UNITED STATES DISTRICT COURT

EASTERN DISTRICT OF LOUISIANA

IN RE: OIL SPILL BY THE OIL RIG * Docket 10-MD-2179
DEEPWATER HORIZON IN THE *
GULF OF MEXICO ON APRIL 20, 2010 * Section J
*
Applies to: * New Orleans, Louisiana
*
Docket 10-CV-02771, * October 8, 2013
IN RE: THE COMPLAINT AND *
PETITION OF TRITON ASSET *
LEASING GmbH, et al. *
*
Docket 10-CV-4536, *
UNITED STATES OF AMERICA v. *
BP EXPLORATION & PRODUCTION, *
INC., et al. *
*
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DAY 6, AFTERNOON SESSION
TRANSCRIPT OF NONJURY TRIAL BEFORE
THE HONORABLE CARL J. BARBIER
UNITED STATES DISTRICT JUDGE

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Proceedings recorded by mechanical stenography using computer-aided transcription software.

I N D E X

AFTERNOON SESSION

(October 8, 2013)

* * * * *

THE DEPUTY CLERK: All rise.

THE COURT: All right. Please be seated, everyone.

All right, preliminary matters?

MR. LANGAN: Your Honor, Andy Langan for BP.

I would like to raise one preliminary issue, if I might. It has to do with the issue that's come up a couple of times regarding the opinion of Mr. Bushnell.

THE COURT: Okay.

MR. LANGAN: There's a bit of a history here that I think is important to understand.

The United States -- I mean, there were limits on the number of experts. The United States decided not to bring Mr. Bushnell live to trial. They made a tactical decision not to do that, just like some tactical decisions BP had made not to bring some experts.

What happened was, thereafter, there was a hotly contested dispute in front of Judge Shushan about attempts by the Department of Justice to bring in use of Bushnell through other means, fully briefed, argued. And Judge Shushan ruled on this on September 12th.

May I hand up a copy of the order?

THE COURT: Yeah -- I've read the order. I'm familiar with the order.

MR. LANGAN: Well, thank you, Your Honor.

THE COURT: In fact, I have it right here on the bench.

MR. LANGAN: Terrific.

In any event, as Your Honor knows, then, as a result of that order, Mr. Bushnell's deposition was excluded from the deposition bundles because he was not testifying and because Judge Shushan found that no United States expert was relying on him. And she took a very close look at that and made that decision. The United States contested it, but that's what she ruled.

Now, the U.S. appealed on September 15th, I think it was, or whenever, and, of course, we never responded because under Pretrial Order 15, Your Honor, if he was going to consider that, would have asked us to respond. So the appeal's never been ruled upon and we've never really had a chance to respond to the appeal --

THE COURT: Well, I -- as I've done in several instances, in order to save trees -- what do you save electronically now? Bits?

Rather than have you all brief the same thing in front of Judge Shushan, I read Judge Shushan's order, I read what you submitted to her, I read what they submitted to her. So I was fully conversant with the issue, and I decided to just not rule on it until the issue came up at trial, and I ruled on it yesterday, so that's where we are.

MR. LANGAN: All right. Well, so what the United States is telling us now is that they think Judge Shushan's prior order is of no effect, and they're going to be able to say whatever they want about Bushnell with any expert. And we don't think the door's been opened that way.

THE COURT: Well, that's not the case. I decided I'll just take it as the questions came up, and I'll rule on it as they come up.

MR. LANGAN: All right. Your Honor, but we don't think there should be open season here on this.

THE COURT: Yeah. We're certainly not going to indirectly let the entire report of Dr. Bushnell come in --

MS. HIMMELHOCH: That is not --

THE COURT: -- by the back door.

MS. HIMMELHOCH: I apologize, Your Honor. It's not the intention of the United States. As we set forth in our briefing papers, three of our experts relied upon Dr. Bushnell's work in similar manner: Dr. Griffiths, Dr. Dykhuizen, and Dr. Pooladi-Darvish

THE COURT: Okay. They've said what they said, I heard it and I'll give it whatever weight I think it deserves, you know.

MR. LANGAN: We disagree with counsel's characterization. Judge Shushan specifically held they hadn't relied on it.

THE COURT: I understand.

MR. LANGAN: Okay. Thank you, Your Honor.

THE COURT: All right. Thank you.

Any other preliminary matters?

MS. PENCAK: Yes, Your Honor. Good afternoon. Erica Pencak for the United States.

I have the list of the United States' call-outs and demonstratives used yesterday in the examination of Dr. Hunter --

THE COURT: Wait, wait, wait. We had some peanut gallery activity going on there.

All right. Go ahead. Start over.

MS. PENCAK: I have the list of the United States' exhibits, call-outs, and demonstratives used in yesterday's examination of Dr. Hunter. We circulated the list to the parties last night and received no objections. We'd file, offer, and introduce these exhibits, call-outs, and demonstratives into evidence.

THE COURT: All right. Any objections to Dr. Hunter's exhibits?

Hearing none, those are admitted.

MS. PENCAK: Thank you, Your Honor.

MR. IRPINO: Anthony Irpino for the aligned parties, Your Honor.

One clean-up matter. There was an exhibit that you ruled on -- it was the last thing of the Source Control part of the trial -- that was previously on the list for James Dupree. You had ruled that it was admitted, so we have an amended list for James Dupree to include a notation that that exhibit is, in fact, admitted. So we attached the minute entry.

THE COURT: All right. Any objection?

That's admitted.

Okay. I think we're ready.

MR. BENSON: Okay. I thought I'd get in line there and make sure I got my spot.

(WHEREUPON, **STEWART GRIFFITHS, PH.D.**, having been previously duly sworn, testified as follows.)

DIRECT EXAMINATION

BY MR. BENSON:

Q. Good afternoon, Dr. Griffiths. Tom Benson for the United States resuming your direct examination.

MR. BENSON: If we could have Demonstrative 21223, please.

BY MR. BENSON:

Q. So before we broke for lunch, we were talking about your alternate calculations. So we talked about your best estimate. We talked about Alternate 1. Now, I'd ask you to go through

01:26 what we have here in this demonstrative, which is known as Alternate 2 calculation.

A. Okay. So Alternate 2 calculation relies on BOP pressure and ambient sea pressure. So this is -- you can see that in the diagram.

THE COURT: Can everybody hear? It sounds kind of low.

Stephanie, did we turn the sound off or something?

All right. Pull your mic up, too, a little bit. Why don't you put it on your tie, I think it works better. Okay. Closer up. There you go. Okay.

All right. Go ahead.

THE WITNESS: Can you hear me?

THE COURT: Yes. Go ahead.

THE WITNESS: Okay. Good.

So the Alternate 2 calculation uses the pressure difference between the BOP and ambient sea pressure. So it does, again, rely on PT-B. It has the issues of no data before May 8th, so that sort of thing.

It does not account for any erosion in the BOP, but it does account for any erosion that would have occurred in the reservoir or wellbore. That's just because it's based on K-BOP, the resistance of the BOP. And if that were changing over time, then it would not account for that.

So, nevertheless, you get, once again, a result of 5.1 million barrels. So we know from the Alternate 1 calculation that erosion did not significantly -- erosion of the BOP did not significantly impact cumulative discharge. And so from this, we reach some conclusion that, then, also erosion did not impact -- erosion in the reservoir and the wellbore also did not impact the cumulative discharge.

BY MR. BENSON:

Q. So looking at your best estimate and your two alternate calculations together, what do you conclude?

A. I conclude that at least from May 8th on, that erosion in the BOP had negligible impact on the cumulative discharge, and I conclude that erosion in the reservoir and the wellbore had a negligible impact on the cumulative discharge.

Q. And in your career at Sandia, was doing alternate calculations of this type part of your practice?

A. Sure. Any time you can calculate things by more than one means, you can learn additional information. It's done all the time.

Q. Now, let's turn to uncertainty analysis. Did you do anything to estimate the uncertainty on your 5-million-barrel estimate?

A. I did.

Q. And why did you do an uncertainty analysis?

A. Well, uncertainties are about what confidence you should place in your results. So I have quite a narrow range of uncertainties, so I offer my best estimate, 5 million barrels, and that's accompanied with statements or belief that I have high confidence in that number.

If my uncertainties had covered a very, very broad range, I might still offer you 5.0 million as my best estimate, but that would be accompanied with statements that you should not have high confidence in that number; you should take it with a grain of salt.

MR. BENSON: If we could have Demonstrative 21224, please.

BY MR. BENSON:

Q. This is Table 1 from your expert report.

In broad terms, what did you do for your uncertainty analysis?

A. Well, in broad terms, I looked at multiple sources of uncertainties, and those -- there's two main categories there. One is things that would have happened that are not included in my model; that's one category.

And the other category is just more classic uncertainties in measurements. So there's -- you measure pressures, there are uncertainties in that; you measure flow rates, there are uncertainties in that. So those are the two main contributors to uncertainties.

What's shown here -- they're not grouped that way in this figure. In this table, the yellow section are all uncertainties from those couple of sources associated with my parameter estimation. And the bottom section there is all associated with things that would have varied or changed over the 86 days.

Q. Now, let's just walk through one of the entries on this table. We won't do all of them, but to explore how the table works, can you walk us through the first entry?

A. Sure.

The first entry is uncertainties associated with the flow through the BOP. And this is specifically associated with uncertainties in my discharge coefficient for the BOP based on the data I used to determine the parameter. So this is uncertainty in the parameter that describes K-BOP.

So what I do is I -- so I assume that's a constant. What I do is I look at -- while I know that density will vary, I know that there are two-phase flow effects that will deviate from that idealized constant discharge coefficient, and so I calculate -- using an equation of state, I calculate over the range of conditions I'm interested in, how much variability would I expect in the flow through the BOP due to those effects that are not included in my model.

And that -- you see this plus or minus 3.4 percent. So over the range of conditions of interest during the shut-in, I estimate that the flow rate through the BOP could vary by plus or minus 3.4 percent relative to my assumption that it's just a constant.

Then I look at how that uncertainty propagates into cumulative discharge. So if you look at the two columns, minus 1.6 and 1.8, those are the uncertainties in the cumulative discharge based on that uncertainty in the BOP during the shut-down period.

THE COURT: So I think I understand what you said, but I want to make sure. Is it just coincidental that the minus 1.6 and the plus 1.8 add up to 3.4? But that doesn't equate to the plus or minus 3.4?

THE WITNESS: That's right. If that's the case -- well, there could be a physical reason that happened, but in general, it would just be coincidental.

THE COURT: So plus or minus 3.4, meaning the effect of the BOP only, you believe, could vary by that amount?

THE WITNESS: That's correct.

THE COURT: But the BOP being only one part of a larger system, it wouldn't necessarily mean that there would be a plus or minus 3.4 percent on the ultimate calculation?

THE WITNESS: Correct.

THE COURT: Okay.

MR. BENSON: Thank you, Your Honor.

BY MR. BENSON:

Q. Now, later on, we're going to talk about some of the

criticisms that BP had made of your model. I want to just walk through those quickly and see if they're addressed in your uncertainty table here.
In your uncertainty analysis, did you do anything to consider the potential effects of erosion?
A. Yes. Well, certainly -- well, my two alternate calculations directly address that and for the period after May 8th. For the period before May 8th, the last entry -- the last row in that table specifically addresses those issues associated with erosion, yes.
Q. And how about the potential impacts for multiphase flow, is that present in your uncertainty table?
A. Sure. If you look at at least the top four -- the top four entries in the yellow section are all associated with changes in density, changes in two-phase flow factors. So those definitely address two-phase flow effects.
Q. And we'll talk a little bit later about a criticism that BP has made about the reliability of PT-B. Is that addressed in your uncertainty analysis?
A. Yes. Again, uncertainties associated with PT-B are explicitly called out and they are the second-to-the-bottom row, I think, in that bluish-grayish section.
Q. Now, Dr. Griffiths, what did you conclude was the overall uncertainty associated with your 5-million-barrel estimate?
A. It was roughly minus 14 percent to plus 10, so the actual

numbers worked out 13.9 to 9.7.

Q. And how did you come up with those numbers based on the rest of the table?

A. Well, I did something that represents just a phenomenal worst case. I grouped all of these just according to their signs. All the negative ones, I took all the negative ones and added them together. That's the minus 13.9. I took all the positive ones and added all those together. And I refer to this as the worst case because, in reality, something like that will never happen. Some of the uncertainties will be positive; some will wind up being negative. So there's some canceling out of things that would go on in reality.

And so I just wanted to do it in a way that would provide very hard bounds on my very best estimate.

Q. So do you think the total could be 4.3 million or less?

A. Oh, the probability that it is 4.3 or less is miniscule.

Q. Now, let's turn now to the criticisms that BP has raised toward your model. Have you reviewed the reports of the BP experts in this case that address your work?

A. Yes, I have.

MR. BENSON: Could we turn to Demonstrative 21225.

BY MR. BENSON:

Q. And can you just sum up, just broad categories, the criticisms that BP experts have made?

A. Sure. I think use of constant discharge coefficients over

01:37 time, my treatment of potential erosion has been criticized.

01:37 Criticisms on multiphase flow effects.

01:37 Accuracy of PT-B has been raised as an issue and then, of course, that I used a nonindustry-standard model.

01:37 **Q.** And we'll walk through those in a minute, but let me first ask you: You've been working on the same basic methodology since the summer of 2010. Have you considered these issues before?

01:38 **A.** Yes. I think I considered all of these in the past.

01:38 **Q.** And have you sort of -- are you comfortable with these -- are you comfortable that you've sort of worked through these criticisms in your own mind?

01:38 **A.** Yeah, I think so. When you do modeling, modeling is always about driving down uncertainty. Usually from a business point of view, it's about driving down risk. So most -- you reduce your uncertainties down to some point that they become irreducible, and then you put them in a table and say, Ah, that's -- that's the best I can do. There are certain things that can never be known more accurately.

01:38 So a lot of these things, like inaccurate BOP pressures, you get to the point where you can say, Well, I can bound it by this; I probably can't do better than that. I addressed it through and through, so, yes.

01:38 **Q.** We'll walk through the criticisms, and we'll start with your use of constant discharge coefficients over time.

First, I want to understand what BP is saying. What's your understanding why BP has suggested that your discharge coefficients might change over time?

A. Well, I think the main thing is erosion.

Q. What did you conclude about whether erosion was changing the discharge coefficient over time?

A. Well, I certainly concluded that post May 8th, there were no significant changes. I concluded that prior to May 8th, there was erosion very early on that in the end significantly impacts the cumulative discharge, but it happens very quickly.

MR. BENSON: If we could have Demonstrative 21226, please.

BY MR. BENSON:

Q. So why did you conclude, Dr. Griffiths, that erosion was not significantly affecting total flow after that early period?

A. Well, again, we just talked about the two -- the best estimate and two alternates, and I don't need to repeat anything there.

I know that over the long term the decay of the BOP pressures are consistent with decay of the reservoir pressures. And through my model, I know that there has to be a certain relationship between those and that relationship -- if these are not changing and this ratio of the decay in the reservoir pressure to the decay in the BOP pressures observes that, behaves in a way that they are not changing. And finally, well, I know that that sort of thing, the resistance in the BOP relative to the resistance in the wellbore and the reservoir, remain essentially constant on a continuing basis over the time period from May 8th on.

And then I think I already alluded to this, you know, I know that erosion is a phenomena that can occur very, very rapidly and then slows once apertures get opened a little bit.

Q. Let's focus on that last point for a minute. Can you describe why erosion happens quickly.

A. Well, why it happens quickly in this case is just there's high pressures, there's great potential to erode things very quickly. So, I mean, if -- I'm not sure. The potential exists to do great damage in a short while.

The business about it happens fast and then slows is really about, you know, if I have flow through a very small orifice, forgetting flow rate, I get very high velocities through those. It's just like a nozzle on the end of a hose. Erosion rates depend very strongly on fluid velocities. So when an aperture is small, I have very high fluid velocities, very high erosion rates. As that aperture opens, the flow rate can stay the same, but the velocities go down. So as it opens, velocity goes down, erosion rates drop very, very rapidly because they depend on power from fluid speeds.

MR. BENSON: Now let's turn to Demonstrative 21227, please.

BY MR. BENSON:

Q. Can you describe some of the physical evidence you've seen of rapid erosion.

A. Sure. So these are laser scans of a piece of pipe that was recovered with the BOP and riser. The images on the left are laser scans. This is a piece of pipe that sort of -- at the time of the explosion, when the upper annular was being closed and all that, at that point in time, this piece of pipe was in the upper annular. And the lower part of that is the tool joint that was in that upper annular. So you see a tremendous bunch of erosion of that tool joint.

And then above that, where the pipe ends, that's actually the top end of the upper annular. The pipe at that point was eroded entirely through the pipe and the pipe was also broken, but there was just tremendous erosion. And the thing about this that tells us about the speed of erosion is that that piece of pipe was, in fact, ejected up out of the BOP and was in the riser at the time the riser collapsed.

And we know that because, if you look at the bottom right corner, there's a big kink in that piece of pipe. It was actually broken, but it's reconstructed here to show the kink. So we know that this erosion was all associated with its presence in the upper annular and that we know that within 36 hours, it was no longer in the upper annular. So that we can say this erosion had to have occurred within that 36-hour

01:44 period.

01:44 It might have been faster. We don't know that, but we know that it happened within 36 hours.

01:44 **MR. BENSON:** Let's turn to Demonstrative 21228.

01:44 **BY MR. BENSON:**

01:44 **Q.** Have you seen other parties agreeing that erosion happened fast in this incident?

01:44 **A.** Yes.

01:44 **Q.** Okay. And what we have here are TREX-1, which is the Bly report; TREX-4248, which is the TO investigation report; and then testimony from Phase One expert Earl Shanks.

01:44 **A.** Uh-huh.

01:44 **Q.** What did BP in the Bly report conclude about erosion?

01:44 **A.** Well, the quote at the top there is from the Bly report. The highlighted part is: "Drill pipe had likely already failed at the eroded section by this time." And the time frame they're talking about is when the top drive fell. And I don't know the exact timing of that, but I think it was within a half an hour of the explosion, maybe an hour.

01:45 But in any case, so we've got physical evidence that it happened within 36 hours. And here we have presumably experts saying that they think it could have happened within an hour.

01:45 **Q.** Now, let's turn to Mr. Shanks' Phase One testimony. What did Mr. Shanks say about the timing?

A. Here he's talking about erosion at the upper variable bore rams. And the highlighted part of this is that he believed that erosion -- and, again, there was very significant erosion at that location -- he believes that it could have occurred in less than a second.

Q. Now, what does erosion in the drill pipe during those first hours, minutes, seconds tell you about erosion in the system as a whole?

A. Well, it tells you the capacity to erode things in these very short time frames exists. You would expect that anywhere in this system that that capacity exists. So whether you're talking about something in the reservoir or the float collar, those sorts of things, that you should expect corrosion, very significant erosion on time scales of seconds, minutes, hours, maybe a couple of days, not on time scales of weeks, months.

Q. Did you review testimony -- I'm sorry. Did you review the modeling of BP's Phase One expert, Dr. Emilsen?

A. I did.

Q. What did you determine from Dr. Emilsen's work about erosion in the reservoir?

A. I determined that he -- his results supported similar conclusions: that erosion in the reservoir or bottom of the well was occurring on a time scale of hours, minutes, days, not weeks and months.

Q. Did you personally examine elements of the system after

they were recovered from the Gulf?
A. I did.
Q. And have you reviewed documents looking at the condition of the riser, the BOP, the drill pipe, after recovery?
A. I'm sorry. Could you repeat that, please.
Q. Sure. Let me fix my mic.
Have you reviewed documents that looked at the condition of the riser, the BOP, and the drill pipe after they were recovered?
A. Yes.
Q. And your findings, are those reported in Appendix I of your expert report and Appendix D of your rebuttal report?
A. I believe they are.
Q. So we won't go into each element of the system, but let's talk about a couple of examples here.
Did you examine the blind shear rams?
A. I did.
MR. BENSON: Let's go to Demonstrative 21229, please.
BY MR. BENSON:
Q. What can you conclude about the blind shear rams and how they affected flow over time?
A. Well, again, much like with the drill pipe and the upper annulars, you can make statements about the speed of erosion in the BSRs. So if you look at the top-right figure, what you see is that there's a great deal of erosion in the upper left part

01:48 of the ram.

01:48 So this is looking at the face of the ram, if that's familiar. So there's the two faces of the ram with the blades that come together. So we're looking on that face with -- and then the pink part shows where the pipe would have set during that -- during the closure.

01:49 So what you see in this is a tremendous amount of erosion in the upper-left corner, across the back face, that recess across the back, and then in the top right corner a little bit more erosion.

01:49 What's really interesting here is that there's open channels at both sides of this. But if you look at the bottom-right corner there, very little erosion. And this is the top-right figure, still, very little erosion down there.

01:49 The figure in the bottom left is just the side view of all this. And then in the bottom right is the figure where you see that sort of directly above that pipe, you know, that whole area of the yellow -- the yellow-colored ram there, that whole area is missing. Like if you look down on it directly, you just see a hole down through there where that pipe is.

01:50 So when you look at all that erosion, you conclude that all that erosion occurred in the upper half of this -- of these blocks. It occurred all downstream of the end of the pipe that extended below the BSRs.

