Docket No. SA-534

Exhibit No. 2-U

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

SUPERVISING ENGINEER FOR
THE ILI AND DA PROGRAMS

(72 Pages)

UNITED STATES OF AMERICA

NATIONAL TRANSPORTATION SAFETY BOARD

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Investigation of:                 *
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PACIFIC GAS & ELECTRIC COMPANY    *
SEPTEMBER 9, 2010 ACCIDENT        * Docket No.:  DCA-10-MP-008
SAN BRUNO, CALIFORNIA             *
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Interview of: FRANK A. DAUBY, JR.

Marriott Hotel
San Francisco Airport
1800 Bayshore Highway
Burlingame, California 94010

Friday,
January 7, 2011

The above-captioned matter convened, pursuant to notice.

BEFORE: RAVINDRA CHHATRE
Investigator-in-Charge

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I N D E X

I N T E R V I E W

MR. CHHATRE: On the record. Good morning, everyone. Today is Friday, January 7, 2011. We're in Burlingame, California, at the San Francisco Airport Marriott. We are meeting in regards to the investigation of pipeline rupture in San Bruno, California, that occurred on September 9, 2010. The NTSB accident number for this investigation is DCA-10-MP-008.

My name is Ravi Chhatre. I'm with the National Transportation Safety Board in Washington, D.C., and I'm the investigator-in-charge of this accident.

I would like to start by notifying everyone present in this room that we are recording this interview for transcription at a later date. All parties will have a chance to review the transcripts when they are completed.

Also, I'd like to inform Mr. Dauby --

MR. DAUBY: Yes.

MR. CHHATRE: Is that the correct pronunciation?

MR. DAUBY: Yes.

MR. CHHATRE: -- Mr. Dauby that you are permitted to have one person present with you at this interview. That person is of your choice. It can be your supervisor, friend, family member or no one at all. So for the record, please state your full name, spelling of your name, your contact information such as email, telephone number and postal mailing address, and whom you have chosen to be present with you during today's interview.

MR. DAUBY: My name is Frank A. Dauby, Jr. My contact information is --

UNIDENTIFIED SPEAKER: Work is fine.

MR. DAUBY: -- my work is 375 North Wiget Lane, Walnut Creek, California, Pacific Gas and Electric Company office. My email address is ----------------------, and I have chosen Dane Jaques as my representative.

MR. CHHATRE: Thank you for that.

UNIDENTIFIED SPEAKER: Spell your name.

MR. CHHATRE: Now I'd like to --

MR. DAUBY: My last name is spelled D A U B Y.

UNIDENTIFIED SPEAKER: Okay.

MR. CHHATRE: Thank you. Now I'd like to go around the room and have each person introduce themselves. Please state your name, spelling of your name, title and organization that you represent, business email and phone number. We'll start with the City.

MR. CALDWELL: City of San Bruno, my name is Geoffrey Caldwell, information contained on the card provided.

MR. DAUBIN: Brian Daubin, PG&E, information is on the card provided.

MR. FASSETT: Bob Fassett, PG&E, information is on the card.

MS. JACKSON: Connie Jackson, City of San Bruno. My information's on my card.

MS. FABRY: Klara Fabry, City of San Bruno, information on the card provided.

MR. SHORI: Sunil Shori, California Public Utilities Commission. Information is on the card I already provided.

MR. KATCHMAR: Peter Katchmar, United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration, PHMSA. My information is on the card provided.

MR. GUNTHER: Karl Gunther, NTSB, Operations Group Chair, karl.gunther@ntsb.gov, phone (202) 314-6478.

MS. MAZZANTI: Debbie Mazzanti. I'm the IBEW's Local's (indiscernible) at this time.

MR. SPERRY: Joshua Sperry, Engineers and Scientists of California, Local 20, IFPTE. My information's been provided.

MR. NICHOLSON: Matthew Nicholson, NTSB, spelled M A T T H E W, N I C H O L S O N, matthew.nicholson@ntsb.gov.

MR. CHHATRE: Ravi Chhatre. I'm NTSB. Email is ravindra.chhatre@ntsb.gov, phone (202) 314-6644.

MR. NARVELL: Rick Narvell, Human Performance Group Chair, NTSB, Washington, D.C., phone (202) 314-6422, email narvelr@ntsb.gov.

MR. JAQUES: My name is Dane Jaques on behalf of the witness, and my information is on the card provided.

MR. CHHATRE: Thank you very much. Karl, do you want to start with the City or do you want to go ahead and start?

MR. GUNTHER: I'll go ahead and start.

MR. CHHATRE: Okay.

MR. GUNTHER: Karl Gunther, NTSB.

INTERVIEW OF FRANK A. DAUBY, JR.

BY MR. GUNTHER:

Q. Could I have your job title and affiliation?

A. My job title is a supervising engineer within the Transmission Integrity Management Group.

Q. Okay. And what are your duties?

A. My duties as a supervising engineer is responsible for the implementation of the ECDA and ILI or inline inspection programs within the Integrity Management Plan.

Q. Okay. Were you involved in the writing of these procedures for risk management or the RMPs?

A. I was involved in the writing of the risk management procedure 11.

Q. Okay. And RMP 11 is inline inspections?

A. Correct.

Q. Okay. Have you done any inline inspections on line 132, 101, any of the older lines?

A. We have not done inline inspection on the two lines you've mentioned. We have done inline inspection on lines of similar vintage.

Q. Okay. And the reason -- what reason would you have for not being able to do line 132?

A. The principal challenge to inline inspecting 132 is the numerous changes in diameter of that pipeline. It consists of 24 inch, 30 inch and 36 inch.

Q. Okay. In your ILI inspections of pipe of that vintage, have you run into any problems?

MR. JAQUES: I'm going to object. It's kind of ambiguous.

BY MR. GUNTHER:

Q. All right. Well, you said that you had done ILI inspections of pipe of that vintage.

A. Correct.

Q. Is that correct?

A. Correct.

Q. When you have conducted the ILIs, what type of defects or if you've found any defects, what type of defects have the ILI found?

A. They typically found external corrosion. We found dents, dents with metal loss, manufacturing defects in the pipe body. That's in general.

Q. Okay. Have you found any problems with pipe seams?

A. We have not found problems with pipe seams.

Q. And in your inspection --

A. Well, to qualify that. With our standard inline inspection tools.

Q. Okay. What type of inline inspection tools do you use?

A. Well, we use the tools that are specific to the threats of the pipeline that we're inspecting.

Q. Okay. And are you using magnetic, ultrasonic, both?

A. All of the inline inspection tools that PG&E has run to date have all used magnetics, magnetic tool.

Q. And how often do you do an inline inspection on a particular line?

A. We're still in the implementation of our baseline inspection plan. So all the runs that we have done to date have been a first time inspection with the exception of one line which has been inspected twice.

Q. Okay. Do you have any thoughts of how often that you would do an inline inspection?

A. We meet the Federal Code requirements of performing a baseline inspection and then depending upon what pressure regime the line operates at would dictate how soon you have to do a reinspection.

Q. Okay. Have you had -- in your inspection, are you able to check girth welds?

A. We do obtains some information regarding girth welds.

Q. Have you found any girth weld problems on that vintage of pipe?

A. We have had girth weld anomalies that we -- have been brought to our attention as a result of inline inspection. However, they have not required any action.

Q. So, in other words, say for example, if it's an anomaly that would not exceed the 1104 code, then you wouldn't take action on it?

A. Correct.

Q. So I would assume then that you haven't seen any anomalies that are say outside of the 1104 code for inspection?

A. We're not using the 1104 code as our criteria.

MR. CHHATRE: Off the record please.

(Off the record.)

(On the record.)

MR. CHHATRE: Back on the record.

BY MR. GUNTHER:

Q. Did you find anything in the girth weld that would require let's say subsequent inspections such as an x-ray or to physically look at it?

A. There have been instances where we would -- found a corrosion on or near a girth weld or a dent on or near a girth weld, that by our procedure and by the code would require us to go back and dig it up and inspect it.

Q. Will your tool pick up stress corrosion cracking?

A. Negative.

Q. Negative. Have you had any problems with SEC on these vintage lines?

A. We have never discovered stress corrosion cracking on any pipeline within the PG&E system.

Q. Okay.

MR. GUNTHER: City of San Bruno.

MR. CALDWELL: No questions.

