Deposition Testimony of:

David Trocquet

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Page 7:16 to 7:17

Q. Please state your name for the record.
A. David James Trocquet.

Page 9:21 to 11:25

Q. What is your -- I guess let's take a step back. Who is your current employer?
A. The Department of Interior, BOEM -- MRE.
Q. Former MMS, correct?
A. Former MMS.
Q. And what is your current position with the -- that Department?
A. I'm the District Manager of -- of one of the District -- five District Offices in the Gulf of Mexico, the New Orleans District.
Q. Okay. And how long have you held that position?
A. Since December of -- of '08, so coming up three years.
Q. Okay. And how long have you been with former MMS, now BOEMRE?
A. Since January 1988.
Q. Okay. What positions? I'm not going to ask you to go through and describe your duties and responsibilities of each, but if you can just let me know what your -- your position was when you were first hired and obviously up through the time you were hired as District Manager in the current position.
A. I started off in an intensive training program over the -- over a two-year period. It was called the PETRO Program, Training of Young Engineers.
After that two-year training, I was moved into a more permanent position in the Plans Unit in the Office of Field Operations in -- in our Regional office, Gulf of Mexico Region.
I was one of three or four Engineers in that Group, reviewing oil spill plans, plans of exploration, plans of development.
From there, after about five years, I applied for a Workover Engineering position in the New Orleans District, and I was selected for that position. I think that was 1995. So I've been in the New Orleans District office since 1995.
I was in that position approximately five to six years when myself and the -- the -- the person who was the current Drilling Engineer -- Drilling Engineer at that time, we -- we swapped positions by -- by everyone's mutual agreement.
Q. So then you became the Drilling Engineer?
A. Yes.

Q. Okay. How long did you hold that position?
A. I've been in the districts from -- from '95, so 16 years. I think it was about five years as the Workover Engineer, three years District Manager, that's eight, so, say, eight years as -- as Drilling Engineer.

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Q. Okay. And what's your highest level of education you've obtained in the field of Engineering?
A. A Bachelor's of Science in Petroleum Engineering.

Page 13:09 to 14:13

Q. Okay. And, obviously, experiencewise, did you work anywhere out in the industry of any capacity before you joined MMS?
A. Yes, I did.
Q. Where?
A. I worked for Chevron.
Q. Okay. How long?
A. Four years.
Q. And in what position?
A. In two different positions: Two years as a Production Engineer, which is similar to a Workover Engineer, and two years as a Drilling Engineer.
Q. Okay. And when you became District -- the District Manager of the New Orleans District, what -- what were your duties and responsibilities and have they changed at all through the present?
A. They -- they haven't changed. My -- my duties and responsibilities are -- are overseeing all the activities of the District: The -- the Engineering side, the -- the -- the Workover Section, the -- the Drilling issues, as well as Production issues, which are more of facility-related issues --
Q. Okay.
A. -- Safety Systems on production facilities, as well as the -- the Inspection Program, both for drilling workover rigs, as -- as well as production platforms.

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Now take a step back. The MC 252 Well was within the New Orleans District, correct?

A. Yes.

Page 17:18 to 17:23

Q. Okay. So with respect to MC 252, when the original APD was submitted by BP back in 2009, the spring of 2009, that's when your office would have been involved in evaluating that and approving or denying the APD?
A. That's correct.

Page 18:03 to 19:16

Q. Okay. Were you, yourself, personally involved at -- at all in the evaluation and analysis, approval, or disapproval of any of the submissions of BP with respect to MC 252, that you're aware of as you sit here today?
A. Yes.
Q. Okay. What do you recall that your involvement was?
A. The -- the involvement that I recall is -- is for a -- for a request for an extension of BOP tests.
Q. And that was in March of 2010, correct?
A. I believe so --
Q. Okay.
A. -- yes.
Q. And what -- what was your involvement?
A. The -- the Drilling Engineer, Frank Patton, approached me on a -- on a request from BP -- I believe it was an E-mail request -- for a BOP test extension. We -- we had a discussion, and -- and I advised Frank to advise BP that we would not give an extension, that they needed to test the BOPs within the 14-day required time period.
Q. Okay. And then what happened after that?
A. I guess upon Frank notifying BP, BP submitted an E-mail to me and asked me to reconsider based on more information that they provided about the -- the state of the well and stability of the well.
Q. And for reference, sir, as we're discussing this today, I know you're basically going upon your -- your recall. If you look at Tab 9 and Tab 10 of your notebook I provided you today. I'll refer you to Tab 9. It's a document that's previously marked as 4055. That would appear to be the denial by Mr. Patton of BP's request to not test the BOP within that 14-day window, correct?

Page 19:18 to 21:15

A. (Reviewing document.)
No, I don't think it is.
Q. (By Mr. Petosa) What -- what is the document, then?
A. (Reviewing document.)
Q. And -- and I'll refer you, sir, to Tab 10, too, because Tab 10 appears to be the E-mail you're discussing, which has previously been marked as 4056. If you can read them in concert, it might help.
A. (Reviewing documents.)
Okay. Yeah. I have never seen the -- I guess, the followup application for permit to modify with Frank's return approval comments.
Q. Okay.
A. The reason why I said "no" is it seems as though I recalled it was either a conversation or an E-mail from BP to Frank, which -- which I do see they did send an E-mail, and he did deny the departure, or the -- the extension request for the BOP test via E-mail prior to, I guess, getting this application --
Q. Okay.
A. -- so I wouldn't -- I didn't even know that this -- that this application -- this isn't an application just for the BOP test extension. It's an application for the temporary -- I guess for the -- for the plug-back, and -- and in so -- and in such, I guess they were asking -- they -- they really don't -- they really don't ask for a BOP extension in here that I can tell.
I think Frank was just reiterating what he said in his E-mail, that, you know, assuming you're testing BOPs when you're proposing in Step 21, I -- I think he's saying if that's over 14 days, then it's going to be denied, need to test. You need to test on the 14-day cycle, which would have been sometime before setting the cement plugs.
Q. Okay. And then what was it, sir, about the original conversation with Mr. Patton that caused you to advise him to deny the request for the departure from the BOP 14-day test?
A. As -- as I recall, he was -- he had told me that the well was stable, so --
Q. They --
A. -- based on the well being stable, I had -- I had said that it's safe to test BOPs.

Page 22:24 to 24:05

Q. What's the purpose of the 14-day test of the BOP?

A. Just to ensure that the BOPs are -- are in -- are in good working order.

Q. Okay. And what -- what's the 14-day test do? What does it test in the BOP itself?

A. It tests the -- the -- the choke and kill valves. It tests all the -- the main BOP components, the -- the annular preventer, the ram -- the blind shear rams, the pipe rams, as well as the -- the choke manifold on the surface.

Q. And what's it testing with respect to the -- to the rams and -- that you just described?

A. It's testing its ability to -- to hold pressure.

Q. Okay. And what's the -- what's the relevance of holding pressure in the BOP to -- to the bottomhole conditions in the well?

A. I mean, the relevance of it holding pressure is -- is if there's a kick and if the BOPs are needed to be used to -- to close the well in, to minimize the influx of the -- of the reservoir fluid, because of the reservoir fluid coming into the hole, they'll be -- it will displace some of the heavyweight mud. So as a result, they'll be pressure underneath those BOPs that they'll have to seal and hold.

Q. And is the Operator required to accurately identify the pressure, maximum pressures available on the rams within the BOP when they submit APBs or any subsequent ARBs?

Page 24:07 to 24:07

A. Yes, there -- they are.

Page 24:15 to 24:17

Q. What's the significant, if any, sir, of the Operator accurately identifying the maximum pressure available to the rams within the BOP?

Page 24:19 to 25:06

A. Well, the -- the -- the available rating of the BOP is -- is such that -- that the BOPs need to be able to be -- to withstand any pressure that they may see, they may have to close against. So the rams need to be rated greater than the maximum pressure they may be expected to hold.

So the Operator does submit the -- the rating of the -- of the BOP stack in all -- and all Permits.

Q. (By Mr. Petosa) And -- and your District Office would rely upon the Operator to submit that information accurately, correct, sir?

Page 25:08 to 25:08

A. Yes. We would.

Page 25:16 to 26:12

Q. On this first topic we're discussing, sir, that you've been produced as a designee for today, the evaluation, analysis, approval, or disapproval of any submission from BP related to MC 252, apart from your involvement that we've discussed on or around March 10th of 2010 regarding the 14-day BOP test, did you have any other involvement in that area; that is, the evaluation, analysis, approval, or disapproval of any submission from BP regarding this well?

A. Yes.

Q. Could you describe that for me, please.

A. It was -- it was during post -- post-blowout response operations.

Q. And for purposes of today's designation, I'd like to ask first about anything prior to the blowout. Apart from the March 10th, 2010 in -- involvement we just discussed, do you have any other involvement in any submissions by BP regarding this well up and through the blowout that began on April 10th of -- 20th of 2010?

A. Not to my recollection.

Page 29:04 to 30:07

Q. Okay. Sir, I'd like to refer you to Tab 49 within your binder, a document that was marked as Exhibit 5335. This is an E-mail between the different Representatives of BP dated April 15th of 2010, five days before the blowout occurred, regarding notes from a Port Arthur spill Presentation by -- it appears BP Shipping, regarding a spill that occurred around the Port Arthur area. And I'd like to refer you to, specifically, sir, the fourth sentence in that first paragraph that says: "Some key points that I felt were important from his presentation were his expectations of the Responsible Party..."

And this is from Earnest Bush, who is with BP as the Crisis and Continuity Management Advisor. And I'd like to go down, sir, under "Expectations of an RP" to the third bullet, "It's the RP's Spill, The USCG" -- the United

States Coast Guard -- "enters a response with the idea that they are there to assist the RP" -- the Responsible Party -- "unless you give them the impression that you're incompetent, then they will take over."

In your involvement in the source control matters that you indicated as a Technical Consultant, reviewing submissions, was it your understanding, throughout that process that, number one, BP was the Responsible Party for this spill?

Page 30:09 to 30:14

A. Yes, it was.

Q. (By Mr. Petosa) Okay. And was it also your understanding that the role of the United States Coast Guard and MMS, and now BOEMRE, their role was there to assist BP in the source control efforts --

Page 30:16 to 30:17

Q. (By Mr. Petosa) -- until the well was killed?

Page 30:19 to 31:06

A. I don't know that.

Q. (By Mr. Petosa) Okay. And why is that?

A. The -- the only direction I was given was to -- was to be present, observe and -- and gather information.

Q. And would you report that information back to anyone?

A. Yes.

Q. Who was that you would report it back to?

A. That would be the -- the MMS Representatives and the Unified Area Command, or -- or it would be to whoever I was reporting to wherever I was at the time.

Page 36:01 to 36:13

Q. Okay. Well, what's the difference between a -- I guess a long string production casing design, and one that would also include a liner, a liner tieback?

A. A -- a long string production casing design would be a -- a -- a -- a string of casing or pipe run from the bottom of the well to the wellhead, all in one -- in -- in -- in one segment, or in one operation, in one stage.

Whereas, a liner would be a subset of that casing string, and it would be run to bottom, hung into a previous liner or full casing string, and then it may or may not be tied back.

Page 37:12 to 37:16

Q. Okay. You -- you're aware, obviously, that -- that wells are run both ways; that is, there's the long string casing design, and -- and those wells that also use the liner tieback feature, correct?

Page 37:18 to 38:01

A. Yes.
Q. (By Mr. Petosa) Okay. And you -- your -- your Department has approved, obviously, both?
A. Yes.
Q. Okay. All right. And you're not able, though, to tell me if there's any added extra safety features or well control features that a liner tieback would provide over a long string casing design?

Page 38:03 to 38:03

A. No, I'm not.

Page 39:22 to 40:13

Sir, I'd like to switch topics now and talk a little bit about the Federal Regulations and if you can explain some things to me as we go through and discuss some of the Regulations.
Specifically, sir, I'd like to talk about Section 250.213, what general information must accompany the EP. That's the Exploration Plan. Now, is that something that normally goes through your office, or is that something that goes through -- I think you described earlier, was it the Regional Office?
A. That -- that's correct. The -- the -- the EP would go through the Regional Office.
Q. Okay. Is it your understanding that when the Regional Office receives an EP from an Operator, that that EP must also indicate and provide information regarding a blowout scenario?

Page 40:19 to 42:10

A. (Reviewing document.) I -- I don't work

with the Exploration Pan -- Plan, so -- so I'm not -- I'm not acutely aware of -- of -- of all the requirements in those plans.
Q. (By Mr. Petosa) The bottom line is, sir, you would agree that you would expect an Operator to comply with the Federal Regulations as it -- as it applies to any submission, whether it be an Exploration Plan, an APD, or an ARB, correct?
A. I -- I would say "Correct," but -- but I'm not sure what -- what an ARB is.
Q. Application For Revised Bypass.
A. Okay. We -- we -- we -- we call them a -- I think, an R -- RBP, a Revised Bypass, but, yes, I would.
Q. Okay. Including an RBP, you would expect the Operator, in their submissions, to provide accurate information and, in doing so, comply with the Regulations, correct?
A. Yes, sir.
Q. And if for some reason the information you're provided is a departure from the Regulations, you would expect that Operator to specifically seek a departure from the Regulations in those submissions, correct?
A. Ye -- yes, I would.
Q. Sir, I'd like to talk to you about Section 250.401, and I'll read it to you. It's -- it's brief. It's regarding Section (a) -- "What must I do to keep wells under control?" -- follows and says: "You must take necessary precautions to keep wells under control at all times. You must: Use the best available and safest drilling technology to monitor and evaluate well conditions and to minimize the potential for the well to flow or kick."
I've highlighted Section (a) for you, sir. What -- what does that mean, that the Operator must utilize "the best available and safest drilling technology to monitor and evaluate well conditions and minimize the potential for the well to flow or kick"?

Page 42:22 to 42:23

Q. (By Mr. Petosa) Sir, what does "best available and safest drilling technology mean"?

Page 42:25 to 43:01

A. In -- in my opinion, it means what it -- exactly what it says.

Page 43:06 to 43:11

Q. Would you expect that when an Operator is managing and attempting to control the well and are -- are drilling and going through the process, that in doing so, that they are utilizing the best available and safest technology?

Page 43:13 to 44:18

A. Yes, I would.
Q. (By Mr. Petosa) Is there any significance to that? I mean, why would you expect them to do that?
A. As a prudent Op -- Operator, there's an interest in -- in minimize the -- the potential for an incident, a pollution event, a Safety event, on a -- on a rig.
Q. And bottom line, it's -- it's -- it's safety for the environment and for the -- the public at large, correct?
A. I would say "Yes."
Q. Okay. I'd like to talk to you, sir, about Section 250.413: "What must my description of well drilling design criteria address?" And it lists under that, (a) through (i), a number of different topics that the -- I believe the Operator must provide?
A. (Reviewing document.) Yes, that's correct.
Q. And with respect to Section 250.413, when the Operator provides in -- information in a submission to MMS, would you expect the Operator to provide that information accurately?
A. Yes.
Q. Truthfully?
A. Yes.
Q. And -- and -- and in doing so, submit that information as -- as required by the Regulations, in Compliance with the Regulations and API?