01:50 At this point, when the BSRs were closed, that pipe ran, you know, all the way down to below the BOP. So all of the erosion resulted from flow through that pipe.

That pipe was cut on April 29th by the casing shear ram. So we know with -- just like with the pipe in the annulars, we know that that erosion occurred in the interval between the time the BSR was closed on April 22nd and the time the CSR was closed on April 29th.

Q. So that's, at most, seven days' worth of erosion?

A. I think so, yes.

Q. Did you also look at the holes in the riser kink, Dr. Griffiths?

A. I did.

Q. Did you reach any conclusion about whether the riser kink holes are evidence of continuing erosion?

A. I did. It is my opinion that all of the leaks in the riser originated as fractures. If you look in the vicinity of all those leaks, you see cracks growing off.

And, you know, the kink in the riser was tremendous. That material is, you know, inches thick. It's been kinked entirely, the material's horribly strained.

It's fairly ductile material, but there are cracks. And those cracks will continue to grow over time. And when they get big enough, they start to seep; and when they start to seep, very quickly they get washed out, eroded, and become the leaks that were observed.

01:52 So I actually believe that all of the leaks in the risers were not a direct result of erosion but instead came about through fractures.

01:52 **Q.** Now, let's turn to the opinions from a couple of BP experts on erosion. First let's talk about BP expert Dr. Adrian Johnson. He may come to testify that there are other possible trends for PI, the productivity index, and the discharge coefficients that are consistent with the pressure data.

01:52 **A.** Uh-huh.

01:52 **Q.** Is that something you've considered, Dr. Griffiths?

01:52 **A.** Yes.

01:52 **MR. BENSON:** If we could go to Demonstrative 21231.

01:52 **BY MR. BENSON:**

01:52 **Q.** What does this depict, sir?

01:52 **A.** This is a figure from Dr. Johnson's report. It shows histories of the productivity index as a function of time. Again, this is over the 86 days, sort of.

01:53 The black curve up at the top is my constant PI of about 44, you know, stock tank barrels a day per psi. And then he gives two alternate -- these are simply hypotheticals, so -- which is fine. But there's two hypotheticals: Path A, that's just a linear increase over the entire 86 days; and then Path B, which remains constant for the first 30 days and then begins, it increases linearly for the balance of the 86.

Q. As a theoretical matter, why might the PI increase over time?

A. Well, if there was something eroding in the bottom, it could be associated with skin, it could be associated with cement, you know, something changing in the bottom of the well that would be increasing the productivity index.

Q. And, Dr. Griffiths, do you believe that Path A and Path B, as set forth here by Dr. Johnson, are plausible alternatives for the PI trend?

A. I don't. And the reason is this business of consistency with the data. So the data says that the resistance in the BOP relative to the resistance in the reservoir and wellbore remained unchanged over the 86 days.

So if you're going to have a change in the PI, so along one of these, like the red curve -- if you're going to have a change in the PI, it has to be accompanied by a very specific change in the BOP, which is two and a half miles away. And that those changes have to occur together like that over the entire 86 days.

So I'm talking about the green line, the Path B, for example. It says the PI stays constant for 30 days, carries with it -- the BOP resistance had to stay constant for 30 days. Then the productivity index starts up. When you're linked at that point, the BOP resistance has to be going down or matching that at just that time. And then they have to move together for that entire period.

So I think that winds up -- these hypotheticals wind up being, you know, within -- it's possible. You can't prove they didn't happen, but -- but they require this coordination between two things that are pretty much unrelated. And so that's why I think it's just -- that's part of why I think this is -- is not a plausible explanation.

Q. Now, let's turn to Dr.-- BP's expert, Dr. Nesic, for a minute, and we'll wrap up our discussion of erosion by talking about his report.

Have you reviewed Dr. Nesic's expert report in this case?

A. Yes, I have.

Q. Can you describe briefly what Dr. Nesic did.

A. Well, he was examined -- he examined a couple of elements within the BOP. So he looked at the casing shear ram, the blind shear ram, upper annular, kinked riser. He calculated pressure drops through these at two states. So he did this for April 22nd. And what he used, I think, were laser scans of piece parts of these things to try to reconstruct what the geometry would be like. He did calculations of the pressure drop through these as of April 22nd.

He then used laser scans of recovered parts, eroded parts, and did a very similar sort of calculation for May 27th. So he got pressure drops through these different elements.

And he then presents a result where he has relative pressure drop through these collection of resistances from April 22nd through May 27th, and he connects these times with straight lines.

And as part of all that, he asserts that this plot, these curves, that line, are -- his word is "universal" with respect to flow rate for all flow rates between 5,000 and 65,000 barrels a day.

Q. Does that make sense to you, Dr. Griffiths?

A. That makes no sense to me at all.

I think I would agree with him that pressure drops are universal for given geometries, but the geometries themselves, how they would have evolved between April 22nd and May 27th, tremendously depended on flow rate.

So flow rate -- well, so particle velocity determines erosion rate; particle velocities track fluid velocities; fluid velocities for a given geometry are going to be proportional to flow rate.

So I think we can just say erosion rates are going to depend on flow rate, and they depend on a flow rate or a velocity to a power, and a power's typically around 3. I think in Dr. Johnson's own modeling he reported things that suggested that the power was about 3.3.

Q. Let me interrupt you for a minute. You said Dr. Johnson?

A. I'm sorry. I'm sorry. Dr. Nesic. My apologies.

Q. Go ahead.
A. So you got flow rate of 5,000 and 65,000. The ratio of that is 13. 13 raised to a power of 3.3 is something a little less than 5,000. I think it's about 4,700.
So for that range of flow rates, erosion rates would differ very -- by a factor of almost 5,000. That's the difference between 26 minutes and 86 days.
So the suggestion by Dr. Nesic that the same results apply for all flow rates in that range and that that history -- excuse me -- history of what happened between April 22nd and May 27th, I think, based on his analyses, it would be impossible to say whether those obey this sort of flow linear decay or whether that decay was almost immediate, followed by nothing happening over the balance of the period.
MR. BENSON: Could we have Demonstrative 21253, please.
BY MR. BENSON:
Q. Dr. Griffiths, it looks like the first bullet is what you were just explaining. Is that right?
A. Yes, it is.
Q. And did Dr. Nesic provide opinions about how erosion would change the flow rate over time?
A. He did.
Q. What are those opinions?
A. Well, his main opinion is that this erosion between

April 22nd and May 27th would have doubled the flow rate. That is based on -- I guess I would -- the word would probably be "flawed analysis." Because, again, he looked at casing shear ram, variable bore rams, upper annular, kinked riser. Those were the only resistances he looked at.

So he didn't even look at the entire resistance of the BOP. Because half of the resistance of the BOP sets in the test rams and the two variable bore rams. And the BOP itself is roughly half the resistance of the wellbore. And then there's resistance in the reservoir as well.

So what happens when you just look at -- you've got a bunch of resistances that determine your overall flow rate. If you change one of them, in fact, it doesn't change the flow rate very much. But if you look at just a subset of those and say, well, these four things changed, and base your assessment of the change in flow rate on that, it exaggerates the impact of your erosion.

So doubling makes no sense at all to me. In fact, BP -- during the response, BP estimated that removal of the entire BOP, along with the riser, would only increase the flow rate from the well by 15 to 30 percent. And I would agree that that's the right sort of ballpark numbers. So a factor of 2, doubling due to erosion in a couple of the elements of the BOP just -- just really doesn't make any sense.

Q. Now, we talked earlier about the validation that you did

02:02 for your model, Dr. Griffiths. Did Dr. Nesic do anything to validate his modeling of the pressures?
A. He didn't, and I don't quite understand that.
His second date that he was modeling was May 27th. May 27th is a day on which -- you know, this is during Top Kill -- pressures were measured at multiple points through the BOP. So these pressure drops that he's calculating were measured on May 27th. And at least as far as I could see in his report, he made no attempt to compare his calculated pressures to these -- these pressures that were measured on the same day.
Q. Is Dr. Nesic's opinion about slow, gradual erosion consistent with the physical evidence that you've reviewed?
A. It's not.
Q. And we talked about that earlier?
A. Erosion occurs on time scales of seconds, minutes, hours, a day or two, not weeks and months. Dr. Nesic's analysis has this very slow, gradual erosion spread over 35 days. I don't think that's consistent with the evidence.
02:04 **Q.** Let's turn to the second BP criticism that we identified earlier, and that's multi- -- the effect of multiphase flow.
What's your understanding of this criticism?
A. I think it's simply that a constant discharge coefficient can't capture the sort of richness and complexity of the multiphase phenomena.

Q. Does your model actually account for multiphase flow?

A. It does. I don't have to put it in there. Because, again, it's based on measured flow rates of collected oil. Whatever multiphase effects were present are reflected in my model.

Q. And we talked earlier about the validation you did. Did any of that validation relate to the issue of multiphase flow effects?

A. Sure. All of Appendix C was about that. All of the first several uncertainties in that table, in the yellow section of that table were related to multiphase effects.

Q. In fluid dynamics, how are area, a flowing area and flow rate related?

A. Let's see. For a given fluid speed, flow rate is exactly proportional to the cross-sectional area.

Q. Now, BP expert Dr. Johnson has offered a criticism of your model, looking at a case with a drill pipe in the production casing. Do you recall that?

A. Yes, I do.

Q. Have you reviewed that modeling?

A. Yes, I have.

MR. BENSON: Could we go to Demonstrative 21232, please.

BY MR. BENSON:

Q. What do we see here, Dr. Griffiths?

A. Well, these are figures from the input -- input or output files for Dr. Johnson's MAXIMUS calculations. He considered three cases: a wellbore with no pipe in it, a wellbore with the drill pipe that was hanging below the BOP dropped into the well, and the third case, a wellbore with the pipe high -- high, still attached to the BOP.

MR. REGAN: Your Honor, I object to this testimony. At the time of his deposition, Dr. Griffiths testified that the only modeling of Dr. Johnson that he had seen -- he had it in a footnote of his report -- it was modeling that was done by a different expert, Dr. Pooladi-Darvish. I don't believe Dr. Griffiths was using Dr. Johnson's modeling. He certainly wasn't testifying about it at the time of his deposition.

So if this is something he's looked at since his deposition, I don't think it's been disclosed.

MR. BENSON: It's not, Your Honor, and I can explain or I can ask the witness.

THE COURT: Well, I'll sustain the objection.

MR. BENSON: Can we get into whether the witness has reviewed this modeling? He's already testified that he did review the modeling.

THE COURT: It wasn't fairly disclosed in his rebuttal report.

MR. REGAN: It was not.

THE COURT: Okay. Sustain the objection.

MR. BENSON: Can I speak to that issue, Your Honor?
THE COURT: No. I sustained the objection.
BY MR. BENSON:
Q. Dr. Griffiths, in your rebuttal report, did you address whether Dr. Johnson's modeling used the correct area for the drill pipe in the annulus?
A. I did.
Q. And what conclusion did you reach about that?
A. I concluded that Dr. Johnson had done calculations where -- for the wellbore with a pipe inside it, where he treated -- so that has a drill pipe and it has the annulus between the drill pipe and the production casing, so annulus between those.
He treated those as two drill pipes -- two pipes, not drill pipes, just two pipes, one representing the true size of the drill pipe and one, second pipe, representing the annulus between the drill pipe and the casing.
Now, the size of that pipe is incorrect. It does not represent the correct area of the annulus. And, in fact, the pipe that represents the annulus, the size of that pipe is an error by a factor of 4. It's a huge error.
Q. So in real life, Dr. Griffiths, which pipe is bigger?
A. The annulus is --
MR. REGAN: Pardon me. Pardon me, Dr. Griffiths.
Maybe there's a citation that you could give to

me in his rebuttal report. But the only discussion he has of parallel flow path by Dr. Johnson, he talks about the composition of the fluid.

Perhaps I'm missing it here, but is there a citation to the report where this --

MR. BENSON: Yeah. Page 10, the third paragraph. The discussion Dr. Griffiths is referring to right now, he says flow rates through the much larger annulus -- and that's through the production casing that's used to describe it -- the flow rates through the much larger annulus are smaller than the flow rates through the drill pipe, just like a distinction in size.

MR. REGAN: There's no calculations here. It's just a statement. There's a footnote, then, that cites the model runs, which were looked at by Dr. Pooladi-Darvish, not this witness.

So, I mean, we're trying to bring things in through witnesses that are the wrong witnesses. This is not disclosed.

MR. BENSON: Your Honor, with respect, it is disclosed in his report, and he's just explaining the sentence in his report. Would it help if we call it up?

THE COURT: What page of his report?

MR. BENSON: It's page 10.

THE COURT: What part of it?

MR. BENSON: It's the third paragraph of page 10, and he's discussing various problems with Dr. Johnson's model.

The sentence begins, "For example, these solutions exhibit flow down the wellbore annulus," and then, "flow rates through the much larger annulus that are smaller than those through the drill pipe."

THE COURT: Wait a minute. I'm still not on it -- oh, I'm on the wrong page. That's fine.

MR. BENSON: We've got it up on the screen, Your Honor, if that's easier.

THE COURT: Page 10?

MR. BENSON: It's page 10, third paragraph.

If we could highlight starting at "flow rates through the much larger annulus," that third line from the bottom.

THE COURT: This is in his --

MR. BENSON: This is in his rebuttal report, Your Honor.

THE COURT: I'm on the wrong page and the wrong report.

MR. BENSON: I apologize, sir. We've got it up on the screen.

THE COURT: Let me look. Okay. I see where you are.

MR. REGAN: May I be heard on that, Your Honor?

THE COURT: Go ahead.

MR. REGAN: What he's referencing there -- see in Footnote 15? That's a reference to modeling runs. Those modeling runs were not done by Dr. Griffiths. They were looked at by Dr. Pooladi-Darvish. And it says "extremely poor convergence." We're going to hear about that from Dr. Pooladi-Darvish. This is the wrong witness for this topic.

There's nothing in this report about him calculating diameters or sizes. It is a generic comment.

He was asked about this footnote, and the question: "Did you ever try to use the software that Dr. Johnson used, that is, the MAXIMUS software, to try to investigate his work?

"Answer: I did not."

MR. BENSON: If I can speak just to that point, Your Honor. He cites the modeling in his report. He looked at the results of the modeling. He needed another expert to convert it into something that he could read, because Dr. Griffiths doesn't have the MAXIMUS model that Dr. Johnson happened to use. It's not a commonly used model in this case. So it was converted by another expert. Dr. Griffiths looked at it, saw the results, and was able to reach conclusions that he can testify to.

THE COURT: All right. Let me go back to see what your original question was that started all this conversation.

I think what he was trying to say is that the --

you addressed whether Dr. Johnson's modeling used correct area of the drill pipe in the annulus.

How does that relate to what you said in your report? Are you talking about the larger annulus?

THE WITNESS: It is. I mean, this whole discussion is about areas of different parts of it. And, in fact, what I had -- I was provided outputs from the calculations. Because I don't have the model, and so I looked at those outputs. And those statements are based on my examination of the outputs of the model.

THE COURT: Okay. I'm going to let him answer the question. It's kind of vague, but I think it's loosely related to what he says in his report. Go ahead.

BY MR. BENSON:

Q. Okay. Dr. Griffiths, can you just explain what you meant by the difference in size and what effect that has on a flow rate.

MR. REGAN: I might -- just one point, Your Honor, on the issue. The prior page -- it was page 389 of his deposition where he gave that answer. And he was instructed not to answer a question about his interaction with Dr. Pooladi-Darvish on this question.

I respect your ruling. But we were blocked from asking him further questions about this in terms of his interaction with that expert.

THE COURT: Okay. I understand.

MR. BENSON: I can speak to that, if you want, Your Honor.

THE COURT: No. Just go ahead.

MR. BENSON: Okay.

BY MR. BENSON:

Q. So, Dr. Griffiths, I think the question is: Can you describe what the issue is with the sizes of the pipe versus the annulus and how those would affect flow rate.

A. What's used in Dr. Johnson's MAXIMUS models is not the correct area for the annulus. It is the area of the hydraulic diameter. That is an improper area to use in the calculation of flow rate.

There's a very specific way you calculate approximate. And it's a valid -- it's an approximation, but it's the flow in an annulus. So this is a disk with a hole in it. You calculate the fluid speed based on the hydraulic diameter. The hydraulic diameter is just the diameter of a pipe that's -- that's -- whose diameter is the difference between the inner and outer diameters of the annulus.

So you use hydraulic diameter to calculate fluid speed. You then calculate flow rate by taking that fluid speed and multiplying it by the true cross-sectional area of the annulus. In the case of Dr. Johnson's calculation, he used the area of the diameter. That area is in error by a factor of 4.

Huge difference.

And so, in essence, Dr. Johnson's modeling something that never did, never could have existed in the Macondo well.

Q. And just to sum up the testimony, you're saying that Dr. Johnson is modeling a smaller amount of flow through the bigger flowing space?

A. Well, what's happened --

MR. REGAN: Objection. Objection, Your Honor. The witness testified that he only examined this a tiny bit. That was his phrase. He did not disclose a factor of 4. He did not disclose this opinion.

MR. BENSON: Well, I'm just trying to sum up because we've had a number of interruptions.

THE COURT: Well, you don't necessarily get to sum up a witness. So you've asked the questions; I've heard his answers.

MR. BENSON: Okay. I'll move on, Your Honor.

BY MR. BENSON:

Q. Okay. Dr. Griffiths, let's turn on -- turn our attention to the next criticism that BP has raised and that's the accuracy of PT-B, the BOP pressure gauge.

A. Yes.

Q. What did you personally conclude about the accuracy of PT-B?

A. I concluded that once corrected, that the pressures would be correct within plus or minus 130 psi.

Q. And you've been talking about a correction. Does that mean the gauge is inaccurate?

A. No, those are corrections for offsets. So offsets in a gauge in the simplest form is just like having a watch that -- that's always off by 10 minutes. You know, if you have a watch that's off by 10 minutes, it's an inaccurate watch. If you know it's off by 10 minutes always, you just subtract the 10 minutes and -- and so that's what these corrections are about.

Q. Now, in your expert report, you describe the offsets that you concluded were appropriate for PT-B. We won't go into those here. Did any of BP's experts also analyze PT-B and propose their own offsets?

A. Yes, Dr. Trusler did.

Q. Okay. At a high level, what did Dr. Trusler conclude about the accuracy of PT-B?

A. He concluded that once corrected per his corrections, that the accuracy would be plus or minus 200 psi.

Q. And how did Dr. Trusler's corrections compare to yours?

A. Well, he did corrections at multiple periods; I only did two. For the period up to about July 11th, he provided two corrections. My correction for that period was 740 psi. His two corrections were something very close to 600 and 800. So my corrections sit just sort of right in between his -- his two. He had one for each of two periods there.

Q. And how about for the period after July 12th?

A. After July 12th, we disagree on the corrections. I believe that the information provided to Dr. Trusler and to me already contained a correction of 966 psi. So Dr. Trusler and I disagree on that. I have done calculations using his corrections.

Q. What do you see if you do those calculations?

A. Well, let's see. If I use -- only use his corrections for the period before July 11th, I get exactly 5 million barrels still. If I use his corrections for, you know, that period up to July 11th, as well as his corrections for after July 11th, my cumulative discharge goes up to 5.4 million barrels.

Q. You're not saying that your opinion is 5.4 million barrels today, are you?

A. No. I don't believe his corrections are correct, and so I would not be inclined to increase my best estimate based on those.

Q. Now, did any other BP experts rely on PT-B for their calculations in this case?

A. I believe Dr. Gringarten did.

MR. REGAN: Your Honor, I'm going to interpose an objection to testimony of this witness about Dr. Gringarten. Dr. Gringarten's name does not appear in his report or in his rebuttal report. And under the four corners rule, he wrote a rebuttal report after Dr. Gringarten's work and report was issued. If he had something to say about Dr. Gringarten at the time, he would have put it in his rebuttal report. He did not. He should not testify as to it.

MR. BENSON: We're moving on. That was it, your Honor.

THE COURT: Okay.

BY MR. BENSON:

Q. Now, Dr. Griffiths, we've walked through three of the four BP criticisms.

Let's quickly look at the last criticism that we identified earlier. Did BP also suggest that you should use a commercial flow rate model rather than your model in this case?

A. Yes.

Q. Are you aware of industry models that could calculate flow rate in a situation like this?

A. No. Commercial software could be used to model, like, flow in the capping stack and choke and kill line and things like that. But the problem I was solving with the BOB -- BOP, excuse me, wellbore and the PI, the geometries are just not known.

I mean, if you want to do a calculation with commercial software, general-purpose software, you have to know the geometry. If you do not know the geometry, you cannot do accurate calculations of flow rate.

02:21 **Q.** Let's just wrap up your testimony. Based on your work, what's your best estimate of the total discharge for the Macondo well?

02:21 **A.** 5.0 million barrels.

02:21 **Q.** And do you have confidence that the total flow was about 5 million?

02:21 **A.** I do. After all the number crunching is done, I spent a lot of time thinking about this -- is there any basis for increasing it to 5.1, is there any basis for reducing it to 4.9. At the end of the day, I have the highest confidence in 5.0.