MR. DAUBIN: No questions.

MR. FASSETT: No questions.

MS. JACKSON: Connie Jackson, City of San Bruno.

BY MS. JACKSON:

Q. Could you just briefly explain the inline inspection procedure? What does that mean? Inline inspection and you mentioned before that you use a magnetic tool. Could you just briefly explain for a layperson's understanding what that means?

A. Okay. Essentially what we're employing is what they call an axial MFL tool which means that the magnetic flux is -- goes in an actual directional along the pipe direction and the technology involves basic saturation of the pipe wall. It's steel with magnetics, and it has a north and a south pole, and you basically put a sensor, the tool has a sensor between those two and it picks up any type of deviation from a continuous pipe wall and so it's not a direct measuring technique. It's an indirect measurement of any type of changes in the magnetics that might be caused by changes in the pipe wall thickness because of, it could be the result of corrosion or third party damage, other types of defects.

Q. And this is all done from above ground?

A. Yeah, the inline inspection refers to, it's a -- basically an inline inspection tool is a sophisticated piece of equipment which is inserted into the gas line and it is propelled by the gas through the pipeline.

Q. So it occurs while the line is under pressure and operational?

A. And in service, correct.

Q. Okay. Okay. And I'm sorry if you already said this. How often do you perform that type of inspection?

A. Well, I indicated that we're still in our implementation of our baseline inspection plan.

Q. And what does the protocol call for once your baseline is completed in terms of frequency of those types of inspections?

A. Like I said, it can vary somewhat based on the results of your inspection and by the pressure regime that your pipeline operates at.

Q. Okay.

A. But it requires some type of a reinspection within seven years.

Q. Okay. Thank you.

MS. FABRY: Klara Fabry. No questions.

MR. SHORI: Sunil Shori, California PUC.

BY MR. SHORI:

Q. Frank, could you please describe your definition of similar vintage when you said pipelines of similar vintage that you've run the ILI on? Define similar vintages.

A. The oldest pipeline that we have performed an inline inspection on to date was originally installed in 1942.

Q. Is there any other characteristic that would be -- that would make it similar vintage to line 132 other than age?

A. Well, along with the age comes the construction techniques and the fabrication techniques that were employed in that era.

Q. And you said you had run one line twice. Can you tell us which line that was and why that was run twice?

A. That was line, a 75-mile section of line 2 which is out in the Central Valley, south of Tracy. It was originally inspected in 2001, and the Code requires us to perform a reinspection, it was basically a line that was inspected prior to the implementation of, or not implementation, but before the Pipeline Safety Act of 2002 went into effect, and we were able to get credit for that inspection but it requires a reinspection within seven years.

Q. And you compare results as the rule requires between runs. So in essence, what you see on one run versus what you see on subsequent runs, you do that kind of comparison?

A. Yes, we did.

Q. Did your subsequent run generally support -- in essence, did it validate the previous run in terms of the kinds of things you saw? Did you see any kind of new items on that? Well, obviously you'd see some new issues at some point, but did it -- you generally use that to validate previous results as well?

A. I can't say that we used it to validate the previous results, because we had validated a previous run based on digs that were performed immediately after it. However, it was consistent with the first run.

Q. And that's generally what I was -- that's a better term I think in terms of comparing the results to see that it's in essence supporting the same kind of features and kinds of things that you -- pipeline features --

A. Yes.

Q. -- that you would see on one run versus subsequent runs?

A. Yes, they matched up.

Q. And as far as, just for clarity, any -- have you ever pigged any portion of line 132?

A. No, we have not.

Q. Which lines on the Peninsula have you pigged and what portions if you recall? And again, I'm referring to lines 109, 101 and 132.

A. We have not performed any inline inspection on the Peninsula pipelines.

Q. And one of the earlier limitations to pigging that you discussed earlier was diameter changes?

A. Yes.

Q. Can you describe some other limitations to inline inspection besides diameter changes?

A. Yes. One significant limitation has to do with the ability of the pig to negotiate bends in the line and PG&E's gas transmission system in general is built with what they refer to in the industry as 1.5 D bends which means that the radius of the bend is 1 1/2 times the diameter of the pipe, whatever diameter that is, and thus many of the inline inspection tools aren't capable of negotiating those types of bends. Additionally, basically none of PG&E's gas transmission system prior to the mid 1990's, when the federal rule required such, was build to be piggable, and thus every project or every pipeline segment that we attempt to inspect requires significant retrofitting in order to be able to accommodate inline inspection tools.

Q. Are there any (indiscernible) restrictions or other things that also limit the ability to be able to pig a line?

A. Yes, there are. There's pressure limitations. Basically, if you don't have adequate pressure because gas is a compressible fluid, at low pressures you cannot control the speeds of the pigs which is very key to be able to perform an accurate inspection and thus in general, lines that operate less than 400 psig are subject to speed excursions which could impact the data quality, and also because the pig is propelled by the gas itself, you have to be able to hydraulically limit gas velocity to be able to run the pig at the speed that the tool's designed to operate at.

Q. Now earlier you were describing the axial MFL.

A. Correct.

Q. What other kind of pigs are available besides the axial MFL?

A. ~~layperson's understanding Whereupon, the interview was concluded.)~~

Well, there's also a circumferential MFL which basically has a magnetic field that operates in perpendicular to the axial direction, basically around the circumference of the pipe and that -- those tools are designed to inspect for long seamed or axially oriented anomalies which could be a seam. There's also tools that employ EMAT which is electromagnetic acoustic transducers which are also used for inspecting for cracks or other long seam type anomalies.

Q. And is that tool available in different diameters?

A. They are available in specific diameters today.

Q. And what are those diameters that are available today?

A. For which technology are you referring?

Q. The transverse or the non-axial that you described.

A. The circumferentially oriented MFL tools are available from 6 inch up to 42 inch today in single diameter which means they can -- they're only designed to negotiate and inspect one diameter for that one tool. The tools that employ the EMAT technology are available in 16 inch, major pipe diameters 16 inch and larger, 16, 20, 24, 30 and 36 that I'm aware of today.

Q. And so when you say available today, is there -- as the technology has evolved or as the industry has evolved, what sizes have -- do you recall what years maybe different diameters became available?

A. Well, starting in, again implementing the baseline inspection plan in 2004, the -- we started with the EMAT. The first EMAT tool came out by General Electric in or PII/GE. GE owns PII, I don't recall the year or the time or not, came out in 2002. That was a 36 inch tool and it was only -- it would negotiate pipelines that had 3 D or less, or larger, sorry, of bends, and they in 2008, they expanded that, upgraded the tool to be able to negotiate 1.5 D bends as well as they also came out with a 30 inch tool and I know that Rosen (ph.) has tools just in the last couple of years that cover a wider size range that I referenced from 16 up to 36 I know.

Q. So as far as a 30 inch tool, are you saying that became available in 2008?

A. In the EMAT --

Q. In the circumferential.

A. Using the EMAT technology. On the circumferential MFL, there was a slow progression. Basically in 2004, they only existed based on my knowledge in 3 D compatible pipelines or 4 and 3 D compatible pipelines, and they slowly transitioned such that today they're available in 1.5 D.

Q. And you have used a transverse tool on any of your pipelines?

A. We have used a circumferential MFL tool on one of our pipelines.

Q. And what was that used for and what line?

A. That was used on line 21E in the North Bay to inspect for, it was a low frequency ERW pipeline that had experienced historical weld seam failures.

Q. And that's the only time, the only line and location you used that circumferential technology?

A. Yes.

Q. And what diameter was line 21E where this tool was used?

A. Principally 12 inch with a limited amount of 16.

Q. And so you had to use two different tools, two different diameter sized tools?

A. We used -- the only pipe that was subject to the long seam threat was 12 inch. So it negotiated the 16 but did not inspect for the long seam in the 16, and it inspected the 12 inch.

Q. And as again technology has evolved, are there tools now available with varying diameters that can accommodate pipelines of different diameters?

A. There are in axial MFL. There are not in circumferential MFL or EMAT.

Q. And again I fully understand there are different manufacturers, but overall in terms for the axial, what kind of -- maybe you can discuss a little bit in terms of what tools are available and what maybe range of diameters the particular tool's going to accommodate.

