BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

ADMINISTRATIVE LAW JUDGES JESSICA T. HECHT and MARCELO POIRIER, co-presiding

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

REPORTERS' TRANSCRIPT
Virtual Proceeding
March 22, 2021
Pages 611 - 803
Volume 5

Reported by: Doris Huaman, CSR No. 10538
Karly Powers, CSR No. 13991
Rebekah L. DeRosa, CSR No. 8708

I N D E X

VIRTUAL PROCEEDING

MARCH 22, 2021 - 10:01 A.M.

* * * * *

ADMINISTRATIVE LAW JUDGE HECHT: We'll be on the record.

The Commission will please come to order. This is day five of the evidentiary hearings in the 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 the Order to Show Cause Why Southern California Gas Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from its Aliso Canyon Storage Facility.

I am Administrative Law Judge Jessica Hecht. I will be presiding today along with my co-assigned judge, Judge Marcelo Poirier. We are both here this morning, and one of us will be the lead at each time. This morning, I will be the lead.

With that, I'm going to reiterate some of the ground rules we went through last week for the benefit of our new participants, and then we can get, I think, pretty well into things quickly.

The basic ground rules are that counsel and parties agree to adhere to the rules and maintain professional decorum. Please speak slowly and clearly. Identify yourselves each time you begin to speak. If there is one primary attorney questioning a witness, it is not necessary for the questioning attorney or the witness to restate their name every time. Please do not interrupt or speak over one another. Please speak only when addressed and called on by the ALJs, unless you're making an objection to a question during the course of examination of a witness. In such instances, after the completion of a question, the attorney may orally interject, provide his/her name, and briefly state the objection. And when there are inaudible statements, the reporter may interrupt the speakers, when it is possible to do so without disrupting the proceeding, or the reporter may insert the word "inaudible" in the transcript when there is dropped, garbled or otherwise indecipherable audio. Therefore, to ensure a -- a complete and accurate record of these proceedings, please adhere to these ground rules.

There are a few other guidelines.

Because we're doing this hearing remotely due to the COVID pandemic, because we are using telephone-only for audio and we are using Webex, but only for video, everybody's Webex will be on mute. We ask that the persons who are classified as speakers for today on telephone keep your phone on mute until or unless you have something to say and you're called on. So everybody please mute your phone when you're not speaking. The ALJs will call upon each person directly, and the speaking party must have both audio and video activated. You need to be visible when testifying, asking questions and so forth. If you experience video problems, we need to know about them. So please let us know. Only the ALJs and the parties that are expected to speak during a particular portion of hearing should be visible on Webex at a given time. This helps the ALJs and our court reporters keep track of who is speaking and narrows down the names so we can match names with faces. During each session, we ask that each participating party designates a single lead for that session, and other participants, even those who may speak later, should turn their cameras off, please, until you're directly participating. We didn't

have problems with any of these things last week, and I don't anticipate that we will have them today.

Now, there are two last things to do, and those also relate to this being a remote hearing. We discussed last week and at our earlier status conference the need to do this remotely. All participants must agree to remote appearances and the remote swearing in of witnesses. In addition for regular swearing in of a witness, we will require both the attorneys and the witnesses to agree to a number of attestations that we will go over now.

So first, we will do the attestations for the attorney, Ms. Frazier, and then we'll continue with the witness.

Ms. Frazier, are you ready?

MS. FRAZIER: I am.

ALJ HECHT: Great. I -- our IT people, I believe, have a copy of this posted, so you may refer to it in one of the grid boxes on your Webex. And I will read it out loud, in any case.

Do you attest that you agree to the evidentiary hearing in this proceeding being held via Webex, do you agree that you attest to the witness testimony and exhibits being

presented via Webex, do you agree and attest that -- to the oaths and remote witnesses are going to be received via Webex, and their testimony via Webex, do you attest that you agree to adhere to all formal rules of decorum, including the prohibition against coaching witnesses, do you attest and you agree that you will not make any recording of the proceeding, do you attest that you agree that you understand that any recording of a proceeding held by Webex or teleconference, including screenshots or other visual copying of the hearing, is absolutely prohibited, do you attest that you understand that a violation of these prohibitions may result in sanctions, restricted entry to future hearings, denial of entry to future hearings, or any other sanctions deemed necessary by the Commission, do you attest that during the evidentiary hearings you'll use only the exhibits premarked and identified by the parties, and do you attest that you agree during the evidentiary hearing you will not use documents not previously shared with the opposing attorneys? Do you agree to --

MS. FRAZIER: I do. I do.

ALJ HECHT: Thank you very much, Ms. Frazier.

All right. As I think we discussed last week, we are starting a new witness today, and that witness is Mr. Ravi Krishnamurthy. He is the witness of Blade, which is an independent organization, not technically a party in this proceeding.

As I said, in addition to the regular swearing in, we're going to go through a very, very similar set of attestations for the witness.

So first, I would like the witness to please state and spell his name and provide his business address for the record.

MR. KRISHNAMURTHY: My name is Ravi Krishnamurthy. The business address for Blade Energy Partners in Houston is 16285 Park Ten Place, Suite 500, Houston, Texas, 77084. Actually, it's Suite 600.

ALJ HECHT: Thank you. Could you also please spell your name, at least your last name, for the record?

MR. KRISHNAMURTHY: Sure. My first name is R-a-v-i. My last name is K-r-i-s-h-n-a-m-u-r-t-h-y.

ALJ HECHT: Thank you very much. Do you solely affirm this testimony you are about to give will be the truth, the whole truth, and nothing but the truth?

THE WITNESS: I affirm, yes.

RAVI KRISHNAMURTHY, having been affirmed, testified as follows:

ALJ HECHT: Great. And then we have a few follow-up attestations that you've heard versions of before.

Do you agree to tell the truth based on your personal knowledge?

THE WITNESS: Yes. Yes, I do.

ALJ HECHT: And -- thank you. And I'll go through the rest.

Do you attest that you will testify based on your knowledge and memory, and free from external influences and pressures, that you will adhere to all formal requirements of testifying under oath, including the prohibition against being coached, do you attest that you will refer to the -- only to materials previously shared with all parties, including exhibits premarked and identified by the parties, do you attest that you will not make any recording of the proceeding, and do you understand that any recording of the proceeding held via Webex or teleconference, including screenshots or other visual copying of the hearing, is prohibited, and finally, do you attest that you know that a violation of these prohibitions may result in

sanctions, including remote -- removal from the evidentiary hearing, restricted entry to future hearings, denial of entry to future hearings, or any other sanctions deemed necessary by the Commission? Do you attest --

THE WITNESS: I do. I do.

ALJ HECHT: Thank you.

THE WITNESS: I do attest.

ALJ HECHT: Thank you very much.

Before we continue, do we have any housekeeping that we need to do?

MR. GRUEN: Your Honor, this is not necessarily urgent, but we did -- SED did re-serve Exhibits SED-204, SED-C-204 and SED-216 on Friday at the end of the day. Would you like to go through the exercise marking those now, or would you like to -- to look -- address that later?

ALJ HECHT: Let's address that later. But, thank you for the reminder, and I'll put it on my list for later in the day.

MR. GRUEN: Okay. Thank you, your Honor.

ALJ HECHT: Thank you. Aside from that, I will note that the Blade report is an important document in this case. It was attached to the Order Instituting

Investigation for this proceeding when the investigation was opened. It has not been marked as an exhibit, and we can discuss later if we want to mark it as an exhibit so that it is part of the evidentiary record and easier to refer to. If anybody has a strong feeling about that, you can speak in a moment.

I am suggesting it is a possibility that we mark it as something like Commission Exhibit-1000, or something like that, just so that we have a number similar to the other exhibits that we're doing. Any thoughts?

MR. LOTTERMAN: Your Honor, this is Tom Lotterman. I will be examining Dr. Krishnamurthy today, and my view is as long as we perhaps at the beginning of examination understand that when we say, "main report," we are talking about the root cause analysis report, that's fine. I will note that there may be a possibility that I will refer to other volumes of his report, and I just didn't want that to get messy, as far as exhibit numbers and all. So I defer to you, but there may be some value, at some point, giving these reports specific numbers so that the record will be clear.

ALJ HECHT: Thank you very much. I'm

inclined to agree with that. The main Blade report has four volumes, I believe, of attached reports, which are more specific. They are Volumes 1 through 4, I believe. And my suggestion would be that we mark the main report Commission Exhibit-1000, and we mark the volumes 1001, 1002, 1003, 1004. I, however, do not have the specific titles of the volumes in front of me, so we can either do that now, if one of you can supply the volume names, and we can identify them, or we can defer on that until they come up, and do it at that time.

Does anybody have a preference?

MR. LOTTERMAN: Glad to do it, your Honor, all -- although, I'll defer to Mr. Gruen.

MR. GRUEN: Yes, your Honor. I -- I -- I think this all makes sense. It will take me just a moment to -- well, I can provide the -- the name of the Blade report right away. I have that at my disposal. The others may take a moment.

ALJ HECHT: Let's start with that.

MR. GRUEN: Okay. And your Honor, if -- if I was tracking, you want that exhibit to be marked as Commission Exhibit-1000, the -- the main report, as

Mr. Lotterman referred to?

ALJ HECHT: Yes. Correct. I think what I'm going to do --

MR. GRUEN: Okay.

ALJ HECHT: -- is I'm going to go off the record for a minute, let us get everything together, and then we can state them all into the record.

We'll be off the record.

(Off the record.)]

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

While we were off the record, we were finding the titles and subtitles to the various volumes of the Blade Report. I'm going to go through our way of referring to them as we move forward, because it sounds like the cross-examination may involve some of the supporting volumes, in addition to the main report.

The main report, the Blade Report, I think we already identified. It was the Blade Root Cause Analysis issued in May of 2019.

The supplemental reports are:

Volume 1, Approach;

Volume 2, SS-25 Well Failure Causes;

Volume 3, Post-22 through -25 leak events;

And Volume 4, Aliso Canyon Casing Integrity.

Does anybody have anything different from that?

(No response.)

ALJ HECHT: I'll take that as a no.

We're going to mark the Blade Report as Commission Exhibit 1000, Volume 1, Approach as 1001;

Volume 2, SS-25 Well Failure Causes as 1002;

Volume 3, Post-22 through -25 leak events as 1003;

And Volume 4, Aliso Canyon Casing Integrity, as Commission Exhibit 1004.

(Exhibit No. 1000 was marked for identification.)

(Exhibit No. 1001 was marked for identification.)

(Exhibit No. 1002 was marked for identification.)

(Exhibit No. 1003 was marked for identification.)

(Exhibit No. 1004 was marked for identification.)

ALJ HECHT: Is everybody pretty clear

on those for now?

And are there any questions before we go to direct and then cross?

(No response.)

MR. GRUEN: Your Honor, SED is clear on your guidance. No questions.

ALJ HECHT: Thank you very much.

All right. Then, Ms. Frazier, please go ahead.

MS. FRAZIER: Your Honor, I think Mr. Lotterman was going to start the questioning of Mr. Krishnamurthy.

ALJ HECHT: Okay. Here we often have the attorney representing the witness just identify them again. But we have already done that, so I don't think it’s necessary to do that now.

MS. FRAZIER: Okay. Sorry about that.

ALJ HECHT: That's okay. You have no way of knowing.

All right. I'll start with Mr. Lotterman.

MR. LOTTERMAN: Thank you, your Honor.

Ms. Frazier and I are in the same boat. And that is that neither of us have appeared before this Commission before. So I wanted to start off by thanking you for the opportunity to do so. And, also, to tell you

that if I stumble along the way, it's not because I haven't read the Commission's rules and all, I just may not be familiar with your procedures and may call for Mr. Stoddard or Ms. Patel to give me a -- throw me a lifeline from time to time, so...

ALJ HECHT: That's fine. Thank you. I definitely understand.

CROSS-EXAMINATION

BY MR. LOTTERMAN:

Q All right.

Dr. Krishnamurthy, are you there?

A Sorry. I'm here. I just unmutated myself.

Q Oh, all right. Good. There you are. Hello again.

How are you?

A Pretty good.

Q Good. I wanted to check a couple things.

Actually, before we do that, I want to say it’s good to see you again. Because we met in Downtown Houston back in November 2019; right?

A That is correct. Yes. A while ago.

Q Right. And these days, when you say, "It’s good to see you again," it means

something, doesn't it?
A Virtually, yes.
Q Yes. Absolutely. Yes. Yes.
And so, if you recall, we spent three days in deposition; is that right?
A That is correct.
Q I believe I had the opportunity to examine you on the third day.
Do you remember that?
A Yes, I do.
Q And there's been a transcript -- and I believe you actually reviewed the transcript for accuracy, and you've submitted an errata.
Is that true?
A That is correct.
Q Good.
And do you understand that you are under oath today, just like you were under oath at that deposition in November 2019?
A Yes, I do.
Q Good.
Quick question for you, are you alone today in your office?
A Yes, I am. I'm in my office, and my door is closed.
Q Okay. Good. So here's what I wanted to accomplish:

I want to walk through various topics that are raised in your main report. And I believe I let your counsel know that if you have a copy of the report handy, it will greatly expedite this examination.

I will, for the record, clarify the pages. Mr. Moshfegh will put them up on the screen. But I think we can proceed fairly quickly -- if you have the report in front of you, we can look at a sentence or two, I can ask for clarifications, and that type of thing.

Okay?

A Yes. I have it with me.

Q Good.

I also may go into some of the supplemental reports. I hope not to, but I have a couple sections here that we may put on the screen. But, again, you should feel free to refer to anything you want to before you answer a question.

If I recall back to November of 2019, your ability to recollect the facts in this project were quite remarkable. And so I'm hoping that happens again today. But I want to let you know that if, for whatever reason, you draw a blank or you're unclear, we will stop and we will make sure you have a

chance to refresh your recollection.

Okay?

A Thank you.

Q Good.

The other thing I was going to tell you is, you are free to defer to others on your team if you need to. And I say that, but I also tell you that while you're testifying today, it has to be your testimony. So I'm assuming you have no ability to communicate with your team sort of offline or through chat, or whatever, while you're on the stand, so to speak, today?

A No. I'm alone. And I have no chat or anything set up, no.

Q Good.

Now, I don't expect you to need to defer to them, because we're not going to get too deep into the weeds. I'm going to start at, sort of, the Google-Maps level and work our way down the well. But you have that opportunity. And if you -- if there's something that you need someone else to answer, we will accommodate that need.

Okay?

A Okay. Thank you.

Q All right. And, by the way, the other thing I was going to mention to you is,

we are going to spend a lot of time on the main report. And that has now been marked as Commission Exhibit 1000.

So if I say "Main report" or "Exhibit 1000," can we understand that it's the main report that Mr. Gruen read into the record just a while ago?

A Yes.

Q Okay. Good.

I also am going to ask you today to explain some concepts, to explain some equipment, and to explain some issues. And that's for me to lay a foundation. That's for the ability for the judges to understand not only your testimony, but future testimony of some of the SoCalGas witnesses, and just to keep the record clear. So I ask your patience in that regard.

Okay?

A Sure.

Q Finally, I'll defer to the judges when breaks are needed. But, obviously, if something comes up and you need a break, please let us know, and we will endeavor to accommodate you.

Okay?

A Thank you.

Q Before we begin, and this is sort

of a last minute thing that we always do is, there's a concern that some third party may attempt to record these proceedings. And I wanted -- and I can tell you that I have not consented to anyone recording what I'm doing here today.

And I'm asking you, do you consent to this proceeding being recorded by a third party?

A I do not.

Q Okay. All right.

Finally, let’s talk about some terms. When I say "Blade," obviously, I mean the Blade Energy Partners and you and your team.

Okay?

A Okay.

Q I may say from time to time you personally, and that's -- that's, I guess, an opportunity for you to maybe step away from you role as the lead investigator of Blade and to give your personal view. But if I say you or Blade today, I'm really asking you to speak on behalf of the -- of Blade Energy Partners.

Okay?

A Yes.

Q Good.

Another shorthand is "Aliso Canyon." By now, I think everyone else in this proceeding knows that that pertains to SoCalGas's Aliso Canyon gas storage facility. But I wanted to confirm that with you.

A Yes.

(Crosstalk.)

BY MR. LOTTERMAN:

Q Also, we talk about "incident" or "leak." And that is the leak that started on October 23rd 2015, and -- well, actually, it was first detected on that date. And it was at the well now called "SS-25."

Agreed?

A Yes, agreed.

Q All right.

And, obviously, the well itself is SS-25. That's short for "Standard Sesnon 25."

True?

A Yes.

Q All right. Good. Thank you very much. Let's begin the examination.

And, by the way, I believe you've got a PhD in Material Science from the great institution of University of the Virginia; is that correct?

A That is correct, yeah, UVA.

Q Well, I'm sorry about your NCAA experience recently. But we won't go there.

What I will do though, with your permission, is I believe you go by Dr. Krishnamurthy; is that correct?

A No. Just "Ravi" is fine. No "Dr.," please.

Q No, "Dr." Okay.

(Crosstalk.)

BY MR. LOTTERMAN:

Q Well, I can't go "Ravi" today, sir, because this is a formal proceeding.

So forgive me, I've got "Dr." In my head. I'll try to adjust. But I'm 65 years old, and that's more difficult as every day goes by. Okay.

So, tell us, are you currently employed, sir?

A Yes. I'm employed with Blade Energy Partners. Yes.

Q How long have you been with Blade?

A Since 2004, I believe. Yeah.

Q And if you had to, sort of, summarize in two sentences, or more or less, what are your primary duties and responsibilities with Blade these days?

A My primary duty is, I'm an Executive Vice President. Actually, that's

my title. But I work actively on projects as an engineer. And, also, I'm responsible for the financial results and overall for Blade --

Q Okay.

A -- so, yeah. I'm one of the principals at Blade.

Q Do you consider yourself a corrosion engineer by training and experience?

A I consider myself a metallurgical/corrosion/fracture mechanics. The corrosion is a very specific area to me. That is one of the areas I was trained in and have experience in, but it’s a broader range. Yeah.

Q Okay. So if I understand your answer correctly, you have expertise in a number of areas. But one of those subareas is corrosion.

True?

A That is correct. Yeah.

Q All right. Okay.

And where did you work before you joined Blade?

A Before Blade, I worked for GEPII. That was an entity that used to work on pipeline integrity and integrity inspection.

But my focus was on pipeline integrity engineering. And then prior to that for nearly ten years -- I'm giving you approximate numbers -- mobile (inaudible), a few years in research, few years in the field, and then in drilling towards the end of --

(Crosstalk.)

BY MR. LOTTERMAN:

Q Thank you. I'm sorry for stepping on your answer. I just broke Judge Hecht's rule.

Are you -- are you familiar with the phrase "oil patch"?

A Yes.

Q What does that mean to you?

A Oil patch is somebody who has been fortunate enough or unfortunate enough to have spent their life in the oil and gas industry. It’s an oil and gas industry domain that's pretty much drilling, exploration, completion, a variety of things. That's what we term as "oil patch."

Q Have you spent time in the oil patch?

A Yes. Yes, I have. Yeah.

Q How much time, roughly?

A Oh, God. I don't want to date

myself, but over 25 years, maybe.

Q All right.

A I need to do some counting, but yeah.

Q Do you try to keep current on new trends and issues in the oil and gas business?

A I do my best. Yeah.

Q Okay.

Do you belong to any professional societies?

A I believe a few, yeah. A few.

Q Okay. I saw one called the National Association of Corrosion Engineers?