02:22 **Q.** Dr. Griffiths, how does the quality of the work that you performed in developing your total flow estimate compare to the work you did at Sandia in areas like nuclear weapons design and nuclear test containment?

02:22 **A.** I would say very comparable. I think in the end, I've actually checked these calculations more carefully than I have ever checked any calculations in my -- in my career.

02:22 **MR. BENSON:** Thank you, Dr. Griffiths.

02:22 No further questions at this time, Your Honor.

02:22 **THE COURT:** All right. Mr. Regan.

02:23 **MR. REGAN:** May I proceed, Your Honor?

02:23 **THE COURT:** Yes.

CROSS-EXAMINATION

BY MR. REGAN:

Q. Good afternoon, Dr. Griffiths. Matt Regan on behalf of BP, and I have you on cross-examination.

Dr. Griffiths, you have a method where you estimate wellbore and reservoir productivity -- wellbore discharge coefficient resistance, reservoir productivity, and parameters as of July 15th; correct?

A. That's correct.

Q. You take those July 15th values and you apply them to every day before July 15th back to April 20th; correct?

A. That is the methodology of my best estimate, yes.

Q. You then use what you call as the measured available data, but you use the PT-B data that existed to then calculate flow rate over the entire flow period; correct?

A. That's correct.

Q. And you only have PT-B data from May 8th through July 15th; correct?

A. Correct.

Q. So using that methodology, you calculate a 5-million-barrel -- 5-million-barrel cumulative -- cumulative estimate; correct?

A. That's correct.

Q. You have uncertainty of negative 13.9 percent and positive 9.7 percent on that estimate; correct?

A. Correct.
Q. So your lower end cumulative release is 4.3 million barrels; correct?
A. Very much so a worst case, yes.
Q. It's within your range; correct?
A. Yes.
Q. You have an upper bound of 5.5 million barrels; correct?
A. Yes.
Q. Now, with respect to April 20th to May 8th, the time period that we just spoke about, you calculate daily flow rates for each of those days; correct?
A. Could you repeat the dates, please?
Q. Yes, sir. April 20th to May 8th.
A. Yes.
Q. You calculate daily flow rates for each of those days; correct?
A. Yes, nominally.
Q. And with respect to your best estimate, the highest flows that you calculate are in those earliest days; correct?
A. Yes.
Q. And the largest uncertainty that you have in your work is as to that same time period; correct?
A. Yes.
Q. So the time period where you calculate the largest proportion of your cumulative flow is also the time period

where you have the greatest uncertainty; correct?
A. Well, I think so. I'm not sure what the largest portion of my flow is, but I think I agree with you, but I'm not positive on that point.
Q. You calculate about a million barrels of your 5-million-barrel estimate in the time period where you have no PT-B data; correct?
A. That's correct.
Q. Your prior work was endorsed -- or you issued a report at Sandia, correct, in 2011?
A. Yes.
Q. And you have a publication also in 2011 that you cited in your direct exam; correct?
A. The journal papers?
Q. Yes.
A. Uh-huh.
Q. And the discussion that you had earlier today about effects of erosion in the BOP, that's not found in either your 2011 peer-reviewed publication or your 2011 Sandia report; correct?
A. Correct.
Q. There's been no peer review of your erosion opinions in that respect; correct?
A. I suppose that's correct.
Q. You're not an expert in oil and gas?

A. I'm not. That's safe to say.
Q. As you said on your direct, you did not use industry-standard models for calculating your flows; correct?
A. Correct. Well, other than the -- in the validation where those were commercial software to validate my methodology. I didn't use it directly.
Q. Your method is not what you would call a general-purpose tool; correct?
A. It describes Macondo well and only Macondo well because it's based on data from Macondo well.
Q. Your approach, in your own words, is not the approach that a traditional fluid dynamics person would go to; correct?
A. Computational person, yeah, somebody that works with big CFD codes probably would throw up their hands and say, I can't do that problem, I don't know the geometry.
Q. Your approach, Dr. Griffiths, is not the sort of traditional fluid dynamics approach that someone would go to; correct?
A. I don't know. It depends on what you mean by "traditional" and -- actually, mine is probably very much traditional, meaning old school. If you'd ask somebody in 1955 or 1960, they probably would have done what I did.
Q. Dr. Griffiths, was the methodology that you used generally accepted in the scientific world that you work in?
A. Well, it is. I just -- you know, it depends how you look

at it. If I had a commercial tool and I chose that as my path, what would I do? I would take that commercial tool, I would build a model, similar to mine, of the whole system. I would take measured pressures during shut-in. I would take measured flow rates of collected oil, and I would tune my model to all the data. And once I had tuned my big computational CFD tool to all of the data, I would have exactly -- not exactly, too strong -- almost exactly the same model I built.

I just didn't take commercial software, tune it to the data. I just said, let's just start with the data and build a model around the data.

Q. Doctor --

A. So it is -- it's the same thing that you do with commercial software when you tune using data. I just said, let's skip all that, start with the data, and work toward the model.

Q. Dr. Griffiths, your approach that you're using in your expert testimony here today is not an approach, the sort of traditional fluid dynamics approach, that someone normally would go to; correct?

A. I don't know exactly how to answer any better than I have.

MR. REGAN: If we could pull up your deposition, November 14th, 561, lines 11 through 21.

BY MR. REGAN:

Q. Were you asked this question and did you give this answer

02:30 at your deposition, Dr. Griffiths:

02:30 "Question: Was the methodology you used generally accepted in the scientific world that you work in?

02:30 "Answer: It would depend on who you ask. I would -- I would characterize these as -- my overall approach is somewhat -- orthodox is too much strong a word. It is not an approach that -- that the sort of traditional fluid dynamics sort of person would -- you know, that had a model would -- would go to."

02:30 Were you asked that question and did you give that answer, Dr. Griffiths?

02:30 **A.** Yes, certainly.

02:30 **Q.** It's not an approach that you used on any other oil well in the past prior to Macondo; correct?

02:30 **A.** Excuse me, that I had used on any other oil well?

02:30 **Q.** Yes.

02:30 **A.** Correct.

02:30 **Q.** You had never analyzed flows at an oil well prior to working on the Macondo accident; correct?

02:31 **A.** That's correct.

02:31 **Q.** You described your methodology as a specialized model; correct?

02:31 **A.** Yes.

02:31 **Q.** It addresses only this particular well and only the particular conditions at this particular well; correct?

02:31 **A.** Yes.
02:31 **Q.** It is not a general-purpose tool, in your own words; correct?
02:31 **A.** Correct.
02:31 **Q.** It would not be useful for modeling flows at any other well; correct?
02:31 **A.** Well, yes, but that's because the parameters, the data used to get the parameters are -- come from the Macondo well. The methodology would certainly work on other wells. If you tell me, here's pressures and here's measured flow rates, I could use the same model to describe another well.
02:31 When I say that, it's only because the parameters that I have come from Macondo, they describe Macondo, nothing else.
02:32 **Q.** You have never tried to use this same approach to analyze another well to see if it would work; correct?
02:32 **A.** I have never analyzed another well.
02:32 **Q.** Your method does not use a detailed description of the physical geometries at Macondo as inputs; correct?
02:32 **A.** It does not require those as inputs.
02:32 **Q.** Does not require them and does not use them; correct?
02:32 **A.** Both true.
02:32 **Q.** You do not use an equation of state in calculating your best estimate; correct?
02:32 **A.** Again, not required by my methodology.

02:32 **Q.** And not used?
02:32 **A.** And not used, yes.
02:32 **Q.** You do not use gas-oil ratios or temperature inputs or parameters for multiphase flow as inputs into your model; correct?
02:32 **A.** All of the same, not used, but also not required.
02:32 **Q.** You do not include any description of the flow path in your model; correct?
02:32 **A.** Oh, that's not true. You know, it's true I don't have to know the details of the flow path, but my little colored diagrams are specifically about what the flow path was. I do need to know that the -- the way the various elements are connected, which is what the flow path is.
02:33 **Q.** You need to know the flow segments in the order in which they appear at the well; correct?
02:33 **A.** Right.
02:33 **Q.** But you don't need to know anything about their actual characteristics?
02:33 **A.** That was one -- that's one of the great strengths of the methodology, yes.
02:33 **Q.** And the only actual flow input, flow input, in your methodology is from data taken on July 15th from a single hour; correct?
02:33 **A.** Well, not exactly. But because I used information from July 14th, which had the same physical configuration. And at

that time the flow rate of collected oil was zero, so I have one value that's zero and one that's not zero.

Q. So your 5-million-barrel cumulative estimate is based on two flow inputs, a value of zero on July 14th and a value of collected oil on July 15th; correct?

A. That's true. I did -- I did discuss uncertainties associated with those.

Q. And when validating issues with respect to uncertainties for your flow, you validated against other periods of collection, three other periods of collection; correct?

A. I did.

Q. And all of those were, again, in July 14th and July 15th; correct?

A. That's correct.

MR. REGAN: If we could pull up D-23401.

BY MR. REGAN:

Q. I'd like to talk a little bit about your parameter estimation. This is a description of your constant discharge coefficients; correct?

A. Uh-huh.

MR. REGAN: If we go to D-24372.

BY MR. REGAN:

Q. This relates them to the well. And I think as you said in your direct, you don't need to know the specific geometry, as you just said a minute ago, just the order in which these

things appear; correct?
A. Correct.
Q. Each of the parameters on the left side of the screen are unknowns; correct?
A. Well, before you do parameter estimation, yeah, they are -- the model is constructed. It contains six constants that until you use the data, you do not know.
Q. The purpose of the parameter estimation is to try to estimate values for these six unknown parameters; correct?
A. Correct.
Q. You do not have any direct measurements of any of these parameters?
A. Well, that's true.
Q. You estimate all of them using data from July 14th and July 15th; correct?
A. That's true.
Q. The pressures that you use for your parameter estimation are pressures from July 14th and July 15th; correct?
A. Yes.
Q. And as you said, the flows that you used, you use a single flow rate of collection plus a flow of zero from July 14th and July 15th; correct?
A. Correct.
Q. And the collected flow rate is just a partial flow, not complete flow from the well; correct?

A. That's correct.
Q. And so you would agree, Dr. Griffiths, that when we look at how you developed your parameters, the pressures that you used and the flow rates that you use are by definition a product of the flow path, the geometry, and flow conditions that existed as of July 15th -- 14th or 15th, 2010; correct?
A. Correct.
Q. You also used some constraints in your parameter estimation; is that right?
A. Yes.
Q. And in your baseline case -- let me go to this. In terms of estimating these six parameters, you estimate them all at the exact same time; right?
A. Well, you have -- you have the collection of -- I don't know what "exact same time" means. You have the collection of data, you have a requirement that you have to satisfy conservation of mass. There's a piece of software that varies all six parameters to satisfy conservation of mass as best as is possible given the measured pressures and measured flow rates of collected oil.
Q. When you run this parameter estimation, all six unknown parameters are moving and then you try to get them as close to a flow rate constraint that you have in your model and then you lock in their values?
A. Well, it's not known. It's not just the flow rate. There

are -- there are about 30 residuals that are defined that define, you know, states as the variable choke is closed. So there are 30 of those. You have to satisfy -- you try to satisfy conservation of mass as best you can for each of those conditions, plus the two constraints that have flow rates.

So it's much more than just trying to match a flow rate.

Q. However the model works, you end up with a single value for each of these six discharge coefficients as of July 15th; correct?

A. Uh-huh, yes.

Q. And then you would lock in that value and use a portion of those parameters for your cumulative flow; correct?

A. I do use those values over the preceding 86 days for calculating flow rates, yes.

Q. You did not independently calculate any of these parameters for any dates prior to July 15th; correct?

A. No, I did not.

Q. So you cannot determine if, in fact, the parameter values that you arrived at on July 15th would be the appropriate parameter values for any of the preceding 85 days?

A. No, I would -- I guess I wouldn't agree with anything that broad.

Q. You had --

A. I might have to hear it again, but...

02:39 **Q.** You did not independently calculate what these parameters would be, what their values would be, for any days other than July 15th; correct?

02:39 **A.** That's correct.

02:39 **Q.** You didn't have the data to do it for any day prior to July 15th?

02:39 **A.** That's correct.

02:39 **Q.** So you can't say whether ten days earlier or 30 days earlier or 50 days earlier, these parameters would have the same value as they do on July 15th?

02:39 **A.** Well, that's what I disagree with.

02:39 **Q.** So you did calculate them at an earlier date?

02:40 **A.** I did not do it by calculating at the earlier date, but there was sort of a leap in there between your two questions and from my two alternate calculations, from what we know about decay rates of the BOP pressures relative to reservoir pressures, from all of the physical evidence and the speed of erosion and from my own examination of physical evidence and opinions about how and when erosion occurred, I have concluded to a very high level of confidence that there was a lot of erosion and it all occurred within the first week or something.

02:40 So I do have reasons to believe that those values, based on July 14th/15th, are reasonable and applicable and justifiable for use over the preceding, maybe not 86 days, but we could say 84 days or 85 days.

Q. Simple question, Dr. Griffiths: You only calculated them for July 14th/July 15th?
A. Yes, I've already agreed to that.
Q. In your best estimate, you use two of these parameters, what you refer to as productivity index and wellbore discharge coefficient?
A. Uh-huh.
Q. Along with reservoir pressure and PT-B; correct?
A. Correct.
Q. What you use as a PI is the constant estimate from July 15th. It's not a measured number; correct?
A. It's the number that I determined. I also did validate it against what BP thought would be a reasonable value.
Q. It's not a measured number. Your constant value of PI is not a measured number; correct?
A. I can't quite agree with that. Because, again, it's determined from data. To the extent -- it's determined in part from data, it's determined in part from my model. So to say simply it's a calculated number isn't the full story. Because it -- if it weren't for the measured flow rates and the measured pressures, which are data, which is about measurements, I would have no estimate of the Productivity Index at all, so --
Q. You calculate the PI; correct? Through your parameter estimation; correct?

A. It is a numerical algorithm. I do calculate it, but its origins are in data and that makes it a measurement. So I can't say that it's simply a calculated number, because it's not. Because it comes from the measured flow rates and the measured pressures and that makes it, at least in part, a measurement.

Q. You do not have a data point that you could point the Court to to say, this is a data point for PI that I grabbed from Macondo; correct? All you have is a calculation?

A. No, it's not just a calculation. It's partly a calculation; it's partly a measurement. If there were no -- if I were going to calculate PI, I would start with permeability and velocity and all that sort of stuff and formation volume factors and everything else, and I could calculate a PI. I did not do that.

I determined a PI partly through calculation but largely through measurements of pressures and flow rates and then that becomes, in part, a measured PI.

MR. REGAN: D-24374.

BY MR. REGAN:

Q. This is a demonstrative exhibit, Dr. Griffiths.

And for your best estimate, you used the values for K-well, that's your wellbore discharge coefficient, and your value for PI, productivity index, the constant value you calculated on July 15th, and you apply those two values uniformly over the entire flow period; correct?

MR. BENSON: Objection. I think we've been over this.

THE COURT: Overruled.

THE WITNESS: Yes. My best estimate methodology uses a PI and the wellbore discharge coefficient as determined, you know, based on the data from July 14th and 15th.

BY MR. REGAN:

Q. So practically speaking, Dr. Griffiths, in your best estimate, everything below the wellbore does not change from April 20th to July 15th?

A. No, no. I think that's -- that's an overstatement.

Q. You use a constant value from July 15th for K-well and PI; correct?

A. I don't dispute that that's how my best estimate is calculated, PI, K-well, constant 86 days, period. But then you asked, so in that nothing changed over those 86 days, and that's a leap that I don't agree with.

Q. In your best estimate, because you --

A. In the calculation -- yeah, in the calculation, there's no doubt they are held constant during that period. Yes.

Q. And the practical import of that, for the Court to understand, is in your calculation, you are effectively holding everything below the BOP as being unchanged over 86 days, in your calculation?

02:45 **A.** Unchanged as it significantly affects flow rate and cumulative discharge. As long as we add that, I agree with you.

02:46 **Q.** You hold it constant? Yes or no?

02:46 **A.** I'm having trouble here understanding because I've said now three or four times, I hold the PI in K-well constant over the 86 days. There's no doubt about that. That's how my best estimate calculation is done.

02:46 But then you say, So nothing at all changed down there over those 86 days?

02:46 And that's where I say, Well, no, those are not equivalent.

02:46 So I apologize, but I'm...

02:46 **Q.** You agree, Dr. Griffiths, that if there was erosion at the reservoir sandface, such as in the cement at the bottom of the well or other damage to the sandface, that could cause the PI to change over the 86-day time period. Do you agree with that?

02:47 **A.** I discussed that at length in my appendix on the period before May 8th. Yes.

02:47 **Q.** So you agree with that?

02:47 **A.** I do.

02:47 **Q.** Do you agree that if there's erosion in the wellbore or changes, such as a change in the location of the drill pipe, that that could lead the -- the wellbore discharge coefficient to change in time over the 86 days?

A. Yes.
Q. And your best estimate calculation, by holding those two values constant, would not capture those changes, if they were to have occurred?
A. Well, yes. If they vary -- if -- yes, I will agree with that. Sure.
Q. In your 2011 Sandia report and in your peer-reviewed article, you use the same methodology of holding PI constant; correct?
A. Yes.
Q. But in your 2013 expert report in this litigation, you acknowledge that there is data about what the effect of PI was as of the time of the accident; correct?
A. Well, I don't know "data." There were --
Q. Information?
A. Information, sure.
Q. You cite it in your expert report, correct, Dr. Griffiths?
A. Correct.
Q. You cite Dr. Emilsen's -- Mr. Emilsen's work; correct?
A. Yes.
Q. And you cite Mr. Emilsen's transient multiphase flow simulation where he matched the pressure data on the night of April 20th to what the effective reservoir face would be. That's what you cite in your report?
A. Correct, correct, yes.

Q. 13 feet to 16.5 feet of the 86 feet exposed; correct?
A. Correct.
Q. And you translate that into a PI; correct?
A. Yes.
Q. The PI is 7.4 to 9.4, according to your calculation; correct?
A. Correct.
Q. So from 7.4 to 9.4 PI, as of the moment of the accident -- so 43, which is your constant value -- the PI at the bottom of the well must change?
A. Yes. Yes.
Q. In your expert --
A. For the sake of keeping it simple, yes.
Q. Well, in your expert report, you state that based on Dr. Emilsen's report, you calculated that that change -- a factor of 5 -- happened in nine hours; correct?
A. No, I calculate that it would have happened in 9 hours. But I also state in my report that neither Mr. Emilsen or I or anybody else knows what was actually going on down there, so we don't even for a fact know that we're talking about variation in productivity index. So...
Q. And your solution to the ambiguity about what's going on down there is to apply the constant value from July 15th to April 21 for PI?
A. From which date to which?

Q. July 15th to April 21st.

A. Yes.

Q. But you cited Mr. Emilsen's work as a basis for changing PI five times in nine hours; correct?

A. Well, it was -- it's supporting information. I actually don't think I did -- ever did anything with the nine hours, so it was just -- it was additional information that supported some -- some other things that I had observed. So the nine hours is -- you know, I say -- all I did with the nine hours was say, Ah, if you extrapolate this, you get to my value in about nine hours. That's consistent with my expectations that things unfold in minutes, you know, hours, maybe a day or so. We're not talking weeks or months.

So there is no special significance to nine hours. And I think when we last met, I said, Ah, I don't -- nine hours, 18 hours, whatever, it really makes no difference as far as any of my analysis is concerned.

Q. It made a difference in your expert report when you used that nine-hour value to conclude that it indicated whatever downhole restriction existed at the time, regardless of whether it was debris, float collar, or cement, failed in nine hours; correct?

A. I don't think that that's what I stated in my report. It might be --

MR. REGAN: TREX-11485R.11.3.

THE WITNESS: I mean, I certainly say nine hours, but I'm just not sure that the words you used were really exactly the words I had in my report. That was the only issue.

BY MR. REGAN:

Q. Well, let's read the words then and test that proposition.

You state here -- at the top, you talk about variations in the wellbore discharge coefficient. You then say: "Under conditions that most closely replicate measured pressures and observable events, their analyses" --

And you're referring to ADD Energy, Mr. Emilsen.

-- "indicate that the effective productivity index increased by over 25 percent between 9:00 and 9:30 on April 20th. This indicates that whatever downhole restriction existed at that time was failing rapidly, regardless of whether this restriction resided in wellbore debris, the float collar, or cement barrier. For continued failure at this rate, I estimated that the productivity index would further increase to my best estimate value in less than nine hours. At this point, the cement barrier or other impediments would provide no significant restriction to flow from the reservoir into the casing."

Is that your expert report, Dr. Griffiths?

A. Yes. But I don't -- that wasn't what I heard when you -- when you asked earlier, so, yeah, I think that's exactly how I feel about it.