Page 44:20 to 44:22

A. In Compliance with the Regulations, but -- but I don't think I -- I understand what you mean by "and also API."

Page 45:09 to 45:14

Q. Does your Office consider aspects of information and Specifications and matters like that before -- by API, when you're evaluating submissions by Operators?

A. We -- we do for the Regulations that -- that incorporate API documents.

Page 45:18 to 46:07

Q. Okay. Sir, I'd like to talk to you about Section 250.416, and it's: "What must I include in the diverter and BOP descriptions?"

It lists a number of information. I'd like to specifically talk with you about (e). Indicates that the Operator should provide "Independent third party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe in the hole under maximum anticipated surface pressure. The documentation must include test results and calculations of shearing capacity of all pipe to be used in the well including correction for MASP."

Page 47:04 to 47:11

A. (Reviewing document.)
Q. (By Mr. Petosa) Now, sir, you -- you would expect that the Operator would provide accurate information about the shearing capabilities of the casing -- of the blind shear rams within the BOP when they make any submissions to MMS or now, in this case, BOEMRE, correct?

Page 47:13 to 47:14

A. Ye -- yes. As of -- as of the date of that requirement, yes.

Page 47:24 to 49:14

Q. Do you know if your Engineers, as they were evaluating submissions by Operators prior to April 20th of 2010, would review the submissions to determine if, in fact, the Operator has provided information about the BOP and, specifically, the blind shear rams' ability to cut the drill pipe in downhole conditions -- with respect to downhole conditions?
A. If -- if that information was included, they -- I'm -- I'm sure they would review that.
Q. Okay. And -- and would you agree that if that information was in -- included by an Operator, you would expect that Operator to provide that information accurately?

A. Yes.
Q. Truthfully?
A. Yes.
Q. Okay. Sir, I'd like to talk to you about Section 250.421: "What are the casing and cementing requirements by type of casing string?" And specifically Section (e), current as of September 13th, 2011.
And at the bottom, it lists a -- a date of February 20th, 2003. Section (e), "Production." "Casing requirements." "Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions."
And it goes on to the right, "Cementing requirements." "Use enough cement to cover or isolate all hydrocarbon-bearing zones above the shoe. As a minimum, you must cement the annular space at least 500 feet above the casing shoe and 500 feet above the uppermost hydrocarbon-bearing zone."
I'll invite you to review that. I have a couple of questions, sir.
A. (Reviewing document.) Okay.
Q. Was that a Regulation in effect prior to April 20th of 2010, sir, that specific section?
A. Yes, I believe it was.

Page 50:13 to 50:20

Q. Okay. If the Operator identifies a top of cement in either their APD or in their submission, say, for Temporary Abandonment, would you expect, in identifying top of cement, that the Operator is doing so in Compliance with the Regulation that that top of cement is 500 feet above the uppermost hydrocarbon-bearing zone?
A. Yes.

Page 51:02 to 51:20

Q. (By Mr. Petosa) Okay. I'd like to talk to you, sir, about 250.427: "What are the requirements for pressure integrity tests?" -- current as of September 13th, 2011, with a date at the bottom of February 20th, 2003. You can review it.
A. (Reviewing document.) Okay.
Q. Why -- why are Operators required to conduct pressure integrity tests, sir?
A. To my knowledge, that's a -- that's a -- a pertinent piece of -- of -- of the well design as to how far they can drill to the next casing point.

Q. And does it have anything also to do, sir, with whether or not there is appropriate casing integrity with respect to the specific tract of casing before they move onto the next lower level of casing, when they conduct the pressure integrity test?

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A. Yes, I -- I -- I would agree. In -- in performing the pressure integrity tests, there -- there's a confirmation that -- that the cemented -- the prior cemented casing or liner, that the cement did isolate the -- the upper zones from -- from any pressure they may see in drilling ahead.
Q. (By Mr. Petosa) And -- and what's the significance of that, if any?
A. The significance is if -- if they do drill ahead into higher pressure and -- and -- and that higher pressure is subject to a -- a shallower formation, there could be an underground flow from that higher pressure to that -- that -- that shallower, weaker formation.
Q. Okay. And, sir, would you expect that that Operator, in -- in providing information to MMS, would provide information about the pressure integrity tests that are done on that casing tract would do so accurately?
A. Yes.
Q. And truthfully?
A. Yes.
Q. And if there was going to potentially be any departure from the Regs, that they specifically identify that information and seek a departure from MMS, now BOEMRE?

Page 52:25 to 52:25

A. Yes.

Page 53:10 to 53:23

Q. If an Operator intends on temporarily abandon a regu -- a -- a -- a well, are they required to get approval from BOEMRE?
A. Yes, they are.
Q. Prior to April 20th of 2010, that approval was supposed to come from MMS, correct?
A. Yes, that's correct.
Q. Okay. And would you agree if there's any subsequent revisions to that Temporary Abandonment Plan, that before the Operator goes

forward with that procedure for Temporary Abandonment, they need to get approval for those revisions or departures from the Plan that's been approved by MMS?

Page 53:25 to 55:02

A. I -- I would agree if the revisions are material, they would need to get approval.
Q. (By Mr. Petosa) Okay. And who -- who decides if those revisions are material or not?
A. If -- if the -- the District Engineer is consulted, it would be his judgment, as well as anyone he -- he may consult with, as to whether a revision is needed, if it's a very minor revision or if it's something that he feels should be documented.
Q. But if, in fact, that Operator intends to change in any capacity the Temporary Abandonment Procedure that's been approved by MMS, prior to April 20th of 2010, would you expect that Operator to at least submit that new procedure to the District Office that applies to that well, for the District Office to determine if, in fact, there needs to be any additional approvals or changes to the original Plan that was approved?
A. Yes, I -- I -- I would either expect that they would submit it or they would at -- at least consult with the Engineer by E-mail, by phone.
Q. You -- you would agree there should be some communication by the Operator about any potential change that they may be intending to go forward with from the original Temporary Abandonment Plan that's been approved by MMS prior to April 20th of 2010, correct?

Page 55:04 to 55:04

A. Yes.

Page 60:08 to 62:07

Q. (By Mr. Keegan) If you would turn to the last page of the -- the -- to the Deposition Notice that I marked there for you, one of the topics is No. 7: "The well design plans for all deepwater wells approved by the BOEM from April 20, 2005 through the present that utilized a long string production casing design."
Mr. Trocquet, other than this information that's contained in this chart in the September 20th, 2011 E-mail, what can you tell me about the well design plans for the deepwater

wells approved by the BOEM from April 20th, 2005 until today?
A. I can tell you that those well design plans are submitted via applications for Permit to Drill, to sidetrack, to bypass, that we review those plans in those Permits.
Q. Can you tell me the number of deepwater wells approved by the BOEM utilizing a long string production casing design that have burst disks?
A. No, I can't.
Q. Can you tell me the number of deepwater wells approved by the BOEM from April 2 -- 20, 2005 the -- through the present that utilized a long string production casing design that set the final casing production in sand versus shale?
A. No, I cannot.
Q. Can you tell me the number of well design plans for deepwater wells approved by the BOEM from April 20th, 2005 to the present that utilized a long string production casing design where the production casing was run prior to Temporary Abandonment?
A. Possibly.
Q. How many of the well design plans for all deepwater wells approved by the BOEM from April 20, 2005 through the present that utilized a long string production casing design included running the production casing prior to Temporary Abandonment?
A. That -- that E-mail may give some -- some indication. I -- I don't have those numbers on the top of my head.
Q. And do you have a copy of that?
MR. FLYNN: Chris, I've given him one.
MR. KEEGAN: Great. I'm going to mark that as Exhibit 5347.
(Exhibit No. 5347 marked.)

Page 62:18 to 63:15

Q. How many of the wells that we are discussing using a production casing, a long string production casing, are you aware of where the production casing was run prior to Temporary Abandonment of the well?
A. If these -- if these numbers are accurate, 100.
Q. And which ones are you identifying as the 100 where the production casing was run prior to Temporary Abandonment of the well?
A. The -- the row that -- that indicates "Casing with no liner top depth."
Q. And what is it about the indication of

"Casing with no liner top depth" tells you that that was casing run prior to Temporary Abandonment?

A. The -- the fact that it did not have a liner top depth in our eWell System to me indicates that it's a -- a full casing string, and the fact that it's in our eWell Drilling Permit System indicates to me that it was run before the well was temporarily abandoned or completed.

Page 63:22 to 64:04

Q. What is different about the four approved after April 20, 2010 than the 100 that were approved after April 1st, 2005?

A. The -- the four that were approved after April 20, 2010 may be a subset of the -- of the 100, or they may not. I'm not sure if the first column was run from 4/1/05 to 4/19/2010 or from 4/1/05 to September 20, 2011.

Page 64:07 to 66:15

Mr. Trocquet, have you ever heard of the "M57B sands"?

A. I -- I may have, but I -- I -- I couldn't say definitively that I have.

Q. What do you recall hearing about the M57B sands?

A. Dur -- during my time at the -- at the Response Command Center at BP's office, in my position as -- as observer with MMS, I do recall -- recall seeing a well schematic with some -- some -- some sands in the last hole section of the Macondo Well, of which the M57 -- was it B sand?

Q. Yes.

A. -- may -- may have been one of those. I can't say for sure.

Other than that, that's my only knowledge of that sand. I don't have any particular specific knowledge of -- of -- of that sand versus any other sands that may have been on that schematic.

Q. I know way too much about the M57B sand.

Can you tell me when your time at the Response Command Center was? What -- what was that time frame?

A. It -- it was various times. It -- it would have spanned from -- from -- from probably two weeks after the -- the incident occurred through whenever we closed the office, which may have been in September, August or September, I --

I don't know that date. And that would be on and off.

Q. You say you saw a well schematic with -- with sands, and potentially including the M57B sands. Do you recall any discussions in that time frame about whether that was a hydrocarbon-bearing zone?

A. No, I don't.

Q. Okay. Do you recall any discussions at any point about a hydrocarbon-bearing zone in the production interval of the MC 252 No. 1 Well that was identified after the incident?

A. Versus prior to the incident?

Q. Correct.

A. No, I -- no, I don't.

Q. Do you recall any discussions in the Summer of 2010 trying to determine where the M -- whether the M57B sand was, in fact, a hydrocarbon-bearing zone?

A. No, I don't.

Q. All right. Any discussions in the Summer of 2010 determining that the M57B sand was not a hydrocarbon-bearing zone?

A. No.

Q. Your New Orleans District Office approved all of the Applications for Permits to Drill that BP submitted related to the MC 252 No. 1 Well, correct?

A. Yes.

Page 70:09 to 70:24

Q. Your office received, reviewed, and accepted all of the Weekly Activity Reports related to the MC 252 No. 1 Well, correct?

A. You said "received" and "accepted"?

Q. Yes. Received, reviewed, and accepted.

A. For -- for -- for some of the -- of the Weekly Activity Reports, yes.

Q. Which Week Activity Reports were received, reviewed, and accepted?

A. To my knowledge, the ones from the beginning of the operation through the week of the blowout. Not through the week a -- through the week prior to the blowout.

Q. Inspectors from the MMS visited the MC 252 No. 1 Well on four different occasions, correct?

Page 71:01 to 71:09

A. I -- I don't know.

Q. (By Mr. Keegan) You're aware that MMS Inspectors visited the MARIANAS on the MC 252

No. 1 Well in November of 2009?
A. No, I'm not.
Q. Are you aware that MMS Inspectors visited the DEEPWATER HORIZON as it drilled the -- the MC 252 No. 1 Well on three different occasions?
A. Yes.

Page 71:18 to 72:03

Q. Has anybody informed you of issues of noncompliance related to the MC 252 No. 1 Well?
A. Is -- is this prior to the blowout?
Q. Yes.
A. No.
Q. Mr. Trocquet, have you ever made the determination that your office should not have approved the application submitted by BP?
A. The -- the application to -- to drill?
Q. All of the applications submitted prior to the blowout on April 20th, 2010.

Page 72:06 to 72:10

Q. (By Mr. Keegan) Sure. Have you at any time made the determination that your office should not have approved the applications submitted by BP prior to the blowout on April 20th, 2010?

Page 72:13 to 72:18

A. No.
Q. (By Mr. Keegan) Have you ever made the determination that your office should not have approved the two End of Well Reports that were submitted by BP prior to the blowout on April 20th, 2010?

Page 72:21 to 72:23

A. Assuming that they are approved, no. We definitely had not made a determination that they should not have been approved.

Page 73:23 to 74:03

Q. (By Mr. Keegan) Sure. Have you ever made the determination that the MMS Inspectors failed to properly inspect the records onboard the DEEPWATER HORIZON as required by MMS Regulations when they visited that rig while it drilled the MC 252 No. 1 Well?

Page 74:05 to 74:10

A. No, I haven't.
Q. (By Mr. Keegan) Have you ever made a determination that your Inspectors should have issued an issue of noncompliance or a warning related to drilling activities onboard the -- that related to the MC 252 No. 1 Well.

Page 74:13 to 74:18

A. No, I haven't.
Q. (By Mr. Keegan) As of April 19th, 2010, there was no determination by the MMS that BP, Transocean, Halliburton, Sperry-Sun, or any of the other contractors on the MC 252 No. 1 Well violated MMS Regulations, correct?

Page 74:22 to 75:05

A. Correct. To my knowledge, that's correct.
Q. (By Mr. Keegan) And as of the date of that the MMS Representatives testified before the Marine Board of Inquiry in May of 2010, there was no determination by the MMS that BP, Transocean, Halliburton, Sperry-Sun, or any of the other contractors on the MC 252 No. 1 Well violated MMS Regulations, correct?

Page 75:09 to 75:09

A. To my knowledge, correct.

Page 76:16 to 76:22

Q. As of September 10 two -- sorry -- as of September 2010, when BP issued its Internal Investigation Report, there was no determination by the BOEMRE at that time that BP, Transocean, Halliburton, Sperry-Sun, or any of the other contractors on the MC 252 No. 1 Well violated MMS Regulations, correct?

Page 76:24 to 77:06

A. To my knowledge, correct.
Q. (By Mr. Keegan) As of November 2010, when the National Commission on the oil spill issued its full Report, there was no determination by the BOEMRE that BP, Transocean, Halliburton,

Sperry-Sun, or any of the other contractors on the MC 252 No. 1 Well violated MMS Regulations, correct?

Page 77:09 to 77:14

A. To my knowledge, correct.

Q. (By Mr. Keegan) As of February 2011, when the Chief Counsel's Report was issued, there was no determination by the MMS of any Regulatory violations related to the MC 252 No. 1 Well, correct?

Page 77:17 to 77:21

A. To my knowledge, correct.

Q. (By Mr. Keegan) And as you sit here today, the BOEMRE has still not issued any violations of applicable Regulations related to the MC 252 No. 1 Well, correct?

Page 77:24 to 79:13

A. To my knowledge, correct.

Q. (By Mr. Keegan) I want to talk to you about your role during the incident. You said you were a Technical Advisor to the MMS leadership. Can you tell me what that entailed?

A. In -- in -- in different locations, I would observe operations, review operations, well, and discuss the operations that were being proposed with -- with the upper -- upper Management of MMS at the Command Cent -- at the Unified Area Command.