Is that one of them?

A Yes. That is one of them.

Q Okay. Is that the group where you keep current on new trends and issues in, at least, the corrosion world?

A Yes, we do.

Q Okay. Have you seen a lot of corrosion over the years?

A Yes. Yes, I have. Yes.

Q On pipelines?

A Everything. On pipeline and downhole. Because my primary experience -- initially, my experience was downhole, then it became pipeline. It’s pretty much both.

What I'm not experienced in is refining or refineries. But pretty much downhole, surface, facilities, and transmission systems.]

Q When you say "downhole," sir, what are you referring to?

A Downhole I'm referring to anywhere from liner, casing, tubing, packer, subsurface safety valve, various completion components, you know, the conduit to produce hydrocarbons, which is pretty much everything.

Q Including the well itself? Excuse me. Including the well itself, correct?

A Yes. Yes. When we discuss what I would call available system, we mean all the casing strings, the wellhead, the trees, the completion tubing, everything. That's what we refer to.

Q When was your first experience with corrosion on a wellbore system?

A '91 maybe. '91 or '92.

Q Was that when you were with -- was that when you were with Mobile?

A That's correct, yeah. That's Mobile, yeah.

Q And I believe you told us in your deposition that was corrosion on a tubing; is

that correct?

A I believe so. It's been ages ago, but yes, that's what I -- what I recall.

Q And I believe your memory at the time was that it was corrosion caused by carbon dioxide; is that right?

A Correct. CO2 corrosion, yeah. That's right. You're absolutely right. Yeah.

Q What are the types of corrosion that you've seen on well pipe?

A CO2 corrosion, pitting corrosion, cracking, various types of corrosion. I could go through a litany of those including microbiological, various, various ranges, and also cracking. So a lot people use corrosion and cracking interchangeably. I like to split them up. Corrosion is kind of a metal loss kind of phenomenon, whereas cracking involves the presence of a crack that is extremely sharp where there is a fracture possibility. So a combination thereof. I've seen that in carbon steels. I've seen it in stainless steels, thirteen chrome, sub 22 chrome, and then also that's for the nickel-based alloys, the difference in the alloy system.

(Interruption by reporter.)

THE WITNESS: I apologize. I'll speak slowly.

ALJ HECHT: We had this issue last week with more than one person. It is not unusual. Please try to keep to a measured pace. It's very helpful for our court reporters to do that.

THE WITNESS: I will do that. Sorry about that.

ALJ HECHT: Thank you very much. We'll be back on the record if we were off of it.

MR. LOTTERMAN: Thank you, your Honor.

Q Dr. Krishnamurthy, have you seen any microbial-induced corrosion in the oil patch?

A Yes, I have.

Q Okay. What types traditionally have you experienced there?

A Traditionally, it's been sulfate-reducing bacteria corrosion. That's the specific variation of microbial corrosion. That's what I'm traditionally used to. That's what I have personally seen.

Q What about iron-related bacteria?

A What do you mean by -- oh. You're talking aerobic bacteria, anaerobic bacteria. Aerobic bacteria I have personally not seen I'm aware of those. I have personally not

seen those. I've seen sulfate-reducing bacteria. I have not seen what you're calling aerobic bacteria. The SRBs and anaerobic bacteria, they happen in the absence of oxygen whereas aerobic bacteria are the type I believe you are referring to. Happens in the presence of oxygen, which is called aerobic corrosion.

Q All right. So let's -- thank you for that background. Let's now turn to the root cause analysis. It's my understanding, Dr. Krishnamurthy, that you were hired technically by SoCalGas at the Commission's and DOGGR's direction to conduct a root cause analysis at the Aliso Canyon facility; is that correct?

A Yes, that's correct.

Q And I was going to actually show you a copy of the contract, which I believe I provided in advance. I'm told now that that contract has some confidential information in it. So I'm going to endeavor to ask you a couple of questions about it without actually putting it into the record. So let me go at it this way, if I can. The contract shows -- showed that it was signed as of January 26, 2006.

Does that comport with your

recollection?

A That's correct. Yeah.

Q And it says under "scope" -- and again, I can show it you to if you want, but let me just read it to you. It says under scope, "performance of a technical root cause analysis" -- and in parens it's RCA -- "on the nature of failure of the S" -- "of the Standard Sesnon 25 well and the technical cause of the leak."

Do you remember that generally?

A Yes, I remember that generally. Yeah.

Q Okay. So let me just ask you about each phrase. You talk about performing an RCA on the nature of the failure of the Standard Sesnon 25 well. What did you interpret that to mean when you walked into this project in January of 2016?

A To understand the failure of the SS-25 -- why the SS-25 failed. Literally why SS-25 failed.

Q Okay. And then what was your understanding as to the aspect of the project where you were going to identify the technical cause of the leak? Is that the same thing?

A Yeah. Yeah. Again, by technical

RCA, what we intended to mean -- at least that was the intent when we wrote the proposal -- in a root cause analysis or failure analysis, when you get -- you have an idea in your mind what the scope is, what the approach is going to be, and then as data presents itself, your approach and scope evolves. And that is common in any root cause analysis work we have done in the past. The terminology that we -- I like to use technical -- is we were not -- we were not planning nor was our intent of the project to understand management-related issues or stuff beyond -- beyond what we would call technical. That was the intent. Okay.

Q Understood. Thank you. And you completed that work about three and a half years later; is that true?

A That's correct.

Q And it culminated in the reports that we just marked as Commission 1,000, Commission 1,001, Commission 1,002 and all the way up to Commission 1,004; is that correct?

A That's correct.

Q No, how much of your time during that three-and-a-half-year period was dedicated to that project?

A I don't -- I don't recall but a bulk of my time.
Q Okay.
A A bulk of my time.
Q All right. And was that project a lengthy effort by Blade's standards?
A Yes.
Q Okay. Was it complex?
A Yes. It was complex.
Q I mean, I saw at some point that you hired more than 23 service companies. Does that roughly comport with your recollection?
A Yeah. That's what we had in our acknowledgment sections, yeah. And that was -- SoCal guided us in there. It was SoCalGas' service companies, and we tried to stick with them where it made sense.
Q Was the project difficult and challenging?
A Yes, it was. Yes, it was.
Q Including weather delays?
A Yes. Weather delays, which is common in Aliso.
Q And I saw something in your report about having to design a special tool to extract the pipe, and we'll get to that in a minute. But is that part of the challenging

aspect of this project?

A Yes. Can I elaborate on that a little bit? May I elaborate on that a little? So when you're looking at a downhole failure, even though this was a shallow failure, pulling it out without damaging anything is a challenge -- operational challenge. And because this was a well that had failed, there were a lot regulatory hurdles we had to jump over. So the regulatory, which was the entity that was to approve any operations on that well, vis-à-vis extraction of tubing or casing had to go through DOGGR, and that was a -- quite a lengthy process where everybody had to be convinced it was safe, justifiably so since we had just got that well under control.

So that added to the time that -- time and effort that it took. And on top of that, a lot of the protocols had to be approved by the regulatory entities. And SoCalGas also reviewed them. So all parties reviewed them. So it was quite extensive. And then there was a period -- I'm really going deep into my memory bank. But it was early in 2017 where DOGGR was concerned that 25A, which had a stage collar leak, which was a really -- a cementing tool that was nothing

to do with integrity of the casing of the tubing. So they wanted to fix that before we do any activity on SS-25. So all of that just added to the time and effort required.

Q Dr. Krishnamurthy, you'll be pleased to hear that at some point in time we're going to talk about each one of those. So I appreciate you giving us the preview, but I actually had those on my list to discuss. So thank you for that introduction, shall we say.

You know, you said something at the deposition in Houston that struck me at the time, but I didn't ask you to follow-up. And I'd like to do that today. You said, quote, "Everything surprised me about this project." And I'm wondering could you explain what you meant by that? And again, just briefly, because we're going to get into the various stages of the root cause analysis. But what about this project generally surprised you?

A Yeah. I may have -- I don't want to say everything surprised me. Some things surprised me definitely, and let me touch on the technical aspects. And perhaps I may answer some of your other questions that may come up. But let me -- because I can't be specific with a general question.

So any time you walk into a failure, whether -- and we attempt to be purely data driven. By "we," I mean Blade. We're very picky about data has to drive our decisions. We may have some preconceived notions or ideas as to why something happened. You have to wait for the data. So as we were waiting and as we were doing things in different phases, which we will go to at some point down the road here, you are looking at the data you have. And it doesn't jibe with what you think may have happened.

So for example, when we came to the location -- I was on the location, I believe, February 1st or 2nd. Bill Whitney was ahead of me. I was there a day later. And so if you looked at everybody's account and newspapers and everywhere it would be, "internal corrosion," "internal corrosion." We didn't know whether the gas was wet and all that. So very quickly, by April, we knew internal corrosion was not an issue. So we were trying to think what would cause this failure. So pretty much all the data we saw -- the results we saw was that was inconsistent with some preconceived views we had -- or I had.

Q Okay. So Dr. Krishnamurthy, I

promise you we're going to get into that. So that's very helpful. I just wanted to understand that -- let me ask it this way so we -- so you don't sort of spoil the story here: Is it fair to say that during this project something surprised you?

A Yes.

Q All right. All right. And your role during the project was primary leader of the team, true?

A Yes, that's correct.

Q And I believe you told us in Houston that you -- if you did not -- well, first of all, you did not write all of the reports but you wrote much of the main report; is that correct?

A I wrote portions of the main report extracting -- I reviewed the main report in details. And it's a team effort. And I wrote -- I helped with some of the supplementary reports but not all of them.

Q But is it safe to say that you blessed what you -- that you reviewed and blessed all of the reports once they were submitted?

A Yes, I did.

Q Okay. So the root cause analysis, by contract, began on January 26, 2016. I

believe your team -- or you and your team arrived on-site three days later, January 29; is that accurate?

A That's accurate, I believe, yes.

Q All right. So when you arrived at the Aliso Canyon facility, what was the status of the leak?]

A It was still leaking. The well was still leaking. And if I remember right, the relief well was getting closer to SS-25. That's the condition when I arrived on site.

Q Okay. Did you witness any top kills by either SoCalGas or Boots & Coots upon arrival?

A No, I didn't.

Q Did you or anyone else --

(Crosstalk.)

BY MR. LOTTERMAN:

Q I'm sorry.

A No, I did not. Neither me nor anybody at Blade witnessed anything, any of the top kills.

Q Did you or anyone from your Blade team play any role in designing or implementing the top kills?

A No.

Q What about designing or implementing the relief well?

A No, we did not have a role.
Q Okay. So how soon after your -- your arrival at the Aliso Canyon facility on January 29, 2016 did you visit the -- the actual well pad?
A Really, let me think about it. It was the -- the -- let me step back to the story I mentioned earlier.
There was a lot of newspaper reports and speculation by various experts in -- saying that internal corrosion was a problem, so immediately I sent a request to SoCalGas requesting samples of the gas. Before that, I asked if anybody had done a gas analysis. I found out that there was a lot of EPA or environmental-type analysis, but nobody had done an analysis with the intent of corrosion or understanding the failure. So I requested gas samples right away. So I forget the timeline and the details around it, but I was on SS-25 site collecting gas samples probably three, four days after I arrived.
Q Okay.
A I do not --
Q What did you see --
A I did not -- sorry. I -- I do not remember the exact dates and all, but, yeah.

That's -- I was there.

ALJ HECHT: Just a reminder --

THE WITNESS: So --

ALJ HECHT: -- to take a breath and stop before you speak over someone. Thank you.

MR. LOTTERMAN: Thank you.

Q So I -- I'm breaking all the rules today, Dr. Krishnamurthy. I apologize. I -- so all right.

So the contract was January 26. You arrived a couple days later, and a couple days after that you first visited the SS-25 well pad. Is that correct?

A That's correct.

Q What did you see?

A Oh, gosh. I don't remember. I saw the crater. I -- there was a pipe coming away from the wellbore. I forget -- which was -- I -- my guess is 60, 70 feet from the wellbore, where we could sample the gas. Me and -- and -- and two other individuals from Oil-Tech were with me, I believe, if I remember right. It was covered in oil. I mean --

Q Well -- sorry. I thought you were done. My apologies.

Did you see the wellhead sticking

out of the ground in the middle of the crater?

A I believe I did, yeah.

Q How large was the crater, roughly?

A We -- we measured it later. I don't remember, offhand. Your -- I have to go to my reports to check. We measured it; quite -- it's quite big.

Q Okay. I have a picture --

A I would -- yeah. Sorry. Go ahead.

Q I have a picture that I'm going to show in a minute, which I think will help clear that up.

When you approached the pad to do your gas samples, did you smell gas?

A I believe I did. Okay? At any -- I'm really digging deep into my gray cells, and I believe I did. It was -- it was a unique smell there on location. I believe it was hydrocarbon gas smell. Yeah, absolutely I did.

Q Okay. And you say in the main report -- and -- and I'm looking at page 22. You don't need to refer to it, unless you want to. You said that -- that the location and type of failure were unknown when the RCA began. Is that a true statement?

A That's correct.

Q Okay. And I believe you said in your deposition: "We didn't know where, we didn't know what, we didn't know how at that stage, so everything was up for grabs."

Not quite as technical as the language in the main report, but does that capture the same idea?

A Yes. Yes.

Q Okay.

A We -- we didn't -- we didn't know what depth it was. You could speculate on all of that, but at that point, it was speculation.

Q And you -- I think you -- you started talking about this earlier, and I want to just clarify for the record.

What were your initial -- your being you and your team's initial suspicions of the cause of the leak when you walked up, when you drove up to the Aliso Canyon facility?

A I -- I honestly -- we did not have any opinion at that point. Down the road, a few months later, we had some opinions. But, at that point, we didn't have any opinions other than -- I honestly did not. We did not know whether the wellhead had failed, we did not know whether the casing had failed,

because remember, I had not looked at any of the data. We had not looked at the temperature logs. Like you appropriately mentioned, we were not there for the kill attempts. So we didn't -- we didn't look at any of those data sets. We had not interpreted anything as we had walked up, so at that point, we were void of looking at any information. So at that point, we probably did not have an opinion, that's correct.

Q Okay. I was actually asking you about your initial suspicions, but let me ask it this way.

You had mentioned during one of your earlier answers some people were talking about in colonel -- internal corrosion. Did -- did members of your team share that suspicion?

A No. Members of my team shared the -- Rudy Hausler is our chemist, who's one of the authors of the internal corrosion section. If there is water in the gas, corrosion is possible. So -- but, once we had the gas analysis results back from Oil -- Oil-Tech, I believe, we were pretty comfortable saying there was -- it's not an internal corrosion.

Q All right. And just so everyone

understands what we're talking about, we may throw these terms around a little bit later, when you say, "internal corrosion," you mean corrosion that's inside the pipe sort of corroding the -- what do you call it, the interior, the ID, the interior diameter. Is that right?

A That's correct. Let me clarify, just to make sure I'm clear, I -- I appropriately communicate.

What I'm talking about is corrosion happening from the internal diameter of the production casing.

Q Got it.

A That's what I'm referring to.

Q Okay. And then today or tomorrow, perhaps, we talk about external corrosion. Is that the corrosion that typically will attack the outside of the pipe?

A Yeah. A -- as -- as -- as we have articulated in the report, the corrosion on the seven-inch production casing happened from the outside diameter, or the OD, of the pipe.

Q Okay. All right. And from your experience in the oil patch, is there internal corrosion and external corrosion on well pipes?

A It's more internal. It's more often internal.

Q Why is that?

A Because in -- in production situations, your gas can be wet gas, and depending on the reservoir, even in underground storage well, your gas can be wet, and if it is wet, you can have internal corrosion, wet meaning you need water. For corrosion to happen, you always have to have water. And quite often, in producing wells, when you produce gas, or even when you produce oil, you may have some (inaudible) water or water being produced along with the gas or along with the oil, and that may cause some corrosion.

There was water in the Aliso Canyon gas, but it was so low that it was -- it -- gas -- the -- the gas that you produce absorbs some water as vapor, or water vapor, and so all the water was water vapor in the gas as it came up. So unless the water condenses as water on the ID of the casing, you cannot have corrosion.

Q I see. Okay. Thank you. That's very helpful.

So it's my understanding -- and I believe your -- your report sets this forth,

that the leak was stopped on February 11, 2016. Is that right?

A That's correct, yeah.

Q So roughly 111 days after it was first detected on October 23rd. True?

A True.

Q All right. Good. And -- and once the leak stopped, Blade proceeded with six phases of its analysis. Is that generally true?

A I believe so. I have to check, but, yes, five or six --

Q Now --

A -- phases.

Q -- again, sir, I'm -- it is my hope today not to challenge your recollection unduly, so let's turn to pages 23 and 24 of the main report, which has been previously marked as Commission Exhibit-1000. And I'm not going to go through these in detail, or even generally, but I just want to refresh your recollection.

Does that report on pages 23 and 24 set out six phases of the root cause analysis?

A Yes, it does.

Q All right. And again -- and I want these answers to be short, because this is --

this is not that important in the -- in the grand scheme of things, but just to -- just to set the -- the table, Phase 1, I take it, was -- was generally the data collection, collation, analysis. Is that true?

A Yeah. We called it Phase 0, and that was well and field data collection, collation, yes.

Q So that kind of surprised me. Is -- do corrosion engineers have Phase 0s, typically?

A Not -- again, I'm not a corrosion -- I would like to say, "Yes, I'm a corrosion engineer." But, in an RCA, one of the most important aspect (sic), especially in a problem like this, especially in downhole problems, data collection and analysis is probably the most important part of the project.

Q Okay. And I take it that, then, also fed into what you call Phase 1, where you actually collected site evidence. Is that correct?

A Yeah. Phase 1 was -- if you -- as you asked me a question before, the crater was there, the hole -- the well was successfully killed. So we didn't know what had -- what -- what had happened, so we were

looking for any phys- -- physical evidence of the failure, if there was something that came up when the gas came out of the well. That was the intent of that exercise.

Q Okay. And it looks like Phase 0s (sic) and Phase 1 occurred during the same time. Is that accurate?

A No. Phase 0 started in February of 2015, went until May of 2019, if you look at it. So it went all the way 'til the end of the project, because as we discovered -- as we analyzed the data -- sorry, as we analyzed the physical evidence, all the data, we had new data requests, and SoCalGas was kind enough to provide us additional information. It was a lot of data required for this project. And that was Phase --

Q That was a good catch, though. Sorry. That was a good catch, because I looked at the dates, and I assumed they were equivalent, but one was through May of 2019, and Phase 1 was through May of 2016. True?

A That's correct.

Q All right. And what you're saying, if I understand you correctly, is that the process of collecting data and collating it and ana- -- analyzing it, that started from the day you got involved with that project

from, it looks like, the -- the very month you published this main report. True?

A That's correct.

Q All right. Phase 2 is called Site Restoration to Rig Readiness. Can you briefly tell the Commission what Phase 2 entailed?

A So, Phase 2, if you remember -- and -- and we can look at pictures a little later. There was a big crater there. We recognized that gas had -- was blowing out for 111 days. So we didn't realize where the gas had gone. You know, some of it could have gone just below surface. So a lot of those questions remained.

And so in Phase 1, we did some logging to understand the condition of the location. We may also have done some small surface boreholes in Phase 1 or Phase 2.

And then in Phase 2, the idea was to restore the site. In order to pull the casing, you need to bring a rig in; whether it was a work oil rig or an actual drilling rig, you needed to bring in some heavy equipment on-site, and we need to prepare the site for that. And so crater had to be filled out. It was a massive undertaking. And -- and SoCalGas managed Phase 2 with our

insight and input.

