Deposition Testimony of:

Patrick Campbell

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Page 10:08 to 10:09

PATRICK CAMPBELL, having been duly sworn, testified as follows:

Page 10:12 to 13:19

Q. Please state your name for the record.
A. Patrick Joseph Campbell.
Q. Where do you live, Mr. Campbell?
A. [redacted]
Q. And who do you work for?
A. I work for Superior Energy Services Incorporated, and I am -- at the same time I am the CEO of Wild Well Control.
Q. Tell me what Wild Well Control is.
A. Well, it's -- one always hopes that you created a descriptive name, and its primary core business is that of resolving issues with respect to wells that either may be out of control or have a high propensity for -- they could become out of control or planning to avoid how they would be out of control.
We also do significant well control training work, about 10,000 people per year that we certify for well -- advanced or conventional well control training.
Q. Does Wild Well have a business relationship with BP?
A. Yes.
Q. Okay. And, in fact, does Wild Well provide some well control training for BP employees?
A. Yes.
Q. And including people that BP describes as their well site leaders?
A. That is correct.
Q. Okay. Tell me what they do for that. Tell -- tell me when a well site leader of BP --
A. Yes.
Q. -- well site leader comes to Wild Well for training, what happens?
A. We have a four-day program that includes certain classroom work, and it includes considerable body of work on simulators that simulate well -- wellbore conditions. They could either be specific at the request of the customer and built just for that class, those scenarios, or they could be a variety of well scenarios that

bear no relationship to any specific project.

Q. Okay. Does -- is part of your training curriculum geared towards Gulf of Mexico deepwater wells or is it geared towards everything?

A. Well, it is -- generally speaking, the courses are broad, and that is that they cross all sorts of geographical lines. And we -- we do have certain specialized courses that are -- contain certain peculiarities to deepwater work, once again, not necessarily specifically for the Gulf of Mexico but for deepwater in general, for floating rigs in general, from what's called MODUs, mobile offshore drilling units in general, and -- and then we can custom 00013:01 build a curriculum to fit any customer's request about the type of wells that are -- are being dealt with in these advanced classes.

Q. Okay. Did BP ever require or -- request or require or ask for specialized training for their particular employees?

MR. OCCHUIZZO:

Objection, form.

A. Yes, from time to time they have.

EXAMINATION BY MR. WILLIAMSON:

Q. Okay. Not across the board, but every once in a while they may ask for a specific --

A. They might just send a group consisting of six to ten, generally speaking, higher-level employees that -- that they wish to expose to a certain set of circumstances.

Page 16:03 to 25:25

00016:03 My question was: When you deal with well control training courses taught by Wild Well, I'm trying to figure out what training is given with respect to BOP configuration or operation or is that really not part of y'all's curriculum?

A. It is part of the curriculum.

Q. Okay. Tell me kind of how.

A. Often there are numerous questions about selecting a BOP configuration for specific well applications.

Q. Okay.

A. And those would then be addressed. Beyond that, our typical courses would say, here is a representative general configuration for a well. And it might be changed in many ways. It might be changed to include more cavities, it might be changed to alter what resides in the individual BOP cavities, the order in which they are assembled --

Q. Okay.

A. -- so -- beyond that, we don't do a lot insofar as choke and kill lines, a little bit; flex joint lower marine riser package, et cetera, it's fairly standardized. So unless a student would ask questions or the customer would ask questions that he would like to see included, that is not something we -- we dwell on.

Q. Okay. Let me see if I can ask a couple of examples to see if I understand.

For example, there is a regulation that requires one to calculate the maximum anticipated surface pressure that the components of the BOP will be subjected to. I'm sure you're familiar with that CFR.

A. Yes.

Q. Is that part of your training curriculum? Do y'all really dwell on that particular aspect of BOP operation or configuration or --

A. Only to the extent that we would reiterate that CFR.

Q. Okay. Like, for example, would you tell -- like, do you know who's supposed to calculate that on a given well -- let me -- I'll back up.

I'll ask this question: MASP will vary depending on the particular well that you are drilling, correct?

A. Correct.

Q. Therefore, it has to be calculated for every individual well, correct?

A. Yes.

Q. Okay. And, of course, one way to calculate maximum anticipated surface pressure would be to carry a gas column to surface or a gas column all the way to the -- to the BOP?

A. Right.

Q. Okay. And I guess that would give you your maximum anticipated surface pressure, a 100 percent gas column to surface?

A. (Moving head up and down.)

Q. Okay. Is that fair to say?

A. That -- yes, that's -- that's pretty close, yeah.

Q. Okay. The -- okay. I'm trying to figure out who's supposed to calculate that as far as you know or is that not something y'all really cover?

A. Once again, I don't think we dwell on that in -- in our training. And if you say, who's supposed to do that, the well construction team of that oil operator, that would be part and parcel of his planning --

Q. Fair.

A. -- of the well itself, and -- and because -- now, he -- as you may well know, he might do an entire well construction program, very detailed, but does not yet know what rig is going to drill that well.

Q. Right.

A. And consequently what the competency and capabilities of the associated BOP stack will be at the time that he's doing the well construction.

Q. Okay. So the answer is, just to take that -- I'm just taking that one little specific example --

A. Yes, sir.

Q. -- okay?

MASP, the operator would calculate it as part of his well construction, well design program?

A. That is correct.

Q. Okay. And then it -- but y'all don't really dwell on, gee, does the engineer do it -- I'm going to deal with BP for a second -- does the BP engineer do it, does the BP well site leader do it, does the BP well team's leader do it, does the BP -- y'all don't get into that level of detail?

A. We do not.

Q. You just tell BP it's got to be calculated?

A. Correct.

Q. And that 100 percent gas column to surface is probably going to give you very close to your maximum anticipated surface pressure?

A. Right.

Q. And you leave it up to BP to figure out how their organization's going to take care of complying with that regulatory requirement. Have I stated it correctly?

A. You have. I would -- I would make a comment.

Q. Please do.

A. And that is, it depends to some extent what you know about the subsurface geology at the zones that will be exposed or of interest because an evacuated wellbore -- in other words, free of -- of wellbore drilling fluids may not be just a free column of gas. It could very well be an interspersed, multi-phased column that would consist of oil, gas, et cetera, et cetera.

Q. Okay. The -- so you'd look at the particular geological features, fracture gradient, pore pressure, bottom hole pressures --

A. Correct.

Q. -- in order to do the calculation appropriately?

A. Yes, sir.

Q. Okay. Likewise, I will tell you -- I'm going to use another example, and I'll deal with the blowout preventers.

There's a CFR that says that the operator of the well shall ensure a testing protocol for the BOP to ensure well control. I'm sure you're familiar with that CFR, too?

A. Yes, sir.

Q. Right.

And I'm sure in your class you make sure that you -- I think you -- I think you used the word "reiterate" --

A. Right.

Q. -- that you have to comply with that, that the operator needs to come up with a testing protocol for the blowout preventer to ensure well control, fair?

A. Yes, sir.

Q. Same question: Do y'all deal on the details of how BP is going to actually do that in your particular class?

A. No, sir, not -- not unless it has been specifically requested that that be a topic --

Q. Okay.

A. -- that . . .

Q. Okay. Okay. Another example, okay? Some BOP systems have systems that are called EDS -- this particular one, a Cameron BOP, has a couple of things they call an EDS-1 and an EDS-2. I'm sure you're familiar with those terms.

A. I am, but you still have to jog my memory.

Q. Sure. I'll tell you: On the DEEPWATER HORIZON, EDS-1 stood for emergency disconnect system dash 1, and on the deepwater -- I understand it varies some from rig to rig -- on the DEEPWATER HORIZON, EDS-1 was programmed to -- to activate the blind shear rams from a subsea accumulator and also chose -- close the associated choke and kill lines and I believe retract the stack

stingers, okay?
A. (Moving head up and down.)
Q. But the main function -- or the -- the primary goal was to close the blind shear rams. That was EDS-1.
EDS-2, okay, we're -- you're -- you're familiar with what I'm saying is EDS-1, at least as it was programmed on the HORIZON?
A. Right.
Q. Okay. EDS-2, as programmed on the HORIZON, was that you would close the casing shear rams first and then close the blind shear rams along with the associated choke and kill lines, fair?
A. Yes, sir.
Q. Okay. Here's my question now that I've kind of told you how the HORIZON BOP was programmed: In your well control training, does that cover the fact that, gee, you should use EDS-1, or you should use EDS-2, you should close the casing shears first, then the blind shears. Do y'all go into that level of detail in your well control training courses?
A. Only if that is a topic that has been identified that the -- the customer, BP, wants to expend some time, energy, and discussion on.
Q. Okay.
A. Otherwise, we just, as you said, reiterate that these systems are to be invoked under certain conditions.
Q. Sure. I'll give you an example. I -- I believe -- don't hold me to it -- I believe API 53 recommends that you know the limitations of your sealing shear ram. And, of course, I'm sure you would agree that's a good idea?
A. Yes.
Q. Obviously if you have a sealing shear ram, you need to know the design envelope of it, when it will work, and when it won't work. That's pretty obvious, isn't it?
A. Yes, sir.
Q. Okay. And -- and I'm just trying to say y'all, of course, would reiterate to your customers that that's important to know and you need to understand the design limitations of your BOP, but y'all would not go into the details of -- of figuring that out for the DEEPWATER HORIZON unless you were specifically requested to do so by BP?

A. That's correct.
Q. Did BP -- okay. Now, my next question to you is: Do you remember -- and I'll -- we'll pull the Wild Well records on all this. But do you remember BP ever making such a request to Wild Well Control?
A. I do not personally.
Q. Okay. But, of course, you may not know. The records of Wild Well would probably be a better source to figure out the answer to that question?

Page 26:02 to 40:13

Q. Right. The -- all right. Did you -- tell me how long you've been with Wild Well.
A. I was with Wild Well Control from 2000 forward.
Q. Okay. Is that when it was formed?
A. No. It was formed in 1975 by Joe Bowden, Sr.
Q. Okay. Tell me a little bit about your work history, Mr. Campbell.
A. I --
Q. You -- where'd you -- where'd you -- let's start with where you grew up and where you got out of high school and what year. We're going to be pretty brief on this part --
A. Okay.
Q. -- because I'm sure you -- my understanding based on my investigation is you've had a pretty colorful career, okay?
A. All right.
Q. So -- but let's start with where you grew up and where you went to high school and what education you got.
A. I grew up in Nebraska until junior high school, then came to California, Bakersfield, California, through high school, graduated in 1963.
Q. Okay. Where did you go to school? Did you --
A. North High School in Bakersfield.
Q. Did you get any formal education past high school?
A. No.
Q. Okay. What'd you -- tell me briefly how it is that in the year 2000 you joined Wild Well. We're going to cover 1963 to 2000 hopefully pretty quickly.
A. Okay. I -- I was employed first

by a firm called Reagan Forge & Engineering. And one of Reagan's specialties was a diverter system that was used on offshore rigs.
Q. Okay.
A. And I followed that by working for Cameron Ironworks as somewhat of a blowout preventer specialist --
Q. Okay.
A. -- mostly by traveling to areas to either conduct maintenance repairs, et cetera, et cetera, wherever the -- wherever the BOPs were located.
Q. Sure. What year were you with Cameron?
A. That would have been '65 and '-6 '-7.
Q. Okay.
A. '75 -- pardon me. '66, 60- -- '65, '66, '67.
Then went to work for FMC Corporation, another wellhead specialty organization and flow control products organization. I worked for them for, oh, I believe it was about 11 years and -- all over the world, living in California, Iran, United Arab Emirates, UK, and then to Houston.
Q. Okay.
A. And in the course of that time, to give you the idea of how I got in this business, from very early on, even in the days with Cameron Ironworks, I knew the people in the Red Adair organization well, and they would ask me from time to time to assist them in obtaining specialty equipment that was required for capping wells.
Q. Flowing wells?
A. Yes.
Q. Okay. And that was an area of the business that must have interested you somehow?
A. It was.
Q. Okay.
A. And I guess one thing that sticks out in my memory was they called one time from Sumatra. These are before fax machines and before -- you had to have an ability to describe what you needed. And the person on the other end had to have an ability to interpret that correctly.
Q. Okay.
A. So I recall one specific job where they said, "Okay. You got it ready. You're going to ship it. And, fat boy, why

don't you just come along with it to make sure it works."

Q. Who is "Fat Boy"? Was that you?

A. That's me.

Q. Okay. A term of affection, I assume?

A. One -- one would hope but unlikely. At any rate, it just turned out, then, that I was requested to go on more and more jobs all the time with either Mr. Adair or Boots Hansen or Coots Matthews. And after some point in time, they said, "Well, why don't you just come to work here? I mean, it will be easier than what we're doing now."

And so in December of 1977, Mr. Adair, Mr. Hansen, and Mr. Matthews split.

Q. Okay.

A. And I went to work for Boots & Coots, Incorporated and worked there until 1985.

Q. Okay.

A. And -- and at that time -- I had already started another specialty business to provide certain narrow-niche products to the oil companies, to the service companies, and to the blowout companies.

Q. Was your split with Boots & Coots friendly or unfriendly or --

A. Oh, no. It was friendly. They were ready to sell out and retire, and they -- they just had different business objectives than I had and --

Q. Fair enough.

A. -- so we -- we parted company. We always remained great friends.

Q. Okay. In 1985 you start your own company, then. What was the name of it?

A. It was BTI, Blowout Tools, Incorporated.

Q. Okay. Which by now is an area you'd been working in for quite a while?

A. Yes. Yeah.

Q. And how long did -- tell me -- tell me how long BTI stayed in business or what y'all did.

A. It has -- well, I could check, but it still better be in business this morning. But there -- we -- we really specialized in tools for which there was not a demand for hundreds of them, but one company could have a broad range of sizes and satisfy the requirement on very short notice that they had high-quality tools built to a specific standard that were verifiable, traceable, et cetera, et cetera, rather than going to a machine shop at midnight and trying to make one.

Q. Is that a good idea? Is it a good idea to have a go-to guy so that if you have an emergency you have the equipment available to deal with it?

A. That's correct.

Q. As a matter of fact, if I'm understanding correctly, you built your career upon the fact that companies need to be prepared to have blowout tools available immediately in the event they have a blowout.

A. Yes, sir.

Q. That's just a good common sense principle, right?

A. Yes, sir.

Q. I assume up until this time most of your work has been done on surface, up to 1985?

A. Oh, we did -- we did a number of shallow water interventions on -- on either subsea wells or wells that had platforms that had been damaged by a ship running over them. For example, platforms that had survived a hurricane or not survived a hurricane and all the wells were submerged.

But all -- most all of those were done in diver depths for either mixed gas air diving or saturation diving. You -- you always had the ability to put humans at the workplace.

Q. At the wellhead?

A. Yes.

Q. Okay. The -- speaking of that, during that period of time did people use anything that they called a capping stack? Because I've seen the term "capping stack" --

A. Certainly.

Q. -- used now.

A. Certainly.

Q. Okay. So the term "capping stack" has been around since at least the Eighties or --

A. Seventies.

Q. Okay.

A. Oh, I -- earlier, perhaps, yeah.

Q. Fair enough.

A. Yeah.

Q. I'll just take it since the Seventies --

A. Okay.

Q. -- the last 40 years.

What's a capping stack? You tell me kind of generically how you would describe that term.

A. Right. A capping stack could be -- a capping device could be anything from a single valve --

Q. Okay.

A. -- to place on top of a damaged production tree or something like that up to a blowout preventer or a series of blowout preventers that have been designed to overcome certain obstacles that exist on this blowout well. And it could take on many potential configurations.

Q. Did BTI have anything they would call capping stacks that would be available?

A. We -- we had components that we made capping stacks from very quickly, from certified components, et cetera, et cetera.

Q. Yeah. For example -- what I understand, like, for example, three at that time -- Eighties and Nineties --

A. Yeah.

Q. -- three of the major blowout preventer manufacturers were Cameron, Hydril, and Shaffer.

A. Correct.

Q. And as I understand it, Cameron, Hydril, and Shaffer each have their own connector systems.

A. For subsea wells.

Q. Correct.

A. Yeah.

Q. And, actually, they may have -- I don't know. You probably do know. Cameron may have more than one connector.

A. They do.

Q. Okay. And that -- is that true for Hydril and Shaffer, too?

A. Less so, but there -- there's at least variations.

Q. Right. So if you were going to put together a capping stack for any particular well, you'd have to make -- I'm going to use the blowout preventer example, although I realize you defined it more broadly. But if you were going to use a blowout preventer-type capping stack, you would need to mate it to an appropriate connector for the particular well; is that right?

A. The -- the majority of the time that would be correct, yes.

Q. Okay. If you'd like to clarify it, go ahead and clarify it.

A. Well, you seldom find a well like the Macondo well where everything is

erect and intact.
Q. Okay.
A. Generally, having sustained either a drive-off, some other accident, wellheads are bent over. Wellheads are no longer erect. There may be casing damage at the base of the wellhead. And, in fact, all of that has to be cut off, and you have to install a new wellhead --
Q. Okay.
A. -- at depth.
Q. So Macondo actually had -- even though it was a large disaster --
A. Yes.
Q. -- it actually had the advantage of having vertical integrity in terms of having the BOP stack and LMRP still intact?
A. It -- it had numerous advantages.
Q. Okay. Tell me what the other -- tell me how you would describe that. In other words, the numerous advantages, I assume, of going about trying to close it in.
A. Yeah.
Q. That's what you mean?
A. Well, and those are only mechanical advantages.
Q. Right.
A. I'm not talking about the wellbore or anything like that.
Q. Correct.
A. Yeah. But it was essentially erect. Now, it was not quite erect.
What -- what happened is as the rig lost power, lost dynamic positioning, and as the current and wind drove it off, it started to apply tension to the wellhead assembly. Furthermore, it sank, and then we don't know exactly the mechanisms that occurred, but for a long time the riser remained connected to the LMRP. And so on ROV inspection of the near well area at the seafloor, you could see a big ellipse which told you that the entire assembly had been pulled over. At some point it broke off, and then it snapped back. It was not quite vertical. It was rather close to vertical. The best we could tell, it was in a couple -- within a couple of degrees of vertical.
Q. Okay.
A. And so our assumption was that -- that the pipe had moved within its elastic range and had bounced back.
Q. By "pipe" you mean --
A. The casing in the well, below

the wellhead housing that the BOP is sitting on.

Q. Is that also true -- did y'all conclude that also for the drill pipe? Because there was also drill pipe in the hole at the time.

A. Well, the drill pipe would be the most flexible. So this -- this amount of movement would not have had an impact on causing a failure of the drill pipe, not a failure, okay? In other words, it would have been moving within its elastic range, plus there was space inside that area.

Q. I assume -- of course, in this particular case we happen to know at Macondo we had 5-1/2-inch S-135 drill pipe through the BOP at the time of the disaster.

A. Yes, sir.

Q. Okay. And what you're saying is there's a certain amount of elasticity to that particular string of drill pipe?

A. To any steel, yes.

Q. Fair.

And I guess in this particular BOP, just to put it in reference, was an 18-3/4 Cameron TL?

A. Correct.

Q. Okay. So you have an 18-3/4 wellbore hole and 5-1/2-inch OD pipe in it, right?

A. Yes, sir.

Q. Okay. So I guess at any given point in time, is that pipe going to be perfectly centered within the BOP or is it possible that it will be off-centered?

A. Yeah. It's -- generally it's unlikely that the pipe will be centered on almost any well.

Q. Okay. To make sure I'm -- I want to make sure I understood you so I don't -- it's unlikely the pipe will be centered?

A. That's correct.

Q. It's more likely the pipe at any given moment will be off-center?

A. That is correct.

Page 40:24 to 41:07

If you're going to have the BOP work, it's going to have to work with off-center pipe as well as centered pipe because lots of times you have off-center pipe?

A. That's correct.

Q. Okay.
A. I mean, that goes all the way to land rigs to anywhere.

Page 41:12 to 44:25

The -- when did you first hear about the Macondo disaster?
A. At about 1:30 a.m. on the night that it occurred.
Q. Okay. And I'm sure your company was then called in to assist with that project, based on all the documents I've seen.
A. The -- the short answer to that is yes. The first call was from my own employee to me who had taken the call from BP, and it was simply to put us on notice that something had occurred. They didn't know all the details. They were fully engaged in trying to get the people that could be rescued and find the others and that they would be back in touch with us shortly.
Q. Okay.
A. But, yes, in other words, prepare for mobilization.
Q. I will tell you from the records I've seen, Wild Well had actually been on the DEEPWATER HORIZON on the Macondo well before April 21st --
A. That's correct.
Q. -- 2010.
A. Yes, sir.
Q. As I understand it, y'all were called out for the March 8th kick and the well control problems affiliated with the March 8th kick --
A. Yes, sir.
Q. -- right?
Were you involved with that at that time or were --
A. From a supervisory role only, yes.
Q. Okay. Who would be the person who was kind of -- at Wild Well who would kind of be most involved with taking care of the March 8th situation?
A. Well, the -- the person that did the majority of the work on that would have been Kerry, K-e-r-r-y, Girlinghouse, G-i-r-l-i-n-g-h-o-u-s-e.
Q. And could you tell me -- that's -- I assume -- is that a man?
A. Yes.
Q. Male or female -- male?

A. Male.
Q. Mr. -- Mr. Girlinghouse, what is his position within Wild Well? What's his job?
A. He is the senior technical advisor, but he is also an engineer and about 30 years of experience.
Q. Okay. So one of your experienced well control people?
A. Yes. Now, we simultaneously had people in their emergency ops room. They gen -- BP generally brings together a group for the purpose of dealing with anything like that at all.
Q. Okay.
A. And so we did have other people involved, but Kerry was the key guy, and he's the one who went offshore and so on and so on.
Q. Okay. So he would have kind of been the point man, but you would have had other employees who would have also had a role?
A. That's correct.
Q. Okay. The -- were you on the Macondo on any other situations? Obviously, on April 21st y'all hear about it and come in after the incident --
A. Right.
Q. -- which I'll deal with in a minute.
A. Okay.
Q. But -- and you obviously come in for the March 8th kick, which eventually ended them closing the well in and sidetracking?
A. Correct.
Q. Any other times when y'all were on the Macondo site?
A. Not to my knowledge.

Page 45:14 to 62:05

Q. Tell me kind of what occasions. And this isn't a memory quiz. I'm not trying -- but I'm trying to get a general idea of your experience with the DEEPWATER HORIZON.
A. As best I recall, it had to do with -- it had to do with the DEEPWATER HORIZON and their BOP stack and their testing -- I'm saying preventive testing protocol for the BOP stack when it was run, lowered into position, and you perform all of your tests and so on. They

00046:01 had a recurring problem, and they were looking for solutions on how to address that problem. Now, that was in -- I do know it was in 2007. I don't remember the dates.
Q. Okay.
A. It had nothing to do with Macondo. The rig was on an entirely different project in those days, at that time.
Q. I will tell you in the summer of 2007 --
A. Yes, sir.
Q. -- they had two VBRs at different points fail function tests.
A. Right.
Q. And they had to pull the BOP stack.
A. Right.
Q. And there's documents that indicate that BP --
A. Yeah.
Q. -- called Wild Well to do a risk assessment on the blowout preventer on the DEEPWATER HORIZON and that that was done in approximately September or October 2007.
00047:01 Does all of that fit your memory of what you're talking about?
A. I would -- I would have to refer to something, but I would say I'm sure that's accurate.
Q. Okay. Does Wild Well occasionally do that, come in and do a blowout preventer assessment for various parties or is that kind of --
A. Yes.
Q. -- something that you --
A. It's a special item, but yes.
Q. Okay. Y'all have the capability to do it and -- but you're not called upon to do it that often. Would that be a fair way to say it?
A. That's correct.
Q. Okay. In this particular case, BP called you to do a risk assessment on the DEEPWATER HORIZON blowout preventer, 2007?
A. They called us to be a participant in a group exercise that included BP, Transocean, and Wild Well.
Q. Okay. I'm going to -- and I can show you the document -- I can show you at
00048:01 least some of the documents. But tell me what your memory is of that. What were they trying to figure out? In 2007 with the BOP assessment, what was BP trying to figure out?
A. Are you familiar with the term

"NPD," nonproductive time?
Q. I am.
A. Okay. So you can imagine you're talking about a lot of money if you run a BOP stack and do all these tests and then you have a single VBR fail and have to recover the stack.
Q. Sure. You have to shut in the well, pull the BOP stack, get it to the surface --
A. Right.
Q. -- fix it and get it reattached to the wellhead --
A. Right.
Q. -- which all takes time.
A. So -- so I'm not going to say -- BP asked us to participate in this exercise. BP did not go into great detail, but I don't think it was necessary to understand that their objective was to try to reduce nonproductive time.
Q. Okay. Well, did they talk -- did BP say, "We want to increase the safety profile of the BOP"?
A. At the same time. They -- they at least wanted to examine the safety profile.
Q. Okay. I will tell you in the discovery in this case we've discovered -- of course, you already -- we've already -- you and I have already discussed, it's a Cameron 18-3/4-inch TL with ST locks.
A. Yes, sir.
Q. That's the particular mechanical configuration, okay?
Apparently, there were more efficient ram -- blind shear ram blocks called double-Vs or DVS, I think is what Cameron calls them. And there's apparently also things called tandem boosters that can provide more shearing force to your blind shear rams.
Here's the question: Did those subjects come up in the 2007 risk assessment, using tandem boosters, using a more efficient ram block cutting configuration, those sort of things?
A. This was not at all about severing the pipe --
Q. Okay.
A. -- the inner string, the drill string.
Q. Right.
A. This had nothing to do with severing the drill string at all. This was

looking for a design or operational fix to what was occurring with the VBRs --
Q. Okay.
A. -- only.
Q. So really the risk assessment that was being done was being done in connection with the fact it had two failures on the VBRs and they were trying to figure out what to do about it?
A. Yes, sir.
Q. I will tell you one of the things that's in the paperwork -- and I'm not trying to hide it from you. I --
A. Okay.
Q. -- actually have it here somewhere. But I'll just tell you: Was -- as I'm sure you know, this particular stack was a five-cavity stack?
A. Yeah.
Q. And the bottom three cavities were variable bore rams or variable bore pipe rams, right?
A. Yes.
Q. And in 2004-2005 BP had requested that the bottom VBR be changed to a test ram. And so the ram block in the bottom VBR was inverted to hold pressure from above?
A. Right.
Q. I'm sure you know that, too.
A. Right.
Q. Leaving them with two effective VBRs?
A. Right.
Q. The -- what they call the middle and the upper?
A. Yes.
Q. Okay. I'll tell you: In the paperwork it seems to say one of the options in the 2007 risk assessment that was being discussed was a bidirectional test ram, namely, to make that lower VBR bidirectional. Do you remember that discussion?
A. It was a discussion, yeah, part of the discussion.
Q. Okay. And what was the reasoning behind doing it, advantages or disadvantages, pros, cons, or do you recall?
A. I mean, the -- the -- the pros and cons are that if -- if -- if one could accomplish this bidirectional VBRs, then that -- that would be an advantage from the testing standpoint, because it could also be an operational VBR not solely dedicated only to testing.
Q. Right.

A. Now, my recollection is that's -- that -- that was the only issue about if I'm just sitting here, why would I prefer to have a bidirectional VBR.

Q. Well, it will give you redundancy on your VBR stack --

A. Yeah.

Q. -- and you can also use it to test?

A. Right.

Q. By the way, if I understand the reason they put in the test rams is also to save NPT. It saves you the trouble of having to set a bridge plug to test the BOP?

MR. OCCHUIZZO:

Objection, form.

A. That is correct.

EXAMINATION BY MR. WILLIAMSON:

Q. Okay. So what you're trying to do, the test ram doesn't give you any safety advantage, it gives you a reduction in NPT and time and trouble?

A. Yes, sir.

MR. OCCHUIZZO:

Objection, form.

EXAMINATION BY MR. WILLIAMSON:

Q. It makes your testing protocol easier?

A. Yes, sir.

Q. Right.

The --

A. And more efficient.

Q. All right. What's the downside to putting in a bidirectional VBR? I guess, No. 1, you've got to buy it and put it in?

A. Well, the VBR is the ram block itself --

Q. Okay.

A. -- okay? But to have a bidirectional VBR means completely changing the -- the actual body of that blowout preventer.

Q. You mean that particular cavity or you --

A. Yes, that -- that whole body of that blowout preventer that the VBRs will reside in, they have a sealing surface typically on top, but you have now inverted that BOP.