Q. And the Unified Area Command was in Roberts -- Robert?

A. It -- it -- it was at Robert at one point.

Q. And then where was it?

A. It was in New Orleans before Robert; then it was Robert; then it was back in New Orleans.

Q. How much time would you spend at BP's offices in Houston?

A. Several times -- several -- several days at a time. Possibly, if I had to estimate, maybe 40 to 50 day -- 40 days.

Q. Around 40 days, from April 20th until September 2010?

A. Yes.

Q. And who would you interact with at BP during this time as you're Technical Advisor to the MMS?

A. Various people. I don't know that I have a recollection of -- of everyone that I -- that I coordinated with or that I had interaction with.

Q. Can you remember any -- any people?

A. Yes.

Q. And who are they?

A. Charles Taylor, Doug -- Doug Chester.

Q. Okay.

A. James Dupree, Andy Inglis, Richard Lynch. There's some people whose names escape me. That's all I can rel -- recall at this time.

Page 85:13 to 85:18

Q. In order to educate yourself on the substance of participation in the evaluation, analysis, approval, or disapproval of the submissions from BP related to the MC 252 No. 1 Well, what exactly did you do?

A. Nothing.

Page 92:15 to 92:19

Q. (By Mr. Keegan) Did you ever visit the DEEPWATER HORIZON?

A. Not that I can recall.

Q. Did you visit any of Transocean's rigs?

A. Yes.

Page 94:22 to 95:17

Lost circulation events are common in deepwater drilling; is that right?

A. I would say yes.

Q. A lost circulation event occurs because the equivalent circulating density, or ECD, of the mud is greater than the strength of the formation, correct?

A. I -- I don't know if that -- it -- I don't know if that's correct or not.

Q. What is your understanding of why a lost circulation event occurs?

A. The -- the pressure in the wellbore is greater than the pressure in the open hole, and -- and the fluid enters the formation.

Q. "Pressure in the open hole," what do you mean by that?

A. The -- the pore pressure of the -- of the sands or shale in the open hole.

Q. So if the pressure exerted by the hydrostatic column is greater than the pore pressure, you lose returns?

Page 95:19 to 95:20

A. I would say in a sand, yes, in a permeable formation, yes.

Page 96:04 to 96:20

Q. (By Mr. Keegan) Sure. For well control purposes, you want the pressure in the wellbore to be greater than the pore pressure, correct?
A. Yes.
Q. So you want to have heavier mud exerting more pressure in the wellbore than the pore pressure in the formation, right?
A. Yes.
Q. And -- and you don't lose returns when that happens, right?
A. You -- you could.
Q. You have to exceed the fracture gradient of the formation to lose returns, right?
A. I -- I don't know that to be correct.
Q. It's your understanding that -- that you can lose returns simply by exceeding the pore pressure of the formation?

Page 96:22 to 96:22

A. I -- I believe that to be true, yes.

Page 98:01 to 98:10

Q. (By Mr. Keegan) And -- and I'll ask you in your personal status. What are your understandings of the safe drilling margins?
A. That there's a margin of the -- the mud weight being greater than the -- the pore pressure.
Q. Okay.
A. Then there's a safe margin of the -- the -- the fracture gradient of the last exposed shoe versus the -- the mud weight.

Page 98:13 to 100:02

Q. Okay. Is the mud weight -- the drilling margin where you're talking about the mud weight being greater than the pore pressure, is that the kick tolerance?
A. I -- I guess -- I guess you can say so, yes.
Q. Okay. And the mud weight of the fracture gradient, the last exposed shoe, that's the regulatory safe drilling margin?
A. I think the regulations have two safe

drilling margins. I think that's one of them.
Q. And are those the two drilling margins that we just discussed?
A. Yes.
Q. And one of them is the mud weight has to be greater than the pore pressure?
A. Yes.
Q. And the other one is that the mud weight has to be a -- a certain amount less than the fracture gradient, as measured at the last exposed shoe?
A. Say that last one again.
Q. Right. The second safe drilling margin in the regulations is that the mud weight has to be a certain amount less than the fracture gradient as measured at the last exposed shoe?
A. Yes.
Q. Okay. Do Operators have to stop drilling when they encounter a lost circulation zone, or a loss zone?
A. I -- I don't know if the regulations specifically require that, but -- but I would expect, yes.
Q. Fair enough. But there's nothing in the regulations that say you have to stop drilling if you encounter a loss?
A. There's -- there's something in the regulations that say if you encounter losses, you need to adjust your casing setting depths, based on those losses.

Page 103:20 to 103:24

Q. (By Mr. Keegan) Fair enough. Fair enough. But just to be clear, MMS, at the time of the incident, did not require the Operator to stop drilling once it identified a loss zone, right?

Page 104:05 to 104:13

A. I mean, I think there would be an expectation that -- that the losses would be tended to and that drilling ahead would not occur.
Q. (By Mr. Keegan) Fair enough. But there is no regulation that requires the Operator to stop drilling when it encounters a loss zone, correct?
A. I don't know.

Page 107:16 to 107:20

Q. You'll agree with me that are there are Regulations requiring an Operator to cement 500 feet above the top identified hydrocarbon-bearing zone?
A. Yes.

Page 108:10 to 108:13

Q. (By Mr. Keegan) What do you consider a hydrocarbon-bearing zone to be?
A. I -- I consider it to be a -- a permeable sand containing movable hydrocarbon.

Page 109:15 to 109:16

Q. If a zone is more than 50 percent water, is that a hydrocarbon-bearing zone?

Page 109:18 to 110:22

A. In my opinion, it could be.
Q. (By Mr. Keegan) What else would you need to know?
A. If -- if that hydrocarbon could move -- flow.
Q. And that's based on permeability and porosity?
A. Yes.
Q. Is there a minimum thickness for it to be a hydrocarbon-bearing zone?
A. Not to my knowledge.
Q. Are there any Guidelines, Regulations, or Policies that identify a minimum thickness for -- to determine whether a zone is a hydrocarbon-bearing zone?
A. For -- for the -- for the purpose of determining a producible well, yes, there is.
Q. And what is that minimum thickness?
A. I -- I don't recall. It's either 10 or 15 feet.
Q. What about for the purpose of determining top of cement, is there any -- a similar definition of a hydrocarbon-bearing zone?
A. No.
Q. You've spent a good chunk of your career interpreting Regulations, correct?
A. I would say yes.
Q. And -- and assisting Operators in -- in understanding those Regulations?
A. Yes, to the best of my understanding.

Page 111:19 to 112:03

Q. Can you take a look at Tab 46, which is a document that has previously been marked as Exhibit 4031. The entire document was marked as one exhibit. It's IMS020-011185 to 11237.
Mr. Trocquet, if I could get you to turn to the document Bates numbered IMS020-011217.
A. Okay.
Q. What is that document?
A. That's a Standard Operating Procedure for the -- the Well Activity Report.

Page 112:07 to 113:02

Q. What is that document?
A. That's a Standard Operating Procedure for -- for the End of Operation Report.
Q. And are these Standard Operating Procedures that are pro -- provided to Operators to assist them in -- in submitting reports?
A. Not to my knowledge.
Q. Are these internal MMS documents that assist the Inspectors or the Drilling Engineers in -- in evaluating eWell submissions?
A. Yes, I -- I would agree that that's what they are.
Q. Okay. If you would turn to Page 6 of 11 of that document -- first -- well, first before we turn, your name is on the front of that?
A. Yes.
Q. Identified as somebody that prepared -- assisted in preparing or prepared that document?
A. Yes.
Q. And it's dated June of 2008?
A. Yes.

Page 113:06 to 113:19

Q. And in the middle of Paragraph 8, there's a -- a line -- and tell me if I read this correctly -- "'Hydrocarbon bearing interval' data field is where the operators identify all producible hydrocarbon zones. These hydrocarbon bearing zone(s) are identified regardless whether the zone(s) will be produced or not. Any hydrocarbon bearing interval with ten feet or greater of pay must be identified on the End of Operation Report."
Did I read that correctly?
A. Yes.
Q. That's a pretty clear definition of a hydrocarbon-bearing interval, correct?

Page 113:21 to 114:15

A. (Reviewing document.)
Yes.
Q. (By Mr. Keegan) Okay. Is there a comparable definition of hydrocarbon-bearing zone related to top of cement?
A. Not to my knowledge.
Q. Okay. And where is an Operator required to identify top of cement? Which -- which filing?
A. I would say in the Weekly Activity Report.
Q. Okay. And so if we were to look through the Standard Operating Procedure for Weekly Activity Reports, do you know whether there's any definition of hydrocarbon-bearing zone in that instruction booklet?
A. No, I do not.
Q. Are you aware of any MMS guidance related to identifying hydrocarbon-bearing zones in a well?

Page 114:17 to 115:03

A. Non -- none other than the -- the requirement for a producible -- producible well, as -- as well as, I guess, recalling or -- recalling that it's in the Weekly -- the End of Operations Report also.
Q. (By Mr. Keegan) And the requirement for hydrocarbon interval in a producible well is a zone that's 10 feet or larger, correct?
A. It's -- as I said before, it's -- it's either 10 or 15 feet. I don't --
Q. It's in --
A. -- it's in the Regulations.

Page 115:25 to 117:03

Q. (By Mr. Keegan) Are you aware of any Regulation, Guideline, or Policy that would require an Operator to identify a 2-foot zone as a potential hydrocarbon-bearing zone?
A. I'm not aware of any -- any written Policy.
Q. It's up to the Operator to identify -- an Operator and its contractors to identify hydrocarbon-bearing zones, correct?
A. It's -- it's required by the Operator that they -- they isolate hydrocarbon-bearing zones. So, yeah, I would assume they would need to op -- identify them to be able to isolate them.
Q. But the MMS does not have specific

criteria for identifying hydrocarbon-bearing zones or not?
A. No.
Q. And there's a -- a degree of engineering judgment involved in identifying hydrocarbon-bearing zones, correct?
A. I would agree.
Q. At a certain point a porosity may mean that -- that it's not a hydrocarbon-bearing zone, a low porosity?
A. I don't know if I could agree with that.
Q. Why not?
A. Because any -- anything other than a zero porosity could contain hydrocarbon.

Page 118:12 to 119:04

Q. Turn to Tab 29, please.
A. (Complying.)
Q. Are you familiar with -- sorry, 30 CFR Section 250.428?
A. Yes.
Q. And this is the CFR section titled "What must I do in certain cementing and casing situations?"
A. Yes.
Q. Other than this Section 428, at the time of the incident, were there any other BOEM Regulations that governed the adequateness of cement jobs or adequacy of cement jobs?
A. (Reviewing document.) I don't know.
Q. As you sit here today, you're not aware of any BOEM Policy, Procedure, Guideline, or Requirement regarding cement jobs other than 250428 -- .428?

Page 119:06 to 119:07

A. Not -- not pertaining to different scenarios that may come up while cementing.

Page 120:04 to 120:14

Q. And 250.428 says: "If you...Have indication of inadequate cement job (such as lost returns, cement channeling, or failure of equipment)," "Then you..." should: "Pressure test the casing shoe...Run a temperature survey...Run a cement bond log; or...Use a combination of" those "techniques."
A. (Nodding.)
Q. What is the purpose of running a pressure test, a temperature survey, a Cement Bond Log, or

a combination of those techniques?

Page 120:19 to 121:17

MR. KEEGAN: Ah, did I say "you should"? "Must," "then you must ...," sorry, "Then you must ..."

Q. (By Mr. Keegan) What's the purpose of -- of running those tests?

A. I -- I -- I can't say for sure because I was not involved in -- in formulating those Regulations, but -- but I make the presumption that the tests were -- the tests are to determine if -- if you did place your cement where you intended to.

Q. To see if you have cement where you want it?

A. Yes.

Q. Okay. What guidance is there for pressure testing the casing shoe?

A. None that I'm aware of.

Q. Okay. And does pressure testing the casing shoe tell you that you have cement -- where you have cement in the annulus?

A. It -- it will not tell you where your top of cement is. It -- it should indicate whether you have adequate cement in the near vicinity of your casing shoe.

Page 123:15 to 123:20

Q. What Guidance, Policy, Procedure, or Manual is there related to running a temperature survey if you have an in -- indication of inadequate cement job?

A. None, other than the -- the option of running one.

Page 124:03 to 124:20

Q. Any Guidelines, Policies, Procedures, or Manuals related to when you run a temperature log when you have indications of inadequate cement?

A. No. No, not to my knowledge.

Q. Any Guidelines for when you run a Cement Bond Log if you have indications of inadequate cement job?

A. No.

Q. Any Guidelines as to which of these three techniques or -- or a combination of these three techniques should be used in any indication when you have indicators of a -- any situation when you have indicators of an inadequate cement job?

A. No.
Q. Okay. And if you don't have indicators of an inadequate cement job, you don't have to do any of these, correct?
A. Correct.

Page 125:05 to 125:11

Q. (By Mr. Keegan) Let's go back to the C -- CBLs, the Cement Bond Logs. When should you run a CBL?
A. You -- you -- you could run a CBL if you have, as it says here, you -- account of the situation where you have "...lost returns, cement channeling, or failure of equipment."

Page 125:22 to 126:06

Q. (By Mr. Keegan) What Policies, Procedures, Guidelines, or Regulations are there related to when you run a Cement Bond Log?
A. I'm -- I'm -- I -- I don't -- I don't -- I don't know of any.
Q. And what kind of information can you get from a Cement Bond Log? Can you get the top of cement?
A. From my understanding, yes.
Q. Can you get the quality of cement?

Page 126:08 to 127:01

A. You know, from -- from my knowledge, although it -- it's subjective, yes.
Q. (By Mr. Keegan) And can you get a quality of zonal isolation?
A. Again, from my understanding, it's open to interpretation, but, yes.
Q. And what's the basis of your understanding? Have you ever interpreted a Cement Bond Log before?
A. No.
Q. Have you ever run a Cement Bond Log?
A. No.
Q. Have you ever talked to anybody who ran a Cement Bond Log?
A. I may have corresponded with -- with people who ran Cement Bond Logs via E-mail or -- or read reports from someone who ran a Cement Bond Log, but I don't recall having specific discussions with -- with anyone.

Page 127:03 to 127:08

A. -- who has run a Cement Bond Log.
Q. Are there any MMS or BOMER -- BOEMRE Regulations, Guidelines, Policies, Procedures discussing what information a Cement Bond Log can provide?
A. No.

Page 128:14 to 128:17

Q. Is there any MMS Guideline, Policy, Procedure related to determining whether there's cement channeling?
A. Not to my knowledge.

Page 131:12 to 132:01

Q. Okay. It's your testimony today that the pressure testing identified in 428 is one that requires you to drill through the cement and do the integrity test?
A. Yes.
Q. Is this pressure test the casing shoe defined in any MMS Guideline, Policy, Procedure, or Manual?
A. (Reviewing document.) I mean, other -- other than its -- its reference in 427, I -- I -- I don't think there's any guidance on it.
Q. And where is it referencing 427?
A. "The District Manager may require you to run a pressure-integrity test at the conductor shoe if warranted..."