Q Got it. It looks like Phase 3, then, was the actual extraction of the tubing and casing and wellhead?

A That's correct. Phase 3 was the most important data collection portion of it. And -- and as we just spoke about it a few minutes ago, moment we finished Phase 1, we started drafting protocols for Phase 3, that is tubing, casing, wellhead extractions, and there were a lot of back and forth with SoCalGas, with DOGGR, with CPUC, all -- all parties involved, discussing how to do that. That's when it all started. And --

Q Okay.

A Yeah. Sorry. I'll leave it at that.

Q No problem. Got it.

Okay. Phase 4, top of page 24, non-destruction (sic) evaluation and laboratory metallurgical examination. Could you tell a political science major like myself what that involves?

A So that was -- once we pulled the tubing and the casing, the goal was to assess them nondestructively. So when you do metallurgical evaluations, before you break or open anything, you want to evaluate them

nondestructively as much as possible to get a picture of what you're looking at prior to opening things and cutting things. So that was all of the laboratory work and analysis associated with this project, was in Phase 4.

Q Understood. And then the final phase, Phase 5, again, at the bot -- or the -- again, on page 24 of Commission Exhibit-1000, you talk about integration, interpretation and final reports. And I take it that's just your sitting down with your team, everyone taking a piece of this, and basically analyzing the results, putting them on a piece of paper, and making sure they're completed at -- as -- to the best of your abilities as far as completeness, accuracy and that type of thing. Is that right?

A That's correct. We did some modeling ahead of that, but by October 2018, or approximately in that timeframe, I believe we were still drilling the SS-9 borehole for water, but I -- I'm not a hundred percent sure exactly when we finished that. But, at that point, we had enough data that we could make interpretations. So the metallurgical interpretation has to integrate with the thermal-hydraulic modeling so we can time things and everything. So that is a very

important phase. That is literally integrating information, the interpret -- finalizing interpretations, and then once you have some of these key conclusions, conducting the RCA, the root cause assessment.

MR. LOTTERMAN: Okay. Judge Hecht, I'm going to jump to the back of the report. If this is a good time to break, fine; otherwise, I'll keep going.

ALJ HECHT: I think this is a good time to take a short morning break. We will take a ten-minute break, and be back at 11:11.

We'll be off the record.

(Off the record.)

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

We just took a short morning break. And I'm hearing a little bit of feedback; hopefully, that will go away.

But, we're back on the record, and Mr. Lotterman can continue.

MR. LOTTERMAN: Thank you, your Honor.

Q Dr. Krishnamurthy, are you with us?

A Yeah, I'm back.

Q Good. All right. Is your camera on?

A I believe it's on.

Q Okay. Good. I just don't see you. That's fine.

So I want to -- I want to skip through this 250-page report back to page 242, which I think in this panel is called the credits.

A Yeah.

Q All right. And I'll ask Mr. Moshfegh to put that up, and you can either use your hard copy, which is what I typically do, Doctor, or you're welcome to look on the screen.

But, this page is actually the last page of the main report, Commission Exhibit-1000. True?

A Yes.

Q And on that page, it looks like Blade attempted to acknowledge the various parties involved. Is that correct?

A Yeah. I wouldn't say, "attempted." We acknowledged.

Q You did acknowledge. Fair enough. Fair enough. That's a -- that's a much more precise answer. I appreciate that.

Did you write this acknowledgement?

A Yes. Yes. I was in -- myself and a couple of our colleagues reviewed it, and -- yes.

Q Okay. And if you look at the first sentence, there you're talking about how long and complex the project was. Do you see that? And I think we talked about that earlier, so there's no need to re-plow that field. Okay?

A Yes.

Q And then the beginning of the second paragraph, you say, "We would like to acknowledge CPUC and DOGGR's overall support by Blade -- of Blade's RCA efforts," and you go on to talk about it. Do you see that?

A Yes.

Q So that's obviously good for client relations, but we'll -- let's -- let's leave that aside.

Tell us what DOGGR's role was in the RCA.

A I'm thinking, yes. So DOGGR -- DOGGR's role was, number one, let's say, I -- we had to have clear traceability, so when we extract something from the wellbore, the -- it has to be marked. There's a process -- I -- I don't want to bore you guys. There's a document that describes the process, which we shared with all parties, and we needed CPUC or DOGGR to sign off as witness as we transfer custody from the SS-25 site to

Blade. And so DOGGR played a very important role in that. DOGGR also played a role in -- in reviewing our -- our protocols, and those protocols would go to national labs. I was not -- and those -- that input was given back to us. So that was -- that was one of the elements of what DOGGR helped us with. I'm trying to think of something else, but that's what I remember at the moment.

Q Did you rely on their expertise?

A No, I -- I did not rely. But, if -- if it -- to me, if anybody gave us input on the protocol, if it improved our -- our protocol, absolutely, I would -- I would follow.

Q From time to time, did DOGGR give you input on various aspects of the root cause analysis, whether you followed it or not?

A No, not on the investigation itself. Their input was more on perhaps data collection, you know. It -- you know, they would -- they would talk about the sample that has come out, but, really, they had no input on the investigation itself, no.

Q Did they attend or were they present at the -- at the site or during the investigation for most of it?

A Yes, they were on-site for most of it. That's correct.

Q Okay. Were there CPUC representatives on-site for most, if not all, of the root cause analysis investigation?

A Yes, CPUC was also on-site.

Q What role did they play?

A Same role. They -- they facilitated any needs we had. Let's say I needed a printer or we needed some space to work on on-site, they would help us with SoCalGas. So as we got to know each other, we may ask SoCal directly, but quite often, CPUC would facilitate those kind of needs or practical needs on-site. So that's the role that CPUC fail -- played. And also, CPUC was very clear to us all along that need -- this needed to be an independent investigation with input from nobody, and we took it to heart.

Q And then in that -- in that very same sentence that we just read, you talk about overall support. You said, "as well as providing guidance for navigating the regulatory, evidentiary and legal requirements."

Which or both entities provided that guidance to Blade?

A So the -- so let me go through each of them a little separately.

Regulatory guidance is approval from DOGGR for any operations on-site, so that's regulatory guidance.

The evidentiary guidance would be, you know, traceability requirements that they would like to see or -- which is part of our normal RCA process, but they would reiterate that.

To me, legal falls under regulatory or legal requirements, right, you know? They were -- you know, we didn't have any legal -- you know, the people may -- you know, I would be on a call where we would have SoCal attorneys, CPUC attorneys talking about some activities coming up. So that's what we meant by that.

Q Okay. Now, if you could move to the next paragraph, see where it says, "We also acknowledge SoCalGas's willing support and cooperation for all aspects of RCA work, including providing data for numerous data requests"?

A Yes. Yes.

Q Why did you put that in the final report?

A You know, I like to -- we just

spoke about the phases. Phase 0, which was the data phase, that was essential to our analysis. So I would -- we were repeatedly asked sometimes the same questions to ensure that -- that our analysis is accurate and appropriate, so that -- we would not have been able to -- to make the conclusions in the root cause analysis without that data. And we also had in-person meeting with SoCalGas, really probably the first one in February of 2016, and then I believe in '18, also, we had two meetings, where both CPUC and DOGGR attended, and we went through data requests. In an RCA like this, if the data request is -- if data is not provided, then the analysis is incomplete or inadequate. So, yeah, that's why we --

Q And were your requests to SoCalGas numerous?

A I believe it was numerous, yes.

Q Because I looked at your report, which we've -- we've marked as Commission-1001, and I counted about 40 sets of requests. Does that roughly comport with your recollection?

A I would have to look at it. There is a supplementary report, I believe, where we summarized this somewhere. But, I

would -- but, yeah, sounds about right, Mr. Lotterman.

Q Yeah. And then -- and I guess that's what I was referring to, sir.

Volume I under Phase 0 summary report, I believe you laid out all the data requests you propounded to SoCalGas. Is that true?

A That's true.

Q Okay. And it looks like they started just pretty -- pretty soon after you arrived at the facility, and it looks like they went right through April 2019 before you finished the final report. Is that right?

A That's correct.

Q And if you look at -- again, this would be Commission-1001.

But, the Phase 3 summary, it talks about all the data that SoCalGas did provide. And is it fair to say it was voluminous?

A Yes. Yes.

Q Okay.

A I'm looking at it --

Q And --

A -- yeah.

Q And as far as you were concerned, was it complete?

A Again, I -- I can't answer that. I

believe it was complete. It allowed us to make the conclusions we made. Yeah, I believe it was complete. We -- we -- certain aspects we requested multiple times. We had in-person meetings, because I'm nervous about writing a report where some data is not provided to us. So we made multiple -- I had multiple conversations personally on this topic.

Q So it's --

A So I believe it's complete.

Q And so is it safe to say, then, that Blade was satisfied -- whether or not it was complete, satisfied with the data production from SoCalGas as part of the root cause analysis?

A Yes, we were.

Q Okay. And as part of that process, did you find any categories of data that SoCalGas should have had, but were -- they were unable to provide to you?

A I don't think so. I -- by that, you mean they should have had the data, but they didn't have?

Q Correct. In other words, as I -- as your -- a typical underground storage operator should have had "X," we asked for it, they didn't have it. Did that ever

happen during your root cause analysis?

A I don't believe so. The only reason I hesitate, Mr. Lotterman, there is because we do identify one of the root causes as lack of failure analysis. But, that has nothing to do with data. That is activity. So --

Q All right. I appreciate that clarification. I -- I believe we'll get to that at some point, too.

All right. So then, who were your main contacts at SoCalGas during the root cause analysis? Do you remember any names?

A Sure. At one point, it was Jill Tracy for a period of time, and then my primary contact was Glenn La Fevers. Glenn was my primary contact all along, all the way through.

Q What about Tom McMahon?

A Oh, yeah, sorry, Tom McMahon. There were a lot of them. Larry -- I -- I apologize. I may have missed a lot of names. It's been a while.

Q Yeah.

A There's a lot of them, but Glenn was my primary contact. If I didn't have something, I would call Glenn.

Q Did you find them overall

professional?
A Yes, absolutely. Absolutely.
Q What about --
A It's reflected in our acknowledgments. It's reflected in our acknowledgements.
Q What about responsive?
A Extremely responsive.
Q Did they seem to share your sense of urgency with getting the project done?
A Yes, they did.
Q Were they collaborative? And when I say that, I mean were they willing to work together with you toward a common goal, whatever the issue was at the moment?
A Yes, they did.
Q Were they creative? Did they help Blade solve problems as they arose, whether they were regulatory hurdles you talked about earlier or technical issues?
A Yes, they were. They were collaborative and creative and contributive to the success of the project, yes.
Q Were they committed to safety?
A Yes, they were.
Q And in your view, in their minds, was, in fact, safety paramount?
A Yes.

Q And was that commitment 24/7?
A Yes.
Q Okay. So did they give you a -- trailers, for example?
A Yes, they did.
Q Did they help you set up a lab on a relief well pad, which we'll look about -- look at in a minute?
A Yes, they did.
Q Dedicated fiber access?]
A Yes, at multiple locations.
Q Multiple rig setups. They gave you a workover rig and then an automated drilling rig with a smaller footprint?
And we'll get to that in a minute, as well.
A Yes, they did.
Q By the way, you mentioned site stability earlier.
Why was that needed once the well was killed?
A It was an unknown more than anything else. We didn't know where the gas went or where the kill fluids would have gone. So there was concern about stability. So a civil engineering firm came in, they did measurements, and confirmed the stability of the site. So, absolutely, it was a valid

concern and had to verify everything was okay. So that was part of the phase 2 process.

Q Okay. Did SoCalGas give you full access to its personnel?

A Yes, they did. Yeah.

Q Did they give you unrestricted site access?

A Yes, they did.

Q Did they provide you a dedicated support team to give you whatever expertise they could lend to your efforts?

A Yes, they did.

Q Including downhole expertise?

A Yeah. Tim McMahon is the downhole -- a lot of folks downhole there. Yeah.

Q What about geology?

A Yes. We chatted with a geologist; Hillary, I believe. We had conversations with her. We had conversations with the reservoir team at one point early on to understand their process and their approach.

They also provided, as part of the data request, earth visual model, which is a geological model they were using, so, yeah...

ALJ HECHT: I'm going to break in here with a reminder to speak slowly and not speak over one another. I know that can be

difficult, but our court reporters appreciate it. Thank you.

THE WITNESS: Sorry.

MR. LOTTERMAN: Thank you, your Honor. We'll try to slow it down just a little bit.

Q What about site preparation?

Did SoCalGas ask you or assist you in that effort, sir?

A I don't follow what you mean by "site preparation." If you're talking about Phase 2, yes. SoCalGas was accountable for a completed Phase 2, which was making it rig-ready.

Q Okay. That's what I did mean, yes.

A Okay.

Q Okay. And did SoCalGas assist you in getting whatever approvals you needed as part of these regulatory hurdles that you discussed earlier?

A Yes, absolutely.

Q And --

A We --

(Crosstalk.)

THE WITNESS: Sorry. I apologize.

We had multiple meetings with DOGGR district, which was the approving authority. We had meetings with the entire DOGGR district team, which was very helpful to us.

And SoCal was part of those conversations and getting the approvals.

Q And did SoCalGas's efforts, its commitment to you, start from the first day you showed up and go all the way through the end of the project?

A Yes, absolutely. Yes.

Q Now, you also mentioned on page 242, you acknowledge SoCalGas's support of the independence of the investigation.

Do you see that on the screen?

A Yeah.

Q Can that be a concern when performing a technical RCA?

A It was. It was a concern of ours to be -- because we are there investigating a failure, and that concern -- we are a bit apprehensive. I wouldn't say concerned. Apprehensive is the right word that comes to mind. But all the parties, including SoCalGas gas, insisted and urged us to be independent and never -- and it’s reflected in the report. It was essential to the process, as far as I was concerned.

Q That was my next question.

Were your apprehensions justified?

A No, they were not justified.

Q And how did SoCalGas support

Blade's independence of the investigation?

A So we were never asked what our conclusions are, where we were headed, never. Never once were we asked about it. Never once until we released the final report on, I forget, May 16th, I believe, when we released the final May report. We released the supplemental 15 days later. But the May report was May 16th, I believe.

I had nobody from SoCal requesting a preview or wanting to know anything. So we were truly independent. And that's true for CPUC. That is true for DOGGR.

Q And this independence is critical for an RCA; correct?

A Essential. Yes, I agree.

Q All right.

And, finally, if you look at the second to last paragraph, you say -- I'm going to read this slowly, since I think we've been reading quickly so far. I'm going to fight the urge.

This RCA project would not have been possible without the unconditional support through the entire period from CPUC, DOGGR, and SoCalGas.

Do you see that?

A Yes. Yes.

(Crosstalk.)

THE WITNESS: Sorry. Go ahead.

BY MR. LOTTERMAN:

Q Sitting here today, Dr. Krishnamurthy, do you personally have any criticisms of SoCalGas's support and cooperation with your root cause analysis investigation?

A I personally, and on behalf of my team, I can tell you -- because a lot of my team members interacted with various SoCalGas personnel during the project, we could not have completed this without their support -- unconditional support, as we state.

Q I guess that was what I was going to say. You actually state that on page 242 of the main report.

True?

A Yes.

Q All right. Enough of the credits. Let’s go back to the story.

I want to turn you to page 15 of the main report, sir. And I want to look at the Aliso Canyon facility itself.

And I'm going to ask Mr. Moshfegh to put up Figure 1 on the screen and do his

best to enhance it. Thank you, sir.

So if you look at page 15 of your main report, Dr. Krishnamurthy, you provide a brief description of the overall facility.

Do you see that?

A Yes.

Q And you note it's in the Foothills of Oat Mountain.

Do you see that?

A Yes.

Q Okay.

Was it difficult to access?

A Yeah. It was a long drive. And SS-25 was towards the top. So, yeah, it was a bit of a challenge, especially on, you know -- yeah. It’s a bit of a drive. And access was challenging. Yeah.

Q Did you ever walk it?

A Oh, no. No. I drove it.

Q Too far?

A No, I couldn't walk it.

Q Would you consider this area to be remote?

A Yeah. Once you enter the facility, it appears remote. But, yeah, specifically as you can see on the map, it's close by Porter Ranch. But it does appear remote in the mountains and the hills.

Q I mean, it's my understanding that this facility was about six square miles.

Is that roughly your understanding, overall?

A Yeah. Yes.

Q And if you turn to page 14 -- I'm sorry -- 17 of the main report, and you look at Figure 3, you can see that the actual six-square-mile facility shows different sectors.

(Audio interruption.)

(Reporter clarification.)

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

We were off the record due to a technical problem. Unfortunately, we have to back up slightly. And I am hopeful that Mr. Lotterman and Witness Krishnamurthy both know where to pick up.

So, go ahead.

MR. LOTTERMAN: I do, your Honor. Thank you. I also note that your description of this process being clunky was probably one of the most diplomatic descriptions I've heard in the many hearings I've done since last March. So we will get by the "clunkiness" here as we can.

Q Dr. Krishnamurthy, let me back up a

little bit, because we lost Ms. Powers at some point in time. I was directing your attention to Figure 3 on page 17 of the main report.

Do you see that?

A Yes, I do.

Q And I believe you testified that the facility was actually broken into or divided into three sectors. You have the left section to the left.

Do you see that?

A Yes.

Q And then the central section and the east section.

True?

A Correct. Yes.

Q And I believe you also testified in that -- this is right in your report, just blow that figure -- that there were 119 active or idle wells at the Aliso Canyon facility during the 2015 timeframe.

True?

A Yes.

Q And then I asked you what an idle well was, and you were about to describe it when we learned Ms. Powers was no longer with us.

Would you tell the Commission what

an idle well is?

A Yeah. Idle well would be a well that is neither, in this particular case, withdrawing or getting gas out of the well or injecting gas in the well. It was just shut in and just sitting. Whereas, an active well will be operating either as withdrawing gas or injecting gas.

Q And a day before the incident occurred on October 23rd, 2015, was SS-25 an active well?

A I believe it was an active well.

Q And what sector of the Aliso Canyon field is it located in?

A I believe it’s the west sector.

Q All right. I have a couple questions about that a little later.

And then one final question about this overall field, are there other wells operated by other producers there?

A I believe so. And we have articulated that in the report. I don't remember how many wells. But, yes, there are other operators.

Q Is that unusual for an underground storage facility, if you know?

A Yeah. I don't know. I don't think it is unusual. Because the only reason I'm

saying it may not be unusual, you could be storing gas in a second zone, and you could be producing oil from a shallow reserve. So it may not be that untypical. But I'm not qualified to say whether that is common or not common. I don't have that kind of data.

Q I appreciate that. I appreciate that.

And can you answer this question for me:

Can the presence of wells operated by other producers complicate underground storage facilities operations?

A Absolutely.

Q Okay. We'll talk about that in a bit.

I want to jump back a page to Figure 2 at the main report, page 16. And I just want to clarify one thing so the Commission understands this.

When we talk about the SS-25 well site or well pad, is that the area depicted in white on Figure 2 of your main report?

A Yes. That is the SS-25 pad -- well site or pad. That is the pad, exactly. If you zoom in, you'll see the pad.

Q And does that pad contain three wells?

A Yes. It contains 25, 25-A, and 25-B.

Q Okay. Thank you. And I think we'll have a picture of that in a minute to show where they line up with each other.

