BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

ADMINISTRATIVE LAW JUDGES JESSICA T. HECHT and MARCELO POIRIER, co-presiding
COMMISSIONER CLIFFORD RECHTSCHAFFEN, in attendance

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Gas Company with Respect to the Aliso Canyon storage facility and the release of natural gas, and Order to Show Cause Why Southern California Gas Company Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from its Aliso Canyon Storage Facility. (U904G)	)	EVIDENTIARY HEARING Investigation 19-06-016

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I N D E X

VIRTUAL HEARING

MARCH 23, 2021 - 10:06 A.M.

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ADMINISTRATIVE LAW JUDGE POIRIER: We will be on the record.

Good morning. This is ALJ Marcelo Poirier. It's March 23rd, 2021. This is day six of the evidentiary hearing in Investigation 19-06-016, the Aliso Canyon Judicatory OII.

Prior to going on the record, we had a discussion on the timing and schedule of the proceeding and the impact of that on service of cross estimates. It appears that as of now that the schedule that has been distributed including right now, the cross of Mr. Krishnamurthy, and the cross of Cal Advocates' witnesses by SoCalGas is consistent with the schedule that was distributed.

As that situation changes or if it does, we've instructed the parties to confer so that we have an accurate understanding of the schedule moving forward. And that parties have a good understanding of when they need to serve those cross-examination exhibits in conformance with the instructions of the assigned ALJs.

We left off yesterday with Mr. Lotterman crossing Dr. Krishnamurthy.

Mr. Lotterman are you ready to continue?

MR. LOTTERMAN: I am, your Honor.

ALJ POIRIER: Okay. Please go ahead.

RAVI KRISHNAMURTHY,

resumed the stand and testified further as follows:

CROSS-EXAMINATION RESUMED

BY MR. LOTTERMAN:

Q Good morning, Dr. Krishnamurthy, how are you?

A Pretty good. Thank you.

Q All right. We left off yesterday discussing whether Blade was able to determine when the corrosion on the exterior of that production casing on SS-25 began. Do you remember that?

A Yes.

Q And I believe you told me that there was no reliable data, or at least Blade found no reliable data as to when the groundwater replaced the drilling fluid in that annulus; is that right?

A Correct.

Q And I believe you also said that Blade also was unable to find any reliable

data as to when those SS-25 well connections began to seep and began feeding carbon dioxygens (sic) to the methanogens; is that right?

A Correct.

Q Right. And so when I asked you, "Does that mean therefore that Blade was unable to determine when the corrosion began?"

You said that, "That is correct."

And that if I were to press you to give you a date, you would be guessing. Is that still your testimony?

A Yeah. It would be a hypothesis. It would be nonfactual; that's correct.

Q Fair enough. Fair enough. What you did say though, which I had not focused on before and I wanted to just pursue this very briefly is you said that:

Under your hypothesis, that corrosion did not start in 1953 when the original well was drilled.

Correct?

A That's correct, yeah.

Q And if I understand your answer -- and kind of a light went off in my head at that point. That's because under your

hypothesis, those methanogens were fed by carbon dioxide, and that could not have started until SoCalGas converted the well in 1977 to gas injection. Did I get that right?

A Yes and no. Let me explain that because I don't -- they were doing gas lift operation to produce the oil. So I don't know what gas was used to gas lift. So I wouldn't be comfortable reading research how oil well was operated over pre-gas storage operations. So you would have to look at that to confirm it.

But there are two items there. And this was the hypothesis portion of it. Is until you started storage gas operations, the loading on the connections wouldn't be at the level at which you may start seeping. So you're interpretation is a fair interpretation.

Q Right. And to maybe put a little more blunt focus on it, I guess what you're saying is although you didn't rule out the hypothesis that the corrosion began before the well was converted in 1977, you believe it's more likely that the corrosion began afterward; is that fair?

A That's fair.

Q All right. Thank you. So I want

to -- also I want to next talk about corrosion rate.

And I'm going to ask Mr. Moshfegh to put up a portion of one of your supplemental reports, and I'm going to identify it for the record. It is taken from Commission Exhibit-1002. And that's Volume II of Blade's report. And it's a supplementary report entitled "SS-25 Casing Failure Analysis." And it's dated May 31, 2019.

Do you see that, Dr. Krishnamurthy?

A Yes, I do.

Q All right. Mr. Moshfegh, would you turn to page 209? And it's section 5.6 entitled "Corrosion Rate. And would you focus and highlight on that second paragraph, first three-and-a-half sentences -- lines, please.

Can you read that, Dr. Krishnamurthy?

A I can see it, yeah.

Q All right. So what you say there -- what Blade says there is:

> The exact corrosion rate for the seven-inch casing, which is the production casing that corroded here,

cannot be predicted because of the limited information about the condition of the well. Particularly the PH, alkalinity, temperature, and composition of the fluid in context with the seven-inch casing OD over the entire life of the well.

And you also say, and I think this is consistent with what we just talked about. You say:

Also the start of the corrosion attack is not documented.

So I think we've talked about the second sentence, and I want to focus on the first.

So is it true today, as you wrote in 2019, that the exact corrosion rate that under your hypothesis attacked SS-25 cannot be predicted?

A That's correct.

Q All right. And I understand the PH and the alkalinity and the temperature, because I believe we talked about some of that earlier with drilling fluids et cetera,

et cetera.

But I was intrigued by the next sentence. You say:

In addition the changes in season in Aliso Canyon could also --

I assume have affected.

-- the factors previously mentioned.

Would you explain to the Commission how the changes of season could have affected the conditions which in turn would have affected the corrosion rate?

A Okay. The changes in season here references the extent of precipitation and the precipitation that gets to those depths.

A lot of those are impacted by the hydrochemical reactions, the water level as it seeps through the clay and various formations to the thousand feet, the pathway of that. So that is affected by season the quantity, temperature, voracity. So there's many factors that drive it. That's really what we imply there.

Q Okay. And is what you're saying basically: In rainy seasons, that wellbore and the annulus might have more groundwater. In the dry season, it might have less. That

would vary and that in turn would affect the corrosion rate?

A Yes; that's correct.

Q Okay. All right.

A Yes. And depending on where you're measuring or trying to predict, it can be different. Yes; that's correct.

Q And I also believe you say in your report, and you certainly explain to us in your deposition, that the corrosion rate itself in addition to your not being able to predict it vary -- or could vary over time; is that true?

A Yes.

Q All right. I believe you called it a "time dependent process" in the deposition. Would you explain what you meant by that phrase?

A Yeah. Again, the microbiological mechanism that we talked about, it's a biochemical reaction, okay. And it's a biochemical reaction dependent in this particular case as a percent of -- probably a (indecipherable) for the methanogens.

And then on top of that, you have what is called a "biofilm." And inside the biofilm there is an environment, there is a PH, there is an alkalinity. You can not look

at the bulk pH and bulk alkalinity for predictions. And that would change with time.

And on top of that as the corrosion reaction happens, you form a corrosion product. And then corrosion product will change the rate of corrosion. So many factors such as those will define how we change over time.

Q And when you say "corrosion product," are you referring to for example the scales that can form on the side of the pipe once the corrosion starts?

A That's correct. In this particular case in the local regions because the corrosion was localized. In the '80s if it was corroded, it would change with time. Yes.

Q And is it your view -- and I believe this is correct. But is it your view that -- and this sounds counterintuitive to me, but I believe it's true.

Is it your view that those scales can actually form a protective layer on the pipe and either frankly enhance the corrosion or protect against it?

A It normally will not enhance. Most of the time the scales will reduce the

corrosion rate. That is well known. You have mass transferred through the scale depending on the diametric on the scale and the nature of the scale. All of those define the rate of corrosion. But, yes, your interpretation is correct.

Q Okay. And when you extracted that pipe from SS-25 in 2017, you actually saw kind of variable corrosion rates on the pipe itself, didn't you?

A Correct.

Q I mean --

A May I clarify? I want to be clear there. I did not see variable corrosion rate. I saw variable corrosion depths. Yeah? That's what I would state.

And the reason I clarified that is it may be 5 percent in one location, 85 percent in another location. Which implies one location started early, the other location started later. So the rates may be the same, but the depths are different.

Q Okay. Got it. And as you point out in your -- in this Section 5.6 in the bottom paragraph, which we don't need to highlight. But you actually say that controlled lab studies were not informative in this case because lab conditions can vary

from field conditions; is that accurate?

A Yeah. It's difficult to simulate the condition, the condition of methanogens and, you know, the people do the work to accelerate the behavior.

But what happens in nature and the real world takes a bit more time. Like in this particular case, it took a long time. And so, yeah, simulating that in a lab is very challenging.

Q And I would think so. Because obviously if you have varying climates and rainfall and the like at the Aliso Canyon facility, I mean how would you accurately replicate that in a lab? You couldn't; right?

A Correct.

Q All right. Okay. So bottom line as you say in this 5 -- Section 5.6:

Blade was unable to predict
the exact corrosion rate
for SS-25.

So if that's the case if you are unable to determine when the corrosion started or what its rate was once it started, does it logically follow that Blade can't say with any certainty when that corrosion would have been detectable on SS-25?

A That's correct.

Q Okay. All right. And by the way, I believe you said this in the deposition. I couldn't find it in your Blade -- in your report. Did you also conclude that the rate was unlikely to be linear with time?

A No. Normally, you know, for simplistic analysis and planning purposes you would use a linear estimate. But in reality corrosion is not linear, it's exponential. And it will be a function of the scale and temperature and various factors. So it is not going to be linear.]

Q All right. Thank you. Okay. Let's move on. And I'm trying to get through this as quickly as I can without our stepping on each other, and I think actually we're doing a pretty good job this morning.

So one of the other aspects of your root cause analysis was examining the past field-wide practices of SoCalGas at the Aliso Canyon facility; is that true?

A Yes.

Q And in your business, that's called O&M, or operations and maintenance; right?

A Correct.

Q And so you went into the records for the various Well Files, et cetera, et

cetera, into SoCalGas' internal gas policies and that type of thing and you examined what those O&M practices were; is that true?

A Yes, we did.

Q You identified a number of leaks that you believe occurred over 40 years, and I believe our expert has taken issue with some of that and there's some back-and-forth about shoe leaks and stage collar leaks and all that stuff. I'm going to table that for now because what I want to focus with you on this morning is what patterns, trends, or correlations you found when you did that analysis; okay?

A Yeah.

Q All right. So there is a volume on this. It's actually in the same volume we're looking at, so let's stay with the same report. I want to turn to -- lost my place here. Excuse me. You know what? Let's do this: Let's turn to -- well, let me back up. I got it.

ALJ POIRIER: Off the record.

(Off the record.)

ALJ POIRIER: We'll be back on the record.

Please continue, Mr. Lotterman.

BY MR. LOTTERMAN:

Q Dr. Krishnamurthy, like I said, I'd like to focus on any patterns, trends, or correlations you found when you investigated the O&M practices of SoCalGas. I'd like to sort of summarize your findings and we can walk through them and talk about them as much as you deem necessary.

First of all, you found that casing failures were not concentrated in one specific area of facility or well location; is that correct?

A Yes.

Q So when we saw that expanse of the foothills of the old mountain and, in fact, we showed that diagram of where the field was divided into three sectors, there wasn't one particular sector that was more corrosive than the other or it wasn't by terrain or anything like that, no correlations about specific area; true?

A True.

Q And, in fact, I think you observed in the main report that you found adjacent wells to each other that often showed differences; true?

A True.

Q Okay. I believe you also concluded that you found no correlation at Aliso Canyon

regarding geology; right?

A True.

Q What was the hypothesis you were pursuing there?

A Can you ask me the question again, please, Mr. Lotterman. I apologize, I lost it.

Q Okay. Glad to. I was noting that your report observes that you found no correlation between corrosion and geology at the Aliso Canyon facility. My question is what hypothesis were you testing there?

A Got it. I'm with you. Okay. No. See, if you look at the SS-25, the failure happened in a basalt, if I remember right. There is a formation above. There's a formation below.

So we were wondering if there was anything in the formation that may be contributing -- even though the formation is outside of the surface casings, this is inside the production casing -- we were trying to look for anything specific formation that could be systemic across the field or across -- you know, depending, on west, central, or eastern zones. And we were looking for any contributory factors from formation such as water.

You could be -- you could be water permeable or water-containing zone that may be contributing some highly-corrosive liquids or water. So that was some of the thinking. And of course we were also looking at geotechnical or other such parameters. So we wanted to eliminate that. That was the intent of that exercise.

Q Okay. And, in fact, you did; right?

A Yes, we did.

Q Okay.

A Yes, we did.

Q And by the way, I believe you mentioned a geologist at SoCalGas who assisted you with the root cause analysis and you said -- was that Hilary Petrizzo?

A Yes.

Q All right. Thank you. Just wanted to clarify that. You also didn't find any correlation between corrosion and converted or newly-drilled wells; fair?

A That's correct.

Q Right. So to sort of set the stage there, obviously SoCalGas converted a number of wells at Aliso Canyon when it took control of the facilities in the 1970s, and we talked about that earlier, but they also, during

that 38-year time period, drilled new wells; right?

A Yes, that's correct.

Q And your analysis of the records that were available to you indicated that there were not necessarily more issues with older wells or newer wells, there was no correlation you were able -- it was about 50/50 is what I recall from your report; is that correct?

A That's correct.

Q Okay. You also -- I think this is along the same lines, I suspect, since many of the converted wells are older than the newer wells -- but you also found no correlation between corrosion and the age of a well, did you?

A No.

Q Did you expect that?

A Yeah. I -- it is, again, a bit of a common tendency to -- to -- I'm looking for a word, but I want to be careful which word -- to automatically characterize older wells are more at risk. In my experience that is not true for most of the structures. It is the environment, it is the condition that it is exposed to, a lot of those parameters come into play so you have to be

cautious about -- or just correlating with age. I am not surprised honestly.

Q All right.

A I was not surprised.

Q And then just to wrap up a couple topics, you found no correlation between corrosion and depth of surface casing shoe; true?

A I don't know. Depth of surface casing shoe. So the location of -- again, I'm not sure about that. I can't recall that particular conclusion, specific conclusion. We did look for the wells that had wall thickness inspections. We analyzed them to see if the corrosion was above the shoe or below the shoe. And of course the shoe depths vary depending on which well you're looking at. Some of them are 500, 580, some of them are a thousand, 1,500.

So the shoe depths varies depending on where, you know, which well you're talking about. So I am not -- I don't recall making that particular conclusion, but I'll have to look at my report more carefully.

Q It's not important for these purposes. Did you find any correlation between corrosion and production casing size?

A No. There was more in the

seven-inch, but that was probably because it was more prevalent size. So, no, we did not find a correlation.

Q Did you find any correlation between corrosion and depth of the well?

A Depth of the well. I don't believe so. I don't think so.

Q All right. Did you find any corrosion between -- sorry, did you find any correlation between corrosion and time periods?

A By time periods you mean life of the well; right?

Q No. Actually I was thinking more of, you know, kind of this decade versus that decade versus that decade.

A No, no correlation.

Q All right. Okay. Did you -- when you looked at that -- when you undertook that analysis, did you identify any kind of quiet periods where there didn't appear to be a whole lot of leaks occurring for whatever reason?

A I believe there was. There was a phase where there was a reduction in number of leaks. There's a period where the number of leaks were lower or -- again, I want to -- I want to be careful here. I think we

define and we are very specific about defining. I don't think -- I don't know whether we called it -- when a casing does not perform its function as defined, we call it a failure. Okay. So I want to be careful. And that was the number we were looking for rather than just leaks. Okay.

So, for example, a tight spot -- at that point the casing is not perform -- is not performing its role as it was designed for so we call that a failure. So I want to kind of clarify that. That's what I mean. But there were periods -- I believe there were few periods where the problems were fewer or less. That is correct, to answer your question.

Q All right. Thank you. Appreciate that clarification. All right. So let's go to the back of the report to the grand finale, shall we say. But before we get there, I want to set the stage if I could. I believe you testified yesterday and you actually set it out on page 22 of the main report, the scope of your root cause analysis.

And, Mr. Moshfegh, if we could just sort of highlight that second paragraph under 1.3. That first sentence. There you go.

Just the first sentence, please. There you go.

Dr. Krishnamurthy, as I understood your testimony yesterday and as I read this portion of your main report, there were roughly two goals of your root cause analysis. One is obviously to identify the root causes of the problems or events. And then the second -- and this is what I want to focus our time for this morning -- is defining methods for responding to and preventing them.

Do you see that?

A Yeah.

Q Okay. And is it fair to say that that second piece, the "Defining methods for responding to and preventing them" is more of a forward-looking analysis?

A Yes. If I may explain that a little bit. You are -- in order to figure out in a root cause analysis, in order to figure what were the root causes, you need to see what actions or activities that would mitigate and prevent such incident going forward. So that is the process we used. The RCA process we used looks to define the solutions. And from the solutions you derive the root causes.

Q Right. So let me boil that down so that I can understand it and you tell me if I missed the boat or not. You know, I view the root cause analysis process that you went through is kind of a round trip, and I take this from reading your report, so this is not out of thin air, but tell me if I'm right.

I mean basically you start with the two effects from this incident, the one being the leak, and the second one being that it took 111 days to stop it. And then you go backward through your diagrams, et cetera, and you identify all potential causes for those effects; is that right?