Page 133:03 to 134:20

Q. Shoe test, casing shoe test, and pressure integrity test are all the same things to you?
A. Yes.
Q. Okay. Why would you drill through your cement to test to see if it was any good?
A. You're -- you're testing -- you're -- you're testing the cement outside the casing, not the cement inside the casing.
Now, this, in my mind, would be applicable for drilling ahead, not for production casing.
Q. Doesn't the positive pressure test test the cement in the -- at the shoe?
A. In my mind, the -- the -- the need for the test at the shoe is to determine if cement was adequately placed behind the casing because of the lost returns. So you would need to drill out the shoe to expose the seal behind the casing shoe. That's -- that's what I -- that's what

you're testing. That's the re -- that's the --
that's the purpose of -- of requiring to
determine some type of determination of where --
where your top of cement is.
00134:01 Q. So if you thought you had bad cement, you
would drill through it to see if that cement was
good?
A. Not drill through it. You'd drill
through the center of the well to be able to get
to -- to test whether you have good cement behind
pipe or not.
Q. Gotcha. The MMS approved each of the
APDs and revised APDs submitted for the Macondo
Well, correct?
A. Yes, I would say so.
Q. And the MMS had authority to reject any
APD that was submitted, correct?
A. Yes.
Q. If a given piece of information was
missing from one of the Macondo Well submissions,
either that piece of information was not required
by the applicable regulation, or the MMS failed
to do its job in properly evaluating the
submissions before them --

Page 134:23 to 134:24

00134:23 Q. (By Mr. Keegan) -- before approving them,
correct?

Page 135:01 to 135:05

00135:01 A. I'm -- I -- I don't know.
Q. (By Mr. Keegan) If the regulations
require information about the blind shear rams,
and that information wasn't in the APD, should it
have been approved?

Page 135:07 to 135:23

00135:07 A. I don't know.
Q. (By Mr. Keegan) Take a look at Tab 19,
please.
A. (Complying.)
Q. Do you know what Maximum Anticipated
Surface Pressure is?
A. Okay. I'm sorry?
Q. Do you know what Maximum Anticipated
Surface Pressure is?
A. Yes.
Q. Do you agree with me that Maximum
Anticipated Surface Pressures are the pressures
that you reasonably expect to be exerted?

A. Yes.
Q. And that is a reasonableness determination of what you are actually going to see in the well and at the wellhead, correct?

Page 136:01 to 136:04

A. I would say yes.
Q. (By Mr. Keegan) That's not the most conservative approach to calculating Maximum Anticipated Surface Pressure, correct?

Page 136:06 to 136:12

A. No, it's not.
Q. (By Mr. Keegan) In particular, if you assumed pure gas filling the entire wellbore from the bottom of the hole all the way to the surface, that would not be reasonable if you're drilling in a reservoir that is both oil and gas, correct?

Page 136:14 to 136:21

A. It -- I -- I don't know.
Q. (By Mr. Keegan) Do you agree that the MMS approves 50/50 mud/gas mixtures for calculating MASPs submitted by both BP and other Operators?
A. In -- in some cases, yes.
Q. And a 50/50 mud/gas mixture is a reasonable -- is something you could reasonably expect to see in a wellbore, correct?

Page 136:24 to 137:07

A. That's -- that's -- that's what -- that's what our official policy is, yes.
Q. (By Mr. Keegan) And, in fact, the BOEMRE is still approving APDs with MASPs calculated using 50/50 mud and gas mixtures?
A. In some circumstances, yes.
Q. Do you agree that BP correctly considered drilling completion and producing conditions in its Macondo APDs and submissions?

Page 137:09 to 137:09

A. I don't know.

Page 140:10 to 140:17

Q. Do you have any reason to believe that --

that BP was informed that the information it provided in its APDs was not sufficient to show that the blind shear rams installed in the BOP stack were capable of shearing the drill pipe in the hole under Maximum Anticipated Surface Pressures?

A. No.

Page 141:15 to 142:11

Q. To the extent the MMS needed information related to shearability that it did not already have and was not included in the Macondo APDs, the MMS could have asked BP, Transocean, or Cameron to provide that information, correct?

A. Yes.

Q. And are you aware of -- of any request from anyone at the MMS to BP, Transocean, or Cameron to provide additional information related to the blind shear rams on the BOP at the DEEPWATER HORIZON?

A. No, I'm not aware.

Q. And the MMS routinely approves APDs submitted by other Operators in the deepwater Gulf of Mexico that include MASP calculations but don't have explicit shearing calculations, correct?

A. Yes. Not -- not currently, but at -- at a point in time, yes.

Q. Prior to the April 20th --

A. Yes.

Q. -- 2010 incident?

Page 144:02 to 144:11

Q. Are there Operators out there using single -- BOPs with single annulars?

MR. PETOSA: Objection, form.

A. Yes.

Q. (By Mr. Keegan) And there are BOPs with double -- with two annulars, aren't there?

A. Yes.

Q. And two annulars is a better and safer technology, right?

A. Yes.

Page 144:22 to 145:16

Q. (By Mr. Keegan) Because a singu -- singu -- single annular complies with MMS Regulations, right?

A. A single annular does comply with MMS Regulations.

Q. Okay. So we've determined that there are BOPs available that have two annulars, correct?

A. Yes.

Q. And BOPs with two annulars are better and safer, correct?

A. Yes.

Q. Okay. And the Operators who are using BOPs with single annulars are not violating this Regulation, are they?

A. No.

Q. If this Regulation and the Requirement for better and safer technology required different equipment than that used onboard the DEEPWATER HORIZON at the Macondo, the MMS could have made that determination, correct?

Page 145:18 to 145:18

A. Yes.

Page 145:23 to 146:08

Q. And the MMS could have rejected BP's APDs and other submissions for failure to comply with this Regulation, correct?

A. Yes.

Q. And it did not do so?

A. Correct.

Q. At the time the MMS approved Macondo -- the BP's filings, did the MMS believe that the DEEPWATER HORIZON equipment was -- to be used at Macondo complied with all of the MMS Regulations?

A. Yes.

Page 146:13 to 146:17

Q. (By Mr. Keegan) As you sit here today, has anybody ever told you that prior to the incident, the equipment on the Tran -- DEEPWATER HORIZON was not, in fact, the best and safest?

A. No.

Page 146:19 to 146:25

Q. (By Mr. Keegan) Prior to the incident on April 20th, 2010, there were no requirements to conduct a negative pressure test, correct?

A. Correct.

Q. And, in fact, BP could have conducted a -- run the cement, conducted a pro -- positive pressure test, and left the well, correct?

Page 147:02 to 147:03

A. Af -- after setting the surface plug, displacing the riser, yes.

Page 150:01 to 150:11

Q. But -- but you're not aware of any Industry Standard for how to do those negative pressure tests that existed prior to the incident, correct?
A. Correct.
Q. They varied from Operator to Operator?
A. I -- I would assume so.
Q. And, in -- in fact, it varied from rig to rig?
A. I -- I -- I would agree that's -- that's -- that's probably true.

Page 151:04 to 151:07

Q. Okay. Is it your understanding that Frank Patton approved this Temporary Abandonment Procedure requiring one or two negative pressure tests?

Page 151:09 to 151:19

A. With -- just with conversations I've had with him, I was under the understand -- understanding that his impression was that there were two -- two negative tests.
Q. (By Mr. Keegan) As you read this Temporary Abandonment Procedure, do you believe that there -- it discloses one or two negative pressure tests?
A. In -- in my -- in my opinion, I -- I think I agree that -- that it does require two negative tests.

Page 151:21 to 155:14

A. Or it does indicate that two negative tests will be done.
Q. And the first negative test is to the mud line?
A. Well --
Q. Why don't you tell me what the two negative tests are that you -- that --
A. I -- I would say in Step 1, yes, I would interpret that that's the first negative test, to -- to the mud line.
Q. Okay. And what's the second negative

test that you perceive in that -- in that Procedure?

A. You know, I would -- I would say a combination of Step 2 and 3, when the -- the -- the three and a half inch stinger is run to 8,367, and -- and 3, when -- when there's a displacement to seawater and monitoring for 30 minutes, that -- that that's the second 30-minute negative test --

Q. Okay.

A. -- at -- at 8,367.

Q. Of those two tests, which places the well in a greater underbalanced position?

A. In -- in my opinion, the second test at the deeper depth.

Q. And -- and why is that?

A. Because it is a deeper depth, so the first test, I think there was a replacement of whatever the mud weight was in the -- from the -- from the rig to the -- to the seafloor, replacing that with -- with seawater, so that -- that's one pressure differential, and I think it's a greater pressure differential when you are replacing that same mud from the rig floor to 8,367 with -- with seawater, so --

Q. And a differential to 8,367 is a more rigorous negative pressure test than one at the mud line?

A. To test -- I -- I guess to test the casing and -- and the shoe track, it would be a more rigorous test.

Q. Is there any way that the MC 252 No. 1 Well could have passed the deeper test, but failed the shallower test on an engineering basis? Do you understand what I'm asking?

A. Yes.

And I -- I -- I would say, I would say -- say "no."

Q. Prior to April 20th, 2010, is your -- were your District Engineers trained in analyzing negative pressure tests or negative pressure test procedures?

A. Not to my knowledge.

Q. Prior to April 20th, 2010, were your District Drilling Engineers trained or given any guidance on how to calculate the amount of underbalance in a negative pressure test?

A. I would say "Yes."

Q. Just through their basic engineering training or specific as to negative pressure tests?

A. I -- I would say through their basic engineering training.

Q. Prior to April 20th, 2010, did your District Drilling Engineers have any training or guidance as to what was an acceptable negative pressure test or not?

A. No.

Q. Procedure, I'm sorry.

A. No, no, no specific training or guidance.

Q. So the -- the decision as to whether or not a Temporary Abandonment Procedure and a Negative Pre -- Test -- Pressure Test Procedure should be allowed or not was left to the discretion of the District Drilling Engineer?

A. Well, there -- there's no requirement for a negative test, but whether it should be allowed, if -- if it's proposed in the Procedure, then it's -- it's required to be done and expected to be done, by virtue of -- of -- of following the approved Procedure.

Q. Right. And that's -- that's after the Procedure has been approved, but when -- when Frank Patton was making -- determining whether to approve this Procedure or not, that was in his discretion?

A. His discretion to do -- to do what?

Q. To approve the Temporary Abandonment Procedure or not.

A. Yes.

Q. Okay. There's no Guideline or Regulation that he says: "This follows this checklist, I'm going to approve it"?

Page 155:16 to 155:16

A. That -- that's correct.

Page 157:03 to 157:04

Q. Operators are permitted to change Procedures on the rig, correct?

Page 157:06 to 157:11

A. That they're -- I'm sorry. You said they're -- they're able to?

Q. (By Mr. Keegan) Yes.

A. They're -- they're able to submit a -- a -- a request for -- for a revision. They can't change the Procedure on their own.

Page 162:03 to 162:14

Q. Mud weights and fracture gradients reported in the eWells have to be reported in tenths, correct?

A. Yes, I think that's -- I -- I believe

that's correct.
Q. You cannot report hundredths in the eWell System, correct?
A. I think that's right, yes.
Q. So if a -- an Operator is reporting mud weights, fracture gradients, or pore pressures in tenths, it doesn't have a choice on eWells, right?

Page 162:18 to 163:13

00162:18 A. -- let -- let -- let me back up a little bit. Theoretically, mud -- mud weights, in -- in different places, can be reported in something other than tenths.
Q. (By Mr. Keegan) Take a look at Page -- or Tab 22, please. This is still in the first binder. If you turn to Page 7 of 10, please. Are you on Page 7 of 10?
00163:01 A. Yes.
Q. Those numbers in the boxes there for annular -- sorry -- for mud weight, for fracture gradient, for formation test, those are tenths, correct?
A. Yes.
Q. And you don't have a choice there. Those have to be in tenths?
A. In -- in that location, yes, you do not have a choice.
Q. And that's true for everything on the -- the Pages 8 and 9, as well, correct?
A. Yes.

Page 168:17 to 168:19

00168:17 Q. Mr. Trocquet, have you ever reviewed E-mails internal to BP, discussing leakoff tests?
A. Not that I recall.

Page 168:24 to 169:06

00168:24 Q. Ever ha -- ever study or -- or analyze any of the formation integrity tests or leakoff
00169:01 tests conducted on the MC 252 No. 1 Well?
A. Not that I can recall.
Q. You aware of the work and discussions that occurred at BP in evaluating formation integrity tests or leakoff tests on the MC 252 No. 1 Well?

Page 171:07 to 175:06

00171:07 Q. (By Mr. Keegan) All right. Let's go back

to Volume 2. Do you know who Scherie Douglas is?
A. Yes.
Q. Okay. You believe Scherie Douglas to be a truthful and honest person?
A. As best I could tell, yes.
Q. How long have you known Scherie?
A. Gosh, I -- ju -- just a guess, I guess working with her, her submitting Permits for BP, and -- and -- and MEB and Drilling Engineer, seven, eight years, ten years. I'm not exactly sure when she started on -- on the drilling end.
Q. Always found her to be straightforward, direct, and honest?
A. Yes.
Q. No questions about -- you had a good working relationship with her?
A. Yes.
Q. Okay. You know Terry Jordan?
A. I -- I don't think so. Is -- is that a -- is that a -- a man or a woman?
Q. It's a man.
A. I -- I -- I don't think I do know him.
Q. Okay. Do you recall a meeting in -- in February of 2008 with Scherie Douglas, Terry Jordan, yourself, and an Engineer Trainee to discuss formation integrity tests and Procedures?
A. I do not -- I -- I do not recall a meeting.
Q. Okay. If you could turn to Tab 43. It's a document that's been previously marked as 4734.
A. Okay.
Q. It's an E-mail from Terry Jordan to several individuals, and it says: "Yesterday Scherie Douglas and I met with the MMS (Mike Saucier," David Trocquet -- "Dave Trocquet, and an engineer trainee) to discuss BP's standard Gulf of Mexico Formation Pressure Integrity Procedure."
Second paragraph, third paragraph: "They understood our method of pumping down both the drill pipe and casing side no greater than one-half barrels per minute to make friction pressure negligible. They understood taking a leakoff test to the point where the pressure curve clearly breaks over, and to report the maximum pressure." Do you see that there?
A. Yes.
Q. Does that refresh your recollection as to a meeting in February of 2008 with BP's personnel?
A. It -- it -- it -- it seemed as though I do recall ha -- having a meeting with Scherie Douglas where Mike Saucier was there, possibly in a Regional Office. I -- I don't recall an Engineer Trainee, I don't recall Terry Jordan,

and I don't recall the subject.

Q. Okay.

A. But I -- it seems as though I do recall a few years back -- it seems like I can recall the conference room we were in. Saucier was there, Scherie Douglas was there, there was at least one or two BP people there, and there may have been one or two MMS -- other MMS people there, but I can't recall who that was.

Q. And do you recall, whether that meeting specifically or not, any ins -- statement from BP that they were going to use maximum pressure when they reported their leakoff test reports?

A. No.

Q. Okay. As you sit here today, do you have any reason to believe that this is not an accurate statement related to what BP told you at the meeting that Terry Jordan identifies in this E-mail?

A. No, I don't.

Q. Okay. Can you take a look at Tab 45 for me? If you look at the -- it's previously marked Ex -- 4736. Take a look at that PowerPoint Presentation there. Does this PowerPoint Presentation look familiar to you?

A. (Reviewing document.)

No, it don't -- it doesn't, although, you know, I do have to say I'm -- I'm more used to more recently seeing BP PowerPoints in BP green, but -- this is black-and-white, yeah.