So let me ask you another big-picture question, and then we're going to start going down the well.

Is it true that Aliso Canyon is a converted, depleted oil reservoir?

A Yes.

Q What does that mean?

A It -- I'm going to attempt to explain that. And I hope I explain it correctly, carefully.

The -- you have porosity and permeability in the rocks. So porosity is volume of oil in the rock. It defines the volume of hydrocarbon in the rock. Permeability establishes conductivity.

So the standard sesnon had good porosity, good permeability. So a lot of oil was produced. And then there's a point at which it either becomes uneconomical or it becomes -- it’s not zero, but the oil levels are very low in that reservoir. But since I've removed the oil from where the oil was, those -- that porosity can provide a space to

store gas. That's really what an old, depleted oil well can been used as a gas storage.

ALJ POIRIER: ALJ Hecht, it looks like Mr. Lotterman might have lost audio.

ALJ HECHT: All right. We'll be off the record.

(Off the record.)

ALJ HECHT: We'll be on the record. We were off the record due to another very similar technical problem, which I believe has now been addressed. And we will continue with questions by Mr. Lotterman.

BY MR. LOTTERMAN:

Q Dr. Krishnamurthy, when we left off, you were explaining what a converted, depleted oil reservoir was. And we don't need the revisit that.

I want the pull up for you though -- and, again, this is just a very quick line of questions. I want to pull up for you Figure 5 from one of your sub-reports. And, for the record, this would be from Exhibit 1002, which is Volume 2 entitled "SS-25 Well Failure Causes." It’s the eighth supplement called "Geology Summary." And I just want to use it for demonstrative purposes.

So, Dr. Krishnamurthy, I believe -- I'm not sure you need to look at the report itself, but you are more than welcome to refer to it.

A Okay.

Q So we're looking at page 14, Figure 5, Mr. Moshfegh. Thank you.

So, Dr. Krishnamurthy, again, I don't want to spend a whole lot of time on this, but you were throwing out some terms there about sesnon zones, et cetera. And I just want the Commission to understand what exactly SS-25 has to go through to get from the well head down to the storage reservoir. So let's start at the top if you would, sir. And then I'm going to just walk you through this very, very quickly.

If you look at the top of Figure 5, it identifies four different sets of wells.

Do you see that?

Frew, standard sesnon, or SS, Porter, and Fernando Fee.

A Yes.

Q Do you know why those wells are named differently?

A They -- again, it’s a geological naming convention. They may be going to different zones at a lower level. And that's

probably why they were named different. That is my guess.

Frew is going through frew fault there. And sesnon is going through a different fault. So that's my guess. I don't know the exact reasons for that. But those would be some reasons you would name them differently.

Q All right. I appreciate that. And I understand that you weren't there when these were drilled. But I think that’s a pretty educated guess, shall we say.

And, just for the record, if you look at the middle of the diagram, there is SS-25.

True?

A Yes.

Q Okay. And it looks like it’s drilled down -- and we're going to talk about this in a minute -- but it looks like it’s drilled down. And it basically ends up in the sesnon zone there, that kind of apricot color?

A Yes.

Q Okay. And we're going to get to some of this in a bit, so I want you to make sure you clarify for me, are you saying that that sesnon zone at one point produced oil?

A That is my understanding --
Q Okay --
(Crosstalk.)
(Court reporter clarification.)
ALJ HECHT: We have crosstalk. We will be off the record.
(Off the record.)
ALJ HECHT: Thank you, all. We'll be back on the record.
Please, go ahead.
BY MR. LOTTERMAN:
Q Dr. Krishnamurthy, is the sesnon zone, to your understanding, the zone where oil was produced for years before SoCalGas took the field and converted it to gas storage?
A That is my understanding.
Q Okay. And you're going to hear the word -- we're going to use the word "caprock" later on today.
Would you explain to the Commission what caprock is, and where you would find it along the sesnon zone?
A The caprock should be on top of the sesnon. Okay? It should be the zone that you have to penetrate to get to the sesnon. That is the one at separates the producing zone from above. That's the --

Q Right. And at the risk of botching that description, is it fair to say that it's because of the caprock that the oil that was produced did not -- well, let me put it this way. Let me strike that.

Is it fair to say that it was because of the caprock that oil was contained in that sesnon zone for millennia?

A That is correct. The caprock is what prevents vertical flow. Yeah.

Q And, likewise, when SoCalGas decided to convert the facility to gas storage once the oil production was depleted, that's the same caprock that keeps natural gas from escaping from that sesnon zone and going to atmosphere; is that correct?

A That is correct.

Q All right. And one last question, just to give us a sense of scale -- because I see it here, but I don't quite understand the at -- the axis here.

It's my understanding that, for example, the SS-25 well, that blue description that starts at the top of the mountain there and goes down into the sesnon zone, it's my understanding that that's 8,000 feet deep.

Is that true?

A Yes. 8 -- around 8,000. 8,300-something, yeah.

Q Right. So roughly a mile and a half deep, well from surface, down to storage zone; correct?

A Yes.

Q Okay. Now, couple last questions and then we're going to move on to the SS-25 itself.

Is it a common practice, to your understanding, in the United States to convert former oil production fields into natural gas storage fields?

A Yes.

Q And is it a common practice in this country, and perhaps even elsewhere, to convert former oil production wells into gas storage wells?

A Yes.

Q And as part of your root cause analysis, did Blade examine SoCalGas's conversion of this field, Aliso Canyon, and its wells to gas storage?

A Yes, we did.

Q And did you find any deficiencies in that conversion?

A No.

Q And, in fact, while that conversion

was going on, did Blade find instances where SoCalGas identified leaks in the then-existing oil production wells?

A Yes.

Q And is that a common practice during conversion?

A Yes.

Q And when you watched it -- when you examined SoCalGas's conversion of this field -- and, again, this is back in the 1970s, but we'll talk about that in a minute -- did you see anything that SoCalGas should have done that it didn't do?

A You mean during the conversion; correct?

Q Yes, sir.

A No, we did not find anything.

Q All right. Okay.

Let’s sharpen our focus now. Let’s look at SS-25 itself. Okay?

As I promised, we're starting at Google Maps and working our way down the well. All right.

So it’s my understanding, sir, that the root cause analysis included reviewing the well itself, SS-25.

True?

A Yes.

Q Its conversion.
True?
A Yes.
Q It’s operational history.
True?
A Yes.
Q And even some nearby wells on the same pad; correct?
A Yes.
Q Give me a second here.
And it's my understanding that SS-25, as a well -- as an oil well, was drilled in 1954 -- and I can give you the cite off your main report if you would like?
A 1953, yes.
Q Well, '53 was the spud date; correct?
A Yes.
Q Okay. And could you tell the Commission what the difference between the spud date and drill date is?
A Well, the spud date would be the date they have the conductor in place or get the location ready to get started drilling. That was October 1, 1953.
Q Okay. So if I understand what you're saying, sir, is that that well was drilled a hundred -- or that one and a half

miles deep -- that completion, was in 1954.

True?

A I'm looking at my records, Mr. Lotterman. I'm not able to confirm that date. But, yeah, that well was completed, yes, with the gas in 1954. That is right.

Q Yeah. I --

A February 15th.

Q Yes, sir. And I see those dates, for your information, right on main report, page 20 -- 25.

So what I would like to do now, and this won't take long. But just for sake of clarification, I would like to ask Mr. Moshfegh to bring up Figure 9 from your main report. And that's on page 27. And this is going to be a little bit hard to read, but I think we're stuck with -- oh, that's better. Okay. All right. Mr. Moshfegh is showing off.

All right. Let’s see what we can do here. So let’s talk about Figure 9 a minute. And I want to make sure everyone understands, when we get into the technical details of the root cause analysis, what exactly we're talking about. Okay?

First of all, this scale here, this is obviously not in miles; correct?

A No. This is feet, I think. Yeah.
Q Okay. Right. Right.
And if you look at the top left-hand corner, there you go, it does show, as you suggested, a spud date of sometime in October 1953.
True?
A Yes.
Q Now, I want to start on the -- I want to build this well. I want to start on the outside of the well and work our way in. If you look at the very top of the diagram, there is a -- I'm not sure how you describe it. It looks like, sort of, a line with a foot on the end -- do you see that? -- and it ends at 990 feet?]
A Yes.
Q Is that the surface casing?
A Yeah. That is the 11 3/4-inch diameter surface casing and (inaudible) 40, 42-pound per foot. Yeah.
Q And that's the obvious, but I'm going to anyway. Is that a steel pipe?
A Yes, it's a steel pipe.
Q And what is the purpose of a surface casing on a -- either an oil well or a gas storage -- or at an oil well upon being drilled?

A The role of the surface casing, the 990 feet is primarily to isolate any aquifers or water zones, or something like that, depending on where you are in the country or the well. That's really the role of the surface casing.

Q Is it used to keep the hole in place when the well is being drilled?

A Correct. It's primary function is to get you to 990 and then allow you to drill from 990 to TD.

Q Is it intended to carry pressure?

A It is not designed to carry pressure, no.

Q And would you explain to the Commission what "carry pressure" means?

A Basically it is not intended as what we call a structural element. So the surface casing, the 11 3/4-inch is intended to just allow you to drill at beyond 990 feet, isolate the water zone, but if there is any gas pressure or oil pressure or anything on the ID, it may not -- it may not have enough structural strength to carry that pressure.

Q Okay. And why, if you know, was SS-25 drilled -- or why was the well that -- let me back up. I'll withdraw the question.

Why was Well SS-25's surface casing drilled to 990 feet?

A Normally the intent of that 990 is to hold back any water zones that were there. That would have been the intent.

Q Yeah. I'm sorry. My question was imprecise. So let me rephrase it.

Who decided that SS-25's surface casing be drilled to 990 feet?

A The operator at that point would have decided that. And he would have had to have -- if I remember right -- and I don't remember this -- would have to -- it needs to get regulatory approval for that depth, but that's my guess.

Q Okay --

A But the operator would be the -- would be the one who designed that, the operator then.

Q I understand the designing aspect of it, Dr. Krishnamurthy. I guess what I'm wondering -- and let me ask you my question a little more directly. Is it your understanding that the regulatory agency like DOGGR decides what depth a surface casing should be drilled for a well?

A And this is -- my knowledge may not be deep enough here, Mr. Lotterman, but my

assumption is that DOGGR would have to approve whether it's 990 or 500 or 1,000. Whatever depth it is, DOGGR would have to approve.

Q All right.

A I --

Q We will -- we will -- excuse me. I just broke my promise. We will clarify that with later testimony, Dr. Krishnamurthy, of someone who was involved with the particulars of this well, but I just was seeing if you knew.

Final question on the surface casing. Is -- are they difficult to monitor once the whole well was in place?

A Yes, because you have two -- you have a production casing beyond that, the 7-inch production casing, and you have a tubing. So it's not easy to inspect or access it, yes.

Q Even with today's technology?

A In today's technology, there are some tools that will look beyond multiple strengths, but yeah, there are some technologies that will do it. They are qualitative in nature, but that's correct. It's very new technology and not necessarily quantitative in nature. But yeah, it's very

difficult to do that.

Q And was that qualitative technology available in 2015 to your understanding?

A I don't remember exactly when it became available, but '15 it was probably available but it was pretty new in the market at that point. And so I can't comment on that, Mr. Lotterman. I'll have to look it up, but it could be somewhere prior to 2015 where they started using it at some wells in the world. But it was very new technology in 2015.

Q And as far as you knew, was it a prevailing practice to use that technology in 2015 to monitor surface casing pipe?

A No, it was not.

Q All right. What's that little stippled stuff -- that's a word -- above the 990 feet? Looks like kind of a little dot -- you know, dot, dot, dot, dot, dot. What's that supposed to designate?

A That's supposed to designate presence of cement.

Q Why would an operator put cement outside that surface casing?

A Again, in surface casing, the idea, again, would be to keep the water away from the surface casing and ensure the surface

casing is protected from water. That would be one reason. Isolate the carbon steel from the water. That would be the primary reason for the cement there.

Q Would it also be there to stabilize the surface casing before you drill the production casing?

A Yes, you would. That's a good point. Yeah. You would apply the cement to hold it in place.

Q In fact, would that be the primary purpose?

A Yeah. That would be the primary purpose. The secondary purpose would be the water. You are correct.

Q All right. So let's work our way in here, and we'll get through this pretty quickly. Is there typically -- or at least with SS-25 is there a pipe inside the surface casing pipe?

A Yes. That is the production casing, the 7-inch casing.

Q Okay. And I don't see it. I don't see an arrow actually pointing to it.

Mr. Moshfegh, could you maybe highlight one side or the other of the production casing and just -- just so Dr. Krishnamurthy can make sure we're on the same

pipe, shall we say. There you go.

You see where there -- you see where we're indicating, Dr. Krishnamurthy? Is that the production casing there?

A Yes. That is the production casing.

Q And the other diameter is on the other side, right? There you go.

A Yeah. That is a 2 7/8.

Q Okay.

A Yeah. That is a 7-inch. Where you're showing right now it's still the 7-inch.

Q And could you give the Commission a sense as to how thick that -- by the way, that's made of steel as well, correct?

A Yes, it's also made of steel.

Q Can you give the Commission a sense as to how thick that casing is? And I've got a site for you, if you need it?

A Yeah. It is about .317 inches, I believe, up to 6,308 feet, if I remember right -- if my memory serves me right. So you see -- under 7-inch, you see the different weights there, 23 pounds per foot, 26 pound per foot, 29 pound per foot. So it was J55 -- or that is the grade of the pipe, which is 55 ksi, that was run from 0 to 2,398

feet. And then there was 23 pound N80 that was around from 2,398 to 6,308 feet and so on.

Q So I have on page 63 of your report that the pipe was .321 inches thick or 8.15 millimeters. Does that roughly comport with your recollection?

A Yeah. That should be correct. The number in the report would succumb my memory.

Q Good. Okay. And we don't need to -- you know, that is what it is. And I'm not sure we need to spend time confirming that, but -- and to be clear, this production pipe -- I mean the surface casing stops at 990 feet. That production pipe goes a hundred -- goes one -- a mile and a half deep into the formation, correct?

A Yes.

Q And it's my understanding that the hole that was drilled into which to put that 7-inch casing was roughly 10-plus inches wide, correct?

A That's correct.

Q Okay. And again, this is the political science major in me, but it's my understanding you don't just drop all that pipe in. You have to sort of put the pipe in in sections, and then what? Do you screw the

threads together? Is that how it works?

A Yeah. You would drill a hole, then you will pedal surface and keep increasing the depth of that casing as you go down.

Q And explain to us very, very briefly how those sections of pipe are connected -- are joined?

A I hope my length is correct. Approximately about 40 feet of casing pipe would be in place. Then you have -- had a threaded connection. Here this was -- this was a special connection called speed type connection. So -- so you would thread it in at every 40 feet. I hope I got that 40 feet right. That number changes. It's 40 to 45 feet, I believe. And you'll thread it in, and you'll run the casing all the way to the bottom.

Q And when you say it's threaded in, do you mean you literally are screwing like pipe A into pipe B through threads -- using threads?

A Correct.

Q And when you look at the SS-25 well, were the threaded connections used at that time? And granted this was 1953, '54, were they considered premium connections then?

A Yes. They were. It was speed types ideal, I believe. Yeah. It is premium connection those days.

Q All right. So we put in the surface casing to 990 feet. We drilled a 10-plus-inch-wide hole down through the cap rock into the former oil production reservoir. We then sort of put sections in at a time, screw them in and work those all the way down passed the cap rock as well, but what, if anything, goes between the outside of that 7-inch production casing and the earth, in the formation?

A Again, as you're showing on the screen right now, you cement it, and you're cementing it all the way to 7,000 feet from about -- I'm reading it from the screen -- 8,585 -- 8,585 to 7,000 feet is cemented in place.

Q Okay. And then, Mr. Moshfegh, if you would scroll up a little bit.

But SS-25 was not cemented from 7,000 feet up to the surface casing, correct?

A That's correct.

Q Was that a common practice when it was drilled in the mid-1950s?

A Yes.

Q Okay. And scroll to the top, if

you would, Mr. Moshfegh.

Between the surface casing that -- sort of that line that has -- like it has the shoe on it and the production casing, there's a space. Do you see that?

A Yes.

Q In your business, is that called an annulus?

A Yeah, that is the annulus.

Q Okay. And as part of the drilling, the well process in the 1950s, is anything contained within that annulus as the well is being drilled and completed?

A Yeah. When you apply cement to 7,000 feet, you would displace that cement into place with another fluid behind the cement on top of the cement and behind you would have drilling mud, which is very common. Drilling mud is what you would have behind that.

Q And what is drilling mud?

A And drilling mud would be probably a water-based mud weighted with barite. That is my guess. I have to go back. I remember we analyzed it. It is a water-based mud. In the report we got some electric log data which showed us the nature of that fluid. It had a PH of about 10 to 12, which is common

for drilling mud, and that is what you would have. That would be the fluid on top of the cement.

Q So if I understand you correctly, as you're drilling this production well into the formation down into the cap rock, drilling fluid is left or exists on the outside of that pipe certainly up around the surface casing and certainly down the bottom around the shoe; is that correct?

A Yes. All the way to surface. Yes.

Q Got it. And is that drilling fluid or drilling mud, as you called it, that -- is it corrosion resistant?

A Yeah. It is really typical, when you run these muds, you run them at a high PH, like 10 to 12 or 9 or 10 to 12 intended -- these higher PH corrosion is not a factor. That is why they -- that's why one uses it. And we had data to indicate that that was used here.

Q Okay. So I guess that was my next question. As far as you know -- and I'm not holding you to amounts or duration or whatever, because we'll get to that in a bit -- but as far as you know, when SS-25 was drilled in the 1950s, there was drilling fluid between that outer surface casing and

that next inner-production casing. True?
A Yes.
Q All right. And if that drilling fluid did what it was designed to do, at least while it was there, it would resist or try to prevent corrosion; is that accurate?
A That's correct.
Q All right. All right. Let's go to the final -- let's finish this well. So I see two lines inside the production casing. In fact, I see an arrow here. It says, "2 7/8-inch," and then it gives some numbers, which I'm not sure we have to deal with today, but what does that depict?
A That is the tubing. That is the 2 7/8 tubing that is run within the production casing, and there is a packer at the bottom.
Q What's a packer?
A A packer is an element. Perhaps an element of elastomer -- combination of elastomer and steel that isolates the annulus from the environment within the tubing.
Q All right. Is that the packer, those three kind of gray lines at the bottom there?
A I don't know. It's the black -- no, no. It's the black line outside of the

tubing.

Q Okay. Got ya. All right. And if I were to ask you to point out the casing shoe on this well, where would that be on this figure?

A It would be at 8,585 feet. That's where I see it.

Q So to be clear -- and is that typical to have a casing shoe that deep?

A Yeah. Yeah. There are wells -- it depends on the wells, yeah, but it's not atypical.

Q And if I read this figure 9 correctly, is that casing shoe below the cap rock?

A It should be below the cap rock. I believe it should be below the cap rock. Yeah.

Q Okay. Why would an oil production company in the 1950s put tubing inside production casing?

A They were produced through the tubing. They will have -- I believe this is a gas lift oil producer. So they would have pumped -- they may have. I don't remember the -- we didn't look at it carefully. But they would have pumped gas to lift oil from the bottom to surface to produce -- produce

oil through the tubing. And 2 7/8 may have been adequate -- or whatever tubing they used would have been adequate for the amount of oil they were anticipating. So it's a design issue.

