FINISHED TRANSCRIPT

U.S. Department of Transportation
Improving Pipeline Leak Detection Effectiveness
Tuesday, March 27, 2012
8:00 a.m. ET

Services provided by:
Caption First, Inc.
P.O. Box 3066
Monument, CO 80132
1-877-825-5234
+001-719-481-9835
www.captionfirst.com

>> JEFF WIESE: I want to reiterate this to keep in my mind that we have a purpose of being here today. It's not just a ramble, but we're beginning the process. The process is not your last opportunity to provide input. If you think of things later you think are relevant or you know others and you are talking to them, I'll show you how you can submit information to us. This is the beginning of a process that will lead to a study.

The study was requested of us by the U.S. Congress in the midst of our reauthorization, which was signed by the President in January of this year. You know, we're on it. We've got several other mandates that we're working on immediately, but we're trying to establish a common level of understanding regarding the effectiveness of leak detection systems. We want to understand any constraints with deploying systems because we're going to basically be informing the Congress. If I were you, I would just take it as that. We will take all the input from you, we will write a report and after submitting to Congress. We are interested not only in what the technologists and industry have to say; we're interested as well in what the public has to say and the regulators. We have other regulators with us as well.

So the public comments, if you go to regulations.gov, you have to remember this arcane stuff, but remember, the slides will be up on our website. PHMSA/2012/0001. That will be a docket where anything can be filed. If you want to file comments up there or you have a study that you think is relevant that we should be paying attention to, please reference that.

I would remind you there will be a Q&A after each of these panels, depending on how much time is left. Again, we want to be paying attention to the folks in the audience who have taken the time to travel here, a lot of whom have spent money in order to get here, but I also want to try, where possible, to pay attention to the webcast, so we do have folks paying attention to the emails that you'll see connected there.

And one of the things that we began years ago, I find at the registration desk out there -- Jim is just walking in. He can turn and point to the registration. Thank you, Jim. There will be index cards out there. Some people aren't comfortable standing up at a mic and asking a question. Feel free. If not, that's okay. Write your question down, try to keep it simple and legible, and we'll try to -- the moderators will try to pull all that together and send the questions out to the fellow panelists as well.

We do need your input. This is the beginning of a process, but there's nothing wrong. You're welcome to say anything. I do want to say to you it's most important for me to remind you that stay on topic. It is crucial. If you don't stay on topic, frankly, I or one of the other moderators will probably cut you off. If you've done enough workshops with us, you'll find -- sorry, Rick.

(Laughter)

Yeah, all right. Well, okay, with the exception of Rick, we'll have to cut you off.

And the other thing that I feel really strongly about, we're here to think about the technical subject at hand; right? We're not here to promote our company. So please do me a favor. Don't start promoting. For those of you who have been around with me long enough, you know I will cut you off, and there's no if, and, or buts. When we tell you it's time to sit down, it's time to sit down.

The other thing that is going to be interesting for us, particularly those of us who are not particularly social media savvy -- hello, Jeannie, out there -- we are following -- what's the right way? We've created a Twitter account. It's the hash sign PHMSA, and we will be -- we have people who will be tweeting on the event. We are inviting comments. I think people have already started commenting. Pardon? The Secretary is tweeting? Okay. Very good. See, he's far hipper than I am, I'm telling you that.

Here's our hashtag. I think we are going to try to later, if we can, I can get Bob to connect us up to the wireless system, we'll try to show you the Twitterfall so you can see the kinds of comments people are providing here.

I do want to remind the webcast attendees, as I said earlier, feel free, we'd love to have your questions. Make sure you identify yourself, whether you are on the webcast or you're here. If you have a question, just tell us who you are, who you are with. We will be happy to take your questions as long as they're on topic. And if you can, try to make sure if you are addressing it to an individual, just say that, or if it's just for the panel. Again, to the webcast people, feel free. This is your meeting as well.

Finally, I did want to point out that there are a number of vendors who have come out here, and there's some technology. As long as you are here to talk about the subject, you might as well take a look at what they have to offer. We don't endorse -- as a federal government, we don't endorse anyone. You should understand that. We can't. It's like verboten for us to endorse a commercial entity, even if we love it, best thing since sliced bread, so just want to make sure you understand that we can't do that.

With that, I'll provide the segue to panel 1 and talking about hazardous liquid pipeline leak detection systems. I'm pleased to introduce Linda Daugherty. Linda Daugherty is going to be moderating this. Linda is my deputy. Amongst the things in her portfolio are engineering and research, prime components up front here, damage prevention. We have the enforcement group that is there as well. Who am forgetting? Most importantly -- how could I forget with Don next to me -- state programs. With no further adieu, I introduce Linda Daugherty. Thank you.

(Applause)

>> LINDA DAUGHERTY: Thank you, and good morning. I have to ask you a question. I always start every talk I have with questions. How many of you here in the room are from this area? Okay. That means the majority of you are from outside this area. Okay. Next question. How many of you are from a state up north? Like North Dakota? Okay. I want to personally talk to you about bringing this cold weather in. We have been -- had beautiful weather. I mean, get up in the morning, it's like 40s, 50s. Get up this morning, it's in the 30s, so I'm holding you all responsible. For those of you that are from outside the area, I encourage you, if you have the opportunity, to go see

the cherry blossoms. They hit their peak I think last week, and unless this cold weather did something to them, they are absolutely gorgeous, so if you get the opportunity, go see them downtown.

We are here to talk about a variety of issues, we are looking at leak detection, we are looking at technology. Today, this panel is looking at considerations for hazardous liquid pipeline leak detection systems, and a couple of the things, when we prepared our charge documents for the panel, a couple of things that we asked them to look at and speak to is what is the extent that hazardous liquid operators are using CPM, how can we improve performance? What are the challenges with leak detection on existing versus new pipelines? And what are some technology gaps?

So you'll probably hear a wide variety of perspectives. If you saw the agenda -- and hopefully everyone picked up one from outside -- you see we've got a good group of speakers. We're going to start off with Byron Coy, who is our Eastern Region Director for PHMSA, and he works out of Trenton, so I will turn it over to you, and thank you.

>> BYRON COY: Well, good morning. I'm going to talk to you a little bit about perspective, how we got here, and some of the regulations that are already in place. You know, if you think about a hazardous liquid leak, there's sort of three categories. You've got the small ones that can go on for a long time. They're very small, subtle, and it takes a long time for the volume to be impactful. Then you have large failures. It's almost obvious to everyone at the time they occur, because of the nature of the spill, and through the data that the pipeline operators see when they occur. Then you have the tweeners. They're bigger than a nuisance, but they are not necessarily a disaster. And from my perspective, the tweeners is what we are trying to get more information out and react to for leak detection. Because I once had an operator tell me that I don't need a leak detection system to tell me my pipeline ruptures. Everybody in the world is going to call me. I need something to find the tweeners. Those tweeners have materialized lots of places. This crude oil spill on the top, products at the bottom, that's a tweener kind of failure. Frankly, because they were tweeners, they probably weren't detected or reacted to as quickly as we all would have wanted otherwise.

Pipes Act of 2006, congress requested that we do a study, prepare a report on leak detection, talking about these bullet points here. And they have extended the nature of our leak detection interest that are were formerly put together with the integrity rules.

Our eventual report emphasized on the prevention. If you leak doesn't occur, then the thoroughness and our ability to react to the leaks, you know, wouldn't be necessary. Unfortunately, That will never happen. We can't find ways to prevent all leaks. But with these measures in place, you know, we can minimize the occurrence, good surveillance practices, maintaining our MOPs and release systems as necessary, and you know, clearly damage prevention, these subbullets are all very important in that category.

This Thursday evening, I'm visiting with the a school district that wants to build a school near a pipeline, and they want it know if that's a good idea or not. So I told them already ahead of time, if the school was already there, the pipeline would have probably been built elsewhere, but the pipeline's been there for a long time.

In the report, we stress the importance of operators knowing about their pipeline, knowing all they can about it, the way it operates, what's in it, the codings, the vintage, so that helps play into deciding what should they design their leak detection system for. And the integrity management rules, we've put a higher emphasis on leak detection in high-consequence areas.

Three types of leak detection. You've got your visual inspection/observation, internal instrumental, and external instrumental. External instrumentation is not practical in a lot of situations. It's more localized. There are various ways to do that. The bulk of leak detection processes that go on in liquids is through internal instrumentation.

Bringing back the tweeners, it would seem obvious to most that the larger the size of the leak, the less time it should take to detect it. The smaller the leak, the more time it will take to detect. The tweeners, I mentioned earlier, were at the knee of that curve. So that the more robust are sensitive, let's say the threshold of uncertainty is improved, and that allows an operator to find a smaller leak a little quicker.

Yes, sir?

>> (Off microphone)

>> BYRON COY: Internal instrumentation is looking at flow properties and characteristics, pressure, material specs to determine various ways of line balance and mass balance processes. External is by sensor for hydrocarbons and the like.

The report that was generated talked about all these various components and attributes that any leak detection system has. You know, there will be answers to -- you know, some leak detection systems that only monitor flow rates, you know, are shortchanging their process because if the line is temporarily shut down or shut in, there shouldn't be any flows. So you know, if an operator has a system, they should run these kinds of things past the characteristics to see how, in fact, it compares and might identify ways to make changes or improve the systems they have in place.

Ultimately, there should be testing regiments in place to find out how well the systems operate.

There are several places in the 195 code that address leak detection, some more explicit than others. In the design criteria we mention for those who have computational pipeline monitoring systems, they, in essence, have to be following some of the guidance provided in API opinion RP 1130. Later on in the main section of the code talks about practices for testing and keeping records for how those systems operate. And the ability to use a leak event to, say, take credit or testing a system, we'd rather tests were conducted so no leak occurred to use as a substitute for a test.

Over in the procedures section, several places are not quite explicit here. You're gathering data, reporting accidents, in the midst of that, leak detection system can play a part. C-9 talks about transmitting data to antenna location, and for the most part, transmitting that data is what brings information to the leak detection system to analyze to provide information. D-1 talks about responding to, investigating, correcting deviations from normal. Abnormal conditions, you know, are often precede leak events that occur, and sometimes abnormal events are created after the leak occurs.

D-4 talks about taking necessary action to minimize the volumes spilled. Frequently, after a leak event that's not detected properly, you know, there are even occasionally restarts. There are probably a hundred scenarios of an abnormal condition that pipeline personnel see every day. Almost all of them have some explanation for, you know, condition of tanks, et cetera. And it's certainly a very rare event that that signature is that of a leak. So it can be difficult, you know, to screen through all the possible scenarios that create a condition to find yourself concluding that there's a leak. And restarts, unfortunately, have contributed a lot more volume into oil in the ground.

The integrity management part of the regulations, there's four parts and subpart i. They address being proactive in preventing, mitigative measures and finding ways to improve leak detection capabilities. It's important for operators to have a documented, systematic process to determine, you know, what practices are best for them, and it's noteworthy here this last bullet, that operators need to document the measures, candidate measures, that they've considered, even though they've not implemented them for one reason or another. So in essence, they take credit for the detail of their evaluation.

In those evaluation, there's a number of factors listed in (i)(3), and some additional factors, you know, looking at pressures and flows. Specific procedures when shut in, I mentioned earlier. And testing of leak detection systems. Very frequently, the SCADA system is the data source for leak detection analysis, and the frequency and the amount of data that's collected from the field, you know, go hand in hand with the robustness of leak detection system.

Looking at the capabilities of these systems, we asked operators to make sure that the systems handle the spectrum of scenarios that they operate under. Critical to some systems and perhaps shortfall to some is their performance number transient conditions, when stack lines occur. The offline conditions are sometimes precursors or results that make things happen.

Here are a few FAQs that were generated as a part of the integrity rules. Often there's a lot more information in those FAQs than folks give credit to. I advise you to take a look at those or refresh them in your mind.

The code reference control room, rather a new section of the code, it talks about rules and responsibilities, and the control room, you know, as well as the response status in the field can have a major impact on leak detection performance.

What's important, you know, in regard to the choice of leak detection systems is what I call here the alignment of resources. You know, a very costly, complex system does not necessarily translate to better performance for leak detection. One size truly does not fit all. A factor that comes into play here, the design choices, you know, that a company decides to engage in has to be balanced with the committed resources they plan to put on the systems and the maintenance that goes along with it.

When more sophisticated systems are installed, the maintenance and the performance of the instrumentation and the like are expected to, you know, stay at high performance level so it supports the expectation of the performance of the system overall.

For controllers, they need to know the viable operating parameters that the leak detection system will perform and also know whenever the leak detection system performance may be downgraded. So they would know how to react differently.

It would be silly of me -- you can say, well, if we had a pipeline constructed of (Indiscernible) back to back, and we had an operator there with pressure gauge, wouldn't this be the ultimate safe pipeline? You know, but without knowing what the information means, you know, a drop in pressure here does not necessarily mean something has gone wrong in the pipeline. So you've got to convert information into knowledge to be able to gain value from it, and that's what leak detection systems should do.

Now, we have been promoting leak detection, you know, for some time now. We've had four research and development forums, solicited for topics in five research solicitations since 2002. A lot of investment opportunities and funding has been brought forward. And we've had two technology improvements that are in marketing development now, as shown here. And research success report of the PHMSA's safety research program website. Don't have that link shown here.

There's also this development of a remote methane leak detector, and there's some effort now to translate that into use in the more conventional liquid products area. There's an R&D forum July this year, and it will provide an opportunity for public input and perhaps spur some more development in this area.

What have we done lately? We had the emergency response forum just this past December. There's a new liquid NPRM that should come out sometime later this summer, and we've got a couple of NTSB recommendations to provide I guess after the fact, whenever leaks do occur, that we provide information to the responders that are going to these events. P-11-9 talks about ensuring that controllers notify the 911 centers in the response areas, you know. That environment more explicitly noted in the development of the controller management rules that asks that the controller or someone else in the company be identified as to the ones who would be calling 911 agencies.

We have congressional mandate in 2011 Act to conduct a leak detection study that Jeff mentioned earlier. That might be why we're here today, perhaps.

And I think we're supposed to hold questions till the end; right?

>> LINDA DAUGHERTY: Yes. Thank you. Thank you very much.

(Applause)

You know, I have to say I'm really impressed. He hit the time right on the dot. I was sitting here passing him notes. He hit it right on target. Thank you, Byron. Really good information.

You know, I have to confess. I have been completely remiss on an important topic. Today is my boss's birthday. Oh, I'm getting the evil eye. (Laughter). He's 35 years old. (Laughter) so during break, harass him unmercifully. Okay?

Our next speaker will be Don Ledversis. He represents the Rhode Island Division of Public Utilities and Carriers, and I just throw a pitch in here real quickly. The federal and the state programs work very closely together. We're partners in pipeline safety. And Don represents one of our state programs. So he brings a different perspective to the whole regulatory oversight, safety oversight, and I want to welcome him and thank him for coming here today. Don?

>> DON LEDVERSIS: Good morning. I work for the State of Rhode Island. I'm the gas inspector. I don't have a liquid program there. So why am I here? Basically, I'm representing the other 49 states that couldn't be here today. Anybody that deals with NARUC, they may know that the Pipeline Commission now is Paul Roberti. He is the Rhode Island, my boss, and basically I am trying to give him a good plug today.

Okay. So who's NAPSR? We've got 52 pipeline agencies. We do all the states, DC, and Puerto Rico. We don't do Alaska and Hawaii. Alaska has their own program. Hawaii I don't know what they do out there. I'll be more than happy to go out there and let you know if somebody will let me go.

(Laughter)

Then we've got a pretty good force of people, 325 inspectors out there inspecting every day. It doesn't matter what state you came from today to come here, but somebody's watching out to make sure that you are safe when you go home tonight. That's what we do. We do about 78% of the pipe in the country, about 2.3 million miles, about 5,000 miles on average per inspector, and we have about 9,000 operators we have to keep an eye on. It's a busy job.

Our mission statement, we want to strengthen these state programs. There's been some incidents recently that have given us that guidance to go in that direction. And we want to promote improved pipeline safety standards. That's our job, to go out there, out there on the field every day to promote it.

Education, always ongoing. We've got training all the time. Our education is always ongoing. I've been doing this for 13 years, and I'm learning every day.

Technology, new technology, there's a lot of people on this agenda that know a lot more about this leak detection than I do, and I'm here to learn, but if somebody's built a better mousetrap out there and we can apply it and we can make things safer, we're all for it.

We are PHMSA partners, so we do have an interest in developing the regulations, and obviously, all the regulations that we regulate every day are fair, clear, unambiguous, and consistent. I have been doing this 13 years. No company has ever told me that the regulation is fair, consistent, unambiguous. It's a very hard nut to crack, as you can imagine, but whatever we come up with today, believe it or not, I'm going to have to go out there and enforce it, and the other 49 states will. So this is the time to get it right.

Now, liquids, NAPSR only has about 15 states that has liquid jurisdiction, so the other states may be pretty quiet on this because it's of no interest to them.

We do actually go out there and regulate three-quarters of the -- I'm sorry -- one-third of the pie, so basically we do have a lot of miles out there that we do regulate, so 187,000 miles of liquid pipe is under state jurisdiction for compliance.

Now, if you look at that list again, like I said, where's Rhode Island? I'm not up there. Why am I here? Basically, believe it or not, I do live in a state that has some liquid pipelines. It is of interest to me because I live there. I have been inspecting 13 years, and this is one of the pipelines. As you can see, it's very well marked. There's a right-of-way there. We know exactly where that pipe is, where it's going. Then we had a problem where a person came in on a Saturday to do an excavation because he was starting to work on Monday and wanted to look good for his boss, so he came out to the field and started practicing when nobody was around, and what does he do? He pulls up a gas line -- gasoline line. Sorry. And that burned for a couple days and cost about $2 million to fix that problem.

Things do happen. They are going to happen. They are going to happen every day. There's nothing you can do to avoid that. Human element, you can't take it out of the equation.

I did say we do have two of these hazardous liquid lines in Rhode Island. Here's the other one. This is a case where this is a nonjurisdictional pipeline for PHMSA. It's a Coast Guard line from the bay to a storage field. Basically, this gentleman was doing his job, due diligence, he did have a dig safe, did he have everything marked. He was digging cautiously. And he came across something, didn't know what it was, he hit it. 15 minutes later he hit the other one next to it. Didn't realize they were twins. These are hundred-pound oil lines. They are not marked, not jurisdictional. They kind of -- you know, they are kind of sleepers out there.

So you would think that that would be the end of this story, that we didn't have any leaks here, good news. But six years later, we're back at the same problem. This time it did rupture. We did have oil all over the place. Our third-party damage contractor did know where it was. We were told actually they did know exactly where it was, and they certainly did. So like I said, things are going to happen. Nothing you can do. It's just a sorry thing.