A. Okay.

BY MR. FASSETT:

Q. Bob Fassett. Point of clarification. I just want to make sure everybody's on the same page. When you say axial MFL, you mean the magnetic flux is moving axially to the pipe, correct?

A. Correct.

Q. And you are looking for flaws that are circumferentially oriented on the pipe. Is that correct?

A. When --

Q. When you say circumferential -- I'm sorry. Go ahead, sir. You were nodding --

A. Okay. Go ahead.

Q. Okay. So when you say a circumferential MFL tool, or a transverse field investigation tool, or an EMAT tool, sometimes referred to as crack tools, you are looking for flaws that are oriented on the pipe in the axial direction like in the seam of the pipe. Is that correct?

A. That's correct.

Q. So when you say circumferential tool, you mean axially oriented flaw. When you say axial tool, you mean circumferentially oriented flaw like corrosion. Is that correct?

A. Exactly correct.

Q. Thank you.

BY MR. SHORI:

Q. And again, another point of clarification, I did ask for axial varying diameters because I believe you had indicated there weren't varying diameter tools available for a circumferential tool.

A. Not that I'm aware of.

Q. Okay. So for an axial (indiscernible) tool --

A. Yes.

Q. -- what are the ranges of diameter pipes that one tool can accommodate?

A. I'm aware of several tools that exist today. We've used some of them. In the GE line up, they have a tool that's capable of negotiating diameters between 20 and 26 inch. They have a tool that's capable of inspecting diameters between 24 and 30 inch. Within the Rosen line up, they have tools capable of negotiating from 14 inch to 18 and from 30 inch to 36 inch, and we're working with IntraTech (ph.) on a tool that's capable of inspecting between 12 inch and 16 inch, and those are all the ranges that I'm aware of that exists at present within the operators, not the operators, within the vendors, the ILI vendor community.

Q. And as alluded to earlier, that the type of orientation of the magnetic field, so for an axial type orientation, you're looking at -- generally it's flaws in a circumferential nature of the pipe.

A. Circumferentially oriented flaws, general corrosion, which also include wall loss due to other means like gouging or third party damage over a certain size and are oriented in a circumferential direction.

Q. Might that tool also pick up axially oriented flaws while it's basically doing its work:

MR. JAQUES: What do you mean might it? Do you mean will it or won't it?

BY MR. SHORI:

Q. What are its capabilities for basic detecting axially oriented flaws?

A. With an axially, with an axially --

Q. Axial --

A. -- oriented flaw?

Q. Yes.

A. The probability of detection of an axially oriented flaw in the same direction as your magnetic flux which is what you're looking at, is very low essentially. It's analogous to having, if you put something that's in a stream and it's in the same direction as the water's flowing, that you're not going to get very many ripples or impact on the flow but if you have something that's oriented perpendicular to the direction of the flow which is your magnetic flux, what it's basically doing is it keeps moving through the pipeline, then your ability to detect that is much greater. So the probability would be very low that you would pick up an axially oriented flaw with an axially (indiscernible).

Q. And again that's based on the type of flaw that you're looking for. If it's -- is there -- I'll stop. I can't formulate my question clearly enough. I'll give it some more thought. So I'll pass for now. Thank you.

MR. KATCHMAR: Peter Katchmar, USDOT, PHMSA.

BY MR. KATCHMAR:

Q. As a supervising engineer, do you have any duties with respect to setting MAOPs on pipelines?

A. No, I do not.

Q. Do you supervise anybody that does?

A. No, no, we do not. I do not.

Q. Okay. Do you have any duties with respect to class location studies?

A. No, I do not.

Q. And you don't know who does that either? Class location change studies.

A. There's --

Q. Do you know what I'm asking about?

A. I believe so. I, I --

Q. Okay.

A. I'm familiar with class location change studies.

Q. Okay.

A. In my present position, I do not have any direct involvement in that. Those are typically handled within our pipeline engineering group.

Q. Okay. Can you give me the name of a supervisor for that group or an engineer that might be in that group?
A. The present supervisor is Gary Grelli.
Q. How do you spell his last name please?
A. G R E L L I.
Q. Thank you.
MR. GUNTHER: No more questions.
MS. MAZZANTI: No questions.
MR. NICHOLSON: Matt Nicholson, NTSB.
BY MR. NICHOLSON:
Q. I just want to clarify something. You talked about three MFL technologies that were available and I think you alluded to this, but I'll ask you. Of those three technologies, which are specifically utilized by PG&E in the ILI program?
A. To date, we've utilized two of those technologies. Our most prevalent use is of the axial MFL to inspect for the threats of external corrosion, internal corrosion and third party damage. We've utilized, as I've indicated to Sunil, we did use the circumferential MFL on one pipeline to inspect for, it was a low frequency ERW.
Q. Okay. So you'd only bring out a CMFL tool if there was a special case. That's not a normal tool you'd run down all lines.
A. Correct.
Q. Okay. I didn't hear you talk about any kind of

acoustical tools. Is there a reason for that?
A. Are you referring to the EMAT?
Q. Is EMAT ultrasonic or is it magnetic?
A. It's a type of -- it uses magnetics to create an acoustic pulse that's being reflected off any types of cracks that are in the vicinity of the sensor.
Q. Do you use UTE tools?
A. We have not used ultrasonic tools.
Q. And why is that?
A. Essentially the main, the main reason we haven't used those is because they require a liquid couplant. So basically you either have to fill your pipeline with water or you have to run it between pigs with some type of a liquid couplant in order to get the ultrasonic signal into the pipe wall and that's -- it requires then that the line essentially be taken out of service or you have to accommodate a large amount of liquids in your pipeline. So it's impractical.
Q. When the ILI run is finished, and you get a report, who does the analysis of the data received from that?
A. Well, the inline inspection vendor who owns the tools basically perform the analysis of the data that's obtained during the inspection run, and they provide the operator, ourselves, with a report indicating what was found.
Q. How do you make a determination from that report what's a threat, what's not, when to revise MAOPs and when not to?

A. We basically, once we've received that report, we apply our standards in risk management procedure 11, which reflects the requirements of the Federal Code and perform any -- we have to validate the results and we perform any repairs that are required.

Q. So that's by you. You specifically look at those and apply RMP 11 criteria to it?

A. I have a team of engineers who report to me who review those reports. We also get the data, both in hard copy and electronic form, so we can look at the actual process data that comes back from the inline inspector vendor.

Q. So you're looking at it like a RPR? Is that the criteria for determining which defects to analyze?

A. We're looking -- when you say analyze, I assume you mean excavate and inspect?

Q. I mean that or just running a R string?

A. Yes, we have -- the vendor basically provides us a report that includes the results of a R string that's already been performed.

Q. Okay.

A. Or a B31G type of failure analysis.

Q. So the vendors supply those?

A. Yes.

Q. So if you find a defect that now lowers the MAOP to the line from R string, how is that communicated to the control room or gas office?

A. It's laid out very specifically in our risk management procedure.

Q. Okay.

A. When we are notified by our vendor, either during their analysis process which they are contractually obligated to do or when we receive a final report, then if it requires a change in the MAOP, then I'm empowered to directly contact our gas operations group and tell them what the pressure needs to be lowered to and they implement that immediately.

Q. What validation is there, if GE is doing the analysis, do you ever go back and check their R string counts or do you just take their analysis and run with it?

A. We do validate based on the anomaly geometry that what the -- they've calculated as their failure pressure. Of course, the anomaly geometry is based on what they've told us. We take that as given until we have a chance to excavate the location and measure it in the field and then that's our validation.

Q. Okay. That's all I've got for now. Thanks.

MR. CHHATRE: Ravi Chhatre, NTSB.

BY MR. CHHATRE:

Q. You (indiscernible). Can you state your (indiscernible) education?

A. Yes. I'm a graduate of Georgia Institute of Technology in civil engineering. I have a bachelor of science.

Q. How long have you been working for PG&E?

A. I've been with PG&E for 26 1/2 years.
Q. And how many of those years involve inline inspection or risk assessment?
A. Approximately seven years. My position as inline inspection program manager was created in 2003 when we staffed to implement the Pipeline Safety Act of 2002.
Q. So you have been in the group since 2002?
A. 2003.
Q. 2003. And what was your position at that time?
A. A pipeline engineer, prior to -- for 10 years prior to this position.
Q. And what is your ILI experience and background?
A. In addition to various industry courses, I've been involved in almost all inline inspection projects that PG&E has performed in its history.
Q. Have you taken any courses in special technology, operating the (indiscernible)?
A. Yes, I have.
Q. Will you enumerate that please, state that?
A. I've taken the basic pipeline pigging course offered through Patel (ph.) which is a week-long course. I've taken various courses such as optimizing inline inspection through Clarion.
Q. And then do you recall approximately what date you took those courses?