MR. LOTTERMAN: Okay. Judge Hecht, I'm about to turn to a different topic or slightly. If you'd like, we can keep going or we can break.

ALJ HECHT: I think we should take our lunch break now. I think that this is good timing. Thank you for letting me know. All right. I'm going to say we're going to have a lunch break until 1:15, and then we will return with the same witness and cross-examination.

We'll be off the record.

(Whereupon, at the hour of 12:13 p.m., a recess was taken until 1:15 p.m.)

* * * * *]

AFTERNOON SESSION - 1:15 P.M.

* * * * *

RAVI KRISHNAMURTHY

resumed the stand and testified further as follows:

ALJ POIRIER: We will be back on the record.

Good afternoon. This is ALJ Marcelo Poirier. We are -- this is the afternoon session for the hearings for Aliso Canyon I.19-06-016. Prior to the lunch break, Mr. Lotterman with SoCalGas was cross-examining Mr. Krishnamurthy with Blade, and let's continue with that.

Please move ahead, Mr. Lotterman. Thank you.

MR. LOTTERMAN: Thank you, your Honor.

CROSS-EXAMINATION RESUMED

BY MR. LOTTERMAN:

Q Dr. Krishnamurthy, I forgot to ask you, when we first began this examination, whether you had an opportunity to watch any of the earlier proceedings last week?

A I watched for a few minutes maybe on Thursday or Friday but not much. Not much. Not much.

Q Okay. The other question I wanted to ask you is you don't seem comfortable with my calling you a corrosion engineer, and I understand that. But is there a phrase I can use so if I ask you a question as a whatever engineer going forward that you're comfortable with?

A I don't know. I'm okay. I'm okay, Mr. Lotterman. I'm fine. You can call me a corrosion engineer or a materials engineer. That should be fine. That's okay.

Q Got it. Thank you, sir. Let's go back to figure 9 on page 27 of the main report, which has been identified as Commission Exhibit 1000. I have a couple minor questions, and then we're going to go down the well.

So couple follow-up questions, Dr. Krishnamurthy, is what are those -- what are those sort of gray slots at the bottom of the well horizontally just above the packer?

A They are probably representative of the annular flow system or the gas lift mandrel or a nipple there. So those are some -- what we call completion components. That's how I would describe that.

Q All right. And where are the stage collars on this well?

A I don't believe this well had a stage collar. I don't think that is used -- that's my -- that's what I remember.

Q Okay. And if a well does have a stage collar, where would it typically be on this 1 1/2-mile continuum?

A I think they use stage collars -- it was more in the gas -- in the natural gas -- sorry. In the gas storage wells that were drilled in the '80s or '90s. I would say it is used for cementing purposes. So wherever you are cementing, that's where you're trying to have a stage collar. That is my understanding. I am not -- I don't have any expertise to go beyond that, Mr. Lotterman, but that's my understanding.

Q Fair enough, sir. And then the final question I wanted to ask you is -- and Mr. Moshfegh, if you would maybe scroll down to the top of the well a minute. We're going to be talking about annuli or annuluses on this well and wells in particular. And to clarify, on a well like SS-25, there are actually two annuli; is that right?

A That's correct.

Q There is an annuli between that surface casing, that 990-foot surface casing and the production casing, correct?

A Yes, that's correct.

Q And then there's an annuli, I assume, between the production casing and the tubing or the tubing casing, correct?

A Correct. Between the -- between the -- the annulus you're talking about is between the production casing and the tubing.

Q Right. And so -- and I guess what I was struggling to say earlier -- so you have sort of a 2 and 7-inch tubing on the inside, right? And then you've got an annulus. And then you have a 7-inch casing outside of that, and then you have an annulus, and then, at least at the top of the well, you have an 11 3/4-inch surface casing, right?

A That's correct.

Q And if -- if you were to say that a well flows tubing flow only, which aspect of this well would that gas or the oil be flowing through?

A If it is tubing only, it will flow to 2 7/8-inch tubing -- inside the 2 7/8-inch. That's correct. And wherever you're marking. Yeah.

Q Got it. And if you were to say it was performing in a dual-flow capacity, which aspects of this well would the gas or the --

the gas in this case, I guess, be flowing through?

A It could be flowing just through the annulus, which is between the 2 7/8 and the 7-inch. It could be flowing just through there, or it could be flowing through the 2 7/8 by 7-inch and through the 2 7/8 depending on what you are trying to do.

Q And if I understand how -- sort of the difference between an oil production well and a gas storage well, oil production well is basically the fluid being produced; i.e., the oil is going in one direction that is out of the well, correct?

A Yes, that's correct.

Q And in the gas storage business, it's not uncommon for a well to not only be used to withdraw gas out of the storage reservoir but also to inject gas into the storage reservoir, correct?

A Yes, that's correct.

Q Very common in the industry?

A Yes, very common.

Q Did that practice bother you in any way?

A No.

Q Okay. By the way, when you -- I assume you put this wellbore schematic

together, you being Blade, yourself, correct?
A That's correct.
Q Did you use the SS-25 well file either in preparing these types of diagrams or in your overall RCA analysis?
A Yes. We used the SS-25 well files to develop these diagrams, the details around everything.
Q Did you find that well file complete?
A Yes. As far as we could see, we had all the information we needed, yes.
Q All right. Now I want to talk about not just converting an overall facility to gas storage but converting this well to gas storage. Okay?
A Yes.
Q And I'm looking at page 25 of your report, because there's some dates in here. Is it your understanding, sir, that SS-25 was converted from oil production to gas storage in 1973?
A That's correct, yeah.
Q And so if I can do the math, that means it produced oil for about 20 years, right?
A Yes.
Q Okay. And I want to give the

Commission a sense as to what SoCalGas did when it converted this well from oil production to gas storage. First of all, it pulled all of the tubing, correct?

A Yes.

Q Okay. And then if you remember that little thing way down at the bottom below the cap rock, it actually replaced the packer, correct?

A Yes.

Q Okay. And any seal assemblies and seals, those were are replaced, correct?

A Yes.

Q And then I assume that, as part of that process, it also replaced the wellhead?

A Yes.

Q Okay. And by the way, when you walked up to that facility in October -- I'm sorry. Excuse me -- in January of 2016, did you sort of do a visual fit-for-purpose evaluation?

A Can you repeat that, Lotterman. Are you talking -- Mr. Lotterman. Are you talking about the SS-25, because it had -- that already had a crater and everything.

Q Yes.

A So -- okay.

Q Right. So. Let me ask you a

little more precise question. When you began your root cause analysis, was it your view that that equipment on the SS-25 was fit for purpose?

A Yes. I believe -- I don't remember which phase it was. I think it was one or two where we actually did an MPI, magnetic particle inspection and all that of they wellhead and the tree and everything else. So, yeah, everything looked together, and there was no issues.

Q And is that basically what fit-for-purpose means?

A Yeah. Fit-for-purpose implies, to me, for the application that you're using, that particular equipment is appropriate from a design, structural strength, load perspective.

Q Okay. So when SoCalGas converted that Well SS-25 to a gas storage well in 1973, it basically replaced anything and everything that could be removed, correct?

A Yes.

Q So, really, I mean, to look at the other side of the coin, the only aspect of the -- the only aspects generally of the well that were not removed and replaced was the surface casing, right?

A Yeah.
Q The production casing?
A Yes.
Q And the casing shoe?
A Yes.
Q Okay. And the reason for that is, as you learned in your three-and-a-half years on the RCA, that's pretty hard to do, correct?
A Yes. You're talking about extracting the casing, correct? That's what you mean by "hard to do"?
Q Yeah.
A Yeah, yeah. Absolutely.
Q And in fact, it basically destroyed the well, didn't it?
A Yes.
Q Okay. And given your knowledge of the oil patch business, when someone is converting a well like SS-25 to gas storage, does it typically do what SoCalGas did?
A Yeah. This would be a very typical conversion you would do of an application of a wellbore. As you can see on the screen, it was just pressure-tested. I have to test to make sure the casing is in good shape.
Q Hold that thought. Hold that taught a minute. You're getting ahead of me.

A Okay.

Q And conversely, you know, if a company or utility like SoCalGas is converting a well and it runs into problems, issues with well integrity, mechanical issues, whatever, it doesn't have to convert the well, correct? It can just what? Plug and abandon it?

A Correct. It can P and A it and move on. Yeah.

Q Okay. All right. Now, next question then. You were getting a little bit ahead of me. That's why I sort of shortened your answer a bit. Forgive me.

And that is, if you look at the bottom of page 25, in addition to SoCalGas' basically replacing every part it could replace in SS-25, absent destroying the well, it also pressure-tested that production casing, correct?

A Yes.

Q Explain to this Commission what that entails.

A Yeah. We've discussed this in a few places. What you're trying to do is confirm that the 7-inch casing can handle the pressure of injection of gas and withdrawal of gas. So what you're looking at in the

production casing is there's an external pressure, which is what we call pore pressure, and then you have internal pressure. What you're looking for is the difference between those two is what a casing string should be able to handle in terms of internal pressure. So that was the version of this test. So 1,500 psi from 8,525 to surface. And these were the different pressures. As you go up, the pressure was increased, and that is reflective that on the top the pore pressure is lowest. At the bottom, the pore pressure is highest. So that was the vision of this test. And as we state in the last sentence there, these pressure tests were higher than the anticipated essential pressure loading on the 7-inch that would be experienced through the life of this well.

Q That's the sentence I wanted to explore for a minute or two now. And that is, if I understand this portion of your report correctly, what you're saying is that various aspects of that production casing were pressure-tested, and when you get to that very last bullet on the top of page 26, it actually was pressure-tested to 3,400 psi; is that correct?

A Yes.

Q And what typically is a pressure in the reservoir -- so-called discovery pressure of a well like SS-25?

A I don't remember, but I know on surface it was 2,700. So my guess is around 2,800 or 3,000. It's not more than that. I don't have that --

Q So basically -- excuse me. Right. So basically, when SoCalGas converted this well, not only did it change out all the parts that could be changed, but it pressure-tested the production casing above and beyond the discovery pressure in the reservoir itself; is that fair?]

A Yes.

Q Okay. And is that a common practice in the oil storage business -- gas storage business? Excuse me.

A Yes. You -- you would want to go higher than you expect, just so that you have some margin there.

Q And -- and is the thought there that if that well has any sort of thinness that if you pressure it beyond what the reservoir itself would pressure that if that thinness is -- is so significant that the pipe would burst, and that well cannot be

used in the future?

A Yeah. Again, you -- you have what you call a safety margin there. Okay? I don't have that number in front of me, but there's a safety margin to the pressure test, and that safety depends on your design basis. It is designed to account for uncertainty in material property, uncertainty in loading in the wellbore, and in some cases, depending on your design basis, you also will design for some amount of corrosion wall loss or metal wall loss. So it depends on the design basis.

Q Okay. So wrapping up this discussion we've had about converting the Aliso Canyon facility overall and converting the SS-25 well, in particular, did Blade identify any issues with that conversion?

A No, we did not.

Q So the well is converted, and four years later it started operating as a gas storage well in 1977. Is that correct?

A That's correct.

Q Okay. So although the well was drilled in 1953, it had a significant overhaul in the 1973 to 1977 timeframe, didn't it?

A Yes. The tubing was replaced and

the casing was pressure tested, and demonstrated to be more than adequate, yeah.

Q And the packer?

A And the packer, yeah. The --

Q And the seal -- the seal assembly?

A Yes. The entire completion was replaced, tubing completion was replaced.

Q And -- and the wellhead?

A And the wellhead, yes.

Q Okay. Did Blade also examine the operations at that well from 1977 until 2015, or for the next 38 years?

A We -- we examined all the data, yes, we did. Yes, we did.

Q Okay. And it's my understanding that that well had a workover in 1979. Is that right?

A Yes, '79 or '80. I think it's '79. You're right.

Q Fair enough.

A So --

Q What is a workover?

A Workover is, you know, replacing something, either a component or you're interrupting the operation of the well, and -- to remove something -- some issue with the packet -- packer, tubing; depends on the issue. In this particular case, it was to

re-install the annular flow safety system, yeah.

Q Okay. That was my next question, but -- but, hold that thought.

So when you kill a well, do you first have to put it out of operation?

A Yes.

Q What does that entail?

A You would -- what you would do is you would pump a fluid that has a density more than that is well pressure at the bottom so that you don't have any inflow or something coming up the well, and that's what we call kill operations. We put some kill -- kill fluid in there, and make sure that well is stable. Then you would do all the other operations.

Q Okay. So -- so when you -- when you conduct a workover on a well, you essentially kill the well first. Right?

A Yes.

Q Okay. And then if there's an issue, say, on the production casing, that -- that outside right against the formation pipe, you know, deep into the well, not -- not at the top where the surface casing is, but if there's an issue with that production casing, that workover has to pull all the

tubing, too, doesn't it?

A Yeah, depending on the workover, you may have to pull the tubing, yes. Correct.

Q Got it. And is that dangerous to do?

A It's -- it's not dangerous. It's very safe, because you've killed the well, so the operation is pretty standard in the oil patch. So you kill the well, you load the oil pressure pretty accurately, and you have a lot of history in this particular case. So to me, it's a pretty safe oper- -- I wouldn't call it dangerous, no.

Q All right. Well, I guess let me ask it quite a different way.

In conducting a workover on a well, whatever the issue, and let's assume it's a significant issue, does that activity have risks?

A Yes, it always has -- absolutely. Okay. In -- in -- yeah. In order to mitigate that risk, you're killing the well. You're making sure the well won't come at you unexpectedly. So you're trying to do it safe. So, yeah, it is always -- always a difficult operation when you operate -- when you work on a well. So, yes.

Q Right.
A However, by killing the well, you are making sure and -- making sure all the components are working and making -- mitigating that -- those risks.
Q And during that difficult operation, have workers been injured?
A Can you repeat the question, Mr. Lotterman? Sorry.
Q Sure. During that difficult operation of conducting a workover in this country, have workers been injured?
A Yes.
Q Same question, have workers been killed?
A Yes.
Q So this is not an activity that someone does lightly. Correct?
A No. It requires a lot of planning.
Q Okay. All right. And the workover that SoCalGas conducted in 1979, you said, was that to replace a subsurface safety valve?
A We use a different terminology in the report. It's not a subsurface safety valve. It's the annular flow safety system, is what we -- that is the terminology we use, as you can see in the report. That's what I

believe that workover was.

Q Okay. And -- and did SoCalGas replace that system in 1979, remove it, basically?

A Yeah, I believe they removed it.

Q And did they remove it because it went bad?

A They were servicing it. If I read my paragraph there, I have to read it, because I don't recollect the exact details, they attempted to service it in January 7, 1980, and this was all based on the SS-25 well file. That's where we're extracting this information from. And they continued to have problems, and then on January 28th, they decided to pull it.

Q And when you pull a system like that, does the housing stay in the -- in the well?

A I don't know the details of this particular well, but my guess is yes. Anything that it can -- you know, you would pull what is easy to pull, and leave the rest there. As long as it doesn't interfere with the flow, you'd leave it alone.

Q Okay. Let's -- let's move on, and I want to talk about the -- the monitoring of this well, in particular, and let's turn, if

you would, sir, to the top of page 30 of your main report, Commission Exhibit 1000. Are you there?

A Yeah, I'm there.

Q Good. Okay. And -- and before we proceed, I want to make sure that our nomenclature is clear, because I think I misspoke earlier.

When you talk about monitoring a well, are you talking about conducting, for example, temperature and noise logs?

A In this context, that's what we are talking about. Again, you could monitor various things, so I want to be careful with the word "monitoring." But here, we are measuring -- running temperature -- or -- or SoCalGas ran temperature and noise logs over the years. That's what we are talking about as monitoring devices. You could monitor various things, so that's what's being monitored. That's correct, yes.

Q Okay. Let's focus on -- on SoCalGas's monitoring of this well as depicted on page 30. Okay?

So if I read this Figure 13 correctly, and then -- and the narrative around it, basically, over the next 38 years that this well was in operation it had 65

temperature surveys. True?

A Yes.

Q Now, can you briefly describe to the Commission what purpose a temperature survey has?

A Okay. So if there is a leak -- so what you're looking for in a temperature survey, and very similar to the noise survey, is we are looking for any leaks in the casing or around the shoe or anywhere else. So when a gas -- when you have a gas leakage, what happens to gas is it goes from high -- it's what is called Joule–Thomson effect. You expand the gas. When you expand the gas, there is a drop in temperature, and you're looking for that signature to say, "I have a leak here or I have -- I have a cooling anomaly," you will say, and you confirm that there is a leak or a -- or some other -- some other cause for that temperature drop.

Q Okay. And if I understand this -- this logging properly, there are no -- there's no need to pull the tubing when you do it. Is that right?

A That's correct. You can --

Q So --

(Crosstalk.)

///

BY MR. LOTTERMAN:

Q So there's no need to do a workover. Correct?

A Yes.

Q So if you're sort of debating between doing a workover and those risks and a temperature log and those risks, is it fair to say that a temperature log is less risky?

A Yeah. Pulling the tubing is a more onerous process, yes.

Q Okay. All right. And -- and if I look at your Figure 13 correctly, it depicts, just above the years in red "Ts," all the 65 temperature surveys that were conducted on SS-25 from the time that SoCalGas converted the well to gas storage until up until the incident. Correct?

A Yes.

Q And if I understand your earlier answer correctly, and I think you talked about the Jule effect or the Thomson Jule effect, something like that, but basically, for those of us who are -- who didn't go to engineering school, what that means is if you have like a pinhole leak in that production casing, or even a -- a -- a larger leak, and gas is escaping from the well into the formation, that gas cools the area around it,

and hence, the temperature log shows a cooling. Is that right?

A That's exactly correct, yes.

Q Okay. And I believe we'll -- talked about this earlier, but is it your understanding that SoCalGas conducted those 65 temperature surveys pursuant to DOGGR requirements?

A Yes.

Q Okay. And then if you look at that Figure 13, if you look above it, you've got some blue "Ps." Do you see those?

A Yeah.

Q Do -- well, actually, let's hold that thought. Let's -- let's -- let's focus on the "Ns" first.

Above the "Ps" I see some black "Ns." Do you see those?

A Yes.

Q Are those the eight noise surveys that you show at -- just above the Figure 13?

A Yes, those are the noise surveys.

Q So describe what a noise survey is and why one would do that in addition to a temperature survey.

A Okay. A temperature survey, if there's a leak, you will see it. But, occasionally, the temperature survey may not

may give you some -- some cooling events, and you have to be careful interpreting it.

A noise survey, if there is any flow -- so you're literally listening to noise at various dB levels and various frequencies and altitude and frequencies, and depending on the altitude and the frequency, you can establish there is gas flowing out of the well or out of a hole or wherever. That's the intent of the noise survey. That's what you're trying to do.

Q So if I understand you correctly --

A And the --

Q Excuse me.

A Sorry. Let me -- it supplements -- it supplements and further supports an interpretation within temperature surveys.

Q Okay. Thank you for that clarification, and my apology for stepping on you.

So if I understand you correctly, if you have a pinhole leak or -- or some sort of hole in the production casing, a temperature survey will show a cooling. Right?

A Yes.

Q And a noise survey will make noise?

A It will show you -- it'll show you

a -- a change in -- it'll show you a -- show you noise there, a dB in the frequency, yeah.

Q Right. I mean you're basically lowering a microphone down that well. Right?

A Pretty much; pretty much, that's correct.