Now, on the natural gas side, we allow leaks. We monitor leaks. We let them leak out there. We go out and fix them if they are bad. If they are not that bad, we let them out there.

Liquid is a different side of the story. I looked at the regulations. Very hard to enforce, so it's going to be interesting here going forward.

Okay. So where do we stand? NAPSR as an organization, we filed comments back in February 2011. Jeff talked about this regulations.gov website. This is a very excellent place to go if you want to find out all the data. Anyone can go in there and get all the information associated with this all in one place. Very easy, very simple to do your homework if you want to.

This is our legal statement. I just need to get this out like everyone else. Basically, what we do is send out a survey to assault states and say hey, we are going to put information on notice. You don't have to respond if you don't want to. You know how these surveys go. Some people don't read them. Some people throw them away. Some people talk for hours and hours because they want to take over the survey. So basically, if you didn't feel comfortable with the answers we submitted, you can submit your own answers for your state. You don't have to submit answers to NAPSR. You can actually put anything on the docket you want. I am just saying that ahead of time.

What I am going to do is go through all the submittals. I am not going to go through them in complete detail, but just to try to give you a gist of where we are coming from on this.

Basically, the first question that was asked, should leak detection requirements be expanded to all different pipelines? And like I just discussed, it was a Coast Guard nonjurisdictional line, that's a sleep you are out there. There are some pipelines out there that kind of fly under the radar, and things happen to them. Is that something we should be looking at? And basically, the answer that we were given to the docket was at the very least, tank balance should be performed. That was the very minimum. If someone is doing that, that's the bottom line. That's a good place to start. Anything after that is a bonus, obviously.

Cost and benefits. There's a lot of questions in the docket on cost and benefits. We don't answer cost and benefits. We are state employees. We really don't have that data, so we can skip those.

If there's any industry practices or standards that are out there that we don't know about that are already, you know, well under way or have some good guidance, good data, good information, we're more than happy to look at these things. If anybody wants to start a committee, we will be more than happy to be on those. But if there's something out there, we are more than happy to take those on.

The only ones that we did reference was the API CPM standard 1130 and the FLIR. And basically, I know there's a lot more out there. Just looking at the agenda today, there's lots and lots more coming.

If there are some practices out there -- and if you look at this, this is a huge list of all technical questions, technical related data. I am going to leave this up to the experts. If you look at my question, the answer there, we basically caved in and said leave that up to the pipeline operator.

State regulations. Believe it or not, there are some states that do have above-and-beyond regulations. Some states have some very, very good jobs on above-and-beyond regulations. They can pass those all the time. That's something that if they don't see what they want out of this regulation, they can go forward and do what they want in their own state.

This one here was actually talking about the Alaska minimum detection sensitivity, which this is a good idea. From a regulator standpoint, if you have a minimum, you have someplace to start. If you have nothing, it's just a clean slate, it really leaves things open to interpretation on the regulator side.

If you look at our answer, basically, we mention that there's -- a leak detection system is only reliable to leaks less than 2% of volume. I'm not an expert. I don't know if that's true or not, but it appears to me -- I think I just heard Byron talk about this -- that some leaks are very, very small and they are very hard to find.

Okay. Now, if PHMSA does adopt some new leak detection requirements, should there be different performance standards for sensitive areas? Now, that's a good question. You know, in other words, I have a leak, but it's out in the middle of nowhere. Is it a big deal? I have a leak, right near an HCA, it could shut down a power plant, it could shut down a railroad track, it could do a lot of different things, and basically, the way we look at this is we feel that a performance standard should include the size of the line, the amount of product, and if a failure does occur, what is the impact? So we are looking for something, for example, where you take into consideration these areas. We are putting on paper we are looking for at least a minimum to take into consideration in these areas. It's pretty common sense to us, I think.

If new leak detection standards were developed, what key issues should they address? Well, we are looking at detection of small-volume leaks and ATAs, USAs, maintenance of systems, accuracy of instrumentation, transient conditions, system capabilities that allow management and flow versus nonflow conditions. So this one here we really went and picked some areas that we're interested in and basically it's right there. If anybody wants to look at it, they can look at it on the docket.

Statistics. Are there statistics out there? We don't know.

Like I said, we are state people. We do our job. We go out and inspect. We don't get into the weeds here. But if there are statistics out there -- I've been given the card to hurry up.

Okay. So what leak detection methods or technologies require further research and development? Basically we are looking at real-time transient models have the best potential for improvement. That's basically what we're leaving there. I am going to beat you to the five minutes. How's that? Do you think I knew that? Thank you.

(Applause)

>> LINDA DAUGHERTY: I am feeling kind of useless here. I keep flashing my card, everybody keeps beating the time frame, which is a good thing. This is a good thing. Thank you very much, Don.

The next three speakers are representing the hazardous liquid industry. The first speaker that we're going to have, Rex Miller, he is the Director of automation engineer with Kinder Morgan Energy Partners. He is representing API, and then the next subsequent speakers are representing a company. So Rex, please.

>> REX MILLER: Thank you. Good morning, everybody. I'd like to -- first I'd like to thank PHMSA and the National Association of Pipeline Safety Representatives for organizing this forum so we could talk about leak detection. And as reported, I'm going to be giving an overview from the perspective of API and a number of API's members on this particular subject.

First thing I'm going to start out with is we're going to talk a little bit about what is leak detection, and I also was going to mention current regulations, but Byron has done an excellent job on that, so we might skip through that pretty fast. Then I am going to talk about industry technology and technical documents that currently exist that industry follows, then go into an area on technical challenges with leak detection, and then some ideas we have for next steps.

Leak detection is a first response system. Leak detection will not prevent a pipeline leak. So we always need to look at it in that perspective. Byron mentioned CPM systems in the regulations. CPM, computational pipeline monitoring, is really a subclass of all the leak detection methods that you can find. And the methods -- Byron hit on some of them -- patrol the pipeline right-of-way. Regulations currently require that, and it's carried on on pipelines all over the United States today.

Automated external monitoring, we've heard a couple of mentions of that. That's newer technology coming online. That's the ability to sense the product released by pipelines with some type of external instrumentation.

Then we start talking about items that -- well, we also, then, got reports from third parties along the pipeline. That falls under your public education, let people know that working in the areas of right-of-way, contractors and people that live in the area, business in the area what to look for. So those are all areas of leak detection.

Then you come to the list that Byron classified as internal leak detection. That's SCADA data analyzed by controllers. That's the instrumentation data you find on pipelines all brought to a central place and observed by controllers in control rooms. Then you have volume accounting data analyzed by controllers. A little bit like the tank balance system that we were just hearing about. That's systems placed on pipelines primarily for business purposes, but the data can be analyzed, and you can infer information about a leak. And then the last consideration, CPM systems, those are purpose-built systems that use software and algorithms in order to analyze pipeline data and make a strict calculation on whether they think there's a leak on a particular pipeline.

Okay. Regulations. Byron did an excellent job on this. A key point is all through 195, there are general indications that you need to be able to figure out whether you're having a leak on a pipeline, industry is aware of that and takes that into consideration in operating existing pipelines and building new pipelines. So we'll just move ahead and look at some of the industry documents that we reference.

API Recommended Practice 1130. That is a specific docket about leak detection systems on computational pipeline monitoring. It's a guide to evaluate pipelines, build systems, control/operate systems, and maintain them into the future. It's a key point is analyzing a pipeline on a per-need basis based on all the various factors, and we'll talk about those in a minute.

API Recommended Practice 551. If you are going to be using your instruments to look for leaks on your pipeline, API has guidance on how to maintain instruments on pipeline. That's what you'll find in 551.

API Publication 1149. This is a document that actually relates instruments that you finds on the pipeline into their effect on calculating leaks on pipelines. Once again, it's an engineering-style document used in an evaluation of specific systems. And was published for that very purpose, to give guidance in those evaluations.

You've got API Recommended Practice 1165. SCADA displays. Byron hit on it. We've had instances where systems tell people that there's an issue, but it's missed. This document is intended to help develop information systems and provide information to controllers that's effective so they can understand what the systems are telling them.

API Standard 1160, managing system integrity for hazardous liquid pipelines. There's a risk assessment part to this and a leak detectability is part of that risk assessment. Guidance is covered in this particular document.

API Recommended Practice 1167, pipeline SCADA alarm management. Once again, it goes toward being able to take information from technically developed systems and provide it to controllers or operations personnel, people in control rooms, so they can interpret it correctly and take the appropriate action.

And then the API Manual on Petroleum Measurement Standards, essentially how do you build an accurate measurement system and put it on a liquid pipeline.

So these are so key documents that industry will reference and recommended practice that is they follow in building and operating pipelines in general, and when somebody is looking at an instrument space, these internal leak detection systems as Byron alluded to.

API conducted a survey and it indicates operator integrity management procedures are being applied in about 83% of all regulated pipelines. Now, that's 100% of all the HCA pipelines, but the spillover as companies are applying that same technology to a number of other pipelines, so that indicates about 83% of regulated liquid pipelines have some form of leak detection associated with them.

In conducting the survey, meaning getting ready for this report, we had a technical working group, and we just did a straw poll and found about 88% of the people represented to provide technical information, companies have these internal leak detection systems installed and running on their pipelines.

Technical challenges. I'm going to talk about four areas, going to break leak detection down for four areas for internal leak detection systems, and we'll talk a little bit about each one of them. The algorithms for data analysis. That's how you -- what's the math that you perform on the instrumentation when you get it in a single location. The infrastructure for gathering pipeline operating data. That's going out, getting instrument readings from the pipeline, bringing them together in a physical location, transmitting off to some central location, and then computer software and computers and analyze that data, and then finally you actually present that data to the controllers.

The procedures that explain how you interpret the system from your leak detection system needs to be thought out as a specific area. Then finally, the training of personnel that are going to be using your leak detection systems.

Algorithms. Data analysis. Increase of the speed of fluid occurs simultaneously with a decrease in pressure. This principle was first documented by Bernoulli in 1738, so it's not that particularly new. From then to today, though, hydraulic analysis has been developing algorithms for quantifying all the factors that affect flow, pressure relation of a liquid and a full conduit. That's what you'll find in the hydraulics textbooks. We have a pipeline, it's full of liquid, and it's flowing. We are trying to understand the system.

Bernoulli's assumptions back then were in viscous fluid. Those are not good assumptions for hazardous liquid pipelines, so a lot of work has gone into over the years to understanding what we need to do to quantify and create algorithms that will work on hazard liquid pipelines.

The PHMSA commissioned a report titled "Hazardous Liquid Leak Detection Techniques and Processes" by General Physics Corporation. This report does a good job of categorizing a lot of algorithms being used in industry today. One of the interesting entries in the conclusion of that document, the same CPM system installed on two different pipelines will not have the same performance. And that goes back to the need to do specific analysis on pipelines to line up the various components in order to meet a specific goal.

Infrastructure. Infrastructure of your pipeline, that's your pipeline instruments, pressure cells, meters, densitometers, PLC and RTUs that collect instrument data. Communication systems that transmit the data to a central location. Central data processing. We have all these systems on the pipeline, gathered them all up with some RQs, put them on phone lines or satellite hop, guide it to a central spot, we've got it all aggregated together, and now we're going to turn our leak detection algorithm loose on it and figure out what's going on. Then once that process is finished, then you've got to present that information to a pipeline controller and operator and analyst to figure out what it's telling them. Special considerations.

Now that we have our data, we've analyzed it, we've got to worry about does everybody understand what the system is telling us? Documentation needs to be clear, it needs to answer very specific questions for the operators. What does the leak alarm mean on a specific system? What does a support alarm mean on a specific system? Support alarm. We've lost communications to pressure cells at the Victoria pump station. Well, how does that affect the fact that I'm also getting an alarm over here that says I have a leak on the pipeline? Training personnel to understand those relationships.

The definition of alarm in terms of meaningful to the user. We've got technical groups that are building leak detection systems, installing them, and commissioning them. Then we've got operational personnel that are charged with using them on a day in and day out basis. Are these two groups of people talking to each other and communicating with each other? Is it clear what the next steps should be when a leak alarm comes into a control room?

Technical challenges. Recognizing SCADA leak detection. It's a systems approach. Reduce the false alarms by using the correct algorithms and correct infrastructure. Account for each pipeline operating range in a system design and training. You've got pipelines that operate in steady state flow, transient flow, then you've got a start-up mode, shutdown mode, you've got pipelines that are in static condition. Is your algorithms working correctly in all of those?

The algorithms themselves need to line up with the infrastructure. Procedures and training need to point people in the right direction and interpret their data.

Risk assessment. Leak detection systems actually come with a form of risk. If we provide incorrect information to people, they will make bad decisions. Fitness of the hydraulic algorithms, accuracy versus range, comparing hydraulic algorithms compatibility to the infrastructure that you've got. Adding more systems does not necessarily make the system better. As a matter of fact, you might be introducing new areas for potential failure or you're actually creating false alarms that lead people off in the wrong direction. So the technical challenge is to perform an accurate risk assessment on your leak detection process and ensure that you are actually improving the overall results and not confusing personnel that need to operate the systems.

Next steps. PHMSA has updated their form 700 to gather data about leaks associated with leak detection systems, plus API's PPTS system has also got those same questions. The new CRM rules are going to start affecting the quality of the results of leak detection systems, and so we should see -- track those systems to see how performance shows up in this analysis.

Actions. Industry should continue implementing existing standards to deploy effective leak detection systems, and regulators should continue to monitor operations to confirm compliance with existing regulations.

So quick overview from the industry side, and I think all the questions are going to be at the end. Thank you very much.

(Applause)

>> LINDA DAUGHERTY: We are just staying right on time. Great. Thank you, Rex.

>> REX MILLER: Yes, ma'am.

>> LINDA DAUGHERTY: I hope all of you are making up the questions you have. We are going to have a Q&A after the

speakers, so please take notes. Those on the webcast, please take track of those. We'd like to hear from you as well. So let's see. Our next speaker is David Bolon, who is the Director with -- of Pipeline and Facility Control Systems with Enterprise Products.

You know, Bob, I'm not closing any of these out. We are going to have like 15 of these open.

There we go.

>> DAVID BOLON: Thank you, Linda. Can everybody hear me? Is this okay? Good. As Linda mentioned, my name is Dave Bolon. I work for Enterprise Products, a major midstream pipeline operator in the United States. I appreciate the opportunity to come talk and speak in front of this audience. I think it's very good that PHMSA invited the operators to talk and give their perspective on operating these pipeline leak detection systems because we have a ton of experience, and I'd like to highlight some of the observations that we have in operating those systems.

In terms of an agenda here, I have one slide that gives an overview to demonstrate the scope of our operation, then there's eight slides that answer the charge that Bob Smith put together about information that would like to be covered here. So those are basically a slide for slide with what Bob said would be of interest for the audience.

So my first slide is the Enterprise Products overview. These are the major assets that we operate. It's totally within the United States. The blue lines are the liquid pipelines. The blue lines and the green lines are the liquid pipelines that we have across the country. In the lower right-hand corner is a little eye chart down there that talks about the key assets. If you add up the has does pipelines we operate for the different products, there's approximately 29,000 miles of hazardous liquid pipelines we operate throughout the United States.

That's my broad overview. That's enough about the company. Let me talk about the leak detection program. And the first point in the charge that was brought forward was the leak detection system changes due to the hazardous liquid integrity pipeline rule.

Let me open up with comments about the enterprise leak detection program. These are guiding bullets we use in structuring and operating our program. First of all, it's all encompassing for all the DOT-regulated hazardous liquid pipelines operated by Enterprise Products. And it's -- you know, so that encompasses the lines that have -- or impact hazardous high-consequence area and those that do not.

The program has a baseline level of leak detection on all our regulated pipelines regardless of HCA impact. We operate these liquid pipelines. We have baseline level of leak detection on all our pipelines.

Pipelines with a higher risk level have enhanced level of leak detections. And the program is risk driven in that more resources and tighter constraints are applied to the higher-risk pipelines. We also have a continual review and process improvement program in place to update the program on our existing and new pipelines, and the CPM systems and processes comply with API 1130. So Rex and others have mentioned API 1130 as a standard that we use to indicate how we should operate our CPM systems.

Next there was a bulleted item about layers of redundancy, how we use layers of redundancy and how they're applied in our leak detection program. And we do use layers of redundancy in our leak detection program today. Aerial patrols or right-of-way monitoring were mentioned. We count that as a means to detect leaks across our pipeline. Field automation devices are in use to mitigate the effect of a pipeline rupture. I mentioned a couple of them here. Low-pressure suction cutoff is installed on most of our pumps so if there's an upstream rupture, the pump will shut down and take energy out of the system. If there is a downstream rupture, high amperage system on the pumps will shut down the pump. Most of people think of the 24 by 7 controls, these are the layers of redundancy we use today.

So we have pressure flow monitoring with alarming on all of our pipeline systems. We have a baseline CPM system, so that's a volume-based over short algorithm with alarming on all of our pipeline systems. Enhanced CPM. Where warranted, we have pressure compensated over short algorithm with alarming. And then on top of that, as indicated, where warranted, we have higher fidelity CPM leak detection systems layered on top of the baseline system. We have overlapping segments in place where it's warranted, and by that I mean we have over short balance segments that might go from point A to point B, another segment from B to C, then an overlapping segment that goes from A to C. So there's multiple ways to monitor and look for leaks on these pipelines.

And then also multiple time periods are used for our over short calculations within the same line segment. So we might have a 15-minute time period where we are looking for the larger leaks; a 60-minute time period, the tweeners, as Byron mentioned; and the 24-hour time period looking for extremely small leaks. We count on the eyes of our operation staff. Partial coverage of our pipeline. They've been trained in what to look for and how to respond to pipeline leaks. And we count on the eyes of the public through our public awareness program. Partial coverage of our pipeline. So our public awareness program notifies people about hazardous liquid pipelines in their area, what to look for in case of a leak, how to respond to that, who to call, the 800 number, the emergency numbers on our pipeline markers.

So we do count on all these different layers of redundancy, and we use more layers of redundancy where warranted by the risk ranking and the complexity operation.

Shut-in time improvement. There was a question about shut-in time improvement and how it can be improved through the use of leak detection systems. And this -- this chart didn't come out too well, so let me use the laser pointer here to go through the eye chart.

Most people think of a leak detection system, they think of algorithms that are operating in conjunction with SCADA to crunch data and to give an alarm to the controller and to warn him that there's a leak on the pipeline system. But an overall leak detection program is much more than that. There's these many moving parts, and they all have to work, and they have to work in conjunction and work well to provide an optimal shut-in time. So on the eye chart here, I start with the SCADA and the CPM system, these two blocks here represent that. So they're bolted together. Our SCADA system is collecting data from devices along our pipeline. It's working in conjunction with the CPM system. So it's sending data over to the CPM system for crunching the numbers. CPM is communicating back with SCADA with leak indications, locations, other information that's prevented to the controllers.