A. I believe the Patel class was in 1998 and the optimization class was in 2006.

Q. And for the record, can you tell us when you became a supervisor?

A. In 2003.

Q. So 2003. How many years of ILI (indiscernible) do you have?

A. Well, I've been involved in some previous inline inspection projects but I wasn't exclusively working on inline inspection. I was working on projects in my capacity as a pipeline engineer prior to 2003.

Q. Can you briefly tell us the experience, the training of the staff that reports to you for ILI, who works in ILI?

A. Okay. In general, we have specific industry type courses including defect assessment class which I failed to mention for -- that I attended as well and was one of the industry sponsored pigging courses either through Clarion or Patel.

Q. I'm looking at the -- the reason I asked this question is because I'm looking at the qualifications and training requirements on your procedure, RMP 11 2.3.

A. Yes.

Q. For the ILI program manager, it states minimum of five years of experience and performance in ILI in the pipeline industry and additionally the ILI program manager shall have a minimum of five years of experience with the pipeline design, operations and safety management.

A. Uh-huh.

Q. With you experience, do you believe you met that criteria in 2003?

A. Yes.

Q. What are your (indiscernible) working currently? Do they meet the classification of experience required for ILI (indiscernible)?

A. Yes, they do.

Q. Going back to the tools and techniques PG&E has used, can you tell me how many miles of transmission pipeline PG&E has as we speak today approximately?

A. I believe the total that qualifies for DOT requirements is about 5700 miles.

Q. Does PG&E have a different definition for transmission lines?

A. Internally we consider any line that operates greater than 60 psig as transmission.

Q. I'm sorry. Did you say earlier there were 5700 miles?

A. Miles.

Q. And by PG&E's definition, how many miles of pipeline, transmission pipeline PG&E has?

A. I believe it's approximately 6700 miles.

Q. Looking at that 6700 miles for the time being, can you tell me how many miles of that pipeline has been inspected in the inline tools, the inspection tools so far, and I'm not including pigging, not pigging ones, just inspections?

A. Well, very roughly it's approximately 700.

MR. CHHATRE: Off the record please.

(Off the record.)

(On the record.)

MR. CHHATRE: Back on the record.

BY MR. CHHATRE:

Q. And what is 700 miles, how many of those will fall into the code definition of transmission lines?

A. I believe that all of them would. They all operate greater than 20 percent.

Q. So they all fall in the code as a transmission line?

A. I believe so.

Q. Can you just give me a (indiscernible) of pipeline diameters for this 700 miles of ILI?

A. The smallest diameter we have inspected to date is 10 inch, and the largest diameter we have inspected to date is 36 inch.

Q. Now magnetic flux (indiscernible) tool, that you use, have you used that tool for all the 700 miles or have you used different (indiscernible)?

A. Yes, we've used --

Q. Other tools also?

A. No, we have used the MFL tool for all the miles that

we've inspected to date.
Q. And can you tell me what generation tools have been used? Earlier tools couldn't tell you the defect inside or outside. The second generation will tell you and I'm trying to find out which tools --
A. They've all been high resolution --
Q. High resolution.
A. -- what the industry would consider (indiscernible) tools.
Q. So all tools is capable of getting the inside or outside defects. Is that correct?
A. Correct.
Q. Have you used any, any tools that will tell you if there's like a seam, defective tools, the actual defect, that identifies any of those in your ILI program, any defects which (indiscernible)?
A. The one line that I referenced earlier is the only --
Q. I know about that.
A. -- is the only --
Q. I know about that. Is that the only location you have for the ERW pipe?
A. It's not our only location we have ERW pipe, no.
Q. Can you tell me how many miles of the total miles, 5700, how many of those miles involve ERW (indiscernible)?
A. I don't know that off the top of my head.

Q. That's fine. Is that available to you through your GIS (indiscernible)?

A. Yes.

Q. Either you or Mark, can you give us that number at later date?

UNIDENTIFIED SPEAKER: I completely lost you when you said --

MR. CHHATRE: I'm looking at how many miles of transmission lines involve ERW pipe (indiscernible).

UNIDENTIFIED SPEAKER: Could you just -- so I don't get it wrong, can you just send me an email --

MR. CHHATRE: I want to give you a heads up so you guys can start working on it.

UNIDENTIFIED SPEAKER: But just to clarify, he did mention earlier that we used the TIF tool on line 21E and that was the only one that we had records of having an issue with the long seam that's pre-70 ERW.

MR. CHHATRE: I’m not saying you have an issue. I (indiscernible) ERW. And the reason for that is we have some concern about longitudinal seams especially (indiscernible).

UNIDENTIFIED SPEAKER: Right, but to be clear, you only have to address if it's pre-70 ERW and you have evidence that it's not stable.

MR. CHHATRE: No, I understand.

UNIDENTIFIED SPEAKER: You understand that.

MR. CHHATRE: I understand.

BY MR. CHHATRE:

Q. (indiscernible), how many locations you have done for, I would say, compare the ILI to it, telling you, verification digs?

A. I'm sorry. I didn't understand the question.

Q. Have you done any verification digs using these ILI inspections?

A. Yes, we do verification digs after every ILI inspection.

Q. And how does the verification digs compare to the (indiscernible) they are finding?

A. You're asking what were the results?

Q. Yes, sir.

A. In general, we found that the tools provide results compared to what we excavate in the field within their tolerance range which is typically plus or minus 10 percent or plus or minus 15 percent of the call. Occasionally we've had some that were outside of that.

Q. Meaning less or meaning more?

A. Both.

Q. Both. Okay.

A. Right. Basically the industry standard is plus or minus whatever that percentage is for the given tool, by a specific vendor with a confidence level of 80 percent or 90 percent.

Q. Have you done any digs where it's really not telling you you have a defect, just to make sure that you didn't have a defect? From what I understand earlier, and if I'm wrong, tell me, that any time they told you there was some kind of a defect, for verification, you dig a hole to inspect it and found out that the defect exists and it's the same size that the tool told you. My question is, have you done any digs where the tool told you there was no defect and you confirmed that indeed there were no defects? Have you done that kind of a verification?

A. We haven't purposely excavated the pipeline to confirm that there were no defects.

Q. That verification has not been done?

A. Correct.

MR. KATCHMAR: If there's a defect and you dig it up, would you dig up a piece of pipe before the defect and after the defect where there were no defects?

THE WITNESS: Yes, typically we would dig up a 10 foot section of pipe even if it's a pinhole type defect and thus it would validate.

MR. KATCHMAR: By validating the fact that you have a defect, it would validate that you had no defect before or after.

MR. CHHATRE: We --

MR. KATCHMAR: Peter Katchmar, USDOT.

MR. CHHATRE: I'm not sure that we are on the record.

UNIDENTIFIED SPEAKER: We're on the record.

MR. CHHATRE: Okay. I wanted to make sure we got it on the record.

BY MR. CHHATRE:

Q. Do you render -- this is Ravi Chhatre continuing. Do you render a time limit as to operating (indiscernible) tool and when they expect to get something back from it?

A. Yes, we do.

Q. Okay. What is a typical?

A. It's typically 90 days from the day that they perform the inline inspection.

Q. Are the vendors the ones who analyze the data for you or you involved in that also?

A. They analyze the raw data that comes off of the tool and provide us a report of the results. We review that report and the process data in order to decide what actions are needed -- we need to take in order to be in compliance with the code in order to maintain a safe pipeline.

Q. Okay. But you internally don't crosscheck based on the data that is coming in and the interpretation of that, that's not done internally?

A. Correct. We are not data analysts.

Q. Is there a procedure in your contract with the vendor that if they see something that might be quite urgent attention, that they contact you without waiting for 90 days or that is not the procedure in the contract?

A. They are required by our contract to notify PG&E immediately if during their analyzing process they find something that meets the criteria of an immediate anomaly as defined by the code and our procedure.