Q. As of your rebuttal report, you then change from nine hours to "hours or days, not weeks or months."
Correct?
A. Pardon me?
Q. In your rebuttal report, your rate of erosion was no longer nine hours; now it was "hours or days, not weeks or months."
Correct?
A. I don't -- I don't remember or know what that's about, but I'll take your word for it.
MR. REGAN: TREX-11486R.14.1.
BY MR. REGAN:
Q. Do you see here in this section of your rebuttal report that you cite the drill pipe that was above the upper annular in the BOP, the same one you looked at on the screen about an hour ago --
A. Right.
Q. -- and you used that rate of erosion. You say, "This did not occur in weeks or months, it occurred in a matter of hours"; correct?
A. Yes.
Q. So you conclude in your rebuttal report, "Because the flow rates are the same throughout the system, I therefore believe that erosion in the reservoir cement plug, reamer shoe, and/or float collar would have occurred on a comparable time scale,

hours or a few days -- not weeks, and this view is consistent with Mr. Emilsen's calculations"; correct?

A. Yeah.

Q. And by the time of your deposition, it was no longer hours or days, it was now three days -- 36 hours -- of how long it would take; correct?

A. I don't know what your questions are. I'm having trouble with reading the text and then -- so if you ask me a question that I can understand, I'd be happy to answer.

Q. When you were deposed, Dr. Griffiths, it was at that time your opinion that it was not a matter of nine hours or ten hours or 12 hours or one day. It was now 36 hours you said that the erosion would take place; correct?

A. Excuse me, but when I use words like "comparable" in this, I'm talking, could be seconds, minutes, hours, a few days. Those are -- they cover a huge range there, but -- but they're all very fast compared to 86 days. So I think I'm just saying, you know, in different ways here, nine hours, there's 36 hours, somebody thinks it could be minutes.

That it sets a time scale for these events to occur in that is very fast, not weeks, not months; minutes, hours, a few days.

Q. Well, your uncertainty calculation, if, in fact, PI took longer than 36 hours to change to its July 15th value, your uncertainty calculation does not include that; correct?

A. Yeah. But it also makes almost -- no difference. I think my flow rate, that 36 hours -- which, you know, by the way, once you get down to 36 hours, almost nothing matters. You know, flow rate's 20,000, it's 50,000, it's a short period of time. It can't significantly change the cumulative discharge.

So I think for the first 36 hours, I have 36,000 barrels a day. For the next, all the way out to I think it's April 29th, so a whole week, that goes up to 41. So it's hardly any -- any change. So maybe -- maybe it didn't take 36 hours. Maybe it took three days. So I have -- then I lined up with a day and a half with a discrepancy between 36,000 and 41,000. These things just don't matter.

Q. The uncertainty chart that you put before the Court on your direct examination does not include the uncertainty that would result from the PI, productivity index, taking more than 36 hours to get to your July 15th value; correct?

A. That's true. And as I just said, if it stood to five days or four days or seven days, it would make almost no difference at all in what those uncertainties were.

Q. You haven't calculated that number?

A. Oh, I know -- I know -- I have a feel for all those numbers.

Q. You may have a feel for those numbers, but those numbers are not disclosed by you in your expert report anywhere; fair?

A. That's -- that's correct, yes.

Q. In fact, the uncertainties that you put up during your direct exam, those uncertainties were based on your work in 2011, not your best estimate that you put forth in your expert report; correct?

A. Partly, partly, but partly not. So --

Q. Everything except the last entry on that uncertainty chart and the reservoir entry were based on your 2011 work where you had a different estimate of flow, not your 2013 work; correct?

A. Well, but they're all percentages, so the sources of uncertainties did not change. And as percentages, they still accurately reflect what uncertainties would be -- it's the same methodology. The assumptions have the same impact. The uncertainties that measure pressures are the same. Why should they change?

Q. Just a simple question, Dr. Griffiths: You did not recalculate the uncertainties for the best estimate number that you set forth here today; you used your uncertainties from your work in 2011 where you had a different estimate?

A. Largely. There is one small thing there. When I did read -- when I looked at the uncertainties, I calculated variations in my Appendix C. I checked whether or not those variations, due to two-phase effects, were bigger or smaller than the values I had already used. And I determined they were always smaller than the values I used, so I did not decrease those uncertainties based on that. I left them as they were.

Q. I'd like to talk to you about the time period of April 20th to May 8th.

MR. REGAN: If we could pull up D-23997.1.

BY MR. REGAN:

Q. As represented here on this chart, you had, I think, over 90,000 values of PT-B; correct?

A. Yes.

Q. The first value starts on May 8th; correct?

A. Yes.

Q. So you had to make an assumption about what happened over the first 18 days with PT-B; correct?

A. Yes.

MR. REGAN: If we could bring up D-23997-2A.

BY MR. REGAN:

Q. What you did, Dr. Griffiths, is you drew a line from May 8th backwards to Time Zero; correct?

A. Yes.

Q. You extrapolated from your first data point backwards to a time period where you did not have a data point; correct?

A. No -- oh, well -- yes and no. The extrapolation threw me because what I actually did is fit the trend over a long period of time and use that extrapolation to obtain the Time Zero pressure.

Q. Okay.

A. The connection to the first data point on May 8th isn't an extrapolation. You just connect those two times.

Q. There is data available to try to determine what the pressure would be at the BOP as of the start of the accident, as of the start of the flow period; correct?

A. I'm not sure I think there's any data that's actually relevant, but...

Q. Well, whether you might not think it's relevant, there is data from drill pipe pressures, working from the top down or from reservoir pressures working from the reservoir up, where you could get a range of what the BOP pressure was as of the start of the flow period; correct?

A. Well, I think that's pretty much what I did, in my perspective, but go ahead. Yeah, there are drill pipe pressures measured on April 20th. The reservoir pressure was known on that date or thereabouts. So, yes, there were pressures.

Q. If we could pull up a chart from your report.

MR. REGAN: TREX-11485R.9.1.

BY MR. REGAN:

Q. This is from your report. Do you recognize it, Dr. Griffiths?

A. This is from my Sandia report -- oh, no, this is from my expert report. Okay, yes.

Q. You have an initial reservoir pressure of 11,850; correct?

A. Yes.

Q. Then you have, "Reservoir less flowing head -- elevation head"; correct?

A. Yes.

Q. And your calculate value is 8,730 psi; correct?

A. Yes.

Q. Where is the elevation head? Where does it go in terms of the well?

A. From the bottom of the well to, in this case, the BOP.

Q. So based most your calculation of the reservoir pressure up to the base of the BOP, the pressure at the base of the BOP would be 8,730 psi; correct?

A. Well, no. I mean, I don't know. That's, you know, in an unflowing state, but the well was clearly flowing. So I don't know...

Q. Dr. Griffiths, at the moment the flow started, based on your own chart, the pressure of the BOP would be 8,730 psi; correct?

A. But that's with no flow.

Q. The moment the flow started; correct?

A. Well, wait a minute. I don't know what "the moment the flow started" means. I mean, before it started, there's no flow, it would be 8700. As soon as there's flow, within minutes, it would drop to 4300. So I don't know -- I don't know how to parse it any finer than that.

Q. Okay. You did not use 8,730 psi as your initial BOP

pressure; correct?
A. Well, that makes no sense at all. The well was flowing.
Q. You did not use that value?
A. That's correct.
Q. You did not use a value that can be derived from drill pipe pressure for PT-B as of April 20th; correct?
A. Not entirely correct.
Q. You're aware that you can calculate a pressure -- PT-B pressure using the drill pipe pressures; correct?
A. Under what conditions? Flowing? Nonflowing? Yes, you can -- okay, yes, you can.
Q. Dr. Johnson calculates that PT-B value to be approximately 8700 psi; correct?
A. It's a nonflowing, static pressure. That's a nonflowing, static, shut-in pressure.
MR. REGAN: TREX-11488.17.2.
BY MR. REGAN:
Q. This is a chart from Dr. Johnson's report?
A. Yeah.
Q. You see that he calculates initial PT-B pressure at 8700 and it has your calculation of about 4300 psi; do you see that?
A. Yes.
Q. Okay. One of the DOJ, Department of Justice's, experts also has a calculation of BOP pressure as of the time of the start of the flow period; correct?

03:05 **A.** Well, let's see -- well, I don't know. Another department -- I'm not really aware of what other DOJ experts do.
03:06 **MR. REGAN:** TREX-11653.27.1.
03:06 **BY MR. REGAN:**
03:06 **Q.** This is a chart out of Dr. Pooladi-Darvish's report. Do you see what his initial value is for PT-B on this figure?
03:06 **A.** On that figure would be about 85-, 8700 psi.
03:06 **Q.** And do you agree, Dr. Griffiths, that, in fact, if you had used 8700 psi as your starting number instead of your number of approximately 4300 psi, that it would lower the cumulative flow that you calculate in your best estimate?
03:06 **MR. BENSON:** Let me make an objection, Your Honor. Mischaracterizes Dr. Pooladi-Darvish's expert report. We'll hear from him later, and Dr. Griffiths has already said he hasn't reviewed this report, so there's no foundation.
03:06 **THE COURT:** Okay. I will --
03:06 Can you answer? Do you remember the question?
03:07 **MR. REGAN:** It was two questions ago.
03:07 **THE COURT:** Okay.
03:07 **BY MR. REGAN:**
03:07 **Q.** The question before you, Dr. Griffiths, is: If you had taken 8700 psi as your initial PT-B value, like we see in this chart from Dr. Pooladi-Darvish's report, like we've seen in the preceding chart from Dr. Johnson's report, you would agree that

03:07 it would have a reducing effect on your cumulative flow estimate?

A. If I had done that, it would reduce my cumulative discharge.

But I do feel I should add, it makes no sense at all to do that. Those pressures are shut-in pressures. Those are pressures associated with the well when nothing is flowing. If I look -- you asked, you know, what information there was. So Mr. Emilsen calculated BOP pressures as part of his best case, Case 7 in his report.

03:08 And what he shows is that when the well is flowing at fairly low flow rates, that he's got calculated BOP pressures that are down 2500, 3,000 psi at the BOP. Okay. Those numbers are quite consistent with my extrapolation back. They're actually lower than my -- than what Mr. Emilsen shows is that when the annulars and the VBRs, especially the VBRs, were closed, that over a period of just a couple of minutes, five minutes, ten minutes or something, the BOP pressures zoom from 3,000 psi or less up to 8700 psi. That is with the well 03:09 shut-in.

Immediately -- again, immediately, when flow resumed, those pressures would have dropped again, over minutes back down to this 3,000, 4,000 psi range.

Q. You agree, Dr. Griffiths, that the chart you just described from Mr. Emilsen shows that when the BOP was

activated shortly before 9:49 p.m. on April 20th, the BOP pressures went up to a range of about 8700 psi; correct? Is that true?
A. That was a shut-in pressure.
Q. The question is: Was that true?
A. The well was shut in at that instant, very temporarily. The traveling block fell; the seal on the pipe was gone within -- within, you know, minutes. And as soon as the seal on the end of the pipe was gone, that well was flowing, those BOP pressures would be back down to 2-, 3-, 4,000 psi.
Q. Everything after the moment of a measurement of 8700 psi, you just testified to, is your speculation about how quickly that pressure would decrease to --
A. Mr. Emilsen's calculations show very clearly the well is flowing. You seal the well, pressures zoom up to 8700; his calculations even show it's flat. Mr. Emilsen in his report says that things would have continued to evolve, continued to change after that. He makes no statement about what would have happened.
My only statement -- my only reliance on his conclusions is: You seal the well, the pressure goes up within minutes. When you unseal the well, when the traveling block fell, when the seal was lost on the top of the pipe, the pressure would drop in a matter of minutes.
Q. The impact of using 8700 psi to the -- at April 20th to

the first May 8th value on your cumulative flow impact estimate is approximately 500,000 barrels; correct?

I understand you disagree with it, but if you --

A. Okay. Okay. I don't know offhand if I ever did that calculation, so I'm not sure -- I don't think I did. I agree with you: Had I used that 8700 linear down to May 8th, I would get a lower discharge. I don't disagree with that. I don't think I ever did those calculations, so I'm not sure I know the impact -- the magnitude of that.

Q. At the time you gave your 2011 peer-reviewed article in your Sandia report, you did not discuss anything with respect to erosion rates inside the BOP; correct?

A. I don't have a clear recollection. I guess perhaps not.

Q. Okay. And, in fact, it's your view, Dr. Griffiths, that you don't believe anybody knows anything about the actual true dimensions anywhere in the BOP; correct?

A. No. No. The piece parts are all out there. You know, they've been measured. They've been scanned. You know what all the dimensions of those parts are. The bores through the thing have been measured. So I don't -- I don't agree with that statement.

Q. Let's pull up your deposition of June 26th, page 43, maybe page 42 to pull in the question. It's the June 26th deposition. Let's start on 42, because I think the question starts on 42.

Do you see the question there at the bottom: "Can CFD tools be used with unknown geometries to determine range of possible flow rates, if you have a known starting position and a known ending position?"

And you say: "Big, big -- well, big caveats there. I don't believe anybody knows anything about the actual, true dimensions anywhere in the BOP."

Do you recall giving that answer, Dr. Griffiths?

A. I don't. It's -- you know, I don't remember the exact contents, what happened before. It's an overstatement.

I think this same -- if it's the conversation I recall, it goes on to say, Yes, we know the dimensions of all the piece parts. The big issue is: You don't know how the piece parts fit together, and that's where the uncertainty is.

So that's an overstatement on my part.

Q. Dr. Griffiths, you did not use any computational fluid dynamics in reaching conclusions about erosion in the BOP; correct?

A. Not directly. I use them as part of validation.

Q. You, yourself, did not perform any computational fluid dynamics work in arriving at your views on erosion rates inside the BOP; correct?

A. That's correct.

Q. You did testify at your deposition that you looked at pictures in the DNV report; correct?

A. Yes.

Q. And you formed mental images about the size of the holes that would have been in the BOP based on your view of those pictures; correct?

A. Well, pictures and of looking at the actual hardware.

Q. You never took those mental pictures and actually put them down on paper or drew them or did any type of computational fluid dynamics to see if it was consistent with your mental picture?

A. Well, you know, I -- I vaguely remember this conversation because I think I was holding my fingers up and saying things like, "They're about this big."

But do keep in mind that when I hold my fingers up and say, Well, they're about this big, I have all kinds of things to reference that to. So "this big" or "this big" or something means something quantitative to me.

It's not just -- and it doesn't require CFD. So it's not just mental imagery.

Q. Dr. Griffiths, in your uncertainty about what happened with the BOP, you postulate that the flow rate in the first 36 hours could be at a lower bound of approximately 36,000 barrels per day; correct?

A. Yeah, or even a little bit lower.

Q. You have the blind shear rams activated on April 21st -- or by April 22nd; correct?

A. 22nd, yes.

Q. And it's your opinion that after the blind shear rams were activated, the flow rate went up to 41,000 barrels per day; correct?

Q. No, that's not a -- the increase occurs at 36 hours. The BSRs are at 33 hours. So the increase from 36 to 41 really has to do with -- with the collapse of the riser. It's not -- that change is not a consequence of the BSR's main function.

Q. In your expert report you estimate a flow rate at the time of blind shear activation as being approximately 41,000 stock tank barrels; correct?

A. Yes.

Q. That's a higher flow rate than the time period before the blind shear rams were activated; correct?

A. Yes.

Q. So is it your testimony that activating the blind shear rams increased the flow rate at the well?

MR. BENSON: Objection. Asked and answered.

THE COURT: Overruled.

THE WITNESS: Well, I have to think about that. Well, I think it does because if before then you've got the entire length of pipe, you know, all the way to the surface, then you've got a lot of resistance in there. If that's your flow path, is that piece of pipe through the BOP and all the way to the surface, when you function the BSR, it cuts that pipe. And the flow path now isn't through that long pipe all the way to the surface; the flow path is now through the riser.

So, yes, I think it does -- it would have increased the flow rate just because it changed the flow paths.

BY MR. REGAN:

Q. So activating the blind shear rams made the flow at Macondo go up under your analysis of the BOP?

A. I suppose, yes.

Q. And then is it also your opinion that a few days later, when the casing shear rams were activated, the flow rate went up again, from 41,000 barrels per day to 61,000 barrels per day?

A. Well, wait a minute. I'm -- you're talking now about my discussion period before May 8th, and I think, before we get too far along there, we need to make clear that there are a bunch of assumptions in there to get lower bounds, upper bounds that influence these things.

So to say that my methodology or my model or my, you know, analysis shows some peculiar behavior is -- isn't quite right. Because you make assumptions to get a lower bound on what you think the flow rates are, and you make different assumptions to get an upper bound. It's an exercise in understanding uncertainties, not in predicting at these different states, you know, what would the flow rates be.

Q. In your appendix to your report, where you go in and give your views about what happened to the BOP, you predict that the flow rate was at least 41,000 stock tank barrels per day prior to the activation of the casing shear rams; correct?

A. No. See, when you say your -- "you predict," I don't know exactly the words in that that bother me. But when say "I predict," I make assumptions to give me a lower bound on the flow rate, upper bound on the flow rate, it's for purposes of uncertainties, not purposes of predicting exactly what's going to happen in this.

Q. Dr. Griffiths, did you write the number 41,000 stock tank barrels per day for your flow rate for the period of April 26th to April 29th in your Appendix G? Did you write that number?

A. Yes.

Q. And did you write a number, 61,000 stock tank barrels per day, starting April 29th, after the casing shear rams were closed?

A. Yes.

Q. And did you write a number of 36,000 stock tank barrels per day before the blind shear rams were closed?

A. Yes.

Q. So under your assessment of uncertainties and under your looking at the BOP, the flow rate, as you wrote in your appendix, went up when the blind shear rams were closed and went up when the casing shear rams were closed, as set forth in your report?

A. But not because of those things. I mean, that's the thing. You know, the flow rate goes from 41,000 to 63,000 on April 29th. It's not because that's when the casing shear rams were closed; it's because other things are going on. That change actually has to do with that's the point in time which I estimated the pipe dropped below.

So that increase isn't because the CSRs were functioned; that increase is because in that time period, I no longer have a pipe below the BOP.

Q. How much of the 20,000-barrel increase at the time the casing shear ram was closed is due to the rams being closed or due to your belief that the drill pipe fell?

A. Well, I think, if you look at the discussion of that, I still have all of the VBRs -- you know, at least one VBR all that seal, perfectly sealed. So I'm making assumptions to give me a low bound on the flow rates. I have all these things sealed on the pipe, perfectly sealed, no leak.

So I think that increase you asked about to, say, 61 has to result simply from the drill pipe dropping from the bottom of the BOP.

Q. So you believe the drill pipe fell no later than April 29th. Is that your opinion?

A. Yeah. I think April 29th -- if I had to pick a single day, I would have picked April 29th.

Q. Okay. Your conclusion, after examining pictures of the

BOP and forming some images of them in your mind, was that there was no great uncertainty in your assumption of a constant wellbore coefficient and a constant PI over April 20th to May 8th; correct?

A. Well, 3.3 percent is -- and that's 3.3 percent of the whole fifth -- 5 million, not just of that period. So that's -- I think that's my single largest uncertainty, is that.

Q. Right. About 170,000 barrels uncertainty?

A. I don't remember -- I don't know the numbers in those units.

Q. But the fact is your 3.3 percent uncertainty includes uncertainty as to whether the PI changed faster or slower than 9 hours, includes uncertainty as to whether you drew the right line for PT-B, and includes uncertainty as to whether your assessment of the BOP, from looking at pictures and looking at piece parts, is accurate.

All of those things, you conclude, result in a 3.3 percent uncertainty. Is that correct?

A. Well, it is. But to understand it, you have to know what's possible there. So I could have done an alternate calculation saying -- let's just assume there was zero flow, zero flow any time until May 8th. What would my uncertainty be? 20 percent, that's the most. I mean, I got 4 million barrels after that. There's 1 million barrels missing before that. That's 20 percent.

So if you look at it from the perspective of I start with a maximum uncertainty for that period before May 8th of 20 percent and ask me, do you think you could drive that uncertainty down by a factor of 5 or 6 through analysis of, you know, the state of the rams and the BOP and when different things happened, I think that's very reasonable.

And if you take 20 percent and drive those uncertainties down by a factor of 5, 6, you wind up with 3, 4 percent, which is where I am.

Q. You can take a percentage of here and a percentage of there, and you ultimately arrive at 3.3 percent. Is that what you --

A. That's not what I was trying to say. I hope that's not what came out.

I'm just saying that 3.3 percent is a small number. I mean, I don't disagree with that. But it is of that period. That's 3.3 percent of the whole 86 days. Of that, 17 days it's something like 20-something percent -- 15 percent of the flow during that time.

But the issue is the uncertainties associated with that 17 days aren't infinite that I can reduce to 3 percent. The biggest they can possibly be on the negative side is 20 percent.

Q. You know how to do computational fluid dynamics analysis,

right, CFD analysis?
A. Yes. I've written lots of CFD codes.
Q. You did not do any CFD analysis of the riser kink; correct?
A. I did not.
Q. You're aware that Dr. Nesic did; correct?
A. Yes.
Q. You did not do any CFD analysis of the blind shear rams; correct?
A. That's correct.
Q. You're aware that Dr. Nesic did; correct?
A. Yes.
Q. You did not do any CFD analysis of the casing shear rams; correct?
A. Correct.
Q. And you're aware that Dr. Nesic used those tools to analyze the BOP during that time period; correct?
A. Yes.

MR. REGAN: Your Honor, I'm going to transition to a new topic. I'm happy to keep going or pause here.