A That's correct.

Q And some of them -- and we'll talk about it -- some of them are, well, tangential and some of them are spot on; right?]

A I wouldn't use the word "spot on." But some of them are tangential and may not have change -- may not have prevented the incident. Some of them would've prevented the incident. That's kind of the categorization.

Q All right.

A I would not say "spot on." That implies this exact event was prevented.

Q Got it.
A So that -- I want to be clear.
Q Got it.
And the best example was -- sort of a really good cause-and-effect was dual barrier, wasn't it?
A Yeah.
Q Because if I understand your analysis correctly, what your root cause analysis says basically is, had SoCalGas been injecting or withdrawing through the tubing only and leaving the production barrier with no pressure whatsoever, or a minimal amount of pressure, and had that production casing corroded to the point of having an anomaly or parting, the gas still would have been contained within that tubing, and we wouldn't have had the leak we had.
So that I view as a cause-and-effect that you think quite important in this root cause analysis.
True?
A True. Yes.
Q Okay. So you go backward from the effects, and you draw these diagrams listing all these potential causes -- and you listed quite a few of them.
But then I think at the end of this

report, you then turn around and go back through those causes, and you try to identify all potential measures for responding to or preventing them; is that right?

A That is correct.

Q And dual barrier is a great example. Because in 2015, and we'll get to this in a minute, it wasn't required. It wasn't a prevailing industry practice.

But your view is, notwithstanding that, underground storage operators like SoCalGas, should implement dual barriers going forward to prevent what happened at Aliso Canyon.

True?

A That was not my role to say what operators should do. Our role was to say, "What are the root Causes?"

And dual barrier is definitely -- as you well articulated -- is a root cause and would have prevented that incident.

Q All right --

A I wanted to clar- --

(Crosstalk.)

BY MR. LOTTERMAN:

Q Excuse me.

That's a very important clarification. Because I take that to heart.

Because what you're saying is, you're not saying what operators like SoCalGas should do. You're saying what could be done to prevent something going forward; correct?

A That's correct.

Q Okay. Good. Good.

And, by the way, this round trip that I talk about, or your analysis that you put forward in your main report, it's not dependent on whether the causes were required by law or regulation; right?

A Absolutely not.

Q Not required -- it's not dependent on whether the causes were required by industry standard.

True?

A That's correct. Yeah.

Their own -- the objective of the exercise of the work was to clearly identify what the root causes are. Whether that is common practice, whether that's regulation or not regulation, doesn't enter our analysis.

We do articulate in one part of our report -- I forget where, Mr. Lotterman -- but we do articulate what the prevailing regulations were and what was the regulation. I believe we do in a portion of the report. But that was not the objective of the -- not

the objective of our work.

Q And, likewise, you don't even really -- you don't Judge, not really.

You don't judge whether such a cause and effect was foreseeable by any particular operator; correct?

A I'm trying to think. "Foreseeable" means something else to me.

Again, our role was to say, What were the root causes? What mitigative practices would have prevented or may have prevented such an incident? "Foreseeable" implies -- I don't believe that's our role.

I'm trying to think, Mr. Lotterman, as we are asking the question. That's a good question. But I don't believe -- our role is to find out the root causes for the Aliso Canyon incident, SS-25 incident, and what were the factors, parameters that contributed to the failure? And from there, deriving root causes, if addressed, will prevent such incident. That's --

Q Understood.

A I want to be --

Q Understood.

A Okay.

Q And that's consistent with what you told us right at the beginning of my

examination, where when I asked you what a technical RCA was, you said -- you explained what it was. And you said, "But let me be clear. It does not address management-related issues."

True?

A That is correct. That was --

Q Okay.

A Yeah.

Q Now, you mentioned the study you did of the regulations pertaining to underground storage. And I believe you looked at both pre-leak and post-leak reservations (sic); is that right?

A Yes, we did.

Q All right.

And you set out these regulations at page 197 of the main report, Section 4.6.

Do you see that?

A Yeah.

Q Okay. And if I understand your analysis, which makes sense, you focused on California gas storage well integrity regulations.

True?

A Correct. I -- I want to -- my memory is weak. But I don't believe, at that point, there were other regulations. I don't

think PHMSA guidelines or regulations came out. Or they may have come out, I don't recall. So...

Q Sir, your memory is not weak. But, as I said before, if you need a lifeline in the report, I'll -- you take it. But I think your memory is actually quite good.

So, again, subject to check, your focus -- because it makes sense. I mean, the Aliso Canyon facility is in California; right?

A Yes.

Q Okay. Did you -- did you also look to find any relevant Federal regulations at the time?

A I believe we did. Again, that's why my memory -- I want to confirm. I don't believe the Federal regulations were either in place or were not complete. I forget -- or they were in that form. The California DOGGR regulations were in detailed, clear form. So that's why we only analyzed that.

Q Fair enough.

I will get to that. I will get to the Federal regulations in a minute. And I can probably give you a pretty good citation for that.

And you note in your discussion of

the main report that there have been significant changes in the regulations since 2015; is that right?

A Yes.

Q Including on the Federal level. True?

A Well, I'm pretty sure. Yes.

Q Do you believe your investigation prompted some of those changes?

A I don't know. I wouldn't want to comment on that. I would ask the folks who drafted it. No, I wouldn't -- no. I'm not --

Q Okay.

A I'm not qualified to comment on that.

Q Okay. Have you worked with a -- or advised any regulators on how to implement the solutions you set out in the root cause analysis?

A No, not in detail.

Q Okay.

A Not the way you're -- not defining the regulations, no.

Q All right. And getting -- all right. Fair enough.

So let’s then look at the

regulations themselves. And I won't take much time on this. But, basically -- and I have this in front of me.

You identify -- you actually wrote a supplementary report. And this is in Volume 4, which I believe is Commission Exhibit 1004. And it's entitled "Gas Storage Well Regulations Review."

Now, I'm not going to go through that report, sir. But I just wanted to -- for the record, to document your earlier testimony that you had done so. And I wanted the record to reflect that that effort is contained in this supplemental report and is summarized in the main report.

Okay?

A Yes.

Q So just so I'm not mistaken, do you see under Volume 4 a supplemental report entitled "Gas Storage Well Regulations Review"?

A Yeah. Yes.

Q And is that the one you were referring to earlier?

A Yeah. I was referring to the main report and the supplementary report. Yes. That's correct.

Q All right.

Mr. Moshfegh, let's go to page 234 of the main report, please.

And while he's pulling that up, Dr. Krishnamurthy, let me sort of set the table on this one as well. So if you look at Table 42, on page 234 of the main report, it's identified "Root Causes and Solutions."

Do you see that?

A Yes.

Q And the first column are all the various -- I call them pods -- but all the various causes that you identified which led to the effect of both the leak and the 111 days that it lasted; right?

A Mm-hm.

Q You then talk about solutions. And we're going to talk about those in a minute.

You then discuss whether they have been addressed by SoCalGas. And I assume that's as of 2019. And then -- this is what I want to focus on, just briefly.

You also have a column called "Addressed by regulation."

Do you see that?

A Yes.

Q And I want to make sure the record is clear as to what you're endeavoring to portray here. That last column, for example,

you say, "not required."

Are you saying that as of 2019, there was no regulation that required the solution that you set forth in the second column?

A That's my recollection. Yes.

Q Good. That --

A And it -- I'm sorry.

It would be specific to the DOGGR regulations. Okay?

Q Fair enough. Fair enough.

Because DOGGR is the primary regulator in California as it comes -- visa vi underground storage facilities; correct?

MR. GRUEN: Objection, your Honor. Asked and answered.

ALJ POIRIER: Overruled. Let’s continue.

BY MR. LOTTERMAN:

Q All right.

And then if you look at the next row, Dr. Krishnamurthy, under "Addressed by regulation," you say, "Yes." But you say, "Included in the latest regulations."

Do you see that?

A Yes. Yes.

Q And does that mean that as of 2015, and we'll go through this in a minute, there

was no regulation that pertained to that particular solution, but there is one today?

A Yes.

Q Okay. And I'm not going to go through all these, but I think that covers it for now. Okay.

So let me pull up something a minute. All right.

So let’s turn to page 231. And if I understand this portion of your report, sir, this is where you lay out the specific mitigation solutions that Blade believes would have mitigated or prevented the primary effect, and that is the uncontrolled release of hydrocarbons for 111 days from the well in question.

True?

A True.

Q All right. So I want to walk through these real quickly. But I'm going to set up kind of a template. And I think once you get the sense of what I want to do, we might be able to knock these of pretty quickly.

So solution one set forth on page 231 of the main report is called "Production casing should be cemented to the surface." And I believe that's basically a

solution that's pretty self-explanatory.

And that is that you believe that for a production casing like the one that ruptured at SS-25, going forward, they should be cemented to surface; correct?

A Yes. That's applicable to new wells. That's what we were talking about.

Q That was my next question, sir. Because is it possible, feasibly or realistically, to retroactively cement a current well to surface?

A Anything can be done. But that is not the intent of that solution. That solution -- and I believe we are very specific in some part of the report. It is intended for new wells that are drilled and completed.

Q All right.

A Not for existing wells.]

Q All right.

(Crosstalk.)

BY MR. LOTTERMAN:

Q And so this is a template I'm going to kind of walk through with each one of these solutions. Did you find in your investigation whether SoCalGas had violated any existing regulations by the fact that SoCal -- that SS-25 was not cemented to

surface?

A No.

Q Same answer with industry standards?

A That's correct. No industry standards. yeah; that's correct.

Q What about prevailing industry practices?

A Yeah. That's a tougher one. I don't think so. There are a lot of wells particularly in the U.S. But the danger in me trying to compare this is this is -- the wells have different applications.

But you are correct. It is not a prevailing industry practice.

Q All right. And did you see whether the SS-25 not be cemented to surface, did it violate any of SoCalGas's internal policies?

A No, it did not.

Q But you do make a recommendation here. This is your Solution 1. You do make a recommendation that if this solution were to be implemented, it could either mitigate or prevent a leak like SS-25; correct?

A Correct.

Q All right. Let's go to Solution 2 and 3. I believe they are, sort of, kind of, one in the same. And if I read these two

solutions correctly, what you're saying is one of your mitigative measures going forward that could either mitigate or prevent a leak like SS-25 is if an operator were to conduct periodic wall thickness inspections; true?

A Yes.

Q Okay. And, again, to set the table here so the Commission understands exactly what's going on, I believe we established yesterday that at least at the Aliso Canyon facility, DOGGR required only annual temp logs as part of its mechanical integrity testing; true?

A True.

Q All right. And we also, I believe, established that those -- that to do a casing inspection for wall thickness can only be done during a workover; correct?

A I would say that a bit differently. A casing inspection such as what you're highlighted there, Solution 2 and Solution 3 requires a workover where you pull the tubing under the well.

Q Okay. I appreciate that clarification. So bottom line is: As of 2015, there were no regulatory requirements for periodic wall thickness inspections to be done in California; correct?

A That's correct.
Q And there was no industry standard; correct?
A That's correct.
Q Was it a prevailing practice to do that?
A I don't believe so.
Q Okay. And did you see any internal SoCalGas policies that were violated by SoCalGas not conducting periodic casing inspections?
A Can I clarify that a little bit both of them a little bit? My previous answer and the new question that you're asking me?
No. 1 there was no internal policy. Just to clarify, there was no internal policy of SoCalGas required to do casing wall thickness inspections.
However, pre-2015 SoCalGas -- in the 2010 -- post-2010 SoCalGas did do a lot of casing inspection with different tools. They used HRVRT or various tools. So I don't want to say there was no prevailing -- there was a practice. All SoCalGas and other operators doing it.
But was there a regular requirement? No. No internal policy

requirement or emissions requirements.

Q All right. Thank you. But I take your solution here to say that notwithstanding what was done before, that going forward you believe if this solution requiring wall thickness inspections were to be put into place, it could mitigate or prevent the leak like we saw at SS-25; true?

A That's correct. True.

Q All right. I want to take a little detour a minute, and then we'll go back to these solutions.

I saw a lot of -- I remember we discussed a lot -- I think that I asked some questions and I think a couple of other lawyers in Houston asked you questions.

We asked you questions about the accuracy of wall thickness logging tools in the late 1980s. Do you remember that?

A Yes, I remember that. I don't recall it from the deposition, but I remember a data request we answered where we did a more detailed study but, yes.

Q And the old technology that SoCalGas attempted to implement or apply in the 1988 timeframe was a technology called "Vertilog," right?

A Yes.

Q And its more updated cousin today is called HRVRT; is that right?

A That's correct.

Q Okay. And if I understand your reports correctly, sir, Blade did not perform a formal review of the reliability of various casing inspection tools circa late 1980s or even 1990s; correct?

A Again, we did a review of what was available in the literature as part of one of the data request there. But we are aware that these technologies are, you know, were done in the 60s. And they go through various generations of tools and they improve in accuracy and tolerances over time; that's correct.

Q Right --

(Crosstalk.)

Q Excuse me.

A Sorry. I apologize. I spoke over you. But they evolve over time. The software evolves, the sensor evolves, the interpretation technology evolves. So absolutely there is improvement in these over time.

Q Right. I guess what I was getting at is I didn't see a separate report. Like I have about 9 or 10 or 11 of them here. I

didn't see a separate report where Blade performed a formal review and laid out its findings on the reliability of casing inspection tools circa 1988. Is that fair?

A That is fair. And there are reasons for that. I give you context for that. Because we considered the tools in -- even in the late '80s, early '90s are reasonably indicative of issues. It may not be as accurate as a 2018 or 2019 tool.

It gave tolerances that were adequate for our purposes. That's kind of why we didn't end up trying to interpret how would that have been different.

So it is more to say a wall thickness tool, it was still high resolution in the late 80s, early'90s, would give indications of wall loss.

Q Right. So I understand that. But I'm sort of focusing on the reliability aspect of it. So let me ask my question a little differently, and let me make sure I understand your answer.

Did Blade perform a formal review of the reliability of the casing inspection tools available before 2000?

A We did not do a formal study, no. We responded to a data request. That's the

extent of which we did it.

Q And was it your view at least in Houston a year and a half ago that you didn't know how reliable that Vertilog technology was in 1988?

A No, we did know. We did believe it was reliable. It -- we knew it was not as good as the current tools.

But in the late '80s, early '90s, the tool was still considered adequate for the purposes of what we were trying to do. So that is why we didn't pursue that angle or issue or challenge to our interpretation.

Q Would you pull up --

(Crosstalk.)

Q Excuse me?

A Sorry. I'm attempting to explain what we did so.

MR. LOTTERMAN: Mr. Moshfegh, would you pull up the deposition of Dr. Krishnamurthy, Volume I. Which I believe is Exhibit-158. If we've got SoCalGas-158. And can you turn to page 330 and highlight lines 19 through 25.

ALJ POIRIER: We'll go off the record until the document is ready.

(Off the record.)

ALJ POIRIER: We will be back on the

record.

Please continue, Mr. Lotterman.

BY MR. LOTTERMAN:

Q So, Dr. Krishnamurthy, this is Volume I which was November 20, 2019, of your deposition. And you were asked the following question:

> Can Vertilog technology in 1988 detect wall thinning in the outer diameter of a well casing prior to a leak?

I objected. And would you read your answer into the record, sir.

A Says:

> I don't know whether it -- how reliable it is. It did detect corrosion.

That's correct. See reliability, Mr. Lotterman, is a quantitative number. Reliability means to me -- someone like me you say "reliability," and we still don't know. Reliability means what is my confidence level? So when I say, "A tool is reliable." In a quantitative fashion that's what I implied here. 95 percent confidence with a 80 percent certainty that it can detect corrosion within a certain tolerance.

Even today I don't know what those

tools did in 1988. That is what I implied there. Now that is what reliability means to me. Reliability is a quantitative number. That is what I implied here.

Now, can it detect wall loss? Can it detect wall loss with some tolerance?

Now, the next question you ask is how reliable it is. Even though I don't have an exact answer, but it can detect wall loss. It did detect wall loss in the past. So that is how I would phrase it.

Q All right. But be clear, and I think you may have misread your answer so let me just put it in the record so we're clear.

To the question:

> Can Vertilog technology in 1988 detect wall thinning in the outer diameter of a well casing prior to a leak?
>
> Your answer was:
>
> I don't know whether it -- how reliable it is. It did detect corrosion.

Did I read that correctly?

A That's correct.

Q Okay. And if I understand some of your other testimony in the deposition, you definitely believe that the Vertilog

technology in 1988 was not as reliable as it is today; correct?

A I would definitely -- yeah, absolutely. More reliable today.

Q Okay. Good, good. In fact what tool -- when you were performing your RCA, what casing inspection tool did you choose to use?

A We used the USIT tool and we also used I believe the HRVRT. I don't remember. I don't recall. I have to go back to my notes. We did use the Vertilog tool for the 11-and-three-quarter inch where it was not in fluid. So I don't recall. I know we used USIT. I don't recall whether we used the magnetic tool for the casing inspection. I don't remember.

Q I'll tell you what, let's do this, and, your Honors, this might be a good time for a break.

Dr. Krishnamurthy, would you mind confirming what tool you used? What Vertilog-sort-of-variation of tool you used during the root cause analysis? And you can let us know after we come back from the break?