Q. Right.

A. You've inverted the BOP. So the sealing surface is now on the bottom.

If you'll imagine when -- if it were back in its original configuration, it has mud relief grooves in the bottom because the bottom has nothing to do with sealing.

Q. Okay.

A. And so as the rams retract, there has to be a place for mud, contaminated cement, et cetera, et cetera, to go in to relieve itself back to the bore.

In order to create a bidirectional VBR, you have to have a sealing surface on both surfaces --

Q. Okay.

A. -- okay? Therefore, just because I could create the VBR ram blocks that could be bidirectional does not resolve all issues. I now -- I have to have a body that can allow the ram blocks to seal against the top in the event of wellbore -- wellbore pressure or to seal against the bottom in the case of test pressure.

Q. I would -- I will tell you Cameron has testified that they did make a bidirectional VBR ram in 2007 that Cameron says is a functional and reliable piece of equipment. Does that fit your memory, also?

A. Oh, I don't -- I don't doubt that. I mean, they said they could do it, absolutely.

Q. Okay. So if it could be done, I'm trying to figure out what's the disadvantage. You've told me the advantage.

A. Uh-huh.

Q. It will reduce nonproductive time and it will increase redundancy in your BOP stack?

A. Correct.

Q. I'm now trying to see, gee, what's the disadvantage?

A. I would -- I would have to familiarize myself once again with DEEPWATER HORIZON's BOP stack. I don't -- I don't recall if the bottom blowout preventer, the one being used as the test ram, was a single cavity blowout preventer or if it was part of a set, a dual cavity blowout preventer.

Q. I'm --

A. I mean, these are technicalities, but they -- but they still affect --

Q. Sure.

A. -- what would have to be altered.

Q. I think it's a -- if it's a single cavity -- and I'll tell you I think it was, but I'm a lawyer, I'm not a blowout preventer expert. But my memory is that it's

a single cavity blowout preventer in the bottom VBR --
A. Okay.
Q. -- not a double.
A. Okay.
Q. If I'm right. And if I'm wrong there will be a hundred documents and a hundred lawyers will tell me so, okay?
But if it is a single cavity, then you could pull out that cavity and put in the bidirectional, right?
A. Yes.
Q. Okay. What would be the disadvantage to doing so other than you'd have to write a check to buy it?
A. Right. I personally don't know of any disadvantage.
Q. Okay. And your memory is that in 2007 the subject of the blind shear rams did not come up for discussion as part of this particular workshop?
A. No, it was not an issue in this workshop.
Q. Okay. Are the wells in the Gulf of Mexico sometimes -- deepwater wells in the Gulf of Mexico, are they sometimes referred to as narrow margin wells?
A. Well, yes.
Q. Okay.
A. Yes.
Q. And what is meant by that? When someone refers to the wells in the Gulf of Mexico as "narrow margin wells," what does that mean?
A. It means that it's -- first and foremost, well construction is difficult because you have to calculate and -- casing setting points that -- that show a strength and a competency to be able to anchor that casing string and to isolate that casing shoe, casing seat, while you drill the next section of open hole.
And what one finds is there's very little margin or tolerance between the previous casing seat and certain formations that you're going to encounter in the next open hole section.
So you are faced with, What shall I do? Shall I -- shall I set this string as a liner, an intermediate liner, and not try to reach for the goal, so to speak, but say, I will set it as a liner and then I will set yet another liner in order to get this weaker section or more powerful section behind pipe, because I don't have enough

tolerance to drill any further than that without exceeding the frac gradient of the -- that may exist in open hole.

So -- and then that -- that liner I will probably tie back all the way to surface.

Q. Why?

A. In order to provide a single conduit that has full wellbore integrity.

As -- as I've run larger ones previously, they may or may not have the ability to withstand internal pressures that I will perhaps be exposed to in the lower sections of the hole. Therefore, I have to isolate that larger pipe and weaker casing shoe away from exposure.

So I will have to tie this liner back to the surface in order to provide a higher pressure conduit and a more competent conduit and one that I haven't already now drilled 10- or 12,000 feet of hole through, which may have had some negative impact on the -- on the condition of that previous casing string.

Q. So --

A. I will isolate all that by running a -- a tieback.

Q. Okay. And so running a tieback provides a safety advantage in terms of terms of well integrity --

A. That's correct.

Q. -- am I -- am I understanding that correctly?

And is it pretty normal procedure when you're drilling deepwater wells in the Gulf of Mexico to use a tieback all the way to surface?

A. It's awfully hard when you categorize it that way, because it -- it could be typical in some circumstances and not so typical in -- generally speaking, yes, typically that's a fair statement.

However, there are always exceptions that are not exceptions for any bad reason, they're just exceptions.

Q. Okay. So if I'm understanding, you set your surface casing strings 36, 32, 30, 22, 16?

A. Think -- think big.

Q. Think bigger?

A. Think big.

Q. Fair enough.

A. When you have low tolerance -- low margin wells, you've got to start out really big.

Q. Because you know you're going to have to taper them as you go down?

A. It's -- I mean, you're talking about a guy that feeds chickens, but, yes, that's what I'd say.

Q. That's funny. The -- you know, I don't think Mr. Adair and Mr. Matthews and Mr. Hanson, the people who set up the most premier well fighting organization in the world and who hired you, I don't think they would describe your experience as feeding chickens.

Having said that, what you're saying is if you do a tieback and tie it back all the way to surface, it gives you a safety advantage in terms of well integrity and protection of that surface casing against downhole high pressures?

A. That's correct.

Q. Okay.

Page 62:23 to 67:24

Q. Mr. Campbell, we got -- I got off the subject on us, and I had you up to 1985 where you opened a company called BTI, Blowout Tools, and you'd told us the purpose of that company was to have tools in the event of a blowout emergency available for a wide variety of operators, right?

A. Correct.

Q. Could you go ahead and tell me kind of what happened in between 1985 in terms of your career and 2000 when you became affiliated with Wild Well?

A. I -- I continued to run with my assistant and partner the BTI operation.

Q. Okay. And all over the world? Gulf of Mexico? Surface? Subsea? Everything?

A. Our business was predominantly domestic, but it was -- certainly had international jobs as they occurred.

Q. Okay. The -- okay. In 2000 you -- how did you come to be affiliated with Wild -- Wild Well?

A. I had -- I had known Joe for quite a long time, and he was very persistent in asking me to come over and do some sort of an agreement with him. And he said he wanted somebody to run the business on a day-to-day basis and to find a buyer for him to -- to take out his interest --

Q. Okay.

A. -- to acquire his interest.

And -- and, of course, that's not quite the way he put it, but -- but -- but that was it. That was the idea.
Q. Okay. So you went over -- you literally bought the company from him?
A. We merged the two companies together, BTI and Wild Well Control.
Q. Okay. And that -- at some point in time after 2000, did Superior come in and buy your company?
A. In 2001 Superior bought the Wild Well Control, Inc., which included BTI.
Q. Okay. But you continued to run Wild Well even after Superior purchased them?
A. That's correct.
Q. And you still -- do you still work there today? And by that, I mean are you like a person who comes to the office and works five days a week?
A. Oh, absolutely.
Q. At this point in your career?
A. Yes.
Q. Okay. The -- okay. So in 2000 you merged BTI and Wild Well Control. And then in 2001 Superior buys them, but Wild Well continues to operate as kind of a stand-alone company?
A. Yes, Superior -- yeah.
Q. Okay. And who is the person -- I know you're the CEO of Wild Well. But since they're owned by Superior, there's bound to be your -- your boss or your -- a person above you in the Superior chain. Who would that be?
A. Well, actually, I run a group of companies for Superior that -- called the tech -- Technology Solutions Group of which Wild Well and BTI are one product service line, if you will. And then they -- there's another one called Well Services Division and another one called CSI, Cement Solutions, Inc.
Q. Okay.
A. And so then I run that group of companies. And then I do have a superior, and that is the president of Superior now, Dave Dunlap.
Q. Okay. All right. Who -- do you have a person who's kind of in charge of Wild Well Control other than you?
A. Yes.
Q. Who is that, please?
A. Mr. Freddy Gebhardt.
Q. And I'm going to deal with Wild Well for a second. I'm going to come

back to Well Services and CSI. But you say Freddy --
A. Gebhardt --
Q. Gebhardt.
A. -- G-e-b-h-a-r-d-t.
Q. And --
A. And his first name actually is Godfried.
Q. Okay.
A. G-o-d-f-r-i-e-d.
Q. Tell me approximately -- I'm going to try to figure out a little bit about Wild Well Control since they had this relationship, and I'm going to be looking at their documents. So I'm going to kind of ask you a few questions about the corporate setup of Wild Well Control, okay?
A. Okay.
Q. Let's start with how many employees, and by the way, approximate.
A. Right. And I am including BTI because it is a subsidiary of Wild Well Control.
Q. Fair enough.
A. And that would be 350.
Q. All right. And tell me how those break down in terms of -- of -- I'm not going to ask you about all 350 people.
A. Yeah.
Q. I'm not being silly.
A. It's right --
Q. But I'm trying to figure out what your kind of organization is within the organization.
A. Right. It's about almost a split, about 150 for BTI and 150 for Wild Well.
Q. And is BTI the equipment part of the business?
A. The short answer to that is yes.

Page 68:03 to 69:21

Q. Okay. By the way, does BTI have available capping stacks?
A. Oh, yes. We own hundreds of blowout preventers.
Q. Okay. Even that will work in a -- in a well like Macondo?
A. We -- we have now, but I'm -- I will say we did not have at that time -- at the time of the Macondo incident.
Q. Okay. If someone had came and said, Look, we're drilling all these deepwater wells and we want to have a capping

stack just in case --
A. Yeah.
Q. -- the worst of all scenarios occurs --
A. Right.
Q. -- would that have been something that Wild Well and BTI would have been happy to do and put together?
A. Certainly.
Q. And configure and have available?
A. Certainly.
Q. Would it have been a good idea?
MR. OCCHUIZZO:
Objection, form.
EXAMINATION BY MR. WILLIAMSON:
Q. If people object, the judge will hear all that later. You just answer the question truthfully and let the lawyers sort all that out later --
A. Well --
Q. -- unless your lawyer tells you to do something different.
A. You're talking about in -- in hindsight.
Q. Yeah.
A. You realize that.
And, you know, the short answer is it probably would have been a good idea. And the longer answer is a very large capital investment that had never ever been needed before, so...

Page 69:24 to 73:10

reach the wellhead.
A. Yeah.
Q. I mean, even in the event of a disaster, you have physical access to the wellhead.
A. Right.
Q. Right?
A. Right.
Q. One of the complications of deepwater drilling -- and by the way, you said up until a certain amount, you even have physical access to the wellhead even offshore as long as you're shallow enough for divers?
A. Right.
Q. At some point when you start drilling deepwater offshore wells, you do not have physical access to the wellhead?
A. That's correct.
Q. And that, of course, creates a complication.

A. Yeah. I'm not sure it's limited to one complication, but yes.
Q. Complications. Okay.
And one of the problems is if you have a leak at the wellhead, if you get flow at the wellhead in 5,000 feet of water, is there any equipment that can gather the oil up subsea?
A. That can gather it up --
Q. Yeah.
A. -- subsea?
We -- we use pollution capture domes and things of that for very small leaks.
Q. Okay. For a leak like Macondo?
A. No.
Q. All right. If you have a leak on the surface, you do have skimmers or other equipment that exists in order to try to pick up the oil, right?
A. Yes, sir.
Q. That technology exists, although we can argue about how efficient it is.
A. Right.
Q. Correct?
A. Yes, sir.
Q. But that technology -- there's no technology that exists presently to capture subsea oil leaks on the magnitude of the Macondo leak?
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. Is that true?
A. Correct.
Q. So, therefore, it's pretty important to prevent a subsea oil leak on the order of magnitude of Macondo?
A. Well, yes.
Q. I mean, that's just --
A. Yeah.
Q. That's just obvious.
A. Right.
Q. Okay. And what methodology do you go about to make absolutely certain you don't have an oil leak at the wellhead on a well like Macondo of the order of magnitude of the Macondo leak?
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. I mean, you spent your career in well control.
A. Yes.
Q. Correct?

A. Yes.
Q. It's a well-control question.
A. Right.
Q. Right?
A. Just restate it, if you would.
Q. Sure. What do you do to make -- you agree it's pretty important to prevent an oil leak like Macondo because you don't have any technology to capture the oil if it escapes subsea.
A. Right.
Q. Right?

Page 73:18 to 82:18

Q. Is it preventible, in your opinion?
A. I'm going to say -- in the first instance when you asked the question, you said something to the effect of what can you absolutely do to absolutely be sure that it won't occur. I don't -- I don't think you can be absolutely sure.
Q. Because nothing in human endeavor is absolute?
A. That's correct.
Q. Okay. What -- can you prevent a disaster like Macondo?
MR. OCCHUIZZO:
Objection to form.
A. It's -- it's possible to prevent it.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. How?
A. Well, it -- it's all part of the process of the well planning, the well execution, the interface between drilling contractor, service companies, all sorts of service providers, the oil operator. And it -- it -- it can be done, but I don't -- I don't know if it's reasonable under any circumstance to say that you could absolutely prevent it.
Q. Okay. What you're saying is -- by the way, have there been a bunch of oil wells drilled in the Gulf of Mexico -- I'll limit it to the Gulf of Mexico -- deepwater?
A. Yes.
Q. Okay. Any other disaster on the order of Macondo?
A. No.
Q. Okay. Why not? Why hasn't Chevron, Exxon, Apache, Shell -- why haven't they had a disaster like Macondo?
MR. OCCHUIZZO:

Objection to form.
A. It would be a guess on my part.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. The -- let me see if I can approach the subject this way. I guess the very first step you do to prevent an incident like Macondo is proper well design, well construction, well integrity, and well planning. Is that a fair way to put it?
MR. OCCHUIZZO:
Objection to form.
A. Yes, sir.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. And I guess if you're drilling Macondo, that thought should never leave your mind, that you have --
MR. OCCHUIZZO:
Object.
EXAMINATION BY MR. WILLIAMSON:
Q. -- to protect integrity at the wellhead?
MR. OCCHUIZZO:
Objection to form.
A. Yes, sir.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. And that's, I guess, got to start with the operator?
A. Absolutely.
Q. It's their well, right? It's their hydrocarbon reservoir that they're trying to reach, right?
A. Right.
Q. Back to Wild Well Control. 150 Wild Well employees. Tell me kind of how they break down. What's the division?
A. Well, I -- I don't have it in front of me, the administrative portion, and --
Q. Let me see if I can make it a little easier.
A. Yeah.
Q. I'm not interested too much in human resources.
A. Right.
Q. And I'm not interested too much in accounting.
A. Right.
Q. Okay. And I'm not interested too much in clerical.
A. Right.
Q. Does that help you a little bit?
A. Yeah.
Q. I'm interested in the people who have well control responsibilities.
A. About 60.

Q. Okay. And is that broken down any further past that?
A. It is, although I don't have it in front of me at this moment.
Q. Okay. Tell me who the -- would Mr. Gebhardt be the person to kind of inquire of that?
A. Yes.
Q. Would he probably have a little more handle on the details than you do in terms of the breakdown?
A. Yes.
Q. Okay. Let's go to Well Services, part of your Technology Solutions Group. What does Well Services do?
A. They perform plug and abandonment and temporarily abandonment and structure removal work on old iron, idle iron, in the Gulf of Mexico.
Q. Okay. So this is going to be more wells that have already been drilled?
A. That is correct. They're old, at the end of their life.
Q. Okay. Let's go to CSI. What does CSI do?
A. CSI is a technology company that -- that also performs physical field work. For example, in shale areas like the Haynesville and the -- other shale development areas, they perform cement -- cementation testing, mostly of primary cement jobs, analyzation, compression testing, so on and so on, a full range of tests, depending upon what the client wants. We have people who go to the field, are there when the job is taking place, collect samples and then perform this testing work and provide the results back to the operators.
Q. Both surface and subsea?
A. These are all -- these are all onshore that we send people on at the present time or at least 90 percent onshore.
Q. Okay.
A. Yeah.
Q. Did CSI have any involvement with Macondo?
A. Yes.
Q. Okay. What?
A. CSI was hired as a participant -- a member, if you will, of a forensic team that was going to study the cementation-related issues of the Macondo well.
Q. Okay. Were you involved in overseeing that or --

A. No.
Q. -- were you --
A. No. They -- they were -- we have a master service agreement with BP, but BP insisted on a special agreement because this was forensic work, highly confidential.
Q. Okay.
A. And that confidentiality agreement and so on, I was not privy to it all. And there has been no discussion of it between myself or Wild Well or CSI. Can't -- can't be.
Q. Okay. So what you're saying is CSI cut a special contractual arrangement on that particular project and you're not privy -- even though you're part of the company, you haven't been privy to that particular set of data --
A. No.
Q. -- or information --
A. No.
Q. -- or conclusion or analysis?
A. Only -- only to the extent that some of it, I believe, was published --
Q. Right.
A. -- yeah. I mean -- so I have no knowledge other than what became public knowledge.
Q. Fair enough.
Do you know who -- who runs CSI for you?
A. Fred Sabins, S-a-b-i-n-s.
Q. Okay. Any involvement with Macondo for CSI other than that? In other words, you have a forensic project for Macondo. Did CSI have any other interaction with Macondo that you know of?
A. Not with Macondo that I'm aware of.
Q. Okay. Does CSI do work for BP?
A. Yes.
Q. Well, you just said they had a master --
A. Yeah.
Q. -- service agreement, so it's obvious that they do --
A. Yes.
Q. -- right?
Is one of CSI's competitors -- I will tell you Halliburton did the cement job on Macondo. Is CSI a competitor of Halliburton's?
A. We don't consider ourselves to be a competitor because we don't -- we don't provide any hardware for cementation. We

don't provide that service. We don't -- you know.
Q. You're just testing?
A. Yes.
Q. You talked about integrity and quality?
A. Right.
Q. Okay. I get it.
Would y'all also be the kind of person -- company that would run cement bond logs or would that be more of a wireline company?
A. No, that would be a -- that would be a wireline service provider.
Q. All right. Got this --
A. Having said that, we might -- we might do interpretation of those bond logs, CSI.
Q. Okay.
A. But that would be the limit of their -- anything to do with bond logs.

Page 83:03 to 110:16

I've handed you what's been marked Exhibit 3900.
A. Uh-huh.
(Exhibit No. 3900 marked for identification.)
EXAMINATION BY MR. WILLIAMSON:
Q. Do you recognize the document?
A. Yes.
Q. Okay. Tell me what it is -- or I'll -- let me start it this way: It's my understanding this is a memo by Wild Well Control called Project Memo No. 19 that deals with the junk shot?
A. That is correct, yes.
Q. Okay. I want to start with No. 1 under this.
And by the way, the date of the document is May 6, 2010, puts it about 16 days after the blowout and explosion, correct?
A. Yes, sir.
Q. At this point in time, the rig had sank, the rig -- the wellhead is flowing, and the riser is bent over and kinked, and the blowout preventer stack is still on the well. Am I right --
A. Yes.
Q. -- about that? Okay.
All right. I want to start with -- under assumptions -- and one of the things that was under consideration was to do

something called a junk shot, right?

A. Yes.

Q. What's a junk shot?

A. This is slang terminology that just sort of exists out there. It is the injection of bridging agents into the flow path in the hopes that you will seal the leak path.

Q. Okay. In this particular case, it looks like y'all were going to go in through the kill line?

A. Short answer, yes. There's a lower kill line, upper kill line, lower choke line, upper choke line.

Q. You've actually anticipated my question, because my next question was going to be: Which kill line were you going to go in?

A. Lower choke -- lower kill line.

Q. Okay. That's what I assumed. You were going in the lower kill line which comes in below the bottom VBR?

A. That's correct.

Q. And, of course, since the well's flowing, that would mean whatever you injected into the junk shot, you anticipate it would go up into the blowout preventer?

A. One would hope.

Q. Okay. And were you trying to -- I will tell you on the last page of this, there's a -- the last page of this, there's the design of the casing shear ram.

Was the idea to try to get these bridging agents in the area of the casing shear ram?

A. Yes.

Q. Why the -- why the casing shear ram?

A. The casing shear ram is -- is all steel. It's not a sealing device. There are no real elastomeric elements in the casing shear ram. And they are known to all -- their -- their only job is to cut, not to seal anything. So by design there is already a fairly large bypass area at -- located at the casing shear rams.

Q. Meaning a place where there can be flow?

A. Yes.

Q. Okay.

A. Which is detailed elsewhere. I don't remember if it's in this document or not.

And so because those rams are all steel, no elastomers, and because we have no way of determining anything about whether erosion has added to the flow path, metal loss erosion has added to the total area of the flow path. Total area can mean a whole bunch of things. It can mean one big area, it can mean ten smaller areas, it -- you know, where -- wherever that flow is passing through there.

And at that point in time, since we're not yet collecting any significant amount of these hydrocarbons, it is our expectation that the sand which we believe is
00087:01 producing would give up solid particulate matter. And at the rate that we're seeing it expelled, we would expect that some further erosion would be taking place.

Q. Let me see if I can understand. Let me see if I can translate in -- in a way I understand.

You're getting a lot of flow and a lot of pressure, and it's not just gas and oil, it's also going to be shale and pieces of sediment and rock?

MR. OCCHUIZZO:

Objection to form.

A. This is our assumption at that time.

EXAMINATION BY MR. WILLIAMSON:

Q. Right.

Do you now -- now, have you seen pictures of the blowout preventer since it's been pulled off Macondo?

A. Yes.

Q. And now that you've seen the erosion in the wellbore, the blind shear rams, the casing shear rams, the annulars, the drill pipe, was your assumption correct?

00088:01 A. Yes.

Q. Okay. And so -- and, of course, you've got it at temperature, too, right?

A. Sure.

Q. The downhole temperature's in the neighborhood of 265 degrees Fahrenheit?

A. (Moving head up and down.)

Q. At the wellhead I assume the temperature's approximately 32 degrees Fahrenheit?

A. Correct.

Q. Giving you a very simplistic way of saying an average temperature in the neighborhood of 120 or 130 degrees, would that be a fair way to look at it?

A. Well, it's -- it's transient as it goes along that pathway --

Q. Right.

A. -- but, yes.
Q. Okay. So you have a temperature component, namely, you have hot oil and gas --
A. Right.
Q. -- and hot sediment shale and rock, right?
A. Yes.
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. So it's going to act as a -- in -- in this -- in the words you used is you're going to have a continued erosion effect?
A. It would be my expectation.
Q. Sure. If you're shooting a stream of oil and gas with sediment and rock and shale at something at 110, 120 degrees and you're shooting it out at 7- or 8,000 psi, it's going to have an abrasive effect on whatever it hits, fair?
A. Correct.
Q. And it's doggone well going to have an abrasive effect on ram blocks and VBRs and elastomeric elements that are in the blowout preventer --
A. Yes, sir.
Q. -- is that fair?
A. Yes, sir.
MS. MINCE:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. You know that from your 30 years of experience?
A. Experience would suggest that.
Q. Right. In this case your experience judgment turned out to be correct because you now have photographs of the blowout preventer that verify your assumption --
MS. MINCE:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. -- am I correct about that?
MS. MINCE:
Same objection.
A. Yes.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. Let's go back to the junk shot that y'all were considering on -- maybe I ought to start with this memo. I'd like to know who these people are. I will tell you Mark Mazzella, I believe, is a BP employee. Does that sound right to you?

A. Yes, he is.
Q. Okay. Who is Dicky Robichaux --
A. Dicky --
Q. -- do you know?
A. Dicky Robichaux is a well control specialist for Wild Well.
Q. Okay. Michael Allen?
A. Michael Allen is a well control technician and well control specialist for Wild Well.
Q. Bill Birch?
A. Bill Birch is a senior well control engineer.
Q. Wild Well, right?
A. Yes.
Q. You've told me Kerry Girlinghouse.
David Moody?
A. David Moody is a operations manager for well control for Wild Well.
Q. David Barnett?
A. David Barnett was the executive BP -- is executive vice president of well control engineering.
Q. For Wild Well?
A. Yes.
Q. And Joe Dean Thompson?
A. Joe Dean Thompson was a VP of operations for Wild Well.
Q. Would Mr. Thompson have really only had administrative duties or would he actually be the one who would be looking at the engineering and making engineering decisions?
A. He would certainly be reviewing them with the -- with this team --
Q. Okay.
A. -- yeah.
Q. Chris Murphy?
A. Chris Murphy was general manager of Wild Well's marine division.
Q. Okay. Same question: Would Mr. Murphy have really involvement -- I'm interested in the well control --
A. Yeah.
Q. -- efforts at well control, capping stack junk shot, top hat, and the engineering decision-making basis for all those things.
A. Right.
Q. Would Mr. Murphy have input on that particular --
A. Yes.
Q. -- thing? Okay.
All right. And Rolly Gonzalez?

00094:01 and 00095:01 are page markers.

A. Rolly Gomez.
Q. I apologize. Rolly Gomez.
A. Yeah, Mr. Gomez is senior well control specialist for Wild Well, and his area of specialty is relief wells.
Q. Okay. Was Wild Well involved in the relief well efforts?
A. Oh, yes.
Q. Where did the relief well intercept the drill string; do you remember?
A. Intercept --
Q. Someone told me it was like 50 feet below the crossover point into the 7-inch casing. Does that --
A. Yeah.
Q. -- does that sound right?
A. Yeah, it's -- it's where it intercepted the 7-inch casing. That was done in stages. I -- I -- I mean, whole separate discussion if you want to get into it.
Q. Well, I -- I wanted to get into it very lightly.
00094:01
A. Yeah.
Q. See if I can figure out how to get into it lightly.
A. No. 1 is you bring yourself right up against that 7-inch casing --
Q. Right, within a -- within --
A. -- at your target depth.
Q. Proximity. You --
A. Yes.
Q. -- get yourself physically close to that?
A. Right. And -- and at that point you establish communication with the outer annuli, that -- that is to say, outside of the 7-5/8 -- 7-3/4 casing. And you pump to see if you have injectivity.
In this case all of this is altered format because of the static kill and the fact that we've already pumped cement which should be on the outside of the casing essentially sealing that off.
Q. Was it?
A. There -- there was a very low level of injectivity, but the problem is we don't know if it was back to the open hole
00095:01
from the relief well or whether it was -- it was very hard to be definitive because of -- because of things that we had already done on the wellbore of the Macondo well.
Q. Yeah, capping stack had been solved and the Macondo well had been bullheaded by that point in time?
A. That's correct.