Q. I think this originally was, but the copies just got black-and-white at some point.

A. No, it doesn't -- it doesn't ring a bell as far as helping me remember the -- the meeting.

Q. Okay. And I don't know that that was the exact PowerPoint that was presented or if one was, but I was just checking to see if you remember that.

Is it a violation of -- of MMS Regulations to have a lost circulation event?

A. I -- I would say no.

Q. Are Operators required to measure downhole pressures as they're drilling?

A. I --

Page 175:08 to 177:22

A. I -- I would say no, but -- but if they -- they did and if any information that they did obtain while drilling a well, they -- they would -- certainly would be expected to -- to use that well -- that -- that information in the drilling of a well.

Q. (By Mr. Keegan) I'm just going to ask the first question. We'll get to the point that you made in the second half of your answer. But are Operators required to measure downhole pressures as they are drilling?

A. I would say no.

Q. Okay. Operators can measure downhole pressures as they're drilling, correct?

A. Yeah, I -- I would -- I would agree that -- that -- you know, that Operators can obtain whatever information they feel that they want to obtain downhole, and generally whatever they obtain logwise, they're required to submit it to us.

Q. In the Driller's Reports?

A. No. I think the -- the actual logs themselves, they're required --

Q. Ah.

A. -- to submit them. But -- but data, they don't -- you know, just the -- just the notation in the Driller's Report that it was obtained, and then -- and then that, you know, as a prudent Operator all data should be used to -- to drill the well safely and -- and use that information to the best of it -- a best ability.

Q. Absolutely. One of the methods of getting downhole pressures is through PWD tools, correct?

A. I -- I -- my understanding is yes.

Q. And PWD tools measure mud weight in the casing, or ESD, right?

A. I'm not sure. It -- it measures -- it measures the pressure where the PWT -- PWD tool is.

Q. And that is either the static density or the circulating density of the mud, correct?

A. I would agree at the point where --

Q. Right.

A. -- where the tool is.

Q. It is not a measurement of the pore pressure, right?

A. I would agree.

Q. And it is not a measurement of the fracture gradient, right?

A. My -- my understanding is that PWD tools are used to conduct formation integrity tests, So --

Q. It --

A. -- so I -- I would say in -- not in -- in some cases, yeah, it's not a measure of the formation integrity test unless it was strictly used in determining the --

Q. So putting --

A. -- formation integrity test.

Q. -- putting the formation integrity test aside, when you're using PWDs as you're drilling, it's not actually measuring the strength of the formation, correct?

A. Correct.

Page 180:24 to 182:12

Q. (By Mr. Keegan) Tab 2, this is a document that's been previously marked as Exhibit 1896. It's the Application For Permit to Drill a New Well.

The application is dated on the bottom electronically generated May 13th, 2009. Do you see that there?

A. Yes.

Q. And the -- the MC 252 No. 1 Well was spud in October of 2009, correct?

A. I -- I know it was late 2009.

Q. After May of 2009?

A. Yes.

Q. Okay. Can you turn to Page 6 of 7.

A. Okay.

Q. And do you see in the box on the right-hand side under Interval 3, on the bottom right corner of that top box, all the way to the right --

A. Okay.

Q. -- a measurement called "Formation Test (ppg)." What does that meas -- formation test say there?

A. 12.3.

Q. And that's an estimated value that BP believes it will get when it drills to this interval and conducts a formation integrity test, right?

A. I would say yes.

Q. That's your understanding of what that information is?

A. In this circumstance, yes.

Q. Okay. BP actually has to conduct a formation integrity test after that casing shoe, correct?

A. Yes.

Q. Because you want them to have an actual fracture gradient result from that formation integrity test, correct?

Page 182:14 to 182:17

A. That's correct.

Q. (By Mr. Keegan) Because the actual measured values are what you use to determine the safe drilling margin, correct?

Page 182:20 to 184:17

A. That -- that's what we would expect the Operator to use.
Q. (By Mr. Keegan) You don't want them to use their estimates?
A. Well, that's correct.
Q. Okay. And I think we both agree that all sorts of downhole data gets collected, and an Operator should use that to drill forward and to analyze its Drilling Program, correct?
A. Correct.
Q. But that doesn't change the fact that the safe drilling margin included in the Regulations is measured by the result of the formation integrity test, right?
A. Well, it is a start unless there's information that is obtained to indicate otherwise.
Q. And one way to indicate otherwise would be to take losses, correct?
A. Not necessarily.
Q. But losses would indicate a -- a weaker zone than your formation integrity test showed at the casing shoe, correct?
A. Not necessarily, in my opinion.
Q. Is there any MMS Regulation that requires an Operator to drop their mud weight a half a pound after experiencing losses?
A. Not to my knowledge, no.
Q. Okay. And there is an MMS Regulation that says the mud weight has to be a half a pound less than the formation integrity test or pressure integrity test at the casing shoe, correct?
A. There -- there's an MMS Policy that -- that requires when drilling a hole section that the safe margin between the -- I guess, the last known formation integrity test or the -- the weakest fracture gradient, that hole section, and the mud weight is at least a half a pound.
Q. Okay. Now, that's -- that's a very important distinction that you just made right there.
What Regulation requires an -- or sorry. It's not a Regulation. What Policy requires an Operator to reduce its mud weight by a half a pound from the weakest zone in the open hole?
A. What Policy?
Q. Yep.

Page 184:19 to 185:07

A. Not a written Policy. It's just a -- it's a -- it's a well-known and agreed Policy within MMS for the last 20 plus years that's been

disseminated to industry.
Q. (By Mr. Keegan) Is it your testimony that when we go back through and look at the Weekly Activity Reports and the submissions to the MMS from other Operators that they reduce their mud weight by a half a pound every time they encounter a loss zone?
A. No.
Q. Okay. It's not MMS Policy to reduce the mud weight a half a pound when you encounter a loss zone, correct?

Page 185:09 to 185:19

A. That -- that's correct.
Q. (By Mr. Keegan) Okay. And is it your testimony, then, that a loss zone is not the weakest zone in a formation?
A. It -- it could be, but I don't know that it is.
Q. Okay. Let's say that the loss zone is the weakest zone in a formation. Do you then have to reduce the mud weight by a half a pound underneath that loss zone?
A. I -- I would say yes.

Page 186:06 to 186:09

Q. (By Mr. Keegan) So you don't have to change the mud weight if you don't know what the weakest formation is. You can just drill ahead taking losses?

Page 186:11 to 186:11

A. No.

Page 186:13 to 186:24

A. No, I don't -- I don't think we -- we ever allow drilling ahead taking losses. I think -- I think -- I think there's the assumption that the weakest formation strength is at the shoe unless there's information to indicate otherwise.
Q. (By Mr. Keegan) And as soon as you get information to indicate otherwise, you need to reduce your mud weight by a half a pound to that information; is that your testimony?
A. In order to drill ahead, I would say "Yes."

Page 191:21 to 192:01

Q. Can you think of a single incident of noncompliance where somebody violated a Safe Drilling Margin Regulation when their mud weight was a half a pound under the result of their integrity test?
A. No.

Page 192:12 to 192:20

MR. KEEGAN: I'm going to ask you to mark this as Exhibit 5 tho -- 349. This is a document Bates-numbered IMS273-001133 through 001306.
(Exhibit No. 5349 marked.)
Q. (By Mr. Keegan) Mr. Trocquet, do you recognize this document?
A. I was going to say "No," but I see my name on it.

Page 192:22 to 192:22

A. Yes, I do.

Page 193:25 to 194:04

Q. Can you turn to Page 147 for me. Under Paragraph 4.8.1.1. Do you agree or disagree with the statement that "The OIM has the overall responsibility for the safety of the crew, the rig, and damage to the environment"?

Page 194:14 to 194:19

Q. (By Mr. Keegan) You don't have to agree with it just cause your name's on it. I'm asking if you agree, as a general practice, that "The OIM has the overall responsibility for the safety of the crew, the rig, and damage to the environment"?

Page 194:22 to 195:01

A. I -- I -- I don't know if I'm qualified to -- to make that statement. But that it -- it's solely the responsibility of the OIM.
Q. (By Mr. Keegan) Partially the responsibility of the OIM?

Page 195:04 to 195:15

00195:04 A. Yes.
Q. (By Mr. Keegan) Okay. Can you turn to Page 155 for me.
Do you see that -- sorry, 153.
Do you see the paragraph in the middle there? It's all caps, and it says: "THE DRILLER IS THE KEY PERSON IN THE WHOLE OPERATION. THE DRILLER MUST DETECT A KICK AND TAKE THE APPROPRIATE ACTION."
Do you agree that it is the Driller's responsibility to detect a kick and take appropriate actions?

Page 195:18 to 195:19

00195:18 A. In -- in general, I would say "Yes." I'm --

Page 195:21 to 195:21

00195:21 A. Yes.

Page 196:07 to 196:15

00196:07 Q. (By Mr. Keegan) Is this still a --
A. -- Drill --
Q. -- Draft document?
A. I -- I -- I don't recall if -- if that's ever gone out final or not.
Q. Would you feel comfortable disagreeing with this statement and recommending that they revise it, or is it just something you don't have experience with one way or the other?

Page 196:17 to 197:25

00196:17 A. It would be something I -- I just didn't -- didn't feel as though I -- I was qualified to -- to make a judgment on it one way or the other. I don't necessarily disagree with that, but I don't -- I don't know that I could say I agree with it, either.
Q. (By Mr. Keegan) And when Operators learn of downhole conditions, they're required to report that in the Daily Driller's Report, right?
00197:01 A. Yes.
Q. And they're required to report that in the Weekly Activity Reports?
A. I -- I would say "Yes."
Q. And is there Guidance, Policies, or Procedures detailing what level of detail needs to be included in the Weekly Activity Reports?
A. No.

Q. And if BP submitted Weekly Activity Reports and the MMS made no comments on those, would BP have any reason to believe that its Weekly Activity Reports did not adequately disclose the downhole conditions?
A. I -- I'm sorry. I was just listening to your last question. I didn't hear that one, because -- I -- I said, no, there's no guidance in -- in the WARs. There may be some guidance requiring maybe a daily breakdown in the narrative section. But as far as the amount of detail in each one of those daily breakdowns, there's -- there's no guidance.
So I -- I'm sorry, if you could ask your next question again.
Q. I think you answered both of them with that answer.

Page 198:02 to 198:08

00198:02 Q. You agree that a long string casing design is a common design in the Gulf of Mexico?
A. I -- I would say "Yes."
Q. No concerns that Frank Patton approved an application for a Permit -- a -- a Revised Permit with a production long string in it?
A. No.

Page 198:22 to 199:01

00198:22 Q. (By Mr. Keegan) Okay. Have you done any of your own investigation or analysis of the causes of the DEEPWATER HORIZON explosion and blowout?
00199:01 A. No, I haven't.

Page 200:05 to 204:11

00200:05 Okay. As I think you probably know, Mr. Patton and Mr. Saucier were deposed earlier in -- in this litigation?
A. Yes.
Q. Both of them testified that they did not recall talking to anyone from Transocean about the Macondo Well from the middle of 2009 through April 20th. During that time frame, did you speak to anyone from Transocean about the Macondo Well?
A. Not -- not to my recollection.
Q. Okay. And during that same time frame, you're not aware of any Macondo-related documents that were submitted by Transocean to the MMS, correct?

A. Correct.
Q. At any point during the drilling of the Macondo Well, did you ever become aware of any issuance of noncompliance or warning with respect to any regulatory requirement related to Transocean?
A. No.
Q. During the drilling of the Macondo Well, did anyone ever report to you that they believed that Transocean was not in compliance with any regulatory requirements imposed on it in connection with the drilling of the Macondo Well?
A. No.
Q. And during the drilling of the Macondo Well, the MMS never issued any INCs or warnings to Transocean, correct?
A. To -- to the best of my -- my recollection, that's correct.
Q. Prior to this incident, you did not consider Transocean to have a callous disregard for the safety of individuals or the environment, correct?
A. Correct.
Q. And you're not aware of anyone within the MMS that considered Transocean to have a callous disregard for the safety of individuals or the environment, right?
A. Yes, that's correct.
Q. All right. You testified a little bit earlier today about your knowledge of three inspections that occurred on the HORIZON in -- in 2010?
A. (Nodding.)
Q. Do you recall that testimony?
A. Yes.
Q. Okay. And those inspections were -- were conducted by MMS Inspectors, correct?
A. Correct.
Q. All right. And they were there to inspect aspects of the rig, as well as the BOP, correct?
A. Correct, as well as the -- the particular drilling of the well, the downhole properties of the well.
Q. Okay. As a result of those inspections, the MMS never raised any regulatory issue with Transocean regarding any problems relating to the BOP or the rig, correct?
A. To my -- to my knowledge, yes, that's correct.
Q. Okay. The MMS Inspectors that inspected the HORIZON and the BOP in 2010 were competent Inspectors, correct?
A. If -- if -- if my recollection of -- of who those Inspectors were, if that was consisting

of -- of Erick Neil and -- and Bob Neil, I would say, yes, that's correct.

Q. And they were adately -- adequately trained to inspect a -- a drilling rig like the DEEPWATER HORIZON and certain components of that rig, like the BOP, correct?

A. I would say yes, correct.

Q. And the MMS has not identified that the two Neils failed to properly perform their duties in inspecting the DEEPWATER HORIZON and BOP, right?

A. Correct.

Q. None of the MMS Inspectors that conducted those inspections reported to you anything regarding the results of those inspections, right?

A. That's correct.

Q. All right. You've -- you've testified a little bit today, too, about the Final Temporary Abandonment Plan --

A. (Nodding.)

Q. -- and the -- and the -- and the procedure in that Plan.

Now, on or about April 16th, Mr. Patton approved the final T&A Plan that was submitted by BP, right?

A. I don't -- I don't specifically know the -- the date he approved it, but I do -- did understand that he approved it a few days before -- before the --

Q. Before the incident?

A. -- the blowout -- the incident, yes.

Q. And I believe your testimony is that if -- if BP was going to deviate at all from the procedure that was approved a few days before the blowout, that BP should have communicated that fact to the MMS, right?

Page 204:13 to 204:22

A. Yeah. I -- I -- I would say if there's a material deviation, we always would require a -- an additional approval for -- for that change.

Q. (By Mr. Thibodeaux) Okay. And you agree that Mr. Patton, as the Drilling Engineer in charge of reviewing those submissions, was in the best position to determine whether a material change was resulting from the operations that were being conducted with respect to the regulatory submissions by BP, right?

Page 204:24 to 204:24

A. Yes, I would agree.

Page 205:03 to 206:14

Q. (By Mr. Thibodeaux) So you would defer to Mr. Patton as to whether or not BP should have sought approval for any changes that were going to be made to that Temporary Abandon -- Abandon -- Abandonment Procedure that was approved by Mr. Patton; is that right?
A. Yes.
Q. Okay. You testified, as well, about the safe drilling margin. MMS Regulations require a safe drilling margin to be maintained at all times, right?
A. I -- I would -- I would say yes, with the caveat "at all times while drilling ahead."
Q. Sure. Now, earlier, Mr. Keegan, who represents BP, was asking you some questions about how the safe drilling margin is determined, and whether it's based on the FIT at the previous -- previous shoe and the mud weight that's being utilized in the hole?
A. (Nodding.)
Q. You agree that if in drilling forward after the FIT is done in the previous shoe, hole observations dictate that the downhole fracture gradient is less than that FIT of the previous shoe, that MMS Regulations require that the safe drilling margin must be maintained between the mud weight that's being utilized and that downhole fracture gradient, right?
A. I would say yes.
Q. So in other words, if the FIT value proves to not be indicative of the downhole formation strength, that downhole fracture gradient must be used in place of the FIT in evaluating whether the safe drilling margin is maintained, right?
A. Yeah. If it's -- if it's lesser than the FIT, yes, the FIT at the shoe.