Q. So you'll know immediately? You don't have to wait for 90 days.

A. Correct.

Q. So going back to the inspections you have done so far, going back to the oldest pipe, 1942 --

A. Yes.

Q. -- what kind of defects were reported to you?

A. For that particular inspection run?

Q. Yes, sir.

A. What I recall, there was a fairly large number of external corrosion anomalies as well as, you know, we dug up a couple of dents.

Q. Does that mean you pass a caliper tool before you do the MFL tool?

A. Yes, we run a caliper tool either as part of the MFL tool or as a separate tool before we run the MFL tool for every run.

Q. And did you guys do any repairs on those dents or any of those external corrosion? Was it pitting or was it wall loss, general wall loss?

A. It was both. It varied. Did we do any repairs? I know we excavated them. I don't recall off the top of my head if we actually required repair once we performed the excavation and inspection.

Q. And during that process, will you be inspecting the condition of the coating also or not?

A. Yes, we perform detailed documentation, both photographic and mapping of any coating loss or disbondment, et cetera.

Q. And how did the coating look? Do you recall? Would that be done by your group or not?

A. We contract out what we call the bell hole inspection which are basically the validation digs or repair locations on the pipeline to a third party.

Q. So the vendor does the, I guess, coating inspection for you?

A. Yes, they do.

Q. And do you recall any -- do you recall the condition of the coating of that 1942 vintage pipe, any area of concern?

A. I believe sections of it had become disbonded and had general corrosion underneath it.

Q. Do you also do the root cause once you see the data as to what caused the anomaly or is that done by some other group?

A. That's done within our corrosion group.

Q. That's reporting to you?

A. No.

Q. Okay.

A. That is done within the gas transmission distribution department.

Q. And was that done on this older pipe, for the external corrosion, what caused it?

A. I believe it has been done at this point in time, yes.

Q. Do you recall the finding?

A. Not in detail.

Q. Okay. The procedure also says during the tool run, any liquids that are collected be analyzed.

A. I'm sorry. Any what?

Q. Any liquids collected in the pipeline will be analyzed.

A. Okay.

Q. Do you know what the analysis is for?

A. Well, is the analysis is to determine if we have what we call general plugs in the liquids. It could be --

Q. Microbial --

A. Microbial --

Q. -- (indiscernible).

A. Yes.

Q. Okay. And who does that testing?

A. That is tested at PG&E's lab in San Ramon.

Q. Okay. And do you recall the results being positive or negative for the microbes that are in the liquid that have been collected?

A. I don't recall for that particular pipeline.

Q. Do you recall how many locations the liquids were

collected or typically you collect it almost all pipelines?
A. We collect some liquids in almost all pipelines. Basically we collect them when we're doing our cleaning process prior to our inspection. So we collect them at the receiver site.
Q. Do you generally analyze those liquids for chemical (indiscernible)?
A. Yes, we do.
Q. What do you analyze it for?
A. We determine the basic constituents of whether it's glycol, water, compressor oils, other production fluids.
Q. Do you do that for any other chemicals? In other words, essentially for sulfates, sulfides, (indiscernible) --
A. Yes, we do.
Q. -- conductivity?
A. Yes, we do. It's part of the report.
Q. Okay. And what happens to the reports? If the San Ramon lab does it, what happens next?
A. They basically return the results to our team and that report goes as part of the data that's reviewed by the corrosion engineer in determining the root cause of any internal anomalies we may find, and it feeds back into our risk algorithm associated with internal corrosion.
Q. Do you recall any type of risk algorithm was devised because of the water chemical analysis?
A. I have no personal knowledge of that. It's not my area

of expertise.

Q. But if they did, wouldn't that information come to you as a supervisor of ILI or not?

A. Not necessarily.

Q. Okay. So if any changes are made in this procedure, will you or will you not know?

A. Changes in the procedure, I would definitely know.

Q. Do you recall any chemistry data for --

A. No. No, I don't.

Q. Do you recall if the inspection showed you any internal corrosion in the pipeline?

A. It would show us any internal metal loss in the pipeline and then we have to review that information and typically we would perform and excavation and then additional in the ditch non-destructive examination to determine whether or not there's internal corrosion or not.

Q. Did you have to do that on any of the pipeline locations that you inspected, like 570 miles you said or 700 miles?

A. Yes, we have.

Q. And does that involve a chemistry analysis?

A. I'm sorry. I'm losing track.

Q. Did you do an analysis if you had to do any digging to examine any of the 700 miles of pipeline that you (indiscernible)? Let me take it step by step. You have 700 of miles of pipeline you inspected.

A. Yes.
Q. You collected fluids in many of those (indiscernible).
A. Yes.
Q. And you send that analysis, the water to lab in San Ramon.
A. Correct.
Q. They analyze it for various species and microbes, and then it comes back to you and based on the results, you will decide or your group will decide if any digs are necessary to address that concern or you don't do that?
A. The digs that we would perform would be based on the results of the inline inspection, not on the results of liquid that may have existed in the pipeline somewhere along it's length.
Q. Okay.
A. So it wouldn’t tell -- it would tell us the constituents of the liquid and whether internal corrosion should be a concern but it wouldn't tell us anything specific as to where along the pipeline that may be occurring.
Q. Where it came from.
A. And that's why we look at the results from the inline inspection tool to find out if we had any wall loss internally.
Q. That is correct. Okay. Now when you do an inspection of the dig because of ILI data, have you done any or do you do to see looks like corrosion? Do you analyze it for chemical species? Let me go step by step.

A. Okay.
Q. ILI data shows you you have corrosion.
A. Well, first of all, ILI data will not tell you if you have internal corrosion.
Q. Wall loss.
A. It will tell you if you have internal wall loss.
Q. Wall loss.
A. Okay.
Q. Now (indiscernible). What the wall loss -- why the wall loss occurred internally in the pipeline?
A. There could be defects as a result of the manufacturing process. We've found that. Sometimes we found that there are grind marks as a result of either during manufacturing or during construction that someone has gone in to smooth some type of a likely manufacturing flaw. Obviously it could be internal corrosion of some type.
Q. And how often you see internal corrosion as a call for wall loss versus manufacturing defects typically? You can give me a bracket. You can give me general number.
A. We have never confirmed internal corrosion of a result of any of our inline inspection runs to date.
Q. Have you done any -- I guess maybe you told me earlier if you do, if you did, just say yes, and I'll go on. Do you have any tools to look for the seam defects in your pipeline, longitudinal seams?

A. The one run on line 21B.
Q. Besides that one.
A. Besides that one, no, we have not done any other runs to inspect for long seams?
Q. Is that a concern? Is that a risk concern or is not a risk concern?
MR. JAQUES: I object. What do you mean by risk concern?
BY MR. CHHATRE:
Q. The risk analysis assigns different factors that we seen earlier in that pamphlet. ILI will tell you the longitudinal cracks in the seam or there are not cracks in the seam. That would change the (indiscernible) on the pipe, would it not?
MR. JAQUES: Do you understand the question? If not, ask that it be rephrased.
THE WITNESS: No, I don't.
BY MR. CHHATRE:
Q. I'll rephrase it.
A. Okay. I didn't understand the question.
Q. (indiscernible) if you don't understand.
A. Okay.
Q. If you found a defect in the longitudinal seam, would that change the risk factor for that segment?
A. If we found --
Q. A longitudinal defect, and I'm not just restricting the

seam, but that is where typically you would find. It can be in the body of the pipe. You see a crack, to be more specific --

A. Okay.

Q. -- if you see a longitudinal crack or wall loss, due to a manufacturing defect --

A. Uh-huh.

Q. -- in the seam, would that or would that not change the risk factor for that particular segment?

MR. JAQUES: You know, I'm going to object. You've got three different factors in there. Does that question make sense to you? If not, ask that it be rephrased.

THE WITNESS: I'm still not really clear.

BY MR. CHHATRE:

Q. Okay. I'll rephrase it.

A. Okay.

Q. Longitudinal defects in the pipe, specifically cracks.

A. Yes.

Q. It can be manufacturing defects. It can be cracks, exposures, places, whatever the reason may be.

A. Okay.

Q. If they exist longitudinally, in the pipe, would that or would that not change the risk factor for that particular pipe segment?

MR. JAQUES: Under what?