Q. So you're saying it's difficult to figure out --
A. Yeah.
Q. -- exactly what you had at the intercept point?
A. Right.
Q. Okay.
A. At any rate, that was part of our plan, was to do that, and then go ahead and penetrate the seven and five -- 7-3/4 casing.
Q. Did y'all penetrate the --
A. Yes.
Q. -- 7-inch casing?
A. Yes.
Q. And what did -- what information did you obtain from that?
A. Well, I'd prefer to be exact about it, and I just don't -- I don't have it all with me, but basically looks like we had cemented it up from the static kill.
Q. Okay. Was the static -- now, is that another -- is the static kill part of the bullheading --
A. It is --
Q. -- operation?
A. -- a bullhead kill.
THE REPORTER:
Please wait.
A. It is a bullhead kill. I don't know why they started calling it static kill.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. And for those of us who aren't in your business, tell me what a bullhead kill is.
A. It's just pumping right straight down through a piece of pipe. And you don't really have any expectation of circulating whatever you're pumping back to the surface.
Q. Okay.
A. Sorry.
Q. And I believe there's actually a letter where you had expressed some reservations about whether the bullhead kill was the right move or not?
A. Yes, sir.
Q. Okay. I'll ask you some questions about that letter in a moment.
Okay. Who's the right person -- I don't fuss at you for the relief well stuff, but I'm trying to figure out who would be the right person within Wild Well to ask those questions to.
A. David Barnett.
Q. Okay. All right. Back to

Exhibit 3900. Under "Assumptions and Design Considerations," it says, "The basic assumptions for this procedure are listed as follows." And No. 1 is, "The flow path for the blowout is up the annulus."
Did I read it -- I read it correctly?
A. Yes.
Q. Why? Why was there an assumption that there was flow up the annulus?
MR. OCCHUIZZO:
Objection to form.
00098:01
A. No. 1, as best I recall, this was a preliminary document --
EXAMINATION BY MR. WILLIAMSON:
Q. Okay.
A. -- that preceded the actual finalized agreed procedure.
Q. Okay.
A. Okay. And you can say it's poorly written or you could say whatever you want to say about it. But flow path for the blowout is up the annulus. Well, let's see now, I've got about five different annuli that I could be talking about. So that's --
Q. You've anticipated my next question.
A. It's not a good definition. I can tell you what they intended to say.
Q. Please do.
A. The annular space between the drill pipe and the casing string.
Q. Right. For you to get -- and -- and that's kind of where I'm going with you, because I'm going to tell you what I'm going to be asking.
00099:01
I'm sorry. Let me make sure I understood your answer.
You said the annulus between the drill pipe and the production casing string?
A. Correct.
Q. Okay. And if that came up -- and if you had flow inside the production casing but outside the drill pipe, that's one particular annulus, correct?
A. Yes.
Q. Where does that flow go when it hits the wellhead? You're now inside the 7-inch and 9-7/8 casing but you're outside the drill pipe --
A. Has it -- well --
Q. -- where is that flow going to go when it hits the wellhead?
A. The other point is you don't

know where the drill pipe -- top of the drill pipe is. Has --
Q. Okay.
A. -- it been severed, has it fallen down the hole? If it's fallen down the hole -- it's -- it's just so complicated. If it's fallen down the hole, the 3-1/2 could
00100:01 have gone inside the crossover joint and -- and, if so, it makes like a stopper at the 5-1/2-x-7-3/4 crossover --
Q. Okay.
A. -- where the 3-1/2 drill pipe changes to five and --
Q. 5-1/2?
A. -- 5-1/2 drill pipe. There -- there are ever so many possibilities here.
Q. Okay.
A. And we don't know -- we don't know whether the drill pipe is suspended at the surface in a set of rams or an annular or what. We don't know that. Or we don't know that it's not just a stub.
Q. Okay.
A. Okay. And under a whole bunch of circumstances, the -- the drill pipe could have settled into that liner crossover and there'd be no flow through that, the drill pipe. It's all coming around and through by whatever mechanism.
Q. Inside the production casing?
A. Inside the production casing.
Q. Okay. I'm -- I'm --
00101:01 A. Is that -- okay.
Q. What I'm trying to figure out: If you have flow inside the production casing that's coming up outside the drill pipe, when you hit the wellhead, does that flow -- it's just going to go straight up through the blowout preventer and into the riser?
A. No, sir.
Q. Okay. Tell me what's going to happen to that flow.
A. Well, it's going to exit through the casing hanger, which is -- the smallest inside diameter is that of the casing itself, the ID of the casing. And it's going to expand suddenly and rapidly into an 18-3/4-inch bore.
Q. Okay. So if it comes up, it's going to hit the casing hanger?
A. Not hit it. It's just going to be flowing through it, yeah.
Q. I -- I used -- I used the wrong word.
A. Yeah.

Q. You're right.
You're going to have flow up through the production casing. It will then flow upward through the casing hanger and hit the 18-3/4-inch wellbore area of the BOP?
A. Correct.
Q. Of course, then it will go up to the flex joint. And on May 6, 2010, it will go up through the flex joint, and at that point the riser is now kinked and broken --
A. Right.
Q. -- correct?
The -- and do you have a chance at that point in time that the casing -- do you have to consider the possibility on May 6, 2010, that the casing hanger has lifted?
A. That is one consideration, that the casing hanger may have lifted. It is in all -- because of the weight of the casing suspended from it, it is more likely that the seal assembly for the casing hanger may have lifted.
Q. Okay. And do you also have to worry about the fact, because of this flow and this temperature effect, that you had expansion of the production casing, namely, that it's literally --
A. Grown.
Q. -- grown?
A. Yes.
Q. I mean, it would only be microns per foot, but in this particular case you have 13,000 feet.
A. Right.
Q. So even a little bit per foot might add up to enough to break the seal at the casing hanger assembly?
MR. OCCHUIZZO:
Objection.
EXAMINATION BY MR. WILLIAMSON:
Q. Do I have that right?
A. Well --
Q. Or is that a possibility?
A. It's a possibility. It's one of many guesses one could make, that there is no way to determine with certainty in advance.
Q. And here's kind of where I'm trying to figure out.
A. Okay.
Q. I'm trying to figure out if there's a possibility of flow outside the production casing.
A. Yes.
Q. Why?

A. Well --
Q. And by the -- let me -- I'm going to -- I'm going to ask you the why question. I'm going to give you one condition.
A. Yeah.
Q. I'm not interested in the possibility that a meteor is going to come from outer space and something is going to happen. I'm interested in the more probabilistic explanations from an engineering standpoint.
A. Okay.
Q. Is that a fair parameter?
A. Yes, sir.
Q. Okay. So when I say can there be flow outside the production casing, I don't mean in the theoretical anything is possible sense. I mean, is that a probable -- is that one of the probable scenarios that has to be considered?
A. I would -- I would change your characteristic -- your characterization to it's one of the possible scenarios, not necessarily probable.
Q. All right. Let me ask you this. Is it one of the possible realistic scenarios?
A. Oh, yes.
Q. Okay. Why?
A. If one did not get a cement job on the outside between the open hole and the production casing, that would -- that would potentially be a pathway for flow outside the production casing.
Q. Okay.
A. There are rupture disks, both rupture disks to prevent high-pressure external pressure from collapsing the casing and -- and high-pressure rupture disks to guard against internal high pressure from rupturing the casing.
Q. Right.
A. Okay.
Q. There's three of them in the 16-inch casing.
A. So -- so they -- if I said that -- there are a group of people within incident command who believe that has already occurred.
Q. Okay.
A. Okay. Not -- not Wild Well. We don't believe that.
Q. You don't believe -- at this point in time you don't believe the rupture

disks have -- the rupture disks that protect against collapse and burst, you don't necessarily believe those have been --

A. Compromised.

Q. -- compromised at this point in time?

A. No.

Q. But there are engineering people within the teams who are looking at this who think -- you say think it has occurred?

A. Yeah.

Q. Okay.

A. Yeah. So if the well is flowing inside the pipe -- inside the production casing, it requires that there have been multiple failures, failure of the cement job --

00107:01 Q. Right.

A. -- failure of the float collar, failure of the float shoe, or possibly that the casing perhaps began with a leak path through a threaded connection and it -- and it worsened or that the casing actually collapsed, because at this point in time on the rig, they are reducing the total hydrostatic force on the inside of the wellbore; whereas, if the well is not cemented and we have native pore pressure on the outside, theoretically -- theoretically it could cause a collapse of the casing.

Now, these -- these are all factors for which we have no way to acquire additional data that would confirm what's taking place. There is no diagnostic work available to us that would allow us to confirm which of these scenarios, including casing hanger seal release at the surface, upward movement of the casing hanger at the surface.

So you say, is there a propensity that one likelihood is greater than all the others?

00108:01 Q. I'll ask that question. Is there a propensity that one -- one scenario is more likely than the others?

MR. OCCHUIZZO:

Objection to form.

A. Well, the -- the greatest likelihood that -- that we believe is, number one, that the cement job did fail.

EXAMINATION BY MR. WILLIAMSON:

Q. Okay.

A. We don't know why. We haven't any idea. We're not in on that.

Number two is that would

potentially expose a 16-inch casing shoe to pressures that would far exceed the FIT or LOT, the leak-off test or the -- the -- my mind just went blank. Anyway, the fitness integrity test.

So -- so we say it -- it seems to us more likely that these things might have occurred rather than failure of the float shoe and the float collar and so on. But we have no way to determine that with any -- any degree whatsoever of confidence that we are correct.

Q. Let me say there's been some discussion about the float collar and whether it's a hydrocarbon barrier or not, in other words, whether it's supposed to --
A. It's not. Yeah.
Q. Well, it's not a hydrocarbon barrier in this case --
A. No.
Q. -- because it didn't prevent the hydrocarbons, right?
A. (Moving head up and down.)
Q. I want to ask you something to make sure I'm on the same -- the right page. And that is, of course, the cement acted as a barrier if the cement job was good, correct?
A. Yes, sir.
Q. And, of course, by definition, the cement job was not good because it failed because it did not act as a barrier. We know that, right?
A. Yes, sir.
Q. And I think you said you do not have an opinion about why the cement job failed.
A. We -- we didn't know anything at that time.
Q. Okay. And, of course, we know that there was a long string production casing in this particular well --
A. Yes.
Q. -- correct?
A. Yeah.
Q. So when the cement job failed -- oh, I'm sorry. Let me back up.

In a normal well, your fluid column also acts as a barrier, correct?
A. Correct.
Q. In this particular well, the fluid column had been underbalanced, so it no longer was acting as a barrier, correct?
A. Yes, sir.

Q. And I'm -- I'm counting the BOP as a contingent barrier, not a -- not a -- isn't that right? The BOP should be considered a contingent barrier?
A. Right.
Q. Okay. Counting the BOP as a contingent barrier, the only barrier between the hydrocarbons at total depth and the top of the riser at the rig is the cement job?
MR. OCCHUIZZO:
Objection to form.
A. It depends -- it depends on the pathway and how the pressure is gaining access into -- or is it gaining access into the production string.
EXAMINATION BY MR. WILLIAMSON:
Q. Sure. I'll -- I'll --
A. Yeah.
Q. -- give you a couple more assumptions.
A. Okay.
Q. Let's assume the BOP is a contingent barrier, which you agree with --
A. Yeah.
Q. -- right?
And assume you have a long string in the hole, which you agree with, right?
A. (Moving head up and down.)
Q. And assume that the cement job is supposed to act as a barrier, which you agree with, right?
A. Yes.
Q. And assume that the cement job fails, which you agree with?
A. Yes.
Q. Okay. And assume they've underbalanced the well so the fluid column is no longer a barrier, which you agree with, right?
A. Yes.
Q. Okay. And assume you have flow through the bottom of the production casing, through the rathole, and that the cement within the rathole and the reamer shoe has failed, okay, which is at least something that you will consider is one of the realistic possibilities.
A. Absolutely a possibility.
Q. Okay. If that's true, if that cement fails such that you can enter the production casing through the reamer shoe, okay, then there's no other barrier between total depth and the rig floor, correct, given the assumptions I've asked you to make?

A. Inside the production casing?
Q. Correct. Correct.
A. Yes, sir.
Q. Okay. Are there other -- is it technologically possible to put another barrier in there such as a bridge plug?
MR. OCCHUIZZO:
Objection to form.
A. Technologically possible, yes.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. What I'm trying to figure out is if you're supposed to have two barriers, and I'm going to continue to ask you to assume that the BOP is a contingent barrier --
A. Contingent barrier.
Q. -- which you agree with, correct?
A. Yeah.
Q. Right. And you're supposed to have two barriers between the rig floor, the top of the riser, and the hydrocarbons. How would you get your second barrier once you make a decision to pull your fluid column and destroy it as a barrier? Where would you get your second barrier?
MR. OCCHUIZZO:
Objection to form.
A. You -- you would have to place it.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. What would exist -- for those of us who are not in the oil field business -- I've used the term "bridge plug" because I'm thinking that's a possibility, but you might think something different. What would exist that you could use to say, This is going to be my second barrier to prevent hydrocarbons from getting to the rig floor?
A. You could place a balanced cement plug, for example --
Q. Okay.
A. -- through the drill string. And you could precede that with typically 50 or 100 feet of sand on top of the equipment that's in there now. In other words, you don't -- you don't -- this is -- to -- to do the temporary abandonment of the well or the permanent abandonment of the well. So place a balanced cement plug on top of a sand barrier, which is really just making a prefoundation, if you will.
Q. Okay. The reason --
A. You can make that long enough

that you can drill off on it and get an idea about its compressive strength and so on.

Q. The reason I'm asking is because BP -- when I read BP's group practice documents and their well control manuals and their well control documents, they say -- this is BP says, We shall always have two barriers between hydrocarbons and the surface and not -- and we don't count the BOP because it's a contingency.

A. Right.

Q. Okay. And I'm trying to figure out -- okay. Number one, they did not have two barriers, correct?

MR. OCCHUIZZO:

Objection to form.

A. To my understanding, yes.

EXAMINATION BY MR. WILLIAMSON:

Q. Right. And number two, I'm trying to figure out from you: Could they have had two barriers if BP had chosen to have two barriers?

MR. OCCHUIZZO:

Objection to form.

A. I mean, that kind of requires a -- if you don't know all the details, I don't think you have any business guessing about that. I mean, I don't know of any technical reason that they could not have had multiple barriers, for that matter. But I -- I don't know what was taking place or -- or what decision-making was based on or anything.

EXAMINATION BY MR. WILLIAMSON:

Q. Fair enough. But I'm just asking you, as a person who knows methods by which you can prevent a well from -- part of a well control issue is preventing the well from getting out of control, correct?

A. Yes, sir.

Q. You spent your career dealing with wells that somehow got out of control.

A. (Moving head up and down.)

Q. And then you've got to get them back in control, correct?

A. Yes, sir.

Q. But the other half of the equation is prevent wells from getting out of control in the first place, right?

A. Yes.

Q. Okay. And what you're saying is yes, you could have had two barriers had you chosen to do so, but you do not know the particular details of what judgment was being exercised on this particular well?

A. Right.

Page 118:13 to 121:23

Q. Sure, Mr. Campbell, I want to go back to Exhibit 3900 because I want to try to understand -- I have a few more questions about that document.
My first question's very easy. Down at the bottom, second line from the bottom on the first page, it says, "Assume the zone will take oil back in at same PI as flowing (500 BLPD per psi). . .
Would you mind telling me what that means?
A. The zone is referring to the zone that is flowing.
Q. Which presumably was thought to be the total depth or did anyone know which zone was flowing? There's three different zones, if I'm not mistaken, in this well.
A. It's -- it's actually thought they were all contributory.
Q. Okay. And --
A. Will take oil back at the same productivity index --
Q. Okay.
A. -- as flowing. This is an estimate. 50-barrel of oil per day per psi.
Q. Okay. In other words, that you can put that oil back into the formation?
A. Yes.
Q. Is -- did I -- am I understanding it correctly?
A. That's correct.
Q. Namely, if you get the -- if you get a -- if you get a barrier with either mud or cement at the appropriate levels going back in there, you can force the oil that's in the well back into the formation? "Force" may not be the right word.
A. No, you have to apply force. But the problem is that's all complicated. There are -- there's a group of people who think the well is producing solid particulate matter from the formation or formations, whether it's carbonate, whether it's a sand, whether it's coming from the gas zone, the oil zone, whatever, we think that the formation is giving up solid particulate matter.
Q. And you now know that assumption to have been correct?
A. Well --
MR. OCCHUIZZO:

Objection to form.
A. Now.
EXAMINATION BY MR. WILLIAMSON:
Q. I know.
A. At that time it's an assumption. It's an assumption Wild Well was making.
Q. Yeah, you --
A. It was not shared by all.
Q. Right. But it was your best engineering judgment that that was true?
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. Correct?
A. Yes, sir.
Q. Okay. Go ahead. I -- I may have interrupted your answer.
A. No -- if and when you stop the movement of that column of oil and gas, suspended solid particulate matter will immediately begin to settle.
Q. Okay.
A. If you wait too long before displacement of whatever's in that wellbore by whatever it is you're going to do next, theoretically you could allow those solids to get all the way back down near the entry point into the casing.
Q. And make it harder or --
A. Because at that point those solids could preclude or interrupt or reduce the effectiveness of your ability to inject back into the formation.
Q. Okay.
A. Sorry it's a long answer.

Page 122:01 to 138:21

All right. Next I've -- I've got a question on page 4. If you'll turn to page 4 of that exhibit, Exhibit 3900.
No. 4 on page 4 says -- the second sentence, says, "The estimated pressure at the BOP is 4,815" -- you're on the right page. No. 4 -- I'm on --
A. Oh, No. 4, yes, okay.
Q. Second sentence.
A. Yes.
Q. "The estimated pressure at the BOP is 4,815 psi with 14.2 pounds per gallon to the mud line. . .
I'm trying to figure out where would y'all have obtained the reading that the estimated pressure at the BOP is 4815?
A. Estimated pressure, I -- I'm not

sure. It came from a -- a team of individuals made up from BP's geophysicists, reservoir engineers, others.

Q. Okay. Is there -- when you have a blowout preventer -- I will tell you: On the blowout preventer on the DEEPWATER HORIZON, there is a pressure temperature sensor. I'm talking about when
00123:01 the blowout preventer's hooked up and working correctly.

A. Right.

Q. Is that pretty normal that you have a pressure temperature sensor on the blowout preventer?

A. Yes, it is.

Q. What's the purpose of that device?

A. It is to feed back information via either one of the control pods to the surface, to the rig, to give you both the temperature at that point where it's sensing --

Q. Right.

A. -- and/or the pressure at that point where it's sensing.

Q. Is that useful information?

A. Absolutely.

Q. Why?

MR. OCCHUIZZO:

Objection to form.

A. Well --

MR. WILLIAMSON:

Why? You object to the word --
00124:01 the question "Why" as to form. State your basis for your objection as to form for the question, quote, Why, unquote.

MR. OCCHUIZZO:

You're asking him to speculate, you're asking with no actual foundation for the context of the word "why." It's vague.

MR. WILLIAMSON:

Those aren't objections as to form. Excuse me. That's just lawyer's talk. Okay. Your objection's noted.

EXAMINATION BY MR. WILLIAMSON:

Q. Why? Why do you want to know the temperature and pressure?

A. Ultimately there are numerous circumstances under which that information is of value. If you are drilling a well in which hydrate formation either potentially could be a problem or has been a problem or is currently a problem, if you know the temperature at that sensing point, you can attempt to calculate the depth at which the hydrates are forming as a result of the temperature and the pressure.

Even though they -- they are probably not forming at the point where that reading is being taken, they have the ability to help you with that calculation --

Q. Okay.

A. -- with respect to the drilling fluid being used, and, of course, as you may know, there are a hundred different types of drilling fluid. If dehydration is a problem, it will be very useful to know what the reading is at the seafloor and what the temperature is.

If separation between certain added chemicals and base materials in the mud is a problem, it would be very interesting -- and, of course, this is all the more interesting the deeper you go, water depth-wise.

Q. Right.

A. Okay. So --

Q. Those are temperature -- those are reasons temperature readings at the blowout preventer could be important?

A. Well -- and --

Q. Am I right about that?

A. Yes, that is correct.

Q. Go ahead. I may have interrupt -- I mean --

A. No.

Q. -- I wasn't trying to interrupt your answer.

A. No, not at all.

Q. Okay. Let's talk -- by the way, for that information to be useful, obviously, it's got to be transmitted to either the driller or the toolpusher?

A. Well, yes. Eventually the answer to that is yes.

Q. Okay. Would it be preferable to have it in real-time or does it make a difference?

A. It -- it would be preferential to have it in real-time. Although under normal operating circumstances, the lag time of transmission is not really a big deal. And then most of these sensors take a reading, transmit, then they do nothing for a little bit, whatever that margin may be, ten seconds, whatever. They take another reading, transmit. And there's -- so there's -- there's the time between readings and there's a lag time in that data reaching the surface equipment.

Q. Okay. Of course, that -- you're talking about a matter of probably seconds. Namely, when you read it, you're a matter of 10 or 20 seconds off of real-time reading?
A. Right.
Q. Okay. Is it useful to have that, you know, within 10 or 20 seconds of the actual reading?
A. Yes, it is.
Q. Okay. Let's talk about pressure. You've told me some reasons that temperature would be a valuable piece of information for the driller and the toolpusher to have.
A. If you are --
Q. What -- let me finish my question.
A. Yeah. Sorry.
Q. What is my reason -- what is a reason that the pressure readings would be a valuable thing for the drillers and the toolpushers to have?
A. If you are circulating out a
00128:01 kick from the wellbore --
Q. Right.
A. -- then it's very useful to know the pressure at the seafloor, what is the pressure under the rams, whichever set of rams may be isolating the riser from the pressure, and what is the pressure as the fluid enters the choke line, upper choke line, lower choke line, whichever it may be, because that helps your anticipation with -- you have lag time. As you -- as you make corrections in your choke control panel setting at the surface, there is lag time that occurs before you will see the result.
I will see it some -- in the case of Macondo, 5,000 feet earlier by means of this sensing device than I would see it if I had to wait for the fluid to exert that force at the choke manifold.
Q. Okay. And what you'd be looking for would be a pressure differential, the pressure going up or down?
A. That is correct.
Q. Okay. And, of course, if you see it off your pressure reading at the
00129:01 blowout preventer, you've got -- you've got information before -- 5,000 feet earlier I believe is the way --
A. Yes.
Q. -- you put it. Right.
Could that be of help to you in detecting a kick?

A. Yes.
Q. How?
A. Well, as kick fluid enters the wellbore, it -- it will exert a force --
Q. Okay.
A. -- immediately. And that force will get transmitted through the column of -- of drilling fluid. So you have -- some actually call it a sort of an early detection system. I -- I wouldn't want to be -- I wouldn't want to be the guy that said, yeah, that's what I'll trust to make me aware of a -- of a sudden ingress into the wellbore.
Q. It would be one of the parameters?
A. It would be one of the parameters, possibly one of the parameters.
Q. Right. Along with, I'm sure, hook weight?
A. Oh, yes.
Q. Pit volume?
A. All of those things.
Q. Pit gain?
A. Exactly.
Q. Right.
And have you seen rigs where the pressure temperature information measured at the BOP gets to the rig floor panel and gets to the toolpusher panel?
A. I -- I would have to say I don't recall that. I know that it generally, I believe, typically goes into the toolpusher headquarters --
Q. Okay.
A. -- in the office and to the mud logger.
Q. And don't know if it goes to the driller at the rig floor?
A. Well, it -- the first thing might be that it would go verbally.
Q. Okay.
A. I -- I've not actually seen one that -- that showed that readout at the driller's panel.
Q. Okay. All right. Before I leave Exhibit 100 -- 3900, I have to ask you a question. And the question is: When I look at what y'all are going to actually put in the hole, you're going to put in golf balls, tennis balls, super balls, rope with knot in it, a cutoff wheel. And I just cannot resist asking you: Why is this the stuff that's going down the kill line? Because it sounds totally weird to me.
A. I -- I -- I cannot avoid giving

you a little bit of a lengthy answer.
Q. Well, this one is going to be worth it. I'm going to take my minutes to hear this answer.
A. Generally speaking, the -- the injection of bridging materials or -- or as they've chosen to call it, a junk shot -- that was not BP's choice, and it was not our choice --
Q. Okay.
A. -- is used to seal off one or more multiple possibly high-pressure leaks but very small orifice size, very small
00132:01 orifice size. So if -- if I had two rams coming together flush and they happen not to seal, it would be reasonable to think I might be able to inject a material below those rams and effect a seal along that area. They are not typically or conventionally used for large orifice leaks.
Q. Okay. Was this a large orifice leak?
A. Look at the film.
Q. No, I'm not --
A. I mean --
Q. Well, I may have asked a stupid question, but --
A. Yeah.
Q. -- I'm not -- I wasn't trying to be silly.
A. Yes.
Q. Yes, there's a lot --
A. Yes.
Q. -- of oil coming out?
A. There's a way lot coming out.
Q. Right.
A. And so --
Q. And, therefore, by definition,
00133:01 you have to have a pretty good orifice to get that much oil out of the ground?
A. Right.
Q. Okay.
A. Or I have to have several moderate size orifices.
Q. Fair enough. Okay. Now I get it.
A. So I am limited about what I can introduce into the wellbore by the ID of the four potential injection points.
Q. Which I thought was a 4-inch inside diameter.
A. 3-inch inside diameter.
Q. 3-inch inside diameter?
A. 3-inch inside diameter, upper choke line, lower choke line, upper kill

line, lower kill line.
Q. Okay.
A. There -- there are reasons why I would not want to lose the ability to inject in any of these lines, preserving my rights for other operations later on, but realizing that one could become a sacrificial lamb in this case.
So first and foremost, as you noticed in your project memo, there is a so-called junk shot injection manifold. And it allows you to pump into the wellbore without introducing any solids of any sort --
Q. Right.
A. -- or it allows you to elect either side A or side B which have been loaded -- preloaded in advance with these materials that you believe you're going to inject. And then this whole manifold has been placed on a mud mat on the seafloor near but not right adjacent to the well itself, and you'll connect to the kill line of the -- kill lines of the Macondo well by means of -- of flexible hose jumpers that -- that will connect to the upper hydraulic connector point on the choke -- vertical portion of the choke and kill lines.
Q. Of the Macondo --
A. Of the Macondo BOP.
Q. -- on the Cameron BOP that was on the DEEPWATER HORIZON?
A. The --
Q. The DEEPWATER HORIZON BOP?
A. That's correct.
Q. Okay.
A. So there -- there are -- 3-inch inside diameter is a -- is a fixed diameter. It's a steel line, and it's 3-inch ID, and it makes one 90-degree turn.
So I have --
Q. Into the wellbore?
A. Into the wellbore.
Q. Right.
A. So I have -- that's my limitation about size.
Q. So you've got to put in materials that fit within that?
A. That's right.
Q. And that will make that 90-degree turn?
A. Because I don't want to plug it up.
Q. Right.
A. Okay. So the things that were selected to inject, some of those had a low

likelihood of doing anything significant.
Can I tell you for just a moment about sort of how this works?
Q. Sure.
A. First of all, I have to have something solid that's big enough to bridge across the gap where -- wherever this one or multiple orifices are. And then I stack up some of those solids. Let's just say they were frac balls or they were steel ball bearings or whatever they were. And they then just touch at edges, multiple edges. And now I have to fill in with a material that has the ability to flow under pressure and fill in the remaining gaps and one hopes eventually bridge off the leak.
Q. Sure. And either stop it or significantly curtail it?
A. Yeah.
Q. Did -- did the junk shot work?
A. No.
Q. You said the junk shot was not your choice. Did I understand that correctly?
A. Yes, sir.
Q. Okay. So you didn't think the junk shot had much chance of working?
A. No, sir.
Q. What was your choice? This is -- I'm talking about -- the date of this memo is May 6th.
A. May the 6th -- my choice?
Q. Uh-huh.
A. Wild Well's choice?
Q. Were they different -- was your choice different from Wild Well's choice?
A. No, I don't think so.
Q. Okay. That's what I thought.
A. Yeah. Once again, I have to give you an answer that's -- would mean something.
There are -- there are several initiatives taking place simultaneously. One is capping the well with the BOP -- capping the well with the BOP on the Macondo BOP. One is capping the well with a BOP on the lower marine riser package of the Macondo BOP. One is a so-called top hat, top hat being a gravity structure. It's filled with lead in the bottom, and it's just going to sit on top of where the riser is kinked over. You're going to cut it off and set this device on there and then flow back as much possible of the -- whatever is being expelled to surface vessels for collection. And it

would generally be thought you would do that while you were completing the relief wells.
Q. Okay.
A. Okay. And then there was the so-called, as they chose to call it -- BP called it top kill. Top kill is where the junk shot was involved.
Q. Okay. Is top kill and junk shot meaning the same procedure?
A. Well, top kill is the pumping portion. Junk shot is the introduction of bridging materials.
Q. Okay.
A. But they are part and parcel of the same initiative.
Q. Fair enough.
And that's the one that you've already said didn't work?
A. Yes, sir.