Page 208:05 to 208:25

Q. Okay. Prior to this deposition, in order to prepare, as I understand it, you did not look at any of the Regulations specific to what would have occurred at the Macondo Well; is that correct, in reference to preparing for this deposition?
A. I -- I -- I have glanced at some of the Regulations.
Q. Okay. Would you say just a peripheral glance, or would you say you actually looked at them in detail?

A. I -- I -- I couldn't say how much -- how much detail I looked at them, but I -- I've looked at a couple of Citations.
Q. Okay. And did you spend any significant time on it, like hours or days, or are we talking about minutes?
A. Well, there were some Regulatory Citations that I looked at in my -- my one day of preparation.
Q. Okay.

Page 209:07 to 209:20

Q. Also, as I understand your earlier testimony, you haven't reviewed the MMS well file for the Macondo; is that correct?
A. I've probably seen bits and pieces of it. I've not reviewed all the Permits from cover to cover and done thorough reviews on it, but I've probably hit -- I probably saw pieces here and there.
Q. Okay. So other than things that you may have looked at specifically which you've probably already testified about, you would have generally looked at some bits and pieces of the well file and not the entire thing?
A. I would say "Yes."

Page 211:08 to 211:20

Q. Okay. Now, generally the Regulations that the MMS deals with, and now BOEMRE, you consider that, don't you, sir, the minimum requirements for the Operators on the well?
A. Yes.
Q. Okay. And Industry Standard may be the minimum requirements plus additional Safety factors; is that a fair statement?
A. Yes, I would say so.
Q. Okay. In fact, API has Recommended Practices that some Operators can use that's in addition to what might be found in the Regulations, true?

Page 211:22 to 213:05

A. That -- that -- that's correct. We do incorporate some of the API documents in our Regs, and some are not.
Q. (By Mr. von Sternberg) Okay. So you do assume, in a situation like the Macondo Well, that an Operator like BP would follow the minimum requirements of the Regulations, true?

A. Yes.
Q. Okay. Let's look at Tab 27. It's already been previously marked in this litigation as Exhibit 4761. Have you seen this document before, to your knowledge?
A. No, sir.
Q. All right. If you'll look on the first page, which starts with the -- with the Bates number, the last four is 9703, and it's a BP produced document.
Do you see that at the bottom, sir?
A. Yes, sir.
Q. Okay. And it's called "MMS Requirements Overview Wellsite Leaders."
Do you see that, as well?
A. Yes.
Q. And it looks like it was drafted by Scherie Douglas on August of 2009.
Do you see that?
A. Yes.
Q. Okay. Now, you agreed with Counsel earlier that Scherie Douglas was a truthful and
00213:01 honest person, did you not?
A. To my knowledge, yes.
Q. Okay. Let's look at Bates No. 9707, if you would please.
A. (Complying.)

Page 213:13 to 215:06

00213:13 Q. All right. Well, needless to say, Ms. Douglas stated that the "Majority of" the "MMS Regulations for offshore" are found in "30 CFR 250."
Do you see that?
A. Yes, sir.
Q. And you agree with that, do you not?
A. Yes, I do.
Q. Okay. And the next statement is: "Failure to comply can result in issuance of an Incident of Non-Compliance (INC) and/or civil penalty."
Do you agree with that, as well?
00214:01 A. Yes.
Q. Okay. Let's move forward to -- quite a ways back. 9727, which is "Subpart D," heading "Drilling."
A. Okay.
Q. And it's entitled: "250.401 - Keeping wells under control."
Do you see that?
A. Yes.
Q. Now, is that in reference to 30 CFR 250.401, to your understanding, "Keeping wells under control"?

A. Yes.
Q. Okay. And she says that: "Operators" may "take" -- "must take necessary precautions to keep wells under control at all times."
Do you agree with that?
A. Yes.
Q. Okay. And then she says: "Use the best available and safest drilling technology to monitor and" evalue -- "monitor and evaluate well conditions and to minimize the potential for...well...flow or kick."
Do you see that, sir?
A. Yes.
Q. And you agree with that, as well?
A. Yes.
Q. And earlier, you testified the best available and safest drilling technology was what was available to the industry at the time; is that correct?

Page 215:08 to 215:25

A. Yes, I did.
Q. (By Mr. von Sternberg) Okay. And the Operator must also: "Have a person onsite during drilling operations who represents operators' interests."
Do you see that, and do you agree with that?
A. Yes.
Q. Okay. And the Operator must: "Ensure that the toolpusher, operator's representative, or a member of the drilling crew maintains continuous surveillance of the rig floor unless" the "well has been secured."
Did I read that correctly?
A. Yes, you did.
Q. And do you also agree with Ms. Douglas that 250.401 requires each of these bullet points that she's listed here?

Page 216:02 to 216:20

A. Yes.
Q. (By Mr. von Sternberg) Okay. Let's move forward to 9730, still in "Subpart D - Drilling."
A. Okay.
Q. This is referring, I think, to CFR -- or 30 CFR 250.410-418. Is that the way you read this, sir?
A. It -- it looks like that she's referring to several different Citations.
Q. Okay. So she's going 410 through 418? That's a better way of saying it.

A. That's the way it looks to me.
Q. Okay. Great. And it talks about "Application for Permit to Drill..." Is that right?
A. Yes.
Q. And MMS approval is required. That's true?
A. Yes.

Page 217:06 to 218:04

Q. (By Mr. von Sternberg) "All cement" -- let's try again. "All cement volumes and test pressures approved in the APD must be followed (minimums)."
Did I read it correctly this time?
A. Yes.
Q. Okay. And you agree that the Regulations require that? It's in italics in Ms. Douglas' Report here. Is that correct?
A. Yes.
Q. Okay. All right, sir. Let's go to what's marked as 9471, the last four of the Bates numbers. We're still in "Subpart D - Drilling."
Do you see the second bullet point which talks about 30 CFR "250.465 - Changes to drilling programs"?
A. Yes.
Q. Okay. The first one is: "Revisions to the approved well plan (APD) require MMS approval."
Do you see that, sir?
A. Yes.
Q. And she's just talking about any change to the APD, is she not?

Page 218:06 to 218:17

A. I -- the -- the word says "Revisions," so I -- I don't know what her intent is in putting that.
Q. (By Mr. von Sternberg) Okay. And then it says: "Approval will be obtained from MMS by regulatory staff."
Do you see that, as well?
A. Yes.
Q. Okay. Do you understand that in BP's Procedures, that the Regulatory staff would get with the MMS to have approval obtained in reference to revisions of the APD Plan?

Page 218:19 to 219:03

A. Yes.

Q. (By Mr. von Sternberg) Okay. And if you'll go second-to-the-last page of the document, it's 9749. It says: "MMS overview for wellsite leaders."

Do you see that?

A. Yes.

Q. And it says: "Failure to comply could lead to this...," and then she has an unpleasant picture there, does she not?

Page 219:05 to 219:07

A. Yeah, yes.

Q. (By Mr. von Sternberg) What does that picture mean to you as an MMS Regulator?

Page 219:10 to 219:22

A. Yeah, I -- I -- you know, we -- you know, we -- we have a job to do, and we're an -- we are an oversight and enforcement agency, and -- and we try to do it in a, you know, fair and equitable manner.

Q. (By Mr. von Sternberg) All right. Well, it's easy to see that failure to comply to the MMS Regulations, or BOEMRE at this point, could cause damage; is that correct?

A. It -- it -- it -- it could cause damage to the environment, to -- to the personnel safety. It could cause us to issue INCs, civil penalties.

Page 220:22 to 221:10

Q. Prior to April 20th, 2010, did you ever speak with anyone from Anadarko regarding the operation of the MC 252-1 well?

A. No.

Q. Prior to April 20th, 2010, are you aware of anyone in the BOEMRE having spoken with anyone from Anadarko regarding the design of the MC 252-1 well?

A. No.

Q. And prior to April 20th, 2010, are you aware of anyone in the BOEMRE having spoken with anyone from Anadarko regarding the operation of the MC 252-1 well?

A. No.

Page 221:15 to 221:22

Q. And are you aware of any information

showing that Anadarko had any input in the design of the MC 252-1 well?
A. No. No, I'm not aware of any.
Q. And are you aware of any information showing that Anadarko had any input in the operation of the MC 252-1 well?
A. No.

Page 223:01 to 223:04

00223:01 Q. In those discussions Mr. Keegan mentioned a WEST Engineering study. You talked about it with him. It's previously been marked as Exhibit 3298. I'd like to hand it to you.

Page 223:21 to 224:24

00223:21 At the top, the WEST Study notes under "4.2.1.1 MMS": "New MMS regulation 30 CFR...250.416" dot E -- sub (e), excuse me -- "requires the lessee to provide information that shows that the blind-shear or" sham -- "shear
00224:01 rams installed in the BOP" for both "(surface and subsea stacks) are capable of shearing the drill pipe in the hole under maximum anticipated surface pressures."
And I'd like to refer you back now, sir, to what was it appears the Regulation on BOPs before it was changed in 2003, 250.406 under (c) -- I've highlighted it for you -- "Working Pressure." "The working pressure rating of any BOP component shall exceed the anticipated surface pressure to which it may be subjected."
Now, I'm going to have some questions for you, but I want to make sure I'm clear from you told earlier on today in the morning. You've been with MMS, now BOEMRE, for how long?
A. Since 1988.
Q. Okay. And in 2003, you were -- I think you were a Drilling Engineer in the New Orleans District, correct?
A. Yes.
Q. And you would have been required to have knowledge of these Regulations as they apply to BOPs, correct?
A. Yes.

Page 225:21 to 226:10

00225:21 Q. Back in 2003, would you have been reviewing and approving APDs for wells in the New Orleans District?
A. Yes.

Q. Okay. You would have been required to -- to be aware of -- of when you're looking at these APDs what the difference would be between the Reg that's said "anticipated surface pressure of all BOP components" -- and I'll rephrase it so it's consistent with the Reg.

You would have to be looking at the working pressure rating of any BOP component so it would exceeded the anticipated surface pressure up to the point the Reg was changed, correct?

Page 226:12 to 226:24

A. The -- from -- from my understanding and knowledge, our -- our Policy did not change when these Regulations changed. We -- we have always calculated the -- the -- the potential surface pressure to compare and to review it against the rating of the BOPs the same.

So from my -- from my knowledge, the changing of the Regs from "anticipated surface pressure" to "maximum antici -- anticipated surface pressure" didn't change the way we were reviewing permits, reviewing this -- this potential surface pressure that -- that -- that a blowout preventer needed to be rated for.

Page 228:16 to 228:20

Q. (By Mr. Petosa) Now, sir, when -- in light of this casing design when BP submitted its APD for MC 252, shouldn't it have calculated MASP to the worst case scenario of a hundred percent gas column?

Page 228:22 to 229:18

A. To -- to my knowledge, we have no -- no -- no guidance as to instruct Operators how to calculate their -- their MASP, and -- and -- and our MASP is -- is not a maximum worst case scenario. Ours has always included some mud still left in the well, with the worst case scenario being 50 percent of the hole being voided of -- of mud. So that is the MASP that -- that we're using to evaluate casing tests, BOP tests, casing -- casing burst design, BOP ratings.

So although Operators submit an MASP with the -- with the Drilling Permit, we may -- we may -- we will review them, compare them against our MASP. It's more for academic, for our

information, see how different Operators are calculating their MASP. We're using our MASP to evaluate the -- the APD, or the -- the Permit.
Q. (By Mr. Petosa) But shouldn't the Operator be accurately calculating the MASP based upon what they believe the conditions are that may occur downhole?

Page 229:20 to 229:21

Q. (By Mr. Petosa) Based upon their own casing design?

Page 229:23 to 230:17

A. Again, the MASP is the maximum anticipated. It almost seems as though those -- those are in conflict. It's not the maximum pressure and it's not -- not just the anticipated pressure, but it's -- it may not be the best -- the best term or wording. But it's -- it's not -- it's not the maximum -- the maximum pressure that could possibly be on the -- on the stack.
Q. (By Mr. Petosa) All right.
A. But it is a very conservative estimate of -- of what the stack could see.
Q. And -- and, sir, would you -- would you agree that the significance of that has to do with whether or not the casing shear, the blind shear rams, are going to shear the pipe under maximum anticipated surface pressure, correct?
A. I -- I would say -- say that that -- that would be a -- yes, a very -- a very important consideration.

Page 231:13 to 231:25

Q. Okay. Sir, I'd like to refer you to Tab No. 48 in the binder. It's an April 30th, 2010 E-mail from Bill Hauser with MMS, to Mike Saucier. You're cc'd on this E-mail, correct?
A. Yes.
Q. It says: "Blind shear rams cutting drill pipe in the well." Starts: "Mike, My concern is that I could not find anything in the APD for the" DEEPWATER "Horizon well about the ability of the blind shear ram to cut the drill pipe in the hole."
You remember talking about that earlier with Mr. Keegan, correct?

Page 232:02 to 232:07

Q. (By Mr. Petosa) The fact -- fact that the APD did not have any information --
A. Yes.
Q. -- for MC 252 about whether or not the DEEPWATER HORIZON BOP could actually shear the drill pipe in the hole?

Page 232:09 to 233:17

A. Yes.
Q. (By Mr. Petosa) It goes on to say: "This requirement has been in the regulations since 2003 and is found at...250" -- I'll read it completely out -- "30 CFR 250.416(e)".
That's the provision we've just been talking about, correct?
A. Yes.
Q. And it goes on to note that there is a preamble to the Final Rule. Now, this was the Rule we just talked about that was changed. And I'm going to read it, sir. "'Finally, one'" commentator "'indicated that the operating limits of blind-shear rams are frequently unclear for some drilling operations due to pipe grades, mud weights, and wellbore pressures, and that consideration should be given to ensure that these limits are clear. We agree that this is important, so we have added a paragraph to Section 250.416(e) that requires the lessee to address these issues'."
The lessee in this case, regarding MC 252, would have been BP, correct?
A. BP was one of the lessees, but they were the -- the designated Operator that submitted the Permit.
Q. All right. "'The new paragraph requires the lessee to provide information that shows that the blind-shear or shear rams installed in the BOP stack (both surface and subsea stacks) are capable of shearing the drill pipe in the hole under maximum anticipated surface pressures'."
Why is it that the lessee, or Operator, is required to provide that information, sir?

Page 233:19 to 234:06

A. (Reviewing document.) They're -- they're required to provide that information to -- to -- to -- to prove that if they did take a maximum anticipated -- if they did take a kick, if it did have a maximum, they did realize that Maximum Anticipated Surface Pressure to -- to have assurance that the blind shear rams could shear the pipe under that -- under that Maximum Anticipated Surface Pressure load.