So that's the -- the traditional part that people think of when they talk about a leak detection system, but you also have to take into account the controller down here. The controller, as I'll talk in future slides, is a critical part of our leak detection program. The training that they undergo, specifically on leak detection, and their response protocol or operational procedures all have to be up to standard and working well in order for them to respond correctly to the information that they're getting on the screen.

Another key part that I have down here is the field instrumentation. You know, sometimes we refer to our leak detection system as a measurement monitoring system. We're totally dependent on the field instrumentation in order to be able to understand what's going on in the pipeline. That field instrumentation, I have in the little box there something about, you know, the selection, the quality of the instrumentation, and the maintenance program of that instrumentation. If the instrumentation isn't working properly, the effectiveness of your leak detection system is compromised. So that has to be working, and it has to be working very well in order for the overall program to work effectively.

On the left-hand side I have a box that indicates alarms management and analysis programs, so thanks to the CRM regulation that has been in place since August of last year, you know, industry is focused a lot on the alarms and analyzing those and making sure the controllers get the right information and they're not receiving indirect or noncritical information to operate the pipeline. So that helps the controller do their job more effectively.

And then finally I have some two boxes over here that deal with more offline processes, CPM testing is key to making sure that the system is in place and working properly. We have requirements in API's 1130 to do initial testing when the system is deployed, periodic testing on at least a five-year basis, and then change-driven testing. If significant changes are put in place, we retest our system.

CPM performance analysis, you know, continual improvement in process is what we're looking for here. And we use the tools like API 1149, which help us predict leak detection performance improvement, depending on the particular changes that we make. So if we improve a meter in the field or we add instrumentation, API 1149 can help us predict the performance improvements that we'll gain from that.

So all of these things are operating within a risk analysis program that is looking at the risk of the various pipelines that we're using, operating within the corporate strategy and the DOT regulations that we have in place today.

I put this up here to talk about, you know, I'm not sure what you mean by shut-in time improvement, but I broke it down into these three components. There's the detection time, which is the time that I would give the leak detection system to grind through its calculations and to determine whether or not it's got -- it sees something anomalous on the pipeline. At some point it's going to raise a leak alarm to the controller, and that would occur at this break here. The controller then has their own protocol that they go through, so it's not instantaneous that the controller receives the leak alarm and takes action to shut down the line. They are looking at other information they have in front of them from SCADA, from their knowledge of the pipeline from situational awareness. Once they make the decision to shut in the line, they have all the tools in place to stop the pumps or to close valves or to call people out to take action to shut in the line.

So shut-in time improvement is a complicated sure, and it involves many moving parts, as I tried to indicate in this diagram here.

There's a question about CAPEX or OPEX costs on existing versus new pipeline. And I included a picture of one of our facilities in the Mt. Bellevue, Texas, area, and this is a manifold where we have the ability to deliver products to many different customers in that local area. The reason I included this picture is to show the difficulty of retrofitting or installing additional metering, additional instrumentation on our existing pipeline systems.

The costs are much higher to install it on an existing line versus new pipelines. For new pipelines, we have the flexibility and the capability to build it into the system as we're designing it. For a retrofit, we have limitations of space, both in terms of land, physical land that we have available to us, and piping. These meters that we're putting in require so much upstream pipe diameter and downstream pipe diameter to do their job effectively. Mobilization costs to get crews out to do the installation. Probably having to retrofit power and communications as well. Maintenance costs may also be impacted by retrofit limitations.

If there are space limitations, we may not be able to install the equipment in an ideal place for maintenance activities. It may mean people have to climb on ladders or go through other steps to be able to calibrate and monitor and maintain the equipment.

Older lines especially were not designed with leak detection instrumentation in mind; therefore, the retrofitter costs are higher. It's a difficult challenge for us to be able to install the metering and the instrumentation required to support leak detection systems on some of our existing pipelines.

One major challenge is how to install low-cost, accurate measurement for leak detection on short existing lines, laterals or stub lines. The lines that lead off this manifold go to customers in the immediate area. There's not a meter or space to put a meter on that lateral as it's going off. So we looked at other alternatives to that.

This slide takes a look at a special case we looked at external leak detection systems. The type is distributed temperature sensing cables or DTS cables. We evaluated that for use on our NGL pipelines. The cables, the way they operate, they're buried, and in the case of NGL pipelines, they're buried above the pipeline, so they are below the ground level but above the pipeline, and if there is a release, a leak out of that pipeline, the temperature of the product as it leaves the pipeline cools, and the temperature detecting table can detect that temperature change, and the data is analyzed and fed into the SCADA system.

It seemed very promising in lab testing for rapid leak detection. We worked with our PSI to test out the capability from several vendors, and it seemed very promising, especially for the short lateral lines that we had difficulty putting metering on.

When we started to do the analysis on the retrofit installation issues and we took a look at the increased pipeline risk and the maintenance issues, we -- it caused industry, after doing the analysis, to focus on field testing another different technology versus this DTS cable technology.

Some of the issues that we ran into, there are company standards about digging near a pipeline, so if you want to bury this DTS cable close enough to a pipeline to be able to detect leaks, you're into the hand-digging type of installation versus being able to use a machine to lay down that pipeline because of company standards about getting too close to a pipeline. Third-party pipeline crossing, we would need to involve other pipeline operators to install this system. And road crossings, which are frequent on our existing pipelines in populated areas, we would have to be digging up the roads in order to be able to lay down the cable above our pipeline. All of these retrofit installation issues drove us to look at other technologies versus DTS cables. Even though DTS cables seem very promising, they have been used in other industries, and they perform well in a lab test.

False positives and false negatives with leak detection systems. Another bullet item that I was asked to consider. False alarms are a major consideration with the installation and operation of leak detection systems. I think everybody has mentioned that so far on the panel. We have a balancing act that we've got going on. We try to minimize the nonleak alarms and keep the sensitivity low. So as we try to find lower and lower size leaks or smaller and smaller size leaks, we run into a problem where the false alarms creep up, and the way to address those false alarms to drive those back down to an acceptable level is to decrease the sensitivity on the pipeline. So these are directly on either end of a see-saw in terms of a balancing act, trying to keep the leak alarms -- non-leak alarms low and the sensitivity low at the same time.

False positives. Internally we have a maximum allowable number for time that we use to set the alarm thresholds. So we look at the false positives that we would get, the variability in that pipeline, and we set the alarm thresholds correspondingly. Then the false positives are monitored and targeted for reduction if they exceed our maximum target.

False negatives. I am going to run over time. False negatives. We have our layers of redundancy strategy to address those.

And this chart here emphasizes the item, tuning to address false alarms and keep sensitivity low. It's a very labor-intensive pipeline-by-pipeline effort. There's one-size-fits-all solution. This chart plots the leak size against tuning time. So tuning time is the configuration time or man power time it takes to make sure the system is operating properly and detecting the correct size leak you want to detect without an unusual number of false alarms.

So as you come down the leak size, it's easy to tune your system for these larger leaks, but as you get down in this category over here, trying to find the smaller and smaller leaks, the tuning time increases exponentially, and it becomes very difficult to maintain that balance when you are looking for extremely small leaks.

Also on this page, I have the leak detection system alarms are just one indicator to a controller of a problem. That controller has additional tools at his disposal, so the leak detection system alarm is not the end-all for him to go off and shut down the pipeline system. He or she also looks at pressure indications on the line. They have knowledge about recent operational activities like the pump starts or stops, the valve open/closing, what's going on on the pipeline. They have indications or knowledge of the operational status of all the equipment. So they know if a meter is misbehaving or some equipment is out of calibration, they are aware of that and they use that in their judgment as to what to do with that pipeline. They have access to field operations personnel. In general, they have the situational awareness and experience to address the circumstances. And in the case of a release, they also have the reports from operations personnel, emergency responders, and the public.

Human factors. Controller trust is a significant part of success with leak detection systems. And we have these ways that we are working to improve controller trust in the system, addressing the false alarm rate is the number one factor in their mind. We involve controllers in testing the system. They have operational procedures that address the specific of the leak detection system. We have lots of feedback between the controllers to the leak detection group and then training of the controllers by the leak detection group to find level of support.

But I guess the main bullet here is the controllers are ultimately responsible to make the call. They are the person in the console that's running the pipeline. They have the independent authority and responsibility of shutting the pipeline system. I want to reiterate that the CRM regulation now in effect has focused industry on display and alarms management in an overall manner that benefits the controllers, and we are just beginning to see the results of those benefits as the operators get better and better as installing or implementing CRM.

External environmental operating systems and their impact on leak detection systems. Again, all these variations must be handled on a case-by-case basis with individual tuning for each pipeline. This has been mentioned before that you put a CPM system on two different pipelines, it behaves differently, it gives you different performance. Variations make performance much more difficult to achieve. They often drive false alarms.

I have this statement in here about the best performance numbers quoted by vendors. I don't want to slam the vendors. I don't want to say anything bad against the vendors. They are the ones that are providing the technology for us to be able to accomplish what they are doing. But generally, their best performance numbers are quoted under steady state conditions, i.e., non-real world conditions. And the vendors, if -- their answer to transient conditions is often to reduce the sensitivity of the leak detection system until the transient passes. So we take all these vendor claims with a grain of salt. We can tune out these transients, we can address them, but it is difficult to forecast them in advance, and it is difficult, as I mentioned earlier, to retrofit instrumentation to address them.

I'm trying to go as fast as I can. Okay. The last major bullet I was asked to address is what new technologies are we following or piloting. The top half talks about the PRCI, the Pipeline Research Council International, and I have another 20-minute presentation in the second panel to cover that, so I am going to skip right by these. I am going to talk about internal testing. I will cover the PRCI work in the second panel this morning.

The internal testing. We ran -- or we are running test on one vendor's leak detection technology for use on these short pipelines. It's based on wave technology. It's relatively new technology for us anyhow. Capital allocate today this project was $400,000, although much more was spent in internal labor and vendor engineering time. And what comes out of this is a pilot evaluation only. It's not installed for a production use. It's a pilot installation for testing purposes. The final results are not available, but the preliminary results look like the vendor has overcommitted. They've overstate what had the system is able to do. We expect to have the end of those results in the spring of this year.

We also completed tests on a metering system. We were looking for a way to facilitate quicker deployment and more segmentation on our pipelines, quicker deployment of meters and more segmentation on our pipelines. We allocated capital of $150,000, and we spent much more, again, on labor.

The final result for these clamp-on ultra sonic meters indicate they only work in a very limited set of real-world conditions. And I indicated some of those in the fine print down here. Non-batched lines, non-varying product density, and flowing at near constant rates. So the meters don't deliver as promised. In these specific conditions, they come close to the specification that is the vendors have claimed, but in real-world conditions, they did not meet our indications -- our needs.

In summary, I have this chart, in summary. Enterprise believes leak detection systems are valuable in safely operating hazardous liquid pipelines. We are successfully using them to detect, locate, and mitigate pipeline releases above minimum threshold level. So there is a qualifying statement in will, the leak size has to be above that minimum threshold level. We are using a risk-based programmatic approach to focus resources on the critical areas. The CPM tools today allow for a 2% to 35% leak detection under most conditions. Less than 5% leak detection is still very labor intensive to achieve and subject to the vagaries of the environmental and operating conditions, and that's where we have potentially driving nonlegal (Inaudible) which undermine confidence. We can drive down. Other operators are getting down to even the 1% level. But this is labor intensive, time consuming, and it's a high maintenance activity to get there. It's warranted on high-risk pipelines, but it's difficult. Yes, sir?

>> (Off microphone)

>> DAVID BOLON: Percent of nominal flow, yes. That gets into my discussion in the next set of bullet items. Challenges remain to improve leak detection. We're actively pursuing these through research and testing. Controller confidence or type management of nonlegal arms is our number one challenge. If we can maintain controller confidence in system, they'll believe the data that they're seeing, and they will act appropriately on that data.

Leak detection system installation is very much a pipeline-by-pipeline process. Large variability in the tools. We're always adding to the toolbox that we have in order to address leak detection.

Leak detection system operation is complex, multidisciplined process, which all must be managed to achieve maximum results. That gets back to the many moving parts chart. And all of those have to work, and they have to work appropriately in order to have a functioning leak detection system.

This comes to my last bullet item, system effectiveness. It's ambiguous. That terms is ambiguous in today's leak detection systems. I don't know of any industry agreement on the definition of the system effectiveness parameters. I indicate three of them down here: Percent of flow, time to detect, and acceptable level of nonleak alarm. I believe that all of those are interrelated, and they must be analyzed for various states of the pipeline condition in order to be able to understand your system effectiveness.

People, they may talk about percent of flow, and even that's an ambiguous term. Is it percent of current flow, nominal flow, max flow? All those must be clarified when you hear the term "percent of flow." But percent of flow is not the only answer. You must tie that to a detection time, and you must tie that to somehow the accessible level of non-leak alarms. If you talk about we're going to mandate that industry to be able to detect 5% of flow in a one-hour period, how do you tie that into the false alarm rate? I believe they must be tied in together, and those somehow can be used to determine a system effectiveness parameter.

Layers of redundancy provides an overall complicating factor in measuring effectiveness now, so you look at leak detection -- CPM is a method of leak detection, but there are all the other layers of detection out there that must be considered. And measuring system effectiveness, I will talk about that later when I talk about the PRCI Research initiative that we, as industry, are moving forward with. But today, just let me leave it as it's a nebulous, ambiguous term, and it needs to be very much clarified in terms of how do you measure effectiveness of a leak detection system. Thank you very much.

(Applause)

>> LINDA DAUGHERTY: Very good information. Thank you.

>> DAVID BOLON: I hope it helped.

>> LINDA DAUGHERTY: Oh, I think it will. So our next speaker is Nikos Salmatanis. Is that right? No? You were supposed to say sure, you got it right. I'll let him correct me. He is the Leak Detection Specialist on the Technology Team with Chevron Pipeline.

>> NIKOS SALMATANIS: Getting this up here. It's Nikos Salmatanis. Can everybody hear me okay? Okay. Good. Thank you again today for allowing Chevron Pipeline speak to you guys today. I think it's a great industry and collective presentation today. We have definitely a lot of experts up here, and you'll probably see a lot of overlap, and hopefully there will be some sort of dissemination between the different presentations.

So on the left-hand side here, we have the charge and challenge that I think Bob had asked us to do, and I'm not going to belabor too much of that because I think both Dave and Rex kind of pointed a lot of those things out. But I think kind of, you know, right at the very beginning, kind of giving you guys some key messages here to each of those different considerations.

Nonconventional leak detection redundancy is being piloted while conventional is being maintained, and that kind of goes with the layers of leak detection. The layers of redundancy there. You will see a slide on that, and there will be some pretty colors in case you can't read in the back of the room.

Leak detection changes due to the hazardous liquids IMP rule. I think we documented at least over 350 leak detection capability evaluation, preventative and mitigation projects, and we kind of bucketized those for you guys today in seven generalized categories.

External, environmental, and operation conditions. Basically, as you've seen already in the two presentations and even earlier on with Don's and Byron's, I mean, the technology and performance don't necessarily line up, and there's a lot of risk analyses that goes on and a lot of layers of redundancy going on to try to get alignment there.

Human factors as it affects leak detection. Both SMEs and the controllers can affect the performance of the leak detection systems, so there are many different human factors besides fatigue. We'll kind of list those out. What's our CMRP plan?

Pipeline shut-in time improves with valves and meters and CPM. I know we've kind of just recently put together an integrated spill management tool where it looks at both the CPM, the controller time, the valves, the CPM, the meters, and the pressures, and trying to get a little bit more of a holistic approach of what that looks like.

False positives and negatives there. I mean, there's a process and a protocol that we have, and we've outlined some key nuggets, some typical things to look at when looking at false positives and negatives there.

CAPEX/OPEX. Millions of dollars have been spent on capital and expense. Pretty much, I think there's been more on the OPEX side than the capital side when it really comes down to it.

Pilots, projects, research development efforts. Not to quote our president, but it's kind of an all above approach here, so you will probably see a pretty lengthy slide there.

So again, briefly, just like Dave had a little bit of overview of Chevron Pipeline and what we own and operate here. I think this number is actually dwindling here, so a little bit over 9600 miles. It's both crude, petrochemicals, refined products, carbon dioxide, LPG, NGLs, and natural gas.

So here's that nice, colorful, pretty slide showing layers of redundancy here. These are based off of risk. We heard today about risk evaluations and leak detection capability evaluations. This is another form of risk evaluation. Kind of borrowing here from Byron. You can get the physical inspection, and you know, that's your aerial and ground surveillance and your community awareness and one cog in the cog wheel. You don't want to negate any one of those things as a means to detect leaks.

Then you have some manual tabulation and real-time monitoring. We heard about tank balancing, SCADA systems, doing kind of in versus out and metering, what have you, having your metering and volume analysts actually doing some of that balancing. You can definitely detect very, very small leaks leveraging those specialists.

Computational pipeline monitoring. When we say computational pipeline monitoring, I think Rex gave a pretty good explanation there, an algorithm that pretty much automatically detects a leak and actually automatically alarms a controller of that leak as well. I think for the most part, most of it is done on Bernoulli's equation and conservation and math, but there are other techniques in CPM, like statistical, that's outlined in API 1130 and rare fraction wave actually outlined in API 1130, but for the most part, we concentrate on the conservation and mass. I've kind of delineated two separate little I guess streams here, where you have in versus out and automatically along-terming the controller but without some sort of line pack compensation and then some with line pack compensation, and getting down to more rigorous type of leak detection, the real-time transient modeling.

Something here in red here I want to highlight is the coupling of dynamic alarm limits. That's a little bit of efforts to help reduce the false positives and negatives and to kind of deal with some of these very small, sudden transients, and not long-term transients there.

Also, too, the external leak detection systems. We have a camera and hydrocarbon sensor based type system as well.

Some pilots in research, want to outline here, some rare fraction wave, real-time monitoring, fiber optic distributed temperature sensing, fiber optic distributed sense acoustic sensing.

Over 350 LDC PAM projects we identified. And the buckets kind of generalized here is more metering and instrumentation calibration and verification and accuracy improvements. Dave mentioned how these are very important in CPM systems, especially conservation and mass systems, that those stay very credible and very good reliability there.

Capital investment and replacement of equipment or maybe even adding more equipment. There is a lot of retrofit in that regard. You know, we don't really have a whole lot of new lines. We have more existing lines and existing infrastructure. So there's, you know, capital investment in that light.

Improving tuning and alarm parameters. We'll go into a little bit of that detail a little bit later, but adding CPM. I mean, physically going for more of a physical inspection and SCADA real-time modeling based to, you know, coupling that with a CPM system as well. And then adding line pack compensation. I mean, one of the things that's been always very difficult in our industry is to have line pack compensation for NGLs and LPGs and RPGs and stuff.