A Sure.

ALJ POIRIER: I think that's a good

idea. We will take a 15-minute break until 11:19. Thank you.

Off the record.

(Off the record.)

ALJ POIRIER: We'll be back on the record.

Good morning. We're just returning from a mid-morning break. We will continue with the cross-examination of Dr. Krishnamurthy by Mr. Lotterman.

Mr. Lotterman, if you could restate the question, I think it would be helpful for the record just at this point.

Thank you.

MR. LOTTERMAN: Glad to, your Honor.

Q I guess the question I was asking you to research, Dr. Krishnamurthy, during break was what tool Blade used during the RCA to inspect wall thickness on casings?

A You can hear me now? I'm sorry. I was on mute.

We used a lot of tools, Mr. Lotterman. We used a Vertilog or a magnetic tool called the HRVRT tool. We also used ultrasonic. I'm talking specifically to wall thickness, okay? Not the other tools. The other one we've used is ultrasonic.

So there are two technologies for

wall thickness measurement: Magnetic and ultrasonic. The Vertilog is a magnetic -- it's a magnetic equivalent from the 1988 to mid '90s. And it went through various name changes and different companies.

So the magnetic tools are good at finding small pits. Corrosion that is really, really small. And it will also find large. But it won't be very good at characterizing the large ones very clearly.

Whereas the USIT log or the ultrasonic log will do a very good job mapping the wall thickness especially for larger corrosion sites. So for the RCA, we used both.

Q Got it. And for -- I believe this might come up later on, and I believe those technologies are called both MFL and USIT, U-S-I-T; is that correct?

A MFL is correct. Its Magnetic Flux Leakage. But USIT is a propriety tool by Schlumberger. So the way I would call that is an ultrasonic tool. USIT is a Schlumberger ultrasonic tool. I just want to be clear.

Q Understood. Thank you for that clarification.

By the way when you said you used a

Vertilog as part of the RCA, are you saying you used a 1988 vintage of the Vertilog in your 2017 RCA?

A No. Let me clarify. The nondestructive evaluation principle was magnetic flux leakage, which is common to Vertilog and the HRVRT in 2017. That's really all I meant to say.

Q Right, right. So just to be clear to the extent you have an old vintage 1988 Vertilog sitting on a shelf at Blade, you didn't fly that out to Los Angeles and use it as part of your root cause analysis; correct?

A No.

Q All right. Let's turn to Solution 4, Dr. Krishnamurthy, on page 231 at the bottom. And, again, I'm going to try to move through these as quickly as I can.

MR. LOTTERMAN: And, Mr. Gruen, I think you should anticipate that I'll be done by early afternoon, sir, if that helps for your planning purposes at all.

MR. GRUEN: Understood. Thank you, Mr. Lotterman. Do you have a bit of precision on -- a bit more precision on that?

MR. LOTTERMAN: My expectation would be to take this through lunch, look at my outline during lunch, and probably go for

another hour if that.

MR. GRUEN: Understood. Thank you, sir.

BY MR. LOTTERMAN:

Q All right. Dr. Krishnamurthy, back to your report. Solution 4 addresses quote:

> A risk based well integrity management system should be implemented.

Correct?

A Yes.

Q And I don't want to get into the details of risk management plans because we're going to talk about some of the current regulations in minute. But basically I get the sense what you're looking for here is a risk management plan that assesses risk and that assesses both the probability of failure with the consequence of failure. Classic risk analysis; correct?

A Yes.

Q All right. And in your description here on the bottom of page 231, you cite both the Transmission Integrity Management Program which, I believe is called "TIMP." And the Distribution Integrity Management Program, which I believe is called "DIMP," right?

A Yes.

Q And to be clear, those two programs, TIMP and DIMP, are required by federal regulation; correct?

A Yes.

Q And as you point in your summary here and it's elsewhere as well, but let's stick with the summary because I think it's in a more cogent form.

You point out that notwithstanding your requirements under transmission and distribution assets, there was no comparable regulation in place for storage; true?

A Yes.

Q All right. So if I were to ask you: Did Blade find that SoCalGas had somehow violated existing regulations or standards regarding the implementation of a risk management plan, what was your answer?

A I apologize, Mr. Lotterman. Can you repeat the question?

Q Probably not. But I will try to restate it. If I were to ask you whether SoCalGas had violated any regulations or standards by its not having a fully up and running integrity management system in 2015, would your answer be no?

A Yes. They did not violate anything. There was no such regulation in

place.

Q And in fact in your brief description here, you observe that notwithstanding the absence of any requirements or standards, SoCalGas in fact launched an integrity management system for storage in 2014; true?

A Yeah. Again, I have to be careful how I say this. There was a general rate case submission in 2014 for I believe 2016. And there SoCalGas articulated a SIMP program. Recognizing that a proactive integrity management was necessary for underground storage wells and that other than a reactive program. And that was what we are referencing here in this statement that you have on the screen.

Q Okay. And I think that's consistent with what you wrote elsewhere and that is that basically SoCalGas filed testimony in 2014 pertaining to the 2016 general rate case seeking regulatory approval to implement the program; right?

A That's correct.

Q Okay. And in fact SoCalGas was waiting for regulatory approval of that program when the leak occurred in October of 2016; true?

A I believe so. I'm not aware of the details of what happened. So, yes. That sounds about right.

Q All right.

(Crosstalk.)

A Go ahead.

Q Fair enough, sir. And I appreciate your clarification there. Was the program that SoCalGas launched in 2014 proactive?

A Yes, it was proactive. And I believe we have discussed it somewhere in our report. I don't remember where. But, yes.

Q Okay. And was that program pioneering in the gas storage industry?

A Yes. And I -- it predated API 1120(c) and 1121 I believe. We articulate that in some place in the report. I apologize. I don't remember where.

Q And that's where I was going next, Dr. Krishnamurthy, because I think part of your analysis that you set out in the report is not only to identify what, if anything, was in place from a regulatory regime at the time of the leak. But you also from time to time point out what has been done since the leak; correct?

A Yes.

Q And in this context in your

proposed Solution 4 to require underground storage operators to have risk based well integrity management systems, that approach is now a federal regulation through PHMSA; correct?

A I believe so. So I have not -- federal regulations. So I will have to look at it to confirm that. But if you say so, Mr. Lotterman, I haven't looked at it lately. I apologize.

Q Is it fair to state, sir, that API 1171 was put into place in 2018 at a minimum?

A Yes, that's definitely true. It was part of our review.

Q And obviously the regulation -- we'll see what the regulation says so you don't need to go there.

Okay. Let's go to Solution 5 and let's plow through this. So Solution 5 is in the middle of page 232 of your main report, and it's entitled "Conduct a Casing Corrosion Study." Do you see that?

A Yes.

Q Okay. I want to ask you about the first -- actually the second line in that narrative. First of all you say:

> Storage wells with good casing and tubing design can last for long

periods and operate safely.

I think that's what we talked about earlier where age may not be or certainty wasn't a correlation at Aliso Canyon. And in fact old wells if managed properly can operate a long time safely; true?

A Yes, that's true.

Q And then you state quote:

> Casing corrosion is not uncommon and its existence does not automatically mean that the casing is going to fail or is unsafe.

Do you see that?

A Yes.

Q And in fact you say that elsewhere in the report on page 221. But we don't need it. It's pretty much the same thing.

So I interpret that statement as saying, "Hey, reader. You need to understand something. Corrosion cannot be eliminated from a gas storage field."

Is that correct?

A I'm thinking. Yeah. Elimination is different. Mitigation is different to me. Elimination meaning removing everything that causes corrosion. That is not practical. So it may have -- it will occur. So the issue is how do you mitigate against it and manage

it?

Q That's right.

A Eliminate is not a word that comes to mind.

Q You're right. And not only is it not practical, it's really not possible, is it?

I mean, you've got 116 wells at Aliso Canyon over a six square mile area, you know, being dug a mile and a half deep into the cap rock of a gas storage facility. You're going to have corrosion somewhere at that facility; true?

A Yes.

Q All right. And I think what the point you just tried to make is the point of your Solution No. 5 was you want that corrosion studied to develop an understanding of why it occurs and what potential measures can be taken to mitigate either its effects or its consequences; true?

A That's correct.

Q All right. So in light of that -- and I assume you're talking about a formal study?

A Again, formal is separate. A true study where the vision I would have in this -- I'm talking about this particular topic.

Theoretically many of these may go into a risk management program. But the intent here is to understand what may be causing the corrosion if there is a corrosion factor in each well. And it required a far more detailed dive than we did as part of this work. So that is what we implied by this particular solution.

Once you know what may be causing it, then you can monitor it and mitigate it at the right time. You don't have to mitigate all of them today. Some of them may take another 30 years. You can plan your mitigation appropriately. That is where the value of something like that comes in.

Q Understood. And if I understand your -- kind of the scope of your technical root cause analysis, that your investigation didn't delve into whether for example SoCalGas employees were discussing corrosion et cetera on an informal basis; true?

A That's correct.

Q And likewise your investigation wasn't for example investigating whether SoCalGas was briefing DOGGR on an annual basis as to the corrosion it was experiencing at its operating facilities; true?

A Again, the documents we checked, we

didn't see a formal report or a study on this topic. So, yes; that's correct.

Q Right. Okay. But as far as communications between and among employees or communications between SoCalGas and it's regulator, DOGGR, you didn't do a deep dive on that, did you?

A We did not check e-mails communications between SoCal employees, DOGGR, or within SoCal. No, we did not.

Q Okay. And --

(Crosstalk.)

A Just to explain just to make sure I give it context, Mr. Lotterman. So our entire work, the entire report, was based on extensive data that we obtained from SoCalGas and from DOGGR records. The main records from general rate case.

And we had probably three in-person meetings with SoCalGas teams that is no more than an hour or two hours long. But we depended on formal written documents that detailed anything. That was the basis of our work as we have put in the report.

Q Thank you for that clarification. Okay. So to kind of wrap up this solution and then we'll move on. Is it accurate to say that in investigating this Solution

No. 5, Blade did not find any instances where a casing corrosion study was required by regulation or industry standard?]

A Yeah. It was not required by regulations. There's no industry standard requiring it.

Q Okay.

A That's correct.

Q And do you know if sitting here today the underground storage industry is required to conduct casing corrosion studies as you propose in Solution 5?

A I don't recall actively at the 11.17, so that is the only standard that is there other than the regulations. I don't remember whether they require that, Mr. Lotterman.

Q Okay.

A I'll have to refer to it.

Q Okay. The other thing I was going to ask you is sort of a clarification and then we'll move on. Do you know elsewhere in the main report -- and I'm thinking at page 17 in particular, and this was under the fact that there was no internal policy on wall thickness inspections.

Do you know what, Mr. Moshfegh? Why don't we just pull this up a minute.

It's page 217. In fact, the 5th or 6th line from the bottom that begins "The MIT monitoring system did find casing leaks on other wells in the fields which were successfully repaired or remediated."

Do you see that, Dr. Krishnamurthy?

A Yes.

Q Is that an accurate statement from Blade?

A Yes. It's in the report. Absolutely.

Q Okay. And is it fair to say that when SoCalGas saw an issue with one of its wells; i.e., especially a casing leak, it took action?

A Yes.

Q Okay. All right.

A By action, I mean mitigated it right away.

Q Right.

A Or removed.

Q All right. Okay. Let's move to Solutions 6 and 7 because I believe they're sort of the same ilk. These address Solution 6. You say, "Conduct a Casing Failure Analysis." And Solution 7 is called, "Regulations Should Require a Level 1" and then in parens you say, "(Per API RP 585)

Analysis of All Failures."

Do you see that?

A Yes.

Q It kind of, you know -- it kind of cut into the chase on this one, because I've read this a couple times. It's my sense, sir, that you're saying bottom line prospectively casing failures need to be more formally investigated; is that right?

A That's correct. 11-1 or a casing failure analysis is really attempting to understand and recognizing you do not have all the data, you don't have -- you may have a log analysis, you may not, or you may want to conduct a log analysis, you may want to run a camera depending on what the problem is.

It organizes the -- it gets a bit organized and systematic understanding if there is a pattern to all these failures. If there is a pattern, then the mitigation is easy and you can execute a mitigation on wells that have not exhibited that problem. So that was the intent of 6 and 7 there.

Q And I believe you say in these narratives -- you don't sort of lay out a specific type of investigation that's warranted or that should be pursued, but you

say really the type of investigation should be commensurate with the risk and the consequences involved; is that right?

A Absolutely. Yes. That's correct.

Q All right. All right. So, so just to be clear -- and I think you mentioned this earlier, but let's put it on the record -- you're not advocating under Solutions 6 and 7 that gas storage facilities, including the utilities, undertake full-blown RCAs every time they find a casing failure, are you?

A No, we are not. We are very specific about it. We discussed this in another portion of the report, I believe. What we are suggesting is when there is a casing integrity failure, a compromised casing integrity, it is important to understand why. And probably 80, 90 percent of the time these will require a Level 1 or some formal process. That's what we're proposing.

Q And when you talk about Level 1, that's one of the levels that's set out in API RP 585; right?

A Yes, we didn't want to describe a Level 1 from a Blade perspective. We were looking for standards that existed and we found a standard and we felt that that

adequately and appropriately described it.

(Crosstalk.)

THE WITNESS: The regulator or SoCal may desire mediation of that. This is more of our suggestion.

BY MR. LOTTERMAN:

Q And what does API stand for?

A American Petroleum Institute Recommended Practice, RP, Recommended Practice 585.

Q And that is not an industry standard applicable to storage wells, is it?

A No, it is not.

Q Okay. And, in fact, I saw elsewhere in your report -- and I can pull it up -- not in your, I'm sorry, in one of your data responses. You said basically -- and I have that -- I think this is a quote -- "As of the date of the incident, there were no documented industry standards related to investigation of casing failures and gas storage operations."

Is that true?

A If you said it, it must be true. I don't remember the dates, but if we answer it that way, Mr. Lotterman, that is correct.

Q Okay.

ALJ POIRIER: This is ALJ Poirier.

Mr. Lotterman, do you have a specific document that references that? I think that would be helpful.

MR. LOTTERMAN: I came to the same conclusion, your Honor.

So, Mr. Moshfegh, if you would pull up SED Exhibit 215, please.

THE WITNESS: I apologize. I can't remember some of these.

BY MR. LOTTERMAN:

Q Doctor, it's -- Victoria's got the right idea, and that is instead of pressing you to embrace something that you may not have a clear recollection of, it's best to pull up the document.

Let's go to page 17, Mr. Moshfegh. Let's get it in the record and we can move on. This should be on page 17.

ALJ POIRIER: And, Mr. Lotterman, if you could read the Bates number in the bottom right-hand corner as well, that will be helpful for the record.

MR. LOTTERMAN: Thank you, your Honor. I will. I want to make sure before I read the Bates number we've got the right page.

Mr. Moshfegh, is that SED Exhibit 215?

ALJ POIRIER: Let's go off the record.

(Off the record.)

ALJ POIRIER: On the record.

Please continue, Mr. Lotterman.

BY MR. LOTTERMAN:

Q So let us -- let's see. So that is -- we are looking, Dr. Krishnamurthy, at SED Exhibit 215. What it is, is it's your responses to the SED's Data Request 69. The Bates number of the initial document is 295, SED_SUR-REPLY_00295.

Let's go to page 17, Mr. Moshfegh. If you would pull up the quote in question. There it is. All right.

So, Dr. Krishnamurthy, if you look at Section 2.2, Question 2, the question on page 9 states: "As of the date of the incident, there was no documented industry standard related to investigation of casing failures in gas storage operations."

Do you see that?

A Yes. And I agree with that conclusion. Yes. Absolutely. I apologize, I couldn't recall -- I didn't recall API 585 so that's why I was struggling. Okay. I'm fine now.

Q Before we leave this exhibit, in Section 2.2.1(a) it says, "Does Blade agree with the statement?"

And what was your answer?

A Yes, we agree.

Q All right. So to wrap up this piece, basically, there were no existing regulations or standards that required SoCalGas to conduct casing failure analyses as you set out in Solutions 6 and 7; is that accurate?

A Yes, that is accurate.

Q Let's go to Solution 8. Solution 8 is entitled, "Well Specific Detailed Well-Control Plan."

Do you see that?

A Yes.

Q I'm not going to dwell on this one, sir, but I'm going to ask you just a couple questions. Was Blade able to identify any regulations or standards in place as of October 15 that required well-specific detailed well-control plans?

A No.

Q And is it safe to say that, therefore, Blade did not find that SoCalGas had violated any existing regulations or standards as of the incident?

A Yes, there was no violation. No, we did not.

Q And do you know if your Solution 8

has been adopted by either California regulators or federal regulators as of today?

A I don't know. I'm not aware whether it has or not been. Again, it was -- I want to repeat. This report was meant for Aliso Canyon. It was meant as solutions for Aliso. It was never meant -- beyond that, it was not our vision for this.

Q Fair enough. Next solution is the one we talked about I think when we were talking about the round trip you took with the root cause analysis, and that is Solution 9, "Tubing Packer Completion-Dual Barrier System."

Do you see that?

A Yes.

Q And, again, we don't need to re-plow this field, but basically what you're saying there is that going forward, injection and withdrawal should be done only through the tubing, and your root cause analysis says, "And if that were done in the future, an incident like SS-25 where the production casing burst and a leak occurred would likely not occur"; correct?