Q. (By Mr. Petosa) Okay. That's a Requirement that the Regs placed upon the Operator of the well, correct?

A. Yes.

Page 235:04 to 236:06

Q. (By Mr. Petosa) And, sir, would you agree that when the -- the Regulations require -- we talked about this earlier and if I'm repeating myself, I apologize -- the -- the Regs require the Operator to identify in their APD, the maximum pressure limits for the annulars and for the shear rams, correct?

A. Yes.

Q. Okay. And you would expect, when the Operator does so, that the Operator is being truthful and accurate, correct?

A. Yes.

Q. Okay. Sir, I'd like to refer you to Tab 16 and Tab 17. They are two revised APDs, both dated April 15th of 2010. And if you look at Pages 6 through 8 on Tab 16, and you look at Pages 7 through 9 on Tab 17, I'd like you to tell me if anywhere you see that the information under Preventer Information indicates that the annular rating is anything less than 10,000 psi.

A. (Reviewing document.) No. In -- in all Sections where they do have blowout preventers run, they -- they're indicated the annular rating is 10,000 pounds.

Q. Now, what does the Operator in this case -- what is BP telling MMS in those two APDs about the annular rating? What's the significance of that?

Page 236:08 to 236:20

A. They're -- they're telling us what the -- what the -- what the pressure rating is that an annular could be used up till. It -- that -- if there's two annulars, I'm -- I'm not sure which one's being reported there.

Q. (By Mr. Petosa) Sir, if -- if, in fact, the lower annular on the DEEPWATER HORIZON was rated at 5,000 and not 10,000, and the BP Policy required that in a shut-in situation, that the lower annular should be activated first, shouldn't BP have been reporting what the pressure rating was on the lower annular at 5,000 and not 10,000?

Page 236:22 to 237:01

A. Yes.
Q. (By Mr. Petosa) Okay. And you would agree, sir, by not accurately reporting what that annular rating is, that's a violation of the Federal Regulations?

Page 237:03 to 237:06

A. (Reviewing document.) I -- I -- I would say technically it's -- it's a violation.
Q. (By Mr. Petosa) Technical or not, sir, it's still a violation, isn't it?

Page 237:08 to 237:09

A. I would say "Yes."
Q. (By Mr. Petosa) And, sir, did you ever

Page 237:13 to 237:15

Did you ever become aware, once the blowout began, if the BOP was able, on the DEEPWATER HORIZON at MC 252, to shut in the well?

Page 237:17 to 238:01

A. It -- it -- it was not able to keep the well from flowing through the BOP stack into the water.
Q. (By Mr. Petosa) So it didn't effectively shut in the well, correct?
A. Correct.
Q. Okay. Sir, I'd like to again just refer you back to that casing design, that Tab 35, which had previously been marked at 1861. One more question about Page 9.

Page 238:06 to 238:09

Q. (By Mr. Petosa) Is -- is -- isn't it true, sir, that BP anticipated, in its casing design, a hundred percent column of gas in the well?

Page 238:11 to 238:17

A. I -- I -- I wouldn't -- I wouldn't say that they "anticipated" it, but they -- they -- they certainly identified that it -- it could happen.

Q. (By Mr. Petosa) And in their Engineers' words, he has seen it happen, so knows it can occur, correct?

Page 238:19 to 238:19

A. Yes.

Page 239:02 to 240:20

I'd like to refer you to Tab 29. It is an Exhibit that's previously been marked as 1343, ending in Bates No. 6046. It's an April 2nd, 2010 E-mail from a Martin Albertin. You remember Mr. Keegan brought up his name earlier.

A. It seems as though I call -- I recall that.

Q. Okay. Subject of the E-mail is: "Macondo 9-78" Leakoff Test "LOT," to be accurate, "FIT Worksheet..."

I'm going to go on and read, sir. It says: "Team, Either the rock, or the casing and cement, are very strong!" That's an exclamation point. "I think it is safe to say that" the "test is not indicative of the true fracture strength of the average shale that we are about to drill - which I expect is much lower than this FIT suggests. Possible ex -- explanations for LOT/FIT tests which are much higher than expected:"

And he lists four different possible explanations: " - tectonic stress increasing horizontal stress, - high formation tensile strength (more likely to see this when little section is exposed beneath the shoe, - error -- error in pore pressure and/or overburden model, - erroneous test."

At the end, Mr. Albertin says: "At any rate, we are probably all on the same page here: we should manage drilling this last hole section with the" expectations "that the shales will fail at about the predicted values - less than overburden - which is about 15...ppg at the shoe."

I'd like to turn to the next tab, sir, Tab 30, Exhibit previously marked as 3734, ending in the larger of the two Bates numbers on this document, 7809. Again, it's an E-mail, sir. E-mail is dated April 3rd of 2010, it's Tab twenty --

A. I'm sorry --

Q. -- Tab 30.

A. Tab 30?

Q. Yes.

Page 241:20 to 241:25

Q. (By Mr. Petosa) Mr. Trocquet, I apologize for the fact that Tab 30 had, I guess, a different document, so I've handed you what has previously marked as Exhibit, I think, 3734, am I correct, at the bottom?
A. Yes.

Page 242:06 to 242:19

Q. (By Mr. Petosa) You -- you've had an opportunity to read it, sir?
A. Yes.
Q. Okay. Could you hand it back to me? I have a question or two, and I'll give it back to you if you need to refer to it.
Sir, I -- I'd -- I'd like to refer you, it starts at the bottom, April 3rd at 9:52 a.m., Mr. Morel, Brian Morel, with BP to others in BP, "Question" is the topic, "Re," "Subject" line. "We did a second test on the casing to 1500..."
Now, this is the casing -- this is the nine and seven-eighths shoe down to the bottomhole. It's the last in the line.

Page 242:21 to 245:12

Q. (By Mr. Petosa) "We did a second test on the casing at 1500 which isn't on the report, as we're not expecting to get anywhere close to 16...ppg with the lot, we decided not to test any higher than a 1500 psi. So when pressure did get that high on the lot we opted to shut down without going to leak off because we wouldn't know if" the case -- "if it was casing or formation."
Mr. Burns, a Tim Burns, responds: "Yes. Make sure that the 2nd test is on the IADC. That is what the MMS inspectors will look at. And for those lucky enough to follow behind you several years later, it would be good to have that information in the Openwells reports as well."
Mr. Morel responds: "We felt as if we only needed to test casing to the permitted pressures and did this for our own knowledge. Do you think this is required for the mms as we went higher?"
Now, if you recall, sir, on the prior E-mail, in reference to the same casing string, there was the E-mail by Mr. Albertin offering

possible explanations for the LOT/FIT tests that he indicated or thought might not be indicative of the true fracture strength of the average shale that they were about to drill.
And further down, in the paragraph that starts "We can't" -- after the four offered explanations, he says: "I wouldn't expect the LOT to be any higher than overburden. I think the most likely explanation is that we have tested a shale that has very high tensile strength. Or we have tested cement casing."
I'd like to refer you, sir, to Tab 31, which hopefully will have the correct document. I think it looks like it does.
It is an E-mail dated April 4th of 2010 from Kate Paine, it's attaching the daily PPFG Report for MC 252 beginning with Bates that end in 8071, and goes through Bates 8074.
Miss -- Ms. Paine notes on the E-mail: "Adjusted pore pressure based on the 14.14 GeoTap and then rounded up to 14.2 ppg for the sand pressures. The shale pressures adjusted the pore pressure model to 13.9 for the corresponding sand FG of 15...ppg. Expect pore pressure to increase 0.1 ppg at least by 18500 based on the most likely seismic estimate. No cavings. Gas comes back with ballooning response when the pumps are shut off."
What does that mean, sir, "Gas comes back with ballooning response when the pumps are shut off"?
A. Just somewhat familiar with -- with the term "ballooning." More prevalent in deepwater wells where permeable formation takes -- takes fluid, and then when the pumps are shut off, those formations give the fluid back to the -- to the well. And sometimes it's confused with taking a kick. Sometimes it's more understood as -- as the ballooning phenomena that's just giving fluid back, but that the well is not actually flowing on you.
So sometimes Operators close in on it, monitor it, bleed it off, and it bleeds down to zero in the --

Page 246:11 to 246:13

Q. Well -- well, sir, if, in fact, BP did not get a valid leakoff test in this casing string, what should they have done?

Page 246:15 to 246:23

A. If -- if -- if there's any question about the validity of -- of any tests, I think it's -- it's -- it's expected and incumbent upon the -- the Operator to -- you know, to -- to convince themself they have a reliable, accurate tests.

Q. (By Mr. Petosa) Any reporting Requirement to the MMS regarding the downhole conditions with respect to leakoff test and what BP is seeing in this interval?

Page 246:25 to 248:05

A. In -- in the Weekly Activity Report or on a Daily Breakdown, they should be reporting any hole problems. They should be reporting the -- the -- the -- the formation -- the -- both of the formation integrity tests in the Daily Breakdown.

There's a -- there's a spot in the Weekly Activity Report where they -- there is one -- one casing test reported or -- or one formation integrity test reported. I'm still a little confused about whether they -- I assume it was a formation integrity test that was being done, although they kept calling it a casing test.

So which one to report would be the lesser of the two. I take that back.

If -- if there's a formation integrity test and -- and it's -- it's squeezed with cement and redrilled out, re -- new formation drilled, and -- and another test is done and a higher formation integrity test is -- is obtained, that would be the one that should be reported.

Both of them, the -- the actual summary of the operation should be contained within the -- the narrative, operations narrative.

Q. (By Mr. Petosa) Would you be -- would you agree, sir, that if BP did not have evidence of a valid LOT that they should not have continued to drill until they were satisfied, within Compliance with the Regulations, and with the figures that they had in front of them that they had a valid leakoff test?

A. Yes.

Page 248:07 to 248:11

Q. (By Mr. Petosa) Sir, I'd like to refer you to Tab 32. It's previously been marked as Exhibit 1562, ending in Bates No. -- for the first page -- 1659. Not the easiest document to read, sir, I apologize for that.

Page 249:07 to 249:18

Next line, "If the wellbore conditions deteriorate (additional losses, wellbore stability, hole fill, etc.) during the planned conditioning trip, then the recommendation will be made to run a liner instead of the long string." And you were asked some questions about that today, sir. Why would BP, as the Operator here, decide if they have deteriorating wellbore conditions, that they would run a liner instead of a long string? Why would an Operator decide to do that?

Page 249:20 to 250:01

A. I -- I -- I'm not -- I'm not sure.
Q. (By Mr. Petosa) Would this seem to indicate, sir, that since BP's noting that if the wellbore conditions deteriorate, they're going to run a liner instead of a long string, that a liner would provide some more stability relative to well control?

Page 250:03 to 250:15

A. To -- to -- to me, it would indicate that a liner, in BP's model, a liner would provide a benefit over a full string. I'm not -- I -- I don't know that I'm capable of describing what that benefit is, whether that's well control, cementing, or what have you.
Q. (By Mr. Petosa) Okay. I'd like to move down under "Justification...," second line: "The long string provides the best economic case and well integrity case for future completion operations. The liner, if required, is also an acceptable option, but will add an additional...$10 million to the completion cost."

Page 250:17 to 251:03

Q. (By Mr. Petosa) "The complete summary of the options and...wellbore conditions are attached...," and it notes a pdf file.
It also notes that there's decision tree attached which is at the back.
I'd like to then go down now to the next section, sir, "Risk/Mitigation..." and it talks about two Risk/Mitigations. One is: "Lost circulation during the cement job." You talked about that today, and I think a lot of questions by Mr. Keegan about that process and what happens.

Page 251:05 to 251:15

Q. (By Mr. Petosa) The second thing it talks about, sir, is: "Single barrier in annulus for" Temporary Abandonment. "If losses occur during the cement job, possible cement evaluation, remedial cement operations, dispensations and/or MMS approvals will be required prior to performing TA operations due to a lower than required Top of Cement in the annulus."
What -- what does that mean when an Operator says "...lower than required Top of Cement in" -- "in the annulus"?

Page 251:17 to 252:03

A. The -- the Regulatory Requirement, I couldn't give you the citation, is -- is that the -- the -- the top of cement, the annulus should be in place -- should be placed such that the top of cement is -- is 500 feet above the highest most hydrocarbon-bearing zone.
Q. (By Mr. Petosa) Uppermost hydrocarbon-bearing zone, correct, sir?
A. Yes.
Q. Okay. It looks like BP had concerns about that on April 15th of 2010 with respect to their top of cement, correct?

Page 252:05 to 252:12

A. Re -- reading this, I would say "Yes."
Q. (By Mr. Petosa) Okay. I'd like to go on, sir. It says: "Possible hydrocarbon zones could be left exposed in the annulus with only the casing hanger seal as the single barrier for the" Temporary Abandonment.
What does that mean when an Operator puts information like that? What does that tell you?

Page 252:14 to 252:23

A. It -- it -- it -- it looks like if -- you know, if there -- if there were losses experienced while cementing resulting in the top of cement being below the hydrocarbon sand, then -- then that hydro -- hydrocarbon sand would not be isolated or separated from the -- from the sea, other than with the casing seal versus cement and a casing seal.
Q. (By Mr. Petosa) You would agree that's not a good thing?

Page 252:25 to 253:05

A. Yes, I do.
Q. (By Mr. Petosa) Would you agree, sir, that that creates a potential safety condition relative to some of the areas you said you'd be concerned about relative to well control for the environment and for individuals?

Page 253:07 to 253:14

A. It -- it -- it would be -- it would be the elimination of a second barrier. There -- there -- there would be a pressure barrier in the casing seal which -- which would be tested, so the annulus will be sealed, would be sealed and confirmed sealed, but with only one mechanical barrier versus the mechanical barrier and -- and cement.

Page 254:17 to 254:22

Q. But you would agree that relative to the last interval that we were just talking about, the nine and seven-eighths, the bottomhole, it appeared that BP had some concerns about whether or not they had a valid leakoff test for that casing interval?

Page 254:24 to 255:05

A. It -- it appears so.
Q. (By Mr. Petosa) Sir, I'd like to refer you to Tab 33, previously marked as Exhibit 1131, ending in Bates No. 184. And on the second part of that, there is an E-mail from Robert Bodek to a Michael Bier -- "Bier-ney." And I'm sorry if I'm pronouncing --

Page 255:10 to 257:18

Q. (By Mr. Petosa) I'd like to refer you down here -- just as it starts, sir, it says: "Michael, While drilling in the 8-1/2 X 9-7/8 hole-section" --
A. That's -- that's not the right one.
Q. The second page, sir.
A. Oh, I'm sorry.
Q. -- "we encountered a sand approximately 400 feet above the projected top of the reservoir."
And then it goes down, sir, and I'd like

to take you down to the middle of the E-mail, where, if you look, it says: "After pumping several..." -- it's the next line. It says: "...we pulled out of the hole for the new BHA."

A. U'hm --

Q. It starts out -- I'm going to read it. "After pumping several LCM applications and cutting mud weight in the riser, losses were no longer observed, and we pulled out of the hole for a new BHA."

A. Yes.

Q. You see that? Okay.

A. Yes.

Q. I'm going to keep reading.

"At this point, the team was faced with a tough decision. We had drilled to 18,260. At this depth, we were unsure if we had drilled through the reservoir in its entirety. It appeared as if we had drilled out the base of the reservoir, but there was no way to be certain. Additionally, the approximately 50 feet of rat hole we had beneath the main sand package was insufficient for both wireline evaluation and completion.