Page 139:01 to 141:09

00139:01 Q. Oh, one more option was relief wells.
A. Well, the relief wells are going on no matter what.
Q. No, I -- I get that part.
A. Right. So --
Q. So the relief well effort by May 6th, I think, had been started or at least was underway to be started?
A. Oh, yes.
Q. Okay.
A. By all means, yeah.
Q. Because do I understand correctly relief wells are one accepted way to regain control of a well?
A. Right. Generally speaking, the conservative posture is I will begin re -- relief wells no matter how high a level of confidence I have in my ability to stop the flow with direct intervention.
Q. And, of course, the disadvantage to using relief wells as your primary source to try to stop a flowing well is relief wells take a long time to drill?
A. Yes, sir.
00140:01 Q. And you've got to then make sure you drill them safely so that you don't make the situation worse --
A. Right.
Q. -- right?
A. Yes, sir.
Q. And when you get a relief well down to your intercept point, you've got to

be very careful that you intercept correctly so that you do not make the situation worse?
A. Yes, sir.
Q. So relief wells -- as I understand it, there is a high degree of accuracy in terms of relief wells being able to intercept an -- an annulus.
A. Extremely high.
Q. Right. The technology has progressed to the point that the oil and gas industry has a tremendous amount of accuracy in relief wells actually intercepting the annulus?
A. That's correct.
Q. Okay. But that's going to be a very time-consuming procedure to start a relief well and get it down, directionally drill it over, intercept the annulus, and do it all safely so you don't make the situation worse. That's going to take a lot of time?
A. Yes, sir.
Q. Okay. So, therefore, as -- if that's your only relief procedure, you've got the potential for a long period of flow, if that was your only relief procedure?
A. If that was your only procedure.

Page 141:13 to 150:13

A. -- if the top hat was highly effective -- now that's open to debate. What -- what is the definition of highly effective? If it was highly effective, meaning a high recovery rate of the total being expelled, then that could persist until the relief wells were in place --
Q. Right.
A. -- with -- with -- with little and perhaps under the very best circumstances no further pollution.
Q. Yeah, or at least you'd certainly curtail the pollution?
A. Yes.
Q. Okay. But the top hat did not work. Do I understand that?
A. The top hat --
MR. OCCHUIZZO:
Objection, form.
A. -- worked perfectly.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. Tell me -- what was the problem with the top hat procedure?
A. It couldn't handle the volume.
Q. Okay. What was the volume? Did Wild Well do any calculations about the flow

rate?

A. They -- if you're talking about the top hat, we -- we had several limitations.

Q. Okay.

A. One, were the vessels on the surface, the HELIX 4000 and the DISCOVERER ENTERPRISE, that -- that had -- they -- they were drilling rigs that we modified to accept the return of oil and gas. They -- they were not production rigs that were set out to handle a high volume of oil and gas.

Q. Okay.

A. So at our best, we were recovering 26,000 barrels per day of oil and 55 million cubic feet of gas and --

Q. Did you say million, MCF?

A. Yes, yeah. And we were maxed out. That -- that's it. That's all we could handle.

Q. And the well was flowing more than 26,000 barrels a day?

A. Once again, just look at the film. Yeah, I mean, it's a whole bunch more than that.

Q. Okay.

A. So -- so valves on the top hat that we had anticipated being able to shut, once we routed all of the flow back to the surface, we could not shut because we simply couldn't handle the volume --

Q. Okay.

A. -- at the surface.

Q. All right.

A. We -- we thought that the answer would be a vessel called the HELIX PRODUCER, which was a purpose designed vessel to go in the Gulf of Mexico to act as the receptor for a field development in the Gulf. But what we discovered was that, like most production facilities, it had so many automated shutdown features on it, and it wouldn't accept any -- any reasonably-invoked bypass to eliminate some of those shutdown triggers, and we really couldn't -- we really couldn't afford to put it out there and hook it up because you'd flow 15 minutes and you'd be shut down and you'd be really putting people in danger.

So we said, Take it back to Galveston, work on it, do what you can, et cetera, et cetera, but it -- it never actually became operational -- operational for our purposes at all any further in the course of this work.

It -- it should have handled 25,000 barrels a day and 50 million cubic feet of gas. So we felt like between the Q-4000, DISCOVERER ENTERPRISE, and the producer, that -- that surely we were covering at a minimum 90 percent of the volume -- I mean, this is a guess -- being expelled from the well.

Q. Okay. The if -- so the -- was Wild Well involved in the development of the top hat procedure?

A. Oh, yes.

Q. Right.

So what you're saying is mechanically you did get the top hat down over the riser and mechanically oil began flowing through into the top hat that could be retrieved on the surface?

A. Right.

Q. But you suffered from the limitation that there was a limited amount -- because you did not have the right vessels on the surface to accept all the oil, you couldn't -- you didn't mechanically have the ability to get -- to capture all the oil --

A. The rest of it.

Q. -- the top hat might have been able to capture?

A. That's correct.

Q. Okay. Had -- before April 20, 2010, had BP ever approached Wild Well regarding this issue?

MS. MINCE:

Objection to form.

EXAMINATION BY MR. WILLIAMSON:

Q. In other words, had -- had BP ever said, Why don't we plan for a top hat procedure in the event we have a subsea oil leak? Had that discuss -- had that discussion ever taken place before April 20, 2010?

A. The short answer is no.

Q. Okay. Is there a longer answer?

A. There is a longer answer.

Q. What is it?

A. We use pollution domes all the time. We had used them for BP. We had used them when we were working on subsea wells that had been blown over during Hurricane Katrina and Rita. We used them possibly other locations as well.

What one would say is they were smaller, they were lighter, none -- none were designed to approximate what was going on at Macondo in any way at all.

Q. Okay.
A. But the same technology and -- I mean, basically serving the same purpose, return to a vessel on the surface.
Q. Okay. So pollution domes had been accepted technology before April 20, 2010, right?
A. Absolutely.
Q. But BP had never discussed with Wild Well the possibility that you might need a pollution dome to capture a catastrophic blowout like Macondo?
A. To my knowledge, no.
Q. Okay. I'm sure if they had, given the fact that you spent your career manufacturing blowout control tools, you would have been happy to plan for that contingency with BP. Am I correct about that?
A. BP or any other operator.
Q. Sure.
A. Sure.
Q. Okay. And so -- so you would have been happy to cooperate with BP in terms of making sure a capping stack was immediately available if they had asked you to do so before April 20th?
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. I've switched back to capping stack for a moment.
A. BP or any other operator.
Q. Fair enough.
And you would have been happy to cooperate with BP in planning for a top hat use in the event that contingency was needed had BP or any other operator approached you for that?
A. Yes.
Q. Okay. Okay. And, of course, if you were going to plan -- if you were going to plan with a view towards, This is our worse-case scenario, we're going to have a subsea blowout in very significant quantities, okay, you would also have to plan not only for the top hat itself, you would have to plan for some sort of vessel to receive the oil that was captured?
A. Correct.
Q. Oil and gas --
A. Correct.
Q. -- that was captured, correct?
A. Yes.
Q. Okay. The -- and what -- what's

happened when you hit this contingency, you had to build the top hat and deploy it and then you found yourself facing not enough vessel capacity?

A. That's correct.

Q. I assume in between April 20th and July 15th, I believe is the date that the capping stack actually was activated, I assume there was some reservoir depletion during that time period?

MR. OCCHUIZZO:

Objection to form.

A. Pressures would indicate that that was so.

EXAMINATION BY MR. WILLIAMSON:

Q. Well, you've actually anticipated my question again.

Namely -- of course, the reservoir's depleted, you've had oil flowing out of it for 86 days?

A. Right.

Q. What I really meant to say was: The pressures had gone down on the reservoir in between April 20th and July 15th?

A. Yes.

Q. Okay. Okay. Back to Exhibit 3900. Now I'm on page 12. Before I -- turn to page 12, and then I'm going to -- I need to finish the line of questioning.

You've told me -- you've now told me about the top hat procedure. And while it was successful, it only had limited success, correct?

A. Yes, sir.

Page 151:17 to 161:22

Q. I'll change to meet your attorney -- did Wild Well have a recommendation that they made?

A. Yes, as participants in the incident command group --

Q. Sure.

A. -- yes.

Q. What was the recommendation that Wild Well made regarding stopping the flow?

A. First -- first and foremost, it seemed to us that it was unreasonable that all of the closure devices of the BOP were not functioning in view of the fact that the stack had been tested at least five times, pressure and operational functionality, since the beginning of drilling the Macondo well.

If you say what sticks out at

you, it is that all of these components would not fail to work at one specific time.

Q. So the first thing you thought of was the BOP?

A. Is the BOP.

Q. Okay.

A. And to take action on the BOP, to do an immediate assessment with ROVs, and to do an operational assessment of everything that we could see on the BOP stack, and to create a very short-term plan of the methodology for how we would go about establishing either the present position of rams, the -- to try to function rams and to try to determine why -- why these things seemed not to be working as being the first order of business.

Q. Okay. So the first approach was we have a BOP stack at the wellhead, let's see if we can operate it in a way to stop the flow?

A. Right.

Q. And, of course, we know by definition those efforts did not work?

A. Yes, sir.

Q. Okay. Did you make a determination why?

A. It was -- it was a very confusing period of time, as you can imagine. They had -- they had just recovered survivors, and they were still looking for the people that were missing from the DEEPWATER HORIZON.

And much of the attention was focused in that direction while they asked others of us and others from ROV companies and so on and so on to try to figure out this plan of how we would go about confirming or determining that BOPs either had functioned, had not functioned, were functioned, what their current position was, so on.

So there was a very quick learning curve in ROV capabilities, what was available, and what could it do, was it just a flying highball, did it have the ability to operate at that depth, how was it going to be deployed? We had to have a dynamically positioned vessel to operate it from. And --

Q. Out of -- out of harm's way?

A. Yes. I'm talking about all tethered ROVs, no free-swimming ROVs at this point.

What was their functional capability, how much electrical power did they have, how much hydraulic power did they have, how much torque could they formulate, and did they have the appropriate fittings to put on those ROVs' so-called tooling to enable them to do those functions on that BOP stack as presently configured.

Q. So the first thing you're trying to do on ROVs is use the ROVs -- among other things, you want to try to assess the BOP stack if you can?

A. (Moving head up and down.)

Q. Right?

A. Right.

00155:01 Q. And, of course, we know up until the rig sank, the rig was on fire?

A. Yes.

Q. It was -- the well was flowing and providing fuel to the fire on the rig floor?

A. Via the riser --

Q. Right.

A. -- yeah.

Q. Was that -- I'm sure you saw video?

A. Yes.

Q. Did you ever actually go in a helicopter or anything and go see the rig?

A. No.

Q. Okay. But you certainly saw video of the rig literally on fire with flames to the crown?

A. Yes, sir.

Q. And any question in your mind that that -- based on your 30 years of experience, any question in your mind that that is being fed by the hydrocarbons from the well?

A. No.

00156:01 Q. Okay. The -- and, of course, therefore, you have a relief ship problem in that you can't just -- you've -- you've got to stay clear of that literal danger, correct?

A. Yes.

Q. Okay. The -- okay.

And so now you say, Gee, we have to obtain ROVs and ROV tooling that can accomplish what we need to accomplish, correct?

A. Yes, sir.

Q. Okay. And I assume no ROVs were immediately available, nobody stepped up and says, I have the ROV and I prepared for this and this is the ROV and this is the ROV tools we need and we're ready to go?

A. No.

Q. That did not exist on -- when you heard about this on April 21st?
A. That's correct.
Q. Okay. Because that part of the planning had not been done --
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. -- before April 20th?
A. Well, there was a very large highly competent ROV on the -- the Transocean rig --
Q. Okay.
A. -- which, of course, was lost.
Q. All right. So you couldn't use -- is that -- was that an Oceaneering ROV or do you know?
A. I don't -- I don't recall.
Q. Okay. The point is: That ROV was on deck of the DEEPWATER HORIZON and, therefore, was not available?
A. Correct.
Q. And no emergency ROV had been planned for or was immediately available?
MR. OCCHUIZZO:
Objection to form.
A. Correct.
EXAMINATION BY MR. WILLIAMSON:
Q. I'll break it up --
A. Correct.
Q. -- into two questions.
A. Yeah.
Q. Okay. The -- so you're trying to -- you, of course, are called in and your suggestion is, Gee, let's see if we can operate the BOP we've got, correct?
A. Yes.
Q. And -- and, of course, you knew there was drill pipe in the hole? I mean, you didn't know if the drill pipe was still there, but drill pipe had been in the hole --
A. Yeah.
Q. -- at the time?
A. Right.
Q. Therefore, you got drill pipe -- presumably you have drill pipe --
A. Suspended --
Q. -- across --
A. -- through the BOP.
Q. Correct.
Therefore -- and, of course -- and you've got dynamic flow conditions. That's obvious, also, right?
A. Yes.
MR. OCCHUIZZO:

Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. So you're going to have to have serious questions, I guess, about what the annulars -- have you seen the annulars -- have you seen photographs of the annulars since they've been pulled up?
A. One or two, yes.
Q. Okay. They show pretty severe erosion?
A. Oh, yes.
Q. Right.
Okay. Would you have a doubt as to whether the annulars could shut in a well in a -- in a high-pressure flowing situation?
A. I -- I don't believe they could, although it's very hard -- that's just a personal guess. And if the drill pipe penetrated through the annular and I cut it off below that with shear rams, it would make no difference. The flow would just come through the drill pipe --
Q. Right.
A. -- yeah.
Q. So what you're saying, in a high-pressure situation, the preferred method to shut the well in would be either the shear rams or the VBR rams. Did I understand that correctly?
A. Yes. You have a lower Kelly valve on the top drive, you have this, you have that. There are lots of other secondary methodologies that if -- that if -- you know, under normal circumstances if you caught a kick early and so on and so on, you would not shear the pipe, you would -- you would close lower Kelly valve or upper Kelly valve on a top drive and close the annular.
Q. Right. And while I'm on this, the stand -- the standpipe manifold is hooked up at the time of this particular procedure, right?
A. Yes.
Q. Therefore, you have protection against flow through the drill pipe assuming that the standpipe manifold and the valves are of sufficient pressure?
A. Yes, and closed in the right order.
Q. Correct.
A. Yeah.
Q. Okay. So if the standpipe manifold is hooked up and you've got the pressure through the drill pipe contained, the next thing you need to do is make sure

you don't get flow through the annulus?
A. Correct.
Q. And the best way to make sure you didn't get flow through the annulus would be to close -- probably close the variable bore rams that you've got two sets of, right?
A. Typically, yes.
Q. Okay. And in an emergency situation, I assume based on your years and experience of training, that's what you would recommend?
A. Well -- my personal opinion?
Q. Yes.
A. Yes, that's what I'd recommend.
Q. Okay. So you --
A. But none of us were there. None -- none of us know anything about what preceded this flow, no one from Wild Well knows that.

Page 163:10 to 164:10

Q. And -- if we now -- given that we've got a recent cement job and given that we've got a fluid barrier that's underbalanced and you now have flow hit the rig floor, mud, debris, would you consider that an emergency situation?
A. Yes, sir.
Q. Okay. And in an emergency situation based upon your 40 years starting with your dealings with Red Adair and your successful company practices since then, your recommendation would be that it be treated as an emergency situation?
A. Yes.
Q. And the best response to that emergency, based upon your experience and training, would be to close the variable bore rams?
A. No. 1.
Q. And not use the annulars first, or maybe you'd use them at the same time?
A. Probably at the same time.
Q. Right. You close the annulars and close the variable bore ram. That might be the most appropriate response?
A. (Moving head up and down.)

Page 164:14 to 164:19

Q. You have to say yes or no.
A. Yes, sir.
Q. Okay. Okay. The -- and, of

course, if that did not stop the flow, you would probably at that point want to consider activating the blind shear ram system?

Page 165:18 to 165:22

00165:18 Q. By the way, is it a known danger -- or risk would be a better word. Is it a known risk in the oil field industry when you have nonshearable tubulars across the BOP stack?

Page 166:02 to 166:03

00166:02 A. Is it a risk if you know them to be nonshearable?

Page 166:05 to 171:18

00166:05 Q. Right.
A. Yes.
Q. Okay. So by definition, if you have tubulars across the BOP stack, you've got to know whether they're shearable or not?
A. Yes, sir.
Q. Okay. That's just fundamental to well control safety, isn't it?
A. Yeah. Yes.
Q. Because if they're not shearable or if there's even a potential that they're not shearable, you have to take that into consideration when you're making well decisions?
A. Yes, sir.
Q. Okay. And I assume you -- did you know the shearing limitations of this particular blind shear ram?
A. Not -- not in advance.
Q. Right. Did you later find them out --
00167:01 A. Yeah.
Q. -- one way or another?
A. Yes, sir.
Q. Okay. For example, the high-pressure blind shear ram functions, the auto shear function, the AMF function and the EDS function all utilize the subsea accumulator bank to power the hydraulic fluid for those functions. Did you become aware of that?
A. Yes.
Q. Okay. And the subsea accumulator bank had a regulator pressure of

4,000 psi. Did you --
A. Yes.
Q. -- recollect that?
Therefore, you're not going to shear pipe if you need more than 4,000 psi to do it, right?
A. Yes, sir.
Q. Would you ever recommend saying, well, we only have 4,000 psi available, but let's just hope that it shears pipe that calculations tell us are going to need more than 4,000 psi?
A. Not if the calculations told me that they were going to need more than that.
Q. Right.
Would you actually want some sort of margin of safety --
A. Of course.
Q. -- below 4,000?
A. Yes, sir.
Q. What if I told you, Well, our calculations show we will shear at 3999, so we're good to go because our casing regulator is going to deliver 4,000? Would you consider that an acceptable safety margin?
A. No.
Q. What would you consider an acceptable safety margin -- if I assume for you the casing regulator -- I'm sorry -- the regulator is going to deliver 4,000 psi to my blind shear rams, what would you want in terms of a safety margin in terms of shear ability?
A. It -- it's kind of a loaded question because --
Q. I hope so.
A. Yeah. It -- that margin would get determined by what happens on multiple functions of the BOP, not just a single function.
Q. Okay. And --
A. In other words, the fact that I close it one time or I now have less reserve in my hydraulic reservoir, even though it may be resupplying it. So I have to say maybe functioning one BOP is not sufficient. Maybe functioning one BOP open and close is not sufficient. Maybe I need to have at a minimum the ability to function two BOPs, open and close, because of factors that I can't possibly foresee that could exist.
Q. All right. You're -- you're talking about volume of hydraulic fluid that's available for multiple uses?
A. Right.

Q. I'm talking about something a little different. I'm talking about would you want to have a safety factor in the pressure available? If I told you the calculation was that it would take 3900 psi to sever this particular piece of drill pipe, would that be an adequate margin of safety --
A. And I --
Q. -- and I told you that you had 4,000 psi available? I'm trying to figure out what you would say would be an adequate margin of safety.
A. Well, it would be at a minimum 20 percent.
Q. 20 percent of 4,000, which is about 3200 psi?
A. Yes.
Q. And you feel comfortable in that assessment based upon -- you feel like you have 30 or 40 years of experience in looking at these issues from a well control standpoint?
A. I'm going to put it to you this way.
Q. Okay.
A. Almost no one has enough experience to consider themselves comfortable with pipe shearing details, whether that's Cameron Ironworks, Vetco, Dril-Quip, whoever it might be. There -- there are just -- you know, it depends on the weight and grade of pipe at the time. It depends upon whether it has tandem boosters or not. It depends -- or -- or a boost mechanism, depending on who is the manufacturer. It depends upon has anyone reliably tested to see if those BOPs will do that repeatedly. So -- and by that, I mean there's all sorts of shear blade designs, different manufacturers, different this and that. What one might expect to reasonably occur once maybe couldn't occur twice.
Q. So having said all that --
A. Yeah.
Q. -- you would take all those factors into consideration, and based on your education, experience, and training, well-control training, your work history, you'd think 20 percent safety margin would be a reasonable number?

Page 171:21 to 171:21

A. It would be the minimum number.

Page 173:07 to 175:24

(Exhibit No. 3901 marked for identification.)
EXAMINATION BY MR. WILLIAMSON:
Q. Now, having said that, do you recognize the document?
A. Daily operations report.
Q. I will tell you the part I want to ask -- it's a Wild Well document dated April 21, 2010, which, of course, is the day after the blowout. And I'm going to be interested in asking you about an entry down below at 5:00 o'clock p.m. where it says, "After reviewing well data there is a possibility that the 9-7/8-inch casing may have collapsed."
See where I am on the page?
A. Yes, sir.
Q. I'm trying to figure out why. Why was Wild Well, when they initially looked at that, concerned that the 9-7/8-inch casing may have collapsed? Can you give me any more information on that?
A. Well, it's not just Wild Well. It's -- it's a team --
Q. Fair --
A. -- looking at this.
Q. -- fair comment.
A. And what they're saying is gas being present behind or outside the 9-7/8 casing combined with a reduced hydrostatic value inside the casing.
Q. Namely, because part of the mud column has blown out?
A. Right.
Q. Okay.
A. Well, I -- I think what they're suggesting is that it -- it might have contributed to or a cause of the blowout.
Q. Right, that there's a --
A. Yeah.
Q. -- concern after looking at some of the well data --
A. Right.
Q. -- that there's a risk that the 9-7/8 has collapsed?
A. Correct.
Q. And collapse for this purpose means that it has ruptured as a result of pressure external to that pipe?
A. That's right.
Q. Right. And I was trying to figure out why.
Perhaps another question might

be, who would be the best person to ask based upon looking at the people who kind of wrote this memo and participated in it?
A. Well, this --
Q. Who might be a logical person for me to ask how they -- how they concluded that?
A. This is our daily report which takes into account data from many sources, not just ourselves. And the person to ask in this instance about that specific comment would be either Mark Mazzella, BP's worldwide well-control advisor --
Q. Uh-huh.
A. -- or John Shaughnessy.

Page 176:21 to 196:13

Q. And it says, "Circulation kill driller's method circulation."
And I'm trying to figure out what the driller's method is.
A. To make the -- the -- pretty much the shortest explanation I can make, it is a way of circulating the wellbore that is predicated upon maintaining a constant drill pipe pressure.
Once you've gone to your slow pump rate and established what that is, then you can -- you can ratchet that rate up and you will maintain -- your objective is to maintain an injection pressure at the bit that will main -- so-called constant drill pipe pressure which will not allow further ingress of formation fluids outside the drill pipe.
Q. Okay. So would -- you would want to get your circulating --
A. Rate.
Q. -- rate?
A. And pressure.
Q. What's that called? Is that ECD or --
A. Well, the -- the ECD is a component of it.
Q. Okay.
A. ECD comes into play by when you're pumping at a high rate, you create a frictional force in the annulus between the drill pipe and the casing. And that small frictional force adds an incremental element to your circulating density. In other words, if I'm pumping 14.2-pound mud --
Q. And you're --
A. -- but I'm --

Q. -- circulating it?

A. And I'm circulating it, but I'm doing that at 60 barrels a minute, then there will be a component of that that is friction pressure that I have to add to the 14.2 pounds per gallon in order to come up with what is the effective circulating density at the bit.

Q. Okay.

A. But that's equivalent -- ECD.

Q. Okay. So the driller's method really refers to a method of circulation once you have the well shut in?

A. Well, yes, yeah.

Q. I'm talking about in connection with circulating out a kick.

A. That's correct.

Q. Okay. We're talking about, gee, we've got the well shut in and we now -- this is the methodology by which we make sure hydrocarbons no longer come in and we hopefully start removing them from the --

A. Right.

Q. -- column?

A. Right.

Q. Did I -- is it -- is that a --

A. Yes, that's fair.

Q. -- simplistic definition? Okay.

All right. Let's go back to my question that I started on. Because we talked a little bit about top hat. We talked a little bit about junk shot. We talked a little bit about the relief wells. And -- and you had given me some other options that were available for consideration -- well, in one of them -- we talked about also BOP activation. Namely, let's take the BOP stack we've got --

A. Yes.

Q. -- and see if we can make it work.

A. That was No. 1.

Q. Right. And that was what y'all concentrated on first?

A. Yes.

Q. Right.

The -- all right. What was -- did Wild Well have a recommendation what to do after the BOP efforts failed over approximately -- approximately three days?

A. Yeah.

Q. There was approximately a three-day period where everybody tried to get the BOP to activate in a way that sealed the well. That did not occur. So other options became more to the forefront. I'm trying to figure out did Wild Well think which one of those should be pursued first?

A. I think a meeting occurred at the BP incident command center in which we discussed many options, many, and some got set aside for one technical reason or another. And so the best way I could describe this is to say that a series of silos was created.

Q. Kind of intellectual silos?

A. Yeah, yeah. I mean, it -- it is to say that a body is going to -- of work is going to take place in that silo, if you will --

Q. Okay.

A. -- that may or may not be interlinked or independent to other silos.

Q. Okay.

A. So No. 1 was to try to activate the BOPs that exist, the DEEPWATER HORIZON BOPs.

Q. Okay.

A. And among the others -- and I'm going to name them really without --

Q. Yeah, you're not --

A. -- preference.

Q. -- trying to give a preference --

A. Yes.

Q. -- you're just naming them? Fair enough.

A. One was so-called top kill which included the junk shot.

Q. Right.

A. Another was the top hat. And top hat was a companion silo to -- you might say to the relief well effort.

Q. Okay.

A. And another silo was the relief well effort.

Q. Okay.

A. Two relief wells. High and low intercept point, a lot of different technical thing, approach from a different azimuth, so on and so on, in order to give yourself the best opportunity to make that interception.

Q. Okay.

A. And the next two were outright capping scenarios that -- that included basically a redundant BOP stack on top of the Macondo or the DEEPWATER HORIZON BOP stack, and then the last silo was several different iterations of that, of -- it's capping but utilizing a different configuration of

equipment in different circumstances.
And they -- they could not be foreseen in advance. If you had trouble getting the LMRP off, there were also complications with the flex joint -- flex joint's limited to 5,000 psi working pressure. We know that the flex joint has been flexed way beyond its working range of 8 or 10 degrees max. It's been bent over virtually horizontally.
Q. So you have to worry about whether that's compromised, it's working -- working --
A. Whether that's compromised, if that has to come off, that presents you with a different interface for capping. And then there are some philosophical issues about should I attempt to install a capping assembly that I believe is easy to install having only, let's say, one closure device, one blind ram, and below that diverter lines, and I can then divert the well and I can install any amount of jewelry on top of that that I wish to. Would this be easier to -- because my positioning is limited to use of the ROVs to assist me.
Q. Okay.
A. And perhaps some skirting and this and that. But anyway.
So those are the main elements that were agreed to be pursued on about the second day while we're carrying out Silo 1 trying to operate the Macondo BOP.
Q. Right. So the capping stack -- okay.
A capping idea, namely, attaching a mechanical device --
A. Yeah.
Q. -- that did not -- that wasn't subsea already --
A. Right.
Q. -- to the Macondo came up literally in the first day --
A. Correct.
Q. -- April 21st, in terms of being discussed?
A. I might say I believe that meeting was on the 22nd.
Q. That's fair.
A. Yeah.
Q. Okay. And that iteration -- I believe is the word you used -- involved -- you could use a preexisting BOP, you could attach to the BOP stack, you could attach to the LMRP, you could come up with a piece of

equipment that would attach to the BOP stack, or you could come up with a piece of equipment that would attach to the LMRP, or 00185:01 you could come up with a piece of equipment that would attach to the flex joint?
A. Correct.
Q. Right. Those are different iterations of a capping --
A. Yes.
Q. -- solution?
A. Right.
Q. Okay. And, of course, you would -- you could cap with or without venting?
A. Sorry. You have to tell me.
Q. Well, I'm -- diverter may be the right word.
A. You could allow the well to flow vertically, and you would allow it to flow vertically while you got any capping device in place --
Q. Okay.
A. -- and locked down. At that point you could divert or you could just shut in.
Q. Did the analysis of the rupture disk and the 16-inch casing and the MIYD, minimum yield of the 16-inch casing --
00186:01 A. Oh, yes.
Q. -- did those part of questions come up in discussing whether or not a capping solution would be appropriate?
A. Yes.
Q. Why?
A. Well, there is some potential that if the outer annuli, the outer casings has been compromised, then putting any type of capping device that you're actually going to think about closing, shutting off, then has ramifications beyond what's taking place at the present time. It could easily make matters worse.
One of our primary directives was whatever you do, we don't want to make matters worse.
Q. And would you consider having a surface blowout worse?
A. Was not worried about a surface blowout, we were worried about a seafloor blowout.
Q. You're right. I --
A. Yeah.
Q. -- apologize. I used --
00187:01 A. Yeah.
Q. -- the wrong word.