BY MR. CHHATRE:

Q. Under your program here, the very first one, probability of failure and consequence of that.

A. Well, that's really not my area --

Q. Okay.

A. -- as far as determining what the, what the risk factor is. My position is to implement the --

Q. ILI.

A. -- inspection of --

Q. That's fine.

A. -- lines that have already been identified.

Q. That's good. Have you seen any girth weld wall loss in any of those tools, MFL tools?

MR. JAQUES: I'm sorry. Girth weld wall loss.

BY MR. CHHATRE:

Q. Metal loss, defects in the -- girth weld can have a metal loss.

MR. JAQUES: Do you understand the question?

THE WITNESS: Yeah, I understand the question.

MR. JAQUES: Okay.

MR. CHHATRE: Thank you.

THE WITNESS: Yes, we have found wall loss in girth welds.

BY MR. CHHATRE:

Q. And is that typically -- can you assign a vintage of pipe for that or just can happen (indiscernible)?

MR. JAQUES: You mean where has he found it?
MR. CHHATRE: No, no. He already established the fact that they have seen wall loss, metal loss in girth weld. I'm trying to find out specifically for the older vintage of the pipe or it can happen on any ages.
MR. JAQUES: Well, you're asking if it can happen on other vintages. If you want to know where he has found it --
MR. CHHATRE: I'm just saying to you why I'm asking it.
MR. JAQUES: That's not what you asked. So ask it again in that way and it's fine.
BY MR. CHHATRE:
Q. Have you seen -- the girth weld metal loss you have seen, is it --
A. Yes.
Q. -- is it specifically what you observed in older vintage of pipe or it is any vintage of pipe, newer, younger, middle age?
A. We've seen it in a variety of vintages of pipelines essentially as a result of external corrosion.
Q. Do any of those data required repairs immediately?
A. There have been cases that have required repair, but I don't believe they were identified as a result of the inline inspection vendor report that it qualified as an immediate anomaly. Based on our repair standard, it required repair.
Q. Okay. Not based on vendor's analysis of the wall loss. Is that correct?

A. Correct.
Q. And what is, what is the probability of detection and probability of identification for the tools you use? Are they (indiscernible) all the time?
A. You have to clarify what type of anomaly you're referring to.
Q. Well, I thought you only use the metal loss tools. You do not use the crack tools except that line you identified.
A. Right.
Q. So I'm excluding that. I'm excluding axial defect tools.
A. Okay.
Q. So it's my understanding that all your tools were designed and used for internal and external metal loss. Am I correct or am not correct?
A. Correct.
Q. So my question is for those metal loss tools --
UNIDENTIFIED SPEAKER: Can we go off the record?
(Off the record.)
(On the record.)
MR. CHHATRE: Back on the record.
BY MR. CHHATRE:
Q. The tools that they use to see the metal loss in the wall, (indiscernible), what is the probability of detection and probability of identification?

A. The answer basically varies significantly depending upon what type of specific defect you're referring to. So if you're referring to specific sizes and orientations of internal or external corrosion, or you're referring to weld defects, the answer doesn't have a simple -- every tool has a specific list of types of anomalies and what their probability of detection and their probability of correct identification is.

Q. Focused only on the wall, not the girth welds. I'm trying to find out whether the tool is capable of giving a more accurate. How much accurate information we are getting from this tool? Is the probability of detection 80 percent, 90 percent? That's what I'm trying to find out. The tools that I remember seeing some time ago were only 80 percent probability of detection and probability of identification, meaning you may miss 20 percent of the defects.

UNIDENTIFIED SPEAKER: He said that.

MR. CHHATRE: That's what I mean. Did you say that? Okay. What are the numbers?

MR. JAQUES: Asked and answered.

UNIDENTIFIED SPEAKER: 10 to 15 percent 80 percent of the time.

MR. CHHATRE: Okay. In that case, that was the last question. Rick Narvell.

MR. NARVELL: Rick Narvell from NTSB.

There were a couple of acronyms I guess. I guess I'm the acronym list person here. Just two. It was a little unclear to me, and I'm not sure if it'll be unclear to the transcriptionist, Sunil, you used the term, and we just talked about it. Can you identify of discuss what axial MFL is briefly?

MR. SHORI: I think it's a type of inline inspection tool.

MR. NARVELL: What does MFL stand for?

MR. SHORI: Magnetic flux leakage.

MR. NARVELL: Okay. And, Matt, you had one. RPR. Is that right?

MR. NICHOLSON: Oh, rupture pressure ratio.

MR. NARVELL: Rupture pressure ratio. Thank you. That's all I have.

MR. CHHATRE: Follow-up questions. Verification questions.

MR. CALDWELL: None.

MR. DAUBIN: None.

MR. CHHATRE: PG&E. City.

MS. FABRY: Klara Fabry.

BY MS. FABRY:

Q. Do you perform ILI for lines 109 and 101 yet?

A. I'm sorry. I missed the beginning of the question.

Q. Did you performance ILI baseline for 101 and 109?

A. No, we have not performed any inline inspection on the Peninsula pipelines including those two.

Q. Any specific reason?

A. The reasons for not performing inline inspection on 101 and 109 are basically the same answer as I provided on line 132 in regards to the changes in diameter and the ability to negotiate the pipeline in its present configuration.

Q. Thank you.

MR. SHORI: Sunil Shori, California PUC.

BY MR. SHORI:

Q. Frank, can you just provide a little bit of information on the pigging steps? You alluded a little bit to the cleaning pig and then also we talked about the caliper tools. Can you describe in summary in terms of the steps involved and then also describe what is a caliper tool and if there's anything else that it's referred to as?

A. Okay. I'll try to describe the overall process. Essentially it's part of our risk management procedure. It requires us to perform a pre-assessment which involves research of all the records associated with the pipeline, both design and test records, as well as operation maintenance records with the line, so we understand if there's any additional threats we may find but our key focus on pre-assessment prior to inline inspection is to determine what has to be upgraded or changed in order for the cleaning and inspection tools to negotiate the pipeline. And then like I indicated earlier, in PG&E's system, none of the lines were basically originally built fully piggable. I mean they had launchers and receivers on them and full port valves, et cetera. So we have to go through a design and then a physical construction upgrade to replace all those components that the pig can't negotiate, and then we go into actual pigging operations where before the pipeline can be inspected, it has to be cleaned. So we have to hook up. We have portable launchers and receivers based on the diameter range we're inspecting and we install those as well as filtration and separation equipment to remove any liquids or debris from the pipeline, that we push out as a result of our cleaning operation so it doesn't contaminate downstream facilities and impact our customers. So then we usually run a series called progressive pigging to clean the pipeline and that includes poly pigs and steel-bodied cleaning pigs to remove liquids and debris that we then catch with our filters, filtration and separation equipment. That's usually three to four runs, et cetera. Then we'll run some type of a geometry tool, as you referred to, geometry or caliper tool, that basically inspects the inside of the line to confirm that there are no unknown or unmapped instructions that may impact the ability of the MFL tool. They also -- they are Smart tools in that they record data, and they provide you with information about any dents or gouges, that type of geometric anomaly that may exist inside the pipeline, and then we would run a final MFL tool which would record data on any wall loss internal or external.

Q. Thank you.

BY MR. KATCHMAR:

Q. Frank, could you tell us why you don't just cut up or dig up the pipeline and replace the bends, the longer radius bends in order to pig a pipeline?

MR. JAQUES: I'm going to object. I think that's beyond his purview.

MR. SHORI: I just want him to say that there's too many of them. May I proceed?

MR. JAQUES: Go ahead.

THE WITNESS: Essentially in most cases, it's impractical because of the large number and extremely high cost of replacing bends.

BY MR. KATCHMAR:

Q. How many bends might be on line 132 that you might have to -- do you know how many bends there might be between Milpitas Station and Martin Station?

A. We do have that information because we've researched the records. I don't have that number.

Q. Would it be more than 10?

A. It would be on the order of several hundred.

Q. Okay. That's what I was looking for. Also one thing you may not have mentioned is, are all valves on the pipeline full open valves that would allow a pig to go through them?

A. No, they are not. Based on the vintage of the pipe, when it was installed, prior to 1965, essentially all the valves in our system and most operator systems are plugged valves which are typically 40 percent opening and thus you need 100 percent opening valve in order for a pig to negotiate a pipeline. So on almost all of our pipeline retrofits require replacement of all those valves. In other cases, we have valves that are, even though they may be (indiscernible) valves, they're not full port. They may have involved 24 inch (indiscernible) valves into 36 inch pipeline. So those would also require replacement.