Adding more trending capabilities. I mean, we talked a little bit about the SCADA displays and alarm management and making sure that controllers understand what a leak looks like and when anomalies are happening what that actually looks like, so providing a little bit more trending capabilities so that way the time to detect is actually sped up. Just because a leak detection system does give an alarm doesn't mean you really detected the leak. It just means that the application detected it. It's not really until the controller hits the red button that says, okay, let's shut down the energy of the pipeline system we've detected a leak.

External environmental operational conditions. So there is no one size fits all. Definitely different layers of redundancy. I mean, we have different layers for a reason. I think in Byron's presentation, he listed out pretty much in detail a lot of the factors, in CFR 195.452 and a lot of the frequently asked questions. There are some other, I guess, factors that I'd like to kind of highlight here. The measurement and instrumentation spacing, the meter proving and meter factoring errors and making sure those are pretty reliable.

Fluid property data. Making sure you have densitometers and gas chromatographs at all the key places is key there. Fluid temperature. I mean, we mentioned a little bit about API 1149 and some of the uncertainties there. Definitely temperature. It advocates that it plagues a leak detection system, but I think it's pretty key there that we have good fluid temperature on the pipeline.

Hours of operation. Slack line or start-up transients, communication outages and latencies. Then human factor, bringing in those CMRP factors about data availability, presentation, the understanding of the fluid behavior, making sure that folks understand what they are actually seeing, is it indicative of the fluid behavior or indicative of a state change.

And then any kind of fixed or manual entry numbers. You know? I mean, that, too, can kind of hinder a little bit of a leak detection system.

So human factors affecting leak detection performance. So a lot of this is really coming out of our CRMP plan, and it encompasses all the factors outlined below. Fatigue mitigation, providing adequate information like the graphics and data transparency, data availability, making sure that not only do you have the available data, but how many clicks does it take to actually get to the answer that you need. Trying to basically have one or two clicks so that way the controller has the information right there in front of them.

Alarm management. There's been a lot of work around alarm management, both from the API side and the CRMP side, and reducing, you know, not only just alarms in general, but even leak alarms as well. Change management, operation experience, and then training. I mean, I think Rex kind of pointed out the fact that we would definitely need a whole lot of training going on here and making sure that folks understand, you know, the trends and alarms that they're receiving. What does that mean?

And then a little bit from the SME side of it, you know, making sure that the things that are gaps inside the actual technology, that's actually communicated and trained as well.

Then the reliability of these systems. What hinders the reliability and what improves the reliability of these systems?

So a little bit on the shut-in times and integrated spill management here. We've developed a quantification tool set. It provides basis for analysis of the qualifying a spill impact. So it takes into account the measurement, the CPM, the controller response time, valves, metering, and a little bit of the physics of the actual pipeline system. And I think, you know, what sort of improvements have we seen? And we've seen a shut-in improvement of two and a half hours to 30 minutes just by utilizing this quantification tool set here.

So addressing false positives and negatives, kind of go a little bit over our process and protocol, then kind of outlining a little bit of the typical reasons of why you see these sort of things. So you know, CPL has developed and implemented a CPM tuning process. All CPM records are evaluated at least once a year per 1130, documented per 1130. There is a balance between, you know, the sensitivity and the averaging periods here and alarms. I think Dave kind of mentioned about the balancing act that goes along. So there is that forever balancing act on pretty much all compensating mass balance CPM systems. Anything that has an uncertainty to it. So just because rare fraction wave, you know, isn't a compensated mass balance, it does have some uncertainty to it, and it will have a balancing act associated with it. Leak detection alarms are documented in the controller logbook, and annotations are actually put on our trending. So you know, that kind of helps out with the controller shift, what have you, and when they train the next controller coming online is going back and reviewing some of those annotations from the prior controller.

Deviation alarming, which, you know, that's documented for historical review on the controller on duty, review of daily console. It's reviewed daily with the console operations representative, weekly with the console supervisor, and monthly with the leadership team.

Something, too, that we've kind of enacted kind of recently is the analytics team, and this kind of helps the controller. It's kind of like a secondary person, their eyes and ears here on the console. It's not so much specific to the console, but to -- to all consoles, but it's actually helped them reduce the amount of false alarms associated with it as well as help detecting leaks. I would say that it's really been a great value to our control room.

So usual reasons for false positives and negatives. I mean, it goes without saying, you know, if you are using a conservation and mass technique, preliminary the CPM system of choice, I think, measurement is an issue. So making sure that you have measurement and that it's whole in integrity, is definitely needed. Instrumentation problems, communication issues, operational issues, software and application issues, as well as PCN or process control network related issues.

And then, of course, the last one is the CPM tuning itself. Once you've been able to rule out all these different things, it might be time for another tuning.

So some industry collaborations. Pretty long list here. We have API, PRCI, IPC, PSIG, but also too I want to highlight a little bit of the vendors and the user groups there. I mean, there's a lot of collaboration that is we do with the vendors and what have you, so you know, it isn't just an industry-specific forum.

External research. I think Dave's going to go into a little bit of the PRCI with the pipeline 1-1, 1-2, and the DP 3-3, but these are some of the ones Chevron Pipeline is involved in. Internal research. We definitely have internal research going on in the statistical algorithms, as well as the fiber optic DTS and DAS types.

Pilot testing. Along with enterprise, we are also pilot testing our own, I guess, value-added way of implementing rare fraction wave and real-time modeling, and so far so good, but we'll see how it all kind of shakes out in the end there.

Some new advances. I mean, there's a joint industry project here on sub-C leak detection, so some of our member back on the map. I think the key thing here is what's the implementation method? What's the protocol for implementing something like this?

Some other thing I want to highlight here is the release elimination culture. I'll get to that in the next slide here. It's kind of like a safety culture. But really focused on the release elimination and driving to zero. You know, definitely in this environment here.

Proactive in repair projects. I mean, that kind of goes hand in hand with our integrity management program and maintenance programs there. Equipment reliability integrity process, control center visualization. Alarm objective analyses. And CRMP plan improvements, SCADA communication system upgrades, withdraw test protocols, and looking back at our historical incidents here and really driving to zero. We like to learn from your prior incidents and others' incidents as well, and I think the key there is not only from a detectability but from a prevention perspective. And then adding more organizational capability.

So talking a little bit about our culture. Definitely Chevron's priority is spill prevention. I think we already had that, you know, leak detection will not prevent a leak. It will mitigate. So again, applying that same focus of safety, you know, zero is attainable, definitely in this environment, that we're always trying to manage that risk. You've heard risk several times today, and everything's based off risk. So that's pretty key there.

And then coordinating a lot of these activities together. I mean, there's a lot that can be coordinated and learned, both from the preventive and mitigative here and the proactive repairs.

Definitely the tone at the top sets the stage. And having that individual commitment is kind of huge. I mean, you definitely see that in our culture. Definitely the tone at the top is there, and definitely if you ask someone in the field, they are going to tell you the same thing.

We definitely share a lot of the same lessons learned, both internally in our company as well as within our corporation of things that we've learned, best practices, and that seems to be very value added as well.

And having said that, thank you very much for allowing me to speak in front of you today, and I've listed a whole bunch of acronyms in case I missed a few there.

(Applause)

>> LINDA DAUGHERTY: Well, we've had quite a bit of information this morning. We covered quite a few topics. I hope you all have been taking questions, writing down notes. I have.

So what I would like to do is I want to open up for questions. Don't be shy. You have index cards, Max and Jim at the back are going to walk around and hand out index cards. You can get them for now, get a few for other panels later on, but happy to have you, if you have a question you'd like to ask, I would ask that you come up to the microphones and state your name and affiliation. Again, I'm going to try to keep people on target. While people are thinking about their question, I have a few questions for the panel just to get us started. Okay?

The first question, you know, we heard a lot of discussion about the balance between technology and human factors. I think just about everybody mentioned that there is -- this isn't an automatic. You can't just turn on a leak detection system and it just runs and tells you where a leak occurs. You have to have a human factor. And so my question for the panel, considering where we are in technology as far as leak detection and considering, you know, the advances we've made with human fatigue issues and human training issues, I'd like to ask where you believe we should focus our attention.

If someone had to say focus on research R&D to bring the technology up or research or focus on dealing with the human element? So if we could, let's just start at one end and roll down -- just roll down from one end to the other. Shall we?

Are these mics -- do you have to activate them? Try them.

>> Is this mic on? Can you all -- okay. Very good. Technology. I think it's two areas on the algorithm side. I think it's -- the answer is not in hydraulic analysis as much as it's going to be in signal processing. Leaks have a certain pattern on the instruments on pipelines, and we're training operators today to look at those patterns. I think techniques that could automate that pattern analysis and give that as an input to controllers is important. So that's really a combination of technology and training on controllers. A technique that we use is to teach them about the patterns that they're seeing. You are getting a leak alarm. Some of the indications from your trends and other places, do they agree with the pattern? We use simulators to simulate leaks on specific pipelines.

We look at the output. We take snapshots of that. We put it in the manuals so operators will know what their displays are supposed to look like when they're operating normally, what they look like when they are doing various transient conditions, and then what they look like in a leak condition. We are training people now. What we need are more sophisticated tools to help them do that pattern analysis.

>> LINDA DAUGHERTY: Great. Thank you. Thank you.

>> Okay. From the technology side, the tools that we have from vendors today take us a long way to being able to detect small leaks. Some of the vendors, especially of the real-time transient models, the statistical systems, they're allowing us to find leaks under a lot of conditions down to, you know, 1%, 2% of the flow through the pipeline.

As I said in my presentation, it takes a lot of labor to make sure you're doing that and doing that properly. So I think there's a valid, vital, growing vendor community out there that takes care of maintaining and pushing their products forward in a preparative manner. I'm not sure that we need to be, you know, giving them extra money to do research and development because they've got a vital community out there, and there are several vendors that are providing technology for us today.

It's when you're trying to get down below that 1% or 2% leak detection, where the technology is lacking today. It's very difficult to find technology that can be deployed to get down to much less than the 2% level in an easy, consistent manner. So research in that area would be valuable, and -- the other thing, the human factors aspect of it, I think work needs to be done there. I think it's not so much human factors as it is the processes that are used throughout an organization. They must be managed. They must be held accountable for it so people understand the results of their actions and the changes that they make and all the different aspects that go into updating and changing the pipeline configuration and testing and revalidating. All those are processes, and if there's a set of best practices out there that can be followed, that's what needs to occur as opposed to -- the human factors, the controllers have benefited greatly through CRM.

I have to take my hats off to Byron over there president focus on controllers and getting them the ability -- the information they need to run the pipeline, CRM has done a tremendous job in focusing that, but it's more process orientation or process focus.

>> LINDA DAUGHERTY: Great. Thank you.

>> Can you have the panelists speak a little bit better into the mic, bring the mics closer?

>> LINDA DAUGHERTY: Okay. Don?

>> DON LEDVERSIS: Yeah, what we are going to do is just the 2% and under leaks, we did put that one in the docket. That is a problem. We can put some more research into that area, that would be, I think, a good idea.

>> LINDA DAUGHERTY: Okay. Byron?

>> BYRON COY: I'll focus more on the human factors part. There's a --

>> LINDA DAUGHERTY: Wait a minute. Can't hear him? He's almost eating the mic.

>> BYRON COY: From a human factor perspective, there's, I guess, a corporate culture change recently where, you know, the control room is invited to acknowledge an issue, and they have the authority to take charge, take action. But there's still a stigma in the control room that, you know, they don't know -- they don't want to shut down the pipeline. There's a hundred reasons why things, you know, are peculiar, and 99% of the time it's explained away to some operational issue. So even though the control room, procedures now, you know, they have the authority at that take action, they're still reluctant. But I expect that will change over time.

>> LINDA DAUGHERTY: Thank you, Byron.

>> So I second that. On the human factor side, CRMP, I think there's a lot of value to learn from the controller's perspective in trying to really understand, you know, the different patterns that they go through on a day-to-day, shift-by-shift operation. I mean, the technology's there. The key there is to tune the technology in such a way that can recognize the same patterns that the controllers see. I think some of the value that the CRMP gives, we really haven't been able to see the full success of that as an industry, but I think with more collaboration there and effectiveness measures there, then we can definitely can.

To resonate a little bit of what reflection said, pattern recognition is huge. Leading to these techniques with another layer of redundancy for statistical means I think is huge. The ability to start looking at this not just from a, you know, where's the silver bullet perspective, but maybe you have five or six silver bullets all at play here, that might definitely help out.

And definitely training. You don't want to gloss over the training aspect here. I think there's training twofold here, both from the SME perspective as well as the controller perspective, and that's the only thing I have. Thank you.

>> LINDA DAUGHERTY: Thank you. It does sound like it's a balancing act, and deciding where we are going to put our focus and our resources will be a challenge and something I'm sure we will have more discussions on.

We have a question. I am going to read it, and then I would ask the panelists to just let me know who would like to respond to it. But I'm going to pin someone.

If existing pipelines are not designed for LDS, what are the most difficult challenges with retrofit? That's part one. Part two, what are the most expensive challenges? And part three, are there simple, economically feasible retrofits?

>> Linda, I can take one. I think that came out of my presentation. Let me pull this a little bit closer. I did address retrofits in my presentation and said that it's difficult on existing pipelines because of the limitations of space, the limitations of right-of-way. I can't go much more over what I covered in my presentation. To install meters for segmentation purposes, there needs to be a physical length of pipeline that the meter can be installed upon, and a lot of times our pipelines are just -- you, they come up at a valve location and go immediately underground. To install our retrofit means repiping as opposed to just putting a spool piece in an existing available piece of pipeline. If you have the right-of-way, the land area to do that, that's nice. That's one benefit in your favor. But the expenses come in in repiping, when you have to, you know, physically go in and change and reconfigure how the pipeline is in the ground.

We've looked at minimal or the least cost. That's the second part of it. Least cost. That's some of the testing we performed on the clamp on ultra sonic meters. They're advertised to be able to, you know, retrofit on the outside of an existing pipeline and use their technology to measure the fluid flow through that particular pipeline. They, too, have their installation requirements, a certain amount of length of pipe upstream and downstream of the meter installation in order to be able to measure, you know, fluid flow through that particular meter. We thought they looked promising. We thought they looked lower cost than other types of meters that are in line in the pipeline. That's why we ran the tests that we did. We actually have deployed many of those clamp-on ultra sonic meters in the thinking that it's a lower-cost solution, it's going to give us more segmentation, it's a quicker deployment, but it turns out they cause more problems than they solve, and I believe it was mentioned at one point in the presentation, giving false information or bad information to a controller is worse than no information to a controller.

So we're seeing these clamp-on ultra sonic meters, which we thought were a low-cost deployment solution for metering, actually turn against us because of the poor measurement that they are providing. So it is a difficult situation, but the in-the-ground pipeline that we have today is our biggest concern from a risk perspective. It's been in the ground the longest. It's built many years ago in a lot of cases, and it's the higher-risk pipeline that we want to protect and we want to put our better leak detection on to be able to retrofit the existing instruments -- or instruments on existing pipelines. It's a difficult problem.

>> LINDA DAUGHERTY: Okay. Thank you. Anybody else want to add to that? No? Okay. Great. Go to the next question. Would it make sense to combine online LDS systems, such as RTPIs, with offline systems which are being used multiple times in a year? What could be the benefit?

>> What was that first one?

>> LINDA DAUGHERTY: Yeah, that's what I was -- I am trying to read it here.

>> Oh, I can read it. Would it make sense to combine online systems, RTTMs, with offline systems, pigs, which are being used two or three times a year? What could be the benefit?

They serve two different functions. The real-time transient models or the online systems are telling you the state of your pipeline as you're operating it to move product from point A to point B. Offline systems, like pigs, we have cleaning pigs, but the smart pigs this one is probably referring to are being run to look at the state of the pipe, the condition of the metal. They're being used to look for, you know, dents and metal loss throughout a pipeline. So they -- they are being used to, you know, maintain the integrity of the pipeline, but the online models or real-time transient models or online systems are being used to understand the condition of the product as it flows through the pipeline and where everything is going normally or not going normally. So they serve two different functions. I don't know how we could combine them to use them for one purpose or one common -- I don't know how we could combine them.

>> LINDA DAUGHERTY: But if you have good ideas on how to that, whoever put this question in, come talk to us. Maybe there are some creative thoughts out here. Et cetera that's what we are here for, looking for the best technology and ideas and how we can make it better. The next question --

>> Can I add another follow-on? Some of the offline pigs, they can be used to be mounted with acoustic centers to listen for leaks. We have leak ball, as a commercial product today, it goes down the pipeline listening for leaks as the product leaves the pipeline, so some of that is in place and used today for detecting leaks.

Yeah, I can see maybe a case where the online leak detection system tells you that there's something wrong and you want to deploy a PIG or a smart ball to maybe find that real tiny, tiny leak that you can't detect and locate through your online leak detection system, so maybe there's some benefit if the leak detection system tells you there's something wrong, you deploy a PIG or smart ball or some other technology that moves through the pipeline listening for a particular type of release.

>> LINDA DAUGHERTY: Okay.

>> Just to follow up a little bit too, also, too, on the pigging operation, real-time transient modeling, when you do a pigging operation, whether it be a cleaning pig or part of an integrity tool, you will see false alarms, and depending on how tight those limits are, and so you know, if your application is not designed to accommodate a pigging operation, you're going to see that. They definitely serve two different purposes. I mean, definitely will detect a very, very small seepier below the tweeners, but at the same time, I think that's also why you have an external leak detection system. You know? Very similarly, where this thing is cleaning the inside of a pipeline, and finding a very, very, very, very small, infinitesimal size hole, it's the same sort of thing with an external type leak detection system. Maybe it's not the same infinitesimal size hole, it might take a little longer, but it is something that you have to consider.

>> LINDA DAUGHERTY: Okay. Thank you. Thank you very much. I do want to encourage people to come to the mics. We have a shy audience here. I'm getting good questions. But come to the mics. Also, the folks on the webcast, please, send your questions in. We would love to hear from you.

So next question. Is the risk decision making just for leak detection, or does it cover other preventative and mitigative measures, et cetera, like EFRDs and digs?

>> Yeah, the risk assessment actually does cover all those subjects. Like I mentioned in the presentation, leak detection is just a response activity, and that's just one component of an overall risk assessment to minimize discharge of product after you've actually had a leak. So some of those other items are minimizing the discharge, where your valves are at, how often you patrol the pipeline, your leak detection system. There's a lot of things that go in before the fact as to how we make sure you don't have the leak to start with. So the leak detection system is just one specialized input into a risk model.

>> LINDA DAUGHERTY: Anybody else like to add? Nikos?