A. Yeah.
Q. That's what I meant to ask.
A. Right.
Q. Okay. Were you worrying about having a blowout where hydrocarbons would exit through either the rupture disk or the 16-inch casing seal and literally come up to the seafloor through an alternative method outside the wellbore?
A. Yes.
Q. Okay. And would that be making matters worse, in your opinion?
A. Yes.
Q. Was that a realistic possibility?
A. It was a possibility.
Q. Okay. It wasn't the most probable, according to you? I don't mean -- I'm not fussing. I'm --
A. Yeah.
Q. -- just trying to understand who was --
A. Right.
Q. -- thinking what.
A. Right. Believe me, there were a lot of people involved in this --
Q. Sure.
A. -- discussion.
Q. Right. I'm trying to go down the road of trying to figure out why -- here's where I'm trying to head: Why were people worried --
A. Well --
Q. -- that they were going to rupture those disks --
A. Yeah.
Q. -- or --
A. Or that they were already ruptured.
Q. Right.
A. Yeah.
Q. Or that they had a -- they had a problem with their 16-inch casing --
A. Casing, right.
Q. -- issue?
I'm trying to figure out why that was true.
A. Well --
Q. What -- what reasoning was behind that concern?
A. Some -- some early calculations were done not by Wild Well, by others, that seemed to indicate that the pressure of the rating of the rupture discs had already been exceeded in the early part of the blowout.

Q. Okay.
A. So that merited much further study, and it got much further study.
Q. Let me -- can I stop you there and ask a question?
A. Yes, sir.
Q. Because there was no tieback that isolated the 16-inch casing from the total depth protection zone, that was a possibility, correct?
A. Yes, sir.
Q. If there had been a tieback that isolated the 16-inch casing from the production zone, then you wouldn't have to worry about the 16-inch casing going out --
MR. OCCHUIZZO:
Object to the form.
EXAMINATION BY MR. WILLIAMSON:
Q. -- correct?
A. Presumably that's true.
Q. Okay.
A. However, if you didn't have a cement job and the flow came up the annular space outside the 7-3/4-x-9-5/8, it might have access at the casing shoe to the 16-inch.
Q. Even if you had a -- a tieback?
A. No, no.
Q. Let's -- that's what I was asking.
A. Okay.
Q. If you had a tieback --
A. Right.
Q. -- if you had tiebacks all the way down to total depth, and even if you had a failure of the cement and you had flow outside the production casing, you would have isolation away from the 16-inch casing, correct?
A. Not if the flow originated -- imagine now that this -- that this casing string that you have tied back --
Q. Right.
A. -- is just dangling there. There is no cement. Now, if the well wishes to flow up that open hole space to the shoe of the 16-inch casing, it could still be exposed.
Q. I'm not following you.
A. Okay.
Q. I'm -- I'm sure it's my fault. Okay?
If you'd had tiebacks all the way down --
A. Yes, sir.

Q. -- okay, instead -- there was a portion of this well that had an open annulus --
A. Right.
Q. -- correct?
A. Right.
Q. And that open annulus, if you have flow outside the protection casing, gives you access to the 16-inch casing?
A. Right.
Q. That's the well -- that's the way the well was actually configured?
A. Right.
00192:01 Q. Okay. Now I want to talk about how the well might have been configured.
If you had had a 13-5/8-inch tieback, wouldn't --
A. Oh, yes, sir.
Q. -- that --
A. Yes, sir.
Q. -- wouldn't that isolate the 16-inch casing?
A. It would have done so, yes, sir.
Q. From the blowout?
A. Yes, it would have done so.
Q. And then you wouldn't have to be worried about the 16-inch casing?
A. I would still have to be worried but not about the 16-inch casing.
Q. Fair enough.
But if you had that tieback, you wouldn't have to be worried about the 16-inch casing or the rupture discs that are in the 16-inch casing, true?
A. True.
Q. Okay. Now, you said -- in fairness to you, you said, "Well, I might have to worry about something else"?
00193:01 A. Yes.
Q. Tell me what -- what you're thinking.
A. Worse -- perhaps worse than uncontrolled flow at the seafloor would be an uncontrolled flow at any point in the open hole section of the wellbore. If I have flow in that annular space and it's exiting at a depth -- I forgot where the 16-inch shoe is, but, say, 8,000 feet -- that's what's called an underground blowout.
If that occurs or if that has occurred or is occurring, I have cut off the height of the column that I have to deal with from either a relief well or from a direct borehole intervention. I have cut off the height to which I can build hydrostatic in

that annular space to stop that flow.

Q. And --

A. It -- it's almost worse than -- now, I say from a -- from a -- a well control standpoint, it's worse than an unimpeded flow at the -- or even an impeded flow at the seafloor.

Q. Okay.

A. Perhaps from an operator's standpoint, it's a better solution because there is no -- there -- there is no pollution. And I may have created a well now that the geometry virtually won't allow me to kill by conventionally known means. But, hey, it's going underground into a shallower weaker formation, what do I care. I'm not suggesting that BP ever thought, said, or intimated anything like that, but it's just --

Q. Okay. What are the advantages, then, of using a tieback system?

A. The -- the advantages of a tieback system in the case of this well would be to protect the 13-3/8 tieback hanger from being exposed to any well pressure and --

Q. But if -- if you had the 13-5/8-inch tieback --

A. Yeah.

Q. Wouldn't you have isolated -- wouldn't you be -- and if you had set it correctly and cemented it in correctly, wouldn't you be isolating that downhole pressure from anyplace above that in the wellbore?

A. Well, theoretically, yes, one would hope so. I can't tell you how often they fail, but...

Q. Okay. What you're saying, there's recorded instances of them failing -- your comment makes me think that there must be some times when they do fail.

A. They do. And -- and, furthermore, drill pipe tool joints, there's always what's called a low side of the hole. I don't care how vertical it is. It doesn't make any difference. There's always a low side of the hole. So if you drill through casing long enough, you're imparting metal loss erosion from the hard banded tool joints, even if they have drill pipe rubbers on them, to the previous string of casing.

Q. Okay.

A. So the liner tieback, which has to be of a pressure rating sufficient to control any pressure from that wellbore --

Q. Downward?
A. -- downward and has to be in a virtually pristine condition so that you have no worries about wear, loss of wall thickness, et cetera, et cetera, et cetera, the -- this is what the liner tieback provides for you.
Q. Okay. And, of course, I guess the flip side of that is if you go to a long string, you've got to worry about not only the annular flow, but you also have to worry about your collapse and burst?
A. Correct.
Q. And for long term, I assume you also have to worry about fatigue?
A. Yes.

Page 197:17 to 202:04

00197:17 Wild Well and BTI been customers of BP or had a business relationship with BP, I guess, is the way I meant to ask it?
A. We provided services -- pardon me -- to BP for a very long time. I couldn't tell you the start date. I could tell you that we provided services -- comprehensive services to Amoco which BP acquired shortly after coming to the US --
00198:01 Q. Okay.
A. -- Gulf.
Q. And does BP -- does BTI or Wild Well have a business relationship with Cameron? Now it's Cameron International. I think it used to be Cameron Ironworks.
A. Right.
Our relationship would be described as a vendor, supplier, customer, a vendor relationship.
Q. They're the vendor and you're the customer?
A. Cameron is, generally speaking, almost always the vendor and Wild Well is the customer.
Q. Okay. So there may be occasions in which BTI or Wild Well had supplied things to Cameron, most of the time it's --
A. Yes.
Q. -- BTI or Wild Well are acquiring equipment from Cameron?
A. Yes.
Q. Okay. And Transocean. Do you have any -- does Wild Well or BTI have any business relationship with Transocean?
00199:01 A. No. It's -- it's only been incidental in terms of if Transocean were the

contractor to a particular operator. So there may have been some considerations during engineering work performed by Wild Well and so on.
Q. Okay. For example, just like on the Macondo --
A. Yes.
Q. -- you were hired by BP on the March 2010 event --
A. Right.
Q. -- but you obviously would have had interaction with Transocean --
A. Right.
Q. -- because they're the people who are the drilling contractor on that particular well?
A. Yes.
Q. Okay. Halliburton. Any -- does BTI or Wild Well have any business relationship with Halliburton?
A. Numerous.
Q. Okay. Tell -- can you describe it?
A. Most of the time we have been purchasers of Halliburton products and/or when Halliburton owned the Otis Engineering company, we were a -- a big purchaser of products, less so in recent years, but we still do buy some specialty valves and fittings and things from -- from Halliburton.
Q. Next is Weatherford. Any business relationship with Weatherford?
A. Very comprehensive business with Weatherford. We provide Weatherford with all support -- all sorts of specialty tools that are used in the conduct of their trade.
Q. Okay. Next is MOEX, which is one of the -- had a working interest in the Macondo well. Any business relationship with MOEX?
A. None.
Q. And next is Anadarko who also had a working interest ownership in Macondo.
A. Yes.
Q. Any business relationship with Anadarko?
A. Yes, we had a --
MR. YAMIN:
Object.
A. Sorry.
MR. YAMIN:
I'm objecting to the question.
A. We have a comprehensive relationship, master service agreement. We do well control work. We provide them with

all sorts of specialty tools to BTI. We do engineering work. We do very much the same body of work that we do for BP.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. Did you ever see Anadarko take any sort of an active role in connection with the Macondo well?
A. Anadarko had personnel that were present.
Q. Post-spill?
A. Yes.
Q. Okay.
A. In the incident command.
Q. Okay. So Anadarko had people who were there in connection with the post-spill efforts and deliberations?
A. Yes.
Q. Okay. The -- oh, and Dril-Quip. Do y'all have any sort of a business relationship with Dril-Quip?
A. It's minor. We purchase certain equipment from them, and that's about it.

Page 203:09 to 216:17

April 27th -- first of all, there's a person named Debbie Kercho who sent this e-mail. Do you know Ms. Kercho?
A. I do not.
Q. Okay. And she sent it to Kurt Mix?
A. Yes.
Q. Who's Kurt Mix?
A. Kurt Mix was a senior engineer for BP.
Q. Okay. And then also sent it to Walt Bozeman and David Epps. Who are they?
A. I'm actually not familiar with either one.
Q. Okay. At the bottom of that, the last sentence in her e-mail of the 4:15 p.m. e-mail is, "The other piece of data that we've received verbally is the measured bubble point is approximately 6550 psig," right?
A. Yes, sir.
Q. What does "bubble point" mean?
A. Bubble point is the pressure at which gas that is entrained in solution, in oil, starts to become free gas.
Q. Okay.
A. No longer entrained, dissolved, or compressed, but starts to become free gas.
Q. Okay. I will tell you the bottom hole pressure on this particular well

was greater than 6550, correct?
A. Yes, sir.
Q. To -- someone has told me -- and I don't know if this is right -- but someone has told me that when the gas -- when hydrocarbons would have actually entered down at total depth, they would have been immersed in the fluids so you wouldn't have necessarily seen them?
A. The gas?
Q. Right.
A. Yes.
Q. Okay. Is that same true for oil or would the oil have been more noticeable if you were looking for it? When the influx started --
A. Right.
Q. -- where hydrocarbons started coming into the production casing --
A. Right.
Q. -- okay -- well, let me back up, make sure I'm on the same page with you.
A. Okay.
Q. We now know that there was influx through the production casing --
A. Yeah.
Q. -- is that fair?
A. Yes.
Q. Okay. When that influx started sometime on the evening of April 20th --
A. Yes.
Q. -- okay, you wouldn't have necessarily noticed the gas influx until it separated -- is that what you're telling me -- until it hits the bubble point?
A. That's correct.
Q. Okay. What about the oil? Would -- when the oil starts entering, would you notice that? Would it be possible to notice that?
A. If -- let me give you the best answer I can.
Q. Okay.
A. As -- as any influx, any, enters the wellbore and -- and you notice that you have either gotten back a greater amount of fluid or a -- in the case of an influx, greater amount of fluid than was in the wellbore, and you see a pressure increase, you know there has been an influx.
Now, at that moment in time, depending on how early you recognize this, you don't know whether that is oil, gas, multiphase oil and gas, condensate, or water.
Q. Okay.

A. At that moment you do not know the -- what that consists of. It's still -- presumably you have caught it early and it's still way down at the bottom of the hole.
Q. Right. Now, on the -- let me switch to Macondo for a second --
A. Okay.
00207:01 Q. -- okay?
On Macondo if you started having influx -- well, actually, let's back up one step.
At Macondo there'd actually been loss of returns at total depth, right, when they stopped drilling?
A. Yes, sir.
Q. Okay. And there was a formation there at total depth --
A. Yes, sir.
Q. -- right? Okay.
So if you start getting an influx on Macondo at that depth --
A. Yes.
Q. -- it's probably not saltwater, is it?
A. Well, in this case, because you already have some data about the well --
Q. Exactly.
A. -- then the answer is yes, it's probably not saltwater.
Q. It's probably hydrocarbons, either oil or gas or a mixture of both?
A. Yes.
00208:01 Q. Okay. The -- and -- and that's because you know you've got hydrocarbons at that location?
A. Right.
Q. You hit them there a few days earlier --
A. Right.
Q. -- when you stopped drilling, right?
A. Yes.
Q. Okay. By the way, have you ever heard of something called a positive pressure test?
A. By all means.
Q. Okay. And the positive pressure test is where you put pressure on the casing to make sure your seal is good on the cement?
A. That's correct.
Q. Okay. And I guess you have to wait to make sure the cement sets up before you run that test?
A. You would do so.
Q. When you're running a positive

pressure test, do you run the risk that you will actually create a channeling or disruption in the cement if you don't wait an appropriate period of time?

A. Yes.

Q. How long's an appropriate period of time to wait?

A. Well --

MR. OCCHUIZZO:

Objection to form.

A. -- I couldn't possibly answer that question.

EXAMINATION BY MR. WILLIAMSON:

Q. Okay. Because it's case specific per well or something --

A. Exactly.

Q. -- or is that not the right criteria?

A. No, that -- that is the right criteria. Someone has to -- to model this well and then create cement formulation, and then there has to be discussion between who's going to pump it, who's going to provide it, and the operator to say, Do I want to put additives in this cement? I could put additives that will retard the setup of the cement or I could put additives that will accelerate the setup of the cement or I can put additives that will stop water loss from the cement that I am pumping. Those are probably the three greatest among a list that's probably 50 items long --

Q. Okay.

A. -- yeah.

Q. Would there be a minimum or could you not even estimate that? In other words, what's the least amount of time you've ever seen that it takes cement to set up?

A. Cement sometimes flash sets.

Q. Okay. And --

A. As a result of temperature, dehydration, et cetera, et cetera, pressure.

Q. So on Macondo you don't -- when we talk -- I want to go -- I want to go back to Macondo.

On Macondo you don't really have an opinion about how long it would take this --

A. I have no opinion. I had -- I had no involvement whatsoever in the planning or execution of the cement job.

Q. Back to Exhibit 3904, the first page, there's another e-mail from this Ms. Debbie Kercho. And the third sentence is, "They're evaluating putting another BOP

on top of the current BOP."
And you've already said yes, they are?
MS. MINCE:
I'm sorry.
A. On May the 2nd, yes.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. The next sentence, the one I want to ask you about. "When they shut the second BOP, they're getting close to the burst pressure of the 16" casing."
What is she referring to?
A. Well --
MR. OCCHUIZZO:
Objection to form.
A. -- I think what she's referring to is that the casing might burst. But that requires a number of assumptions about things that are largely unknown.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. So this is one realistic possibility, but it's hard to know how realistic it is given the number of variables?
A. You -- you -- you -- you cannot -- you cannot possibly quantify the accuracy of someone's statement like that.
Q. Because there's just too many unknowns on April 27, 2010?
A. Well, that is correct, and that you have no means by which to corroborate evidence.
Q. Okay. Of course, you're not critical of someone who thinks of that as a possibility, are you?
A. Oh, I hardly think so. We had about a thousand different opinions. I wouldn't pick on this gal.
Q. Okay. Next one -- I'm going to hand you the next one that's been marked. It was Tab No. 26. It's been marked Exhibit No. 3906.
(Exhibit No. 3906 marked for identification.)
EXAMINATION BY MR. WILLIAMSON:
Q. And this one's actually dated April 23, 2010, from William Burch. Who --
A. Yes.
Q. -- is William Burch?
A. Williams Burch is one of our senior technical advisors and well control engineers.
Q. Right. That's what I thought you had told me -- I thought you had told me that name before or I'd asked about it.

Okay. Down below that he's got some final drawing of the DEEPWATER HORIZON wellbore status and then he has a description that says, "Burst Disk - 7500 psi at 6,000 feet. With an 8.6 pounds per gallon backup gradient, 10,204 psi to exceed the burst disk on 16-inch casing. 22-inch casing 6320 psi. With 8.6 ppg backup gradient, 8586 to burst. . .

Okay. Here's your -- here's my question: 7500 psi burst disk, that's the rating of the burst disk?

A. That's correct.

Q. And is what he doing is he is -- he is adjusting that basing upon the conditions that might be in the well? In other words, what does he mean when he says, "With 8.6 ppg, 10,204 psi to exceed the burst disk"?

A. If the fluid or the back side of that casing string is equivalent to at least an 8.6 pound per gallon equivalent gradient, then it would require 10,204 psi to exceed the pressure rating of the burst disk.

Q. Because burst disk, of course, is differential pressure?

A. That's correct.

Q. Okay. And -- okay.

Now, the problem on April 23rd -- and, of course, the calculation where he says, "If you have 8.6 ppg, it's 10,204," that's a mathematical calculation, correct?

A. Yes, sir, that's correct.

Q. Right. The problem is you don't know if you've got 8.6 pounds per gallon --

A. Right.

Q. -- on the back side --

A. That is --

Q. -- correct?

A. That is also correct.

Q. What you're saying is we don't know if we have any pressure on the back side or if we have 8.6 or if we have some other number? And if that's not right, just correct me.

A. Well, we -- we have reason to believe that this is a reasonable assumption --

Q. Okay.

A. -- based on the fact that the -- that annulus was left with an 8.6 pound per gallon equivalent fluid.

Q. Which is seawater?

A. I could not answer that

accurately. It's unlikely that it was just seawater.

Q. Okay.

A. It certainly would have been treated seawater. Could have consisted some mud and seawater. It depends if they didn't have any way to further displace that annulus, then at that time then they -- they had probably precalculated what was going to remain in place above the top of cement in order to provide some backup for the casing and would almost certainly have been treated with some additives to prevent corrosion, metal loss corrosion.

Q. Have -- to refresh my recollection, what is seawater pounds per gallon?

A. 8 -- well, roughly, 8.4. It depends on where in the world you are.

Q. Right.

A. Yes.

Q. So the -- well, I'm in the Gulf of Mexico off the coast of Louisiana.

A. Well, you could use 8.4.

Q. Fair enough. The -- and what you're saying is this kind of assumes mostly seawater, but perhaps some of the -- some of the mud still remains?

A. Right.

Page 217:21 to 218:11

Q. Okay. And so now this is a -- 3906, Exhibit 3906, is kind of a precursor to determining whether we want to try to cap the well in some way?

A. In a very general way, yes.

Q. Fair.

A. Yeah.

Q. Okay. Because we're now going to start looking at the option should we cap this well somehow?

A. Right.

Q. Capping stack, BOP --

A. Right. Yes, sir.

Q. -- BOP on BOP, BOP on LMRP, et cetera, et cetera, right?

A. Yes, sir.

Page 218:13 to 221:21

Next I'm going to hand you what was tabbed 65, Exhibit 3909.

(Exhibit No. 3909 marked for

identification.)
EXAMINATION BY MR. WILLIAMSON:
Q. This is also -- the top -- this is an e-mail chain. And this is actually August 7, 2010, right?
A. Yes, sir.
Q. And, of course, at this point there has been a capping stack applied, and actually the well has been bullheaded, right?
A. I believe by the 7th the bullheading has taken place. I'd have to refresh my memory, but --
Q. Okay.
A. -- I believe so.
Q. And now there was a decision being made as to whether or not the relief well should actually intercept the annulus?
A. Correct.
Q. And he says, "The decision point for finishing the relief well is all dependent on whether there's oil behind the production casing or not and BP's willingness to accept risk if the various elements break down and result in a well control during the plug and abandonment. . .
Okay?
A. Yes, sir.
Q. Okay. Was that a big issue from your point of view?
A. From my point of view? The answer is no.
Q. Okay. So you thought they should intercept the annulus or they shouldn't?
A. I thought they should.
Q. You thought they should?
A. Yes.
Q. Okay. Did you feel like they should go ahead and bullpen it -- I'm sorry. My tongue got tied.
After the cap -- capping stack was put on, did you have an opinion as to whether they should proceed with the bullheading effort or should they wait until the relief well intercepted?
A. I had an opinion.
Q. What was it?
A. That they should wait.
Q. Okay. And your opinion, I guess, got overruled somewhere along the way?
A. Yes.
(Exhibit No. 3908 marked for identification.)
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. I assume -- I'm going to

hand you what's been marked as 3908, which was Tab 64. And, in fact, isn't that the letter where you expressed that very opinion?
A. Yes, sir.
Q. Let's see if I can find the statement I want -- right here, second page, three bullet points up from the bottom. Your sentence was, "The only fact known by anyone at the present time is that the well is holding 6,950 psi at the seafloor."
A. Yes, sir.
Q. Okay. That's kind of the crux of your opinion at this point in time, right? Namely, there's still a lot of variables that we do not know?
A. Many, yes.
Q. Okay. And you thought the safest approach at this point -- given the fact that the capping stack was holding 6,950 psi, the safest approach was to let the relief well do the interception?
A. I thought so.
Q. Okay. And this letter kind of sets forth your reasoning for that; am I correct?
A. I tried to be detailed about it.

Page 221:25 to 222:01

(Exhibit No. 3907 marked for identification.)

Page 224:03 to 228:23

Q. Okay. Okay. Down here -- this is Mr. Burch's e-mail at the bottom. I'm going to go to the bottom of the -- well, first of all, before I go to the bottom, I'm going to go two bullet points up to make the point that Mr. Burch is making that we talked about a while ago.
Two bullet points up from the bottom of the first page, Exhibit -- could you please give me the number on that exhibit?
A. 3907.
Q. Thank you. Okay.
He says, "18,186 - 18,190 massive losses were reported while drilling the base of the sand."
Did I read it correctly?
A. Yes, sir.
Q. What does that mean?
MR. OCCHUIZZO:

Objection to form.
A. I would have to admit that I don't personally remember the overall
00225: verticality of that sand.
EXAMINATION BY MR. WILLIAMSON:
Q. Uh-huh.
A. But when they say "the base of the sand," they mean at the bottom of the sand.
Q. Okay. So what he's saying is -- this is what we were talking about while ago. They hit hydrocarbons in a formation and lost returns at this very level, right?
A. Yes, sir.
Q. Okay. And then actually below that he says, "Neutron/density curves are offscale indicating gigantic gaping hole fracture."
What does -- what does that mean? What's "neutron density curves are offscale"?
A. A neutron density log is an electronic log that you run on -- on electric wireline.
Q. Uh-huh.
A. And it gives you a readout in a graph form that -- that tends to show what it's doing. Neutron density, it's acting as
00226: a densiometer. In other words, you -- you shoot out a signal, and you're looking for the delay in the return of that signal in order to get an idea about the depth of this fracture or whether it's a massive hole, whatever it is. And the neutron is the -- is the -- what's being fired from the tool to provide that feedback data.
Q. Okay.
A. Is that fair? I mean, that's --
Q. Yeah. So it gives --
A. I'm not an electronic log guy myself, but...
Q. But you're saying this gives you some indication of the size of the formation?
A. It gives you an idea about the -- the geometry of your wellbore. In other words, if it were just bouncing back, bouncing back, bouncing back, bouncing back, I could -- I could reasonably assume --
Q. A more or less circular wellbore?
A. -- a wellbore that is symmetrical and without what you call vugs or big holes or anything like that.
00227: Q. All right. Down below this, "Modeling results to date are the following:

Reservoir Engineering slapped together a quick number this morning to give to management of 162,000 barrels per day and then this afternoon revised those numbers to 92,500 barrels per day. . .

Did I read that correctly?

A. Yes, sir.

Q. Okay. "The revised numbers are based on the modeling aspects of a similar sand patch as Nakika and assumes a 10,000 psi frictional pressure loss from surface to TC" -- "TD."

Okay. Is that -- is that a reasonable assumption, a 10,000 psi frictional pressure loss?

MR. OCCHUIZZO:

Objection to form.

A. It's -- it's an assumption. And, you know, what -- what parts -- members of that team thought were reasonable is -- is now, was then, and will always be arguable.

EXAMINATION BY MR. WILLIAMSON:

Q. Okay. Well, actually, Mr. Burch goes two sentences down, "They pulled this frictional pressure loss number out of their collective butts."

Okay?

A. Way to go, Bill.

Q. I guess frank speech is encouraged over there at Wild Well, isn't it?

A. Pretty much if they're watching me, it is.

Q. The -- yeah. Okay. Well, what we do know is these are showing very significant flow rates, correct?

A. Yes, sir.

MR. OCCHUIZZO:

Object to form.

EXAMINATION BY MR. WILLIAMSON:

Q. And you know empirically that it was a very significant flow rate, although you can't tell from the video exactly how many barrels per day?

MR. OCCHUIZZO:

Objection to form.

A. Yes, sir.

Page 229:06 to 235:09

Q. I'm going to tell you I want you to turn to page 3 of that. That's where I'm going to ask you questions.

Page 3 talks about an 11-inch 10M capping stack. Is 10 -- 10M is 10,000?

A. 10,000-pound working pressure,

rated working pressure.
Q. And I assume if it's rated to a 10,000 working pressure, that's what you'd expect or that's what you would try to use the equipment for?
A. Well, you mean in other -- what -- what -- I would not put it on a well if I anticipated higher pressure.
Q. Sure. If you had a piece of equipment that's rated at 5,000 psi --
A. Yeah.
Q. -- would you -- would you -- you would design your well so to hold then a 10,000 psi flow?
00230:01 A. No.
Q. Okay. You just wouldn't do it --
A. No.
Q. -- would you?
If you have a piece of equipment that's rated at 5,000, you would actually want to use it to hold in flows that are less than 5,000 because you'd want some safety margin --
A. Yes.
Q. -- correct?
A. Yes.
Q. Okay. The reason I pulled this piece of paper out -- this looks like this is another option, namely, that this is a capping stack over the drill pipe. Am I reading this right?
A. It would -- it would be an option if drill pipe were present when the LMRP and the flex joint are removed.
Q. Okay.
A. You follow me?
Q. Yeah. I think I do.
A. Yeah.
00231:01 Q. So I'm going to kind of follow up to make sure I follow you.
A. Yeah.
Q. Okay. What you're saying is, gee, if we cut the riser and pull the flex joint and we have a piece of drill pipe sitting there, this will be an option to have a way to cap that particular configuration?
A. That's correct.
Q. Okay. Next I'm going to hand you what was marked as Tab No. 27, and it's been marked as Exhibit No. 3905.
(Exhibit No. 3905 marked for identification.)
EXAMINATION BY MR. WILLIAMSON:
Q. This is also from William Burch.

This is also April 24, 2010.
A. Very early on.
Q. Right.
A. Yes, sir.
Q. And he's talking about possible failure paths for 7-inch times 9-7/8-inch casing annulus flow, correct?
A. Yes, sir.
Q. Okay. Now, I'm trying to make sure. Obviously, the 7-inch by 9-7/8-inch, that's your production casing long string, correct?
A. Correct.
Q. And what he's talking about is do we have flow outside that string of production casing?
A. One of the things we're trying to determine.
Q. Right.
A. Yeah.
Q. Okay. I want you to look at No. 5 on this. "Up the 7-inch by 9-7/8-inch casing annulus to failed 16-inch liner top and exit out 18-inch casing shoe. Took a kick, losses occurred while circulating out influx, ballooning issues. Highly likely due to previous losses reported. . .
Did I read it correctly?
A. Yes, sir.
Q. What does he mean?
MR. OCCHUIZZO:
Objection to form.
A. I -- I don't know without further investigation.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. At least at this point in time -- and this is only four days post-incident.
A. Right.
Q. At this point in time, Mr. Burch has concluded that one of the possibilities is that he's got flow in the annulus.
A. Or that he has pressure present in the annulus.
Q. Okay. And one of his thinkings is, gee, that we took a kick -- took a kick and losses occurred while circulating out the influx, right?
A. Right.
Q. Meaning that he's worried about the integrity of the cement job on the 16-inch liner or -- or do I just -- that may not be it?
A. I think --
MR. OCCHUIZZO:

Object to form.
A. -- they're talking about the 16-inch casing shoe as being a weak point at which flow might exit.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. And by casing shoe, you mean the bottom of the 16-inch casing --
A. The bottom --
Q. -- where it's -- the bottom of the 16-inch casing where it's cemented in?
A. Yes, sir.
Q. Okay. All right. And what he's saying is that the bottom of the 16-inch string there had been a previous loss and an influx there, so one of the risks or one of the possibilities is that we do not have well integrity at that particular point?
MR. OCCHUIZZO:
Objection to form.
A. May not have --
EXAMINATION BY MR. WILLIAMSON:
Q. Okay.
A. -- well integrity.
Q. Right. That is one of the possibilities that he is examining on April 24th?
A. Correct.
Q. Okay. And other people also shared that concern other than just Mr. Burch, right?
A. This is a group of about 30 people.
Q. I know. So I'm right. Other people --
A. Yes.
Q. -- had the same concern? Some put more weight on it than others?
A. Correct.