A Yes.

Q Okay. And I believe we also talked about the fact that as of 2015 just before

the leak, it was not an industry practice to have single barrier -- or excuse me -- to have dual barrier wells; correct?

A Yes, that's correct.

Q So to wrap this one up, is it safe to say that as of 2015, SoCalGas did not violate any existing regulation or standard by operating most of its wells at Aliso Canyon using a single barrier?

A There were no standards or regulations in 2015.

Q Thank you. My apologies.

Do you know whether SoCalGas currently operates any of its wells in Aliso Canyon on single barrier?

A I don't believe so because we reviewed the current practices. I believe we addressed that somewhere in the report. That's why I know.

Q So as far as you know and as far as I know, you are correct. As of today, there is not a single active well at Aliso Canyon that does not have the dual barrier system that you identify on page 233 of the main report; is that right?

A That's correct, that's my understanding.

Q Have regulations been put into

place in California to require dual barriers on gas storage wells?

A I believe that was part of the DOGGR regulations. I have to again -- I'm pretty sure it is part of the DOGGR regulations. I don't remember. I'd have to look.

Q It's okay. And are you aware, Dr. Krishnamurthy, whether other operators in California, including PG&E, are currently running their wells with single barrier?

A No, I am not aware. I am not familiar what they're operating.

Q Let's turn to Solution 10 shown at page 233 as well right in the middle. It says, "Implement Cathodic Protection as Appropriate." I don't want to belabor this one either, but under that solution, you give sort of a thumbnail sketch of what that entails, and I actually believe you have a more robust discussion in one of your sub-reports.

But I want to just sort of tease out a couple of thoughts here. One is that putting cathodic protection on a field where there are other wells and other operators makes it complicated, doesn't it?

A Yes. It is complex.

Q And, in fact, there's a possibility, which may not be intuitive -- there's a possibility that by doing so, you could actually encourage corrosion on other nearby wells; true?

A Yeah, if it is inappropriately designed, you know, it has to be -- there are specialists in this area, and I'm talking in the area of cathodic protection. It has to be appropriately designed. It is not straightforward, but it's done. It's done in some cases where we have -- where there are surface casing access to water. That's what you're looking for.

Q And is it also true that -- to put it very bluntly as well -- CP will not work on all wells?

A Again, I want to be very clear. The CP we are talking about here is only for the outermost surface casing where there is a cement issue, which is in the second sentence there. You have either cement isolation or there is access to water. So that is the situation we are talking about. We are not talking about production casing. We are only talking about surface casing that is shallow. By shallow, I mean shallow related to the total depth of the well.

Q Understood. Thank you for that clarification. To sort of follow up on that thought, I think you just said it, but let me make sure we're clear on this as well. Is it your view that on a well like SS-25, to the extent you could put cathodic protection on the outside surface casing, you could not technically also put it on the inside production casing?

A That's correct.

Q All right. And let's wrap this one up as well. Did Blade identify any regulations or standards in place at time, in the time of October 2015, that required SoCalGas to have cathodic protection on any of its wells, including SS-25?

A As we articulated in the report, there are no regulations. There are standards that discuss, it may discuss CP, but it is not a requirement. It is more of if you apply CP, what do you do, how do you apply CP.

Q Got it. All right. Let's go down through Solution 11. I think we have just two more to go and then maybe we could break for lunch.

Solution 11, Dr. Krishnamurthy, says, "Ensure Surface Casings Are Cemented to

Surface for New Wells." And maybe to cut this one short, this is for new wells only; correct?

A That's correct, yeah.

Q All right. SS-25 was not a new well; right?

A No, it was not.

Q So just cutting to the chase here, is it fair to say that as of October 2015, SoCalGas was not violating your recommended Solution 11 at SS-25?

A No.

Q "No," it was not correct or, "no," there was no violation?

A Sorry. It was consistent with regulation and SoCalGas was cementing surface casing to surface.

Q All right. Thank you. That leaves one more solution. And I got a bone to pick with you on this one, but it won't take long. Basically your final solution is "Well Surveillance Through Surface Pressure" and in parens you put, "(Tubing and Annuli)."

Do you see that?

A Yes.

Q And I don't want to get into a whole lot of detail about this because I don't think it's important, at least for my

purposes, but what you are saying here basically is there is value in putting or having realtime pressure measurements on wells like SS-25 so that you can constantly monitor both the tubing, the production casing, and the surface casing pressures and provide better insights as to whether you might have a leak, that type of thing.

Is that a gross but accurate summary?

A Yes, that's an accurate summary.

Q Okay. And, in fact, SoCalGas was in the process of implementing realtime pressure monitoring systems at its facilities before the incident; true?

A I don't recall that, Mr. Lotterman. I don't remember. But I know that such a system was installed when we were there.

Q Okay.

A So whether it was considering it prior, we didn't investigate that, but it -- I believe it was being installed or it was installed during the time we spent at Aliso.

Q Fair enough. Fair enough. And I believe Ms. Kitson from SoCalGas will be addressing that later for the Commission so there's no need for you to go there and I appreciate that.

So bottom line on this one is as of October 2015 when the incident occurred, were there any regulations and standards in place that required well surveillance through pressure -- through surface pressure realtime measurements?

A No, there were no regulations that required it.

Q The bone I have to pick with you on this one, sir, is I'm not sure what impact, if any, it would have had on addressing the SS-25 leak. And here is why I say that: It's my understanding that on the morning of October 23, 2015, in Blade's view the leak occurred. And, in fact, I believe, if my recollection is correct, within a short amount of time not only did the casing get a hole, as you saw in the pictures, but, in fact, it parted completely.

It's my understanding -- and I believe this is actually set out in your chronology on -- I'll find the page for that. Yeah, there it is. On page 126 of the main report, that leak was discovered at 3:15 p.m. and that SoCalGas closed the injection header valve 15 minutes later.

Do you see that?

A Yeah.

Q Okay. And then, to make a long story short, SoCalGas worked all night bringing in contractors and the like and attempted to kill the well itself on the morning of October 24, 2015.

Is that your recollection, sir?

A That's correct, yeah.

Q All right. So let me ask you kind of a picky question, but I feel like I should ask it since we've spent so much time together. Why would it matter if that leak were detected at 3:15 in the afternoon or 7 o'clock that morning?

A Good question. We discussed this quite a bit, as you can imagine, Mr. Lotterman, within Blade as we articulated the solution. This is an important point. The pressure for a production engineer, the tubing pressure, the casing pressure, and the surface casing annuli pressures will immediately tell you in the morning of 23rd that the valve was potentially flowing or it was flowing at 90 or 93 million a day. I forget the exact numbers, so don't quote me on that, but the exact number is in the report.

That number will tell you right away that this is a very complex well-control

issue. It will define your well-control plan immediately. That is the intent of that. It is -- it -- that pressure data you can use, which we discuss in the report, but I don't recall where, but we do this because where we discuss the estimate of flow rates, that that is the value of that pressure. That pressure data on an ongoing basis where if it's a little leak, you know it's a little leak and the reaction can be commensurate with that.

If it's 80-, 90-million-a-day leak, the reaction will be commensurate with that. That is the value of that pressure measurement, and that is the reason we put it in the solution.

Q One last question and then, Judge Poirier, I think this would be a good time to take lunch.

Dr. Krishnamurthy, looking at the 12 mitigation solutions that you set out on pages 231 through 233 of your main report, which has been identified as Commission Exhibit 1000, are you aware that SoCalGas has implemented or is in the process of implementing each one of them?

A I believe we discussed -- as part of the same program, I believe SoCalGas had already implemented quite a few of them. I

have not followed up, Mr. Lotterman, to see if all of them have been implemented, but I absolutely believe that they would have, yeah.

Q I guess what I was asking -- my apologies, Judge. I'm going to do one follow-up question if you don't mind.

I guess what I was asking, Dr. Krishnamurthy, have you read, for example, Ms. Kitson's testimony that was submitted in this case?

A I don't -- I receive -- if we read it in context of the DR, I don't recall. I can read it tonight or this evening, but --

Q No. No, sir. I wasn't suggesting you do so, and Ms. Kitson will testify on her own. I just didn't know if you knew of what the current status of the measures that SoCalGas are. If you don't, we'll break for lunch and we'll talk to you afterward.

A I don't recall right away. Thank you, Mr. Lotterman. I will look at it.

MR. LOTTERMAN: Your Honor, this might be a good time to break for lunch.

ALJ POIRIER: Okay. Let's go off record.

(Off the record.)]

ALJ POIRIER: Back on the record.

While off the record, we were discussing some timing for the afternoon, cross-examination, and witness orders and so we have a better idea of that moving forward.

We're going to take a lunch break now until 1:15. And we'll be off the record.

(Whereupon, at the hour of 12:06 p.m. a recess was taken until 1:18 p.m.)

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AFTERNOON SESSION - 1:18 P.M.

* * * * *

ALJ HECHT: We'll be back on the record. We were off the record for a lunch break.

So we are beginning the afternoon session on March 23rd of the hearings in I.19-06-016. We are going to pick up where we left off with cross-examination of Witness Krishnamurthy by Mr. Lotterman.

So, please go ahead.

MR. LOTTERMAN: Thank you, your Honor.

RAVI KRISHNAMURTHY,

resumed the stand and testified further as follows:

CROSS-EXAMINATION RESUMED

BY MR. LOTTERMAN:

Q Good afternoon, Dr. Krishnamurthy.

A Good afternoon.

Q All right. I have a couple of clarifications, and then I want to turn to the final topic of my examination.

Mr. Moshfegh, would you pull up that portion of the main report at page 215, right in the middle of the first long paragraph, before Figure 152?

And I'm going to ask you to

highlight the following language. It says -- I think it was the fourth line down:

> While a cathodic protection system would have provided casing protection to the 11-and-3/4-inch casing, it would not have provided (sic) the 7-inch casing inside the 11-and-3/4-inch casing.

Do you see that, Dr. Krishnamurthy?

A Yes.

Q And to, sort of, shift from casing sizes to casing names, are you saying there that while it’s possible that a cathodic protection system would have protected the surface casing of SS-25 from corrosion, it would not have been able to protect the production casing from the same?

A That's correct.

Q All right. Okay.

The second thing I was going to mention to you -- and don't worry, I'm going to go back to your mitigation solutions.

But I want to note that I didn't see a solution for annular flow safety systems -- which I call subsurface safety valves, but you prefer to call annular flow

safety systems.

And, I guess, my question to you is, why was that not included as a potential mitigation solution in your root cause analysis?

A Yeah. We studied -- and I don't have the -- I believe we have a supplemental report or some discussion of that system. We did look at it. It was -- as we went through the well files, it was -- it was installed in 1978, '79. And then there was some issues, it was removed.

That technology in the oil patch has never been successfully applied. There is some indication that there is some technologies, but we didn't find any --

(Audio interruption.)

(Court reporter clarification.)

ALJ HECHT: We'll be back on the record. We went off the record, once again, due to technical problems with our telephone line. I appreciate everybody's patience. I believe Mr. Krishnamurthy was in the middle of his response.

And I will say, Mr. Krishnamurthy, do you want Mr. Lotterman to repeat his question? Or can you pick up about where you left off?

THE WITNESS: I can pick up. I can pick up roughly where I left off.

ALJ HECHT: Great. Thank you very much. And you can err on the side of restating anything that you think might have been missed, based on the update the court reporter gave us before we went back on the record.

THE WITNESS: Thank you.

So the annular surface systems -- or subsurface safety valve is another -- annular safety valves were installed in '79. And I believe there were some issues with it, and it was removed in '80. We researched it quite a bit. We attempted to understand what it's supposed to look like. And we are quite familiar with subsurface valves that are commonly used in the oil patch, especially in offshore wells and some land wells, depending on what application they are on. And that technology is highly evolved and used commonly.

However, the annular safety system that was being considered for Aliso was not viable, necessarily, in '80. And we didn't see its viability in the period we were looking at. And so we didn't see it as a solution or as a root cause of the problem.

Because that technology was not where it needed to be to be an effective solution, perhaps, even -- at least in 2019 when we wrote the report. That is why we didn't have it as part of our root causes. It didn't fit the explanations -- it didn't fit the solutions we were looking for.

BY MR. LOTTERMAN:

Q And is it safe to say, Dr. Krishnamurthy, that in light of the infeasibility or impracticability of those type of safety systems in gas storage wells, that there were no regulations in place that required SoCalGas to have them in place?

A I don't believe DOGGR had any regulations. That is correct.

Q All right. Thank you. All right.

Let’s -- oh, by the way, when you say, "annular flow systems," are you talking about a valve that would be able to somehow block the flow of gas between the tubing and the production casing?

A Yes, that is --

Q Okay. And is that --

(Crosstalk.)

BY MR. LOTTERMAN:

Q Excuse me.

And is that the challenge visa vi

oil production wells, where they are typically flowing up one pipe sort of in one direction; but in a gas storage well, they could be flowing up the tubing, they could be flowing up the annular flow, they could be flowing up both, and, by the way, you could be injecting gas six months later?

A That is correct. It is a challenging, challenging operation, as you well described, Mr. Lotterman. You described it very, very well. It is through the tubing or through the casing. And you have to isolate both. You have to be effective during injection, and then when you're doing the withdrawal. So there are quite a few challenges. So, yes, we studied it quite a bit. And we didn't identify it as a solution here.

Q Okay. One final area, sir. And I want to talk about the well kill.

And when I say, "well kill," that's sort of the industry way of saying stopping the flow of gas from the reservoir up into the well head or the atmosphere.

True?

A That is correct.

Q All right. So, let’s set the stage a minute. And then I've got a handful of

questions for you.

You set out on pages 125 and -- I'm sorry -- 126 and 127 of your main report, the chronology of key events during the SS-25 incident.

Would you mind turning to that page a minute?

A Yes. I'm there.

Q Okay. And, in fact, in your main report and then some of your sub-reports, you review the various attempts to kill the leak at SS-25, which started, according to chronology, on October 23, 2015.

True?

A Yes.

Q And you note in your chronology that the first attempt -- first attempt -- first kill attempt was made on October 24, 2015.

Do you see that?

A Yes.

Q And then they were six additional attempts. And the last one was made on the next page on December 22, 2015.

Do you see that?

A Yes, I do.

Q All right.

And I believe it's your

understanding that the first attempt on October 24 was conducted by SoCalGas.

True?

A Correct. Kill attempt number one. Yeah.

Q Right.

And then kill attempts 2 through 7 were conducted by various representatives of Boots and Coots; right?

A That is correct.

Q All right.

Had you heard of Boots and Coots before you took on this project?

A Yes.

Q Okay. Were they pretty well known across the world for their expertise in killing wells?

A Yes, they are.

Q And have you -- and are you aware that they indeed have killed wells across the world?

A Yes.

Q Okay. Have you ever been involved with them when they are killing a well?

A No. Not me, personally, no.

Q Okay. What I would next like to do is, Mr. Moshfegh, to turn to main report page 227 and highlight or elaborate on Figure 164.

And, again, this is Commission Exhibit 1000.

Are you with me, Doctor?

A Yes, I am with you.

Q All right.

So it’s my understanding, sir, that this configuration, or this figure, depicts basically what SoCalGas and what Boots and Coots did, generally, to try to kill the leak at SS-25.

Is that your understanding?

A That is correct.

Q All right.

And then if we just sort of walk through this very quickly, if you start at the top of the figure where it says, "Kill fluid," that's where, basically, they would attach a pump truck to the appropriate well head and, basically, try to pump, kind of force feed, kill fluid down that tubing; right?

A Yes.

Q Okay. And depending on the plan and modeling and whatever, you pick a certain weight of the fluid, and pick a certain pump rate, and then you go out there and hope for the best; right?

A Correct.

Q And then if you follow that

diagram, the kill fluid goes all the way down that tubing. And then when it gets to the bottom, what you see are two arrows which go out of the tubing and into the annulus between the tubing and the production casing; is that right?

A Yes.

Q And if I understand how this well was configured, that was able to occur because that tubing actually had perforations in it --

A Yes.

Q And so -- I believe there's actually a phrase for that, something about communication between the two pipes or whatever. But the idea is that given a certain configuration, gas could flow from the tubing into the production casing or vice versa; correct?

A Yes.

Q All right.

And then if I understand your Figure 164, that kill fluid then, once it goes down the tubing to the end and hits that obstruction and goes out either way through the tubing perforations, it's then in the annulus between the tubing and production casing, then it’s got a couple options.

One, it can continue to go down and actually go into the storage reservoir; right? -- which is depicted at the very bottom of the figure?

A Yes.

Q And the other option, which I think we're well aware of it at this point, is it goes up the annulus between the production casing, the tubing, and, as we found out later given your extraction of the production casing, it went out of a parted casing at about 892 feet into the formation; right?

A That is correct.

Q All right.

And if there had been no parted 7-inch casing where you show in this diagram, the kill fluid would have gone down the tubing and up the production casing and would have basically, sort of, stopped at the top, because it would have nowhere else to go; right?

A I think I followed the question.

So what you're saying is, if the casing was not parted, it would just be on top of the reservoir. That is correct.

Q Yes. Yes.