THE COURT: All right. Let's go ahead and take a 15-minute recess.

THE DEPUTY CLERK: All rise.

(WHEREUPON, the Court took a recess.)

THE DEPUTY CLERK: All rise.

THE COURT: All right. Please be seated.

All right. Mr. Regan.

MR. REGAN: Thank you, Your Honor.

BY MR. REGAN:

Q. Dr. Griffiths, I'd like to put up TREX-41026.54.1, which is an excerpt from the Add Energy Appendix W that you cite in your report.

My question is: Did I read the top paragraph correctly with respect to Case 7?

"Case 7 assumes a lower volume of hydrocarbon influx was taken prior to 2130 hours; this was achieved by using 13 feet of net pay of 12.6 ppg sand. When the pumps are shut down at 2130 hours, the pressure drops, creating a higher drawdown on the reservoir and from this point forward, 16.5 feet of net pay is assumed in the simulation."

Did I read that correctly?

A. I believe so.

Q. There's nothing in that report that suggests that a change from 13 feet to 16 feet took place over 30 minutes; correct?

A. That's correct.

Q. There's an instantaneous change in the Appendix W between 13 feet and 16 feet; correct?

A. Yes.

Q. At 9:30?

A. I think the 30 minutes is the preceding 30 minutes of data that he was looking at, so --

THE COURT: Pull the microphone a little closer to you, please.

THE WITNESS: I'm sorry. From 2100 to 2130 is the 30 minutes.

BY MR. REGAN:

Q. Mr. Emilsen used 13 feet of net pay from 9:00 to 9:30 in this simulation; correct?

A. Correct.

Q. And he used 16.5 from 9:30 to the time of the accident; correct?

A. Yes.

Q. So there was a change at exactly 9:30; correct?

A. Yes.

Q. There's no change over 30 minutes, is there?

A. Well, in his report, he says he, in fact, calculates these with constant net pay heights, but he also says that he believes that they're more likely variable pay heights, and I think the word "likely" is exactly the word he used.

So he acknowledges freely that he's just got a constant for some period of time and then he changes it to another constant. But he says within his first two pages of his report that varying PI or net pay height would be more likely.

Q. You recognize the exhibit in front of you is actually his

report?
A. Yes.
Q. And you know that he testified in the Phase One trial about this exact topic?
A. That, I don't know anything about -- well, I guess I do. Yeah, I do. Because I think I -- I think I read his testimony, but I don't -- I don't remember for sure.
Q. With respect to PT-B, after May 8th, you finally have PT-B data; correct?
A. After May 8th, yes, PT-B.
Q. Once you have that data, you don't use all of it; correct?
A. I exclude the Top Kill period and then there's some noise just before July 11th that I exclude.
Q. You exclude dropouts, you exclude what you view as noise, and you exclude the Top Kill period; correct?
A. Yes.
Q. And then in your best estimate, your flow rates are derived by the difference between reservoir pressure and the pressure shown on PT-B; correct?
A. Correct.
Q. But before you use PT-B, you then add additional corrections to it; is that right?
A. To correct for persistent offset, yes.
Q. Right. So you add 740 psi through July 9th, thereabouts; is that right?

A. Yes.
Q. And you add a different offset for the last time period; correct?
A. Yes.
Q. And then after you take the data and add an offset, you then add an error to the offset PT-B data; right?
A. Yes, the plus or minus 130.
Q. So in your best estimate, you're using PT-B data that includes an offset and then has a plus or minus 130-psi error on top of the offset; correct?
A. Well, more or less correct.
Q. You agree that if you use the higher offset for PT-B, you would get a lower cumulative discharge?
A. Only if I used it during the period before July 11th. Then, yes.
Q. And, in fact, when you did your report in 2011, you used a different PT-B offset than what you have in here in 2013; correct?
A. Correct. I had very limited data available to me then.
Q. And one of the conclusions you had in 2011 was one of the drawbacks of your approach was uncertainty -- well, first, the sparse nature of BOP pressure measurements; correct?
A. This is my Sandia report?
Q. Yes.
A. At that time, yes, sparse data.

Q. And also uncertainties in the BOP gauge offsets; correct?
A. Yes.
Q. And given that your entire best estimate is leveraged off of PT-B, those are significant uncertainties?
A. Well, those were uncertainties that existed at that time. I think by the time I wrote my expert report -- well, certainly, there was data -- I had no data in most of June and into July at the time I wrote that report, so I had additional data and I had a great deal more information about offset PT-B at the time I wrote my expert report.

MR. REGAN: If we could put up D-24368, just so that we can all be using the same terms.

BY MR. REGAN:
Q. You see here in D-24368 that I have ambient pressure, PT-B pressure, and reservoir pressure. Do you see that, Dr. Griffiths?
A. Yes.
Q. And you see the PT-B gauge is right at the mud line at the bottom of the BOP; correct?
A. Yes.

MR. REGAN: If we go to 24369, D-24369.

BY MR. REGAN:
Q. If we talk about upstream of PT-B, we're talking about the reservoir and wellbore resistance. Is that fair, in the way you use the terms?

A. Yes.
Q. Okay.
MR. REGAN: If we could go to 24370.
BY MR. REGAN:
Q. If we're talking about downstream, we're talking about downstream flow, so downstream is the area above the BOP, above the gauge; is that fair?
A. Yes.
MR. REGAN: D-24401.
BY MR. REGAN:
Q. Just to orient the Court, do you agree, Dr. Griffiths, that if the PT-B pressure decreases, that can happen for two reasons: Either the resistance downstream has decreased or the reservoir in the wellbore resistance has increased? Do you agree?
A. I believe that's correct.
Q. Would you also agree that if the PT-B pressure increases, that can happen either because the reservoir in the wellbore resistance has decreased or the BOP or downstream resistance has increased? Do you agree?
A. I would agree.
Q. And, finally, if you have a resistance of BOP -- a decrease in BOP resistance or a decrease in reservoir resistance, you could have your flow increase; correct?
A. I'm not sure I followed the whole question, but I think

03:56 it's probably right. So far you've been right about these things, so I'll trust that you continue to be so.

03:56 **Q.** All right.

03:56 **THE COURT:** It's dangerous to trust a lawyer, particularly when he's cross-examining you.

03:56 **BY MR. REGAN:**

03:56 **Q.** Well, let's try to right that.

03:57 **A.** Okay.

03:57 **Q.** Do you agree that if the reservoir resistance increases or the BOP resistance increases, you would expect flow to go down? Right?

03:57 **A.** If the reservoir -- I'm sorry, one more time. It's just a little bit hard for me to follow --

03:57 **Q.** Okay.

03:57 **A.** -- those words.

03:57 **Q.** If you have the reservoir and wellbore resistance increase or the BOP resistance increase, you would expect flow to decrease in either of those situations; correct?

03:57 **A.** Yes.

03:57 **Q.** If you had the resistance in the BOP or the resistance in the reservoir and wellbore decrease, less resistant, you'd expect more flow; correct?

03:57 **A.** Yes.

03:57 **Q.** Your PT-B, if it goes down, that could be either because the BOP is less resistant or the reservoir is more resistant;

03:57 correct?
03:57 **A.** That's -- that's possible, yes.
03:57 **Q.** And if PT-B goes up, it can go up for two reasons: The reservoir resistance has decreased, less resistance in the well, or you've had more resistance in the BOP; correct?
03:58 **A.** Correct.
03:58 **Q.** And one example you cite in your report as to this phenomenon is that when the test rams were closed; correct?
03:58 When the test rams were closed -- I'll give you a little more context. When the test rams were closed, you had an increase resistance in the BOP and, therefore, your PT-B pressure increased; right?
03:58 **A.** Uh-huh.
03:58 **Q.** And you saw that in the data; correct?
03:58 **A.** Yes.
03:58 **Q.** But this gauge, because it's in the middle of downstream and upstream, what it actually reflects is the combination of what's going on above it, or downstream of it, and upstream of it?
03:58 **A.** Yes.
03:58 **Q.** It represents the combined effects of what is going on in the reservoir and wellbore and what's going on in the BOP; correct?
03:58 **A.** It does.
03:58 **Q.** And because you have resistances on each side of this

gauge, just looking at the changes in PT-B alone, you can't know whether a change in PT-B is because of a downstream change or an upstream change; correct?

A. I would agree, if that's the only piece of information you have.

Q. You would have to get additional information to reach a judgment that just because PT-B has either gone down or up, you know exactly what's going on in the wellbore; correct?

A. I agree with that.

Q. Okay.

MR. REGAN: Let's pull up TREX -- sorry, D-24531.

BY MR. REGAN:

Q. What I have here, Dr. Griffiths, on D-24531, is a chart that contains three lines. The lowest line is your adjusted and extrapolated PT-B pressure, the middle line is your flow rate calculation under your best estimate, and I have a green line for reservoir pressure. Do you see that there?

A. Yes.

Q. Okay. This May 8th to May 14th time period, there's approximately 800-psi drop in PT-B; correct?

A. That number -- I don't know that number off the top of my head, but let's see. It would be something like -- oh, 800 in the trend? No, I think that's too high.

Q. From May 8th to May 14th, right here on your chart --

A. May 8th to May 14th, yes.

Q. Okay. Are you with me? 800-psi drop; correct?
A. Okay.
Q. That drop is greater than your error bar for PT-B; correct?
A. It is.
Q. And in your report, you discuss this drop; correct?
A. Yes.
MR. REGAN: We go to TREX-11486R.29.2.
BY MR. REGAN:
Q. In your report you say: "Between May 8th and May 14th, the ratio of pressure drops falls very significantly, and this indicates that the resistance in the BOP fell relative to that in the reservoir and wellbore." Correct?
A. Yes.
Q. So PT-B went down because, in your view, the BOP became less resistant; correct?
A. That's what's stated here.
Q. You say: "This conceivably resulted from some sudden and real change in either resistance or might conceivably result from expected inaccuracies in the BOP pressures. If real, this sudden fall could represent a drop in BOP resistance or sudden increase in the reservoir and wellbore resistance."
That sentence is what we just went through; right?
A. Yes.
Q. PT-B can go down either because the BOP is less resistant

or the wellbore is more resistant; correct?

A. Uh-huh.

Q. You say: "The first of these seems most likely. In this case, the drop in BOP resistance might be, for example, the drop in the pipe below the BOP or sudden failure of the seal in one of the rams."

Did I read that correctly?

A. Uh-huh.

Q. You testified about 40 minutes ago that you believe the drill pipe fell on April 29th; correct?

A. Yes.

Q. You now say the data between May 8th and May 14th, that drop may actually -- that may be when the drill pipe dropped; correct?

A. These are all hypotheticals. I'm just -- I'm speculating about it could mean this, it could mean that. It is not saying that I believe those things occurred. It's just a discussion of what -- what might have occurred.

Q. You are speculating about when the drill pipe dropped in saying that it either was on April 29th or May 14 -- between May 8th and May 14th; correct? You don't know?

A. Wait. This statement ends with -- I mean, I know the drill pipe didn't drop after May 8th. This is a just discussion of the sort of things that you might be able to conclude just from this, but there's all kinds of other information that you bring into it.

Q. This discussion is in your expert report; correct?

A. I think that's right.

Q. Okay. But you rule out the drill pipe drop because you say it's "irreversible, while the ratio of the pressure drop largely recovers on May 19th. As such, I can offer no physical reason for this behavior."

What you're referring to there is that the PT-B starts to go up again; correct?

A. Yes.

MR. REGAN: If we could go back to D-24531.

BY MR. REGAN:

Q. This is the increase in PT-B, May 14th to May 19th; correct?

A. Yes.

Q. We know that that increase in PT-B could be the wellbore and reservoir becoming less resistant; correct?

A. I presume there's something that would allow that, yes.

Q. The gauge, the pressure that we read, PT-B going from a lower value to a higher value, that could represent actually erosion in the reservoir or wellbore that's allowing PT-B to go up; correct?

A. It could.

Q. Just as you say the decrease in PT-B could be the BOP becoming less resistant; correct?

A. It could be.

Q. In your best estimate, you have flow increasing when the BOP becomes less resistant. That's the purple line, May 14th; correct? Right there.

A. Well, in my best estimate, keep in mind, there's nothing about the resistance. The BOP is not involved in that. I looked at BOP pressures. What you said, the resistance of the BOP changed in such and such a way and I'm just reminding you that, in fact, my best estimate calculation does not involve in any way K-BOP.

Q. I'm not talking about K-BOP. You've testified that your best estimate allows you to predict any erosion that happens downstream of PT-B; correct?

A. Correct.

Q. So you have --

A. No, I -- I don't know predict. It accounts for it.

Q. Okay.

A. If that erosion occurred, that methodology would account for erosion that occurred downstream of PT-B.

Q. Your methodology has flow going up when PT-B goes down; correct?

A. Okay.

Q. Is that correct?

A. Well, those are the plots of the curves.

Q. Is that correct, Dr. Griffiths?

A. Well --
Q. Is that your flow rate curve above your PT-B curve?
A. Yes. Yes, yes.
Q. You then have flow rate going down when PT-B goes up between May 14th and May 19th; correct?
A. Correct.
Q. What is happening in the BOP to make it more resistant to have your flow rate go down?
A. I don't think we know with any certainty at all that anything is happening. You know, that first swing, the very first swing is a big one. All the rest of these things are just dancing around inside the bands of what you expect from uncertainties in the PT-B gauge.
So there's no -- there is no meaning -- you can't read, well, this went up and that went up. This is just uncertainties in pressure. This is just noise on the PT-B, and you get these changes accompanying changes in flow rate. That doesn't say anything at all about resistances actually changing.
Q. Well, Dr. Griffiths, it's your testimony that your best estimate, the value of it is that it's actually capturing all the changes downstream of PT-B; correct?
A. It does, yes.
Q. So these dancing around, this is actually how you're calculating your 5 million flow rate; correct?

A. Yes.

Q. You're adding up all of these days that include all of this dancing around; correct?

A. Yes.

Q. And you can't explain why you have flow rate going down when PT-B goes up between May 15th and May 19th; correct?

A. No. No. The flow rate is going to go down if PT-B goes up.

Q. Not necessarily; right, Dr. Griffiths?

A. Barring like really bizarre things, yes, necessarily.

Q. If the wellbore and the reservoir became less resistant, PT-B would go up and flow rate would go up?

A. Assuming that they have the ability to decide that collectively, we're both going to do this at the same time -- which I don't believe they do have that ability -- then those things are possible. Otherwise, what you described is not possible.

Q. So what is happening then in the BOP to make it more resistant to have your flow rate go down?

A. It is not more resistant. You're trying to interpret noise on a gauge through physical mechanisms. It doesn't make any sense to do that.

Q. So the line that you drew using your best estimate through which you calculate your integrated flow rate is noise? I don't think you mean that, but I think that's what you just said.

A. There are fluctuations and there are uncertainties in PT-B, plus or minus 130, I said. Dr. Trusler says plus or minus 200. Maybe that's the right number. It hardly makes any difference in any of this. Those pressures are just -- you know, there's some uncertainty in them, they go up, they go down.

From my methodology, all that happens is when they're high, I underpredict flow rate a little bit; when they're low, I overpredict the flow rate a little bit. They go up and down. Almost all that stuff cancels out.

Q. So the actual daily flow rates that you're calculating to get your 5 million to you don't really matter because of the average of them --

A. No, no, they matter tremendously. The little ups and downs in them don't matter. Those -- the values themselves do matter.

Q. The ups and downs between May 8th and May 19th are outside your error range for PT-B; correct?

A. Certainly the first one is, and that's why I discussed it. It's not way outside; it's, unfortunately, kind of in a gray area. It's a little bit outside the bounds, which is, you know, something I need to think about, but it's not terribly outside the bounds.

So it's a little hard to say is it just uncertainty in PT-B or is it something physical.

MR. REGAN: Go to D-24527.

BY MR. REGAN:

Q. Dr. Griffiths, this is just the PT-B chart with some dates on it of the events that were going on at the time. Again, we have May 8th to May 14th, a decrease in PT-B. Do you see that?

A. Yes.

Q. And May 14th to May 19th, an increase in PT-B. Do you see that?

A. Yes.

Q. And those events are happening at exactly the same time in exactly the same time period as Dr. Zaldivar's predicting slug flow appearing at the well; correct?

A. I -- I have no idea.

Q. Well, you are predicting an increase in flow as this line goes from May 8th to May 14th. You are predicting flow rate is increasing during this time period; correct?

A. I don't think I'm going to be able to discuss Dr. Zaldivar's work. I have not read carefully his work, so --

Q. Okay. Let me ask you about a different data point. Do you see the peak of PT-B from May 14th to May 19th is May -- is May 19th. Do you see that?

A. Yes.

Q. And that's the day that a third hole appeared in the riser, additional erosion; correct?

A. These -- these are not associated with holes in the riser. I just -- that's not possible.

Q. So this additional information is not helping you interpret PT-B?

A. What additional information?

Q. The fact that physical evidence of erosion appeared on May 19th with the third hole in the kink of the riser.

A. What -- oh, no, I mean, there are many things that Dr. Nesic and I agreed on, but we both agreed that holes didn't do much of anything to affect flow rate from the well. I mean, I think he -- he concluded that it changed the pressure drop through the riser by 20 percent or something, you know, from zero holes to all holes.

Well, the pressure drop through the riser was at most about 300 psi, 20 percent of 300 psi. We're talking tens of psi. That's not related to any of this stuff.

Q. Dr. Griffiths, let me turn to your alternate methods. Your first alternate method is one where you hold three things constant, that is, the BOP resistance, the well resistance, and the reservoir resistance; correct?

A. Alternate 1?

Q. Yes.

A. Yes.

MR. REGAN: If we can go to D-24375.

BY MR. REGAN:

Q. So you're holding K-BOP locked, K-well locked, and PI locked all over 86 days; correct?

A. They're held constant, yes.

Q. And you predict a flow rate by comparing these three constants to the decrease in reservoir -- the difference between reservoir pressure and ambient pressure; correct? In Alternative 1?

A. Yes.

Q. And because your reservoir pressure is a straight line, effectively, and your ambient pressure is a straight line, and you're using three constants, your flow rate line for Alternative 1 is a perfectly straight line; correct?

A. No, I don't think it is, huh-huh. Because if -- if -- if -- well, I don't think it is.

MR. REGAN: D-24532.

THE WITNESS: I could be wrong, but my immediate response is no, it would not be a perfectly straight line.

BY MR. REGAN:

Q. Let's test it out. In terms of Alternative 1, you have three constants for BOP, PI, and wellbore as of July 15th; correct? As of the last day, you have three things held constant in Alternative 1; correct?

A. Okay.

Q. And the only thing you're comparing for pressure change is

04:13 reservoir pressure and ambient sea pressure; correct?
04:14 **A.** Yes.
04:14 **Q.** So in your methodology, you would end up with a flow rate that's a perfectly straight line?
04:14 **A.** Huh-uh, no.
04:14 **Q.** Why not?
04:14 **A.** Because of -- because if you have the ambient sea pressure as a constant --
04:14 **Q.** Yes.
04:14 **A.** -- that means the -- and the other is linear, that means that the difference is linear, but the flow rate is not linearly proportional to pressure differences. It is dominated in these cases by the square root, so it would not be a perfectly straight line. It would -- it would have some curvature to it.
04:14 **Q.** But you're holding all of your discharge coefficients constant; correct?
04:14 **A.** Yes.
04:14 **Q.** Have you ever drawn the line, the actual flow rate line for your Alternative 1?
04:14 **A.** No. It cannot be -- it is not a straight line. It is just simply not possible that it is a perfectly straight line.
04:14 **Q.** How about Alternative 2? If we could talk about that.
04:15 **MR. REGAN:** Alternative 2, D-24376.

BY MR. REGAN:
Q. In your Alternative 2, you hold 1 discharge coefficient constant, that is, K-BOP, and you compare reservoir pressure -- PT-B pressure and ambient; correct?
A. Yes.
Q. Well, because, again, you're comparing now PT-B and ambient with ambient being a straight line, your Alternative 2 flow rate is going to look exactly like the signature of PT-B; correct?
A. Could you repeat that, please?
Q. Sure. Let me put it up on the board. It might be easier to see.
MR. REGAN: D-24408.
BY MR. REGAN:
Q. In Alternative 2, you're only comparing two pressures. One of them is constant. The other one is PT-B; correct?
A. Okay.
Q. You're comparing a constant pressure and PT -- against PT-B pressure?
A. Yes.
Q. And as a result, in your model, if you calculate flow rate in Alternative 2, your flow rate is going to look exactly like PT-B in terms of its shape because it's going to follow this difference between PT-B and ambient; correct?
A. The ups and downs do track, but to say that it follows it

exactly is not correct because in this case, for sure, the flow rate is proportional to the square root of that difference. And so it is not going to be any kind of one-to-one mapping of flow rates and PT-B pressures.

MR. REGAN: Go to D-24409.

BY MR. REGAN:

Q. What I have on this demonstrative, Dr. Griffiths, is a calculation of what the flow rate lines look like under your Alternative 1, under your Alternative 2, and under your best estimate.

We've looked at all three of these flow rate lines, and do you agree that under your alternative methods you will have different flow rates for the same day in each of the different methods, as represented here in D-24409?