Page 236:22 to 239:14

Q. And did Stress Engineering Services -- have you done business with them in the past?
A. We have, but in this case they were -- they were retained by BP.
Q. Okay. So this is an analysis that Stress has done for BP on oil and gas flow?
A. Yes.
Q. Okay. And did you look at it when you saw it?
A. Surely.
Q. And did you think it was a well-done report or a reasonable report when

you looked at it?
A. I -- I thought that it was a reasonable report.
Q. Okay. I'm going to ask you to turn to page 6, I believe it is --
A. Yes, sir.
Q. -- in this report.
And they say -- they did an analysis method where they had fluid properties and they put down the oil properties, correct, the seawater properties and the gas properties?
A. Yes, sir.
Q. And are all those numbers look reasonable to you based upon what you know, what they put down as fluid properties?
A. I'll be very honest with you, I would like to convert them back to American measure to -- to be doubly sure.
Q. Okay.
A. But, yes.
Q. All right.
A. They're -- they're close.
Q. At first blush you're thinking they're okay, but to be honest with you, you might prefer to do it in pounds per square inch?
A. I would, yes, sir.
Q. I gotcha.
Okay. Next is their oil flow rate that Stress Engineering estimated for BP on May 2, 2010, was 69,500 barrels per day.
Did I read that right?
A. Yes, sir.
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MR. WILLIAMSON:
Q. Did that sound like a reasonable estimate at that time based upon the fact that Stress had been hired by BP to come up with this?
MR. OCCHUIZZO:
Objection to form.
A. It didn't matter who hired who.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay.
A. And insofar as its accuracy, there was really no way to -- to gauge its accuracy other than the mathematical computations and the input data.
Q. Okay. And so what you're saying is you're neither critical of this nor adoptive of it?
A. That is correct.

Page 248:02 to 248:11

Q. Do you remember any interaction with Mr. Sims over well control policies?
A. No.
Q. Or blowout preventer policies, the way you should go about --
A. No.
Q. -- configuring, operating, understanding, and using a blowout preventer?
A. Not -- not -- not insofar as I know.

Page 249:08 to 253:15

Q. I will tell you that BP -- before this blowout they had had some documents, some of which they filed about the MMS --
A. Yes.
Q. -- talking about their well control response plan --
A. Oh, yes.
Q. -- and talking about what well control response plan they had.
A. Yes.
Q. Did Wild Well help them draft those documents?
A. For the Gulf of Mexico?
Q. Correct.
A. Well, I believe so.
Q. Okay. Well --
A. Yes.
Q. -- some of those documents are the ones that refer to walruses and have the phone number --
A. No.
Q. -- for the Japanese station.
A. No.
Q. Did Wild Well have anything to do with those kind --
A. No. There -- there are -- there is a pollution response plan --
Q. Okay.
A. -- and an environmental response plan and then there is a blowout contingency plan.
Q. Fair enough.
The pollution response plan and what was the other -- the environmental response plan, did Wild Well have any involvement in those?
A. No.
Q. Okay. What you're saying Wild Well did have an involvement is the

blowout contingency plan?
A. That's correct.
Q. Okay. And who at Wild Well would have been the person who would have been the point man on that?
A. I would just have to go back and look and see who it was, because I believe so far this year year-to-date we've done 190, to give you an example.
Q. Okay. For multiple companies?
A. Of course, yes.
Q. Now, is that -- when you say that, are you talking about -- I guess I want to make sure I'm talking about this apples and apples.
Are you talking about we were called in for a specific event on a specific well?
A. No, I'm talking about creating, amending, or enhancing the emergency response plan insofar as it relates to well control.
Q. Okay. And at what point in time would that response plan kick in, after a well's went out of control?
A. Well, depending -- depending upon what the document stipulates, which you create in conjunction with the operator, the operator may specify if we take over a 1 pound per gallon kick, this goes into effect; another operator may specify if we have an uncontrolled spill, this goes into effect.
Q. Yeah, you're -- you're -- you're anticipating my distinction, which is BP had several documents. Like, for example, I'll give you an example. One of them is Drilling Well Operations Practice, it's a manual.
A. Right.
Q. They have another document called GP 10-10, which is group -- BP Group Practice 10-10.
A. Right.
Q. And I was -- I guess I was under the impression those are BP documents.
A. They are.
Q. Okay. Those are not the plans that Wild Well had a part in drafting?
A. That's correct.
Q. Okay. What you -- I've seen other documents, and I forget the exact name of it, but I want to say the one I saw was Well Control Response Plan?
A. That is one name that's used.
Q. Right. And that --
A. WCERP.

Q. And that document is talking about, gee, after we have some sort of an event -- and I don't mean just a five-barrel kick that gets --
A. Right.
Q. -- that they shut in. But after we have some sort of event, these are company procedures that we will follow in connection with that event.
A. Right.
Q. That's the sort of document you're telling me Wild Well helped with?
A. That's correct.

Page 254:04 to 254:06

Q. Hi, Mr. Campbell. My name is Nancy Flickinger. I'm from the Department of Justice for the United States.

Page 254:08 to 275:14

Q. Good. I just want to talk with you a little bit about the kick prespill back in March. Do you remember that there was a kick on the DEEPWATER HORIZON rig?
A. Generally aware of it.
Q. Okay. And Wild Well Control was brought in to help BP address that -- that kick?
A. Yes.
Q. Can you tell me what you remember about that and Wild Well's involvement?
A. I know that we were mobilized to BP's headquarters, and the emergency team convened in order to try to create a forward plan.
Q. Okay. Was this considered to be -- well, go ahead. Were you saying more?
A. No. I -- I must say I don't recall on that particular instance. We had planned to dispatch someone to the rig. Whether we did or not, I don't recall because it really got resolved pretty quickly.
Q. Okay. But you were saying it was an emergency dispatch team. Was it perceived to be an emergency at the time?
A. Anytime they take a -- a kick, yes.
Q. Okay. And this one involved a struck -- stuck drill pipe, which adds another layer of complication, correct?
A. Yes.

Q. Is it fair to say that this is not a desirable event when you're drilling a well?
A. That's true.
Q. Because it results in additional costs, correct?
A. Yes.
Q. And sudden nonproductive time?
A. Yes.
Q. Why was Wild Well brought in to assist BP in this particular event do you think?
A. I think -- you know, BP, like many operators, identify certain wells before they're ever drilled as being critical wells. And so they -- they might establish protocol that is really tailored just for that well. And so I think it's very customary that they call us in. I don't -- I don't claim to know or recall whether there were specific criteria that triggered that in this instance.
Q. Okay. When you say a "critical well," does that mean a more challenging well?
A. A more challenging well.
Q. Okay. Is that a function of there being a fairly narrow margin, a fairly narrow drilling margin?
A. That's one element.
Q. Do you think that was an element in this case?
MR. OCCHUIZZO:
Objection to form.
A. Yes.
EXAMINATION BY MS. FLICKINGER:
Q. Okay. What causes -- when there's a kick and a drill pipe gets stuck, what causes the drill pipe to get stuck?
A. There are numerous reasons. As I said earlier to Mr. Williamson, there's -- there's always what's called a low side of the hole. I don't care how vertical it is, there's -- there is a side to which the drill pipe would preferentially lay. When it does that, the -- the force from the drilling fluid in the wellbore is applied unevenly along the high side of the drill pipe, and that's what's called being differentially stuck as a result of the mechanics of what's taking place with the tension in the drill string, the mud, et cetera.
There is just simply the fact that you were circulating and you stopped circulating and that solids suspended in the

drilling fluid tend to settle out and
accumulate probably near a tool joint or a
drill pipe rubber that's trying to protect
the wall of the casing, and a bridge starts
to form. And then pressure either from
below -- exerted by the well or pressure
exerted from the surface by trying to pump
down the annulus will compress those solids
and -- and form a bridge.
Q. Okay. And is the precipitating
event often that you've stopped circulating
in the well?
A. Yes.
Q. Okay. All right. Well, I just
want to go through just a few documents that
were in the Wild Well Control production that
will -- that will just kind of walk through
the chronology of what happened a little bit,
and maybe you can explain some of the
documents to me.
A. Okay.
Q. Okay. So if you could take that
binder and turn to Tab No. 10.
MS. FLICKINGER:
And this will marked as
Exhibit 3911.
(Exhibit No. 3911 marked for
identification.)
EXAMINATION BY MS. FLICKINGER:
Q. And this is just the call-in
report dated March 9th.
Is this a standard Wild Well --
A. Yes.
Q. -- control form?
And here the call came in
apparently to Kerry Girlinghouse who I think
you identified earlier this morning, correct?
And what's his position again?
A. Senior well control engineer and
technical advisor.
Q. Okay. And the call came in from
David Sims of BP?
A. Correct.
Q. And that's someone that you had
worked with previously?
A. Many times.
Q. Okay. So the comment is on the
other side, "Rig took a kick. Wellbore
packed off and the drill string is struck.
Current mud weight 11.9 PG." And then it
says, "SIDP, SICP" and some pressure and
talks about pit gain.
Does the pit gain -- is that an
indicia that there was a kick going on?
A. Yes.

Q. And the SIDP and SICP, what does that --

A. SIDP is the shut-in drill pipe pressure. Normally to -- sometimes called the ISIDP, meaning the instant shut-in drill pipe pressure. And you are very interested in that because the drill string -- if you're not off bottom, somewhere partially out of the hole, that is a sensor to the bottom-hole pressure. And so if you could capture what the instant shut-in drill pipe pressure is immediately rather than if it's allowed to build up for an hour and so on and so on, and that number will be changed, and that will have some impact upon your forward plan for your circulation of the well.

SICP is the shut-in casing pressure. And you'll see after the 360 psi it says, "Initial" --

Q. Uh-huh.

A. -- "increased to 500 psi."

It doesn't say over what interval of time. But, thankfully, someone recorded the instant shut-in casing pressure.

The pit gain of 30 to 40 barrels --

Q. Uh-huh.

A. -- although it's not conclusive, it would suggest to you that the total volume of the ingress into the wellbore from the formation was some 30 to 40 barrels.

Q. Okay. So at this point it sounds like the well is already shut in?

A. Yes.

Q. Okay. If you could turn to the next tab, Tab 11, and this will be Exhibit 3912.

(Exhibit No. 3912 marked for identification.)

EXAMINATION BY MS. FLICKINGER:

Q. And this is an e-mail that Brett Cocales forwarded to Kerry Girlinghouse again. And Mr. Cocales is from BP. Do you remember him? Had -- had you worked with him?

A. Brett? I think I spoke to him on the phone a few times. I never really met him myself.

Q. Okay. All right.

A. They -- they would not consider me to be the drilling expert that they would wish to have during this situation. We have many people who are, but that would not be me.

Q. Okay. So they would deal mostly

with Kerry Girlinghouse?
A. Right.
Q. Okay. And what -- did you have other people working in BP offices at Houston during this event?
A. Possibly, but I wouldn't know -- I -- I could guess that there was at least one more person working, but I -- I don't know who that was.
Q. Okay. And here is some -- it looks like some initial information concerning the well status, and it looks like they're forwarding the schematic of the well and the bottom hole assembly, correct? This is all like a preliminary exchange of information?
A. Right.
Q. All right. Looking -- looking at the description of the well status, can you -- can you tell me again -- you know, it looks like they've shut in the annular. And then it says, "Packed off above reamer but below jars."
What does that mean?
A. Well, related to their placement in the drill string, if -- if the jars are operating, you are not stuck at that point. The jars reciprocate up and down.
Q. Okay.
A. And when you pull tension it -- it slowly releases hydraulic force, and then the jars jump trying to free you. The reamer is below the jars. So the fact that the string will move up and down the length of the stroke of the jars and that they will trip means you're stuck below that point at the reamer or below, but you are free from the jars up.
Q. Okay.
A. Okay.
Q. Okay. And then Mr. Cocales -- and the rest, you know, they have -- a 35-barrel kick in the hole is consistent with the call-in. And then the concluding sentence is, "Most likely scenario is to shot holes and bullhead or circ out kick, then sever and pump cement."
What does he mean to say "to shot holes in bullhead"?
MR. OCCHUIZZO:
Objection to form.
A. Well, first of all, the word "shot" is incorrect. It should be shoot, shoot holes. And I don't know what this bottom-hole assembly looks like. You would

normally like to perforate as deep as possible where you know that you're free.

If you perforate, now there's going to be drill pipe, heavy-weight drill pipe, then a bottom-hole assembly. The likelihood is the deepest that you could accurately perforate would be in the heavy-weight drill pipe. So, number one, you calculate based upon your pressures that exist. Can I kill this well from that depth if I perforate here or what density of fluid would it take to kill this well from that depth?

So, first of all, he meant shoot holes, not shot holes. And the order of bullhead and circulate out are somewhat reversed. In other words, you shoot holes and then you circulate out above where you've shot the holes, where you know the pipe to be free.

Bullhead is an option that would jump all the way back to the beginning of that sentence and say, I either try to pump -- that is just bullhead down the annular space and work the pipe to see if I can dislodge the bridge. It's a -- it's a bit of a difficult sentence to interpret.

EXAMINATION BY MS. FLICKINGER:

Q. So you're saying the sequence would be first you try to shoot fluids or something down the annular space and dislodge the pipe and then --

A. It -- it could be -- I mean, it's really in that case going to be a joint decision of the team as to whether they think that's the best approach. It could be that you try to bullhead first, could be you just don't even mess with that, you immediately perforate and circulate above, and that really then comes down to do I want a fishing job to recover the lower portion of this drill string below where I'm going to perforate or do I want to keep messing with this pipe longer to see if I can get it free and eliminate having to face a fishing job or a sidetrack and leave the fish in the hole.

Q. Uh-huh. Uh-huh. So when Wild Well is called in to work with a operator, how -- how does it participate in making those kinds of decisions?

MS. MINCE:

Objection, form.

EXAMINATION BY MS. FLICKINGER:

Q. Does it participate in making those decisions?

A. We --

MS. MINCE:

Objection, form.

A. We -- we participate. Our advice is not always taken. You -- you would just have to imagine you have very large, very responsible operators with lots of human resources in which I would put BP in that classification. You have very small, independent operators who may be underinsured, may not have sufficient funds, they would end up having to abandon this well if they took one course of action versus they might recover the wellbore if they took the other course of action. It's just -- it's just not so simple to say there is a best way.

There may be a way that has preferred safety issues and elements. There may be a way that has preferred technical elements or issues, but it is -- and then different operators have different tolerance for risk. They are -- they are not all identical.

So to say our business sort of runs the gamut, if you will. We show up on one job and they say, We're sure glad you're here. We'll be at the Holiday Inn in Houma, Louisiana. Call us when you get done. They want no input.

Two, a BP who is fully immersed in every aspect of what's taking place.

EXAMINATION BY MS. FLICKINGER:

Q. Okay. And do you have any information as to how Mr. Girlinghouse worked with BP in this particular event?

A. Can you be more specific? I mean, in what way?

Q. In terms of drawing up the procedures and making decisions as to how to go forward?

A. No, I'm afraid I can't. I mean, they -- they -- they -- they did it jointly and they finally decided upon a procedure to go forward.

Even a procedure to go forward can easily and probably does have ifs, ands, or buts involved in it as well. We're going to do this, but if we find this to be the case, we have to alter that procedure, then, to take into account that, do this.

So quite often you'll draw a decision tree that tries to anticipate the most likely set of results and then those that are less likely. But to say what will I

do if my primary methodology doesn't work. If it doesn't work because of pressure, I do this. If it doesn't work because of stuck pipe, I do this. So on.
Q. Okay. Thank you.
If you could turn to the next tab, and this will be Exhibit 3913.
(Exhibit No. 3913 marked for identification.)
EXAMINATION BY MS. FLICKINGER:
Q. Tab No. 12, and this is -- this is WW-MDL-00000032, an e-mail from Girlinghouse to Dave Barnett and Joe Dean Thompson. And those are both --
A. Both Wild Well.
Q. -- from your company dated March 9th.
And this describes a little bit of -- it's his report of what happened. Can you take a minute and look at that?
A. I'm looking at it.
Q. Okay. Let me -- let me read it for you. "Looking back" --
A. I've read it.
Q. Okay. So it looks like they penetrated through a sand, correct?
A. Yeah.
Q. And then they took a kick in the sand?
A. Yeah.
Q. Okay. And then it talks about WL Services will be rigged up.
Is that Wireline Services?
A. Wireline Services.
Q. Okay. Is that a step that has to be taken before you sever the pipe?
A. Yes.
Q. Okay. And it looks as if they're deciding to set a plug, correct?
A. Yes.
Q. And then they're going to sever the pipe?
A. Yes.
Q. Okay. John Hattenberg (sic), is that --
A. John Hatteberg.
Q. Is that someone from your company?
A. Yes.
Q. Okay. And he's running kick modeling. What exactly is that?
A. Well, at this point in time, it's probably about what -- what happened originally just to try to verify some of the better -- some of the things that we think,

and it could also be about dynamic kill as -- and still come under kick modeling, if you will, about if we shoot holes in the drill pipe after setting the mag-range plug, what can we reasonable expect for a gas to surface pressure, what can we reasonably expect will happen since this is synthetic oil-based mud, et cetera, et cetera.

Q. So remodels all those different --

A. Yes.

Q. -- variables?

There's a sentence there -- there that says, "The EMW is probably higher than the shoe can withstand. There's a good possibility the kick zone EMW is probably higher than the shoe can withstand."

Does that basically mean that they're out of drilling margin, that to -- to -- to change the mud weight to address the kick, they're going to reach a higher pressure than the shoe can withstand?

A. Yes.

Q. Is that one reason why they're thinking about abandoning the -- the drill pipe and setting a plug?

A. Yes.

MR. OCCHUIZZO:

Objection to form.

EXAMINATION BY MS. FLICKINGER:

Q. Okay. Then I just have one more. If you could turn to Tab 20.

(Exhibit No. 3914 marked for identification.)

EXAMINATION BY MS. FLICKINGER:

Q. And this will be Exhibit 3914. This is WW-MDL-00000031. And it's another e-mail from Mr. Girlinghouse to the same recipients, Dave Barnett and Joe Dean Thomas, on March 12th.

And it says, "Background: BP does not wish to disturb the existing annular bridge or plan to fish the BHA."

So that statements mean -- means they've decided to leave the drill pipe in the hole, correct?

A. (Moving head up and down.) Correct.

Q. And then it says, "Initial plans were to set a Mag range plug in the DC and sever the HWDP at 12,900 feet."

So initially they were going to set the plug and then cut the pipe at 12,900 feet?

A. Correct.

Q. But then it looks as if they ran into some additional complications, correct? If you read the -- the next paragraph, it says, second sentence, "While going in the hole, the operator stopped to adjust something on the computer and the tool stuck at 12,200 for some reason"?
A. Yes.
Q. And so as a result of that, they had to modify the depth, correct?
A. Correct.
Q. Okay. Do you remember any discussions about that modification to the plans?
A. No, but it was -- if -- if you had your choice, you would get this cast-iron bridge plug all the way down near the end of your drill string in order to make it so that any other connections in the drill string are no longer consequential. As deep as possible would be preferred near -- near the bit.
The fact that you had to move up the hole a little bit since you intended to abandon this fish further up the hole, it's not a desirable result, but it's certainly not a deal killer.
Q. Okay. So the plug is not set at the top where they're abandoning the hole, the plug is set --
A. You would set it as --
Q. -- at the bottom?
A. You would set it as deep as possible.
Q. And then cement?
A. Correct.
Q. Okay. All right. Moving to the post-spill period.
A. May I say one thing?
Q. You may.
A. Some -- someone might argue with me, but they -- they were going to sever the heavy weight drill pipe at 12,900 feet. The plug only got to 12,200 feet. So 700 feet of heavy-weight drill pipe and 700 more feet of hole that you will have to drill once you set your whipstock and -- and sidetrack is just not desirable.
I mean, that -- that information is not included here really because it presents technical or a safety issue, it's -- it just makes things more expensive.
Q. More expensive.
A. Yes.
Q. They have to go back further and drill a little bit longer to get back on

track?
A. That's correct.
Q. So it's more -- more nonproductive time?
A. Yeah.

Page 276:10 to 282:08

Q. And so I just want to talk with you to see what efforts were made to try to estimate the flow and in particular did -- did BP provide you with any flow estimates during that period between April and, say, September.
MR. OCCHUIZZO:
Objection to form.
A. That -- that I am aware of, BP did not supply us directly with any flow rate data. We -- we were hearing the same thing that everyone was hearing, whatever was being reported on the news and so on. Doesn't mean that's what we thought, just means that's what we were hearing.
And flow rate -- there are a number of things in which flow rate and flowing pressure would be extremely helpful to know. But it -- it was clear from right at the outset that what -- whatever data was developed was going to be based on mathematical calculation. It was not going to be measured like by a flow meter or something like that.
And so, clearly, it would be subject to interpretation, and there will be many viewpoints, many, and the likelihood of getting two or more people out of a room full of 50 to agree about a flow rate and pressure was nearly nil --
EXAMINATION BY MS. FLICKINGER:
Q. Okay.
A. -- so, yes.
Q. I'm sorry.
But you -- you don't remember BP actually doing an estimate and providing it to -- to Wild Well Control or anybody else who was involved in the responses?
MS. MINCE:
Object to form.
A. Very early on there was another independent third party involved whose specialty was modeling complex flow paths, Mr. Ole --
EXAMINATION BY MS. FLICKINGER:
Q. Uh-huh.
A. -- Rygg of -- from a

Scandinavian institute, and they had developed some pretty comprehensive software. And we had worked together on a number of jobs, so we -- we -- we knew something about the reliability of that software, if the input data were accurate, if it were.

And the problem was here that nobody had any ability to -- to get further confirmation or any confirmation with certainty about the flow path and the wellbore. We -- there were no diagnostics available to us at that time to do that.

Q. Okay. So Mr. Ole Rygg -- that's the company, correct, were they retained --

A. Well, that's the individual.

Q. All right. Were they retained by BP?

A. Yes.

Q. All right. Can you turn to Tab 23 for me, please.

(Exhibit No. 3915 marked for identification.)

EXAMINATION BY MS. FLICKINGER:

Q. And this will be Exhibit 3915. And this, again, was produced by Wild Well, and it's Bates No. Wild Well 0009224. It's a native production, so it doesn't have Bates stamp.

Have you seen this document before?

A. Yes.

Q. Yes?

A. Uh-huh.

Q. The date is July 11, 2011, but I take it that's not when this was generated?

A. That's correct.

Q. Okay. Can you tell me what this document is?

A. This is a document about -- which I was referring earlier --

Q. Uh-huh.

A. -- about narrowing the scope to what are believed to be or what you can get a group to agree are probably more likely scenarios than others and discard the others.

And so these particular scenarios were ones that not -- not just ourselves, many people provided input data and comment to Mr. Rygg, and the culmination of that was pretty -- pretty much what you see here, which is predicting flow rate based on certain circumstances.

Q. Okay. Do you know what he was basing his numbers on?

A. Well --

Q. I mean, I'm -- if you -- if you look on page 4, for example, there are different scenarios with different ranges of oil and gas coming through different flow paths.
A. Right. Well, the -- this analysis is saying if you accept this flow rate, then dynamic kill modeling reveals that here is what would be required to -- to kill the well with different mud densities --
Q. Uh-huh.
A. -- and at -- and at different rates. Does that make sense?
Q. Yeah, it does.
So -- but my question was: Do you know what he's basing his assumed oil rates on or would we have to take him --
A. They're coming from other modeling that he's already done.
Q. Okay.
A. They're coming from a -- a very comprehensive set of modeling documents.
Q. All right. That he's done separately that's not reflected in this presentation?
A. I don't see it in this particular -- here he's trying to extrapolate the resulting data from that modeling for certain selected scenarios, saying if that is true, what will it take in terms of kill rate and mud density to kill this well dynamically.
Q. Okay. Was there anybody else besides Mr. Rygg who was working on issues that involved an estimate of flow rate --
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MS. FLICKINGER:
Q. -- either BP or Wild Well?
MS. MINCE:
Objection to form.
A. Not that I'm aware of. They -- they -- they assigned that responsibility -- I say BP assigned that responsibility --
EXAMINATION BY MS. FLICKINGER:
Q. Okay.
A. -- to Mr. Rygg.

Page 282:22 to 282:25

Q. Good afternoon, Mr. Campbell. My name is Rebecca Patty, and I represent State's Coordinating Counsel in the State of Alabama, Attorney General Luther Strange.

Page 283:21 to 283:22

A. I will assure you we -- we were as upset by what was taking place as anyone.

Page 285:18 to 303:06

Q. -- far as -- object to form somewhere in there, and then I was going to finish with -- as far as a contingency plan?
MS. MINCE:
Object to form.
MR. YAMIN:
Same objection.
A. It's -- it's a -- it's a little bit difficult to answer that. Number one, I -- I know that we had participated in an emergency response plan previously.
Now, usually there are two plans. This is typical. Two or perhaps three major plans. One is an emergency response plan by that operator, not necessarily predicated just on upstream operations. It would be a response plan that would be invoked for any type of emergency.
EXAMINATION BY MS. PATTY:
Q. Uh-huh.
A. Any type.
Q. Meaning what -- what we could call minor?
A. No, not minor. Major, meaning it could be related to a pipeline, a petrochemical plant, a refinery, a ship accident --
Q. Or --
A. -- whatever --
Q. -- deepwater drilling?
A. And -- and that is where the blowout contingency plan --
Q. All right. Let's focus on that --
A. Okay.
Q. -- since that's what we're here about or this incident.
What would you have proposed, if anything, to go beyond what was there, the blowout preventer, if they said, "Okay. Let's -- let's go with the -- the BOP is going to fail. Mr. Campbell" --
A. Yes.
Q. -- "what would you" --
A. Yeah.
Q. -- "what can you do for us?"
A. Uh-huh. Well, it's --

MR. NICHOLS:
Objection, form.
A. -- it's a fail in what way --
EXAMINATION BY MS. PATTY:
Q. Uh-huh.
A. -- because it did fail.
Q. Yes, it did. Let's go with the way that it did fail in short, then.
A. Right. Then the first --
MR. NICHOLS:
Objection, form.
A. In that instance if that was our task, we would wish to know updated drawings of that BOP stack. We would wish to interview the subsea engineer who is acting on Transocean's behalf and/or on BP's behalf, because sometimes those people are employees and sometimes those people are contract personnel that move from situation to situation, rig to rig, et cetera.
And we would want to interview Transocean and BP to see if they had already, by any chance, identified areas that they suspected might be problematic under a variety of circumstances --
EXAMINATION BY MS. PATTY:
Q. Uh-huh.
A. -- and then we would try to evaluate what solutions could be imposed and what equipment is available to -- I'm just giving you the typical rundown now.
Q. And that's exactly what I want.
A. -- and what equipment is available to attempt to deal with that issue.
Q. And having -- having said that, would you propose to create, if the technology was available, equipment that wasn't available when you made that determination if it would help?
A. You have to appreciate --
MR. OCCHUIZZO:
Object to form.
DEFENSE COUNSEL:
Object to form.
A. Sorry.
-- that -- that this is a collaborative effort.
EXAMINATION BY MS. PATTY:
Q. Correct.
A. And consequently if you said there is nothing to deal with this issue or whatever exists to deal with that issue --
Q. Uh-huh.
A. -- could potentially be insufficient under certain circumstances.