Q All right. And just like a temperature survey, when you conduct a noise survey, there's no need to pull the -- there's no need to do a workover and pull the tubing. Correct?

A That's correct.

Q Okay. All right. Now, let's look at the blue "Ps" between the "Ns" -- the black "Ns" and the red "Ts." What do those depict?

A Those are pressure surveys. And if I remember right, this is not a pressure test. It is a pressure survey. So you're not displacing the gas. You have -- you shut the well in and monitor the pressure to see if there's any pressure change.

Q And -- and why is a pressure -- why might a pressure change be important?

A Again, if there is -- if there is any -- any -- any, again, hole, hole or some -- some part of the casing or tubing where you have gas leaking in or out, you

will see a pressure change, a pressure drop, a local pressure drop.

Q And like the temperature survey and the noise survey, when you conduct a pressure survey there's no need to do a workover and pull the tubing. Right?

A That's correct.

Q Okay. But, I guess what I want to distinguish between, for example, temp surveys and pressure surveys, temperature surveys were required by DOGGR, but pressure surveys were not. Is that true?

A Yes, I believe so. There were -- there was -- and we discussed this in the report. There was some issue around requiring some pressure tests and doing pressure surveys and some of that, so I don't recall that, Mr. Lotterman, so I want -- but, I believe temperature surveys were definitely required. I'm not -- I don't believe pressure surveys were required. I'll need to reference my -- refer to my report to confirm that, but that's what I recall.

Q Let's do this, because I promised you earlier this wouldn't be a memory test. Turn to page 199 of your main report, sir.

A Thank you. Yes.

Q Okay. Would you read -- under

Section 4.6.2, would you read that first sentence into the record slowly?

A Sure.

Although SoCalGas performed 41 pressure surveys in 41 years, neither the DOGGR project approval letter nor the SoCalGas inventory monitoring verification operations required pressure surveys.

Q All right. And so basically, what -- going back to Figure 13 on page 30, what you do there is you depict a hundred and fourteen surveys of SS-25 that were conducted over 38 years. Right?

A Yes.

Q You can trust me on the math.

A No, I -- absolutely. Yes.

Q Okay.

A That's correct.

Q But, what this -- what this Figure 13 does not depict, sir, it does not depict, for example, daily site inspections. Correct?

A Yes, it does not.

Q What's the -- what's the purpose of a day -- daily site inspection on an underground storage facility?

A I think the site visit is to see if there's any leakage, any -- any anomalous --

any anomaly in the operations. That's the intent of the daily site visits.

Q And the daily you show on page 30 and in Figure 13, also, it doesn't depict weekly pressure readings, does it?

A That's correct. There were weekly pressure readings.

Q What is the purpose of a weekly pressure reading?

A Again, if there is a leak event, let's say, in the casing or the tubing or somewhere, you will see variations in the pressure, whether it be tubing pressure, tubing casing pressure, casing -- surface casing pressure, any of those annulus pressures. That's what you're looking for.

Q All right. And your Figure 13 also does not depict monthly well site inspections. Correct?

A It does not.

Q What's the purpose of a monthly well site inspection?

A It's similar to a daily well site inspection, again, looking for anything anomalous, any -- any event, any -- anything that appears unusual operationally.

Q Okay. So getting back to -- to the -- the -- the temp logs, the 65 temp

surveys that you depict on Figure 13, you confirmed in your report, did you not, that DOGGR approved the use of temp logs for mechanical integrity testing?

A Yes.

Q And you also concluded that SoCalGas complied with those requirements, didn't it?

A That's correct.

Q All right. And, in fact, what you say on page 30, right, right below the figures there, you say that no anomalies were ever recorded during the measurements. Do you see that?

A Yeah.

Q And those -- and when you say during those measurements, that's basically the life of this well as a gas storage well?

A Yes.

Q From 1974 until the incident in 2015, almost 40 years?

A Yes.

Q And then if you turn to page 31 -- by the way, there's that temperature survey. Right?

A Yeah.

Q We won't go there. But, go down to the narrative, if you would, just below that

Figure 14.

You conclude no temperature, pressure or noise anomalies in the surveys indicated a preexisting casing failure before the incident of October 23, 2015. Is that true?

A That's correct.

Q Okay.

A Yes.

Q You also say -- -

A But -- yeah.

Q Sorry. And you also say, in the very next sentence, "Additionally, no physical observations from well inspections and weekly pressure measurements indicated an existing casing integrity problem." True?

A Yes, that's correct.

Q Okay. So if you were a diligent engineer at SoCalGas or -- or wherever in the weeks before the incident and you're working at Aliso Canyon facility and you're reviewing its 40-year operational history, including its well file, its logging data and its physical inspections, would you have seen any warning signs of a casing leak?

A SS-25 data, as we discussed here, there was no indication, that's correct.

Q Okay. And that was accurate when

you wrote the report in May of 2019. Right?
A At -- yes, absolutely.
Q And is it still accurate today?
A Yes.
Q All right. Now, let's talk about the two wells on the same pad, SS-25A and SS-25B. Let's turn to page 16 of the main report; actually, back to page 16, Figure 2. Let me know when you're there. You're there?
A Yeah. Yeah, I'm here. Thank you.
Q Okay. Good. So those wells are pretty close to each other, aren't they?
A Yes.
Q What, 10, 20 feet, maybe a little bit more?
A Yeah, a little bit more. I want to say 20 feet; 20, 30 feet, yeah.
Q Okay.
A I have to recollect. Yes.
Q But, on the same pad?
A It's on the same pad, yes.
Q Okay. And by the way, when you say, "pad," is that sort of a -- a leveling of that terrain so -- so you can drill wells and monitor wells and inspect wells safely?
A Yes. It's a flat area. It's kind of a -- I view the word, terminology, knoll. The SS -- if you see that road, you drive

around that road, there is a -- there's a pad, a well pad that was built, I'm sure ages ago, and it contains three wells, SS-25, 25A and 25B.

Q And did you say, "knoll," like n-o-l-l?

A K-n-o-l-l, yeah. It's kind of a --

Q Oh.

A It was a word we used which was to describe -- I forget. Is it 200 feet above the road below? So that kind of explains the -- the cooling on some of the logs. So we use the term k-n-o-l-l.

Q Got it. Thank you. And as part of your root cause analysis and inspection did you look at the history of the two other wells on that SS-25 pad?

A Yes, we did.

Q Okay. And let's -- let's take them one at a time. And again, forgive me if this is pressing your memory. And maybe we should just get to the -- the conclusion, but let me -- let me try to walk you through to make sure we're clear.

When you looked at well 25A, did you see any warning signs there that something might be amiss on that pad, generally?

A No. Again, I'm -- I'm going by memory, which is kind of -- I have to think carefully. 25A had -- see, they -- they -- those wells were completed differently, were drilled much later in -- in the history of Aliso, so the -- the drilling and the completion is different than SS-25. But, there was no indication in 25A or 25B about problems in the pad or -- in SS-25.

Q And -- and there also was no indication, was there not, of any problems in their operational history that might correlate with the issue that arose at SS-25?

A No.

Q And for 25A, and you can trust me on this one, if you wish, or you can look at the -- the report, not only did you look at the logging data that historically had been done on that lot -- on that well, you ran your own logs in 2017, didn't you?

A Yes, we did.

Q And if I'm not mistaken, you concluded that you found no analogous corrosion. Right?

A That's correct.

Q All right. So -- so looking at the SS-25 well, in particular, there were no warning signs of a casing leak, and when you

looked at the two sister or brother wells on the same pad, you came to the same conclusion. Right? No warning signs about SS-25 leak either from the well itself or its two nearby wells. True?

A Yes.

Q All right. Let's go down the well.

Your root cause analysis included a physical investigation of the SS-25 production casing wellbore itself. Correct?

A Can you -- can you repeat the question again? I apologize. I -- I -- can you repeat it again, Mr. Lotterman?

Q Do not apologize. It was a long one. Let me -- let me shorten it.

As part of your root cause analysis, did you inspect the physical pipe of SS-25?

A Oh, yes. Yes. Yes, we did.

Q And did it include extracting all the tubing?

A Yes.

Q Did it include extracting some of the production casing?

A Yes.

Q And is that endeavor outlined in your -- I believe it's the Phase 3 summary, which is part of Commission Exhibit 1001?

A That's correct.

Q So if I understand you correctly, as part of this aspect of the root cause analysis, you extracted about a mile and a half of tubing, and -- and little over 990 feet of production casing. Right?

A Yes.

Q So not to put too blunt a point on it, about two miles of pipe?

A Yeah. I -- again, the miles I'm not able to type -- line up, but approximately seven to eight thousand feet of tubing, and around thousand feet of casing string, yeah.

Q Actually, to be fair to you, sir, I calculated 1.7 miles. So --

A Oh.

Q All right. Had -- had you ever done that before?

A I have. In one other case, we have done -- a lot of casing strings were pulled; but -- but, I have pulled -- I have pulled 3000 maybe feet of casing, but not this much tubing, yes. That is -- that is the first time, yes, in terms of just the length.

Q And is it common in the oil and gas business to be pulling tubing and production casing out of a well?

A No, you don't normally pull casing. You may pull tubing. Casing you pull only if there is a failure, and you want to find something out. But, that's -- that's -- and quite often, it's cemented. So it's cemented. You cannot pull them. So it's quite hard.

Q Okay. But, nonetheless, for this root cause analysis, Blade decided that excavating at least a portion of the production casing was necessary here. True?

A Yes.

Q Because you believe that it was the only true way to investigate what happened in that wellbore. Right?

A Yeah. Yes, because in this particular case, the tubing had failed, as we found out through our logging in Phase 1, so pulling it was not as -- as much of a challenge as it would be if it was in place. Yeah, the direct means was the best way, since this was a failure.

Q Right. Because, you know -- and -- and we'll get to this in a minute.

Because when you ran cameras down that -- when you pulled the tubing out of that well, and I'm going to slow myself down a little bit, and you ran a camera down the

production casing, you were able to tell where that production casing failed. Right?

A Yes.

Q But, you weren't able to show how it failed, were you?

A No.

Q And you were not able to show why it failed, were you?

A Not at that point, yeah. That's correct.

Q And but for pulling that production -- but for pulling out 990 feet of production casing out of that hole, can you think of any other way to answer those two questions, how the production casing failed and why it failed?

A In this particular case, that was necessary, yes.

Q Okay. So you go on in the report to describe the extraction process, and that begins on page 37, sir.]

A Yes.

Q And, again, you can -- I pulled this out of your report, because I was trying to keep this examination going on somewhat efficiently.

But here's what I gleaned, basically, is you pulled the tubing from July

to September of 2017; right?

A Yes.

Q And you pulled roughly 244 joints of the tubing?

A Yes.

Q Did you see anything unusual in that exercise?

A In the tubing you mean? No.

Q Okay. All right.

And then, as we talked about earlier, you ran what's called an EV camera down the production casing; is that right?

A We ran it down the production tubing first. And we looked at the casing.

Q Okay. And when you looked at the production casing using that special camera, you saw a -- that the casing had parted at joint 22; right?

A Yes.

Q So that was the first confirmation that anyone had that SS-25 production casing failed at that depth; right?

A It was a confirmation. There was suspicion based on tubing logs we ran and temperature logs that were run in November of 2015. I don't have the exact date on that, sometime in the end of November, I believe, or middle November.

So there was a couple times at which there were cooling anomalies that showed up that suggested it could be at 892, or it could be shallower. So those were the two options. So, yeah, this was the first confirmation -- visual confirmation.

Q Did that visual confirmation change the focus of your root cause analysis?

A No, it didn't change the focus. Because it -- perhaps -- at that point, we didn't have a clear idea of what this was going to look like, so -- some suspicion. But, really, we had not set the direction of the investigation. So the assum- -- the fact it was parted and it was offset made the extraction operations a bit more complicated. But, perhaps, I don't want to say "RCA."

At that point, we were in a prelim -- we didn't have a view on exactly why this happened or what happened, so... I wouldn't say direction of the investigation. But, yeah, the extraction approach got further refined after that.

Q Fair enough. Fair enough.

And to be clear, and for the record, when you ran that camera down the production casing, you found that the casing had parted at 892 feet below the surface;

right?

A Yes.

Q And so to put that in the perspective of someone who doesn't deal with wellbores on a routine basis, that was roughly a sixth of a mile deep; right?

A Yep.

Q Or to use, perhaps, a measurement that I'm more comfortable with, about three football fields?

A Okay. Yes. I'll take your word for it.

(Crosstalk.)

BY MR. LOTTERMAN:

Q Okay.

And the reason why I say that is, I want to make sure when we talk about "shallow leaks," or shallow -- you know, the shallow leak at SS-25, that we all understand that that leak was three football fields below surface; right?

A Yes. 892 feet, yes. That's correct.

Q Fair enough.

So, yeah -- so they're on the goal line. They're on the goal line about to break in, but -- but close enough. All right.

And to sort of cut to the chase on this, Blade decided to cut and extract a total of 25 casing joints as part of this investigation; right?

A I believe --

Q Look at page 40, sir --

(Crosstalk.)

ALJ POIRIER: Let's go off the record.

(Off the record.)

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

Mr. Lotterman, can you re-reference the place in the report that we're discussing?

MR. LOTTERMAN: Yes --

(Crosstalk.)

MR. LOTTERMAN: Yes. Thank you, your Honor. I was asking Dr. Krishnamurthy to identify how many casing joints they decided to cut and extract from the production casing. He was a little unclear. And so I directed him to the main report at page 40.

THE WITNESS: May I answer? Can I clarify?

BY MR. LOTTERMAN:

Q We're ready.

A Yeah. There was a total of 25 joints, full joints, that we extracted. But

we also extracted -- and I need to confirm this, which is shown on page 51 -- part of 26. That's what I wanted to make sure, yeah. I believe it was 26.

So, yes, a total of 25 full joints, part of 26.

Q Right. We're going to walk through each extraction, sir. I just wanted to take this one piece at a time.

So the initial extraction of the production casing, until the casing was at the surface, all the way down to the parting; is that correct?

A That is correct.

Q Okay. And if I understand correctly from page 41, that began in October 2017; right?

A Yes. Yes.

Q And you talk about cutting.

Could you tell the Commission what was involved with extracting the upper portion of the production casing from that hole in October 2017?

A So we were told, as shown on the figure here -- Figure 25 on the screen, we would pull the pipe above the valve and have -- there was a cutting unit from, I want to say, Cameron (phonetic). And that would

place a cut, I forget, 1 or 2 feet below the connection. What you're seeing there is a connection of the collar, depending on how you define it. We were cutting it. And the intent of the exercise was to maintain the integrity of the connection and assess the connections. And that's why we were cutting.

Q All right.

And -- I lost my place. One second, sir.

ALJ POIRIER: Let's go off the record.

(Off the record.)

ALJ POIRIER: Back on the record.

We will be taking a short afternoon break until 2:20.

Thank you.

(Recess taken.)

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

We are just returning from a short afternoon break. We will continue with Mr. Lotterman's cross-examination of Mr. Krishnamurthy.

MR. LOTTERMAN: Thank you, your Honor.

Q Dr. Krishnamurthy, I have two clarifications, and then I want to keep going down the wellbore.

First of all, when we were talking

earlier about pressure testing the SS-25, and really any well, during its conversion from oil production to gas storage, we were talking about the pressure test that's conducted.

And I just wanted to make clear, is it the practice in the underground storage business to pressure test above the reservoir operating pressure?

You're on mute, sir.

A Sorry. I apologize.

Yeah. You're talking about reservoir pressure. But what you're looking at is the pressure profile in the wellbore, the delta peak. You have the pressure inside the casing, and you have pressure outside the casing. You're looking to make sure that as you test, you are more than that delta peak at any depth. So the practice should be to be higher than that. You can't be lower than that delta peak.

Q Right.

A So to look at absolute numbers, yeah, you may be equal or similar. But you have to be higher than the delta peak to have some safety margin in there, so... which is what was done here.

Q Okay.

And so the thought is, whatever -- whatever pressure the reservoir provides up that wellbore, a diligent underground storage engineer is going to design and make sure that wellbore can take that pressure and a safety factor more; is that right?

A That is correct.

Q All right.

And was that done at Aliso Canyon, generally? -- and at the SS-25 well, in particular?

A It was done at SS-25. I'm not sure how many other well records we checked in terms of conversion. But we did check SS-25 in some detail. And it was --

Q Fair enough.

A -- definitely done.

Q Fair enough. Thank you.

The other question I have for you is, when you finally got on to the well pad after the relief well had killed the well, and it was safe to -- to go in there and start investigating, was there -- was there fluid in the -- in the formation outside of the surface casing?

And was there fluid in the annulus between the production casing and the surface casing?

And was there fluid, in fact, in the tubing?

A Yes to at all of them. There was fluid -- and I don't remember the fluid levels. I remember reading it a couple of days ago.

There was a fluid level that was measured in the annulus between the production casing and surface casing, between the production casing and tubing, and in the tubing. There was fluid everywhere.

Q What was the fluid?

A It would have been most probably the kill fluid or completion fluid, whatever was used either during the kill operations or during the -- or during the intersection of the relief well with the SS-25. So a combination thereof.

Q Okay. So -- and not sure this matters -- but, just to be clear, when you were lowering that camera down the production casing to try to figure out where it had parted, you were actually lowering it down through that fluid, whatever it was; correct?

A Yes. So it is shown in one of these figures. But we were pulling the tubing out. And as we -- we -- we knew -- because of the tubing logs we had run, we

knew roughly where it was -- 895, in that vicinity, was where we believed it was failed. So the camera was there at the bottom of the tubing, right around the point where the seven-inch casing had failed.

So that is shown in Figure 24 of the report -- or Figure 23, to see the configuration. And so the tubing -- and so what we did at that point, the fluid was, as you can imagine, was -- there was high turbidity in the fluid, so you cannot see things with the camera. So what we did was, we pumped clean fluid as that camera was in that spot to see the failure. And that's the pictures you see.

Q Okay. Thank you. All right.

So let’s continue extracting this pipe. And let’s got to the bottom of this.

So if you -- I want to turn your attention to Figure 33 on main report page 45. And not the picture quite yet, but just the figure itself.

It’s my understanding, Dr. Krishnamurthy, that sort of depicts the sections from the parted casing above that were first extracted from the wellbore; correct?

A Yes.

Q All right.

And as you're pulling out the first, let's just say, 600, or so, feet of this 7-inch production casing, did you see any external -- any significant external corrosion on it?

A I believe around depth -- I don't remember which casing number it is -- around a depth of 14 -- C-14 was the first time we started -- which is on Figure 28 -- we started seeing some external corrosion. Up to that point, it's around 600, 700 feet in the wellbore, there was limited to no corrosion. And the corrosion started appearing at C-14, I believe.

Q Okay. So from 6- to 700 feet above, as you pull out this production casing, you didn't see any corrosion; right?

A That is correct.

Q Did that surprise you?

A No. Because I actually -- very honestly, I expected the OD to be not an issue until I saw the corrosion -- started seeing the corrosion on C-14.

Q All right. Okay. Hold that thought. We're getting there now.

So as you're pulling out this pipe, you are laying it on the rig floor and

inspecting it.

True?

A Yes.

Q And then you performed, what I believe you call, an NDE, or a non-destructive evaluation, of the regions; right?

A Yeah. It was more visual, I would say, at this point. We -- on the rig floor. We did a visual examination. And we would also attempt to collect scale, which was -- see if there was a relevant scale, ID scale, OD scale. So -- and then we would move it from there. Because this was a big operation, so it was moved to PS-20, which was a staging location where we would do more detailed examination of the pipe.