And the idea is, at some point in this time, if you put enough kill fluid into

that wellbore, the weight of that fluid is greater than the weight of the pressure pushing the gas up into the well, and you effectively stop the leak and you kill the well operation; is that right?

A That is correct.

Q Okay. And, in fact, you know, when you do a workover, isn't that exactly what you do? -- you sort of kill the well? -- obviously, it doesn't have any holes or casing partings. But you kill the well, that allows you to pull the tubing, go in and do your workover, and do whatever you want to do.

So, I mean, but for those case -- that parted casing, this diagram would show sort of a successful, routine well kill; right?

A Yes and no. The situation is a bit different when you're talking about just pulling the tubing and killing the well for a workover. Because you do not have gas flowing at a very high rate, like in this case. Okay? So the situation is different. It's not the same.

The kill -- the fact that you overwhelm the reservoir with a kill fluid is similar. The act of overwhelming the well is

similar. But what is important in a case like this, not just density, is also pump rate. So those are the two things that will overwhelm the reservoir in a case like where you have parted casing or gas flowing at a very high flow rate from the top.

Q Fair enough.

So I guess what you're saying is the principles are same for a routine or standard well kill where you're just going to do a workover, and what happened here. But the calculations as far as the pump rates and the density of the fluid, that's all a very different operation when you're trying kill an uncontrolled well; right?

A That's correct.

Q Okay. And so -- that's helpful. Because I want to talk about a couple of things here.

First of all, when you first arrived at the SS-25 well pad, in February 2016, you didn't the know the depth of that -- where that casing parted, did you?

A When we arrived, we didn't know. But when we looked at the temperature log, we had some estimates of various depths. That is correct.

Q Fair enough. Fair enough.

And you also didn't know, really, what specifically failed on the well -- although, I think you said at one point your suspicions were -- was the production casing; right?

A That is correct.

Q And you certainly didn't know whether the issue was a joint, a pinhole, a big hole, or a parted casing, like, as depicted in Figure 164; right?

A Yes. We didn't know; but, yeah. I'm -- I will wait for your next question. But you had some data telling you it was bad; it was pretty big kill rate. But, yeah, we didn't know it was a big pinhole or a failure or a parted casing. That is correct.

Q Understood. And I appreciate that clarification. So you didn't know those things.

And is it fair to assume that when SoCalGas attempted its first well kill on October 24, 2015, it didn't know that either?

A That is correct.

Q And, in fact, those are critical elements, or they could be very critical elements, when designing and planning a well kill.

True?

A Can you repeat -- what is the critical element, please? I didn't hear the first part of the question.

Q Depth of the leak, what specific leak failed, size of the breach, those types of factors.

A Yes. Often in a well kill, you don't know those exactly. What you're looking for is what rate is the -- possibly, the well is slowing at. And that's really, your only indication at that point --

Q Right.

A -- that is correct.

Until you run the temperature log or some other parameters.

Q Right.

And I'm not saying you can't model for contingencies. All I'm saying is, if you have that information, like the depth of the leak, the size of the breach, and all that kind of stuff, that makes your modeling a little easier, doesn't it?

A Yeah. But the -- again, I need to articulate this.

We did do the modeling with information that would have been available at that point. And we also did the modeling with a lot more information that we had -- we

were privy to after the RCA or after we pulled the casing.

But with the pressure measurements on the surface, which is the tubing pressure measurement and the flowing -- casing measurement of the shutting casing pressure measurements, you could estimate the rate of the leak, and that would have given an estimate of the flow rate. We talk about that in the report --

Q Right --

A So I --

Q Okay. And what I want to stop and just talk about very quickly before we actually talk about the specific well kills themselves is that your report acknowledges, I believe, in the one or two spots that as a general matter, SoCalGas was able to stop well leaks at Aliso Canyon; correct?

A Correct. Two other underground -- I forget the number. And SS-34, I believe, was successfully done in the past.

Q Right. I've got Frew 3, and then I think Fernando Fee 34-A.

Does that roughly comport with your recollection?

A That is correct. Yes.

Q And both of those wells are at

Aliso Canyon; right?

A Yes.

Q And both of those wells were successfully killed by pumping fluid down to tubing of the well, as you see in Figure 164; right?

A Yes.

Q And both of those wells were killed almost immediately, at least within a day or so of finding the leak; right?

A That's correct. That's what I remember, yes.

Q And that's what SoCalGas tried to do on October 24 for SS-25, didn't it?

A That's correct.

Q But your analysis, if I'm not mistaken, showed that there was significant differences between Frew 3 and Fernando Fee 34-A and SS-25; right?

A Yes.

Q And so, unfortunately, in this circumstance -- and maybe add this to the list -- past experiences that SoCalGas had in almost immediately killing two large leaks at the Aliso Canyon facility were not helpful at SS-25, were they?

A That is correct. We discuss that in the report, I believe.

Q Good. All right.

And to make a long story short here, if you turn to page 148 of the main report, if you're looking at what SoCalGas did, you conclude right underneath Table 19 -- and that's actually kill attempt number 1, alternative. And I'm not going to get into all that, 'cuz I have -- I really have no idea which -- what you mean.

But if you look at the sentence below the table, it says:

This kill attempt was a reasonable response, because the extent of the failure at SS-25 was unknown.

A That's correct.

Q True?

A Yes.

Q Okay.

And, in fact, I think you told me at the deposition, you called it a good first pass; right?

A That's correct.

Q Okay. So let me stop you there a minute.

Sitting here today, looking at what SoCalGas did in attempt number 1 -- and, by

the way, looking at the attempts Boots and Coots did, do you believe that well was capable of being killed from a top kill?

A Yeah. Our conclusion is yes, which was discussed in the report.

Q Right. All right.

Now, let's skip ahead. All right.

So let's talk about Boots and Coots's six attempts. Okay? And, again, I'm not going to get into mud rates and rate -- pump rates and all that stuff.

But you say in your report -- first of all, you assume in your report that Boots and Coots did no modeling on its first six attempts. So remember, kill attempt number one was SoCalGas. Boots and Coots were 2 through 7.

So you say for kill attempts 2 through 6, there was no modeling done by Boots and Coots; is that right?

A Let me carefully phrase this. We requested data around modeling multiple times, because we were looking for models that were done. And that -- we had probably about 3 to 5 requests on this topic. And we also had this discussion in person to get some data, any data, to show that modeling was done. We didn't find any.

And based on that, is the only way we can prove. Yeah. We requested quite a few times on this topic, explicitly and implicitly. And we didn't get any information. So that is why we concluded.

Q And so your critique of -- one of your critiques of Boots and Coots kill attempts 2 through 7 -- or 2 through 6, I guess, since I believe you acknowledged that kill 7 did have some modeling done. So let me rephrase the question.

So your critique of Boots and Coots's kill attempts 2 through 6 assumed, rightfully or wrongly, that no modeling was done in preparation of those attempts.

True?

A I wouldn't say rightly or wrongly, Mr. Lotterman. Because there was extensive discussions, extensive data requests, there were requests to talk to Boots and Coots. We never managed that. So, we were very clear about this. There was not data that indicated transient modeling was ever done to design these kill attempts.

And when we looked at the kill attempts -- I don't want to say -- basically, the same mud rate was used 2 through 6, with some variations to it. And -- whereas, when

the modeling was done after 6, there was a clear change in weight and pump rate. I don't have the details in front me. I can go to my tables. So take that into account, plus the fact that we had no data, that is why we made the conclusion.

Q Fair enough. But I don't want to get there yet. I want to focus on the one assumption in your analysis. And let me phrase it this way.

As far as you were concerned, as far as you knew, Boots and Coots did no modeling in preparing and implementing kills 2 through 6; correct?

A That's correct. Based on the data we had and based on the conversations we had, yeah.

Q And do you now believe -- or do you now know that that assumption is incorrect?

A No. I don't know anything to -- to change my mind. I haven't been given -- we have not looked at it with any additional information. We haven't seen any additional information.

Q Okay. All right.

So let’s turn to the seventh kill attempt. That one, I believe, you just said did have some transient modeling; right?

A Well, yeah. Because that was shared with us. There was a lot of data shared with us --

Q Right. Right. Right.

And, again, I don't want to get into the mud weights and all that stuff.

But at the end of the day, were you satisfied that Boots and Coots did model that kill and then went out there and tried to implement its plan?

MR. GRUEN: Your Honor, if I may, just before that answer. And this may be an objection for vagueness for the record.

Is this a question specific to well kill attempt number 7, at this point?

MR. LOTTERMAN: Yes. And I will clarify, your Honor, for the record. And let’s find the page here a minute. I'm trying to find the chron right.

If you go back to the chronology, Mr. Gruen, and you go to page 127, this would be the well kill showing up on December 22, 2015, called kill attempt number 7 failed.

MR. GRUEN: And for clarity, for the record, the questions are relating to that specific kill attempt; correct?

MR. LOTTERMAN: They are. They are.

MR. GRUEN: Thank you. Understood.

ALJ HECHT: Thank you for clarifying.
BY MR. LOTTERMAN:
Q So, Dr. Krishnamurthy, in light of that clarification, I want to focus on Boots and Coots's last kill attempt.
Okay?
A Yeah.
Q And if I understand your analysis, you acknowledge that modeling was done. And, obviously, you're aware that Boots and Coots and SoCalGas implemented the plan. But you believe, and your modeling shows, that if Boots and Coots had continued pumping and not stopping when it did, it would have been able to bring that well under control; correct?
A That is correct.
Now, the reason they couldn't keep it under control, I believe, we al- -- we discuss that somewhere. There were practical challenges for them to continue pumping. That is why they couldn't pump. So it was well understood that by well kill number 7, the conditions had deteriorated, there were challenges all -- like we talk about there. You have it on the screen -- the gas flow out of a two-range outlet, the crater enlarged, so -- so it was a challenge. So it was understandable why 7 didn't hap -- didn't

work.

Q Right. And I want to actually talk about that. But maybe we should -- and this is my last line of questions, sir. So I'll ask you to be patient. But maybe we should pull up a picture here.

Mr. Moshfegh, why don't we go with Figure 17 on main page 33. There you go. If you could just enlarge that a bit?

So, Dr. Krishnamurthy, is that the crater you're talking about?

A Yeah. Yeah. That is a picture, probably, we took April 1, 2016.

Q Right.

And, by the way, are those the two brother wells right on the same pad, the SS-25A and -25B?

A Yes. That is correct.

Q And do you see that bridge that goes across the crater?

Was that put in by SoCalGas to allow, basically, access to that well head that you see in the middle of the bridge there, where the bridge seems to not have any footing?

A Yes.

Q All right.

And if I understand how that last

well kill on December 22, 2016, -- '15, excuse me -- transpired, you pull up the pump truck, you attach the pump truck to that well head -- which you can't really see that well; but it’s just that kind of piece of equipment that you can see sticking up in between that -- sort of like a cage with no bars.

Do you see that?

A Yes.

Q Yeah. Yeah. Okay. So you -- there you go. There you go.

So you attach the pump truck, you've got your plan, and then when it’s time to go, you start force-feeding that kill fluid down that tubing with the hope that at some point you can overcome the reservoir pressure and stop the flow of gas to atmosphere; right?

A That is correct.

Q All right.

And it’s my understanding, sir, that there are two paramount concerns when killing a well. One is, maintain safety. And what I mean by that is, you avoid injuries, you avoid deaths.

Do you agree?

A Yes.

Q And, as far as you know, have

people been injured and died attempting to kill wells like that around the world?]

A Yes.

Q Okay. Second paramount concern is: Don't make the leak worse or don't make the situation worse. And what I mean by that is if somehow you overpressure the wellbore during a kill attempt, you can for example fracture the rock and lose fluid to formation, can't you?

A Yes.

Q Why is that a bad thing?

A Since you don't successfully kill, you'll have more gas coming at you. So that could be one problem if you fracture the rock.

Q Okay.

A You could have an underground -- well, there are a lot of scenarios, yes.

Q Okay. The other aspect of don't make the situation worse is you don't want to do further damage to the wellbore; right?

A That's correct.

Q Because you got -- now you got a leak at 892 feet. You don't want one at 2,000 feet; right?

A Sure. You don't want to have additional leaks; that is correct.

Q Right. You don't want to go to one failure mode to two; right?

A Correct.

Q And if you do, you might make a top kill like we depicted earlier more complicated or even impossible; true?

A If you did that, yes. Correct.

Q Right. Right. So when on December 22, 2015, when SoCalGas and Boots & Coots stood on that well pad and hooked up that pump truck to that wellhead and began their planned modeled well kill, they had those two paramount concerns in mind didn't they?

A Yes.

Q Okay. And I assume you learned later on that during that kill the wellbore, that piece of equipment that's sort of shown there between that cage with no bars, started flopping around like a loose fire hose. Is that your understanding?

A Yeah, it was vibrating. That was the reason for stopping of the kill attempts; that's correct.

Q Yes.

(Crosstalk.)

MR. GRUEN: I am sorry, your Honor. I couldn't hear the witness finish his answer

to the question.

ALJ HECHT: Yes. Please avoid crosstalk. Let's hear from the witness, and then we'll keep going.

THE WITNESS: I am sorry. I'm trying to speak slowly, Mr. Lotterman. So occasionally I pause. I apologize for that.

But, yes, we were -- we had read detailed reports from the order from SoCal. And I believe there was some reports from Boots & Coots where it was very clear when -- this type of pumping on seven, the density was good. But this time the location had become so challenging that the wellhead was vibrating and the pump lines -- the pumping lines were moving.

And now the imagery that, Mr. Lotterman, you depicted I don't have that imagery in my mind. But we understood it was vibrating and it was moving. So definitely at that point you want to stop.

Q Got it. Because you told me in the deposition that those were indications -- there were indications that things were shaking, moving, vibrating, so it was dangerous to continue; true?

A That's correct. Kill No. 7, we write that in the report and absolutely.

Q Right. So that was a pretty serious situation involving possible harm to persons and/or more damage to the well; true?

A Yes. The wellhead was moving. So that is not a good idea.

Q Right. And so at that point in time at that pad and at that moment, SoCalGas needed to make a realtime decision using its best judgement involving many moving parts with very serious consequences; true?

A Yes. And the decision was solid. Yeah.

Q Good. And only SoCalGas was in a position to make that decision; isn't that right?

A That's correct.

Q And so from what I hear you saying to me now, you -- meaning Blade -- you are not contesting the decision by SoCalGas to suspend the top kill on December 22, 2015, as they did; correct?

A That's correct.

Q And are you contesting the decision at that point to stop top kills altogether and to focus on the relief well?

A No, we are not.

Q Okay. And in fact that relief well was in the process of being drilled when this

kill attempt was being performed; correct?

A Yes.

Q And that relief well drilled 1.5 miles into the formation and successfully intercepted that SS-25 wellbore at its base, or roughly at its base. And it hit that wellbore at a spot about the size of a coffee can. Is that your understanding?

A Absolutely.

Q And then at that point, SoCalGas pumped kill fluids not down the well but through the relief well into the bottom of the SS-25 wellbore. And that in turn flowed the well-kill fluid up the wellbore and killed it; true?

A Up and down, yes.

Q Right. Was that a pretty remarkable feat in your view?

A Yes. Relief wells are done -- again, I'm an oil patch guy. It's a very unique achievement and unique application of technology in the oil and gas industry. And it's amazing every time we do it.

Q And was it amazing here?

A Yeah. It was successful here. Yeah.

MR. LOTTERMAN: No further questions, your Honor.

ALJ HECHT: All right. Thank you very much.

So I think at this point, we have some additional clarifying cross from Safety and Enforcement Division. And I don't know if there will be any redirect from Ms. Frazier for Blade.

MR. GRUEN: Thank you, your Honor. I see Blade is raising their hand. If I may, will your Honors indulge us for a short break just to consult and be sure that we have everything in order in light of Mr. Lotterman's most recent line of questions?

ALJ HECHT: Let's hear from Ms. Frazier, and then it is likely that we will take at least a short break.

MS. FRAZIER: Mary Frazier on behalf of Blade. Your Honor, I was just going to mention we do have a few clarifying points. I think it will be less than 30 minutes. But I just wanted to make you guys aware of that.

ALJ HECHT: Okay. You're breaking up a little bit for me. I do not know if the court reporters are also having the same issue or if it's on my end.

I think what we're going to do is we will take a 10-minute break until 2:10, and

then we will come back and pick up with SED and then with Blade for redirect. Okay.

MS. BONE: Your Honor, Traci Bone from Cal Advocates.

ALJ HECHT: Yes.

MS. BONE: Before we signed off for lunch, Cal Advocates also requested that we have 15 minutes to do some cross-examination of Blade, and we understood that ALJ Poirier would allow that.

ALJ HECHT: Yes.

MS. BONE: We would go after SED.

ALJ HECHT: Yes. Thank you for reminding me of that. That is what we will be doing. At this point, we will take that break until 1:10.

We'll be off the record.

(Off the record.)

ALJ HECHT: We'll be on the record.

We just took a short afternoon break. And now we are going to pick back up with more cross-examination of Witness Krishnamurthy. We will be starting with the Safety and Enforcement Division and then the Public Advocates Office and then redirect by Blade's Ms. Frazier.

Mr. Gruen, are you ready to proceed?

MR. GRUEN: Yes, your Honor. We are.

ALJ HECHT: Thank you.