A. That I will have different flow rates for the same day by the different methods. Yeah -- well, they'll be slightly different, sure.

Q. Well, we can see in your best estimate, flow rate goes up when PT-B goes down. In your Alternative 2 method, you have flow rate going down when PT-B goes up.

So for the very same day, on May 8th, one of your methods has a flow rate of almost 70,000, and your best estimate has a flow rate of a little bit less than 60,000. Is that fair?

A. Well, I suppose.

Q. Your testimony is, well, all of these flow rates, they all add up to the same total number.

But it is a fact that if you actually chart the daily flow rates of your alternative methods, you'll get wildly different flow rates for the same days; correct?

A. I don't think these plots are even credible. I didn't make these plots; they're not mine. But something seems very screwed up here because you have Alternative 2 flow rate. Clearly -- just visually the integral of that is going to be larger than Alternative 1. In fact, they're very, very similar, like 5.1, in both cases.

So I don't know exactly what I'm looking at, but I sort of am a little suspicious already that something here is screwed up.

Q. You've never used your Fortran code that you produced in this litigation to actually derive the flow rate signature of your Alternative 1 and Alternative 2, have you?

A. Well, sure I do.

Q. So you know what your lines would look like; correct?

A. Yes. I calculate them. That's how I calculate the cumulative discharge.

Q. Exactly. So you know that they don't -- they are not the same line for the same day; correct? Regardless of whether you accept this chart --

A. Oh, no, no. They're not exactly the same. But, you know, as long as we're at it, you've got a chart here with no zero on it, and we've talked about that in the past. It's called "whoopee plots." It starts at 50,000. So it really exaggerates all these variabilities. We're looking at things that around 60, 65, they peak up to 70. Those are significant differences, but they're not, you know, like, whoa, this one's 1,000 and that one's 15.

Q. The simple fact is, Dr. Griffiths, that the three alternative methods -- your best method, Alternative 1, and Alternative 2 -- that you say verify each other, actually have different daily flow rates amongst -- along the time scale from Day Zero to Day 86?

A. Well, absolutely. They're independent -- they use different datasets. So they shouldn't have the same flow rate on a given day by the three different methods. I mean, that would be just very strange.

Q. But there is only one true flow rate for each day; correct?

A. And calculations are always an approximation of that one true flow rate.

Q. Amongst your alternative methods, Dr. Griffiths, there's no method that you ran where you allowed the parameters for PI, wellbore coefficient, and BOP coefficient to be anything other than constant over the 86 days?

THE COURT: All right. Mr. Regan, this is getting very repetitive now.

MR. REGAN: Okay.

THE COURT: I've given you a lot of leeway, but it seems like you're beating this to death.

MR. REGAN: Just one more question on this, Your Honor, and then I'll change right into the -- turn to the report.

THE COURT: Let's try to move on.

BY MR. REGAN:

Q. If both the PI and the BOP resistance varied in your work, Dr. Griffiths, none of your cases would yield a cumulative discharge that is a true discharge. All of your cases -- let me say it again.

If both the PI and the BOP varied over time, all three of your cases would yield a cumulative discharge that differs from the true value?

A. If both the PI and the BOP varied over time, then my calculations would differ from the true value? My calculations always differ from the true value.

Q. Let me show you your report, 11486R.12.6.

My final question on this topic is, reading your report, the last sentence, did you write, "If both the PI and BOP varied, then all three of" your cases -- referring to best estimate, Alternative 1 and 2 -- "would yield a cumulative discharge that differs from the true value"? Is that correct?

A. Yes.
Q. You talked a little on direct about the work of Tony Liao. Do you remember that?
A. Yes.
Q. Do you know what Dr. Liao was actually modeling in terms -- for your comparison? Do you know what he was actually modeling?
A. He was modeling the Macondo well.
Q. Well, was he modeling casing or casing with drill pipe or casing with no drill pipe? Do you know?
A. Well, I think there were a couple of different ones. I think that one was the casing normally compared with.
Q. Do you know how many models he actually ran?
A. You mean how many cases?
Q. Yes, sir.
A. No.
Q. And you matched one of his cases; correct?
A. Yes.
Q. Okay. Dr. Griffiths, in your uncertainty chart that you put up, you have an uncertainty if you have the wrong final reservoir pressure; is that right?
A. I'm sorry?
Q. Let me put up the chart and see if we can do this faster.
MR. REGAN: D-21224.

BY MR. REGAN:

Q. Directing your attention to the line that says "Res Press" -- that's reservoir pressure; correct?

A. Uh-huh.

Q. -- "7260 versus 6605."

A. Uh-huh.

Q. That's a reference to what the appropriate final reservoir pressure is less an elevation head; correct?

A. Yes.

Q. And it's your calculation, using your models, that if the final reservoir pressure less elevation head increases -- that means there's less depletion -- your flow rate numbers go up?

A. That's correct.

Q. So as the -- using your methodology, as there is less depletion of the reservoir over time, your flow rate calculations actually increase the amount of flow from the well; correct?

A. Different delta P is not the same as less depletion. I mean, it depends what you're talking about, "depletion" here. But, okay, I'll agree, sort of, so far. Go ahead.

Q. And it's true, Dr. Griffiths, that using your methodology, if you held reservoir pressure as an average value over time or as a constant, you would still calculate a cumulative flow of approximately 5 million barrels?

A. Yes. If I -- my methodology is based on calculating flow rates and integrating those in time to get the discharge.

If I had used -- instead of the decaying reservoir pressure, if I had instead used the average reservoir pressure over that time, I would still have gotten a calculated discharge close to 5 million.

Q. In fact, Dr. Griffiths, if you used the initial reservoir pressure of 11,850 and held that constant over the entire time period, no depletion, you would still calculate 5 million barrels using your model?

A. Well, it wouldn't be 5 million, but, you know, you could do a calculation like that. And as long as -- I mean, an integral is sort of the beginning of an average. If I used the average pressure over the time to calculate my flow rates, then on average they're going to be right. And if they don't change on average, then my cumulative discharge does not change.

Q. I'll try it one more time, Dr. Griffiths.

You could run your model with either just an average reservoir pressure or even a final reservoir pressure that was the same as the initial reservoir pressure, 11,850, and your model would still predict a cumulative flow of around 5 million barrels; correct?

A. True.

MR. REGAN: Thank you, Dr. Griffiths.

THE COURT: Redirect?

MR. BENSON: Yes, Your Honor.

REDIRECT EXAMINATION

BY MR. BENSON:

Q. Okay. Dr. Griffiths, a couple things I want to just return to quickly.

First, you had a lot of questions from Mr. Regan about PT-B data, especially early on in May. Do you recall that?

A. Yes.

MR. BENSON: Could we have TREX 11486R.27.

BY MR. BENSON:

Q. While we call that up, Dr. Griffiths, did you do anything to average out some of the ups and downs in the PT-B data?

A. I'm not sure what you mean. Sometimes, when I want to fit them with a curve, I do some daily averaging to get rid of issues associated with episodic sampling.

MR. BENSON: If we could call out Figure 3 on this page.

BY MR. BENSON:

Q. And this is from your rebuttal report; correct?

A. Yes.

Q. And, Dr. Griffiths, is this a daily average plot you've made of the PT-B data?

A. Yes, it is.

Q. And the one -- and the red lines are a plus or minus 200 psi; is that right?

A. That's correct. Those are the -- those would correspond to Dr. Trusler's assessment.

Q. And you see the area -- the plots that go beneath that red line on about May 26th to May 30th, what are those?

A. Well, those are the test rams being opened. So you see that on May 26th, the test rams are opened. They stayed open for about three or four days. As soon as you close those, the pressures go right back up. So that's the trough in the middle.

At the left there -- this is when I was responding to questions by Mr. Regan -- this issue is these first two sets of pressures are just a little bit outside the plus or minus 200, and so it's a little bit hard to say are they, you know, just uncertainties associated with PT-B, or is there something physical happening here.

So it's just a gray area. It's hard to discern.

Q. And based on your review of the PT-B data, what did you conclude about what was going on in the well over time?

A. Over time? Well, the decay in a very reasonable way, consistent with the decay in the reservoir.

Q. Let me switch topics. You and Mr. Regan had a lengthy discussion about some of -- I think what's in your Appendix I, and that was the discussion about when the BSRs, the blind shear rams, the casing shear rams shut in and what the flow rates were associated with happening around those events.

A. Uh-huh.
Q. Let me just ask you, in broad terms, what was the purpose of your Appendix I?
A. Well, the entire purpose of it was to characterize the uncertainties associated with that period.
Q. And so the flow rates that you were talking about with Mr. Regan, those aren't your best estimate flow rates for particular days?
A. No, no. Because of those uncertainties, I had a set of assumptions that would give me lower bounds on what I thought were reasonable for the flow rates as well as upper bounds. But those -- those sorts of assumptions aren't consistent with an effort to obtain a best estimate.
Q. And the conclusion of your Appendix I was -- what conclusion did you reach about your uncertainty for that period?
A. Well, that it was, you know, plus or minus a few percent.
Q. Plus or minus. Was it --
A. Minus 3.3 was the lower bound.
Q. I think, as Mr. Regan said during your cross-examination, that's about 170,000 barrels?
A. I think that's -- again, I don't have that number in my head, but I will -- it's 5 times 3.3. It must be about that, yes.
Q. Let's -- you had some questions from Mr. Regan about

Mr. Emilsen's report -- I'm sorry, Dr. Emilsen's report. Or Mr.--
A. Mister.
Q. First let me ask -- there were some questions about how Mr. Emilsen varied the net K over time and what conclusions you drew from that?
A. Uh-huh.
MR. BENSON: Could we have TREX-41026.8, please.
If we could call out the paragraph that begins "constant net pay" in the middle of that page.
BY MR. BENSON:
Q. Dr. Griffiths, is this paragraph from Mr. Emilsen's report consistent with how you looked at Mr. Emilsen's results?
A. Well, it is. And, in fact, I referred to some of this when I was talking. He just says, I used constant values, but he acknowledges that varying the net pay -- varying net pay is more likely and, I think, importantly, can also explain some -- you know, remaining discrepancies between his calculations and the data.
MR. BENSON: And if we could go to TREX-41026.57, also in Mr. Emilsen's report.
This is a slightly different topic. If we could call out the bottom figure there.
BY MR. BENSON:
Q. On a different topic, you also talked with Mr. Regan about

the PT-B extrapolation and what was going on in PT-B before the blowout?
A. Yes.
Q. Is this data that you reviewed?
A. Yes.
Q. And this is something you referenced in your answers to Mr. Regan?
A. Yes. They're actually calculations rather than data, but, yes.
Q. Okay. And what is Mr. Emilsen showing here about the pressure before the blowout?
A. Okay. So he's showing -- these are calculations for his best estimate case, Case 7, pressures above and below the BOP. So once the BOP is sealed, those diverge, they split.
And so the blue line there is the pressure below the BOP and -- so this is the moment, like 2140 is when the VBRs were closed, right in that time frame.
And you see the pressure below the BOP over a period of a very few minutes goes up and then is flat. At that point, that's a shut-in state. There is zero flow from the well in that condition.
And so my comments to Mr. Regan were, okay, that's fine, that's interesting; but there's no flow, and we certainly know there was flow. And that shortly after this the seal on the top of the pipe would have been lost, flow would have

resumed, and this pressure, this 8700 psi would drop right back down to -- Mr. Emilsen has it at about 3,000, mine was about 4300 -- drop right back down in a couple of minutes, back to these 3 or 4,000 psi pressures.

Q. Is it possible to get a pressure here higher than what you're calling the shut-in pressure?

A. No. It's the maximum possible pressure that you could have at the BOP.

MR. BENSON: If we could have Demonstrative 21230, please.

BY MR. BENSON:

Q. And this is another version of the chart that Mr. Regan showed you on your cross-examination; correct?

A. Yes.

Q. And what Mr. Regan suggested is that you should use 8700 or 8600 as your pressure for the first day; is that right?

A. Yes.

Q. Do you think that's a reasonable thing to do?

A. No, I don't.

Q. And then the extrapolation he suggested would be a straight line from Day Zero to May 8th.

Again, do you think that's reasonable?

A. Not at all.

Q. Why not?

A. Well, again, you know, 8700 is a nonflowing well. There's no doubt that there was flow and high flow rates from the well at this time. And the 8700 exists only because there is no flow. So I think 8700, fine, that's a good pressure at 2150 on April 20th.

And two minutes later or five minutes later, when the seal was lost on the pipe, pressure would be back down at 3 or 4,000 psi.

Q. And let's just -- last question. Let's look at the final -- or the other end of that extrapolation. Is there any physical reason you're aware of that the pressure trend over time would go down from 8700, sort of sharply decline, and then take a left turn at May 8th?

A. No, I know of no physical basis for that sort of behavior.

MR. BENSON: No further questions. Thank you, Dr. Griffiths.

THE COURT: All right. Thank you, sir. You're done.

All right. Next witness.

(WHEREUPON, **AARON ZICK, PH.D.**, having been duly sworn, testified as follows:)

THE DEPUTY CLERK: Please state your full name and correct spelling for the record.

THE WITNESS: My name is Aaron Zick. First name A-A-R-O-N; last name, Z as in zebra, I-C-K.

MS. KARIS: Your Honor, we do have an issue with respect to Dr. Zick's testimony.

THE COURT: I have not seen any Daubert motion.

MS. KARIS: That's correct.

THE COURT: In fact, I was rather shocked that I didn't see a Daubert motion.

MS. KARIS: I don't have a Daubert motion.

THE COURT: Okay. So what do you have?

MS. KARIS: What we have is -- just by way of background, Dr. Zick initially, as part of his opinions, offered that a four-stage separator process is appropriate.

When he issued his rebuttal report, he then opined that rather than the four-stage separator process, he was now recommending an oceanic separator process.

However, none of the experts retained by the United States in this case, including those that we've heard in the last couple days -- and this is why it's become mature or ripe, if you will -- rely on Dr. Zick's oceanic separator for any purpose for any of their opinions. So his opinions with respect to the oceanic separator are not relevant to any of the issues.

THE COURT: Well, I don't know if they're relevant or not. We'll see where it goes. Okay?

MS. KARIS: Okay.

MS. CROSS: Thank you, Your Honor. Good afternoon. Anna Cross on behalf of the United States.

There is one preliminary matter I would like to raise, and it relates to an issue of Dr. Zick's testimony.

The United States is offering Dr. Zick as an affirmative witness on the conversion from reservoir barrels to stock tank barrels. We're also offering him as a rebuttal witness to BP/Anadarko expert Dr. Curtis Whitson. Like we are already aware, Dr. Whitson offers an opinion regarding dissolution of hydrocarbons in the ocean.

The United States has filed two motions that are currently pending relating to Dr. Whitson's testimony about dissolution, a motion in limine and a partial summary judgment motion -- those are Docket Nos. 11056 and 10752 -- to preclude Dr. Whitson's testimony regarding what the United States regards to be a pure question of law, which is whether dissolved hydrocarbons are nonetheless discharged into the waters of the United States.

Since these motions have not been ruled on, I'm ready to proceed with questioning Dr. Zick about his rebuttal opinion to Dr. Whitson's dissolution --

THE COURT: All right. Go ahead and do that.

VOIR DIRE EXAMINATION

BY MS. CROSS:

Q. Dr. Zick, you've been retained as an expert for the United States; right?

A. That's correct.

Q. Did you prepare a set of demonstratives to assist you

today?
A. Yes, I did.
MS. CROSS: Would you please call up D-22001.
BY MS. CROSS:
Q. Do you hold any degrees, Dr. Zick?
A. I have a Ph.D. in chemical engineering from Stanford University.
Q. Let's turn to your professional experience as it relates to the modeling of fluid phase behavior.
Where are you currently employed?
A. I'm the founder and president of my own company, Zick Technologies. I've been doing that since 1993.
Q. What does Zick Technologies do?
A. I provide petroleum engineering consulting and software services particularly related to the thermodynamic modeling of hydrocarbon fluids.
Q. What is thermodynamic modeling?
A. That's the modeling or the prediction of the properties and phase behavior of the hydrocarbon fluids.
Q. Can you briefly describe your professional background prior to forming your own company, Zick Technologies.
A. Upon leaving Stanford, I went to work for ARCO Oil & Gas company in Plano, Texas. I was there from 1983 to 1991, where I -- my principal duties were the equation of state -- were the equation-of-state modeling of petroleum reservoir fluids and

the development of equation-of-state modeling software.

In 1991, I took a position with Reservoir Simulation Research Corporation, a small Tulsa-based petroleum engineering software company, where I was the director of research, and my duties were the development and improvement of their equation-of-state software.

Q. What expertise did you draw on to do your work in this matter?

A. Well, my principal activities for the last 30 years have been the equation-of-state modeling of petroleum reservoir fluids and the development of equation-of-state fluid characterization. In particular, I've -- during the course of that work, I've analyzed PT-B laboratory reports, I've built equation-of-state fluid models, I've simulated separation processes and analyzed the results of those.

MS. CROSS: Your Honor, at this point the United States offers Dr. Aaron Zick as an expert in fluid phase behavior. Ask the Court to note that there are no Daubert motions pending against Dr. Zick.

THE COURT: He'll be accepted as an expert in that field.

DIRECT EXAMINATION

BY MS. CROSS:

Q. Dr. Zick, did you prepare an expert report in this matter?

A. I did.

MS. CROSS: Could you please call up TREX-11490R.
BY MS. CROSS:
Q. Is this a copy of the front page of your opening expert report?
A. Yes, it is.
Q. Did you prepare a rebuttal report in this matter?
A. Yes, I did.
MS. CROSS: Would you please call up TREX-114901R.
BY MS. CROSS:
Q. Is that a copy of the front page of your expert rebuttal report?
A. Yes, it is.
Q. Are you adopting the content of your two expert reports as your testimony to the Court today?
A. Yes, I am. Although I have one small correction to note regarding Table 6 of my rebuttal report.
Q. What is that correction?
A. I inadvertently, in building that table, made an editing mistake. That's a table regarding single-stage shrinkage factors. In the line of that table related to the Intertek sample, I accidently left in data from the four-stage shrinkage factors of the Schlumberger sample that were found in Table 7.
Q. Does that error that you just identified have any impact on the opinions you're offering?
A. No, it doesn't.

MS. CROSS: I move Dr. Zick's expert report and his rebuttal expert report, TREX-11490R and TREX-11491R, into evidence.

THE COURT: I'll admit those with the understanding that Ms. Karis may convince me that some of his rebuttal report is not relevant, and I can decide that later. Okay?

MS. KARIS: Thank you, Your Honor.

THE COURT: All right.

What was the table that you said had the error?

THE WITNESS: Table 6, the last line.

THE COURT: Table 6, that's on...

MS. KARIS: On page 19, Your Honor.

THE COURT: Page 19. What part -- are you going to talk about that?

THE WITNESS: Not really. It's the line relating to the Intertek.

THE COURT: The last line, which has the title Intertek, "Sample Intertek"?

THE WITNESS: Right, right.

THE COURT: Okay. Thank you.

MS. CROSS: Would you please call up D-22002.

BY MS. CROSS:

Q. Dr. Zick, can you please summarize the opinions you'll be testifying about here in court today.

A. Yes. It's my opinion that the most appropriate conversion method for dividing the stock tank oil from the Macondo reservoir fluid is through some sort of multistage separation process. And my first recommendation would be to use the oceanic separation process that I developed because I believe that's most representative of what -- of the separation process that the ocean would have subjected the fluids to.

My second recommendation, which is also a viable alternative, would be to use a four-stage separation, the separation process that BP had directed its contractor laboratories to perform on each sample. I believe that that -- or in my opinion, that would have been the likely separation process that BP would have used during production, had there been normal production.

Q. Are you offering an opinion about whether single-stage separation should be used for the conversion?

A. Yes. It is my opinion that single-stage separation would not be appropriate for the conversion from the live Macondo fluid stock tank conditions.

Q. Why is that?

A. Single-stage separation would not have been used in the field --

THE COURT: Before you get into that, why don't you briefly describe to me the three different -- the single-stage, the four-stage, and the oceanic method.

THE WITNESS: Okay.

THE COURT: Very -- just an overview.

THE WITNESS: The single-stage method takes the live reservoir fluid directly to stock tank conditions. A lot of gas is released, and with it, it takes a considerable amount of the valuable hydrocarbon components that you could otherwise stabilize within the stock tank liquid.

The multi-stage method takes the reservoir fluid to stock tank conditions in incremental stages, reducing the temperature and pressure stage by stage. That releases less of the dissolved gases, leaving more of the stock tank oil behind.

And the oceanic process is -- would be similar to a multi-stage process but performed at the -- in a series of many, many stages -- essentially continuous stages -- that would be experienced by the fluid as it floated up through the ocean from the sea bed to the surface. And that turns out to be a little more efficient than the four-stage multi-stage process.

THE COURT: Okay. Go ahead. I forgot what your original question was, but you might ask him again.

MS. CROSS: Sure.

BY MS. CROSS:

Q. Dr. Zick, let's turn to the methodology that you used to come up with your opinions about what the shrinkage factors would be for the single-stage, four-stage, and oceanic separation.

MS. CROSS: Can you please call up D-22003?