>> NIKOS SALMATANIS: One thing, too, when you are doing -- you asked about risk decision making there with regards to leak detection and EFRDs. I know within Chevron Pipeline, I mean, I know those two different evaluations kind of go somewhat hand in hand or at least collaboratively have tried to take place at the same time. So there's a lot of value in having both those types of valuations kind of collaboratively going hand in hand. Because in the end, you are trying to mitigate, and both of those things are mitigation.

>> LINDA DAUGHERTY: Thank you. Anybody else? Okay. We have someone at the mic. Thank you.

>> My name is Martin Phillips with Keatner and Associates. I

heard the term, four-letter word "risk" several times. I'd just like to have a couple of the panel members clarify what they mean when they talk about "risk." They talk about the programs are risk driven. Are we talking about the effect of a leak on the community, or are we just talking about the likelihood of a leak?

>> LINDA DAUGHERTY: Very good question.

>> I'm not sure what you mean by "risk."

>> Can I start? In our program, we're looking at both aspects of that, but we've weighted the risk analysis higher on the consequence. So we look at risk as consequence times probability and all the factors that go into identifying the consequence, and HCA is definitely part of that. And so we've weighted, you know -- given more weight to the consequence aspect of the risk model. So you know, we have a model that is calculating a consequence score for every assessment part -- assessed part of our pipeline system. We look at that, and where there's a higher consequence to a leak, we put on better leak detection technology on that particular pipeline. Better technology, more layers of defense. We try for tighter sensitivity levels on that particular part of our pipeline system.

>> That's what I was after. Nikos, would you like to comment on that?

>> NIKOS SALMATANIS: It's actually the same thing. So there is a higher weighting on the consequence as well. You mentioned about the likelihood and what have you. There's a lot of -- I am trying to remember if it was Rex's or Don had the geographical slide there, where mentioning some of the factors to actually look at when you look at risk. That's a little bit of the caveats there is to look at the geological factors there and the likelihoods. HCAs. You mentioned HCAs. But the biggest key here is consequence.

Probability does come into effect, but --

>> Yeah, I wasn't looking so much for the definition, but how your view of risk drives your program -- (Off microphone) -- they're aware what the consequences are. And that you -- problem with the mic. And that you actually take account of that in the types of -- sorry -- types of leak detection systems that you employ in the areas where risk is higher to the public. Is that what you said?

>> Absolutely, the public and the environment. We are looking for where there's the greatest consequence in addressing that.

>> LINDA DAUGHERTY: Thank you.

>> I have lots of questions. Can I ask another one?

>> LINDA DAUGHERTY: After this gentleman does.

>> Okay.

>> LINDA DAUGHERTY: Please.

>> Yes. My name is Lyle Welch with American Innovations. How much investigation has been done in correlating cathodic protection effectiveness and smart pigging measures to existing CPM systems? In other words, in a statistical or probabilistic analysis, to correlate the trends and the histories of the data information coming from your pigging operation, you know, and cathodic protection data with existing CPM systems?

>> LINDA DAUGHERTY: Very interesting concept, basically integrating the information you know about your pipes, what you've learned about your pipe, with your leak detection capabilities. Nikos?

>> NIKOS SALMATANIS: So we've done -- kind of speared off some failure mode effects analyses and looked at cathodic, other type programs, put together some growth plots, put together some Y trees, what have you, where are the failures happening. Definitely get a prado of kind of the significant views, the things to actually focus on. So yeah, I mean, it's a very good question, and it's actually one in which we have asked ourselves internally and trying to tackle that a little bit with our FMEA as well as our -- some of our historical analytics.

>> Yes, because this goes back to what we were talking about earlier, which was the confidence level of the CPM system and being able to relate that to other known technologies and practices that have been around for quite a while, which was, you know, the pigging measures and cathodic protection maintenance and everything in order to build that confidence level in a CPM system. Thank you.

>> LINDA DAUGHERTY: Thank you. We have time for probably two questions plus this one, and so we'll move through these quickly. So you had another question, sir.

>> Yeah, I have a question to do with the physical inspection, line walking or whatever methodology you use from above ground. Is this method -- does this method produce results?

>> The physical patrolling the pipeline produces results. There's a number of reasons to do it. It's done in high congested areas and industrial areas where you can't fly, around airports. There's two pipelines that come into Dulles airport out here. One goes into Washington National. You are not allowed to fly around those anymore, so those are all patrolled every 14 days on foot. They are very effective.

In those particular areas, in results, looking for vegetation, encroachment, and other aspects for it, so yeah, we've got a good history with ground inspection of pipelines in very specific areas.

>> LINDA DAUGHERTY: Thank you. Gentleman here.

>> Yes. Bryant Moore with Wilbroughs Engineering. I think it was reflection who mentioned in his talk 83% of the industry, I guess, said they had an LDS system. I was wondering is there any kind of breakdown on what that is as far as is everybody using real-time, or is everybody using CPM SCADA, and if so, on top of that, I guess, the next question is is there a hole in the industry available system that you think is not being addressed as far as not enough people adopting that particular type of LDS system?

>> LINDA DAUGHERTY: Good question.

>> The survey was done by the API, and they did not go for that granularity of the data. But it goes back to, again, the key point is the systems that are being chosen are used in the engineering approaches outlined in some of the documents that I listed, so the systems that are being chosen are appropriate for the specific pipelines that are being done. So the representation of a specific system isn't a prejudice about the industry. It should be an engineering analysis of the specific systems.

>> LINDA DAUGHERTY: Thank you. Alan?

>> I'm Alan Mayberry. I just wanted to touch on a point that was mentioned at least in a couple of presentations related to aerial leak detection. You know, in particular, it's the method you use instruments to -- such as LIDAR, or technology such as that to find small leaks. Is that called for? Is there an opportunity there to maybe use that more as a matter of routine during aerial patrols than it is now?

>> The only thing I know about that is the work PRC has been doing of testing vender's equipment over gas pipelines, not over hazard pipelines. I believe Mark Piazza is going to talk about that in this afternoon's panel on gas pipeline research. I don't know of anybody who is using that for hazardous liquid pipelines.

>> Alan, I know a couple years back we had a pilot product where we significantly invested a lot of time, money, and resources in looking at that LIDAR, and there were places it proved out very successful, and there were places it proved out to be not successful. And so we were kind of on the fence of, you know, maybe fit for purpose at certain places. So it's not to say frequency couldn't be improved there, but I think there's a fit for purpose.

>> LINDA DAUGHERTY: Thank you. I have one last question for the panel. We operate static pipelines. What is the percent of leaks detectable for nonflowing lines? Is there a recommendation? Your panel has indicated capabilities down to 2% for flowable lines.

>> I guess I would expect that if there are at times certain line segments not being used and they're shut in, that during the shut-in conditions, you know, they're monitoring the state to take advantage of it being idle. It's a very nontransient state, so that they should be shut down and some exercise of pressure monitoring or otherwise be used during this bridge of time to take advantage to identify what would otherwise be undetectable leaks when the line was flowing.

>> LINDA DAUGHERTY: Anybody else?

>> You know, we use the pressure monitoring on static lines to look for leaks, and you know, temperature is an important consideration there, if the temperature is changing over time. But we don't -- we, Enterprise, don't talk about that as a percent of flow. Obviously, that wouldn't apply. But percent of volume or any of those types of things. We are looking for very small, unexplained drops in pipeline pressure, and we've never gone back to calculate what percent of volume of the pipeline we're able to detect leaving the pipeline. But if we do see an unexplained drop in pressure, you know, we're talking on the order of pounds, you know, one or two pounds that are, you know, dropping on a pressurized pipeline, that's not explained by a temperature change, then yeah, an investigation is warranted at that point.

But there's no percent of volume or anything that I'm aware of that we're doing on those pipelines.

>> LINDA DAUGHERTY: Okay. Thank you very much. I want to thank the panel. I think they've done a great job today providing information. Please join me in showing them our appreciation. Thank you.

(Applause)

I do have a few comments. I was asked to provide a clarification. The public comment on the DOT docket will be available this Friday or by next week. Please check back on that. Also, remember when we break here -- we are getting ready to take a break -- go check out the vendors if you have time. Talk to people. Get to know folks. Network. Also, we will be reconvening at 10:25. That's about 15 minutes. So thank you all. See you back in a bit.

(Please stand by.)

>> LINDA DAUGHERTY: Valves. You're going to wonder, why is she bringing up a valve study on leak detection day. The reason I'm doing that we may lose operators here today who wouldn't be able to be here tomorrow. We have some General Accounting Office reps who

are here in the audience, circulating making contacts. We want you to know who they are so you can run -- no! Sarah, would you and your crew stand up? Everybody see who they are? They are going to be looking at a number of issues here. This is general information. We'll have it up again tomorrow. Whoops.

Matthew Cook is the coordinator on this one. He's got phone number and contact information up here.

The main reason I want to point this out today is, if you get an opportunity to talk to the team here, please do so. I'm sure that they could, they would like to get some contact information so they can contact you later. So thank you very much.

So did you want to say anything? No? Good? Short and sweet, hmm? There you go.

So our second panel has to do with capabilities and research. You know, we heard today about where we are. We heard about technology. We heard about some challenges. We heard leak detection is not an easy subject. There's the technology factor, the human factor. When it doesn't work it can have potential huge consequences. It's something we have to put a lot of focus on. When we look at R&D and we look at where we are right now, people might say, well, if you have any indication of a leak, why don't you just automatically shut down a pipeline? Well, those of us that have been in the business know sometimes you can cause more safety hazards responding to false alarms. When we look at R&D it helps us get better detection and response to leaks. The panel today will be responding to some of these speakers. The first speaker is -- I'll try to say this right. It's Shane Siebenaler. He's group leader with Fluid Dynamics in the Southwest Research Institute. Join me in welcoming Shane.

>> SHANE SIEBENALER: Good morning. I'm here to speak a little bit from the research community's standpoint on different challenges that are faced in research and in testing for leak detection system to provide a different perspective than you would get from the operating community as well as the vendor community.

As has been mentioned several times this morning, there are a number of different tools that an operator has to be able to detect leaks. These include visual patrols, they could be from an aerial platform in a more sensitive area or someone was mentioning this morning, Rex was mentioning near an airport you might do this on foot. Rely a lot on trained controllers to be able to recognize process updates that you might see in the SCADA system. Within the liquid community a more common approach is to use some sort of CPM system. Could be a compensated mass, for example. There are a number of what you might call external tools. These are technologies that use sensors to detect either fluid outside the lines so they could be something like die electric cable that is requiring direct contact with the hydro carbon. Or something that is detecting an indirect process. An example would be a system that could measure a temperature change resulting from a leak or vibration or acoustic profile that might be present in the case of a leak. Dave this morning was talking about layers of redundancy. Most likely an operator particularly in an high consequence area might employ more than one technology. For example, you might have something like a mass balance system that would allow you to quantify the amount of leakage, but it may not give you a good indication as to where that leak is in between two end points. Whereas other technologies may be able to very accurately locate a leak but would give you no information about the size of the leak. So having layers of redundancy, having systems that are complementary are very useful.

In by reason's talk this morning he gave a different flavor of the same chart. In terms of the size leaks he was talking a little bit more about what kinds of leak detection system you might want to employ in these scenarios. As mentioned this morning, for a large leak you don't need a large leak detection system. You need to have somebody who can see product in a river system.

For controlled leaks, controllers can look at the process upsets you might see from the instruments in the SCADA system. From the majority in the lakes, in the tweener category you would use CPM. There's a threshold below which the uncertainty in your leak detection system, this could be instrument uncertainty, this could be from the fact that you're making assumptions of either steady state conditions or not accounting for various transients. When that sensitivity, you start bumping up against those uncertainties, you raise the specter of false alarms. We try to drive the thresholds for CPM systems down and look at other technologies that might be able to detect leaks smaller than that percentage.

In detecting leaks, it is not just a matter that you have a system that can detect the leak. There are other parameters. Dave this morning was talking about when you look at a leak detection system you have to do it in the context of things like response time, the ability to locate the leak. The fact that I have 100-mile long segment and I know there's leaks somewhere is useful but not as useful as knowing where that leak is.

The false alarm rate is obviously a very key consideration.

In the response time, as Dave was mentioning this morning it's not how long does it take for your system to alarm. It's how long between the on set of the leak to the time that the controller can actually make a decision. The system may be able to provide a very rapid alarm, but if it takes that controller two hours to dig through trending data, to really assess whether or not that leak, that let's say somebody event is actually a leak as opposed to some other anomaly is something that is of key consideration.

Also, I'm going to talk a lot more about this in subsequent slides, but most systems, CPM and even many external systems are highly tuned to a specific pipeline or specific segment of pipeline.

And so a system that has the ability to cover many different kinds of pipelines, fluids, operating conditions is something that is useful.

So within the research world we look at several different areas of pipeline leak detection one is improvements on systems and another is to establish how a system is performing. Documents like API 1155 that talk about how you quantify the apathy, robustness, et cetera, of a CP system but trying to make that quantification for a specific scenario.

Making improvements in the ability to recognize alarms being either a non-leak event. Also how easy it is to implement that technology. If it's something that you can't pull out of the box and plug in that takes you three months of tuning and there's continual tuning as you go along is not as useful as a system that kind of stands alone.

So in addition to actually looking at the instrumentation in a leak detection, another part of research is focused on the leaks themselves. So when you have a leak, what is happening to the fluid? How does it propagate in soil, for example, in a buried pipeline, what kind of hydraulic response do you get? This is important when you look at an external leak detection system when you measure some property of the leak.

And in addition, I showed the chart earlier talking about there's a lower end threshold. Another part of research is driving down that threshold. It can be to make improvements in the way CPM systems are tuned but evaluation of other technologies that might complement a CPM system as well.

There are a number of challenges that present themselves. When doing research and testing for leak detection systems. Would be of them is simply a matter of perception. A lot of people think there should be a technology that would find a leak in a quick amount of time. If there was a technology to do that in a quick effective way without false alarms, we wouldn't have this forum today. A lot of the people in this room would make that recognition; maybe not so much in the public.

Different pipelines have different challenges. Not all leaks are created equal. Leaks in areas of high water content in the soil may respond differently than ones in dry areas. Working systems that -- finding systems that work across mediums is important.

One of the factors to get over is to put the information out there, there is not a leak detection system that will find all leaks. People are reluctant to adopt new technologies because they say it won't find the seepage leaks. The system that you have won't find the leaks either. But what is the cost/benefit of employing that new system.

People test technologies and there was a mention earlier about gas pipelines. There has been a lot of testing where you can simulate a release and you have different technologies that are looking at say plumes and plume recognition. You don't necessarily afford yourself that same opportunity in a liquid release where you have some technologies that are looking at direct contact. Some are looking at thermal properties. Other technologies are looking at what is happening inside the pipe. Creating a one size fits all test is very complicated. As mentioned earlier each of these systems, whether they are external or internal have to be tuned to the system. If you do a test under one set of circumstances, can you apply those tests to others?

One of the obstacles to the external leak detection system, you create a leak intentionally. Even in a controlled manner, the actual remediation, environmental aspects are something you can't ignore.

The market forces actually is something that impact research and development. A lot of the more novel technologies come from firms that have a relatively small portfolio of products. If they can't move those products to market quick enough, they may not be around.

From the operator standpoint that may mean that investing in a technology that three years from now there is not support for. Also one of the other challenges is that particularly when it comes to non-CPM systems, there is a lack of benchmarks available. So as I was mentioning, there's API 1155 that talks about how you quantify the performance of a CPM system. Those kinds of documents don't present themselves in a more generic form that you can apply across a number of different technologies.

Sometimes what that means is that a vendor might be responding to the particular needs of one operator and doing testing or research for that one area. And then the next operator comes back with a little bit different problem to solve. And they have to go redo that testing. So instead of being able to independently validate their system they are kind of having to chase individual problems.

So what I want to do, I want to briefly mention one example of, I will give you an example of research that was done and talk about some of the challenges it presents and give you an idea of some of the ways it can be solved. David mentioned this morning the temperature sensing, using a continuous -- the fiber is buried near the pipe. Assuming you have a different temperature or a volatile fuel like propane that will during phase change produce cooling is that your cable will detect a localized temperature change wherever you have a leak. Some of the advantages are, it is not as prone to transient things in the pipeline, pumps turning on or off don't have an influence. Unlike external technologies that use discrete probes, this gives you coverage along the entire pipeline and gives you coverage around the clock.

When you look at whether or not these systems complement a CPM system to be able to detect small leaks, there are some challenges. One is that this requires you to actually discharge fluid which I mentioned is maybe not the easiest thing to do sometimes.

When you look at how the hydro carbon moves in the soil it's dependent on porosity, water content. As the hydro carbon moves and displaces that, fills voids, displaces water, you render that entire test bed useless. You can't run test after test in the same bed. If you are running many permutations of the test, it becomes a complex system.

How do you test a system designed to run over many, many miles of pipeline in the lab environment or some segment of the pipeline. It is unknown what is really influencing the behavior of the leak. Is it a viscosity thing. The line pressure, how does that influence it?

You can run into these huge sets of permutations you run into in afield system.

The systems have different ways to configure them. How often they take a sample, how often they do the averaging. It presents a large challenge.

One way of perhaps mitigating that is to actually break the research up into different buckets. I mentioned at the top of the presentation there is some research done in how systems respond to the process variable. In this case it's temperature. Other research is done in what kind of process variables are produced by a leak. So how does fluid move, what is the thermal profile. Since these can be somewhat decoupled from a baseline standpoint, one idea is to actually do it in this manner.

You can do some laboratory testing and model work to study how fluid moves in soil conditions based on different kinds of fluids. You can say not whether or not given leak will produce a temperature change at a given location, but what if a temperature change was produced at that location, would the system be able to detect it.

Also you can use this approach to identify the fluid properties that are important and then perhaps find substitute fluids that you can use so that you can discharge these into the environment and you don't run into environmental issues. You can do analysis on batch flows where you have fluids moving at different temperatures, does the interface trick the system into thinking there has been a temperature event. If you have a cold front blow in for a buried cable, does the system think that the temperature changed from the fluid moving is from the leak? From these independent assessments you can down select and reduce the overall test matrix that you need and you can do end-to-end testing where you produce a leak and look at the if the system can detect the leak and whether it's discriminating that from other temperature anomalies.

At the top I was mentioning there's different challenges you would face. One is the fact of discharging actual fluid. If you come up with a surrogate fluid where you match the fluid properties, fluid mechanics properties, that would solve that problem. The reuse of the test bed. One of the things you can do with modeling and some small scale testing, you can actually determine how the fluid moves. Does it come out like a cone, finger itself out? You can determine the volume in which you would need to run one test and then you can determine how you would line-up various tests.

Related to the long lengths that you would see in a real pipeline, the difference in running the system over, let's say 50 meters versus 5-kilometers is the fact that 5-kilometers down range is producing more optical loss which looks like noise in the system and you see fluctuation in the temperature measurement. You can simulate that by hooking up bare fiber that would give you the optical loss or an attenuator that would give you that loss without installing miles of cable.