CROSS-EXAMINATION

BY MR. GRUEN:

Q Good afternoon, Dr. Krishnamurthy.

A Good afternoon.

Q So, Dr. Krishnamurthy, if I may just through the -- understandably Mr. Lotterman and Ms. Frazier indicated they had not practiced before the Commission before. And as a matter of practice, if I may just ask you a few basic foundational questions about the Blade Report.

So if I may, where there are facts in both the Blade report and the four supporting attachments, both Commission's Exhibits 1000, 1001, 1002, 1003, and 1004, where there are facts identified in the Blade -- the Blade report and those supporting attachments, are those facts true and correct to the best of your knowledge and understanding?

A Yes, they are.

Q Thank you. And in those reports where there are opinions, conclusions, or interpretations expressed, are those expressed to the best of yours and your colleagues at Blade's professional judgement and expertise?

A Yes, they are.

Q Thank you very much. Okay. So with that basic out of the way, if I can turn you if you recall to when Mr. Lotterman had referred to, if you will, rolling credits looking at the acknowledgements page in the main report. And he was asking you about SoCalGas's efforts related to that. Do you recall being asked about that?

A Yes, I do.

Q Okay. Thank you. And would it be accurate to say that without SoCalGas, you could not have done the root cause analysis?

A Yes, we could not have.

Q Okay. So without SoCalGas providing you with the information it did, that was a necessary component for the root cause analysis; is that correct?

A Yes.

Q And that would include information from its well file for well SS-25; is that also correct?

A That's correct.

Q And would it be accurate to say that SoCalGas controlled the information it provided to you regarding well SS-25?

A I don't know about control. But, yeah. They were giving us information;

that's correct. We procured information on that from SoCalGas. And also we would look at DOGGR websites being publicly available. But the crucial information would come from SoCalGas.

Q Understood. And that -- what you just described well SS-25, was that also accurate for SS-25A, the sources of information from SoCalGas with cross checking from DOGGR?

A Yes. 25A, 25B, yes.

Q Yes. Thank you, Dr. Krishnamurthy. Do you recall Mr. Lotterman also asking you if you found the well file for SS-25 to be complete for your analysis?

A Yes, I do remember. Yes, I remember him asking, yes.

Q And if I recall correctly, you answered something to the effect of:

> As far as we could see, we had all the information we needed.

Does that comport with your recollection?

A Yeah. You know, I couldn't comment on things missing because we didn't see any gaps in information. And if there's some additional information -- not that we don't know about it. But information for what it

appeared complete to us.

Q Okay. Thank you. And that addresses -- just for the record, if SoCalGas had provided you with incomplete well file information, you would have no way of knowing?

A Yes and no. Occasionally depending if there's a question on 25 and 25-A, we go through every information all the data bits. So if there are obvious gaps, let's say I look at daily reports and then five days are missing in the daily reports. We would know and we would ask and we would tell them.

So very similar to the modeling information we just talked about. We know that was not there. So we asked.

So to me, yes. If there are some really massive additional information that we didn't have, yeah we wouldn't know. But if things don't fit we know. Because we're analyzing the information. And we look for data trends and stuff like that. So as far as we could see, it appeared complete. That's all I could say.

Q Thank you, Dr. Krishnamurthy. And you were jumping into the next question. Your answer related to it. But just for the record if I could. What if SoCalGas provided

you with certain inaccurate information from the well file well SS-25? In that instance would you be able tell certain of the information from the SoCalGas SS well 25 well file was inaccurate?

MR. LOTTERMAN: Your Honor, I will object to this for calling for speculation.

MR. GRUEN: Well, your Honor, I'm not -- sorry.

ALJ HECHT: Go ahead, Mr. Gruen.

MR. GRUEN: Your Honor, I'm asking for his stated knowledge. I'm not asking him to guess.

ALJ HECHT: He can answer to the best of his abilities.

Go ahead, Mr. Gruen.

MR. GRUEN: Thank you.

Q Just to restate, would you be able to tell if certain of the information from the SS-25 well file was in accurate?

A Okay. Sticking to SS-25, Mr. Gruen. So for example we had a lot of the temperature surveys, we had a lot of special surveys. So with a lot of that information, we can assess that really no workover happened in SS-25.

So I don't know the answer to the question because inaccuracy can be small, can

be large, and it's very difficult for me to even state of the intelligence on that. Yeah, the data tells us a lot. When you analyze the data, the data tells you a story. If the story doesn't fit or there are gaps, we normally can figure that out and we didn't see any.

But that doesn't mean -- I don't know how to answer that question. I don't know if I answered your question, but.

Q Did you have an opportunity to quality check all of the information on the SS-25 well file for accuracy?

A Oh, yeah. Because if we see a temp -- so I'll give you an example. If the temperature log indicated some issues, and so what you look in the data is that trend will continue or the trend will appear. So you're looking for other things.

So we do do quality checks absolutely. We have to. We use that information to model and analyze. So the information that's provided, we do quality checks.

Q Okay. Thank you. And the quality checks -- I think you had begun to answer that certain pieces of data, maybe the smaller pieces of data, might have been

inaccurate without you knowing. Could the quality checks have pulled for the smaller pieces of data or inaccurate data whether those were in fact inaccurate?

A Let me phrase it another way, Mr. Gruen. So if the data impacts any of my conclusions, we would throw it out. If there is something -- I made a conclusion that wall thickness inspection is necessary or required and wall thickness was done or some such thing, then I would drill down. So I don't know if I'm answering the question.

But any data that would impact my conclusion, I -- we would throw it out whether it's small or big. I don't know whether I'm answering the question.

So I -- we did do QC on all the data pretty much. So we analyzed -- normally in a normal course of operations, you will have some information not match exactly and we pick those up.

Q Okay.

A But I can't say every little issue we picked up, no. I wouldn't be able to say that.

Q Okay. Thank you, Dr. Krishnamurthy. Moving on do you recall being asked by Mr. Lotterman whether you

found a quiet period? I believe that was the term he used and forgive me if I misstated it. But whether you found a quiet period where there were no leaks in the Aliso Canyon field for whatever reason?

A Yeah, again, I am going by my memory, which is sometimes dangerous. There was a period if I remember right if you read the casing -- Aliso Canyon casing integrity section. The period of time where the number of incidents dropped, the number of casing integrity incidents dropped, and I believe that's what Mr. Lotterman was referencing, and that's what I -- that's how I answered.

Q And in response to that, I believe part of your response was also that there was a period where a number of leaks were lower. And you added that when a casing does not perform its function as defined, Blade called it a failure. And you included the term "tight spot" in what you considered a failure. Do you recall that?

A Yes. Yes, I recall it.

Q Thank you. And we reviewed the Blade report as best we could, SED did, and could not find a tight spot identified in the Blade report specifically with regards to well SS-25.

Do you recall whether the Blade report identified any tight spots on the SS-25 well casing?

A No. We did not find a tight spot in SS-25; that's correct.

Q Okay. Thank you. And if Blade had identified -- so hypothetically if Blade had in fact identified a tight spot on well SS-25, would you have considered that to be a casing failure then?

A Yes. In our report on the historical casing failures section, we defined what compromises the functionality of casing. And tight spot is one of them.

Q Okay. Thank you.

A It is an important factor if there was an event like that.

Q Thank you, Dr. Krishnamurthy. So another hypothetical if I can. If there was an indication of a leak above or below the packer in SS-25 that you described to Mr. Lotterman in some detail yesterday I believe, would that impact the findings and conclusions of your root cause analysis?

A Above the packer, you know, let's review -- it's a hypothetical question. We didn't find one of course. However it may. At most probably it may not, Mr. Gruen,

because it so deep in the well, you know, 8,500 feet. And -- (inaudible). So it's much shallower. So it may not have a material impact on it. We would have attempted to figure out why it did. It would be important because it happened in SS-25. But it may not have directly impacted the failure analysis. May or may not. So probably not.

Q Okay. And why given your answer "probably not," why not?

A Because, again, you have a packer issue. The packer implies maybe a tubing issue, okay. So if it is a tubing issue, that's really not relevant for a casing failure. Tubing may be a separate problem. We would have flagged it if there was an issue with that.

But it won't have a material impact on the interpretation of the failure at 892 and root causes.

The root cause to be identified if you -- the definition of a root cause: If it needs to address events similar to SS-25 and any other casing integrity instance. It should. The root cause analysis all sorts of incidents. Not just the -- type of failure to address the packer in any of these so.

Q Thank you, Dr. Krishnamurthy. And just to clarify, I believe you were talking about tubing leaks there if I understand correctly.

Let me change the hypothetical slightly. What if there was an indication of a casing leak above or below the packer in SS-25? Would that impact the findings and conclusions of your root cause analysis?

A It would be very important because we ran logs not all the way to the packer or below the packer -- above the packer in the casing if I remember right. So we didn't find any indications or any trends that showed us the seven --

Q Okay.

(Crosstalk.)

A However, if there was a leak at the packer, yeah. It may impact. It may impact.

Q Okay. Thank you. And do you recall -- just turning to another point. Do you recall being asked whether there was any other way to check for why or how SS-25 failed other than through the process of pulling the tubing?

A Yes.

Q And you said "no" in that case; is that right?

A Yes. Because the SS-25 -- just to explain that answer. SS-25 ruptured and parted, yeah? So that is a big failure. You can't run logs in that case. You can run tubing logs like we ran, but you won't know enough about it. You will know it's parted, but that is really all you will know at that point.

Q Thank you. And under what conditions would SoCalGas, if any, under what conditions would SoCalGas be able to check for how or why a well failed without pulling the tubing?

A Again, without pulling tubing, that's a different question. Without pulling the tubing the way the weight has been monitored with temperature logs and noise logs, you know there's a hole, there's a leak. That's really what you would know.

Now, based on that information you can then look and say, "Okay. Is there an environment internal to the casing that could cause corrosion?

And if you like the gaps, you conclude like we concluded the gaps cannot cause the corrosion.

So by process of elimination, you could assess then, "Hey, this has to be

happening from the outside. If it's not happening from inside, it has to be happening from the outside."

So that is one way of doing it. But it would be a hypothesis. You would come up with two or three possible reasons and you would attempt to mitigate all of them assuming you cannot pull the tubing, you can't do any of these other things.

Q Thank you. Okay. Turning to another point another line, do you recall being asked in Mr. Lotterman's cross-examination about SoCalGas's communications with DOGGR to inform the Blade report?

A Can you repeat, Mr. Gruen? I apologize. I didn't follow.

SoCalGas communication with DOGGR.

Q Yes. Just generally if I recall Mr. Lotterman did ask just this morning about if you had reviewed specifically the communications that SoCalGas had with DOGGR in order to inform your -- the Blade main report. Do you recall him asking about that?

A Yes, yes, yes.

Q And if I understood your answer correctly, you said you did not check communications between SoCalGas employees and

DOGGR. But the entire report is based on extensive data that was obtained from SoCalGas and DOGGR records. And I believe you also included general rate cases. Did I understand that answer correctly?

A That's correct.

Q Okay. So with that understanding, if we could pull up the Blade main report?

A Can I explain -- expand a little bit, Mr. Gruen, on that answer?

Q Yes.

A And clarify?

If DOGGR -- if DOGGR -- if DOGGR included those communications as part of the documentation for their well on the website, we would have it. Or if SoCalGas had it as part of the well file, we would have it. I want to be very clear.

Q Understood. Thank you Dr. Krishnamurthy. And if I may with that if we could turn and using the screen share pull up the main report, the Blade main report.

And just for -- while we're doing that, I use the term "Blade main report." I believe that was the same term Mr. Lotterman used. You'll understand that I'm referring to Blade's root cause analysis; is that correct? Of the Aliso Canyon -- the release

from Aliso Canyon well SS-25?]

A Yes.

Q Thank you. So turning to page 245 here, I believe. You see that this is page 245 of Blade's main report?

A Yes.

Q And if you look at references 54, for example, do you see that? There's a reference to DOGGR's "History of Oil or Gas Well," from September 8, 1988.

Do you see that?

A Yes, I do.

Q And also reference 65 toward the bottom of the screen as we see that that's the "P-50A Well History File from SoCalGas."

Do you see that as well?

A Yes, I do.

Q And that one references -- the date in that one is 2016, I believe.

Do you agree?

A Yes.

Q And the date for the top one, I failed to mention, looks like 1988.

Does that look right to you as well?

A Yes.

Q So would you agree that these are examples of history records?

A Yes.
Q Okay.
A Or Well Files, or it could be from the Well File.
Q History records or Well Files. Understood. And do you recall how in the -- let's stick with history records for a second. How did you acquire those documents if you would?
A So looking at 54, that would be from DOGGR. Okay. It says, "Division of Oil, Gas, and Geothermal Resources." That's where we would have got that data set. Now, the bottom data set we obtained from Southern Cali -- from SoCalGas, so that's the source document.
Q I see. And this illustrative, is it not, that these history files, the sources of those documents were either from DOGGR or from SoCalGas; is that right?
A That's correct.
Q Okay. Turning to Well SS-25, the Well File there that you reviewed, did that contain a folder titled "Well History"?
A That is very specific, Mr. Gruen. I'll need to check. I don't recall.
Q I don't know if it will be necessary for this line of cross. I could

maybe ask it more generally and see if this refreshes your recollection just to keep things moving forward.

Do you recall if Well SS-25 had well history information akin to what we're reviewing on this page?

A I'll have to check. My guess is yes. Okay. Now, it may not be titled that. I see -- I'm looking at the references now. We got an SS-25 Well File so that had 2,000 pages in it. I'm reading from a reference here, Mr. Gruen. And also we got from DOGGR an SS-25 chronology summary, so an SS-25 event every which way to get data.

And there was also towards early 2019 we got a lot more electronic data on 25, 25A, 25B, which in many cases we had already been provided. But as an abundance of caution, there was some additional information provided by SoCalGas and so we did get a lot of data. But, yeah, looking at "History of Oil and Gas Well," did we have a file titled exactly that for SS-25? I cannot answer. But we did get a Well File on SS-25.

Q Understood. I'm tracking you. Thank you, Dr. Krishnamurthy. And do you recall -- just with regards to the history documents that we've been talking about, do

you recall seeing history documents on Well SS-25 between 1997 and 2015?

A I don't recall. That doesn't mean it's not there so I want to be careful. I need to check. I can get back to you.

Q Understood. If it was there, would it show up in the Blade report in these references here?

A It may or may not. Can you go to Reference Number 8.

Q Sure.

A I'm looking at Reference Number 8. It may show up in 8, so it may be a subset of that. Okay. So I want to -- so you can see the facility. That is one. And then you go back at 6, it tells you the chronology summary. So there was a lot of data and information on SS-25 so I want to be careful to say. It may be contained in that so I don't want to say it is or it isn't.

Q I see. Okay. Would there be any other references that we could check to see if that information is available -- was provided to Blade?

A Those would be the two references. I'll have to look carefully and talk to my team because, as you can imagine, everybody who has worked on it has gone through the 25

data set for sure.

Q Yes. Understood.

Your Honor, if I may, if we could ask for an answer. If Blade could consult and get back to us with an answer to that question, we'd appreciate it for the record.

ALJ HECHT: Are there any objections to that request?

MR. LOTTERMAN: I guess my only concern, your Honor, is this going to be a written submission or are we going to drag poor Dr. Krishnamurthy back into this proceeding? What did Mr. Gruen have in mind?

MR. GRUEN: Your Honor, I certainly have no intent of having Dr. Krishnamurthy testifying any further than he needs to. It was -- in asking this question --

Q Maybe I should clarify, Dr. Krishnamurthy. How burdensome for you is this question?

A Let me rephrase your question, Mr. Gruen, and see if it makes sense and then I'll answer the question.

ALJ HECHT: I'm going to ask to pause for a moment. I believe that Ms. Frazier would like to say something and I'd like to give her that opportunity before we continue.

MS. FRAZIER: Thank you, Your Honor.

Mary Frazier on behalf of Blade. If I -- I guess what I would suggest is maybe we take a break so that I can visit with Mr. Krishnamurthy to figure out what this entails and then we can report back on whether it's something we're able to do or not.

ALJ HECHT: I think that's a better idea.

Mr. Gruen, is it possible to continue with other questions and take a break later after that to find this out or would it make more sense to take a break now?

MR. GRUEN: Your Honor, we can do whatever your druthers are. We can move on or, if you would prefer, we can take a break now. Either way.

ALJ HECHT: All right. I'm having computer bandwidth problems so we will take a break. We will take a break for 10 minutes coming back at 2:48. Thank you.

MR. LOTTERMAN: Your Honor, I'm sorry, before we do --

THE REPORTER: Are we off the record?

ALJ HECHT: No. We are not yet off the record, and I apologize. I was about to say that.

THE REPORTER: Thank you, Judge.

ALJ HECHT: Mr. Lotterman, you were saying.

MR. LOTTERMAN: Yeah, I wanted to get this on the record. Could I understand exactly what Mr. Gruen's ask is.

ALJ HECHT: That's a good idea.

Why don't you repeat that.

MR. GRUEN: The question is any history documents, either the DOGGR History of Oil and Gas Wells or SoCalGas Daily Well Activities in the SS-25 Well File for the period from 1997 to October 2015.

MR. LOTTERMAN: And so are you asking Mr. Krishnamurthy to confirm they exist or to produce them or what?