And this we do all over the world. I'm not just talking about BP.
Q. Correct.
A. You say, "What's here, What's not here, what do I need to have here in the event of a -- of a -- a major incident" --
Q. Uh-huh.
A. -- "that is not presently here" --
Q. Right.
A. "Where will I get it? Is that reasonable?" In other words, if it's in Europe and I need it in Angola --
Q. Uh-huh.
A. -- it may be unreasonable to say, "I have to bring that from the Norwegian North Sea to Angola." That's too long. That's too late.
Q. That -- that --
A. That's too --
Q. -- would be a long time frame --
A. Yes.
Q. -- however, if it at least existed, that would shorten the time frame?
A. Well, yes, that is correct, yeah.
Q. So what I'm getting at is -- well, would -- would the junk -- let me ask this: Would the junk shot have been -- if it was solely left up to you. If we took the collegiate affair out of it, if we -- if we took out meddling managers and politicians and things done by committee back in the day when you could make a decision --
A. Right.
Q. -- go with it --
A. Right.
Q. -- and get some action --
A. Right.
Q. -- if we're -- if we're in that --
A. I'm -- I'm listening.
Q. -- would the junk shot have been what you went with?
A. No.
Q. What would you have gone with?
A. Scenario-based planning --
Q. True.
A. -- is very difficult.
Q. Of course. But -- but this is in --
A. Because --
Q. -- it. This is during it.
A. Because what occurs will not be just exactly like the scenarios you

envisioned.
Q. Sure. Snowflakes?
A. Right. Now --
Q. But you knew enough that you -- junk shot, no. So what would you have done?
A. Well, I mean, I'm not saying no, I'm saying it would not have been my area of first perusal.
Q. Okay. So where would we have perused amongst the snowflakes or the oil -- massive oil droplets first?
MR. OCCHUIZZO:
Object to form.
A. The so-called pressure control equipment.
EXAMINATION BY MS. PATTY:
Q. Okay.
A. And that -- and that is very inclusive. That includes everything in the BOP stack.
Q. Uh-huh.
A. It would include everything in the rig surface choke manifold --
Q. Uh-huh.
A. -- the -- the rig mud gas separator, the exhaust and vent system, the diverter system in the moon pool area of the rig.
Q. Uh-huh.
A. A lot of different things --
Q. And all --
A. -- a lot of different things.
Q. -- that's not working and you're aware of that?
A. In your scenario --
Q. Sure.
A. -- all of that's not working?
Q. Uh-huh.
A. Yeah, it's the shits.
Q. Yeah, it is. And -- and your honesty is true. And it's -- and it's that for the well, it's that for the possibility of your scenario where you could have that undersea eruption --
A. Right.
Q. -- it's that for the environment --
A. Right.
Q. -- it's that for the lives --
A. Yes.
Q. -- lost --
A. Right.
Q. -- both in the accident --
A. Right.
Q. -- future health in the

environment --
A. Right.
Q. -- the fragile ecosystem out there --
A. Yes.
Q. -- it is the --
A. If -- if --
Q. -- stuff?
A. -- if I may back up for a second.
Q. Please.
A. When we said that an emergency response plan, the central point of it is usually for a response by BP and BP's management to any event of any type --
Q. Uh-huh.
A. -- then on the one hand you have the well control aspect of it --
MR. OCCHUIZZO:
Object to form.
EXAMINATION BY MS. PATTY:
Q. Uh-huh.
A. -- but just equally important --
Q. Uh-huh.
A. -- you have the environmental and pollution capture portion of it.
Q. Absolutely.
A. Those plans are created by different people. We do --
Q. Probably unfortunately, but --
A. Yeah.
Q. -- yeah.
A. Yes. But, however, they are experts at what they do. We hope that we are experts at what we do. And one of the very first things we suggest all operators is that all drills involving a release of hydrocarbons into the environment be joint drilled, that they -- that you should not have blowout-related drills and environmental and pollution capture drills separately from --
Q. Why?
A. -- each other.
Q. Why? Because --
A. You -- well, let me try to explain. You could have an environmental pollution situation that did not include the well.
Q. You could. But that's going to be probably minor, relative?
A. Probably.
Q. Okay.
A. You -- you probably will not have a well control event that doesn't have

at least some association with pollution management.
Q. Yes, sir.
A. But, largely, those things have been treated separately by -- by all the operators. I'm not --
Q. Including BP?
A. -- I'm not picking on BP.
Q. No, no, but including?
A. Yes.
Q. Okay. Benefits of bringing those --
A. Consolidation.
Q. Benefits of consolidation?
A. Yeah, unification.
Q. Unification?
A. Yeah. I -- I believe that to be very important. That's one of the things that we would target very early on.
Q. Okay.
A. The other is to try to make sure that assets are available to meet what are reasonably foreseeable or forecastable circumstances, and it will never be perfect, never.
Q. Nothing will?
A. No.
Q. But --
A. But that would be -- that would be the focus of the early stages of that collaboration.
Q. Okay.
A. Yes.
Q. The latter stages?
A. The latter stages focus on assigning some level of importance to those things which would not be available and what should we think about doing about that.
Q. Uh-huh.
A. Now, I could tell you that there have been numerous attempts mostly by service oriented companies like ourselves --
Q. Yes.
A. -- and including our competition and so on who have said, "Let's do a joint industry study and try to establish some parameters for this" and to say, then, "If we are in collective agreement about what sort of assets are required that either are not available or there's not enough of them available and that whether that be in the pollution side or the well control side" --
Q. Uh-huh.
A. -- "let's take action collectively as a group, you operators" --

Q. Uh-huh.
A. -- "and -- and you could pick us to be a catalyst for that" --
Q. Uh-huh.
A. -- "or you could pick others. We -- we have no exclusive right."
Well, those -- those type of studies seem like historically in the Gulf of Mexico they just didn't get off the ground.
Q. Is that because of the competitive nature, maybe?
00299:01 A. You have -- no, no.
Q. No?
A. -- I don't think that was it at all.
Q. Okay.
A. You had operators that are drilling in areas that are almost wholly natural gas-producing areas.
Q. Okay.
A. They say, "I could have a really big blowout, but I have no pollution."
Q. Uh-huh. Or minimal?
A. Or minimal.
You could say, "I have people that are drilling in known oil-producing areas who say, "I have leases here, but I really don't have anything on production, but I'm in the oil producing area." So you say, "Theoretically I'm at risk, but in practice I'm not at very much risk."
Q. Uh-huh.
A. Does that make sense?
Q. Yeah.
A. Okay. And then among all of that, the guy who has gas wells doesn't want 00300:01 to pay a premium for hardware and so on and so on or processes that he doesn't think are going to be required or brought to bear.
Q. Uh-huh.
A. The fellows who have oil that immediately start arguing about, "But you produce 240,000 barrels a day, I only produce 100,000 barrels a day, I'm not going to pay the same thing you pay." Well, doesn't take very long to get tired of all that.
Q. Uh-huh.
A. So those -- those efforts -- there have been efforts and they simply never got off the ground.
Now -- now, that's not attributable to BP, that's across the board with all sorts of operators, large ones, small ones, all types.
Q. Okay. If you had had access to

the capping stack, would you have killed the well sooner --
MR. OCCHUIZZO:
Objection to form.
EXAMINATION BY MS. PATTY:
Q. -- for us?
MS. MINCE:
Object to form.
EXAMINATION BY MS. PATTY:
Q. If you had it on 21st, although you couldn't have put it on on the 21st, could you have killed the well sooner than 87 long days and nights?
MS. MINCE:
Same.
MR. OCCHUIZZO:
Object to form.
A. Well, I -- that requires some assumptions and, you know, you could say possibly, possibly.
Now, if you say, "But I -- I didn't have anything to use," but, in fact, the development driller which was about to drill a second relief well had a complete BOP stack.
EXAMINATION BY MS. PATTY:
Q. Uh-huh.
A. So -- however, it was decided to start the second relief well, and it was not until the second relief well reached, I don't know, a depth below kickoff point, I mean, something like 10,000 feet --
Q. Uh-huh.
A. -- before they said, "Suspend operations, recover that BOP stack, and make it available for use as a capping device on the Macondo well."
Q. If you could have had both going on, a capping stack with a BOP --
A. Right.
Q. -- as far as we knew working BOP and that --
A. Right.
Q. -- and that second relief well being drilled with the working BOP, would that have been more effective -- that way they weren't mutually exclusive as it turned out, they were collaborative, to use your word?
MR. OCCHUIZZO:
Object to form.
EXAMINATION BY MS. PATTY:
Q. Would that have cut the time, I guess, essentially?
A. Well, possibly, yes, yes.

Q. More than likely, it would be less than 87 days --
MR. OCCHUIZZO:
Object to form.
EXAMINATION BY MS. PATTY:
Q. -- since it took you 87 days --
A. Yeah.

Page 303:09 to 313:18

MR. OCCHUIZZO:
Same objection.
A. But other work was taking place on alternative capping stacks during that period.
EXAMINATION BY MS. PATTY:
Q. Sure. But they weren't the ones used and they didn't work --
A. There -- there --
Q. -- or they didn't kill this?
A. There is a problem that all of the analytical work cannot be done in the first few moments --
Q. Sure.
A. -- of the blowout.
Q. Sure. I'm not expecting it to be capped, like I said --
A. Right.
Q. -- the 21st.
A. So by utilizing a remote oper -- tethered remote operated vehicles --
Q. Uh-huh.
A. -- we did a survey of the capping stack on the well --
Q. Right.
A. -- and we learned two things about it, basically: One at the sea floor, there was a big ellipse in the sea floor --
Q. Right.
A. -- where the capping stack had been bent over by the rig tugging on it --
Q. Right.
A. -- prior to it sinking and then when the riser and everything collapsed. So we had to run a number of inquisitory formulas to figure out was all of that movement taking place within the elastic range of the steel.
Q. Uh-huh.
A. It bounced back, it bounced back --
Q. Uh-huh.
A. -- almost vertical --
Q. Uh-huh.
A. -- not quite but almost. So

what we were suspicious about was, was there casing damage below the wellhead housing that the BOP was attached to? If there was and if we could determine that or determine that there was a high likelihood of that, that would alter our plans about capping.

Q. Uh-huh.

A. Still -- doesn't mean you don't need a capping assembly, but you might not need what was available.

Also, the -- the flex joint on the lower marine riser package --

Q. Uh-huh.

A. -- was only rated at 5,000 psi, and it had been bent over far beyond its working envelope --

Q. Uh-huh.

A. -- so we had to assume that that's been compromised, that has to come off --

Q. Uh-huh.

A. -- no matter what.

So there -- there were a lot of considerations taking place. One was what happens if we add a 75-ton BOP stack on top of the existing BOP stack and we know that it's not perfectly vertical, what are the bending stress loads that will occur as a result of that and what is the compressive weight load that will recur -- will occur as a result of that, trying to determine was the DDII rig's BOP even possibly a player; therefore, in the overall doing of things, they said, "Start the relief well. If we have to stop it, we'll stop it."

Q. Sure?

A. Yeah. So that -- that's --

Q. But basically it capped and killed the well?

A. Well, one --

MS. MINCE:

Object to form.

A. -- like it, sort of like it --

EXAMINATION BY MS. PATTY:

Q. Right.

A. -- but not exactly, yeah.

Q. Snowflake?

A. Okay.

Q. Has -- has BP come to you post-accident and asked you to comprise or work on the -- the class that you teach that some of them have attended to update it based on what happened at the DEEPWATER HORIZON?

A. We -- we are bound by one other thing. A regulatory agency actually oversees

the curriculum --
Q. Uh-huh.
A. -- of the normal course.
Q. Sure.
A. And so we cannot just freely modify that. But we do hold special courses --
Q. Uh-huh.
A. -- all the time, advanced courses and very advanced courses.
Q. Uh-huh.
A. And we do that routinely.
Q. And -- yeah, I was going to say I've seen that you do. And in addition, it was my understanding in looking at the curriculum and the regulatory requirements that you can ask -- in the regular curriculum you can make application to make changes to it. They just have to approve it.
A. Yes, correct.
Q. So you could approve it at the regular level or the advanced or the very advanced level, correct?
MR. OCCHUIZZO:
Object to form.
EXAMINATION BY MS. PATTY:
Q. And has BP come to you or has anyone come to you and said, We'd like a class in this; we'd -- we'd like to know your -- your lessons learned, both in how to cap it or what to do to prevent it?
A. Uh-huh.
MS. MINCE:
Object to form.
MR. OCCHUIZZO:
Object to form.
A. Operators have come to us recently. And I can't -- I can't tell you whether BP has since the Macondo incident. I know they have sent people to our schools.
EXAMINATION BY MS. PATTY:
Q. Uh-huh.
A. Whether they went to the advanced classes or not, I don't know.
Q. Uh-huh.
A. But what you have to imagine is that the basic course curriculum for well control goes all the way down to the driller and the toolpusher level.
Q. Uh-huh.
A. And there are -- there are certain things that would probably not be appropriate in that class that are appropriate in the advanced class.
Q. Sure.

A. And it's certainly available to them if they wish to take what they call advanced well cap. I mean -- or even a customized course. It's available to them. But the curriculum for the basic certification, I don't know whether IADC, International Association of Drilling Contractors --
Q. Uh-huh.
A. -- would favorably receive a request for a change in that curriculum.
Q. But the -- but the rules do allow --
A. They do allow it.
Q. -- for provisions to be made?
A. Yes.
Q. Okay. In your previous testimony you, I believe, stated -- if I can find it -- that if a certain incident occurred, you had no problem stopping what was going on on the rig. Does that sound familiar? If not, I can pull it up.
MR. OCCHUIZZO:
Object to form.
A. Well --
EXAMINATION BY MS. PATTY:
Q. Let me pull up the right phrase. I believe it was injuring people.
Okay. While I'm searching --
A. I -- I can probably answer the question.
Q. That would be great.
A. It's -- it's a matter of we -- we are, no matter what else, a service contractor to our client --
Q. Uh-huh.
A. -- and whether we're providing them with professional advice or hands-on services, offshore, whatever it is. And every one of our employees has stop-work authority, every single employee.
So if -- if exception is taken to what the client wants to do, we would say -- pull the stop card and say, We don't think that that's appropriate, and here's why. And sometimes a long discussion ensues about that. There are many opinions, so on and so on. And -- and we'll -- we'll just come to the point where we say, It's your well; you're the operator; and you may do that if you wish, but we can no longer be associated with that.
Q. So you would walk over a safety issue, an environmental issue, and I believe you're -- if I can find it, but you are

answering the question. So --
A. Yeah.
Q. -- I do thank you. It was specifically over personnel. It was safety to personnel?
A. Yes.
Q. And so you would --
A. Well, that's number one.
Q. Right. And I'm sure the environment is right up there, too, after that.
A. Yes. Oh, yes.
Q. Sure. But you walk a contract. So every dollar counts doesn't apply --
A. Not really.
Q. -- to Wild Well?
A. Not in this case, not in the case where there's potential for harm to human beings or harm for the environment is number two or the loss of assets is number three.
Q. And so you would and have --
A. Many times.
Q. -- many times walked a contract?
A. Yeah.
Q. Okay. Were you aware of the problems BP had encountered with the THUNDER HORSE regarding a subsea valve being installed backwards and it sinking or listing post-hurricane?
MR. OCCHUIZZO:
Object to form.
A. Personally, I'm generally aware of it, yes.
EXAMINATION BY MS. PATTY:
Q. Uh-huh. And the Texas City disaster with the 15 dead, 170 injured, 300 safety violations found, are you generally aware with that -- aware of that?
A. Yes.
Q. And the 2006 BP pipeline leaking 267,000 gallons of oil into Alaska's Prudhoe Bay?
A. Yes.
Q. 62 OSHA violations at a BP oil refinery in Ohio?
MR. OCCHUIZZO:
Object to form.
A. I don't know that I was privy or aware of that.

Page 313:20 to 316:21

Q. Okay. Do you believe that you have learned lessons since your involvement

and your company's involvement, post-catastrophe things that you wouldn't have known because that snowflake had not occurred?
A. Yes.
Q. Okay. That "catastrophous" snowflake --
A. Right.
Q. -- if that's a word?
Okay. Are you going to be implementing this in the future?
MS. MINCE:
Object to form.
MR. OCCHUIZZO:
Object to form.
A. Many of those things have already been taken into account.
EXAMINATION BY MS. PATTY:
Q. Yes, sir.
A. So I'm not sure where you want to go from there.
Q. Are there things that are still in process?
A. Yes.
Q. Okay. So there are still more lessons that you're open -- both you personally or you as a representative of Wild Well -- or Wild Wells are open to learning to make your company even safer for humans, the environment, and equipment, et cetera?
A. Absolutely. Our success is predicated on that.
Q. Yes, it is. Yes, it is.
If you had -- I believe you testified as to using solution prevention domes in previous incidents, mainly dealing with hurricanes coming into the Gulf and deepwater vessels. I believe -- was it the HORIZON and the THUNDER HORSE or was it just in general that you would use those --
A. No.
Q. -- only insofar as hurricanes?
MS. MINCE:
Object to form.
EXAMINATION BY MS. PATTY:
Q. Okay.
A. Yeah. Well, I don't know that you could say only insofar as hurricanes because a ship might run over a platform --
Q. Okay.
A. -- and submerge all the wells.
Q. I hate it when those --
A. Yes.
Q. -- when you're driving a ship and those platforms just jump right out in

front of your ship's path.
A. Yes.
Q. Okay. But -- so a ship may hit a rig --
A. Right.
Q. -- a platform?
A. Yeah, and the well would be submerged.
Q. Correct.
A. But they are still live wells. They still have to be dealt with. That's another example. There are probably numerous examples of old wellheads that have severe corrosion that have fallen over to be submerged and so on. Most all of those are in shallower water depths, of course, than Macondo. And pollution dome -- pollution capture domes and the simple idea of how they work is similar to what we did in Macondo but on a considerably different scale.

Page 322:17 to 322:19

00322:17 Q. Good afternoon, Mr. Campbell. My name is Mike Occhuizzo. I represent the BP defendants in this action.

Page 323:02 to 326:03

00323:02 Do you recall having a discussion with counsel for the -- the plaintiffs about the differences between the long string and liners with tiebacks in terms of well design. Do you recall that?
A. Yes, sir.
Q. Okay. Now, neither you nor Wild Well Control was involved with designing the Macondo well; is that right?
A. To my knowledge, yes.
Q. Okay. And to your knowledge, you don't know what data or information BP had available to it about the formation when designing the Macondo well; is that right?
A. That's correct.
Q. Okay. And you don't know sitting here today as representative of Wild Well Control why BP chose the well design it ultimately chose to use with Macondo, correct?
A. That's correct.
Q. Okay. You also mentioned earlier that some of the CSI information had made it into the public, and you were talking
00324:01 about cementing work done by Fred Sabins'

division; is that right?
A. Yes, sir.
Q. Was that in relationship to the Bly report?
A. To the report.
Q. Okay. You were also asked earlier today about different types of barriers that might exist in a well. Do you recall that?
A. Yes, sir.
Q. Okay. Have you ever done or has Wild Well Control ever done a systematic study of the barriers that were in place prior to April 20th at the Macondo well?
A. No.
Q. Okay. Earlier you were also asked about flow rate, and I believe you gave an estimate of 26,000 barrels per day of oil and 50 million scuffs of gas. Does that sound about right?
A. Well, that's what we were measuring on the -- on the Helix 4000 and the ENTERPRISE.
Q. Okay. And that was collection through both the top hat to the ENTERPRISE?
A. Right.
Q. And through the choke line to the Q-4000?
A. That's -- well, whichever way it was, yes.
Q. Right.
One of the lines on the BOP --
A. Right.
Q. -- running up to the Q-4000?
Now, that number, 26,000 barrels of oil per day that was being collected, that was after the top kill procedure had been attempted, correct?
A. Yes.
Q. Okay. And that was also after the riser had been removed --
A. Cut off.
Q. -- from the --
A. Yes.
Q. -- from the BOP?
And prior to that time, the only device that was collecting oil was the riser insertion tube tool; is that right?
A. That was the preliminary and first methodology. I believe the recovery rate was 6,000 barrels a day, something like that.

Page 326:10 to 327:09

Q. Okay. In relation to well control post-Macondo, have you been recommending that operators look into capping solutions as a possible way to handle emergency well control situations, blowouts such as the Macondo?
A. Short answer, yes.
Q. Okay. Did you do work with these operators in developing their emergency response plans prior to April 20, 2010?
A. Very possibly.
Q. Okay. Do you recall -- or sitting here as a representative of Wild Well Control, did Wild Well Control ever recommend to the operators prior to April 20, 2010, prior to Macondo, that they should include a deepwater capping stack in their response plans?
A. I don't recall specifically. You're -- you're talking about a -- a narrow group of operators. I'm talking about worldwide. And so some of those solutions included capping equipment that was not readily available. But I don't recall anything that discussed deepwater capping.

Page 330:04 to 332:16

Q. Do you consider Mr. Mazzella to be experienced in dealing with blowouts?
A. Very much so.
Q. Do you consider yourself to be experienced in dealing with blowouts?
A. I have some experience, yes, sir.
Q. Okay. Do you -- are you considered by your peers in the industry to be an expert in well control and blowouts?
A. That's possible if they're talking behind my back. I -- I -- I think they -- I think they use other terms a lot more often than expert. But . . .
Q. Now, you co-authored a -- a book that dealt with how to deal with a well that's out of control, correct?
A. Yes, it dealt with numerous facets of well control.
Q. Okay. And it looks like it was co-authored with William Abel?
A. Bill Abel, yes.
Q. And -- and Joe Bowden, Sr.?
A. Correct.
Q. And who is Mr. Abel?
A. Mr. Abel is a very proficient well control man himself.

Q. Okay. And he was with Wild Well Control at the time that the book was authored?
A. He was, yes.
Q. Okay. And -- and who's Joe Bowden, Sr.? I think we mentioned him before. He's the founder of --
A. Yes, he's the founder --
Q. -- Wild Well?
A. -- of Wild Well Control.
Q. Okay. Do you use -- or has Wild Well ever used this book in teaching its courses?
A. No, not in teaching our courses.
Q. Okay. Has this book, to your knowledge, ever been used by others in the field as an authority on well control?
A. If 10,000 people bought it and they never used it, it's a big waste of money.
Q. Have you ever relied on the book in dealing with any of the blowout situations you've been involved in?
A. Oh, certainly.
Q. Okay. Has Wild Well, a company -- Wild Well Control, a company that's been active for 30 years now, relied on the techniques that are explained in this book?
A. To a large extent, yes.
Q. Okay.
A. Most of them do not address deepwater.
Q. Okay. But it does address well control, correct?
A. Yes.

Page 334:23 to 339:19

A. Generally.
Q. Okay. As of April 20, 2010, did any operator in the Gulf of Mexico have a deepwater capping stack like what was used at Macondo on the shelf and ready to go?
A. No.
Q. Did any operator in the Gulf of Mexico have a freestanding riser system that could connect to a FPSO vessel available for deployment as of April 20, 2010?
A. No.
Q. Okay. Did any operator in the Gulf of Mexico have a junk shot manifold or a riser insertion tube tool on the shelf and ready to go as of April 20, 2010?
A. No.

Q. Okay. Did any operator in the Gulf of Mexico have a containment dome with collection capabilities already designed into it on the shelf as of April 20, 2010?
A. No.
Q. Okay. Do you know if any operator in the Gulf of Mexico had a deepwater delivery system for subsea dispersants that was ready to go as of April 20, 2010?
A. No.
Q. Now, Wild Well Control, I think you mentioned before, had some containment domes or pollution containment domes in their inventory prior to April 20th, correct?
A. Yes, sir.
Q. And those were designed for shallow water use, not deep water use; is that right?
A. And -- and not for anything of the magnitude of a Macondo well.
Q. Okay. And so when the event occurred on April 20, 2010, modifications would -- needed to be done to these coffer dams or pollution domes or containment domes in order to allow collection of hydrocarbons to take place in deep water, correct?
A. Yes.
Q. Okay. Did Wild Well Control have a deepwater capping stack on the shelf prior to April 20, 2010?
A. No.
Q. You mentioned -- you mentioned BTI --
A. Yes.
Q. -- does work. One of the things that BTI tries to do is find tools and products that are somewhat of a niche service, maybe used once or twice that operators don't want to have on stock but -- but you would seek out and provide to them; is that right?
A. Yes, sir.
Q. Okay. And prior to April 20, 2010, BTI never thought or decided or tried to have available a capping stack like what was used with the Macondo well; is that right?
A. Nothing like what was used with the Macondo well.
Q. Okay. But you had other capping stacks that would be used, for instance, on a gas well in Wyoming?
A. Yes. We -- we even had some blowout preventers that were used on blowouts

in shallow water.
Q. Okay.
A. They -- they were subsea rated, but they were not anything like what would be required for a Macondo.
Q. Okay. Now, you mentioned before that some of the operators have agreements with more than just Wild Well Control. They might have agreements with some of the other providers.
A. Yes.
Q. I'm familiar with a few of them. Cudd Well Control, is that one of the other --
A. Yes.
Q. -- well control providers?
A. Right.
Q. Boots & Coots, is that a well control provider --
A. Yes.
Q. -- as well?
Who else provides well control services similar to Wild Well Control in the Gulf of Mexico besides the two that we just named?
A. No one -- no one else that I'm aware of.
Q. Okay. To your knowledge, did either of those well control companies, Cudd or Boots & Coots, have a deepwater capping stack available in inventory prior to April 20, 2010?
A. No.
Q. Okay. Did any of those service providers have the other source control devices we talked about, freestanding riser, RIT tool, containment domes, on the shelf prior to the Macondo incident?
A. No.
Q. Is it fair to say that as of April 20, 2010, no one in the industry, operators or these well control service providers, contemplated the need to have the deepwater capping stack or source control devices that were ultimately created for use with the Macondo well?
MR. NICHOLS:
Objection, form.
A. I don't know if they contemplated it. I know they didn't execute on it.

Page 339:21 to 344:17

Q. Okay. Would you agree with me

that standard practice in the industry in terms of well control response for a blowout such as Macondo is to drill a relief well and also develop devices to directly intervene with the well?

A. Both options, yes.

Q. And one of the ways in which you would directly intervene or -- strike that.

One of the considerations that needs to be given for the direct intervention is the need for purpose built or fit-for-purpose intervention devices; is that right?

A. Yes.

Q. Okay. And so the top hats and the capping stack that was used with Macondo well were purpose built for that DEEPWATER HORIZON BOP to which they were going to attach or hover above, correct?

A. The capping devices with specificity, yes. The pollution domes could actually be altered to fit on a variety of well circumstances.

Q. Now, in -- in term of well control response capabilities as of April 20, 2010, would you agree that BP was following industry practices by having companies like Wild Well Control on retainer and available to assist in the event of a catastrophe and also the capability of drilling a relief well?

A. Yes.

Q. Okay. We talked a bit this morning about the well -- Macondo well taking a kick on March 8, 2010. Do you recall some of those discussions?

A. (Moving head up and down.)

Q. I don't recall ever getting the word defined. Could you just tell us for the record, what is a kick?

A. A kick is when an influx of -- of reservoir fluids -- fluids can mean gas, oil, condensate, water -- enter the wellbore.

Q. Okay. Now, an operator, a driller, anyone out on the rig wants to minimize the chances of a kick, correct?

A. Of course.

Q. But it's not unusual when -- when drilling a deepwater well to experience a kick; is that right?

A. That's also correct.

Q. And not all kicks turn into blowouts, correct?

A. Not at all.

Q. Okay. Wild Well was brought in

to help assist in figuring out how to mitigate the effects of the March 8, 2010, kick, correct?
A. Yes.
Q. Okay. Sitting here today as a representative of Wild Well Control, do you have any reason to believe that BP did not reasonably or appropriately respond to the March 8, 2010, kick?
MR. HASSINGER:
Objection.
A. After the kick occurred, no, I -- I find everything that they did was pretty much in keeping with the industry standard practice.
EXAMINATION BY MR. OCCHUIZZO:
Q. And you mentioned before that one of the mitigations or twists to the mitigation somewhat was that instead of going down at 12,900 feet, they had to leave about 700 feet and set the plug a little higher than they intended. And the only real ramification I think you identified was cost; is that right?
A. I know of no technical reason that it made any difference, no drilling-related issue.
Q. No safety-related issues --
A. No.
Q. -- from doing that?
Now, I mentioned your book earlier or the book you co-wrote. There's a chapter in there on well control. Are you familiar with that?
A. Yeah.
Q. Okay. And I'm going to read you a -- a little passage from it. On page 16, it states, "Early kick detection and proper handling of the kick is the best insurance for the prevention of blowouts."
Do you agree with that statement?
A. Yes.
Q. And later in this same chapter it states, "In pressure control, kick detection is the drilling crew's single most important responsibility."
Do you agree with that statement?
A. From a well-control perspective, yes.
Q. And Transocean was the driller for the DEEPWATER HORIZON Macondo well, right?
A. Yes.