You can determine what is driving the leak in the laboratory. Is it soil? Is it more driven by fluid properties and what the fluid properties are. Also in the laboratory setting it affords you to run different configurations, different kind of leaks without all the costs you would see in a full scale field test.

All that being said there are still some gaps that exist in research and testing for leaks. One of them is still down to perception and what I have on the right here are some perhaps ways that we could go about closing these gaps.

So when it comes to perception, again these are things like the fact that all systems should be able to detect all leaks or that all leaks are created equal. One is through education. Events like this where we are informing the public about the limitations of toll is important.

Also the fact that there are in many types of technologies a lack of benchmarks. I have been talking about how API 1155 gives you the ability to quantify the performance of the CPM system because that kind of standard doesn't exist for other technologies, it's hard to really communicate how well in terms of things like response time, false alarm rate, et cetera and even for some CPM systems to try to put it in terms of not just the flow rate that you can detect but how fast could you detect that leak, what is the false alarm rate, et cetera, would help with that perception.

One of the things that you hear a lot from vendors is that there is a little bit of a disconnect in them understanding what kind of leaks are really out there. While third-party damage historically has been the largest attributed factor for causing the leaks there are different mechanisms for leaks including corrosion and corrosion can come in the form of pin holes. You can have cracking in the line. Particularly for external systems that rely on some kind of fluid property or direct contact, understanding the mechanism of the leak is very important. If there was a way with all legal considerations, proprietary information, PR things to somehow disseminate more of that information, in a blind manner would help vendors understand what they are trying to design their systems to.

Not to beat you too much on the head with this, but I mentioned many times in this presentation that there are a lack of benchmarks and standards particularly with respect to CPM systems. There is no set of criteria that is universally accepted. Vendors are having to respond on a case-by-case basis which then can be something that is very costly. And so in addition to the actual how it's performed also providing guidance on instrument selection. So some of that exists in things like 1149, for CPM systems. If you had a rare fraction way system and you want to pick a dynamic pressure system or distributed acoustic or distributed temperature system, there aren't benchmarks for that.

One of the key factors is what happens on the back end? So I was mentioning one of the large parts of the response time is not so much how long it takes the system to generate alarm. It's how long it takes the user to make a determination of whether or not that alarm is actually the result of a leak. If there was some standardization about how that information gets communicated, that might help with that process.

Operators are either having to learn a specific set of responses or they are having to use third-parties to help interpret that data. If there was a more standardized way of communicating that and even being able to communicate with SCADA systems, et cetera.

One of the challenges is stability in the marketplace. Some of this comes out of the fact that smaller technology firms may not have the financial resources. Using something like joint industry collaboration is one way of providing they will opportunities to test their product. If you have a benchmark for them, it allows they will to comprehensively test their systems under a commonly accepted set of guidelines without having to incur the costs and resources to run a bunch of different types of tests.

Also by sharing the results it provides context on results. A common thing that operators bring up is that a vendor -- Dave mentioned this this morning, might quote their technology as being able to detect a leak of this size. When you look at the context of it, was it done in steady state conditions? If it was done for external -- in steady state systems, if you have a fiber optic system, how much of that cable was actually affected by the leak when they did the testing? Did they put all 10 miles of cable at that condition or only 3 inches of that cable at that?

By sharing the results and putting it in the context of common benchmarks would hopefully allow for more stability within the market.

Thanks.

>> LINDA DAUGHERTY: Wow.

So thank you very much. You ended quicker than I was expecting.

(Laughter.)

>> SHANE SIEBENALER: No questions.

>> LINDA DAUGHERTY: We are saving questions. Everyone got their note pad out, questions that you are going to take to the mic, right? Nodding your head.

People on the webcast, take notes and submit them. We are happy to cover them at the end of the panel.

Next speaker is Rick Kuprewicz, president of Accufacts. I understand people in the back are having a hard time hearing us. I'm going to try to speak louder and ask all the panelists to speak louder when they come up to the mic, okay?

>> RICHARD KUPREWICZ: You want to pull up the program? I can't figure this up.

>> LINDA DAUGHERTY: Are you Power Point?

>> RICHARD KUPREWICZ: Power Point.

>> LINDA DAUGHERTY: It's right there.

>> RICHARD KUPREWICZ: Very good.

Thank you.

Thank you. I'm going to talk about the hazardous liquid pipelines here. Shouldn't take the full 20 minutes. If I don't, I'll sing.

>> LINDA DAUGHERTY: No, no, that's all right!

>> RICHARD KUPREWICZ: Then you're all going to tem I the room.

Couple of observations from the industry perspective as well as the public perspective. This leak detection stuff is getting a lot of discussion from the legal aspects as well as the need for it. There's been a lot of effort over the last 30 or 40 years, a lot of money being spent. It's a very frustrating process. Believe me, the last place you want to be is a control center operator getting leak detection alarms that are false. He doesn't need additional noise. It is not by accident that the control room management rules as they evolved over the last ten years starting with the C cert process started getting a handle on how many false alarms you're getting. My advice to everybody in the room, whether a public representative of a regulatory representative or the industry, is beware of the release leak propaganda. No one sells leak detection claiming it doesn't work. I'm not critical of the vendors here, please. I know there's a lot of effort going on. It is a real trap. You heard comments earlier today about this. Basically, you know, the claims have to be verified. That's a very frustrating part for the people who actually go to the expense of installing these or piloting, whatever.

But the bottom line is that if you start getting false alarms, you know, you're in trouble.

There's a big difference in what the public wants versus what they need to hear. Okay? This is a tough one. You cannot detect all releases. It is currently unrealistic. You need to somehow portray that information without sounding from an industry perspective you're spinning. Let's be clear here, the spin goes on both sides. I've seen it.

Welcome to the misinformation age, folks. It's what they want to hear. You need to start telling people what you can do and can't do. Try to be as clear as you can. You don't have to be defensive. Try to stay factual.

And we've all had this discussion today and a couple times, what we call the leak detection conundrum. The greater the potential for leaks, the greater the possibility of alarms.

I want to be clear here, the mind set that we are generating within the industry and within the public is that lower thresholds are always better. False alarms train operators to ignore real events. I won't discuss the criminal investigations we have been involved in over the decades. It is not a really nice place to be.

And usually at the criminal level they are not going off the control center operator, all right? Unless he's on drugs. Most of them are not.

Again, there's a serious disconnect between what the public want versus what the industry can deliver. I have to be very clear here because this is not going to make me popular today. Leak detection thresholds is a function of through-put makes no sense. All right? You're setting yourselves up. Think about this. It's the size of the hole, the pressure at the hole and it's the fluid.

It's rate. We need to shift the dialogue here to rate. It's barrels per hour especially for ruptures. And I've got to tell you we have had way too many liquid pipeline ruptures lately where the control center could not detect the rupture. I won't name names. It's more than one and it's really tough. I'm not discounting the ability or need to find leaks, but if you can't find ruptures, chances are you've got something wrong and you can't find the leaks.

All right? Real good chance you won't be able to find them. It's not your fault. It's a tough problem. You heard some of it today.

I won't dwell too much on the internal versus external. We already talked a lot about that today. Others will probably mention it.

My focus usually when we come in to the various schemes or designs, approaches, whether it's post incident vehicles or looking at the capabilities of various systems, and there's a wide variation. There's a wide variation here. We tend to first focus on the high volume ruptures. They should be something you should be able to detect, but it's challenging because you are dealing with a compressible liquid here, folks.

Then we see if we can go after the smaller leaks. It's tough. The whole challenge increases exponentially. We advise the primary focus to stay on ruptures for now. That's a good way to start. I'm not discounting that you don't need to look at the leak releases. If you can't do this part, the other part is chasing your tail and you're going to waste a lot of money.

Doesn't mean that you shouldn't try to make the effort, but try to be realistic about it. It's a research project if you're not careful.

Give you an example, for those who may not be familiar with some of the industry. A 50-mile long crude oil pipeline has approximately 35,000-tons in its inventory in that 50 miles.

You can give or take a futons. It's compressible. That means it really varies. Even though there's a lot of sophisticated algorithms out there. If you are trying to make corrections for, there the reality is, how good are you? How good are the algorithms and the measurements and sensors?

I keep getting this discussion in the industry and in the public. They think we can measure this in a refinery. A refinery vessel is dealing with a thick finite volume and furnish's lucky it might be a cull tons. It's a real challenge. We need to disconnect between this illusion we are creating with the public that we can do this in a refinery with a fixed boundary versus thousands of miles of pipeline running across the country. It's a real problem.

It is important for everybody to understand and this is something we need to communicate in the regulatory process because it miscommunicates. In some countries they actually have this in their regulations. You shall mass balance. Well, mass balance to a process engineer means something different, okay? You actually balance the mass. In the liquid systems you really are measuring volume and correlating to mass. Inventory correction noises, example that 50-mile 35,000 tons usually limits your ability to detect. It adds additional level or challenges of noise.

And if you are not liquid full, a slack line, the challenge gets several orders of magnitude greater. It gets really complicated. We had a conversation here some time back, I won't say who, and we were trying to say we need to move this line from a slack line operation to a liquid full line operation. And so what we had to weigh was: Well, wait a minute. Yeah, we can tighten up the leak detection balance but we are increasing substantial operating risks for a line that was going to run at substantially higher pressures. Really intelligent people in the room were having a dialogue. The public was screaming for better leak detection and we're going yeah, we can do that, but we are going to fill the line and it's going to increase the hell out of this pressure. Where it was located, it was like you've got to be out of your mind.

We have to convey to the public some disconnect or dialogue here in a manner that doesn't come across like you're trying to avoid the challenge.

I've already mentioned this, but I can't beat this enough. Beware the control center release false alarm over load.

It is usually after an event. One of the first things the regulators and investigators are going to look for and if you've got three false alarms per shift, you're probably not in a real good defendable position here, okay? If you've got one false alarm per month, okay, only you folks can understand your systems and how many alarms you are recording.

Are you setting up the control room operator for a failure? It's a tough job. Some of these pipeline systems are very complex. I've already mentioned about the lower false alarm thresholds. We have to get the mind set off of that. It's going to be tough because we have been setting people up that lower is better and we can really do this. I'm not saying you don't take that challenge and try to do it. I know a lot of you are trying that. Be realistic about the expectations.

If you are setting expectations here and the reality is you're here, when it does fail, the backlash is extremely severe.

In the internal leak detection systems, SCADA systems, simplify the alarm systems under the control of the control center management. You have to be adults about describing this, but it's hard to go ahead and say we'll accept the lower threshold, meanwhile you gave the control room operator another 100 alarms a week that are false.

For the external leak detection approach, there are many out there in the last ten or 20 years. Some are developing as we speak now. They have mostly, most cases limited applications in the field and how long the pipeline they can monitor. They can generate many false alarms from other hydro carbon backgrounds, as an example. The advantage is if they are truly leak detections. It's not like you have to shut down the system or a rupture where you drop thousands of barrels a minute here, hopefully.

From an internal perspective, I would advise the message that you focus on rupturing. The ability of the systems will be based on the number and types of the sensors and the algorithms. Simulations help in training your control 10 center personnel. I have to advise you, all the simulations in the world, Murphy says the event that you have is the one you haven't simulated. Time and again. That doesn't mean you don't go through the simulations and use the sophisticated tools to train your system, but be aware that simulations will not compensate for possible gaps in your leak detection approach.

Already mentioned the smaller problem of the leak detection is with the CPM systems.

External systems, advise focus on leaks. Many different approaches are developing. We heard a couple today, some on the noise, some on frequency, hydro carbon identification, several approaches related to fiber optics. Some, I think you've seen some for temperature. Some are for frequency. There are some advantages. The various approaches.

What I look for in external is: One, does it really have to hit the fluid? With a pipe shadow, the sensor from the release. Because Murphy will say if it's sensitive to the fluid and you have it on this side and the leak occurs on this side, you may or may not pick it up. Those are the kinds of things we look for in evaluating external leak detection viability. You get false alarms with externals. That's all I had.

>> LINDA DAUGHERTY: You did it too me, too.

>> RICHARD KUPREWICZ: You're scaring the hell out of all of us.

(Applause.)

>> LINDA DAUGHERTY: Thank you, Rick. That was ... okay. We have

some questions coming in. That's good. We are going to hold those

until after all the panelists speak.

Our next speaker is Dr. David Shaw, the managing director, Technical Toolboxes Consulting.

>> DAVID SHAW: You have a Power Point.

>> LINDA DAUGHERTY: There you go.

>> DAVID SHAW: Thank you, Linda. I have the privilege of working with not just one but a large number of pipeline companies and I also have a background in research. So what I would like to talk about is kind of the interface between research and the newer technologies. Not just a few select pipeline companies, but I would like to bring out the bulk of pipeline operators into the discussion as well.

So the other thing I would like to do is to make sure that we leave the workshop having covered all of the topics that were in the program. So what I'm going to try and do, and remembering I've only got 15 minutes here, is to try to at least hit each of the topics from the workshop program and pick out, if you like, to me the biggest elephants in the room under each of those topics.

So let's start with the very first topic. The first topic was: Well, what is the current state-of-the-art for liquid pipelines?

And let me perhaps bring out something up new. There's really two worlds of liquids pipelines in terms of leak detection. They are the guys who are typically pipeliners, the guys who do the high volume interstate pipelines and I don't want to exaggerate, but they really do focus on internal LDS. Once again internal means that I take what I think is the state of the pipeline based on measurements and then a model. That's why it's often called computational pipeline monitoring. And I compare that with the actual state of the pipeline, which I take from measurements on the pipeline.

Therefore, it's heavily dependent on instrumentation like low metering flow measurements, temperature and so forth.

Now, I will stick my head out and say that the actual fluid dynamics of a pipeline is fairly well developed. I would highlight that the better systems have a really good deviations analysis algorithm. In other words, how do I decide whether the state of the pipeline is different from theoretical.

I would also say that the better systems today make heavy use of statistics. And everyone is kind of thinking about this as cutting edge. Well, it's not, folks.

API 1149 identifies these methods and this is ten years old. So that is on the internal side.

Now, there's another world of pipelines out there. These are typically the behalf product pipelines. Guys who come from a process background believe in instrumentation. They believe in external instrumentation. So they are into the sensors world. They are looking for monitoring the air; monitoring the soil; monitoring the water if it's a river crossing.

And they are into acoustic and pressure sensing. So I'm going to bring up my first message under this topic here. I would say that the state-of-the-art LDS combines principles, not just based on flow measurements in modeling and not just based on acoustic or external sensing of some kind. It combines the two. That is truly the way to get something that works very well in this kind of environment.

Which is a good way of leading into redundancy and backup. People talk about backup a lot. And I would say that there's a difference between redundancy and backup. Redundancy is when I've got two independent leak detection systems that are complementing each other. And that is typically running in parallel and I do mean in realtime. I won't take the excuse of yes, I patrol the line every week or so as a redundant system. It is not. In realtime two independent physical principles backing each other up and verifying each other. Of course, you still need backup systems. It always amazes me that in normal automation and control we have duly, triply redundant failover backups and so forth. Certainly in SCADA systems and we have one leak detection system running away in the corner. It doesn't make sense.

So I'm also very much encouraging the approaches we saw this morning, which were that you have multiple different ways of doing the deviations analysis, for example.

I'm also trying to get this one out of the way. Nearly everything -- and I know that most cable technologies are expensive to retrofit because they involve a lot of labor and manual work. But a lot of other systems can be retrofitted. And so also to say something unpopular, the issue is it's easy on a new pipeline because I'm flush with CapEx. It's difficult on a running pipeline because it's operations budget. Let's say it.

Now, and the bigger elephant in the room is, I put in an LDS and I'm not improving throughput. I'm not getting new customers. I'm not improving my profitability. It's all about risk. Now, I really would wish that pipeline operators would just sit down and say this is my level of risk. I am willing to accept this level of spill. Because that's what you are doing when you don't spend money on an LDS.

Now, I'll complement Rick for bringing this up just now. The whole of the regulation area tries to cloud this. It tries to say: I want to detect a 1 percent leak in under five minutes. Well, folks, 1 percent on a 100,000 barrel pipeline is a awful lot of oil. Now, what you really mean is what is the size of spill that I am going to be able to accept?

So I think that the whole area of how much I'm going to spend on Op ex-is how much risk I'm prepared to maintain.

False alarms and misses. This is the big one. And let me put it -- let me just follow-up on what I just said. Every time you fiddle with your threshold you are increasing your level of risk. That's okay. Just say so. And so what you really are trying to do here with traditionally based fixed thresholds types of leak detection systems internally based is that you are trying to minimize operator controller, I should say, nuisance. Let me just bring up something again. If I do have a well-engineered leak detection system with multiple inputs, the multiple inputs might be two separate leak detection systems complementing each other. The state of the pipeline. This morning we had a question about how we would use an ILI PIG log. If I'm in an area where I know that I'm more prone to corrosion or nearer to heavy traffic, and therefore third-party damage, I'm going to drop my threshold. Surely. Because it's part of an overall complex risk calculation, rather than just give me a threshold and I'll be within my 1 percent legal requirement.

Human factors. I'm going to bring up, just going to hit the second one really hard. A real problem with pipeline companies is who owns it? Is it going to be engineering? Is it going to be compliance? In which case I just fill in forms and make sure I'm DOT compliant and walk away? Is it going to be instrumentation and control?

Those guys, again I don't know want to make too many enemies, really want the ac me mark five leak detection system. What is the rating? What percent? How long does it take? What is the reliability? Repeatability?

What you really need to do and I know PHMSA is very, very strong on this one. It's really part of integrity management. Now, integrity management to many pipeline companies means the defect prevention part. So they are all the corrosion specialists and the inspection guys.

Integrity management is really a circle. You start from as-new. You try and avoid the leak happening, but it happens.

You detect the leak. You shut the leak off. You repair the leak. And you bring it back to as-new.

That is integrity management. So it is very difficult to engineer a leak detection system without that whole cycle in mind. It is pointless having a leak detection system that sound an alarm in five minutes when it takes you three hours to drive down the road to shut the valve off. So the whole thing has to be considered as a whole.

Environmental and operational issues. Naturally the more noise going on around the leak detection system, the less performance you can possibly expect. I do want to bring this up because -- and it's not the DOT regulated right now, but as we speak there are some massive production operations going on upstream production operations going on with miles and miles and miles and miles of unregulated pipes that one day will be regulated.

Now, so in very crowded environments I think that that kind of issue for the research folks especially is going to become very important.

Now, we've mentioned transient operations as being a killer for internal leak detection systems. I'm going to say once more, okay, back it up with an external system too perhaps.

The perfect is often the enemy of the good enough. If you have two systems that are 80 percent reliable and you combine them intelligently, you are going to get yourself a 90 percent reliable system. And so that is really the concept here. Don't throw it away because it is not perfect. Back it up with something else.