"It was unanimously accepted amongst the team that approximately 100 more feet would allow us to 1) make sure we had drilled through the entire reservoir package, 2) provide sufficient rat hole for wireline evaluation operations, and, 3) provide ample rat hole for completion procedures.

"We had one major problem, however. The sand we took the initial GeoTap pressure in was measured at 14.155 ppg. The absolute minimum surface mud weight we could use to cover the pore-pressure in this sand was 14.0 ppg. This would give us approximately a 14.2 ppg ESD over the aforementioned sand."

I'd like to skip a little more, two sentences, sir. Actually, one. It says: "We had already experienced static losses with a 14.5 ppg ESD!" That's an exclamation point, correct, sir?

A. Yes.

Q. "It appeared as if we had minimal, if any, drilling margin."

Now, sir, from this, doesn't it appear that the drilling margin was basically .15?

Page 257:20 to 257:25

A. (Reviewing document.) I don't know.

Q. (By Mr. Petosa) You would agree, sir, from reading this that it sure appears that in this section, that BP was attempting to drill and was drilling -- that they were not drilling with a safe drilling margin.

Page 258:02 to 258:06

A. They -- they -- they -- they thought they had minimal drilling margin, if any.
Q. (By Mr. Petosa) Shou -- shouldn't they have sought a departure from MMS before they continued to drill at this point, sir?

Page 258:08 to 259:07

A. If -- if they had reason to believe that -- that -- that they had less than a half a pound safe drilling margin between what they thought was the -- the -- the minimum fracture gradient in that hole section and -- and their -- their mud weight, their downhole mud weight, I would say "Yes."
Q. (By Mr. Petosa) And if you see, sir, the next sentence, it says: "It was decided to trip back into the hole with the simplified BHA," in parens, "(no underreamer) and very slowly and cautiously drill the requisite a hundred additional feet of formation."
And go all the way down to the second -- third to last sentence, second -- that second line there at the end that says: "We had simply run out of drilling margin."
Don't you agree, sir, as the Director of the New Orleans District Office in charge of this well, that at this point, on and around this time when BP was drilling this well and they knew they ran out of safe drilling margin, that they should have stopped drilling and contacted Mr. Patton or someone else at the office before they continued to drill that additional hundred feet?

Page 259:09 to 259:12

A. I -- I would say "Yes."
Q. (By Mr. Petosa) And that's a violation of the Regs, sir, to -- to -- to not conduct your drilling in a safe manner, correct?

Page 259:14 to 259:18

A. I wou -- I would say it's a violation of not maintaining a safe drilling margin.
Q. (By Mr. Petosa) Which has been understood in the Industry, as you described earlier, for about 20 years, correct?

Page 259:20 to 260:04

A. Yes.

Q. (By Mr. Petosa) Sir, I'd like to talk to you about the Temporary Abandonment. There's been some discussion about that today.

Let me refer you back to something that was already brought up to you today, Tab 40. It's been previously marked as Exhibit 570. It's the Approved Temporary Abandonment Procedure for MC 252. The third page of that document is the actual Plan.

Page 260:11 to 260:18

Q. Sir, I'd like to refer you to Tabs 41, 42, and 43. Tab 41 is an exhibit that's been marked as 566, Bates ending in 1670. It's an E-mail from Brian Morel, on April 20th of 2010, at 10:43 a.m.

Would you agree -- I guess it's noted as Ops Note. That appears to be a revised Temporary Abandonment Procedure. Would you agree, sir?

Page 260:20 to 261:05

A. (Reviewing document.) Yes, I would say so.

Q. (By Mr. Petosa) I'd like to turn you -- turn you to Tab 42, another Ops Note E-mail from Mr. Morel, Exhibit 547, ending in Bates Nos. 9108. This is the same date, sir, of April 20th, the day of the blowout. This E-mail is at 15:36, 3:36 in the afternoon.

Would you agree, also, sir, that that appears to be another revised Temporary Abandonment Procedure?

Page 261:07 to 261:15

A. (Reviewing document.) Yes, I would.

Q. (By Mr. Petosa) I'd like to turn you to Tab 43, sir. It's previously been marked as Exhibit 1992, ending in Bates 1107, another E-mail by Mr. Morel, same date of April 20th, the date of the blowout. This is timed at 15:43, 3:43 in the afternoon.

Would you agree that that appears to be another revised Temporary Abandonment Procedure?

Page 261:17 to 262:04

A. (Reviewing documents.) I would say it's a revised Procedure from the one that was approved, not -- not necessarily from one of the earlier E-mails, but --

Q. (By Mr. Petosa) Would you agree, sir, that the three different revised Temporary Abandonment Procedures within that five or so hour window on April 20th of 2010 -- those Procedures should have been communicated to Mr. Patton or someone else in your District Office, to obtain approval before BP went forward with the Temporary Abandonment on April 20th of 2010?

Page 262:06 to 262:14

A. I -- I -- I would say contact should have been made with -- with Frank Patton to determine whether the proposed change was material enough for him to require a -- a Revised Temporary Abandonment Procedure.

Q. (By Mr. Petosa) But that -- that determination was for Mr. Patton, as the MMS Engineer, to make, to -- to -- to decide, not for BP to decide, correct, sir?

Page 262:16 to 263:08

A. I would say "Yes."

Q. (By Mr. Petosa) Sir, I'd like to move on to discuss another topic you've spent some time talking about today, top of cement. I'd like to refer you to Tab 40, back a couple of pages, again, in the Temporary Abandonment Procedure, sir, behind -- the last page behind the one we were talking about.

Bottom left, it looks like, you would agree, it says "TOC-17,500 MD." Does that appear to be the top of cement?

A. Yes.

Q. That's what BP represented to Mr. Patton and, in turn, MMS on April 16th of 2010 was going to be this well's top of cement, correct?

A. Yes.

Q. The Regulations required what with respect to that top of cement, sir?

Page 263:10 to 263:15

A. That it be placed a minimum of 500 feet above the highest-most hydrocarbon-bearing zone.

Q. (By Mr. Petosa) The -- the -- the Regs' specific language, you would agree, is "the

uppermost hydrocarbon-bearing zone," correct?
A. Yes.

Page 263:23 to 264:01

Q. (By Mr. Petosa) If -- if BP was aware that this top of cement was not 500 feet or more above the uppermost hydrocarbon-bearing zone, what was BP required to do under the Regulations?

Page 264:03 to 264:25

A. Wou -- would they be aware of this after pumping the cement, or was this by design before the cement job?
Q. (By Mr. Petosa) If -- if -- if they became aware, sir, up to the point of pumping the cement, what would they be required to do under the Regs?
A. I -- I -- I would say submit a revised -- this was submitted under a -- an RBP?
Q. M-h'm.
A. -- another Revised Bypass Procedure to -- to amend that -- that proposed top of cement, such that it would be 500 feet above this -- this uppermost hydrocarbon-bearing zone.
Q. And would you agree, sir, that if BP identified the top of cement at 17,500 on April 16th of 2010 to MMS, you would have expected them to be making that representation with the understanding that they're going to comply with the Regulations and make sure that that TOC is 500 feet or more above the uppermost hydrocarbon-bearing zone, correct?
A. Yes.

Page 265:02 to 265:17

Q. (By Mr. Petosa) Sir, I'd like to turn you to Exhibit Number -- I'm sorry -- Tab No. 44. It's previously been marked as Exhibit 3512, ending in Bates No. 2330. It's an E-mail from Mr. Robert Bodek to Galina Skripnikova, both with BP -- the April 13th, 2010 E-mail from Mr. Bodek to Ms. Skripnikova. "Subject," it says "Top hydrocarbon bearing zone?"
"Galina, The drilling team, in their cement procedure" op -- "preparations, need to know the depth of the shallowest hydrocarbon-bearing interval in the open hole."
The response from Ms. Skripnikova at 11:51 a.m. on that date is: "I think the shallowest HC" -- hydrocarbon -- "bearing sand is

at 17,803."

Page 266:12 to 266:17

Q. You would agree, sir, that -- that BP knew when they submitted this document to MMS for approval for the Temporary Abandonment on April 16th of 2010, that they were not going to be in Compliance with the Regulations with respect to the top of cement?

Page 266:20 to 266:22

A. Yeah. I would have to say "Yes."
Q. (By Mr. Petosa) Should BP have sought a departure?

Page 266:24 to 267:03

A. Yes.
Q. (By Mr. Petosa) Or should BP have submitted a Plan that would have indicated that that top of cement was in Compliance with the Regs?

Page 267:05 to 267:17

A. You -- you -- you -- one of the two.
Q. (By Mr. Petosa) Okay.
A. They either needed to cover the sand that -- the sand they knew about, with 500 feet of -- of cement, or they needed to ask for a departure to do otherwise.
Q. (By Mr. Petosa) And would you agree, sir, that when BP went forward with the Temporary -- with pouring the cement and the Temporary Abandonment Procedure on the 19th of April and the 20th of April of 2010, they did so in violation of the Regulations as it applies to the top of cement?

Page 267:20 to 267:24

A. It -- it ap -- it appears so.
Q. (By Mr. Petosa) You say, "It appears so," sir. Don't you agree as the District Manager of the office that was overseeing this well and the MMS Representative here today?

Page 268:02 to 268:24

A. If, indeed, the -- the shallowest

hydrocarbon sand was at 17,803, and -- and this Permit was submitted after that fact was known, and it was proposed to put cement at 17,500, I would say "Yes," that's a violation of the Regulatory Requirement.

Q. Sir, I'd like to turn you to Tab 45, a document previously marked as Exhibit 7279. It's an E-mail string beginning with what ends in Bates No. 7413.

I'd like to turn you to -- if you turn it over, sir, it's the second page, Bates No. 7414, on the left side there, sir. At the top, it's an E-mail from Kent Corser to Morten Haug Emilsen. These were individuals involved in the post-blowout Investigation for BP.

It says: "Morten, We need some help with an update on the dynamic model. Are you available now some are is there someone else who could run the model? We have sand at 17,467 feet MD that is two" inches "thick. 14.1 ppg and classified as GAS and would flow. Want to see how that fits to at least start the kick."

Page 269:04 to 269:18

MR. PETOSA: "2 feet thick." I'm sorry. "2 feet thick." I apologize.

Q. (By Mr. Petosa) And if you could turn back, sir, to the first page, I'd like to go all the way to the top, Mr. Corser's E-mail to Morten Haug Emilsen. And I apologize if I'm saying his name wrong.

"This sand is new. They did a new study and have classified it as a gas bearing incapable of flow. See attached chart. This is NOT the brine sand."

Would you agree, sir, that, in fact, the uppermost hydrocarbon bearing zone, in reference to that top of cement, was not at 17,807 we talked about before. It was, in fact, at 17,467?

Page 269:21 to 270:09

A. (Reviewing document.) This E-mail is dated after --

Q. M-h'm.

A. -- after the cement job, so I don't know at what point in time, if they found the -- the two-foot thick gas sand.

Q. If on the day of the incident, Ms. Skripnikova, the individual with BP that was in charge of determining what -- the uppermost hydrocarbon bearing zone, became aware that they, in fact, had a probable hydrocarbon zone at 17 --

at 17,467, would you have expected that information to be communicated to the individuals on the well to take appropriate action?

Page 270:11 to 270:22

A. I would expect that -- that -- that BP should have revised their --
Q. (By Mr. Petosa) At Tab -- Tab 40.
A. Was the -- this -- this is not the Permit that the -- that the casing string was -- was run in, so the -- I mean, I don't -- I don't know if this is a -- just a notation error, but -- but -- but I would expect that if they knew that before they ran the casing, that they would revise their cement volume, such that the proposed top of cement would be 500 feet above that -- that two-foot gas sand.

Page 271:16 to 271:22

Q. Let's move on, sir. We're going to talk a little bit about the -- the JIT Report and this -- this -- the part of the Report from BOEMRE dated September 14th, 2011. You've been asked some questions about it today.
A. (Nodding.)
Q. It's been marked as Exhibit 5327. I'll

Page 272:09 to 272:18

Q. If, in fact, INCs are going to be issued at any time, would those INCs come from your office?
A. Yes, they would.
Q. Okay. And I know you mentioned you haven't reviewed this Report, correct, sir?
A. Correct.
Q. At some point in time, you do intend to do so, correct?
A. Yes.

Page 272:22 to 273:13

I'd like to refer you to Page 173 and 174, sir, the section entitled "Incidents of Non-Compliance."
And, at the bottom, I'd like to refer you to Footnote 423. "This list of violations is based upon the evidence gathered by the JIT during its investigation...upon the Panel's findings and conclusions. Additional evidence may reveal further violations. After this Report

is released, BOEMRE will issue Incidents of
Non-Compliance based upon evidence contained in
this Report and/or other relevant evidence."
If that happens, it's coming through your
office, under your direction as District Manager
of the New Orleans District, correct, sir?
A. That -- that's my understanding, yes.
Q. Okay. Sir, I'd like to go through with

Page 275:16 to 275:20

Q. (By Mr. Petosa) Sir, you would agree that
some of these Incidents of Non-Compliance we just
talked about relate to some of the matters that
you've talked about here today, in fact, I've
just discussed with you now?

Page 276:01 to 276:01

A. Yes.

Page 278:23 to 279:03

Q. (By Mr. Petosa) Do you remember that MoC
we talked about, sir, where BP was evaluating
whether or not to go forward with the long string
design or the long string design with a liner,
and one of the driving factors was what, sir? It
was cost, correct?

Page 279:06 to 279:14

A. I -- I do recall there being a difference
in cost.
Q. (By Mr. Petosa) And you also remember, in
that same MoC we reviewed, sir, which was dated
April 15th of 2010, BP recognized the risk of
going forward with that design, was going to
eliminate one potential barrier, if you had
hydrocarbon flowing within the zones relative to
the cement, correct?

Page 279:16 to 280:01

A. Yes, I do recall that.
Q. (By Mr. Petosa) Yet, BP continued on with
the Temporary Abandonment on April 20th of 2010,
correct, sir?
A. Yes.
Q. And the blowout occurred, correct?
A. Yes.
Q. Okay. Do you agree, sir, that when you

have an opportunity to fully evaluate this JIT, that your office should issue INCs with respect to BP and the others' conduct?

Page 280:06 to 280:09

A. I can't answer that now.
Q. (By Mr. Petosa) But you're going back and review this Report and make that determination for your office, aren't you, sir?

Page 280:12 to 280:12

A. Yes.

Page 281:04 to 282:04

You stated earlier that a -- during drilling operations, it is possible that, in downhole, the mud may be flowing into a sand without fracturing it. Is that an approximation of what you said?
A. Yeah, that -- that's -- that's my belief or understanding.
Q. On the other hand, you -- I -- I take it you would agree that you could be fracturing the sand if the -- the pressure was high enough?
A. I would -- I would agree, yes, you could be.
Q. Okay. And do you consider yourself an expert in fracture gradients encountered while drilling?
A. No.
Q. So does MMS rely on the Operator to be the experts in determining whether the fracture gradient has changed downhole?
A. I -- I would say definitely, yes.
Q. And if those experts, meaning the Operator, determined that the fracture gradient has changed, and that the fracture gradient is now less than .5 ppg above the mud weight, they're required to stop drilling?
A. I -- I would agree with that, yes.