BY MS. CROSS:

Q. Dr. Zick, can you describe the steps you took to arrive at your conclusion?

A. Yes. The first step was that I evaluated all of the laboratory PT-B data -- pressure, volume, temperature -- that's the phase behavior data -- and I created an equation-of-state fluid characterization to accurately represent that data. So it accurately represents the phase behavior of the Macondo fluids.

I then used that equation-of-state model to simulate various separation methods and to evaluate the results of those methods.

Q. What is an equation-of-state fluid characterization?

A. Well, an equation of state itself is the set of equations that can be used to describe the fluid properties in the phase behavior of the collection of fluids. And to apply them to a particular fluid, you need a fluid characterization of that fluid, the set of parameters that you'll input into the equation of state.

Q. You're aware that Dr. Whitson has presented his own equation of state in this matter?

A. That's correct.

Q. For purposes of your separation analysis, can you summarize how your equation of state compares to Dr. Whitson's?

A. Our equations of state have differences in the details, but, overall, they both reproduce the behavior of the Macondo fluid reasonably well. And the differences between them, at least as far as the shrinkage factors, are relatively insignificant, only about 3 percent, which, relative to the uncertainties in the PT-B data, I believe, are, in my opinion, are not significant.

MS. CROSS: Please call up D-22004.

BY MS. CROSS:

Q. Dr. Zick, you're offering an opinion about the appropriate conversion from reservoir fluid to stock tank fluid. Can you explain what the relationship is between reservoir fluid and stock tank fluid?

A. A reservoir fluid can't exist as a stable, single-phase liquid at the surface -- at surface conditions, the standard of which would be 60 degrees Fahrenheit in one atmosphere.

The reservoir fluid contains a lot of dissolved gas, which must come out of solution when it's brought to ambient conditions. Now, that makes the stock tank oil a subset of the live reservoir fluid, and the surface gas would be the remainder of the fluid, the gas that comes out of solution.

Q. Is there a way to quantify the relationship between reservoir fluid and stock tank fluid?

A. It's quantified by a term called "shrinkage factor" or by another term called "formation volume factor." Those are actually just inverses of each other, and either one can be used.

MS. CROSS: Please call up D-22005.

THE COURT: What is the relationship -- is there a formula, a ratio that is used? In other words, if you had a -- how many reservoir barrels would you need to get one stock tank barrel at 60 degrees Fahrenheit?

THE WITNESS: That would be the formation volume factor. So if the formation volume factor were around 2, you would need two reservoir barrels to get one stock tank barrel.

For a given process that would take you from reservoir conditions to surface conditions, the formation volume factor will depend on the process that you choose. For that same example, the shrinkage factor would be 1 over 2 or .5.

THE COURT: But you're always going to have -- the stock tank barrel number is going to be smaller than the reservoir number?

THE WITNESS: Yes.

THE COURT: That's the shrinkage factor that you're talking about?

THE WITNESS: Right.

THE COURT: Okay. I'm sure I'll have some other questions, but go ahead.

BY MS. CROSS:

Q. Dr. Zick, if you know the shrinkage factor, how do you determine the formation volume factor?

A. You take the inverse of that.

Q. And the inverse means 1 over the shrinkage factor?

A. That's right.

Q. In the example that's on the screen, if you have a shrinkage factor of .5 and you're trying to go from reservoir barrels to stock tank barrels, how do you do it?

A. You would multiply the number of your reservoir barrels by .5. Or you could divide the number of reservoir barrels by the formation volume factor of 2. Either way, you get half as many stock tank barrels as the number of reservoir barrels you start with.

THE COURT: So is the idea of stock tank barrel -- let me reask that question.

What I'm trying to understand is: Were you trying to come up with a model to replicate the stock tank barrel number that would have occurred in normal operating procedures for this well if this blowout never occurs and they're just producing oil from this well?

THE WITNESS: Yes, that's one of the processes that I simulated.

THE COURT: That's the four-stage method?

THE WITNESS: That's right.

04:55 **THE COURT:** Is the other method that you talked about, the oceanic method, instead trying to model what you believe happened in the case where the oil is not being brought up directly to the surface, but is coming out of the blowout preventer or broken riser and coming up through the sea?

04:55 **THE WITNESS:** That's correct.

04:55 **THE COURT:** Which one would likely give you a bigger or smaller number? What would be the relationship there?

04:55 **THE WITNESS:** Well, when I set out to determine that, I didn't know, but it turns out that the oceanic separation process gives you slightly more -- about 2 1/2 percent more stock tank oil than the four-stage separation. It's just able to stabilize more of the hydrocarbons in the liquid phase.

04:56 **THE COURT:** It sounds like it's not a huge difference.

04:56 **THE WITNESS:** It's not.

04:56 **THE COURT:** Okay. All right.

04:56 **BY MS. CROSS:**

04:56 **Q.** Dr. Zick, you testified that you looked at a single-stage separation and a four-stage separation and an oceanic separation process. How did you decide to look at those three separation processes?

04:56 **A.** Well, a single-stage process is routinely done by the PT-B laboratories every time they analyze a bottom hole sample, because they can't analyze the sample directly without first separating it at ambient conditions. And so they always report those results. They're available for use in tuning the equation of state. And so I always include those for that purpose.

But it's not a very efficient process for performing the separation in the field. So oil companies generally ask the laboratories to perform multi-stage separator tests, and those tests were performed on each of the four samples that were collected in this case. They were all performed at the same set of separator conditions, and so those were the conditions that I used for my simulations of the four-stage separator process.

MS. CROSS: Please call up D-22006.

BY MS. CROSS:

Q. Dr. Zick, you just testified that the labs conducted four-stage separations. Which labs are you talking about?

A. PENCOR, also known as Core Lab; Schlumberger; and Intertek.

Q. And can you also identify on this demonstrative what is depicted here as the front pages of TREX-60988, TREX-130815, TREX-11575, and TREX-130963.

A. Yes, these are the cover pages of the PT-B reports for the four primary samples upon which the most extensive laboratory experiments were run.

Q. When were those laboratory experiments run?

A. The experiments, I believe, were run -- well, the reports came out in June of 2010, so the -- and the fluids were collected in mid-April of the same year, just a few days before the blowout. So I imagine the experiments were performed sometime between then and early June.

MS. CROSS: Please call up TREX-60988.003.001.US.

BY MS. CROSS:

Q. This is an excerpt from TREX-60988. This is an excerpt from one of the PENCOR reports we just looked at. And this specifically is from the page with the scope of work. Can you read what the top line says?

A. "Multi-stage separator test of reservoir fluid (stimulation of production facility)."

Q. Can you explain what you understand that description, that scope of work, to mean?

A. Yes. That means that the laboratory performed a multi-stage separator test on this particular fluid sample, and they -- they described that test as a way to simulate the surface production process.

Q. What is your understanding, Dr. Zick, of why four-stage tests are run prior to production?

A. Well, they -- on the -- a multi-stage separation process is normally what's used in the field to separate the stock tank oil from the live reservoir fluid because it's more efficient than a simpler, single-stage process at stabilizing more of the stock tank oil, which, of course, is much more valuable than the surface gas that is removed.

MS. CROSS: Please call up D-22007.

BY MS. CROSS:

Q. Dr. Zick, can you describe the process that is depicted here?

A. This is a simple schematic of a four-stage separation process in which the reservoir fluid is brought to the surface and it's put into the first-stage separator, which is equilibrated at the conditions of that separator. The gas is removed. The liquid then is passed to the second stage, where the fluid is again equilibrated. The gas is then removed and the liquid is passed to the third-stage separator, where it is equilibrated one more time, recovering more gas. And then the liquid is finally passed to stock tank conditions, which may give off even a small amount of additional stock tank gas.

And the end result, the residual liquid from the whole process, is your stock tank oil.

Q. Did your four-stage separation analysis produce a shrinkage factor?

A. Yes, it did.

Q. What was that?

A. Going from the original reservoir fluid at original reservoir condition of 243 degrees Fahrenheit and 11,850 psi, one barrel of that average reservoir fluid would produce

0.494 barrels of stock tank oil, according to my equation-of-state model.

Q. Did you compare the .494 shrinkage factor that you obtained from your four-stage separation to that obtained by the labs?

A. The labs actually measured the shrinkage factors from a different initial starting condition. They measured it from saturation pressure conditions. So the numbers they report would have to be converted into numbers relative to the original reservoir fluid.

But in the course of tuning my equation of state, I just simulated the laboratory experiments directly and matched the reported laboratory results directly.

Q. And what was the difference between the laboratory-reported results and your four-stage results?

A. I overpredicted the results by about 3, 3 1/2 percent on average except for the Intertek fluid sample, which was an obvious outlier that both Dr. Whitson, BP's corresponding fluid behavior expert, and I both realized that that fluid -- there was something wrong with the data, that it was an outlier.

But of the data that appeared reasonably reliable, I overpredicted it by just 3 1/2 percent or so.

Q. Did you run a single-stage separation using your EOS as well?

A. Yes, I did.

Q. How did the results of your single-stage separation using your equation of state compare to the results you obtained for the four-stage separation using your equation of state?

A. The single-stage separation results in about 9.9 percent less stock tank oil than the multi-stage separation would. Or put it another way: The multi-stage separation would stabilize about 11 percent more stock tank oil than the single-stage separation would, given the same conditions otherwise.

Q. Let's turn briefly to your oceanic separation model.

MS. CROSS: Would you please pull up D-22008?

BY MS. CROSS:

Q. Dr. Zick, can you please explain, using D-22008, your oceanic separation model?

A. Yes. Let's see if I can use this laser pointer. The separation process begins at the exit of the well on the seabed. At the exit conditions of the well, the exiting reservoir fluid is not in a single stage. It's at equilibrium in those conditions in two phases, an oil phase and a gas phase. So that's the first stage of the separation.

My model then tracks the oil stream as it rises to the surface and the gas stream as it rises to the surface. And along the way, as the oil encounters ever-decreasing pressures, additional gases will evolve from that stream. I combine those gases with the main gas stream for purposes of separation at the next stage.

Similarly, as the gas stream rises to the surface and encounters an initially much lower temperature than the well exit temperature, then lower and lower pressures as it rises, it will condense additional liquids as it moves up through the water. And those liquids, I combine with the main oil stream for purposes of separation at the next stage.

And at the -- once the two streams reach the surface, the final liquid stream defines your stock tank oil and the final gas stream defines your surface gas.

Q. Why did you model the oil and gas as separate streams?

A. Well, because it's my opinion that the ocean would tend to separate these streams. These streams aren't continuous, nice flowing streams. They're actually -- they're actually jets of small oil droplets and small gas bubbles. And the water will keep those -- those droplets and those bubbles isolated from each other, for the most part.

MS. CROSS: Please call up D-21023.

BY MS. CROSS:

Q. Dr. Zick, having discussed your single-stage separation and your four-stage separation and your oceanic separation, can you explain using this demonstrative what the results of each of those separations were?

A. Yes. If you start with 100 barrels of reservoir fluid at the initial reservoir conditions, the single-stage separation process would result in 44 1/2 stock tank barrels. The four-stage separation process would result in 49.4; that's 11 percent more. The oceanic separation process would depend very slightly on the exit temperature of the well, but it would produce between about 50.6 and 50.7 stock tank barrels, which is almost 14 percent more than the single-stage process would produce.

Q. And can you explain, based on this demonstrative, which separation mechanisms you believe are appropriate in this case?

A. Well, it's my opinion that the oceanic separation process is the most appropriate because I believe that that's how the fluids would be separated by the conditions they would encounter within the ocean. But the four-stage separator process would be a good alternative because that's what I believe would have been used -- or something very similar to that -- had the fluids been produced in a normal fashion.

Q. Let's turn now to Dr. Whitson.

What is your understanding of the criticisms Dr. Whitson offers of your work?

A. Well, he had -- he had some criticisms of the accuracy of my equation of state, particularly in matching the four-stage separator shrinkage factors. I mentioned my predictions were about 3 1/2 percent off on those, which I felt was insignificant, but he felt that that -- that those were errors that could have been less.

Of course, the converse could be said. I found many other data points within his that were predicted less accurately by his equation of state than by mine. My opinion's still that the 3 percent difference between my equation of state and his on the shrinkage factors is not particularly significant.

He also felt that a four-stage separation was not the most appropriate, and he proposed either a single-stage separation or the oceanic separation process that he put forth, which is a little bit different than the one I put forth.

Q. But Dr. Whitson offers an opinion about the dissolution of the hydrocarbons. Are you aware of that?

A. Yes. That's another difference between our view of the separation of the fluids.

Q. What is your understanding of Dr. Whitson's dissolution opinion?

A. Well, in his modeling work, he subjected his -- at the Macondo -- the live Macondo reservoir fluid to his oceanic separation process and produced a stock tank oil from that process. And then he subsequently argued that the volume of that stock tank oil should be discounted by removing all of the light hydrocarbon components that he believed were readily soluble in the water.

Those included all of the light alkanes, methane through pentane, and all of the light aromatics up to about C12, and those included benzene, toluene, xylene, ethylbenzene, trimethylbenzene. He believed that all of those components would dissolve in the water and that, therefore, they should be removed from the volume of the resulting stock tank oil.

Q. What is your opinion regarding Dr. Whitson's dissolution analysis?

A. Well, I don't believe that -- in my opinion, that's not an appropriate method for modifying the stock tank fluid. That, basically, changes the definition of the stock tank liquid to something that is unlike the stock tank liquid that would be produced in a normal fashion.

And also those hydrocarbons that he allows to dissolve in the water, it's not like they're suddenly gone. They're still in the water. They're just not going to be in the liquid oil phase, if you believe his model.

And, also, those oil -- those hydrocarbon components would not dissolve in the water instantly. They would take some time to dissolve, but he makes no estimates of how long it would take or -- or provides any sort of mass transfer rates or anything that would tell you whether that happens in an hour or a day or a week.

And so I just overall find it to be inappropriate.

Q. In a normal production scenario, what happens to the hydrocarbon components that Dr. Whitson assumed dissolved in the Gulf?

A. They would still be present in the stock tank oil to some degree. Those components may predominantly leave the stock tank oil in surface gas, but the stock tank oil will still retain a significant amount of those components.

MS. CROSS: Would you please pull up TREX-60988.26.001.US?

BY MS. CROSS:

Q. This is an excerpt from the PENCOR 19 lab report that we looked at earlier, TREX-60988.

Dr. Zick, can you explain what this excerpt from page 26 depicts?

A. Yes. This is the compositional analysis of the stock tank oil that resulted from their multi-stage separator test on this particular sample. It shows the percentages in terms of moles, volume, and weight, for each of the components up to -- this particular part of the table shows up to C12.

Q. And can you identify which of these components Dr. Whitson excludes as dissolving in the ocean?

A. Yes. He excludes the first seven components, methane through N-pentane. And then he also excludes certain fractions of the C7 to C12 components, roughly 10 percent of those -- of those total components.

Q. And what percentage of the volume of stock tank oil from this Macondo sample at surface conditions is in Dr. Whitson's "Dissolved" category?

A. Well, just the components methane through pentane comprise a total of about 6 1/2 volume percent, which could be determined by adding up the volume percentages for those components. And then I've looked at his modeling runs and have seen that the components like benzene and toluene and so forth would comprise about 3.1 additional volume percent and making the total that he's removing -- that he would remove from this particular stock tank oil about 9 1/2 percent.

Q. How is Dr. Whitson's dissolution analysis related to his oceanic separation opinion?

A. It's completely separate. He first performs his oceanic separation calculations to determine a stock tank oil volume and composition. And then he modifies that composition by removing all of these water-soluble components and recalculating the volume of the resulting stock tank oil. And that results in a reduction between 7 and 13 percent in volume, according to his report, although he doesn't actually offer any actual calculated results.

MS. CROSS: Would you please pull up TREX-11491R.0012.

We can just start with 11491R. Could you please go to page 12.

BY MS. CROSS:

Q. Dr. Zick, is this your depiction of Dr. Whitson's oceanic separation model?

A. Yes, it is.

05:17 **Q.** Can you focus on the differences between your oceanic separation model and Dr. Whitson's and explain what those are?
05:17 **A.** Well, they start off exactly the same where they -- the fluid coming out of the well is separated into an oil stream and a gas stream by the conditions at the exit of the well. His oil stream travels up toward the surface and at each stage, much like mine, a gas stream -- an additional gas stream evolves because of the decrease in pressure.

05:18 What's a little bit different is that he takes those gas streams straight to the surface then. He doesn't try to recombine those with the main gas stream. On the other hand, he takes the gas stream that exits from the well and he takes that straight to surface conditions for separation at standard temperature and pressure, which condenses a small amount of liquid from that stage.

05:18 **MS. KARIS:** Your Honor -- I'm sorry.

05:18 **THE WITNESS:** That differs from my --

05:18 **THE COURT:** One second.

05:18 **MS. KARIS:** Your Honor, I'm sorry to interrupt. But I believe this is beyond the scope of what Dr. Zick has disclosed in his report. His entire criticism of Dr. Whitson's work is in his rebuttal report at pages 2 and 3. And this stage-by-stage analysis is nowhere in the report. Instead, Dr. Zick does say he disagrees that the dissolved components should not be accounted for.

He does conclude by saying: "Whether the oil counts for purposes of this case is a legal question."

So this entire analysis that we're seeing here I don't believe is stated anywhere in his report.

MS. CROSS: It's stated on page 8 of Document 11491 where Dr. Zick says: "My oceanic process differs from Dr. Whitson's with one significantly different assumption, however. Dr. Whitson made a serious omission by assuming that the gas stream would rise all the way to the ocean surface before any additional liquids would condense from it," and it continues on.

THE COURT: Okay. It sounds like it's fairly within the bounds, so go ahead.

THE WITNESS: All right. So his gas stream, as I said, is he takes it straight to surface conditions where he separates out a small amount of additional condensate, but that differs from my model in that my model allows condensate to condense from this rising gas stream at every stage along the way, at every --

THE COURT: Is this because -- I'm trying to understand. You had said before that there was essentially oil and gas -- there was -- initial separation occurred at the wellhead; right?

THE WITNESS: Right.

THE COURT: But it's not like we see two distinct streams. I'm just referring back visually to the videos that I've seen. It looked like one big large plume, essentially, but within that they had streams of oil and gas. Is that what you're saying?

THE WITNESS: That's right. That's right. They exist as gas bubbles and oil droplets, but they're -- there would be a distinction between the oil phase and the gas phase.

THE COURT: Going up together in a sense but at different rates?

THE WITNESS: They could be traveling -- they could be traveling at different speeds because of the --

THE COURT: And is that how you believe there's this -- I guess you call it transfer during the trip up to the surface between oil and gas back and forth?

THE WITNESS: Yeah. The oil bubbles would give off additional gas -- or, I mean, the oil droplets would give off additional gas bubbles and they would -- you know, in the turbulence of all these rising droplets and bubbles, if they should happen to encounter another gas bubble, they would easily coalesce with that gas bubble.

They may then equilibrate with that bubble and they may break apart again. But the bubbles will tend to coalesce together and the droplets will tend to coalesce together. But it's my opinion that the bubbles and the droplets won't -- won't mix together for any appreciable time to re-equilibrate. And so the gases that evolve from the rising oil bubbles will end up mixing with the other gas bubbles, and the liquid that condenses from the rising gas bubbles will end up mixing with the rising oil droplets.

THE COURT: Okay. Go ahead.

BY MS. CROSS:

Q. Do both you and Dr. Whitson assume that there would be separate oil and gas streams?

A. That's correct.

MS. CROSS: And turning to the results of Dr. Whitson's analysis, could we please have D-22009.

BY MS. CROSS:

Q. Dr. Zick, can you explain what shrinkage factor Dr. Whitson derives from his oceanic separation model?

A. Yes. He gets a shrinkage factor of about 46.7 to 48.0 barrels of stock tank oil for every 100 barrels of initial reservoir fluid. Depending on the exit temperature that he assumes for the well, the higher that temperature, the more hydrocarbon -- the more liquid-like hydrocarbons will -- will go into the original gas stream and those he doesn't account for, as well, so that would produce a lower shrinkage factor, the 46.7.

Q. Can you explain why the shrinkage factor of 46.7 to 48.0 is reduced in this slide to 43.3?

A. Well, this is where he applies his separate dissolution theory. So he takes the stock tank oil that results from his oceanic separation, the 46.7 to 48 barrels, and then he removes all of those light hydrocarbons that he claims should dissolve readily in the water. And that reduces the volume of the stock tank oil to approximately the same volume that he says he would get from his single-stage separation.

He doesn't offer any of the exact calculated results in his report, but he just says that after you remove those components from his oceanic separated stock tank oil, you get basically the same amount as you would get from the single-stage separation, which he reports is 43.3 barrels.

Q. I'd like to turn now to another expert offered by BP and Anadarko, Dr. Blunt. Did you review Dr. Blunt's report?

A. Yes.

Q. Do you have an understanding of whether Dr. Blunt applied Dr. Whitson's separation analysis?

A. No. He didn't apply any of Dr. Whitson's separation analyses directly. Dr. Blunt offered -- or he adopted the single-stage separation model, and he chose an experimental value from the -- one of the lab reports. The only mention he makes of Dr. Whitson's analysis is to use Dr. Whitson's observation that if you perform Dr. Whitson's oceanic separation and remove the soluble -- the water-soluble components, that you get about the same result as a single-stage separation.