Let me just highlight my favorite emerging technologies. I think that here is a few things that are really happening as we speak in terms of research. I think that the atmospheric area especially, atmospheric sensing is almost space age. I mean, it's very, very advanced.

We're now talking about being able to take satellite photographs of pipelines and detect leaks from space. And that's the kind of thing that we are now seeing as practically possible. This might be a complete quantum leap in how we do leak detection in general.

What we need to also think about is that one thing that kills internal leak detection systems is poor instrumentation. And the expense of instrumentation. I can say that in the last couple of years $100,000 instruments are now becoming $10,000 instruments so that there is the excuse of I can't afford more flow measurements is kind of going away.

I would also say -- once more, these technologies have been around. Things like DSP and patent recognition. They are actually becoming practical and are available from at least a couple of off the shelf vendors. I know they are not getting much traction but you should be looking at these because they are practical right now.

And going back to the upstream environment, I think that people have just basically said: I give up on production flow lines and so forth, simply because I can't do multiphase metering.

I would say withins two, three-year time frame we will have practical $10,000 multiphase metering that you can be using in that kind of area.

So I hope that at least I've caused some food for thought and at least I've hit the major topics here.

So I look forward to a whole bunch of questions a little later on. Thank you very much.

(Applause.)

>> LINDA DAUGHERTY: You know, I think I better put my sign away.

Everybody is finishing before I even, before you even get close.

>>: Keep us scared.

>> LINDA DAUGHERTY: Keep us scared? We have back with us -- looking to make sure I don't say the name wrong, David Bolon, the director of pipeline and facility control systems with enterprise, but he's representing PRCI. Thank you again.

And I forget, were you the pdf?

>> DAVID BOLON: It's pdf, yes.

>> LINDA DAUGHERTY: This one is up. Is that your last one?

>> DAVID BOLON: That's it. That's the one for this session.

Thank you, Linda. Can everybody hear in the back of the room?

Okay. As Linda said, for this session I'm speaking on behalf of PRCI about the work that has been taking place for improving leak detection system effectiveness or leak detection research activities. I'll be speaking this morning on behalf of PRCI. This afternoon Mark Piazza will be speaking about gas pipeline systems. There is overlap, complementary technologies taking place. You will hear specifics about leak detection system, but some of what Mark will talk about is also applicable. I will cover past, present and future activities based upon what Robert asked me to cover. Very briefly, past, present and more about what future industry needs are in the research world.

Past. We have had this ongoing project on small leak detection in liquid pipelines for a number of years now. The objective is to push the state-of-the-art and ability to push small leaks in hazardous pipelines. There are a number of projects that have taken place over the years starting in 2006 with gap analysis to find out what the industry desired and what the leak detection providers were providing at that time. It continued on in the 20082009 frame with trade study, evaluating the different technologies out there against what the industry listed as their top priorities. Those were about 40 different technologies that were evaluated. Some from commercially available to some very off the wall ideas developed during brainstorming sessions.

Of the 40 technologies, two bubbled to the top of the list. They went into lab testing in 2010. So the two that went into the lab testing as showing the most promise for the most immediate deployment by pipeline operators were the acoustic or negative pressure wave technologies and the distributed temperature sensing technologies.

So you have heard some of those discussions throughout the morning already. But we went through lab testing with those in 2010. Report came out in early 2011. And it was decided to take the acoustic or the negative pressure wave technology forward to field testing in 2012. I listed the funding levels down there. This does not include the in kind funding from the operators or the vendors involved in this testing effort. The total funding has been approximately $600,000.

The present activities in leak detection. Let me talk a little bit about the field testing of the acoustic, leak detection technologies. The research objective is to conduct a full scale field test of several different acoustic systems on a production pipeline to determine if they can detect leaks while minimizing the non-leak alarms. The deliverable out of this will be the evaluation criteria listed below, leak location, smallest detectable leak, tools, configuration time, nonlegal alarm rate, response rate, it will be guidance to operators on complementary technology.

This is scheduled to take place in 2012. Work is already underway. It is a funded effort right now. We expect it will be completed by the end of 2012.

Also taking place this year is an update to the API 1149 document. This is -- I have a wonderful title, a new look at pipeline variable uncertainties and their performance. This is a document that API has published ten years ago and it allows operators to predetermine leak detection sensitivity performance for given pipeline configuration. So what we use this for is to look at a pipeline and analyze if we change out a meter to have these better accuracy or repeatability specifications, what performance improvement can we detect in the leak detection system.

So it's an offline tool to allow us to do that. The current API 1149 document addresses crude oil products under steady state conditions. This update will expand that to address not only crude but also refined products and the HVL fluid as well under steady state and transient operations.

The benefits will be, we'll be able to determine up front the leak detection sensitivity improvement before committing to those improvements. Budget of nearly 400,000 over a four-year period.

The third one taking place starting off this year, research for small leak -- we are looking for an alternative to FS6 because of the greenhouse gas implications of FS6. We are looking for alternative ways to determine small leaks under hydro static testing. The budge it is $88,000.

What I want to spend time talking about is the roadmap or where the industry cease future needs for leak detection.

The roadmap is a work in progress, basically underway for a year now. Started in early 2011. It is circulated for review and continues to be circulated for review by various stakeholders. The roadmap is a living breathing document and will continue to evolve as improvements takes place and addresses both liquids and gases. That is what Mark will be talking about this afternoon. I have the following slides. I want to show the graphical view of the roadmap.

I'm not going to go through all of these in detail on this chart because there's five more charts that have the details pinned behind it. What I want to indicate is that we are starting with the end in mind. There is a business driver out here that we are trying to achieve through all of this research in the leak detection world. We are trying to reduce detection time, spill volumes associated with pipeline integrity breaches. That's the overriding business driver of all this research.

To achieve that, we've identified five strategic goals. They are included in the area I circled with the pen here along with the major pipeline or the road. There's five strategic goals. For each strategic goal, it's a high level goal that is pretty vague in terms of what we are trying to achieve, but for each strategic goal there are research objectives. That's where we tried to take that goal and to quantify what we are trying to achieve for that goal. And then beyond the research objectives there are a set of projects that will helpful fill those research objectives. This is an overall one page graphical view of our roadmap to help explain on other operators and for discussion purposes say here is what we're trying to accomplish. Here is how we are trying to accomplish this. Here is the research we need. We can start to take a look at how long this will take, how much money it will cost. When will we be there at the end of the road. We are not executing a series of research projects one after another. It's in the context of the overall programmer complex.

Let me go over the five major areas or strategies that we have outlined so far. As I said it's a work in progress. The first one is, you'll be glad to hear this, highly --

>> RICHARD KUPREWICZ: Did you see my slides?

>> DAVID BOLON: I did not. It's amazing how we Colorado together on these things?

>> RICHARD KUPREWICZ: Great minds think alike?

>> DAVID BOLON: There you go. This applies to both liquids and gas. To develop a means to consistently detect leaks in pipelines. We took it further, the end point to this objective should be to have an automatic shut in signature for a segment when a rupture is detected. Proposed research and these are subject to, detect a large leak, greater than 50 percent leak rate, 99.99 percent

certainty in less than five minutes. Under all operating

conditions.

So as we have had discussions about this strategic objective, we believe that the technology is out there today. It's not a technology problem that we are facing today. It is a process problem. It is a best practices problem.

We believe that some operators are doing this today. They are very good at doing this but not all operators. We need to come together as an industry and have the means to do this. The required research or the needs are to have a best practices document which is knowledge, and a risk analysis in support of leak detection knowledge. Bringing the minds of industry and vendors and academia and the researchers together to take a look at this problem and figure out how can we address in a very, very reliable manner the pipeline rupture detection problem.

You have heard that discussed this morning by Richard. It has been discussed by members of API, discussed by NTSB. The industry needs to solve this problem with very, very high degree of reliability.

So that's the number one objective there.

Number two is continuing R&D on small task size detection on liquid pipelines. We would like to develop a means to confidently identify smaller leaks in a shorter amount of time than is currently achieved today. So that proposed research objective, to take 1 percent of current flow rate in less than five minute with 95 percent confidence level. And Richard, I'll talk about this percentage of flow in a little bit because I know you made some comments about that earlier. That not being a meaningful statistic or characteristic of leaks.

And I tend to agree with you on that. One of the research objectives is about system effectiveness.

But to continue to push the boundary on small leak detection is the research objective. We're looking at research projects. Field test results from promising technologies. PO1-one, the field test on acoustic or negative wave false into that category. Fiber optic based or thirdly the field test environment. We have vendors and Shane talked with smaller vendors coming forward and saying we have this great idea for detecting leaks. I need a vendor to test it out. To test new technologies on our pipeline systems is a thing that we are not very much inclined to do because we are a cautious industry. Putting changes to our pipeline, we analyze that. We carefully study those. We are reluctant to do that if there's any chance it would increase the risk to the pipeline.

What we are looking for here is afield test environment, some place where we can go and test out new ideas, new technologies and release the product that Shane was talking about or release alternatives to the product and be able to test out and prove to the industry community that this technology is worth moving forward to deploy and pilot efforts.

That's number two is continuing R&D on small leak size detection.

Really?

Number three, metrics to measure leak detection performance. So this gets into what I was talking about, Richard. There is a lack of industry agreement about how to measure leak detection system effectiveness and we talk about percent of flow. We talk about time frame. We talk about confidence levels, but there is not one standard way to look at this. I agree that looking at the size of the release as opposed to percent of flow is very, very meaningful. A 1 percent leak on a 10,000 barrel an hour pipeline is much more of a catastrophe than a 1 percent leak on a 400 barrel an hour pipeline.

So we need to take a look at how to measure leak detection pop answer. I would like the research to look at all aspects of leak detection program, the CPM system, layers of the defense, SCADA performance and human factor performance of the controller. What we suggested is an updated API, CPM measurement standard, some kind of way to know how do we know that the systems are performing in line with the risk level of the pipeline?

And then along with that leak detection testing methodologies, how do we know that the system is going to bear out what we say it will do? How do we test it to prove that it will actually perform as expected?

Number four, facilitate more rapid implementation of C p.m. systems. This was discussed a little bit this morning in terms of the tuning time it takes to be able to implement and put these systems into production for a controller to monitor.

Develop a means to be able to more rapidly implement CPM systems on new pipeline systems. Current systems can take on the order of months to implement for a complex pipeline. That's not only to install the hardware and the software, but to tune it out to make sure that it's detecting the appropriate level of sensitivity with a minimum number of false alarms.

The research objective should be days versus months. This is a nemesis for those of us in management in the pipeline operations world. It takes a long time to put the systems in place and to tune them out and to make sure they continue to perform as they are desired to perform. Research to identify roadblocks and methods to overcome them.

And finally, leak detection program effectiveness survey. The integrity management program, was mentioned it should be part of integrity management. This is a take off on the integrity management report that companies are required to produce. It will be beneficial to industry to have a means to measure whether leak detection programs are reducing the response times and spill volumes in given releases over a given period. Research to determine the data to be given over time to determine that the risk level is appropriate for the pipelines.

Coming together on what data should be collected, how often it should be collected, looking at year over year leak detection program in minimizing spill volumes associated with the ruptures.

Those are the five areas we identified today in the leak detection roadmap and I'm glad to have a chance to bring it forward and to discuss it and get your input on that and questions about that. As I said, Mark Piazza basically has the other side of the story this afternoon when he talks about gas and some of the aerial surveillance program that tend to apply to the liquid pipelines as well. Thank you very much. I appreciate your listening.

(Applause.)

>> LINDA DAUGHERTY: You know, it seems like there's never enough time. You hear, we have our panelists from both this panel and the previous panel. And I always have more questions. I feel like we never have enough time for dialogue. I guess this is just the start of the process and we have more dialoguing to done and we will have opportunity to be gain input from everyone.

I do have a question that came in from the Web. Thank you.

I'm going to start right into them. How is the benchmark data currently established for CPM type leak detection systems?

Any takers?

>>: Shane, are you willing to take that?

>> SHANE SIEBENALER: Not really.

>> LINDA DAUGHERTY: I got some chickens up here.

>>: Aww!

>>: Go ahead and ask the question again.

>> LINDA DAUGHERTY: Here is the question: How is benchmark data currently established for CPM type leak detection systems?

>> DAVID BOLON: I'm not sure, is the questionnaire here to clarify

what they're asking?

>> LINDA DAUGHERTY: No, webcast. Wave to the Web difference Dave wave to the Web.

(Chuckles.)

>> DAVID BOLON: To me a benchmark would be something used across industry. How is industry doing across the average industry benchmark. There is no agreement on system effectiveness. I've said that a couple times now. People have their own ways to define how their system is working from a leak detection effectiveness. Percent of flow is used very, very frequently. We know that there are problems with percent of flow.

We know that people aren't coming forward and addressing the false alarm rate when they talk about percent of flow that is able to detect.

So basically there's not an industry benchmark that says the average industry capability for leak detection is this. It's just not out there today.

>> LINDA DAUGHERTY: Okay, fair enough.

>> DAVID SHAW: Can I follow up?

>> LINDA DAUGHERTY: Please. Pull it close to you.

>> DAVID SHAW: Yes, let me repeat the answer. The answer is no. The other thing is, I think it's worse than that. I don't think we, even if we were trying to benchmark internal based leak detection systems, we wouldn't even know how to set up the table, the ranking, the scoring. And let me also repeat something which was said earlier. Study after study after study will tell you that the same exact computational based leak detection system on two different pipelines will give you different performance. So even if you had a benchmark, I don't know how valuable it would be.

Those were just my comments.

>> LINDA DAUGHERTY: Thank you. I know there's people sitting out there that really want to step up to those mics. Please do.

While you are doing that, I encourage the people on the Web to continue to be send in questions.

I have one from here in the room. This is for Dave.

Are you concerned about the pressure control implications of automated shut downs? Now, how can accidental main line block closures be avoided if the system is automated?

>>: Which Dave?

>> LINDA DAUGHERTY: It's for you, but if you have an answer, why don't you both answer?

>> DAVID BOLON: Let me start. I thought this was coming out of the my number one strategic slide I had up there where I said we should be able to handle rupture detection so well that we are able to implement automated shut-in systems and what I envision and it has to be fleshed out is the, some system, some software system would be able to crunch the numbers and indicate that there is a rupture on the pipeline and then for that given segment there is a set of predetermined steps that the SCADA system or the leak detection system or whatever would take to safely shut in that particular pipeline.

You know, so the over-pressure situation would be addressed by the analysis that would say, okay, here is how we are going to safely shut down this pipeline. In the case of the leak detection system identifying a rupture.

The other part of the question dealt with inadvertent or accidental closures.

>> LINDA DAUGHERTY: Right.

>> DAVID BOLON: That gets into we are looking at large detection ruptures in our pipeline. Systems that have a high level of confidence, 99.99 percent is what I threw in there as a confidence factor. This is always a difficult step for the operators to take, to remove the human from the loop and say we're going to turn it over to the system and allow the system to shut in the particular pipeline system without the human involved in that loop.

It's difficult for operators to do that step, but I think the technology is there today. I think research could be undertaken to prove that reliable systems with high degree of confidence can be built out so that we are not inadvertently shutting in pipelines in an unsafe manner or inadvertently, accidentally without ruptures having to take place.

>> LINDA DAUGHERTY: Thank you. Dr. Shaw?

>> DAVID SHAW: I couldn't have put it better myself. I think the issue is you engineer these systems. So you don't, you don't shut the valves on the basis of just like one data point maybe or something that has got a 95 percent probability of confirming the leak.

What you have is that you have one leak detection system and another leak detection system and there's this risk factor and so forth tacit to a 99 percent level.

That's when you would activate the control automatically.

>> LINDA DAUGHERTY: Okay. Rick?

>> RICHARD KUPREWICZ: I was going to comment. Tomorrow's presentation for those who won't be here, we'll address this issue, both liquid and gas. You want to look at that presentation. It is going to flow right into the comments we heard earlier about you never rely on a single point. You go to an independent, not redundant but independent signal system.

I can tell you this was a very sensitive issue after the terrible Bellingham rupture tragedy. The operator there figured out a way, to their credit. It was a good idea and it works.

>> LINDA DAUGHERTY: Thank you. I don't know who was here first. Let's go with you first and then we'll catch you, Keith, okay?

>>: Jason of Marathon Pipeline. Really a follow-up to that question. It sound good having an automatic shut-in. Ultimately our goal is to reduce the consequence to the public, to the

environment. I guess I'll wondering, how do you factor in, you have a leak between point A and point B. You may want pump station B to continue running to pull product away from the leak because it's in between the two points.

How do you factor that in knowing if you shut in you may increase the consequence versus keeping pump station B running to lower the consequence?

>>: If I could begin to address that, there has to be an engineered response in every case to the rupture. Think of a set of tests that an operator would go through. If he saw that particular situation. And being able to program that into a computer system. I agree, you know, keeping the downstream pump running to pull the product away from the breach is the typical steps that an operator would take and that's what we would want to have the system do.

Don't misunderstand me that this is a current thing that we are going to roll out in 2012. We are suggesting that this is a research area that industry would like to see pursued and all of these problems being brought up as far as inadvertent shut-downs or incorrect steps being taken, those are what need to be investigated and to be understood and to see if this is possible.

It's a goal out there. It is a long-term goal of being able to do this.

>> LINDA DAUGHERTY: Any other comments from the panelists on that one? No? Okay, you're up.

>>: Keith Labis with P-Tech. It's a follow up as well and also to the consequence. One of the reasons we are here as engineers, we are doing a pretty good job, we think. However, the neighbors that live along the pipeline think there's a humongous gap. There's a difference in perceptions. Perceptions in consequence are difficult to handle as well. We have the industry here, which are, I think

we're doing a pretty darned good job and we have the public who think there's a horrendous gap. We have GAO and regulators looking in trying to do the best they can, right?

One of the things, if we introduce technology before its time, the public needs to also buy into the fact that there could be more outages. We really haven't talked about that. We talked about the price of gas going up in Chicago, where I'm from, because there was a pipeline break. So there's also a relighting, things of that nature.

So the public needs to, we need to communicate that and there were a couple lads here on this panel who were beginning to discuss that. So we have a perception. Linda is telling me that maybe we need to talk about this over lunch.

(Laughter.)

>> LINDA DAUGHERTY: Yes.

>>: We have a perception gap and I think we could use some guidance on how to do that.

>> LINDA DAUGHERTY: Okay.

>> RICHARD KUPREWICZ: I'll comment on that as a Haz OP leader. Never underestimate the ability of a room full of very smart people including engineer to come up with the stupidest solution. I don't say that to be demeaning lip.

>> LINDA DAUGHERTY: I hope he's not referring to us!