Q. Okay. Also methods of propulsion. Why wouldn't you -- could you -- excuse me. Stop that. Start over again. Methods of propulsion of pigs. You talked about not being able to push a pig down a line with less than 400 pounds. Why wouldn't you perhaps tether a pig and run it down the pipeline and run it down the pipeline, pull it with a --

A. Right.

Q. -- tether?

A. Well, tethered pigging has severe limitations in terms of how many bends you can go through because of the issues of trying to pull a steel cable through a pipeline that has numerous, in some cases, 90 degree bends. So essentially most of the vendors have a limit once you get over a total degrees of the order of 180, 200 degrees, in summary. So if you go through a couple of 90 degree bends, you basically can't go any farther. So in our system because of the number of bends that are there, they can only do very short sections of pipeline at a time.

Q. Thank you. That's all I have.

MR. GUNTHER: No more questions.

MS. MAZZANTI: No more questions.

MR. SPERRY: No questions.

MR. NICHOLSON: A couple of follow-up questions. This is Matt from NTSB.

BY MR. NICHOLSON:

Q. I think earlier on you were asked will the tool you use for ILI pick up SCC and you said no, stress corrosion cracking.

A. Correct. The tools that we have utilized in basically axial MFL will not detect SCC.

Q. And then you were asked, have you ever seen SCC on your lines, and you said you've never seen SCC on the lines.

A. That's correct.

Q. But really the reason you've never seen it is because you're not using a tool that's capable of seeing it. Is that correct?

A. We do perform an inspection for SCC at every bell hole inspection that's performed be it as a result of inline inspection or be it as a result of ECDA. So we've done on the order of 500 digs on our system associated with integrity management since 2003 and we've inspected for SCC at all those locations and we've never found any SCC.

Q. And just getting back to what Peter was talking about a little bit with the number of bends and feasibility of changing out specifically line 132 to make it piggable --

A. Yes.

Q. -- who makes that decision that it is not feasible to alter a line? Is that your decision?

A. I'd be one -- our analysis would feed into part of that decision, yes.

Q. Who ultimately says it's not financially viable to change a line out?

MR. JAQUES: If you know.

THE WITNESS: I don't have a good answer to that question.

BY MR. NICHOLSON:

Q. You're not the person that makes that determination as to whether it's financially feasible to change a line?

A. No.

Q. There's not such a thing as a self-propelled (indiscernible) tool?

A. Not that I'm aware of presently commercially available.

Q. Okay. Thank you. That's all I have.

MR. CHHATRE: Ravi Chhatre, NTSB. I have a few follow-up questions.

BY MR. CHHATRE:

Q. Are you aware if the industry, if you participate in various industry groups, any operator does the I believe they're magnetic or ultrasonic tools using what I'm going to call liquid couplant? You did mention that you need a fluid to conduct it, to run the tool, and maybe I'm not using the right terminology here. But earlier you mentioned some technique are not used because it requires to have fluid in the pipe.

A. Correct.

Q. Which you have learned this through industry contacts or whatever, if you have any, do you know if anybody in the gas industry use those tools using liquid couplant, the way the liquid moves the --

A. Yes, I am aware that it has been done within the pipeline industry, the gas industry.

Q. The gas industry.

A. Yes.

Q. The other question is the older vintage line, 1942 that you inspected using ILI tools, the lines not of San Francisco I guess, you're using ILI tools on any other lines that you have used ILI tools, did PG&E have to make any modifications before the tools were used on those lines?

A. Yes, we had to do significant modifications on every inline inspection project that we've performed to date.

Q. Can you be more specific? What do you mean by significant?

A. Basically replacement of bends, mainline valves, installation of launchers and receivers, on the order of 2 to $10 million capital pipeline upgrades for each project.

Q. For each project?
A. Yes.
Q. 2 to $10 million.
A. Yes.
Q. Each project involve how many miles?
A. They vary from 7 1/2 miles up to 110 miles.
MR. CHHATRE: No more questions. Do you have any questions?
MR. NARVELL: No question.
MR. CHHATRE: Any follow-up questions? Bob.
MR. FASSETT: Bob Fassett, PG&E, to clarify a couple of things.
BY MR. FASSETT:
Q. We talked about or you mentioned, others have asked questions about the factors that affect whether you pig a pipeline or not.
A. Yes.
Q. We talked about that. One of those I didn't hear brought up is actually in my mind, just to clarify, would you agree that one of those factors that hasn't been spoken to yet were schedules, specifically the schedules stated in the code that you have 10 years to assess your baseline assessment program, you had to do the first 50 percent of highest risk in the first 5 years and the second 50 percent of highest risk in the second 5 years, which leads us to, especially with all the Greek

instruction necessary, sometimes you're going to choose DA if it's feasible to make sure you get your schedule on assessments and then would follow up with ILI after that, if that's decided. Is that reasonable?

A. That's definitely reasonable. It's definitely a factor as to what technology we would choose.

Q. So absent any concern about finance, if you have a fixed amount of time and requirements that put you in a position where they're just not enough logistical capability to achieve an ILI within that time, and providing ECDA is a feasible and effective tools for the threats of concern, it would seem reasonable would you say to go first with DA to accomplish the requirements of the code and then if necessary, follow up with ILI at a later date?

A. Yes, I would.

Q. We had a discussion about putting a couplant, a liquid couplant between two pigs and the Smart pig in the middle.

A. Right.

Q. Absent the fact that as you and I have almost 25 years combined as pipeline engineers in this business, absent the fact that we have worked all of our lives to keep liquids out of the pipeline, when you have to do that, you mentioned one of the other restrictions is pressure. Pressure on the pipeline as I recall is as your pipeline gets larger in diameter, and your pressure gets lower, so you have lower pressure pipelines, it gets harder and harder to push that pig at the appropriate speed. Is that a reasonable statement?

A. Yes.

Q. So like with a 400 pound lines, that are large diameter, you mentioned bearing between 16 to 36 inches. If I remember my statics in dynamics, if you put a 2500 pound pig inside a large slug of liquid, pushed and effectively locked, so two pigs on each end of it, that's a great deal more friction than just the pig by itself and is therefore likely to be improbable to be able to push down these lines. Is that a reasonable statement?

A. Much more difficult than the pig by itself, yes.

Q. Also for clarification, you said that GE provides the analysis and the data. I just wanted to clarify that GE stands for General Electric and not Gas Engineering.

A. Yes, that's correct.

Q. Okay. And as I recall, they, General Electric, have a QC program in house. They do peer review or quality control of the people that are writing the reports that do the data analysis that is then sent to PG&E. Is that correct?

A. Yes, they do, quite extensive.

Q. That's all I have. Thank you.

MR. KATCHMAR: This is Peter Katchmar with the USDOT. One clarifying question. Did you -- were you talking about, you, Bob Fassett, were you talking about when you asked that question about the slug of liquid with two pigs and a pig in between in a 400 pound line, were you saying that it might take more pressure than the 400 pounds so that, so that, you know, your limitation would be the pressure, not going over MLP of that line in order to push that pig with couplant down the line.

MR. FASSETT: That's what I was implying, yes.

MR. SHORI: This is Sunil Shori, California PUC.

BY MR. SHORI:

Q. We talked a little bit about the error rate of any -- of the devices, the ILI devices, and I believe we've mentioned 10, 15 percent of confidence levels. Can you describe, Frank, just in lay terms what that means?

A. What that means is that when we get a report and it has a specific location with a specific size of an anomaly, say it's 50 percent through wall and it's 2 inches long, then that's the call that's made by the inline inspection vendor as a result of analyzing the data they obtained from the tool, and along with their algorithms and their individual analysts that have provided that information back to us. That call could be plus or minus 10 percent of that. So if it says 50 percent wall, it might be 40 percent, it might be 60 percent, and that confidence level that it would be within that range of between 40 and 60 percent is 80 percent. So 80 percent of the time that anomaly is going to be between 40 and 60 percent of the depth of the pipe wall.

Q. Also, again one of the items of this discussion was limitations of ILI inspections as far as your providing information. Does that also mean that as sophisticated as a device is, is it possible for it to miss certain features?

A. Yes, it is possible for it to miss specific features. Like I said before, each tool has its own list of features and what its probability of detection and probability of correct identification is for each one of those types of features.