Q And you took photos; right?

A Yes.

Q Lots of photos?

A Yes.

Q All right.

And let's turn to one of those photos right now. If you go just below this Figure 33, you've got a Figure 34.

And is that the upper portion of the parted casing at 892 feet?

A Yes.

Q Okay.
A That is correct.
Q So here's my question for you, sir -- and maybe it’s better to turn to page 43 for this. Let’s do that.
And I want to look at the bottom two photos there, not the top one necessarily. I believe you said in your deposition that when you pulled out that portion of the casing, you saw a grooved, striated, s-t-r-a-i-t-e-d (sic), corrosion; is that right?
A Yes.
Q And is that synonymous with tunnelling and scooping?
A Scooping, not tunneling. Tunneling requires more investigation, which we saw first, as you well know. But at this stage -- again, when we pulled it, it looked unusual. Yeah, it looked striated grooves, as we state below.
But, yeah. Perhaps, scooping -- not scooping the way microbiological folks talk about. There's elements of it that look scooping. Elements of it look striated, so a combination thereof.
Q Okay. And when you saw this grooved striated corrosion that's depicted on

Figure 29, had you ever seen that before?

A No, not in this nature. No. It was -- it's quite unique.

Q Yeah.

And, in fact, you told me in the deposition that you considered that morphology to be very unusual.

True?

A Correct.

Q Okay.

And when you say "morphology," what do you mean?

A By "morphology," I mean the shape and the character. The shape, the depth, the nature of it. So if you look at it, the circumferential nature of it, the longitudinal nature of it, it's quite unusual.

I mean, there are similarities you can find to, say, CO2 corrosion, but it's not similar to this. So it didn't match with some other sets of data we have on the well. So it is unusual, yes. That is correct.

Q Okay.

And if I'm not mistaken, Blade undertook a pretty extensive search of the literature, for example, the similarly grooved, striated corrosion; is that right?

A Yes, we did.
Q And if I recall from your deposition in Houston almost two years ago, you didn't find any pictures, did you?
A No.
Q So the morphology you saw on SS-25, to your knowledge, was not reported in the engineering and scientific literature; is that right?
A I want to be careful. We researched it quite a bit to look for similarities. In the literature, they discuss it. But we didn't see any pictures. That is correct.
Q Right. Right.
Did that surprise you?
A No, it doesn't surprise me. It’s just unusual. You know, I don't know how -- yeah. It is surprising there is no literature on this.
But, yeah, there wasn't -- we couldn't find any pictures. There are people who describe it in words. But we didn't see it associated with the pictures.
Q Here's what I don't get -- and, again, I'm not an engineer.
But it’s my understanding that they have been drilling oil wells in this country

for 150 years. And I actually Googled it, and it said the first well was drilled in 1859 in Pennsylvania.

And yet, even though the oil and gas business has been around for a century and a half, you couldn't find a single picture of a similar morphology from what you found on SS-25; is that right?

A That is correct.

Q Okay. And that includes any lab study that someone could have done. I mean, you've got major research, engineering, colleges, universities across the world. You got Imperial College in the United Kingdom. You've got LSU and Texas A&M. And you've got your alma mater, University of West -- of Virginia -- excuse me. And none of those labs had produced pictures similar to what you found on SS-25.

Did that surprise you?

A It did surprise me. However, I want to be careful. I don't want to, by any means, tell you that I have -- we at Blade have looked at everything, and we can confirm. So in the literature search we did, we did not find it. That's how I would word it. I want to be careful. That is number one.

Number two, when you look at this, this is, of course, as you're well aware, it's on the OD of the 7-inch casing. And as we conclude in the report with different sets of data, that this was caused due to microbiological in the groundwater. So this is the ground water with some microbiological groups that appear to have caused it.

It is unusual. I -- we couldn't find it in literature. So I don't -- I want to be careful that it doesn't exist. We didn't find it. That's how I would word it.

Q Fair enough.

But you didn't find it after an extensive search; is that right?

A Correct.

Q Okay. All right.

That's fine. That's fair enough. I didn't want you to -- I didn't want you to speak on behalf of the entire oil and gas industry. Okay.

So did -- when you saw the grooved, striated corrosions on the OD of the production casing that you pulled out in 2017, did that change the focus of the root cause analysis?

A Again, I want to -- we didn't have a focus prior to pulling these casings. We

had a view, you know. We had some hypotheses as to how it may have happened. But we didn't know until I -- I don't want to say change. It directed us a little bit more to what we need to investigate, as far as the cause of the corrosion, yes.

Q All right. Let me ask you a slightly different way.

When you pulled off that piece of pipe and you saw that grooved striated corrosion, did MIC suddenly become the hypothesis -- or the primary hypothesis in your root cause analysis?

A MIC was one of them. We were very deliberate to make sure we could prove MIC. But, yeah, MIC was one of them.

We still -- at this stage, when you're looking at this pipe, I didn't know how the connection was leaking. So there are other parameters that could enter. Very easily, we could have argued this is CO20. Because the connection was leaking heavily. The connection was not leaking, as you well know. So that eliminated it. So I wouldn't say that is the only mechanism. But that was one of the mechanisms on the table, in addition to CO2 corrosion.

Q Right.

I guess what I'm getting at is, when you saw that grooved striated corrosion, did MIC suddenly become a pretty significant or quite possible hypothesis in your investigation?

A Yeah, absolutely. It was definitely a hypothesis we had to consider and either prove or disprove. Yes.

Q Okay. And I guess what I'm wondering is, this investigation started in January of 2016. You pulled this pipe in October 2017, so about a year and a half later.

Why wasn't MIC on anyone's radar scope?

A Good question. Very simple reason.

Up until this point, there was a variety of factors to come out. You're -- if in a conventional well, you think you're drilling mud behind pipe. That drilling mud, if it was the right weight, it should hold on forever. And it should give you protection.

There is no -- you cannot -- I don't like to start an RCA assuming everything is off. You don't start an RCA until you have proof, otherwise, that the drilling mud has been displaced. You cannot start with that. You presume the drilling

mud is there, and drilling mud -- people with the drill with drilling mud, they applied ICH. So there's no reason to suspect external until you see external corrosion.

And then when you see external corrosion, you then start seeing what would cause external corrosion. So that is a process. We don't like to start with the assumption something went wrong. So that is not a fair assumption. You have to start with the assumption that everything is as it should be, and then see what all don't fit. So that is a process.

Q No, I understand that. But I'm a little confused by your answer.

I guess, you know, it’s my sense, Dr. Krishnamurthy, that when you walked into that project, you had a number of hypotheses in mind. And when I say "hypotheses," I don't mean suspicions. I mean hypotheses. You had a couple theor- -- you had a couple of possibilities in mind that you were either going to prove or disprove as part of your investigation.

And, I guess, what I'm wondering is, when did the possibility of MIC become the main hypotheses?

A Until when we started looking at

the picture here that you're showing --
Q Right.
A -- failure picture.
Q Right.
And that happened in October 2017; correct?
A That's correct.
Q Okay. And as part of that, once you saw those striated grooves, you actually decided to bring in an expert in microbiology, didn't you?
A Yes. But she was already involved if I remember right. She was involved when we were pulling the tubing. Getty (phonetic) was there even prior to this. We did suspect it. But it was not a major hypothesis until we saw this. They were, I believe, already involved in it prior to this.
Q And her name was Elizabeth Summer; right?
A Correct.
Q What did she add to your root cause analysis team?
A She added the microbiological element that we didn't have ourselves.
Q Okay. And do you remember when specifically she came on board?
A I would have to look back. It was

prior to this. It was, if I remember right, when we were pulling tubing. I want to say sometime in '17, prior to this. But I'll have to check --

Q Okay.

A -- I don't have it handy.

Q So the root cause analysis started in January 2016. And she joined your team sometime in 2017, subject to check; right?

A Yeah. I can check that. I can find out.

Q It’s not that important, sir. I just want to make sure she didn't fly in with you January 2016.

And I think the answer to that is no; right?

A Oh, no. No. No.

That's not what -- she -- I -- again, my recollection is she was there when we were pulling tubing either from 25-A -- I want to go back to 25-A, which was in '17, actually. Again, I would have to look at my listing. But, yeah, sometime in that timeframe.

Q Okay.

A But I can have an approximate date very easily.

Q Okay. Let’s keep going here.

I want to talk about -- so then at some point after you had pulled out the piece depicted in these pictures, you decided to actually extract the lower portion of the parted casing about a week or so later; is that right?

A It was not a week. It was a bit longer, I think.

Q Oh, what --

A I don't remember. It was longer than that I thought. Let me see.

The lower portion, I -- I know we had a plan. But it started -- it was a bit longer than that. I have to go back and look.

Q Dr. Krishnamurthy, it’s not that important. You actually caught me here, because I don't have a citation from your main report on that.

But suffice it to say that -- and I think this is no surprise to anyone, you pulled out the upper portion of the parted casing before you pulled out the lower portion; correct?

A That is correct.

Q Okay.

A And it was -- because we had to design -- like you pointed to earlier in your

question, we had to design a casing extraction tool. So I have a feeling it was not a couple weeks, it was month, I think. I can check.

Q Okay. And why did you need that special tool?

A Multiple reasons. There -- if you look at the -- when we pulled the top one, of course, the gas was flowing through there. It was highly eroded. So the features were destroyed. So we recognized that the bottom half becomes extremely important, and to get it without any damage to the bottom so that we can make the interpretation. So that is why it was essential to pull it carefully.

Q And -- and I think you mentioned this already, but let me make sure the record is clear.

And as part of that process, you had to basically design a special tool to allow for extraction without damaging the casing itself; is that right?

A Yes. I wanted to clarify that a little bit. This was a tool that NOV already had. We just repurposed it for this purpose. So we put the design in place with NOV. And one of our engineers worked with NOV to make sure it would work, and we made it work. So

to the existing design that required mild modifications, or even with some modifications, we made it happen.

Q And were those modifications part of the creative aspect we talked about earlier on the credits page?

A Yeah. This was, I would say, close to NOV and Nigel (phonetic). Nigel is engineers who worked with NOV. That's my assumption in this. But actual operations in field, a lot of people, SoCal, and the service providers -- a lot of people in all of that.

Q All right. So let’s go to Figure 44. Because I want to get down to the bottom of this pipe as soon as we can.

So let's go to Figure 44 on page 52 of the main report.

Okay?

A Yep.

Q And what I see there, and you tell me if I'm wrong -- and I'll -- we'll talk about the particulars in a minute. But what I see there is both a diagram of the upper portion of the casing and the lower portion on the left, and an actual picture of the pipe on the right.

Is that accurate?

A That's correct.

Q Okay. And if you look on the -- at the diagram on the left, where you have boxed it in red, and then you point to an arrow. And then there's the word actual -- "axial" rupture.

Do you see that?

A Yes.

Q So if I understand how this extraction went, you pulled out the upper portion of the production casing and didn't see any corrosion; you pulled out the upper portion of the parted casing and you saw grooved, striated corrosion; and then you pulled out the lower portion using this modified excavation system, and you saw an axial split.

Is that accurate?

A Can I clarify?

Q You bet.

A We -- broadly accurate. But I just need to be a little bit clearer in this. The top, what is called joint 22 in that figure, was pulled, first, out of the top fracture surface. And there was striated corrosion on that piece, just to be clear, which is in one of the pictures somewhere.

Q Okay.

A And then we came in -- it's on Figure 35 -- then we came in with this NOV power tool. What you see as connection -- you see connection 22 at the bottom, you latch onto it, you pull on the bottom portion -- you have to pull -- you pull non-to bottom portion, then come in with a cutter and cut the 7-inch casing somewhere below. That's the process.]

Q Okay. And when you saw that axial rupture, did that have any significance in your root cause analysis?

A Yeah. It was a very important part of the root cause analysis, yes.

Q Why?

A Because it had the -- it had the failure origin in there. With just the top half, you may not see the failure origin. The failure origin wasn't there. So we need to know where the failure originated. Then you can start building a hypothesis at this stage to say what caused it.

Q Right. Right. Because that was my impression when we had your deposition. And I can show you these two pages. But let me read you the question, and let me read you your answer. You (sic) said:

Now, when you personally learned

that the production casing had parted at roughly 890-some feet, did your suspicions of the direct cause change?

And your answer was:

It changed as I looked at everything. So first it was just the circumferential parting. So when you just look at the parting, I had a hypothesis. We had various hypotheses at face. We had 6 or 7 or 8 or whatever, and of course all of them were off once we saw the axial split.

Is that true?

A It's true. It's true. We had a lot of hypotheses. Once you look at the bottom, some of those go away. As an example, we had heard about geotechnical or some earth-movement issues. So the movement hypothesis goes away. So yeah, that's how you eliminate all of them. But when you look at the top by itself without the bottom half, yeah, you are -- your interpretation of the failure is different. But there was a corrosion patch there, but the importance is not put to the corrosion patch because that didn't appear to be involved in the failure.

So that is -- that's correct. And then -- when you see the bottom, then a few of those go away. That is a correct statement.

Q Good. So tell me how -- tell me how your hypotheses changed from pulling the top portion of the parted casing to pulling the bottom portion of the parted casing?

A So if I look at the top one -- if I leave out the bottom one -- just say the top one is like that and the bottom one is a mirror image of that and they go together, then it's what I would call a low temperature or some sort of a brittle failure. That's what I would have hypothesized. And there are reasons why you could have a brittle failure. I don't want to go through those, but there are -- a connection is leaking. I have gas coming out. It's cooling locally. And I have a failure. There was a preexisting crack, and it's failed. So that's one. If you just give me the top, those would be some of the hypotheses.

And when you see the bottom, you see corrosion implicated more than it would have been without the bottom half.

Q I see. Okay. And when -- you talked earlier about a corrosion patch. And I guess my question is, it's my understanding

that sort of the corrosion patch that was at issue here -- and there may have been others around the pipe -- but the one that was a particular issue was about 9 inches long; is that right?

A Yeah. There were two dimensions there. There is a local dimension that is, I believe, 4.15 inches. And there's slightly broader area of 8 to 9 inches long. And -- yeah. Again, that's a corrosion patch. Again, I use the terminology "patch," but it's a corroded region. Yeah.

Q Okay. And the corroded region also was about what? Two and -- two-plus inches -- the deep area, actually, of that corrosion region was about a little over two inches long; is that right?

A Yeah. That is the core of the area. It was 2 -- 2.13, yes -- yeah, that's correct. Sorry.

Q Okay. And so for those of us who aren't corrosion engineers, even though you're not truly comfortable with that label, is it fair to say that as you pull that pipe out, there wasn't corrosion on every meter or every inch of it?

A Again, Mr. Lotterman, could you repeat that question.

Q Yes. Let me come at it a different way. I believe you said it in the deposition, as used in that, it was localized corrosion?

Do you remember that?

A Yes.

Q What does that mean?

A Okay. Localized means -- it means it's not general corrosion. It's not corroded up top to bottom in this length. As you can see in this picture, or some other pictures in the report, the corrosion is localized. There are regions of corrosion, and they were equally distributed around the casing string.

Q Okay. So you can have corrosion on one side of the pipe and not on the other, right?

A Yes. You could, but not here. Here it was on both sides. It was distributed. It was localized. Okay? By "localized," I mean -- we use that terminology to differentiate from gentle corrosion, which means I don't have corrosion everywhere in this joint or the other joint. It's local. There are regions of corroded area.

Q Okay. Got it. All right. That's

helpful. Thank you.

Let's finish pulling the pipe, and then we'll move on to the actual MIC corrosion itself. So to be clear, once you -- even after you finish that lower portion of the parted casing depicted in figure 44, you continued to pull a little more pipe, didn't you?

A Yes. I think after we did figure -- if you look at figure 44, you would see we removed joint 23. Then we tied the 7-inch back to surface, and I believe -- and this is where my memory is a challenge. I believe we ran logs to understand the condition of the casing itself because early on -- by "early on," I mean at some point earlier we were not sure whether we needed a lot more casing than we were going to extract above the shoe. So there were a lot of discussions with DOGGR and SoCalGas and CPUC about that.

And -- so once we got this piece out, the intent was to understand what the rest of the casing strings looked like and either affirming the need to go for more casing samples or finalizing -- saying, "Hey, I need a couple more joints, and I'm okay." And that's kind of where we landed at the end

of the day.

Q Meaning you decided to leave the rest of the production casing in place?

A We did pull 24, 25, part of 26, and then we left everything in place. We didn't need it.

Q Okay. So to be clear, you pulled out the production casing from the parted casing up. You pulled out the bottom of the parted casing, and you pulled out a couple joints below that but left the rest in place; is that right?

A That's correct.

Q Okay. And eventually you shipped all that pipe to Houston, right?

A That's correct.

Q And did you ship it to your facilities at Blade?

A No. We have a warehouse. We had to rent a warehouse because of the volume of pipes, and we wanted to maintain traceability and make sure everything is safe. So it is in a warehouse with security and cameras.

Q Okay. And it's my understanding that once you got it to Houston, you undertook a bunch of tests, which I think only you would understand, and involving proctography and casing loading analysis and

that type of thing, right?

A Yes.

Q And I'm not going to get into that today, but the bottom line is you shipped the pipe to Houston. You tested it, and that pipe is still in Houston today, right?

A Yes.

Q So to wrap-up this line of questioning, I have a couple more questions for you. After pulling out the tubing, a mile and whatever tubing, and pulling out three football fields of production casing, did you consider extracting the surface casing?

A We did. We did. But we discarded that idea. So if you go early on in 2016, we considered it. We -- at that point, we didn't know anything. We didn't know anything about exactly where it failed, but as we gained more knowledge -- and the surface conditions, first 300 to 400 feet is weathered rock with a lot of vertical land horizontal permeability. So it is quite impractical, or it is very difficult and -- to extract the surface casing. So we did a very good logging program, which was more than adequate for our purposes. So we left it at that.

Q Okay. Understood. Question for you, and then we'll move on to another topic.

Is -- if you're a gas storage operator and you've got a well in place that has surface casing, production casing and tubing -- so you've got basically three pipes as well as some cement on the outside of the surface casing, how would you investigate whether you got any corrosion on the outside diameter of your surface casing?

A You cannot -- other than removing the production casing, you cannot inspect the surface casing easily. So the only way to assess whether it has ID aerobic corrosion is through a wall-thickness inspection tool. In order to do that, it's quite challenging on a surface casing. And if I remember right -- again, I'm testing my memory -- there were a couple of surface casing logs that we did look at. If I'm not right -- I -- it's been a while. I need to check. But, yeah, it is challenging.

Q Right. So let me just ask you a couple more questions on this. So I understand your answer correctly, for a gas storage operator like SoCalGas to measure the wall thickness of the surface casing, at least in the 2015 time frame or whatever,

they would have had to remove the tubing and the production casing near that area, correct?

A That's correct.

Q And if an underground storage operator like SoCalGas wanted to understand the cause of that wall thinness on the exterior of the surface casing, it would have to remove the surface casing itself, wouldn't it?

A Yeah. If you want to do a really true root cause analysis or something, yeah, that's the only way to do it, but normally the way operators deal with surface casing corrosion is where it makes sense, not everywhere. And if you suspect your cementing is not in place or you have a water zone, you mitigate that corrosion. That's really all you can do. You cannot -- its not very practical to undertake an assessment of the surface casing. You would just try to mitigate that. That's really the practical approach.