Q. Okay. Also on page 43 it states, "Experienced drilling crews have been able to detect a kick and react by shutting in the well so that the kick size was just a few barrels. This is exceptional performance, but it shows that alert crews can in fact detect and react to a kick quickly if trained and motivated to do so."
Do you agree that a properly trained and motivated drilling crew should be able to detect a kick quickly?

Page 344:20 to 344:20

A. The answer is yes.

Page 344:22 to 345:01

Q. Okay. Would you expect a crew that's properly trained and motivated to allow a well to float undetected for 33 minutes and experience a 35 to 40-barrel gain?

Page 345:04 to 345:07

A. Well, it's -- it's not a matter so much of what I would expect. I would say that that's disappointing, but I don't know all of the conditions.

Page 345:16 to 352:13

Q. Okay. Now, you -- you talked a little bit before about the different silos and a few of the other ways in which the response was organized. How were the Wild Well Control teams divided between construction and fabrication, advisors, technical support? How -- how was your team allocated to the response?
A. Each one of those silos had participants who had a background in that particular area of work. As far as construction, probably the -- the best example I could give you would be we had numerous people working at the Port of Fourchon to actually fabricate the pollution domes that were being designed at the incident command center and adopting revisions and so on. The same would be true for the -- for the -- the big pollution dome that we tried first.

And -- and so anything that was being fabricated, that work was being called out and supervised and authorized by the people in that particular group, our -- our people and perhaps the manager -- the BP manager of that group.
Q. Okay. So to -- to try to --
A. A coffer dam. I'm sorry. My mind went blank, but I thought of it.
Q. No problem. It's -- it's been a while since those -- those events. And it's not a memory test today, hopefully.
Within the silos, then, the team members responsible for the various projects would communicate with Wild Well's construction facilities in Port Fourchon?
A. If -- if fabrication was our job.
Q. How -- and -- strike that.
The teams in Houston were the ones making the decisions as to who would be used for the construction of which project?
A. Yes.
Q. Okay. Now, you mentioned incident command earlier. Are you familiar with the incident command system --
A. Yes.
Q. -- that was in place?
A. Yes.
Q. Have you participated prior to Macondo in incidents that fell under the ICS system?
A. Well, the short answer is yes. And the second answer is that's a system we use. We don't much give a flip what they're using.
Q. Okay. Now, in terms of the ICS system. Your understanding is that's a -- a way in which parties to a response can communicate using similar tools. Everyone knows what a Form 207 or a Form 21 -- 213 is because these are common tools that -- everyone is trained on that system, correct?
A. Generally, that is true, yes.
Q. Okay. During the response -- we -- we've talked a bit about or you were asked questions about BP doing something as part of the response. In actuality, isn't it true, Mr. Campbell, that all of the source control response activities were directed by the Unified Command ICS system that was in place?
MR. HASSINGER:
Objection, leading.
A. Yes.

EXAMINATION BY MR. OCCHUIZZO:

Q. Are you aware that under that system the federal government has the final say as to whether a procedure or activity will be approved?

MR. HASSINGER:

Same objection.

A. After a certain point in time when the spill was called a spill of national significance and Unified Command was invoked, then, yes, that was true. Prior to that, there was consultation, there was jawboning, there was this or that, but BP was the responsible party.

EXAMINATION BY MR. OCCHUIZZO:

Q. Well, you say responsible party. Do you mean in terms of leading the response?

A. In -- in terms of the incident commander, and there's an offset to the incident commander. I have to think about it a minute. But, yes, it was -- it was within BP until such time as -- as it became Unified Command.

Q. Okay. And at the time it became Unified Command, you'd see things like the federal on-scene commander would show up?

A. Right.

Q. And -- and he would have authority over top of the BP incident commander?

A. That's correct. Well, nothing is ever quite that easy. He did have immediate veto authority. He -- he could ask you why you're not doing something else or suggest that you do something else, but his only real power at that moment in time was veto power.

Q. Sitting here today as -- as the representative for Wild Well Control, were you ever told or was Wild Well Control ever told by anyone at BP not to try a particular course of action that they thought might work for the reason that it would cost too much money?

A. Oh, no.

Q. Is it fair to say that cost was never an issue with BP during the response?

A. It was not.

Q. Okay. And you've already listed a few of the different types of source control response methods that were discussed, so I'd like to sort of jump into some of those, if that's all right.

Let's start with -- with the BOP intervention. What role did Wild Well have with respect to intervening on the R -- on the BOP?

A. Well, we had the -- the primary responsibility for identification of potential problems, and we had the primary responsibility for design once the scenarios were agreed upon of what could be wrong, what might be wrong, what might preclude us from using this type of a device. Then our task was to further develop the alternatives that might be the solution.

EXAMINATION BY MR. OCCHUIZZO:

Q. Okay. And do you recall during the BOP intervention phase learning that the as-built or as-deployed BOP plumbing didn't match the schematics that were originally provided?

A. We -- we did learn that.

Q. Okay. And in your opinion did that have an effect on the ability of the teams to respond through BOP intervention?

A. If you're talking about the earliest B -- intervening on the BOP, the -- the DEEPWATER HORIZON BOP that was already on the well, the answer is yes, it did have an impact.

Q. What sort of impact?

A. Well, to put it simply, we're barking up the wrong tree. In other words, we're trying to follow with a flying eyeball where that line initiates and where it terminates, and that doesn't match up with the drawing.

Now, the drawing which we had at that moment in time came from Transocean. We asked for a drawing from Cameron, but, of course, Cameron had delivered the system in 2001 and had not been asked to make any modifications to that -- to their drawing.

So we said, Well, that's actually not very useful for us either. So we focused on getting updated as-built drawings from Transocean.

Page 352:18 to 352:25

Q. You -- you mentioned that Cameron's original drawings matched perhaps what was provided but not what was down on the sea floor?

A. (Moving head up and down.)

Q. That's because Transocean was responsible for maintenance of the BOP, correct?

Page 353:03 to 357:18

A. Transocean -- sometimes they hire third parties to do certain work, so on, but I would have to say the overall responsibility was Transocean.
EXAMINATION BY MR. OCCHUIZZO:
Q. Right. So under the overall responsibility under Transocean, they may have made changes that were to the BOP that were not reflected on the original Cameron design, correct?
A. Correct.
Q. Let's talk for a moment about the coffer dam, which is one of the first source control options deployed after the BOP intervention; is that right?
A. Yes, sir.
(Exhibit No. 3916 marked for identification.)
EXAMINATION BY MR. OCCHUIZZO:
Q. Okay. I'm going to hand you what is marked as Exhibit 3916. It is Tab 14 on the disk. It is Bates WW-MDL-00015519 through 522.
Do you have that exhibit in front of you?
A. The one you just handed me?
Q. Yes.
A. 3916?
Q. Yes.
A. Yes.
Q. And that's entitled "Project Memo No. 5," correct?
A. Yes.
Q. And it's discussing pollution mitigation, capture of hydrocarbons; is that right?
A. Yes.
Q. Okay. And -- and the first thing it mentions. Drill pipe.
Do you recall that there was a -- a drill pipe sticking out of the end of the riser initially when --
A. Yes.
Q. -- during the first part of the response?
A. Yes.
Q. And --
A. And although just tracing the riser to its end point was a pretty good chore. And it took many hours to trace its entire length to that end point.
Q. And -- and when you got to the end point or when you observed having gotten

to the end point, there was a piece of drill pipe that continued out of the riser that was still leaking, correct?
A. Yes.
Q. And one of the first things that the response team did was put a slip-on wellhead on that drill pipe?
A. Yes.
Q. Okay. And if you flip to the second page of Memo No. 5, Exhibit 3916, we see a picture of a coffer dam; is that right?
A. Yes, sir.
Q. Okay. And so this memo, which is dated April 23, 2010, is indicative of when the project related to the coffer dam would have begun?
A. Yes.
Q. And was it Wild Well Control's position early in the response, April 23rd or so, that a coffer dam was a -- an appropriate -- a reasonable solution --
A. Temporary --
Q. -- at the end of the --
A. Temporary solution.
Q. Because it would allow capture of hydrocarbons without damaging or dealing with the wellbore or BOP?
A. Correct.
Q. Do you have an understanding why the coffer dam was unsuccessful?
A. Yes.
Q. Why, to your understanding, was that -- the coffer dam unsuccessful?
A. We made -- we made a tactical error in the placement of the coffer dam and, that is, we lowered it into position essentially vertically over the leak point, whereas had we held the coffer dam off to the side and swung it into position, we probably could have got it in place without the tremendous formation of hydrates that occurred. It was just -- really just a tactical error.
Q. So was it an installation problem with the coffer dam rather than perhaps a execution problem once it got to the sea floor?
MR. NICHOLS:
Objection, form.
A. Well, it was execution because we're the ones that were doing it.
EXAMINATION BY MR. OCCHUIZZO:
Q. Okay. But was it Wild Well Control's belief that the coffer dam would provide a temporary solution had it been

successfully installed at the bottom?
A. Yes, we -- we were trying to capture the oil and gas that was coming from a large rupture in the riser with the coffer dam. We were trying to capture as much as possible of the balance of that flow from the end of the drill pipe at the far end of the riser.

Page 357:20 to 360:16

procurement of processing vessels, topside processing vessels, like the ENTERPRISE?
A. No.
Q. Okay.
A. We -- now, we were involved with vessels. We -- we had to provide fire-fighting vessel or -- or vessels that had fire-fighting gear on them or water-spray ability or cooling or whatever and for cleaning up other vessels so that they could go to port and come back.
And BP asked us if we could contract two vessels on their behalf because their process was burdensome and would take a lot of time.
Q. The -- the process to obtain the fire-fighting ships?
A. No, to obtain two other ships.
Q. Do you know what ships those were?
A. I don't recall right now.
Q. Okay.
A. Generally speaking, they were very large work boats.
Q. Okay. They weren't any of the vessels that were used for processing of hydrocarbons?
A. No, the Q-4000 and the ENTERPRISE were a different matter.
Q. Okay. So as you sit here today, you don't know whether or not because you -- you know, Wild Well Control wasn't involved -- whether or not there were any other vessels available with topside processing capabilities besides the DISCOVER ENTERPRISE at the start of the incident?
A. There -- there were none that we were aware of at that time. And the equipment that was placed on the Helix 4000, it didn't exist before it had to be placed there.
Q. So we -- we talked a little bit about the -- the RIT tool earlier. How was

the design -- or I guess -- strike that.
What was Wild Well Control's involvement with the development or construction of the RIT tool?
A. The RIT tool. Are you talking about a riser intervention tool or --
Q. The riser insertion tube tool.
A. Yeah, insertion tube. Okay. Oh, I think we had plenty of experience at -- at building flow bypass devices that allowed you to insert pipe into a flow path and to divert that flow temporarily allowing you to get it into place and then to remove the plugging device that was forcing the fluids and gas to go externally that allowed you to make the original insertion.
So based on that we were basically just a participant in that team that -- that developed that tool.
Q. Do you have any understanding how the design of the RIT minimized the potential for hydrate formation?
A. Only to the extent that it allowed accelerated flow through multiple orifices, which -- which may or may not have been significant. I don't think we even fully understood at that time.
Q. Okay. I'd like to move ahead

Page 360:19 to 371:03

Do you recall discussions earlier today about the top kill?
A. Yes, sir.
Q. Okay. Now, Mr. Mazzella has testified the top kill operation consisted of what he called a momentum kill and junk shots. Would you agree with that description of the top kill operation?
A. That's a fair description, yes.
Q. Okay. Could you just explain generally: How was the top kill operation supposed to work?
A. Utilizing a manifold -- pardon me -- that had been preplaced on the sea floor near but not immediately adjacent to the well, the Macondo BOP, and connected by jumper hoses from the manifold to the BOP choke and kill line entry points.
And you had the ability by shifting the valves in the injection manifold to either bypass junk and just pump fluid or you could divert the flow -- the injected fluid behind the junk and push it into the wellbore.

(Exhibit No. 3917 marked for identification.)

EXAMINATION BY MR. OCCHUIZZO:

Q. Were you one of the experts who were brought in to participate in a peer assist for the top kill?

A. Yes.

Q. Okay.

A. I was one of the people brought in for it.

Q. Just sort of broad picture in terms of -- of the -- the peer review or peer assist process, did you participate in any others besides the -- the junk shot/top kill peer review?

A. Yes.

Q. Okay. What other ones did you participate in?

A. A couple that re -- that revolved around capping, the one that recalled -- that was related to removal of the riser using the genesis shear and other devices.

Q. Okay. And what was your understanding of the purpose of these peer reviews?

A. My understanding was they wanted to get input from a broad cross-sectional number of specialists who had some experience with one aspect or the other of the top kill, being whether it be with a -- the pumping regime or whether it be with the plugging regime.

Q. Well, I'm going to hand you what we've marked as Exhibit 3917.

MR. OCCHUIZZO:

And this is Tab 30 for the folks following along on the disk.

EXAMINATION BY MR. OCCHUIZZO:

Q. And this is a document that outlines the junk shot peer assist on --

A. Yes.

Q. -- May 6th --

A. Yes.

Q. -- is that right?

A. That's correct.

Q. And this is one that you would have participated in?

A. I did.

Q. Okay. And we see down below, you mentioned a cross-section of -- of folks brought in. We see what's listed as the peer assist team under C --

A. Yes.

Q. -- on the -- on the first page?

A. Yes, sir.
Q. David Moody from Wild Well is also included?
A. Yes.
Q. Okay. What was Mr. Moody's specialty that would bring him into a peer review or peer assist such as this?
A. Because he had done many, many bridging agent injection shots previously.
Q. And are you referring to -- excuse me -- killing wells in Iraq?
A. That would be one example, certainly, yes.
Q. Okay. My understanding is that several of the people from Wild Well were involved in the Nineties in Iraq --
A. Yes.
Q. -- in putting out oil fires --
A. Yes.
Q. -- using junk shot?
A. That's correct.
Q. Okay. And were you part of the team that was over there doing that?
A. Sure.
Q. Okay. Was Mr. Moody, also?
A. Yes.
Q. Okay. How many times would you say you've previously used junk shot to -- to kill a well or -- or seal --
A. Collectively --
Q. -- a well off?
A. -- collective -- well, you're stopping the flow, you're not killing the well.
Q. Right.
A. Collectively within our company, at least 100 times.
Q. Now, how many of those times had ever taken place in what we would call deep water?
A. None. Well -- no, none.
Q. You paused for a second. Are you thinking of one that was in shallow or intermediate water?
A. Yeah, intermediate water, 2200 feet, Aegean Sea, but it's not -- it's not qualified by the term "deep water."
Q. Did you have to -- strike that.
Did you rely on those experiences in helping develop the -- the junk shot and -- and top kill operations that were used by BP during the response?
A. Yes.
Q. Okay. Looking at the list, we have some academics on the first three lines;

is that right?
A. Yes.
Q. Okay. And are you familiar with any of those three individuals?
A. Oh, absolutely, Dr. Smith and Ted Bourgoyne.
Q. Okay.
A. We worked together very often.
Q. Okay. Do you know what their specialties are?
A. Mr. Bourgoyne is a retired chairman emeritus of the petroleum engineering college at LSU, and Dr. Smith is his replacement.
Q. Okay. One of the purposes of this peer review or peer assist process of looking at -- under A(2)(c) is to provide feedback on the overall risks and potential mitigations.
Do you recall what some of the risks were with junk shot?
A. The risks would have had to do almost solely with plugging the flexible lines between the injection manifold and the entry point into the choke or kill line and with making a -- one -- you had to make one 90-degree bend, didn't matter whether you used upper choke and kill or lower choke and kill.
Q. So there's concern with blocking access to --
A. If --
Q. -- a -- a potential --
A. You would be just taking away one injection pathway that could potentially be very important to you in other well kill scenarios.
Q. Okay. And one of the things -- I think you mentioned before one of the -- the mantras of the response was don't make the situation worse?
A. Correct.
Q. Okay. And one of the things you didn't want to do with junk shot was make things worse by eliminating an access point to the BOP?
A. Right.
Q. Despite the -- some of those risks you talked about, coming out of this peer assist, were there any reasons that were expressed as to why to not proceed with the top kill?
A. Well, I would say looking at that list, if that's -- is that the whole list? Can't be the whole list.

Q. There's BP people on the second page.
A. Oh, yeah. Okay. Well, I'll -- I'll -- I'll leave them out. And I'll say that of the people on the first page -- I actually don't see anybody that thought this was a good idea.
Q. What sort of reasons did they give for thinking that this was not a good idea?
A. Well, the inside diameter of the flexible lines and the choke and kill lines was 3-inch ID. And so what we saw was that there's a very generous flow path. We don't know if that's multiple moderate cutout areas or if it's a single large cutout area. We don't know what that is. We only see what's being expelled. And what's being expelled to a person of experience would suggest I can't stop this with a junk shot.
Q. Now, the operation involved more than just the junk shot. It was also a momentum kill, correct?
A. A momentum kill. However, for a momentum kill to work, I have to have -- make some progress at impeding this exit velocity and volume in order for the momentum kill to work.
Q. Was -- did you participate in any peer reviews or peer assists regarding the momentum kill?
A. Yes. It's -- I mean, because our teams were all sort of cooperating together. You know, I -- I see two people who do not appear here who are not BP employees, and that's also -- my recollection is that they -- they did not come to this meeting. And -- and that would be John Sherson and Robert D. Grace.
Q. Okay.
A. And I -- I don't know, but I think the reason they didn't come was because they thought that that was just totally illogical.
Q. But you didn't ask them?
A. I did not ask them.
Q. Okay. We have -- I'll keep going here real fast.
What was Wild Well Control's role in the top kill operation itself? Were you involved with pumping the mud or junk shot?
A. First and foremost, we were instructed by -- by the manager of this operation that there could be only one field

team leader. It would be in this instance BP. Quite often that's a role that we would take on, but in this case it was BP. And it was to be Mark Mazzella. And no action would be undertaken without instruction from Mark, which was just fine with us. I mean, that's fine.

But our role was running the -- the high horsepower pumps that delivered the mud, took on the mud, transferred the mud, et cetera, et cetera, from two vessels in the field and in helping Mr. Mazzella onboard the rig to manage valve closures, opening, et cetera, et cetera, for the injection lines and eventually the -- the bridging agent injection.

Page 373:08 to 376:24

Q. And this memo, this Project Memo No. 13, discusses well capping and installing a capping stack on the existing BOP, correct?
A. Yes, sir.
Q. And it actually provides a potential design for the capping stack?
A. It does.
Q. Okay. Do you recall when fabrication of the capping stack first began?
A. Well, I can tell you that right about along in there certain components began to get collected, not to say that the stack was being assembled or anything like that.
Q. Okay.
A. Certain components that were known to be required, irrespective of what the configuration of the valves were and so on, those that could be identified were identified and were placed on order.
Q. Okay. So if you -- if you flip to the second page of the memo, under the summaries of procedures, it indicates that the first procedure is to cut and remove the damaged riser from the top of the existing LMRP, correct?
A. Yes.
Q. Okay. And that was eventually done June 2nd, I believe, after the failed top kill attempt and before the top hat; is that right?
A. Yes, sir.
Q. Okay. And one of the other things that this memo contemplates for using a capping stack is that -- is to disconnect and recover -- if you'll look at No. 6, recover the LMRP; is that right?

A. Yes, sir.

Q. Okay. And that would require BP or those involved with the response to lift -- to unscrew and then lift off the LMRP?

A. That's correct.

Q. Okay. And that posed an additional risk in terms of being able to successfully remove the LMRP because you didn't know what condition that LMRP was in or what was inside of it; is that fair?

A. I don't know anything that's risk-free.

Q. One of the cons listed with this capping stack idea, if you look on the last page, is that it would leave the wellbore open to the environment with no barriers in place until the capping stack is installed, correct?

A. (Moving head up and down.)

Q. And it certainly would be reason to think that you'd want to minimize that period of time, correct?

A. Absolutely.

Q. And one of the other cons they say is if you're unable to release secondary wellhead disconnect and recover the stack. Is that referring to recovering the LMRP?

A. That's correct.

Q. Okay. And that would be an instance where you go to take off the LMRP, you can't take it off, and it just results in flow up in a whole bunch of different directions, correct?

A. Yes, sir.

Q. Okay. If that was the case, what options would there have been, other than the relief well, if you had an LMRP half bent over the top of the BOP?

A. Well, we -- we were planning on the eventuality of removing the flex joint at the flange connection below that in order to give us an alternative option that would then, in turn, give us a different seating arrangement for a capping assembly, which would be installed in two pieces, one, the piece that was made up with a flange where the flex joint had been, and the second -- and it would result in having a male connector hub look up, and we would have a capping assembly with a female connector hub looking down. And so the installation of that would be fairly straightforward.

Q. Once you were able to remove what you needed?

A. That is correct, yes, sir.

Page 377:09 to 381:05

Q. And if we look, it discusses -- the attachment talks about the Well Capping Team. Do you see the attachment?
A. Yes, sir.
Q. Okay. It has the major areas of operation on the first substantive slide. And if you go over to the page ending in Bates 3950, which are the numbers on the bottom right corner -- I'm sorry.
A. That would have to come before.
Q. You know, mine is numbered a little different.
A. Okay.
Q. Let's flip until you see the one that says "Capping Stack Design."
A. Yes, sir, got it.
Q. And just so we have some clarity here, that ends in 3956; is that right?
A. Yes, sir.
Q. Okay. And it indicates the resources that are being used, and it lists Wild Well Control or WWC Marine and WWC Ops; is that right?
A. Yes, sir.
Q. What's the difference between those two companies?
A. The marine division are -- are essentially marine specialists. And that could -- that could include almost anything, from a marine engineer to a technician who had specific experience with subsea devices, so on and so on.
Well Control Ops from the Wild Well Ops means that their -- their origin is from within the well control operations group.
Q. Okay. And it goes on to list several other people including Cameron, Vetco, TOI, which I assume is Transocean?
A. Yeah.
Q. And then is that -- strike that.
It goes on to say Cameron, Vetco and TOI, which I assume is Transocean. Are those the companies, to your knowledge, that were involved with the design and construction of the capping stack?
A. They -- they -- they are and those companies were -- were involved to some extent, at least. And what I don't see there -- it says ROV tooling, but it doesn't specify that, for example, Oceaneering,

SonSub and others had people that would participate in this group and then maybe go away after they had made their contribution about what could be done with their -- with their device.
Q. Okay. So there would be permanent members of the group to some extent and there would also be people who were brought in --
A. Yes.
Q. -- as specialists to deal with issues as situations arose, correct?
A. Yes, sir.
Q. If you look at 3969.
A. I'm getting there.
Q. This is a little bit more of a
00380:01 granular breakdown of those companies we just talked about and the number of people who would be involved in the design and the fabrication and then the deployment and operations; is that right?
A. Yes, sir.
Q. And if you flip to the next page, you have something called "Key Milestones." Are you there?
A. Yes, sir.
Q. Okay. And when is the load-out date for the capping stack when it was initially conceived or designed in -- in early April -- or late April, I suppose?
A. Well, you must remember that in early April there were still numerous things that we did not know about the Macondo -- about the DEEPWATER HORIZON BOP stack, and as we learned them, they tended to influence what design, why, why would you consider that, so on, so on.
So it was not really possible to say on the 27th of April to make a prognostication about when this would be ready to deploy.
00381:01 Q. And to your understanding, when was the capping stack that was used ready to be deployed?
A. You know, I don't -- I don't recall, but -- I don't recall the date.

Page 381:08 to 381:09

00381:08 (Exhibit No. 3920 marked for identification.)

Page 381:11 to 382:11

Q. And this is a daily operations report, correct?
A. Right. 3 ram capping stack shipped offshore.
Q. And what's the date of this operations report?
A. 2nd of July.
Q. Okay. And -- and you were kind of reading it out loud there, but if you look at the second sort of paragraph within the first box of details, it discusses the 3 ram capping stack, correct?
A. Yes.
Q. And what does it say about it?
A. "Shipped offshore, will be loaded onto the INSPIRATION rig."
Q. Did you understand that to mean that as of July 2nd, the construction of the 3 ram capping stack was complete?
A. It was complete.
Q. Okay. So it's fair to say that the stack was physically complete and on its way to the site as of July --
A. 2nd.
Q. -- 2nd?
A. Yes.

Page 382:17 to 387:11

Q. Tab 19 will be 3921.
And this is July 5th daily operations report, correct?
A. Yes, sir.
Q. Okay. And it says -- if you look down here -- that the plan -- the forward plan to be confirmed -- what does it say about the capping stack there?
A. "Start operations on the 9th of July, start operations to install the 3 ram capping stack with the INSPIRATION rig."
Q. Okay. Do you know of any reason why BP was not permitted to install the cap as soon as it was physically ready?
A. I don't know.
Q. Okay.
A. I -- I can tell you this: There was still discussion taking place among the team about which rig to run it on. There was even discussion about whether to run it on wire or run it with a drill pipe riser.
We -- we had already started and stopped the relief well probably a half a dozen times, because the team -- the relief well team in conjunction with BP management would say, We don't want to intercept until

we have this in place ready to go, et cetera et cetera.

Well, we were at the point where we could do that in a matter of hours, but they were not ready to do so at a matter of hours for a variety of reasons. So the -- the only thing I could say is they were still discussing options.

Q. Did you participate in any discussions with the -- with Secretary Chu or the Federal Science Team regarding whether or not BP would be permitted to install the capping stack?

A. Permitted to install it. I did not.

Q. Okay. Were you involved with any discussions with Secretary Chu -- or strike that.

Were you involved or aware of any discussions with Secretary Chu or the Federal Science Team regarding BP's ability to close the capping stack once it was installed?

A. The ability to close it, no.

Q. Okay.

A. The wisdom of closing it, yes.

Q. Okay. Let's -- let's go with the wisdom of closing it. What sort of discussions are you aware of regarding the government's position on the wisdom of closing the capping stack?

A. There -- there were a lot of things at that moment in time that I did not really understand the basis of. The relief well was ready to intercept, but they were telling us -- "they" meaning BP or -- and/or Unified Command -- to hook up the injection lines in a manner that precluded the possibility of flowing the well back to the HORIZON and the ENTERPRISE.

I said, I don't think that's very wise. However, we don't have enough lines to do everything.

And at that time someone said, Well, that's okay because we're going to do a static kill.

Well, kind of the first that I personally had heard about that, the first that some of our team members had heard about that, and their comments to me were, You probably need to say something about this.

Q. Okay. And was it your understanding that these discussions regarding static kill took place before or after the installation of the capping stack?

A. Before.
Q. Okay.
A. Definitely before.
Q. Okay. So when abouts was the first time you heard about the static kill idea if we were -- if BP was to install and close the capping stack?
A. Oh, probably around the 9th or 10th of July.
Q. Okay.
A. And -- and when you say when I heard it, what I -- what -- I didn't hear anything. What I saw was their instruction to hook up the lines in this manner, and that told me all that I needed to know about what they intended to do.
Q. Were you aware of the -- of the -- excuse me -- of the government's insistence that BP hook up the H -- HP1, the HELIX PRODUCER 1, prior to the installation of the capping stack?
A. I -- I was not aware of that.
Q. Okay. And one of the line issues that you're talking about is the hookup to the HELIX PRODUCER caused some problems --
A. Yes.
Q. -- with respect to the ability to flow back?
A. That is correct.
Q. Okay.
A. Yeah, yeah. There -- it is correct that without the HELIX PRODUCER we could not possibly handle the entire volume from the well.
Now, all we knew was that the HELIX PRODUCER was being prepared, don't for sure know what that means. I haven't -- that was a -- a different team of people.