Q. Thank you.

BY MR. NICHOLSON:

Q. Just one last one. I want to be sure I understood. This is Matt Nicholson, NTSB. We were talking about financial impacts to make a line piggable, and I just want to make sure I understand. Was there a capital project in budgeted status to make line 132 piggable prior to September 9th that was delayed because of scheduling?

A. No, there was a project, a future project to make line 132 piggable.

Q. There was a future project. When did that project get identified?

A. Prior to the PG&E's 2011 through 2014 rate case finding.

Q. Which occurred on what date?

MR. FASSETT: This is Bob Fassett. Are you asking when was the request or when was the settlement of the rate case?

MR. NICHOLSON: Both I guess. Well, the settlement of the rate case would have been what I was asking for as opposed to --

MR. FASSETT: So we haven't actually seen the finalized settlement.

MR. NICHOLSON: Okay.

MR. FASSETT: We hear it's coming. We expect it January of this year.

MR. NICHOLSON: So --

MR. FASSETT: The rate case was -- it was part of the rate case. The rate case, not the transmission side. It was the distribution side. I think we've put -- 2008 was the base year. So we put the request in like in 2009.

MR. NICHOLSON: Okay.

MR. FASSETT: And then we just went through hearings pretty much all of last year.

MR. NICHOLSON: So in essence, there was a project on the books.

MR. FASSETT: There is a project on the books.

MR. NICHOLSON: There is a project.

MR. FASSETT: It was requested. We have used DA to meet the Subpart O requirements to get it assessed and in the BAP and we're requesting that we make it piggable for the future.

MR. NICHOLSON: Okay. So in this case, budgeted status doesn't hit until the rate case is settled. Is that accurate?

MR. FASSETT: Right.

MR. NICHOLSON: Thank you.

MR. KATCHMAR: I have another question. Peter Katchmar, USDOT.

BY MR. KATCHMAR:

Q. Do you have any idea why they wanted to make line 132 piggable? Why was it in this rate case?

A. Yes.

Q. Can you tell me what that is?

A. Because the technology for performing inline inspection has advanced to the point that it's feasible to inspect it in significant long lengths to make it practicable.

Q. Okay. All right. Thank you.

MS. FABRY: Klara Fabry. What is the -- what estimated cost is included in the budget (indiscernible)?

MR. DAUBY: I can't say exactly. It's on the order of $13 million for part of the line, for approximately 32 miles.

MR. KATCHMAR: Peter Katchmar, USDOT.

BY MR. KATCHMAR:

Q. How long is the whole line of 132 approximately?

A. I believe Sullivan Station's about 46.

Q. Forty-six miles.

A. Actually about 46 miles up to where the pressure's cut going into San Francisco.

Q. Thank you.

MR. KATCHMAR: One other questions. Peter Katchmar, USDOT.

BY MR. KATCHMAR:

Q. Are there other lines that are identified for making piggable?

A. Yes, there are.

Q. And what would those be if you know?

A. Well, the plan is to continue to upgrade pipelines around the PG&E system to make them piggable. Specific ones also identified included 101 and 109.

Q. Okay. And why would those be identified before other lines in the system? Is there a hierarchy for identifying lines to make them piggable?

A. It has to do with the, well, with the feasibility as well as with the amount of high consequence areas that are on particular pipelines and the Peninsula lines have a lot of high consequence areas.

Q. Okay. Thank you.

MR. CHHATRE: Ravi Chhatre, NTSB. I have to go and make some phone calls, and I do have a couple of follow-up questions. Why don't we go off the record and I'll be right back.

UNIDENTIFIED SPEAKER: I have more follow-up questions. Klara had more follow-up questions.

MR. CHHATRE: Yeah, why don't we go to the follow-up questions, but I'll go and will be right back.

BY MS. FABRY:

Q. Do you have the estimated cost and estimated timeline for 109 and 101, what is proposed project?

A. I don't have a figure in terms of the dollars required to perform the upgrades on either of those pipelines. I can tell you it's several million dollars apiece. In regards to timelines, they were part of the rate case, but I don't have any more specifics.

Q. Thank you.

MR. FASSETT: Bob Fassett, PG&E.

BY MR. FASSETT:

Q. Not only are there future projects planned to pig lines that have already been DA'd. As I recall, there are already pipelines that have been pigged after we've DA's them. Is that correct? Specifically in the East Bay.

A. There are sections that we have ILI'd that were the portions that were --

Q. DA'd.

A. -- required to be DA'd prior to the first five years of the program because they were high risk, high consequence. They were subsequently ILI'd, yes.

Q. Thank you.

MR. NICHOLSON: Any other follow ups? Anyone?

UNIDENTIFIED SPEAKER: Not at this time.

MR. NICHOLSON: I've got a question then.

BY MR. NICHOLSON:

Q. If you perform a dig or you run ILI, this is Matt Nicholson, NTSB, if you run an ILI opposed to DA, what database is that information stored in?

A. We don't have a master database that covers those. However, we will review the results from the previous ECDA and overlay that with our results from the inline inspection prior to performing any calibration repair damage.

Q. So this is a manual operation. It's not something that's saved in a database or (indiscernible)?

A. Basically.

Q. Okay.

MR. NICHOLSON: That's all I have. I guess at this point, we'll go off the record until Ravi returns.

(Off the record.)

(On the record.)

MR. CHHATRE: Back on the record. This is Ravi Chhatre, NTSB.

BY MR. CHHATRE:

Q. My question to you is the pipelines that were inline inspection, I believe the number as about 700 miles of natural gas line --

A. Yes.

Q. -- can you tell me which area they transverse in terms of big city population density?

A. Which cities they go through?

Q. Yes. I'm trying to find out the population density associated with those lines (indiscernible) lines.

A. Maybe you could rephrase it.

Q. Okay. The lines that you have ILI'd, the inline inspection so far --

A. Yes.

Q. -- can you (indiscernible) location in State of California, can you tell me which major cities or populations that it travels through?

A. Well, we've performed 21 inline inspection projects between 2000 and 2010. So they obviously are spread out across the PG&E service territory including Bakersfield, Sacramento, several in the East Bay, including Fremont, Livermore, Antioch, that area. We've had inspections in the South Bay including part of San Jose, Milpitas. We've had some in the North Bay including portions of Penn Luma (ph.), Santa Rosa. We've had others in the East Bay that covered Richmond, basically the Richmond-Antioch Corridor, Fremont up through San Lorenzo, San Leandro, Hayward. That's all I can think of at this time.

Q. That's more than I expected you to remember.

A. Okay.

Q. So that's good. Is it reasonable to say that I guess none of the inspections or the lines travel through urban areas, (indiscernible) populated?

A. Yes.

Q. The other question I have is you mention about line 132 being rate case and a rating, I guess whatever the financial rate case, I'm not that familiar with the rate case, what happened in the rate case and what happened. My question is if your rate case, and I don't know who had the (indiscernible), but the funding for this, and if it is delayed or rejected, does that mean that 132 and the other lines will not be inline inspected?

MR. FASSETT: I'm going to object. That's outside the scope of his authority.

MR. CHHATRE: Okay.

BY MR. CHHATRE:

Q. So you have no knowledge of that. Who made the decision the lines will or will not be inspected? Does your group do that or somebody else does that?

MR. FASSETT: Bob Fassett. I think he testified earlier that all lines that are in our baseline assessment plan that are required to be assessed by code will be assessed by code within the scheduled required.

BY MR. CHHATRE:

Q. Irrespective of the rate case. Is that correct? Okay. Great.

A. That's correct.

MR. CHHATRE: That's all I will ask. Thank you so much for your time and working with us. Off the record.

(Whereupon, the interview was concluded.)

CERTIFICATE

This is to certify that the attached proceeding before the

NATIONAL TRANSPORTATION SAFETY BOARD

IN THE MATTER OF:	PACIFIC GAS & ELECTRIC COMPANY SEPTEMBER 9, 2010 ACCIDENT SAN BRUNO, CALIFORNIA Interview of Frank A. Dauby, Jr.
DOCKET NUMBER:	DCA-10-MP-008
PLACE:	Burlingame, California
DATE:	January 7, 2011

was held according to the record, and that this is the original, complete, true and accurate transcript which has been compared to the recording accomplished at the hearing.

Kathryn A. Mirfin
Transcriber