MR. GRUEN: The question is whether or not Blade had access to that information while during the preparation of the Blade root cause analysis and supporting attachments.

ALJ HECHT: To be clear, you're not asking that they actually produce those documents because --

MR. GRUEN: That is --

ALJ HECHT: -- the --

MR. GRUEN: That is correct, your Honor. We're not asking Blade to do a data gathering exercise at this point.

ALJ HECHT: Okay.

MR. GRUEN: My apologies if we left a different impression.

ALJ HECHT: Thank you.

With that understanding, I'm hopeful, Ms. Frazier, that you can check with your witness and when we get back, we can address this.

That being the case, it is now 2:40. We'll take a 10-minute break until 2:50. We will return then. Thank you, everyone, and thank you Dr. Krishnamurthy.

THE WITNESS: Thank you.

ALJ HECHT: Appreciate your time.

THE WITNESS: Thank you.

(Off the record.)

(Recess taken.)

ALJ HECHT: We'll be back on the record.

While we were off the record, we got some clarification on the ability to answer that last question.

Mr. Gruen, I believe that you will ask the question again and we'll go from there.

MR. GRUEN: Yes, your Honor, certainly.

Q Dr. Krishnamurthy, before the break, do you recall I had asked you just for

the record do you recall seeing any history documents, either the DOGGR "History of Oil and Gas Wells" or "SoCalGas Daily Well Activities" in the SS-25 Well File for the period 1997 to October 2015.

I understand you have a preliminary answer to that question and that you are going to check to be sure that the answer is accurate by tomorrow.

A Yes.

Q Very good.

A Yeah. Thank you, Mr. Gruen. Yeah, we believe we have a lot of -- we have data post-1997 to 2015. We have -- we believe we have logs, we have various things regarding data from SS-25. Like Mary mentioned, we will confirm by tomorrow, but we believe we have data post-1997.

Q Okay. And if you could, just for clarification, if you could clarify whether you got that data from DOGGR or from SoCalGas.

A Yeah. We should -- we'll try to confirm that.

Q Okay.

A But we do have substantial data. We also have the weekly pressure measurements and other information that we've used so I'll

confirm that.

Q Okay. Thank you.

MS. PATEL: Your Honor, this is Avisha Patel for SoCalGas. May I interject an objection for this line of questioning?

ALJ HECHT: Before we do that, I am going to say I'm still having technical difficulties so I am going to hand the lead back to Judge Poirier for the rest of the afternoon, so he will be the one responding to your question and I apologize for that. It's a video problem. My audio is fine.

ALJ POIRIER: Ms. Patel, please go ahead.

MS. PATEL: Sure. The basis for my objection is that in December of 2019 SED data requested all the documents that Blade reviewed in the course of its investigation from Blade, and Ms. Frazier provided a copy of that to SED, again, December of 2019 and we actually got a copy of that hard drive as well. So Mr. Gruen is actually in possession of this information that he's asking the witness to go research tonight.

ALJ POIRIER: Mr. Gruen.

MR. GRUEN: Your Honor, it's my understanding from our witness that we haven't been able to get certain of this

information from SoCalGas, so we have concerns that it hasn't been provided to Blade. But if we're mistaken, we'll certainly defer to Blade to provide that answer. But we think it's helpful for the record just to be sure that Blade was given the information. In light of Blade saying they can provide this by tomorrow, we don't think it's a particularly onerous task. We think it's quite doable. This is a quick check of a drive it seems.

ALJ POIRIER: Ms. Frazier.

MS. FRAZIER: I just wanted to point out one thing. We weren't anticipating producing anything. We were just going to confirm whether the information exists.

ALJ POIRIER: Okay. I'm going to overrule the objection. I think if it's just the confirmation, let's go ahead and do that. I'd like to move on with the hearing today.

So, Mr. Gruen, please continue.

MR. GRUEN: Thank you, your Honor. And just to confirm, our understanding matches that of Ms. Frazier's, that this is only for a request for confirmation.

Q With that, moving on, this is the next line of questioning. That's all I had on that one.

Dr. Krishnamurthy, do you recall being asked questions yesterday from Mr. Lotterman about SS-25 having both tubing and casing? Sorry, Dr. Krishnamurthy, I think you may be on mute.

A Yes. I apologize. I was on mute. Yes.

Q Not at all. And the purpose of the tubing? Do you recall being asked about that as well?

A Yes, I believe, yeah.

Q And if I -- okay. Pardon me. Now I'm talking over you. I'll do my best not to. You responded, if I understood correctly, that tubing was initially for oil production.

Do you recall that?

A Yes.

Q Was the original construction of SS-25 as an oil well intended to include service for extraction and injection of high-pressure gas through the annulus between the tubing and the casing?

A The original design of the well was an oil well as you mentioned and Mr. Lotterman mentioned. It was converted into a gas well in the late 1970s, I believe, mid to late 1970s. So, yeah, the initial

intent of the well was probably an oil well, that's correct.

Q Okay. And just to be sure I have a clear understanding to my question, the original construction of SS-25 as an oil well, was that intended to include service for extraction and injection of high-pressure gas through the annulus between the tubing and casing?

A That design would not have envisioned that. That design would have envisioned -- what you do normally in an oil well or a gas well is -- in conventional oil or gas well, I'm not talking about storage -- you produce through the tubing and you design the production casing to handle that entire pressure, so that's really would have been intent of the design.

Q Thank you.

A As an oil well.

Q Yes. Understood. Thank you.

Dr. Krishnamurthy, do you recall being asked if you heard Ms. Felts testifying earlier prior to you testifying?

A Yes.

Q And you said that you had listened; is that correct?

A Very little. It was a half hour or

so. I just couldn't peel off some other things I was doing so I did not attend as much.

Q Okay. Did you happen to hear SoCalGas asking Ms. Felts if she had seen information that Blade did not have for purposes of producing the Blade main report and the supporting reports?

A No, I did not hear that question.

Q Okay. Following the Blade report, the issuance of it in May 2019, you're aware that the Commission ordered -- opened an Order Instituting Investigation and an Order to Show Cause; is that correct?

A Yeah.

Q Okay. And that's the incident proceeding where you're testifying.

You understand that?

A Yes.

Q And were you aware that during the course of this proceeding, SED --

(Reporter call dropped.)

ALJ POIRIER: We'll be back on the record.

Why don't you restate, Mr. Gruen. Mr. Gruen, you're on mute.

MR. GRUEN: I'm sorry. Can you hear me?

ALJ POIRIER: Yes.

BY MR. GRUEN:

Q Dr. Krishnamurthy, during the course of the Order Instituting Investigation and Order to Show Cause, were you aware that the Safety and Enforcement Division asked Southern California Gas Company data requests?

A I'm not aware, but I'm sure that happened.

Q Okay. So that's after Blade issued its root cause analysis; is that right?

A Correct. Correct.

Q And since you're not aware, you did not review any of the data responses that SoCalGas provided in response to SED's data requests of SoCalGas during the course of this proceeding.

Is that also true?

A That's correct. That's true.

Q Thank you. Mr. Krishnamurthy, if I could turn to another line of questioning -- I'm sorry, Dr. Krishnamurthy. I should be more careful and accord you the respect that you're due. Do you recall that you had originally told SoCalGas -- and I believe it might have been the Commission as well -- that Blade intended to produce its root cause

analysis; that is, the main report and supporting attachments, in March of 2019?

A I don't remember saying that, but it's possible. I don't remember saying the March deadline, Mr. Gruen, but it's possible.

Q Okay. Maybe if I just state it more generally. Do you recall that Blade had let SoCalGas and SED know that Blade was intending to publish its main report and supporting attachments prior to May of 2019?

A Yes. We had a couple of deadlines and March was one of them. We were thinking of finalizing it in March.

Q Okay. Thank you. And so I'm noticing the discrepancy in dates there between Blade's intent to finalize in March and Blade actually finalizing in May. So if I may, why wasn't Blade able to finalize the main report and supporting attachments that it produced until two months after it had initially projected?

A Yeah, our target was, if I remember right -- and, again, I'm going back deep into my memory bank. Sometimes it's challenging -- it was around middle of March, if I remember right, Mr. Gruen, middle of March. And then we got some additional data, electronic data. For me, the most important

part of this project was to make sure we are not missing any data because the data there is crucial to our conclusion, in addition to all the physical evidence. And so we were given data, I believe in February, February of -- or January. I forget. Don't hold me to the dates -- in electronic form to con -- I believe that that (inaudible) from SoCal was just to make sure we are not missing anything.

And so we went through that data to make sure, and really that data had been provided in other forms and we had already had it so it didn't make any change to our conclusion but we wanted to check everything. It gave us a bit more time to tighten up a few things and so that's why it went to me.

So I don't want to say it was only the data. Data was part of it. And also we wanted to tighten and couple of things, but I did want -- we did want to confirm that we had anything materially new in the data set that could change our conclusions or modify or inform it differently.

Q Understood. Thank you. And did that new data -- do you recall whether that came in before or --

(Reporter call dropped.)]

ALJ POIRIER: We'll be back on the record.

Mr. Gruen, please go ahead and proceed.

BY MR. GRUEN:

Q Dr. Krishnamurthy, before the break, we experienced some technical difficulties there. But before the break, we were discussing the discrepancy between when Blade announced, initially, it would finalize its main report and when Blade actually produced the main report.

And if I understood right, the approximate dates, the initial statement was March of 2019 when Blade would finalize. And Blade actually ended up publishing in May of 2019.

Is that accurate?

A Yes. That's accurate.

Q And I had understood your answer to be that Blade -- you -- -- that Blade had received some additional data from SoCalGas prior to the finalization March date of the Blade data report. And that was part of the reason for change in dates.

Did I characterize that accurately?

A That is correct. I want to be careful. That is part of the reason. Of

course, it also gave us a chance to work it and make sure everything was right.

So we had to review the data just to check and make sure everything was there, and it was not an issue. It didn't change. But we had to check a few things, make sure some new information was not there that we may miss.

Q Okay. And did SoCalGas provide the new data that you were just referencing before or after Blade mentioned that it was intending to finalize the main report in March? Do you recall?

A I don't recall, Mr. Gruen. I don't recall that at all.

Q That's okay.

A That is quite a challenge. No, I don't recall.

Q I agree with Mr. Lotterman. I'm, frankly, in awe of your memory. So I certainly appreciate your answers.

If I can, the data that Blade received that you were just referencing, would -- were these data provided in response to data requests that Blade had issued?

Do you recall?

A I don't recall. But I can go back and check. It would be in request (sic) to

some of our data requests. But, like I mentioned, we checked everything. And I believe it was -- I want to -- I want to say it was 25-A there was some data, 25-B there was some data. But this data we had already received before, I believe. And so it didn't really have an impact. But we had to check everything.

Q Okay. Let me just -- let me ask you, if I could, I believe that Mr. Lotterman had asked you about your knowledge of Boots and Coots as a well-kill contractor.

Do you recall being asked that?

A Yes.

Q And I believe your answer -- and correct me if I'm misstating this.

I believe your answer to that was you were familiar with them?

A Yes.

Q Okay. And that you had wanted to talk to Boots and Coots and ask them questions.

Did I understand that correct?

A Yeah.

Again, I don't want to phrase it "ask them questions." It was more -- our goal was, there was -- as I had mentioned to Mr. Lotterman earlier, we didn't see any

modeling, data, results, anything. And we were a bit curious.

And, whereas, kill number 7, there was a lot of good information. We understood what was done. The other kills, 2 through 6 we couldn't see it. And that was the intent of the question.

That was the clarification we wanted to have. That was the reason for wanting to meet with them and understand what was the thinking behind each of the kills so that we can reflect that in our analysis.

Q Thank you --

A That was the intent of our request.

Q Thank you, Dr. Krishnamurthy.

And in -- was Blade granted access to asking questions of Boots and Coots, or to communicating with them about what you just described?

A No, we couldn't. We didn't have the ability to do that yet.

Q Okay. So that's an example of information that you wanted to get but weren't able to get during the course of root cause analysis; is that right?

A Yes. Yes.

So the assumption we made -- so consequently, as we articulated in our

report, we assumed modeling was not done. And other factors guided us in that conclusion. So that is why we were comfortable to write the report at that point.

If I were -- if we were not comfortable writing the report, we would have attempted to do some other stuff. But we had enough information to write our report. So we decided to go without that information.

Q Understood.

Your Honor, at this time, that's all I have on redirect.

ALJ POIRIER: Thank you, Mister --

MR. GRUEN: And if I could just thank Dr. Krishnamurthy and Blade for all their hard work and their contributions to the proceeding.

Thank you very much.

ALJ POIRIER: Thank you, Mr. Gruen.

I believe Ms. Bone indicated that she had a short amount of clarification cross.

Ms. Bone, are you ready to proceed?

MS. BONE: I am. Thank you, your Honor.

ALJ POIRIER: Please go ahead.

///

CROSS-EXAMINATION

BY MS. BONE:

Q Dr. Krishnamurthy, good afternoon.

A Good afternoon.

Q My name is Traci Bone. And I'm representing Cal Advocates in this proceeding.

And I wanted to be clear that I'm not an engineer. So please bear with me and correct me where you need to.

Can you do that for me?

A Yes, I will.

Q Okay. Thank you.

On cross-exam with Mr. Lotterman, you seem to agree that SS-25 was pressure tested at over-the-average pressure in the well field, at an operating pressure over that of the general field.

Do you recall that discussion with Mr. Lotterman?

A Yes, I recall. May I clarify that statement a little bit, just so that --

Q Please.

A Is that okay?

Yeah. What I -- what we wrote in the report, and what I meant to say to make sure I say it correctly, is that the well was tested above the pressure it was supposed to

operate at as a gas storage well, giving yourself a safety factor. That is what I meant. Okay? I want to clarify.

Q All right. Thank you for that clarification.

Do you know when that pressure test was performed?

A I believe it was '73 or '77. That's the timeline that sticks in mind. But, yes, that would be the time.

Q Did the utility perform any other pressure test after that time on SS-25?

A No.

Q Is there anything that you know of that prevented SoCalGas from pressure testing the well after that time?

A You would have to pull the tubing to do the pressure test. That's the only way I can think of. There are other ways to do with the tubing, but it’s more complicated, so -- so that would be one issue. And then we would kill the well.

Those are some things to do, which I believe Mr. Lotterman asked me questions on that. So those are things you would do. You would pull the tubing, kill the well, and then do the pressure test.

Q So how often do you believe that a

pressure test should be done to ensure the mechanical integrity of a well?

A Yeah. I'm not a fan of the pressure test. So I'm talking as a technical opinion, Ms. Bone. Because the way I would -- which we articulate in our root cause of solutions, we don't recommend a pressure test. What we would recommend is a wall thickness inspection instead and periodic timeframe. And there's a reason for that.

What a pressure test does for you is, if you have a corrosion that is deep enough to fail, it will cause it to fail. And that is what we would call a trailing indicator. By that time, the casing has failed. So you would want to do wall thickness so that you prevent -- it prevents a pressure test or underoperation. That is what you want to do.

That is why a pressure test is not an ideal way. It is a more complicated way. It's not a simple way in a wellbore. And like a pipeline, which is the result when external pressure is constant, when you look at a downhole casing, there is an external pressure to the casing, which we call pore pressure. And that changes with depth, so...

Q Okay. So, it sounds to me like you

would prefer ultrasonic imaging tools or magnetic flex leakage tools to be used; correct?

A Yeah. Those are better options and more practical and easier options. Yeah. That would be the better option.

Q So when you say, "easier," they are easier to implement than a pressure test?

A No. It is easier from a mitigation point of view. So you -- you don't go to the point of which a pressure test and you have a hole. You want to do it before that. So that is why a well-thickness inspection is better.

Q So do you believe that a USIT or an MSL tool could have detected the corrosion in SS -- in SS-25's casing before 2015?

MR. LOTTERMAN: Objection, your Honor. I'm going to object on several grounds, vagueness is one.

What time period is she talking about? The day before? Or let’s say 1982?

I guess that's my main objection. I would like a timeframe.

ALJ POIRIER: Ms. Bone, can you restate, please?

BY MS. BONE:

Q Sure.

Do you believe that a USIT or an MSL tool could have detected the corrosion in SS-25 in 2015?

A Yes. In 2015, it could have.

Q And could it have detected corrosion in 2010?

MR. LOTTERMAN: At this point, your Honor, I will object on speculation grounds as well.

MS. BONE: Your Honor, I would remind everyone that yesterday Mr. Krishnamurthy testified that the corrosion was very, very slow. And so it seems like he may have a sense of how long, how far back the corrosion would have been existent in the pipe.

ALJ POIRIER: Objection overruled.

Mr. Krishnamurthy, please answer to the extent you can.

THE WITNESS: Yeah. It would be -- I don't want to use the word "speculative." I would be making an educated estimate of some of this. So we want to be careful.

The data we looked at in literature for metallogens and bacterial corrosion showed a low corrosion rate. And depending on how you measured it in this well, it could be a bit higher, could be a bit lower, so that is why I called it -- it’s a hypothesis

or a speculation. But I would say in 2010, you would have seen it. That would be my guess.

BY MS. BONE:

Q What about in 2005?

