weight required relative to the leak-off test of the prior casing shoe goes inside a .3, then that is a casing point.

Page 360:18 to 361:14

The reporting requirement in terms of the safe drilling margin, my understanding of it, as is spelled out by the MMS CFR, is that safe drilling margin is related to surface mud weight and surface LOT.

It does not have language that designates if you find a rock in your wellbore that is weaker than your leak-off test, then there is a requirement to readjust safe drilling margin based on that. I don't know what that -- if that requirement actually exists in the regs.

Q. (BY MR. THIBODEAUX) Okay. With respect to BP's own policies as you outlined them a few minutes ago with respect to .5 and .3 drilling margins, does BP have a policy that if the known frac gradient, if it's less than the FIT, is within .5 ppg of the actual mud weight being used, does BP have a requirement to then suspend operations and notify MMS?

Page 361:16 to 361:18

A. I don't actually know if there is a BP requirement at that point to actually suspend and notify the MMS.

Page 362:19 to 363:03

Q. (BY MR. THIBODEAUX) I'm just asking you about the FIT. Under your understanding of what -- as you stated, what you think the BP policy is regarding a .5 ppg drilling margin -- and you've said repeatedly that relates to the FIT -- in this case, in the final hole interval, that reporting requirement would not have arisen unless the mud weight would have gone to or above 15.5 ppg; is that right?

Page 363:05 to 363:24

A. If there had not been a loss event at TD of the well, then the .5 PPFG that we are referencing would have been relative to that, as indicated there, the

approximately 16-pound-per-gallon leak-off test.
Q. So there was a loss event. And how did that change things?
A. There was a loss event. And in some of the previous documents that we actually referred to, you will see documentation that actually talks to us actually lowering the ROP, reducing the ECD to stay below the actual mud weight of interval that create the loss event.
Q. Now, under BP policy, if that drilling margin was going to get within .5 ppg of the known frac gradient than the mud weight being used, would BP suspend operations and notify the MMS?

Page 364:01 to 364:02

A. If you -- again, there's the .5 and then dispensation to .3.

Page 364:12 to 364:16

Q. But it is your understanding that if you're going to go less than .3 ppg for your drilling margin, then that is a casing point at which you would suspend operations; is that right?

Page 364:18 to 364:20

A. That is a stopping of that particular drilling section, and there is -- it's not going to go any further than that.

Page 365:21 to 365:24

Q. (BY MR. THIBODEAUX) Is there an MMS regulation requiring a driller to maintain a certain margin between the pore pressure and the mud weight?

Page 366:01 to 366:04

A. I'm not knowledgeable with what that reg is.
Q. (BY MR. THIBODEAUX) But you think there is a reg?

Page 366:06 to 366:09

A. There is a regulation that actually specifies safe drilling margin. I have not actually read that regulation cover to cover.

Page 366:17 to 367:16

Q. (BY MR. THIBODEAUX) It could be DWOP. It could be any policy that you're aware of in BP.
A. When drilling a well, one maintains a balance between what is the actual pore pressure of the well and what is an assessment of the fracture gradient. And we maintain a mud weight that is in between the two.
Q. Certainly. But is there a certain mud weight margin over the actual pore pressure so that you provide -- maybe the purpose would be to provide a factor of safety over that pore pressure?
A. I do not know the BP policy. I could only speak to in practice, based on my experience, what is actually done.
Q. Okay. Well, what is your experience and practice?
A. It's at least 1/10th of a pound per gallon, and in many cases, .2.
Q. Now, is there any policy in BP to suspend operations if that .1 or .2 ppg margin cannot be maintained over the pore pressure?

Page 367:18 to 367:22

A. I'm not aware of any policy that specifically relates to that.
Q. (BY MR. THIBODEAUX) Are you aware of the DWOP policy regarding maintaining a 25-barrel kick tolerance?

Page 367:24 to 368:03

A. No. The parts of DWOP that I'm familiar with actually relate to the requirements in these documents, GP-10, -15 and -16. That is my -- that is the extent of my knowledge on DWOP.

Page 368:11 to 370:01

Q. (BY MR. THIBODEAUX) We talked a little bit about the 14.15 ppg water-bearing

sand in the Macondo well that you've referenced a couple of times?
A. I don't recall what the interpretation of the fluid content of that sand is. I remember there was an upper sand that was --
Q. Okay.
A. -- 14.15 ppg.
Q. Okay. Do you remember if any determination was made by the TIGER team as to whether that sand was permeable?
A. The fact that we were actually able to measure a pressure in that sand would speak to that sand having some level of permeability.
Q. Is the TIGER team's job to determine if a sand is permeable or not?
A. It is not.
Q. Who within BP makes that determination?
A. That would be the petrophysicist on the project.
Q. So for Macondo, that's Galina?
A. That's Galina.
Q. And Galina is not part of TIGER team?
A. She is not.
Q. What section -- or where does she fall under? Is she part of the drilling engineer group?
A. She is part of the subsurface geology and geophysics team, the team that actually develops the prospect.
Q. Who does she report to?
A. At the time she was reporting to a gentleman by the name of Rob Satter.
Q. What's his title?
A. He is exploration manager of the Central Gulf of Mexico.

Page 370:05 to 370:07

Are you familiar with a BP process of analyzing trainwreck early warning indicators?

Page 370:10 to 370:19

A. I actually helped develop it.
Q. (BY MR. THIBODEAUX) What is a trainwreck early warning indicator?
A. Trainwreck is a very poor slang term in hindsight. It is a process by which we try and identify wells in the global BP

portfolio that actually need more expertise that may not exist actually in the particular team that's actually moving that well forward.

Page 371:10 to 371:10

(Exhibit 3068 was marked.)

Page 371:13 to 372:10

indicator analysis to -- what is the -- what is the intent of a trainwreck early warning indicator?
A. If you look at the columns listed across the top, we had identified a series of topics that could potentially create a new challenge for a particular wells team.
So, for example, are you going to drill through rocks that you don't have an analog well that you previously penetrated? Is it a new rig? Is there a new technology required to be employed to drill the well? What is the complexity? You know, has -- does the team actually have the time and space to actually adequately prepare the plan for the well? It's an assessment tool.
Q. It's a risk assessment tool; is that right?
A. It's a very, very high-level risk assessment tool.
Q. Was a trainwreck early warning analysis done on the Macondo well?

Page 372:12 to 373:13

A. Macondo was not drilling through new rocks nor using a new rig nor having a new team, did not require new technology, was not drilling for multiple targets, was not outside complexity we had previously drilled, and we had the space to actually plan and deliver the well. So technically, it's not part of this analysis.
Q. (BY MR. THIBODEAUX) You're certain such an analysis was not provided on Macondo?
A. You are actually looking at the level of detail of the analysis that would form the assessment of a trainwreck indicator.
Q. Got you.

A. We just did it.
Q. Who would have been responsible for doing a trainwreck analysis on the Macondo well if it was done?
A. This -- this particular version of an assessment tool is actually maintained in the wells organization and is actually maintained at a very high level in the wells organization. At the time of Macondo, this would have actually sat in Barbara Yilmaz's direct leadership team.