05:25 So he uses that observation to bolster his argument for using single stage. And he also claims that Dr. Whitson supports the idea of using a single-stage separation directly as well.

I didn't read that from Dr. Whitson's report. Actually, Dr. Whitson doesn't come right out in his report and make a recommendation. He provides the shrinkage factors for the single-stage separation, the four-stage separation, his oceanic separation at two different exit temperatures, and then he makes the claim that the result of removing the water-soluble components from those stock tank oils would result in about the same amount as single-stage separation, but he doesn't actually provide that calculated shrinkage factor separately.

And I didn't see any real recommendation from him as to which process to use.

Q. How does Dr. Blunt characterize the difference between four-stage separation and single-stage separation?

A. Well, he says in his report that a multi-stage separation process is the normal way that oil companies produce their fields in order to maximize the amount of stock tank oil, and yet he disregards that normal production separation scheme and says that the single-stage separation scheme is more appropriate in this case.

MS. CROSS: Could we please see

TREX-11553RNoHC-2.27.1.US.

BY MS. CROSS:

Q. Is this the excerpt from Dr. Blunt's report that you're referring to?

A. Yes.

MS. CROSS: And could you please call up D-24467.

BY MS. CROSS:

Q. And, Dr. Zick, this is a slide from BP's opening statement characterizing Dr. Blunt's reasons for accepting single-stage flash -- or advancing single-stage flash as the appropriate methodology. I'd like to question you about his five points.

Dr. Blunt says that single-stage flash is standard in the industry. Do you believe that to be the case?

A. Well, not exactly. It's -- it's standard -- it's a standard experiment performed by the laboratories in the process of performing compositional analyses. And if an engineer were told to simulate a field with no information about how the surface processing would be done, he would be likely to assume single-stage flash just to be able to perform some calculations.

But it's not the -- it's not what would be standardly applied in the field to perform the separations. It's just too inefficient. The oil companies would lose a lot of money by doing single-stage separations in the field instead of a multistage separation.

05:29 **Q.** Let's turn to the second bullet. "Unambiguous, don't need to know conditions on any given day."

05:29 For a four-stage separation or an oceanic separation, do you need to know the conditions on any given day?

05:29 **A.** Well, you need to know the conditions, but in this case we do know the conditions. We have the conditions for the four-stage separation that were specified by BP and experimented upon by all the laboratories.

05:30 And for the oceanic separation process, it's not too difficult to determine the temperature and pressure profiles within the ocean that are used to simulate that process.

05:30 **Q.** And with regard to the third bullet, "realistic, oil and gas will stay in equilibrium," what is your opinion about whether that is an accurate statement scientifically?

05:30 **A.** Well, neither Dr. Whitson nor I believe that assumption. Both of our oceanic separation models assume that the oil stream and the gas stream will remain isolated from each other.

05:30 **Q.** The fourth bullet: "Approximates Whitson's oceanic process."

05:30 Do you believe that, in fact, single-stage flash approximates Dr. Whitson's oceanic process?

05:30 **A.** No, it doesn't. It only approximates Whitson's oceanic process if you then subsequently remove all of the water-soluble hydrocarbons, then you get about the same shrinkage factor, but it doesn't approximate Dr. Whitson's

oceanic process directly.
Q. Finally: "Conservative, other processes would result in less oil released."
Do you believe that's accurate?
A. No, that's not true. Of all the processes that we're looking at in this study, the single-stage separation process produces the least amount of stock tank oil.
MS. CROSS: Could you please pull up D-22013?
BY MS. CROSS:
Q. Dr. Zick, could you please explain what this demonstrative shows?
A. This shows on a line to scale the different shrinkage factors in terms of barrels of stock tank oil per 100 barrels of initial reservoir oil that have either been proposed or recommended in this case, ranging from the value used by Dr. Blunt on the far left to the two values on the far right and highlighted in yellow, which are the ones that I can recommend.
Q. To summarize, what is your opinion about the appropriate shrinkage factor to be used in this case?
A. Well, it's my opinion that the most appropriate shrinkage factor would be the one from my oceanic separation model and -- because I believe that that would best represent how the ocean itself would separate the fluids.
Q. What is that shrinkage factor?

A. It would be about 50.6 or 50.7.

Q. What is the shrinkage factor for your four-stage separation?

A. That's about 49.4, about 2 1/2 relative percent less or a little more than one barrel per 100 original reservoir barrels difference.

MS. CROSS: Thank you. I pass the witness.

THE COURT: All right.

MS. KARIS: Your Honor, I am not going to finish today.

THE COURT: I'm sorry?

MS. KARIS: I'm sorry, I'm not going to finish today.

THE COURT: That's okay. We'll go to at least around 6:00. When you get around 6:00, tell me when it's a convenient place to break for you.

MS. KARIS: Great. Thank you.

CROSS-EXAMINATION

MS. KARIS: May I proceed?

THE COURT: Yes.

MS. KARIS: Thank you.

BY MS. KARIS:

Q. Good afternoon, Dr. Zick. Hariklia Karis. For the record, I have you on cross-examination on behalf of BP.

Now, you're offering opinions in this case on two separate topics. One is the equation-of-state fluid

characterization model; is that correct?
A. That's correct.
Q. And the second one is the separator process that you recommend be used; correct?
A. That's correct.
Q. And you recognize the issue of what the proper separator process to be used in your own opinion is a legal issue for the Court to decide?
A. Yes, that's correct.
Q. Okay. Now, to back up, you are not offering an opinion on what the cumulative flow from the Macondo well was; correct?
A. That's correct.
Q. And you're also not offering any opinions on what the daily flow rate for any particular day from the well was, regardless of which separator process is used; correct?
A. That's correct.
Q. You're not offering even any estimates as to the amount of flow coming out of the well on any day using any separator process; correct?
A. That's correct.
Q. Likewise, you are not offering any opinions on the pressures that were encountered by the Macondo reservoir fluids between the reservoir and the point that they exited at the ocean; correct?
A. Between the point they exited at the seabed, correct.

Q. So you're not offering any opinions as to either the pressures or the temperatures encountered by the Macondo reservoir fluids between the reservoir at the point that it exited into the ocean at the seabed; correct?

A. Correct.

Q. And I know you mentioned Dr. Blunt. Just to be clear, you have no opinions regarding the compressibility of the rock or what effect that had on any of the oil that was coming out of the reservoir; correct?

A. That's correct.

Q. You, likewise, have no opinion regarding what effect erosion or similar issues had with respect to the oil coming out of the reservoir; correct?

A. That's correct.

Q. Now, I want to talk a little bit about your experience in doing equation-of-state fluid characterization. You performed approximately four to six equation-of-state fluid characterizations while you were with ARCO; correct?

A. Correct.

Q. And then similarly, during your time with Zick Technologies, your company, you developed approximately another 12 to 15 equation-of-state models yourself; correct?

A. Yes.

Q. And then you've developed an equation-of-state characterization model for purposes of this case?

A. Correct.
Q. Now, approximately half of your work, about 50 percent of your work has involved software development as opposed to equation-of-state modeling; correct?
A. Yes.
Q. Now, you testified briefly about your critiques of Dr. Whitson. You know Dr. Whitson for years; correct?
A. That's correct.
Q. You're aware that he has been retained by BP to offer opinions in this case on fluid characterization and separator processes, the same subjects you're talking about?
A. Yes.
Q. And you're aware -- or are you aware that he has done over 200 equation-of-state fluid characterizations?
A. I don't doubt that.
Q. Okay. You used a software called PhazeComp?
A. PhazeComp.
Q. PhazeComp. Excuse me. PhazeComp with a Z, P-H-A-Z-E-C-O-M-P, for the record; correct?
A. That's correct.
Q. And you were the author of that program?
A. I was.
Q. Dr. Whitson's company actually financed the creation of that program; correct?
A. It provided partial financing for the creation of that

program.

Q. All right. And you consider PhazeComp to be state of the art, to use your language?

A. That's correct.

Q. In fact, in your opinion, you wouldn't use anything else if you were doing equation-of-state characterization; correct?

A. That's correct.

Q. And in your opinion, it is the most reliable way to determine the fluid characterization using equation-of-state modeling; correct?

A. I would say so.

Q. Okay. Now, have you looked at which of the government's experts have used the model that you contend to be the most reliable way to do fluid characterizations; yes or no?

A. The equation-of-state fluid characterization model or the --

Q. Yes. Yes, the one that you developed.

A. I'm not exactly sure what they ended up using, but I think Dr. Kelkar has used it.

Q. All right. We'll talk about that briefly. But it sounds at least like you looked at which of the United States Government that looked at fluid characterization used the model that you contend to be the most reliable; correct?

A. Yes.

Q. Now, before we go to that, I want to discuss briefly your opinion of Dr. Whitson since you offered some critiques of his work. It's correct that you used to have a close personal and professional relationship with Dr. Whitson; correct?

A. That's correct.

Q. And approximately three to five years ago, you guys had a falling-out, but you still respect him professionally?

A. That's correct.

Q. And you agree that Dr. Whitson is proficient in equation-of-state fluid characterization modeling?

A. Yes.

MS. KARIS: If we can look at 11492.2.2, please.

BY MS. KARIS:

Q. Dr. Zick, do you recognize this as a recommendation you wrote for Dr. Whitson?

A. Yes, I wrote this recommendation for the LinkedIn website about six years ago, I think.

Q. And the Curtis, you say, "I have known Curtis for over 20 years," that's Dr. Curtis Whitson; correct?

A. That's correct.

Q. And you say you've known him for 20 years, you've collaborated with him on many projects during that time. And then you go on to write that, "He wrote the book, literally, on reservoir fluid characterization and phase behavior"; correct?

A. That's correct. I'm referring there to his SPE monograph entitled "Phase Behavior."

Q. And in your opinion, as you stated here, "There is no one in the world with more experience in these areas"?
A. Expertise.
Q. I'm sorry. Expertise. Thank you for correcting me.
A. Yes. That's what I stated.
Q. And you still hold that belief today, don't you?
A. Yes, that's still a true belief.
Q. Dr. Whitson's book on phase behavior, monograph, is that one of the materials that you relied on in reaching your opinions in this case?
A. Yes, I referred to it during the -- yes.
Q. And you agree that it is the book for fluid characterization and phase behavior?
A. It's the best reference source that I know of that's been written on the subject.
Q. Okay. Now, let's talk a little bit about equation-of-state models in general. You agree that the way to judge the accuracy of an equation-of-state model is to look at how well your model matches measured data; correct?
A. That's one of the criteria, correct.
Q. And the measured data for the equation-of-state modeling that you did was samples that were taken from the Macondo reservoir and tested at three different laboratories; correct?
A. Correct.
Q. And those laboratories would be Schlumberger, Pencor --

A. Yes.

Q. -- and I think Intertek you said?

A. Yes.

Q. And you did, in fact, look at those samples and rely on those samples in building your model?

A. Yes.

Q. And I heard you express some disagreements that you had with Dr. Whitson, minor I think you characterized them, with respect to his equation-of-state model. But just to be clear, both you and Dr. Whitson used the Peng-Robinson 1978 equation of state. You both started from the same baseline; correct?

A. That's correct.

Q. And overall, you believe that Dr. Whitson created an equation-of-state model that accurately predicts the most important fluid behaviors for the Macondo well fluids; correct?

A. For the most part, yes.

Q. And you call it -- in fact, quote, you say his model -- you consider his model to be a good model; correct?

A. Yes, for the most part.

Q. Okay. And, in fact, I think it's your opinion that you think Dr. Whitson's equation-of-state model is better than yours in predicting some parameters and in other parameters you view yours as slightly better than his?

A. That's correct.

Q. And so to be clear, you are not critical of the overall conclusions of Dr. Whitson's model because, again, as you said, it's a good model?

A. Yes. I -- the calculations that he made with his model are valid to within the uncertainties between his model and mine, I would say.

Q. And you called his model a good model -- a good EOS model; correct?

A. For the most part.

Q. Okay. Now, we talked about -- briefly you talked about your equation-of-state model. I think I heard you testify that you built that model based upon some data that had came from the various labs.

You saw the four reports; correct?

A. That's correct.

Q. And the data that the various labs looked at, that basically looked at the volume of liquid oil at stock tank conditions -- at different stock tank conditions; correct?

A. That amounted to about .8 percent of the available data.

MS. CROSS: Okay. And just to be clear, if we can pull up 11490R.34.1.

BY MS. CROSS:

Q. And this is from Appendix C of your report. You recognize this table; correct?

A. Yes.

Q. And what you have charted here on the left-hand side are

05:47 the different samples that you looked at. You've got Intertek, you've got PENCOR, and then samples from each of those companies and then some of the conditions. And one is atmospheric flash and the other one is multistage separator test; correct?

05:47 **A.** Correct.

05:47 **Q.** And is the atmospheric flash the same as single-stage flash?

05:47 **A.** Yes.

05:47 **Q.** And then the multistage flash, that's the four-stage flash that you told us about; correct?

05:48 **A.** Correct.

05:48 **Q.** Okay. And you looked at the test results that existed for those models both at single stage as well as multistage; correct?

05:48 **A.** That's correct.

05:48 **Q.** Now, part of the analysis in looking at going from a single stage to a multistage separator test is to look at how much gas and liquid is separated at some points in time in the process based on temperature and pressure changes; correct?

05:48 **A.** Yes.

05:48 **Q.** And the reservoir temperature for Macondo was approximately 243 degrees Fahrenheit?

05:49 **A.** Yes.

05:49 **Q.** And the initial reservoir pressure was approximately

11,800 psi; correct?

A. 11,850 is the value I assumed.

Q. 11,850.

And you agree that as fluid rises, temperature decreases?

A. As fluid rises from where to where?

Q. From the wellbore to the surface.

A. From the wellbore to the --

Q. From the reservoir -- I'm sorry. If I can correct myself. As fluid is released from the reservoir, it rises through the wellbore up to the surface, the temperature decreases?

A. I believe so, but that's not what I -- I didn't look at that. I didn't try to model that, so I'd rather not speculate.

Q. Okay. And did you look at whether the pressure also decreases as fluid rises from the reservoir up to surface?

A. Yes. That would have to occur.

Q. Now, you said you didn't look at whether the temperature changes, but you're aware that at stock tank conditions, that's approximately 60 degrees Fahrenheit; correct?

A. Yes. But now we're talking about outside of the well and outside of the ocean.

Q. Okay. And you didn't look at what point in time it gets to that 60 degrees Fahrenheit other than outside the well and outside the ocean?

A. Well, actually, it never reached those -- that temperature because the -- well, no, that's not true. Somewhere between the seabed and the surface of the ocean, the temperature will be 60 degrees, because it's 40 degrees at the seabed and roughly 80 degrees at the surface. So somewhere in there, the temperature will pass the 60-degree point, but at higher pressure than 1 atmosphere, of course.

Q. But you didn't look at what point in time that happens, is my point.

A. I could -- my models included pressure at that point from which you could determine the approximate depth, but I don't know at what -- how long it would take for the fluids to float from the seabed to that point.

Q. Is it fair to say that your equation-of-state model overpredicts the amount of stock tank oil when compared to the laboratory results no matter which surface process is used?

A. For the four-stage separation process, that's true. But for the single-stage process, that is not true.

Q. Okay. If we can look at your deposition, 346, lines 4 to line 10.

BY MS. KARIS:

Q. Were you asked the following question, "Is it fair to say that your equation-of-state model overpredicts the amount of stock tank oil when compared to the laboratory results no matter what surface process is used?"

And did you give the following answer, "For the --

for the measured surface processes, it slightly overpredicts, yes"?

Did you give that answer?

A. Yes, apparently I did, but I mis-- I misspoke slightly. Because there are -- on at least one of the single-stage processes, my equation of state actually underpredicts the stock tank oil.

Q. Now, you produced a comparison of your equation-of-state stock tank oil figures as opposed to the measured or laboratory data stock tank barrel predictions or calculations; correct?

A. Yes, I have.

MS. KARIS: Your Honor, I'm happy to stop here because we're going to go into this table, which will take some time, but whatever the Court pleases.

THE COURT: All right. We can recess.

It's 10 minutes to 6:00. We'll recess until 8:00 a.m. tomorrow morning.

Before we leave, I have a question. There's an issue that Ms. Himmelhoch reminded me of -- somebody reminded me of a pending U.S. motion regarding the issue of whether oil that is allegedly dissolved in water should be counted or not.

MS. HIMMELHOCH: Yes. We have a pending summary judgment motion. It was Ms. Cross, but, yes, we did remind you of that, sir.

THE COURT: So it's also this -- also the subject of a motion in limine; right?

MS. HIMMELHOCH: That is correct, Your Honor.

THE COURT: So it's all the same issue.

So who is going to respond to that for BP -- first of all, when is -- is it Dr. Whitson? When is he expected to be called to testify?

MR. BROCK: I don't think he'll be this week. It's likely next week. We're doing some juggling on the scheduling now for Thursday.

THE COURT: Maybe what I'd ask you all to do, then, is to file a response.

Have you filed a response?

MS. KARIS: We have, Your Honor.

THE COURT: You have. Okay.

MS. HIMMELHOCH: On the motion in limine, they have. On the motion for --

THE COURT: If it's the same issue, then I don't want people to repeat what they've already done.

MS. KARIS: I'm happy to give the Court a copy if you like.

THE COURT: No, I must have it here. I have a package. I just haven't read it yet. I'm sorry. I didn't realize that just a second ago there was the same issue raised in a motion in limine. I thought we only had the motion for summary judgment.

So I'll look at that between now and before Monday or by Monday, so I may be able to rule on that. Okay.

MR. BROCK: We return on Tuesday next week.

THE COURT: That's right.

MS. HIMMELHOCH: You gave all of us a little bit of a heart attack there, Your Honor.

THE COURT: Well, actually, I wanted to work on Monday, but with all this crazy stuff going on in Washington, the marshals told me I would put a serious dent in their budget if I -- which they have little of now. So they convinced me not to hold Court on a federal holiday.

MR. BROCK: Just for planning, do you all know if we'll see Dr. Pooladi-Darvish or Dr. Kelkar after this witness tomorrow?

MS. HIMMELHOCH: We'll go in our stated order, Your Honor.

THE COURT: So next would be Dr. Kelkar?

MR. O'ROURKE: Yes, sir.

THE COURT: And then Dr. Pooladi-Darvish; correct?

MR. O'ROURKE: With a 15-minute video deposition in between. So we're assuming we're going to be finished tomorrow, depending on the cross-examinations.

Are you going to address Thursday? People don't know what's coming.

MR. BROCK: Thursday, my plan is to have Dr. Martin

Blunt here. He has arrived, but I haven't talked to him yet, so just to make sure everything is okay with that.

If there is any change to that, I will let you know as soon as I get back.

MR. O'ROURKE: Who's the second witness?

MR. BROCK: Right now...

MR. O'ROURKE: You're sticking with the same order?

MR. BROCK: No. I don't recall who we've got second.

THE COURT: You received their order of witnesses? It's in here? You put it in here? Okay.

MR. O'ROURKE: I think he's changing it.

MS. KARIS: I think, Your Honor, one of the issues is just getting people here, because a lot of our witnesses are traveling. We weren't expecting that you would be done this early. That's what Mr. Brock is addressing.

THE COURT: You still expect that Martin Blunt will be your first witness?

MR. BROCK: Yes, sir.

THE COURT: Whenever that is.

MR. BROCK: Whenever that is. It sounds like it will be first thing Thursday morning. He will not be ready tomorrow afternoon, so if we get to tomorrow afternoon --

THE COURT: Well, I don't think it's likely we'll get to him tomorrow afternoon.

MR. BROCK: We'll start with him first thing on

Thursday morning.

And I don't think we have Dr. Zimmerman in town yet, so I don't think he would be the next --

THE COURT: So if he's not here and we get past Blunt, who would be your next witness, likely?

MS. HIMMELHOCH: Dr. Gringarten is next on their list, and I know he's in town because I've seen him.

MR. BROCK: I don't think that's the order in which we prefer to call our witnesses. We could do Dr. Whitson. I actually need about 15 minutes just to chat with the team just to see what we can do --

THE COURT: Maybe you can let them know this evening.

MR. BROCK: I will just as soon as we get back.

MR. O'ROURKE: Your Honor, we have to prepare. This is the day after --

THE COURT: He's going to let you know this evening.

MR. O'ROURKE: What time?

MR. BROCK: Well, we'll get back at 6:15, and I'll get a note to you about 6:45.

MR. O'ROURKE: Thank you.

THE COURT: Anything else before we recess?

All right. See everyone at 8:00 a.m.

THE DEPUTY CLERK: All rise.

(WHEREUPON, the proceedings were concluded.)

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CERTIFICATE

I, Jodi Simcox, RMR, FCRR, Official Court Reporter for the United States District Court, Eastern District of Louisiana, do hereby certify that the foregoing is a true and correct transcript, to the best of my ability and understanding, from the record of the proceedings in the above-entitled and numbered matter.

s/Jodi Simcox, RMR, FCRR
Jodi Simcox, RMR, FCRR
Official Court Reporter

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