A I would have to do -- I would have to do some thinking to come up with those. So wha- -- the way an engineer or a scientist would do that is, you would bring a lower bound and upper bound and say, "How back could I go?" And I would have to do that kind of an analysis to go beyond, say, 2010 or 2005 to understand what is an upper bound of cor- -- so if you can understand my question, is the corrosion rate at 17 mils per a year -- mills is 1,000th of an inch -- then I would say, "Hey, probably 2010 is the limit." But if the corrosion rate is 15 mils per a year, then 2,000 is the limit, you know what I mean?

I haven't done what I would call an upper bound, lower bound corrosion rate to truly establish what those boundaries are. So I would -- it would be close speculation at this point, if I go beyond that 2010. But -- by "beyond," I mean before 2010.

Q So do you have an opinion as to how often an MSL or a USIT inspection should be

performed?

A Yeah.

Again, like we discussed earlier, you don't want to remove the tubing every year or two years. It’s too -- it is not a -- it is not something necessary. So you have to understand the corrosion rate phenomenon.

So what I would do in a case like this is, I would say every 10 years, every 15 years to be conservative. 10 or 15 years is more than adequate, if not longer. Depend -- see, the problem with that answer is, it depends on the corrosion mechanism. That goes back to the root causes or solutions we identified.

You want to understand the mechanism of the corrosion, which will then inform you on what rate this corrosion is growing. If it's microbiological, it's one way. If it's CO2, it’s another way. And once you understand that, then you can come up with the frequency. But the frequency has to be defined by or -- informed by the mechanism in place.

Q Thank you, Mr. Krishnamurthy.

Could you -- we've heard some discussion about pressure tests and also

pressure surveys.

Can you tell us what the difference is between a pressure test and a pressure survey?

A Absolutely. I -- and I want to clarify something that I answered earlier when Mr. Lotterman asked me.

So the pressure test is what was done in 1973. I just found the date on the report, so that's why I'm a little bit more confident. In 1973 when the conversion happened, a pressure test was done.

So you're actually putting a retrievable bridge plug at the bottom, separating the reservoir from the well. And so that pressure test actually pressures the casing. And you go -- they go back up and they pressure different portions of the casing like they did in '73. And, like I mentioned earlier in your Q and A, that pressure test was above the safety factor -- or above the pressure anticipated in the wellbore.

Whereas, a pressure survey is, you're open to the reservoir at that point, your reservoir is still there, and you're running a transducer mapping the pressure inside the tubing. Okay? That is a pressure

survey done.

Now, I misspoke when Mr. Lotterman asked me this question. This is one of the clarifications I was going to make is, you would have -- since you're running it through the tubing, a small casing leak would not be picked by the pressure survey. The pressure survey quite often is done to establish the reservoir pressure, understand what the reservoir pressure is over time, which is an important data point to have.

So when you're running it through the tubing, you're going to see that now the casing had a massive rupture or leak which, of course, other things would have found it. You would see the bottom hole pressure shift. But in the leak situation, or under other failure situation, a pressure survey will not help. The temperature and the noise is far better tools that were used.

Q Far better tools to do what?

A To monitor leaks or identify leaks.

Q Would a pressure survey be expected to reveal the corrosion from the SS-25 production casing?

A Not the way I understand the pressure survey that is done, yes. No, I don't believe so.

Q Okay. And do you believe that a noise log or a temperature survey would be expected to reveal the corrosion in the SS-25 production casing?

A No. Those are what we call trailing indicators. So you need to have a leak already in place. And then the temperature will tell you right away. So it would be a very good indicator to that. But prior to that, it won't. And that is why in SS-25 there was never any indication of leak ever in the history. We didn't find any.

Q Thank you, Dr. Krishnamurthy.

Mr. Lotterman also asked you about what kind of tests might be available to measure the wall thickness of a surface casing.

Do you remember that?

A Yes.

Q And as I understood it -- and, again I'm not an engineer -- it’s saying that you agreed with him that if you wanted to measure the wall thickness of a surface casing, you would have to remove the production casing to measure the wall thickness.

Do I have that right?

A That is correct. Again, let me

clarify and explain further. Yeah? Because that's an important -- so the way we did it in SS-25 as part of our RCA, we wanted to have had a good handle on where was the corrosion, how much. So we did a direct measurement.

Now, since I don't know the timeline on this, close 2016 or 2015 or -- there are tools today, they are not accurate by any means, they -- what they do is they run through your tubing, and they identify leaks in multiple casing --

ALJ POIRIER: I'm sorry --

THE WITNESS: They are not -- the reliability --

ALJ POIRIER: I'm sorry, Mr. Krishnamurthy. We have some background noise.

(Off the record.)

ALJ POIRIER: Let’s go back on the record. Please continue. I apologize for interrupting you, Mr. Krishnamurthy.

THE WITNESS: That is okay.

So that is correct. To do a good measurement of well thickness loss, you have to pull the casing to render evaluation. But as part of SS-25, our RCA, we identified technology that per- -- I don't know when it

came to market. It was new to me when I -- when we looked at it in 2016. I -- and this technology has been floating around. It's still -- reliability is an issue.

But what they do is, they give you a qualitative estimate of wall loss in different strengths. They are not as accurate as some of the tools we ran. But, currently, there are some technologies that do -- the reliability or repeatability, all that should be reviewed in detail. We did it for an RCA where -- that was -- we wanted to get an indication. But when I'm attempting to do this on a field-wide basis, I would work it a lot harder before I come to that conclusion. That is an option.

Q Okay. Thank you for those clarifications. My question is a little more simplistic than all of that.

And it’s just that I got the impression that it was a very significant undertaking to remove production casing; is that correct?

A That is correct. It is a significant undertaking.

Q Okay. And -- but, there's a difference between a surface casing and a production casing; is that correct?

A Yes, it is.
Q Okay. And so in your report, you found that SoCalGas's failure to perform a -- a wall thickness inspection for the production casing was the issue, not whether they had measured the wall thickness of the surface casing; is that correct?
A That is correct.
Q And that, in fact, SoCalGas's failure to perform a wall thickness inspection for the production casing was a root cause of the incident; is that correct?
A Yes. That was one of the root causes. That is correct.
Q So SoCalGas did perform wall thickness inspections between 1988 and 1990 for the seven wells that were Vertilogged; is that correct?
A That is correct.
Q Do you know why they didn't perform Vertilog on the other 13 wells that their engineer recommended?
A We didn't find any record of the rationale for it in the documentation. I believe, at some point, we requested it -- and, again, I'm testing my memory here -- and SoCalGas gave us the rationale for it. I -- I don't recollect what that rationale was.

But we didn't find any records from 1988, 1991, '94 stating this is why it was stopped. And we articulated that in the report.

Q Thank you.

Dr. Krishnamurthy, I just have one other short line of questioning and then we'll be done, if we can continue.

I believe that yesterday you testified that the water found around the surface casing for SS-25 was from rain and that that was the only source of water; is that correct?

A That is correct. Yes.

Q So is it strange or surprising to you to find rainwater around the surface casing?

A I don't want to call it strange. But when you look to the shallow geology in Aliso, about 200, 300 feet shallower, I mean 0 to 200, 300 feet, the rock is weathered and it has a lot of permeability. So it makes sense that you would have precipitation at 145 -- 80 to 145, which is where some of the largest external corrosion was on the surface casing. And the challenges of cementing the surface casing all add up.

So it -- going in, I would not have expected that. But, again, I didn't know

enough about Aliso at that point. But the shallow geology clearly indicates the rock is weathered and highly permeable where it's -- the shallow result. So it kind of makes -- it adds up.

Q So do you think that the rainwater was present there for a long time?

And by "a long time," I mean, you know, 10 or 20 years?

A I don't know. I wouldn't -- see the challenge there is, what you're dealing with this water is two things. There are two mechanisms possible with water. I'm talking shallow now. Okay? I'm not talking deep in the seven-inch.

When you go down around the seven-inch, around the shoe, which is what we believe initially happened, what you're dealing with is, the water will deoxygenate at different -- so water has some oxygen in its rainwater. The oxygen comes from the air at 20 percent -- whatever the oxygen number is, it will dissolve in the rainwater.

So your first source of corrosion is the oxygen in the water. Once that oxygen is depleted, then other mechanisms step forward. But that oxygen corrosion, with a finite amount of oxygen and finite amount of

water, there will be little bit of wall loss due to it. And then the mechanism may shift the microbiology and other things.

So my expectation is, this would take a long time. How long? You know, those are the things where I would be speculating.

Q Mr. -- Dr. Krishnamurthy, the water that was found around the surface casing for SS-25, is that something that would have been visible during an inspection of the well?

A No, I don't think so. No, it wouldn't be visible.

Q And that concludes my cross-examination. Thank you very much. It’s been a pleasure meeting you.

A Thank you.

ALJ POIRIER: Thank you, Ms. Bone.

I think now we'll turn now to Ms. Frazier.

Are you ready to proceed?

MS. FRAZIER: If we could take a short break, I think that would be helpful.

Mr. Krishnamurthy, do you need that?

THE WITNESS: Yeah. Can we talk for 2 minutes, 5 minutes?

ALJ POIRIER: Let’s take a 5-minute break until 3:40. And then we'll be back on the record.

So, off the record.

(Off the record.)]

ALJ POIRIER: Back on the record.

We took a short break, and now we're back on. Ms. Frazier is going to do redirect for Dr. Krishnamurthy.

Please proceed.

REDIRECT EXAMINATION

BY MS. FRAZIER:

Q Dr. Krishnamurthy, my name is Mary Frazier. Obviously I'm the attorney for Blade and for yourself here at this proceeding today. You understand that; correct?

A Yes.

Q It has been a relatively long two days, and I understand you would like to make some clarifications to your testimony; is that correct?

A Yes.

Q Okay. So I'm going to bounce around a little bit. But to the extent that you need to provide further details on the scope of the question, please feel free to do so.

The first line of questioning relates to the first day when you were asked about a stage collar leak in casing

integrity. Is there anything that you would like to clarify as it relates to the stage collar leak on the SS-25-A?

A Yes, I do. A casing stage collar is part of the production casing, which provides pressure containment. So a leak in the stage collar does affect casing integrity. I misspoke that day. I was focused on problems with the casing itself. But when you put a stage collar in a casing, it becomes part of the casing strength.

So I wanted clarify that. Mr. Lotterman asked me that question. I wanted to make sure I clarified that.

Q There was also a discussion on well mains. Do you know how the well mains in Aliso were selected?

A See I don't know how they were selected in Aliso. But that day I was focused on standard Sesnon which was another formation. When -- when you -- especially when you look at land base wells, they're based on leaseholder names. So my assumption is that Aliso was something similar.

There's somebody more qualified to answer that. But I wanted to make sure I clarify that.

Q Okay. The next area that I want to

visit with you about is surface casing. Can you please provide some additional detail on the purposes of surface casing?

A Yeah. I wanted to clarify this. Again, this is a detail I believe I may have neglected a couple of points when I addressed this. I want to clarify and enhance my answer.

Of course the primary one of the functions of the surface casing is isolate and protect the fresh and groundwater.

The other two are also important roles. It is to provide structural support during well construction. That means during drilling the next section of the well.

And also once you have the surface casing, that is when you put the BOP on and you can drill containment for drilling.

So it has multiple objectives in addition to what I mentioned. So I just wanted to make sure I clarify that.

Q And who is it if you know that proposes the surface casing depth?

A Surface casing depth, normally it would be coming from the -- that depends. Normally the person who is drilling the well will propose the depth for the regulatory (indecipherable) to make sure it covers the

water zone. That is our understanding.

Q Right. Mr. Lotterman asked you some questions about Blade's involvement in revising regulations. Was Blade involved in the revision of storage gas well regulations for California or any other state?

A No. I want to clarify that. Our -- since May 2019, we generate the report. We have not been involved with DOGGR or PHMSA or any other regulators in terms of contributing to any regulations. Nobody had asked us and we have not volunteered.

UNIDENTIFIED SPEAKER: Be careful.

(Crosstalk.)

BY MS. FRAZIER:

Q You confirm reliability several times during your deposition -- or your trial testimony. So the record is clear, can you please describe what you mean by the term "reliability"?

A Yeah. This is a very important term for us. I hate to use the word "nerds," but engineers and scientists. Reliability is a statistical term. You cannot say something is reliable, not reliable. You can say something is less reliable, more reliable. But it has to be quantified.

For example an inspection tool such

as USIT or HRVRT, you would run it 20 times in a well whether it's 1998 or 2016. And you would say it runs just as the -- I have 95 percent confidence it will sight the corrosion within plus or minus 10 or 20 percent. That is the reliability.

So when you say -- so just looking at growth of technology and computers and everything else, 1998 would have been less reliable than 2016.

So we have to frame that it is not reliable, it is reliable. That's not the way we look at it even today. And the downhole tools have -- do not have well documented reliability not even today.

Q All right. Just two more short topics. You provided some testimony regarding API recommend practice 585 and how it applies to gas storage wells failure investigation. Do you need to clarify anything as it relates to that testimony?

A Yeah. Again, we recognized 585 is not for gas storage. We were looking for analogous pipelines that we could reference other than just put up a Blade approach to this.

We followed API 585, which was very good. And the API 585 they are explicit that

other components that are pressure containing such as could be gas storage, could be other wells, other components, could draw and apply their approach. So we researched it. So I wanted to give context to our reference.

Q All right. And then finally before we took our last break before I started asking you questions, Mr. Lotterman believed that you had an incorrect date for the dates the pressure tests were performed.

Could you please look to page 197 of the main report, which I believe is Exhibit-1000, and confirm the dates that the pressure test was done on the SS-25 A?

A Yeah. The -- just to clarify, the pulses of conversions started in May 1973. And pressure tests were done during that time. That is the pressure I was referencing.

But as Mr. Lotterman said, there were additional pressure tests done in '76, '79, in addition to 1973. And that is on page 197. That is correct. I wanted to make sure I clarified my dates from before.

MS. FRAZIER: All right. Dr. Krishnamurthy, that's all the questions I have. Thank you for your time.

THE WITNESS: Thank you.

ALJ POIRIER: Thank you.

Mr. Lotterman, do you have any additional recross on what was covered by Ms. Frazier?

MR. LOTTERMAN: I do not, your Honor. I have one question to ask Dr. Krishnamurthy off the record but nothing else.

Thank you.

ALJ POIRIER: Mr. Gruen, do you have any additional cross based on what Ms. Frazier raised?

MR. GRUEN: Nothing further from SED, your Honor.

ALJ POIRIER: Ms. Bone, do you have anything?

MS. BONE: Yes, your Honor, actually I do. Give me a second to come put myself back on.

RECROSS-EXAMINATION

BY MS. BONE:

Q So, Dr. Krishnamurthy, as I understand it then, there was a pressure test performed in 1976 and then another one in 1979?

A Yes; that's correct.

Q What do you understand that these pressure tests would have revealed at that time?

A Well, the 1973 pressure test was a big one. Okay. And then they had some workovers after that, '76, '79. And there were pressure tests at each site. That is my understanding from the records from SS-25.

Q So the pressure tests that you were discussing with Mr. Lotterman yesterday is that the 1973 pressure test? The one that was done at a certain level above the reservoir?

A That's correct. The others we would have to calculate because it was a single number. So we need to look at -- because remember you have a hydrostatic of 2,500 on surface. What is it on bottom? We haven't checked all that. But either equal or higher. I'll have to check.

Q And is that something that you can do and report back on?

A Sure.

MS. FRAZIER: Let me just interject. And maybe I can visit with Dr. Krishnamurthy off line and figure out what is involved and whether we're able to comply with that request.

MS. BONE: Understood.

Q So you said that the 1976 and 1979 tests were associated with workovers. Is

that something that would normally occur with a workover? You would then do a pressure test?

A No. It would not be normal. It would be something you would have to actually do.

Q And do you have any understanding of why it was done?

A No. My guess would be because it was being converted to a gas storage well. It was part of that process would be my guess. That would be a guess though. I don't want --

Q Okay. And we don't want you to guess. So thank you.

MS. BONE: That's all I have.

ALJ POIRIER: We'll go around once more.

Ms. Frazier, any redirect?

MS. FRAZIER: Nothing from me.

Thank you.

ALJ POIRIER: Mr. Lotterman, do you have anything based on what Ms. Bone just asked?

MR. LOTTERMAN: No, your Honor.

Thank you.

ALJ POIRIER: And, Mr. Gruen?

MR. GRUEN: Nothing from SED at this

time.

Thank you, your Honor.

ALJ POIRIER: Okay. Dr. Krishnamurthy, sounds like you're done. Thank you.

We'll go off the record.

(Off the record.)

ALJ POIRIER: We'll be back on the record.

While off the record, we just discussed some matters in terms of witness order and who is going to be on for tomorrow. And we also determined that there was an outstanding answer from Dr. Krishnamurthy to one of Ms. Bones' questions, and that will be provided another day on the record. And we will be reconvening tomorrow at 10:00 a.m.

And thank you, everybody.

We'll be off the record.

(Whereupon, at the hour of 3:57 p.m. this matter having been continued to 10:00 a.m. March 24, 2021. The Commission then adjourned.)]

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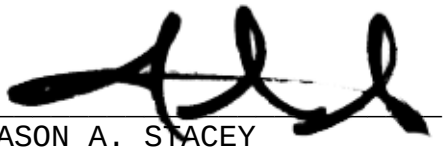

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