Q Well, when you say it's not practical, I mean, basically, if you pull the production casing, you're destroying the well, correct?

A No. You're not destroying the

well. I want to be careful. You can always tie back to the production casing and get the well back in operation if you wanted to. It's more difficult. It's more onerous to do that. But no, you're not destroying the well. You would cut the production casing to the bottom of the surface casing, and then you would inspect the surface casing. But that's a pretty onerous undertaking.

Q And extremely, extremely unusual in the oil patch, isn't it?

A I'm thinking. I don't know how unusual or usual it is. I -- yeah, it is not normal. Yeah, that's correct.

Q Now, it's beyond that, isn't it, sir? It's extremely unusual for an oil gas operator or a gas storage operator to pull the tubing and to excavate or extricate the production casing out of a well to determine its corrosion, correct?

MR. GRUEN: Your Honor, if I may, the question's been asked and answered. Objection.

ALJ POIRIER: Sustained.

BY MR. LOTTERMAN:

Q Let me ask it this way, Dr. Krishnamurthy: If a gas operator wanted to remove the surface casing of a well, would

that destroy the well?

A Yes. That is extremely unusual.

Q Okay. All right. All right. Let's talk about if this is -- Poirier, is it a good time to break, or shall I continue?

ALJ HECHT: Yeah. Let's take a 10-minute break until 3:10, and we'll return then.

We'll be 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, let's keep going deeper and deeper into this issue, and let's talk about the corrosion on the outer portion of the production casing. Okay? And basically, if I read your report correctly, you conclude that the corrosion is caused by a MIC, a microbial induced -- or influenced corrosion species called Methanobacterium Aarhusence. And I'm going to spell that for the court reporter.

M-E-T-H-A-N-O-B-A-C-T-E-R-I-U-M. New word, A-A-R-H-U-S-E-N-C -- S-E-N-C-E. Excuse me. Is there a -- I have a handful of questions on that. Is there a shorter name we can use?

A (Speaker on mute.)
Q You're on mute, sir.
A I apologize. Methanogens.
Q Okay. But I guess what I'm wondering is -- well, let me ask the question and then see if that new phrase helps.
I had the impression that as part of your report you couldn't rule out the presence of other methanogens in the area; is that right?
A No. What was done was we collected what we call a sample to match against from the location of Aliso, and we eliminated those methanogens. But the methanogen -- Methanobacterium -- the two Methanobacteriums have been known to cause corrosion, and they were in abundance in two joints that was sampled on location.
Q Right. I understand that, and we'll talk about that in a minute. Well, actually, let me ask you this: So if I understand you correctly, what you're saying is it was the predominant species, correct?
A That's correct.
Q Okay. My question is were there other species there as well besides the predominant one?
A Yes, there were.

Q Okay. And in fact, that's not unusual to have a community of methanogens or species in an area even if one is the predominant one; is that right?

A That's correct.

Q And to state it in a slightly different way, it's rare to have only one species present, true?

A True.

Q Now, I Googled that bug, and I got a website called Microbewiki, which exists, believe it or not. And it describes the methanogen as a very picky microbe. Do you know what they are referring to?

A No, I have -- I don't know.

Q Okay. It said that it's mesophilic, M-E-S-O-P-H-I-L-I-C. Do you know what that means?

A I think mesophilic -- I don't know. I don't want to speculate.

Q Okay. It says it's moderately halophilic, H-A-L-O-P-H-I-L-I-C. Do you know what that means?

A There are hydrocarbon degrading bacteria that those are called Halomonas, but I don't know whether that's what they're referring to. I have not looked at the wiki page.

Q Okay. And it also said that they are non-motive, M-O-T-I-L-E (sic). Do you know what that means?

A It could mean non-mobile. I don't know.

Q Okay. All right.

A I'm not qualified to comment on that wiki page. So I apologize for that.

Q Well, I was just wondering if you knew those particular biological terms.

Okay. So if I understand your hypothesis -- or Blade's hypothesis correctly, Doctor, it is as follows -- and this is going to be a -- kind of a gross rendition, and you're free to refine it any way you wish. Under your hypothesis, there was water in the area and there was the presence of this microbe in the area and/or in the groundwater and that the microbe entered the annulus between the surface casing and the production casing at some point via groundwater and was able to do so because whatever drilling fluid was in that annulus had left, and then the microbe was fed by seeping carbon dioxide from the pipe joints in the casing, became the predominant species and corroded the production casing until it burst on October 23, 2015. Is that

kind of a rough rendition of your -- of what -- of your findings in the root cause analysis?

A Yes. That's a good summary.

Q All right. So let's unpack that a bit, if we could, in our remaining time today. First of all, where did the water come from? And I don't mean the -- I don't mean the water with the microbe in it, or whatever, but just where did the water come from that you believe got in between the surface casing and the production casing?

A Okay. Let me step back a little bit. So the drilling mud that is above the cement is about what we call 10 ppg mud. Okay. 10 pound per gallon. So it doesn't settle hydrostatic pressure and load. And so at around 990 feet or around that area, that height -- that drilling fluid would have leaked off because of the density by itself, and that was then replaced with groundwater that is -- because we do have a section in the report -- I don't remember where -- there are no existing aquifers in that area. So the only source of that water is rainwater that penetrates the ground through various hydrochemical reactions.

As we demonstrated in the bore

holes on SS-9, there was water at 1,000 feet, 1,100 feet and 400 feet, if I remember right. And so that water went into the annulus of the -- between the 7-inch and the 11 3/4-inch. And with that water, it would carry microbes, and the microbe with gross methanogens was fed with CO2.

Now that -- there are -- there are -- when we make one interpretation of, say, microbial corrosion or -- we look at two or three factors that guided in that point. And if one of them is a contraindicator, I have to be careful about making it our primary interpretation of the failure.

So the three aspects that drive us towards microbial-related corrosion was the nature of the grooves, the presence of tunnels, which really no other corrosion can cause, the fact that the connections all tested very well. There was no massive CO2 leak in any of those connections. And then lastly, if you look at the temperature log, through the history of SS-24, which I believe is in one of the pages here -- I have to find it -- it shows that there was a fluctuating water level. There is a small cool-down at that depth, around 600 to 700 feet, which matches everything we found physically, where

there was no corrosion up to 600, 700 feet and when there was corrosion.

And what is important to note also is the corrosion in the 11 3/4 matches with the 7-inch corroded. So all of those data points come together. And so this is why we interpret it as micro MIC -- MIC-induced and most probably methanogens.

Q Okay. You got a little bit ahead of me, but that's okay. I'm going to back up a little bit and focus on the water just a little bit longer, and then we can get into the methanogens themselves.

So if I heard you correctly, what you said was there were no aquifers in the area. So it's not like the water was sitting there at some sort of a groundwater table, correct?

A That's correct.

Q Okay. And then what I also thought I heard you say is you believe that the water came from rainwater -- from rain, basically, right?

A That's correct. Precipitation.

Q Yup. And obviously -- or maybe not obviously, but certainly one would expect that rain -- that water level would ebb and flow because rain comes and goes. And so

that in itself probably fluctuated, correct?

A That's correct.

Q Did you look at whether the water came from any of SoCalGas' storage-fueled operations, for example, any of their water injection processes and that type of thing?

A Yeah. We -- again, that was in our initial -- in our early-on thinking, there is, I believe, if I'm not wrong, is water injection. Again, I'm searching memory, Mr. Lotterman, but I think 3,500 feet, there was some water depth, if I remember right, but I don't -- they didn't have anything to do with this. No.

Q Okay. So it's fair to say that you ruled out the possibility that somehow SoCalGas' water-injection system caused the corrosion on SS-25, to the best of your recollection; is that right?

A That's correct.

Q Okay. All right. And in determining whether or where that shallow water was around the SS-25 pad, you drilled two shallow water wells, true?

A Yeah. We and, I believe, the L.A. Water Authority was also interested in that. So we didn't want to -- we wanted to be time and cost-effective. So that -- those two

wells were drilled with both those objectives in mind.

Q And you also analyzed the rainfall during a particular period of time; is that right?

A Yeah. We analyzed rainfall to look for trends when the -- yeah, it's in the report. But, yeah, that's correct.

Q And did you do anything else besides drilling the wells and analyzing the rainfall to try to figure out the ebb and flow of the rain in and around that pad?

A No. The two water wells at SS-9, which is about 600 feet from SS-25, provided us adequate data to indicate how SS-25 would behave. And SS-25 -- the plan at that point in the RCA, which was, I forget, September of 2018, I believe, the plan was also to drill a well on SS-25 pad itself. That was one of -- it was one of our discussions we had with SoCalGas and CPUC, DOGGR. But then when we looked at the data from SS-9 and we looked at log data from SS-25, we were -- we said, "This is adequate." It was quite challenging to do these wells. It's not easy to do these wells, and we didn't want to take any risks with the SS-25 pad. So that's why we didn't do it.

Q Okay. Okay. All right. And then, um, where did the methanogen come from?

A Methanogen could have been carried to the location -- as the water seeps through the ground, it may have captured some methanogens, and they may have evolved with nucleons. It's pure speculation at this point on my part. All we can state is there was a lot of methanogens on the pipe, and it was consistent with the presence of a groove, and we couldn't find another source of water there. So that is the only source of water. So some of it is by elimination.

Q Okay. And is it your -- is it your hypothesis that the rainwater came into the area and went down the outside of the surface casing and then went in -- under the shoe and up into the annulus?

A The exact pathway I would be speculating, but all we know is it would get through to two places. There are two possibilities. Okay? One possibility is around the shoe. The other possibility we couldn't rule out is through possibly holes in the surface casing. Those are two ways it can get in there. Okay? But most probably -- because if you look at the log in one of the pages, there is a water-permeable

zone in SS-25 at around 1,000 feet. So the two logs from SS-9 and the bore hole or water well will be drilled on SS-9 and the SS-25 logs, if you look at, you'll see permeable zones below the shoe.]

Q So is it your view that the most probable explanation for how the groundwater with the methan- -- with how the, I'm sorry, rainwater runoff with the methanogen got into the annulus was under and up around the -- the casing shoe?

A Yeah, that's -- that is -- that is definitely one strong hypothesis appearing. Strong -- that is one interpretation. The other interpretation we cannot rule out is through the surface casing.

Q Right. I understand that. But, I guess what I'm wondering is, if you had to sort of give 'em odds, shall we say, is it more probable than not or whatever -- and I apologize for pressing you on this, but I think it's -- it's helpful -- which -- which is a more likely scenario, in your professional view?

A Looking at the -- we discussed this quite a bit, as you can imagine, internally, the source of the water. I would say the -- the more probable one would be through the

shoe.

Q Through the shoe, meaning under the shoe --

A Yeah.

Q -- of the surface casing?

A Around the shoe. If you look at the log in page -- Figure 81, you will see there are water-permeable zones, so that's where we think it came in from.

Q Okay. Fair enough. All right. And I understand this is -- this is somewhat of a -- there's a little speculation here, but I kind of wanted to get your best judgment on that. So a couple more items, and I think we're going to break for the day.

Question one for you: Were you able to find reliable data as to when those methanogens first entered the annulus?

A I would use methanogens and water interchangeably, if that is what you're after. It would be speculative, Mr. Lotterman, so I want to state it as such. I have no data to base it on, necessarily. It would be -- I would -- I would -- I would say it's early on in the well life, is my guess. It's a guess right now. I -- you know, it -- it requires a lot more investigation and understanding and -- to

time it. That's not straightforward.

Q Okay. And -- and -- and to be clear, I'm not pressing you to guess here, so if it's something that you weren't able to -- to determine with any sort of reasonable sense of certainty, let me know. I just want to sort of try to figure out what your analysis was able to determine and what your analysis was not.

So if I understand you correctly, you were unable to sort of land on a reliable date as to when that methanogen and that water first entered the annulus. Is that fair?

A That's fair. Can I explain a little bit on that?

So the one thing we did note, and this is where my speculation even there (inaudible), is the corrosion is -- appears to be very slow. It is not like sulfate-reducing bacteria, the other form of metal corrosion, which is what we -- we initially suspected, and ruled it out later, as we analyzed the scale and everything else. We didn't find proof of that. The corrosion -- it would be slow, which means it took a while.

Q Okay. I think Judge Poirier's

about to jump in, sir.

Are you -- is it -- have we run out of time, your Honor?

ALJ POIRIER: No. We've got more time. I'm open to go 'til about 3:45 or 3:50.

MR. LOTTERMAN: Okay. Thank you.

Q All right. Thank you, Dr. Krishnamurthy. I appreciate that explanation.

Because part of what I'm trying to figure out -- and I think this is why you're unable to give us -- or unable to give kind of a reliable date is, under your hypothesis, the groundwater has to replace the drilling fluid in the annulus. Right?

A That's correct. It -- it -- it would have to displace, and -- and -- and it would have to -- see, the -- the terminology we have is called leak-offs. So this -- this drilling mud in the annulus would have leaked-off, and then rainwater would have come in, and so then, as -- as you can imagine, there'll be some intermixing over a period of time. So that is why speculating on time is a little difficult to do.

Q Okay. And is it fair, also, to say that you don't really know when those SS-25 well connections first started seeping and

feeding carbon dioxide to the microbes?

A That's correct.

Q Okay.

A And -- and just to address this whole connection issue, the connection -- as we -- we have a connection testing or analysis that we did. It is a seep. I would use the word seep rather than a leak. Okay? And the reason is it is -- if you -- and that's -- you're right. It could be intermittent, it could be -- so we can't -- that would be -- but, it did leak a little bit, so that is real.

Q Okay.

A But -- sorry, seep a little, seep a little bit, not leak. We need to be careful.

Q Understood. And when you say, "seep," I guess what I'm wondering is my sense is we're talking about a pretty small amount. True?

A Yes. I would have to look at the reports we have, and we have the leak rate there very small.

Q Right. Because the reason why I ask you is earlier on today we were talking about if there's a pinhole leak in the -- in the wellbore, you get a cooling in the temp log, or you might get a -- you might get some

noise in your noise log. And is it safe to assume that the seeping that you believe occurred would not have triggered either an anomaly in the temp log or the noise log?

A It definitely -- it can be below the threshold of that. These are -- that's why I use the word seeping. Yeah? It's below the threshold of such tools, the noise and the temp.

Q So does it follow, then, from that answer that, to the extent SoCalGas was conducting its annual monitoring with temp logs or noise logs are (sic) needed, it would not have picked up that seeping?

A Yes.

Q Okay.

A May I clarify further? So it's important. When we do a root cause, we're looking for various factors. Everything should match. So let's say the connection started leaking at a high rate, and none of the temperature logs showed us that. That would be a problem for us. Everything should match. So the review of the temperature logs from the well matched the low leak rate for the connection, really, really low leak rates. So all of those added up together, and it made sense.

Q Okay. Got it.

One final question, and then, I think, your Honors, this might be a good time to break, because I'm about to go into a whole 'nother area.

But, Dr. Krishnamurthy, is it -- is it safe to say that the MIC that you believe entered the annulus and began corroding the production casing did not start on the date that SS-25 was drilled in 1953?

A That's definitely true.

MR. LOTTERMAN: Okay. Your Honors, I think this is a good time to stop. I'm going to go into another long area, and I think this time of the day it's probably not a good place to start and stop in the middle.

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

(Off the record.)

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

While we were off the record, we discussed various issues regarding exhibits, including the fact that SED would be moving some exhibits, and also we will be looking at an issue of making sure that we do not have too much duplication of exhibits. To the extent necessary, there may be some that may

have to be in there because they were marked, but that's something we're going to get to tomorrow.

In the meantime, Mr. Gruen, do you have a motion?

MR. GRUEN: Yes, your Honor.

At this time, SED would move to enter into the record Exhibits SED-204, the Reply Testimony Supporting Attachments, Public Version, SED-C-204, the Reply Testimony Supporting Attachments, Confidential Version, SED-216, which is SED's Sur-Reply Testimony of Margaret Felts to Violation 331. And I would note that all three revised exhibits were served at the end of the day on Friday, last Friday. Thank you.

ALJ POIRIER: Thank you. Do we have any objections for moving these exhibits?

MS. PATEL: No objection, your Honor.

ALJ POIRIER: Okay. Hearing none, we grant SED's request to move the Exhibits SED-204, SED-C-204, and SED-216.

(Exhibit No. SED-204 was received into evidence.)

(Exhibit No. SED-C-204 was received into evidence.)

(Exhibit No. SED-216 was received into evidence.)

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

(Off the record.)

ALJ POIRIER: Let's go back on the record.

We have concluded for the day. We will -- we will be reconvening tomorrow at 10:00 a.m. and continuing the cross of Mr. Krishnamurthy by SoCalGas. Thank you, all. Have a good afternoon.

Off the record.

(Whereupon, at the hour of 3:39 p.m., this matter having been continued to 10:00 a.m., March 23, 2021, the Commission then adjourned.)

]

* * * * *

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

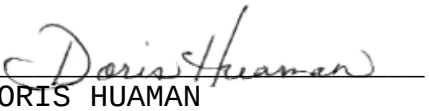
STATE OF CALIFORNIA

CERTIFICATION OF TRANSCRIPT OF PROCEEDING

I, DORIS HUAMAN, CERTIFIED SHORTHAND REPORTER NO. 10358, IN AND FOR THE STATE OF CALIFORNIA, DO HEREBY CERTIFY THAT THE PAGES OF THIS TRANSCRIPT PREPARED BY ME COMPRISE A FULL, TRUE, AND CORRECT TRANSCRIPT OF THE TESTIMONY AND PROCEEDINGS HELD IN THIS MATTER ON MARCH 22, 2021.

I FURTHER CERTIFY THAT I HAVE NO INTEREST IN THE EVENTS OF THE MATTER OR THE OUTCOME OF THE PROCEEDING.

EXECUTED THIS MARCH 29, 2021.



DORIS HUAMAN
CSR NO. 10538

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

CERTIFICATION OF TRANSCRIPT OF PROCEEDING

I, KARLY POWERS, CERTIFIED SHORTHAND REPORTER NO. 13991, IN AND FOR THE STATE OF CALIFORNIA DO HEREBY CERTIFY THAT THE PAGES OF THIS TRANSCRIPT PREPARED BY ME COMPRISE A FULL, TRUE, AND CORRECT TRANSCRIPT OF THE TESTIMONY AND PROCEEDINGS HELD IN THIS MATTER ON MARCH 22, 2021.

I FURTHER CERTIFY THAT I HAVE NO INTEREST IN THE EVENTS OF THE MATTER OR THE OUTCOME OF THE PROCEEDING.

EXECUTED THIS MARCH 29, 2021.

KARLY POWERS
CSR NO.#13991

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

CERTIFICATION OF TRANSCRIPT OF PROCEEDING

I, REBEKAH L. DE ROSA, CERTIFIED SHORTHAND REPORTER NO. 8708, IN AND FOR THE STATE OF CALIFORNIA, DO HEREBY CERTIFY THAT THE PAGES OF THIS TRANSCRIPT PREPARED BY ME COMPRISE A FULL, TRUE, AND CORRECT TRANSCRIPT OF THE TESTIMONY AND PROCEEDINGS HELD IN THIS MATTER ON MARCH 22, 2021.

I FURTHER CERTIFY THAT I HAVE NO INTEREST IN THE EVENTS OF THE MATTER OR THE OUTCOME OF THE PROCEEDING.

EXECUTED THIS MARCH 29, 2021.

Rebekah L. DeRosa

REBEKAH L. DE ROSA
CSR NO. 8708

N

U