>> RICHARD KUPREWICZ: I'm guilty of this. I have built in checks and balances so I don't go whacko. All of you have information coming in at you at the speed of light. It's an easy and compartmentalized approach to miss the effect. In the '80s it was getting out of hand and they had the regulation that said this is what you need from a management process and if you follow these steps it will keep you out of trouble.

There's a similar process in the liquid and gas side of it. Not criticizing any particular engineer, most of them are well meaning. As you get compartmentalized you might not focus on the system perspective and in terms of the automatic remote control systems. You look at the system. You can't say I put this in and look at the ramifications. That's the message, I'm not speaking for the others, but I'm hearing that that works. That's a assumption -- if you can convey that process, the public will be, they still will be reactive if they think they are being spun, okay. But there's a large body that I have seen consistently, if you are honest and straightforward, most people will cut a little slack for you. It's when they get the impression that they are not being, you are not being honest or somebody is being evasive. I advise people all the time: If you don't know the answer, it's okay to say you don't know.

>> LINDA DAUGHERTY: Okay, thank you. It is definitely a challenge. I have one last question and then we will break for lunch. So is that an indication to go fast? Currently CPM system performances are tested with by fluid withdrawal and simulated leak tests. How effective are these tests in giving an idea of the performance of the running CPM?

Shane has an answer.

>> SHANE SIEBENALER: In addition to actually doing withdrawal tests, you can stimulate the actual process variable. So if you want to look at, you know, what if my flow went down X percentage, you can actually send the system live, you know, basically sill lated data to test it.

I think that as long as you keep it in the context of what operating conditions that CPM system is monitoring, for example are you doing this in the middle of a line pack? Are you doing it when a pump turns on or off or a valve closes? Often times if you only would do it in the steady state case you may be missing something. I think that between sending simulated signals and doing withdrawal testing under the right conditions that you can accurately quantify the ability of that system to detect that leak.

The other thing you need to do when you're doing that test is to see if the system is alarming to other events that actually aren't happening.

>> LINDA DAUGHERTY: Okay, thank you. Any other comments? Are we good?

>> RICHARD KUPREWICZ: Let me add one more comment. This came up during the post Bellingham issue. The first thing was, we are not going to simulate a rupture, okay?

(Laughter.)

>> RICHARD KUPREWICZ: That was a no-brainer. We had to explain that to some fairly understandably people who were raising serious questions.

I think the application here is mainly in the leak end of it, trying to validate that other. And what you do is, you do have to use science and engineering approaches. I mean, I haven't been to the moon, but I can tell you you need air to breathe, okay? There are certain things that follow the laws of science. That's the thing that we keep asking people. If you are stepping beyond the realm of the laws of science, you may be in trouble.

>> LINDA DAUGHERTY: Science tells me we are standing between people and lunch. Thanks to the panels. They did a great job. I want to thank everybody.

(Applause.)

>> LINDA DAUGHERTY: Okay. So we will reconvene at 1:00 o'clock sharp. There are a list of restaurants in the area out on the registration desk. Thank you all.

(A lunch break was taken at 10:55 a.m. CDT.)

(The meeting is on lunch break until 1:00 p.m. EDT)

>> ALAN MAYBERRY: I'm Alan Mayberry, Deputy Associate Administrator for field operations at PHMSA. I'd like to thank Linda for a fine job moderating the morning panels. I'll take care of the afternoon two panels. The topic today of panel number 3 is considerations for natural gas pipeline leak detection systems. So we're shifting gears. Morning session

was dedicated to liquid pipeline. The afternoon will be natural gas. So for that, today we have for this panel representatives from the federal pipeline -- federal pipeline safety program, as well as the state program, and also operators represented today.

And the charge documents that were given to this panel, similar to this morning, were -- of course, the regulators are going to talk, give some regulatory perspectives, but there will be discussion on the current state of leak detection usage, ways to improve, how to factor in -- I think this morning it was talked about a bit -- was redundancy and backup systems, but how to factor that in. How does CAPEX and OPEX funding come into play? Environmental impact of decision making on leak detection systems.

And, of course, you know, related to this topic, as you all know, we have -- there are also recommendations from the National Transportation Safety Board for PHMSA related to leak detection systems that really cover the gamut of detecting leaks from the transmission side of natural gas through to distribution, which presents an interesting opportunity, and I'm sure Rick Lonn will speak to that.

To get started, I would like to introduce our first speaker today, who will be Jeff Gilliam, PHMSA Director of Engineering and Research. Jeff? It's not break time yet.

>> JEFF GILLIAM: Well, good afternoon. I hope everyone took in plenty of caffeine so you're wide awake now and not too much comatose out there. One thing I did want to point out, to begin with, I'm sure everyone is aware that this next month is Dig Safe Month in April, and I think the industry and also the federal agency and state agencies, this is a good example of where we work together, made huge improvements in the industry, and I just want to thank you and give you some kudos out to industry, and I think it's a good example of success when we can work together.

Just a couple of things. I've got several slides, so I am going to hit the high points, and I am going to go fairly quick, just to put you on notice.

Three things I want to cover is general perspectives, system specifics, and some recent actions that PHMSA has taken.

This is a very simplistic schematic, as you can see, of basically gas from the wellhead to the burner tip, and there's lots of moving parts in between. Right? It's very complicated, you know, potentially. And of course, what we're after is to prevent major leaks, ruptures, those things that cause basically significant incidents and fatalities. That's what we're after. We want to prevent those, just like everyone else, and hopefully we can find some new technologies or partner with someone later in the year during our research forum so we can develop those technologies with industry.

The key points here I wanted to point out was leak detection system depends. It depends on the system. It depends on if it's real simplistic, real short. You know, you don't need a lot of complexity in those type of systems. When you have a cross-country, multiple connections, large volumes being transported, then perhaps you need to consider very complex leak detection systems.

There's lots of trade-offs, right, that comes with cost, liability, sensitivity, et cetera, as noted.

Public and environmental safety is the priority. That's the number one priority that we need to keep in mind. There's different simplistic types we've used for decades. There's the visual, and there's also new technologies that we've married up with the visual, whether it's fixed to an aerial vehicle, helicopter, fixed wing, or some people are looking at these UAVs; right? But there's also the time when you just want to be out there where it's very densely populated and you are doing your typical leak survey you do in a class 3 and 4. All of those methods are verifiable, valid leak detection methods.

Now, whether we need to marry that up with new, more sophisticated techniques will depend. Right? On what this study comes out with and perhaps some research initiatives that we come up with over the summer.

Simple. This is the simple way. A guy is out there, he looks -- or a lady -- and he looks at the pressure gauge, he takes the reading, he radios it in. Yes, the dispatcher can take the information, and we say everything looks fine.

Now we get into the more complex systems, whether that is using a radio tower, or that could be a microwave tower, cell tower, or you could be also using satellite; right? It could be very complex, and yes, some of those systems are expensive.

Under the general perspectives, small pipelines. Right? Complexity increases. Complex leak detection systems. SCADA systems employed in many pipeline control centers are very sophisticated. Some of them, as I alluded to in the graphic, have a lot of moving parts. They require a lot of calibration. They require a lot of technicians to make sure everything stays in calibration in order for those systems to work properly. I think everyone understands that.

Some very sophisticated systems could improve, though, on design, management, and operation. The key point here between automation and people. Again, it depends on the system. If you don't need it automated, you need probably people to be involved more; right? Or, regardless of if it's automated or sophisticated leak detection system or it's manual, you must have well-trained, competent and vigilant employees. Basically, it boils down to the safety culture; right? That's a mandatory aspect for successful companies and programs when it comes to safety and leak detection.

What is the gas-specific considerations? I'm just going to hit the high point here. Basically, the risk/reward considerations when trying to push more volume overall through the pipeline system, whether that's the new, large-diameter, high-pressure systems or it's the older systems where we're trying to maximize the efficiency through those. Those are going to have the highest levels of risk potentially, thinking of risk as likelihood versus consequence; right? And I'll link that a little bit more tomorrow when we get into talking about valves.

Comprehensive leak detection program. A shared responsibility with all stakeholders. That means it's not just the -- I don't -- I shouldn't say it this way, but I don't think it's just the responsibility of the company. It's also shared responsibility on the regulation side and the public. Just like the 811 program. People need to be aware of what's out there, what's under the ground, and be aware of the consequences when you don't follow basic regulations.

Take into account interactive threats. Where is that important? We've seen some recent incidents of that through different areas where increased rainfalls caused heavily clayed soils where they had slope toe failures, basically, and movement amongst pipelines, causing failures, and they were basically failures regarding historically benign construction defects that when they had interactive threats acting on them, it led to a failure. All of those things we need to be aware of.

Lack of appropriate mitigation following detection affects outcomes. What am I trying to say there? Basically, one, you've got to detect the leak. Can you respond to it promptly? And if you do so, it will mitigate some of the consequences.

Here's a classic photo from Sam Bruno. I can't tell you if that's in the first 15 minutes or an hour later. I think the visual probably looked about the same. Okay? Because if you don't shut the gas off quickly, the fire plume and the fireball doesn't get any smaller. That's the basic facts.

Are all key personnel involved? When you're involving the decisions. Is the emergency responders involved? Do they know where to call? Does the public know where to call when they see something like this happening? Do they understand 811? Do they know how to dial the number if they're digging in their yard and if you have an incident, can they identify a pipeline incident and call 911? Do they know the dispatch number and where to call there?

Can improvements be made in leak detection? That's really the question we're trying to determine; right? Through this study and through some of our research.

Leak detection in the code. Basically, it's covered in multiple areas under 192, 605(b) and 613 talk about it specifically when it comes into transmission. We talk about control room management. Control room management, here is a good example. They can be very sophisticated, probably a simple schematic there, with -- I can't see if this is just a log of what's happening and this is an alarm screen. Most likely that's probably what it is. And it's a good example of if a guy is seeing a hundred alarms a day, is he really going to act? I heard that earlier, and I think that's a valid point. If someone's overwhelmed by a lot of false alarms or other issues, perhaps he's not going to respond like he should when he gets a real -- a real factual alarm.

Control room management. Basically, under control room management, the code doesn't require SCADA. That's a biggie. If you don't require SCADA, you can't have a leak detection system, necessarily, that's sophisticated. You can have a simplistic one, back to some of the simple models I talked about, but if -- you must have those two pieces working together if you're going to have a valid, sophisticated leak detection system.

Roles and responsibilities. Adequate information. Fatigue mitigation. All those things are important for control room management. All have an impact on improved leak detection. Tying human factors and safety culture considerations. Those things are a must. You must be accountable for those. Because we are all human. We all know if you have something at home going on, the guy didn't get to sleep for two days, maybe he is sick, or the lady, they don't respond, you know, to inputs. And that includes alarms on alarm screens. So we've got to be aware of some of those factors.

Repairing leaks. Basically, we all know that you've got to repair leaks, but it's also factual that a gas system can leak and be safe. That's something that we all need to be aware of, and there's lots of small leaks when it comes into flange connections, so on, that's monitored and maintained by local distribution companies, and they keep those in a safe category. There's different grades for those leaks.

That's where this talks about a little bit. We're talking about switching topics a little bit, but another kind of leak detection is patrolling surveys. When it comes into transmission, we are talking about 705(a), 705(b), and distribution, it talks about 721 and 723. That's where I was getting at where it talks about the type of leaks and grading those leaks and managing those issues.

Pressure-limiting and reg station gauges. Basically, telemetering and recording gauges are required, right, on a distribution system when it has multiple, basically, regulating stations. If it has a simple, single one, then perhaps it's up to the choice of the company, and that's what the regulations allow. That's what's important to point out.

Operator qualification. Under 192, subpart N, we talk about covered tasks. We talk about pipeline patrolling, leak survey, maintaining SCADA equipment. All of those things have to have qualified people doing those tasks because it's just like -- I can't think of the phrase I am trying to spit out, but basically, the smallest little element that goes inappropriately maintained can lead to catastrophic failure somewhere else. Right? If you get bad data in the system or you gate false signal because the PI or the TI isn't working anymore, right, the pressure indicator or temperature indicator is giving you bad readings, the daggone CP model then throws out bad data and bad indication of possible leaks or failures. So all working parts are important to be maintained.

Under a gas IM, additional preventive and mitigative measures. This has been around -- folks, I've been doing this for years when I was in the field doing these inspections, and I can tell you that this has been around a long time when we talked about, you know, installing computerized monitoring or leak detection systems or automatic shutoff valves and remote control valves that we're going to talk about tomorrow. And these are in there, basically, for one simple reason. Right? It's not to prevent the incident. It's mitigation of the consequences after. That's what these two topics that we're talking about really address. They're not preventing any failures; they're basically helping us mitigate the consequences. And that's why it's in the regulation where it is.

One thing I wanted to point out here -- because the regulation does talk about pipelines operating below 30%. But we're really talking about those between 20 and 30% when we're talking stuff that operates below 30%. And pipelines that's operating in storage fields. That's really what that section of the code covers.

I'm not going to read this -- the code to you. You guys can do that. The standard issues, not choosing the best methods or technologies. That's the standard issue that you seem to find. Sometimes more basic issues, like odorant effectiveness, proper grading of leaks, et cetera there. Those are the issues that you find kind of repetitively as problems.

Natural gas leak detection research. We have tried to -- and actually have -- partnered with industry quite a bit on four R&D

forums looking for leak detection topics. We did do five research solicitations in 2002. We had seven technology development projects using about 3.7 million of PHMSA funds. And we successfully, I think, got three of those technology improvements to the marketplace, where companies can invest and utilize that technology for leak detection.

Active and new research. Development and field testing of highly sensitive mercaptans instrument. This right here I'm not that familiar with it, but I can tell you that intrigues me. If we have a better more, more sensitive way to put the additives we put in to odorize the gas, perhaps we will have better and more accurate leak detection systems on the ground out there. Then, of course, a little plug for R&D forum, July -- that's actually July 17 and 18. That's when we plan on having that. That will be here in DC. I could give you more specifics, but I can do that at the break more appropriately, I think.

The next issue I have here is other actions we're taking. Currently reviewing comments -- this is about the gas ANPRM that we've got out. We've got over a hundred comments. It's going to take us a little while to work through those and categorize and respond, but we will. So the timing right now depends on addressing some of those issues.

Pipeline Emergency Response Forum was held, as you know, December 9 of 2011. Those are some additional actions we took. We also are initiating this leak detection study as part of a congressional mandate and also in response to some of the NTSB recommendations. This workshop is also one of those actions that we're taking.

The congressional mandate. There is a congressional mandate I alluded to. I won't go through and read that to you, but basically, it's directing us to do this study, to determine if there's a technically, operationally, and economically feasible standard or a system that would be practical for the industry to invest in.

The NTSB recommendation talks about the SCADA piece and the locating leaks and line breaks, which we will also address in this study. Let's move on to the next one here.

The study itself -- the study itself, I'm not going to go through and talk about all the different topics. That will be public, made very transparent to anyone who wants to be involved. We are going to be collecting, as we've noted, comments and questions on a website for the next 30 days, so you have plenty of time to comment. This is one of that -- this is part of that effort to gather some of those inputs so that we can formalize that study in a final scope of work and make sure that we complete that on time. That study must be completed and reported back to Congress by January 3 of 2013 so that we are on a tight time frame, as you can imagine.

The study goes on and talks about some more things. Carry over into the technology panel. I wanted to make sure I made some comments here. Basically, current leak detection systems and methodologies, are they adequate? That's the question. How can we make existing technology more cost-effective and practical to use? We all know that the liquid industry has used that technology much more than on the gas side. Is there some learnings there we can transpose across the boundaries and use it on the gas side? I think we do understand that it's much more challenging; right? Gas is very compressible. There are some real challenges there in leak detection. Does more sophisticated or robust methods as far as conservation of mass and mass balancing and their methodologies, is that appropriate to use on the gas side?

How do you or how do we maximize the pros and address some of the cons with leak detection? And what does the technology community need from PHMSA? I think that's the key. We really need to know what you guys need or how we need to partner up and, you know, do some core research. If we need to do core research to try and make some of these technology leaps, we're here to work with you to do that.

Other than that, that's all I have. Thank you very much, and I look forward to your questions.

(Applause)

>> ALAN MAYBERRY: Next I would like to introduce Hans Mertens. He is Director of Engineering and Chief Engineer at the Vermont Department of Public Service. Hans is here to give us a state perspective.

>> HANS MERTENS: So first of all, a little advertising there, just in case somebody missed it. By the way, we had 82 degree temperatures on March 20, and our economic development folks decided to go down to Florida and see if they could develop a citrus crop -- (Laughter) -- to sort of balance our maple syrup industry.

No. No. (Laughter). Don't fall for that one. But I do have a safety message for you today, and I think that's the more important one, and I'm sure the reason you've come here. I'm speaking today on behalf of NAPSR, not for NAPSR. There's 50 different program managers out there, and they all are focused on their particular issues and problems. This is a very unique industry, and the solutions are very etch customized. I'll talk a little bit more about that as we get into it. But we do have a common theme, and that common theme is that we all care about this industry very much, and we want to do well.

Okay. So I figured out where I'm at. Bob Smith, the meeting organizer, gave us a challenge. He said there are several messages we want you to address and make sure the audience hears. There they are. Something about congressional requests, improvements, opportunities, and regulatory expectations. And before I jump into those -- and they'll come -- but before I jump into those, I think you have to remember that back in the day, we relied on very knowledgeable, concerned people, and then we added technology to it, bigger, better, more powerful tools, and we even went to creature comforts so that the operator didn't suffer from fatigue. But in the final analysis -- and that slide advanced farther than I wanted -- and in the final analysis, it still comes down to the people behind the meter. The folks that are out there taking the readings, the smart boots on the ground, and that is, I think, the most important part of the message that I carry today.

Now, my focus is on distribution, but I'll be honest with you, when I listened to Dave and some of the other speakers earlier in the day on Linda's panel, the message was very consistent. The consistency is that in whatever tools you use, whatever hardware, there's got to be an application, and the person that is pushing those buttons and interpreting the data has to be knowledgeable, and I'll talk a little more about that in a moment.

So clearly, technology has advanced. It is a powerful progress, lots of progress on the part of consultants and the engineering community out there. They've done a lot of good things. We've created remote leak detection, which has assisted both accuracy and remote detection out there, and the consultants as well as the operators benefit from that. And in doing so, we've also come up with all sorts of ways to take readings, adding flexibility and integrating the results with GPS. And this is all very impressive.

Still, all this hardware is less useful, in my mind, without those smart people out there. My colleague from New Hampshire, Randy Nepper, he and I had a conversation, and he said, you know, it really comes down to block and tackle; doesn't it? And there's truth in that. And that's one of the messages that I share with you.

I believe Congress has demonstrated similar views through their initiatives and the instructions to PHMSA. And so the congressional requests, which I alluded to earlier on the message slide, I've boiled it down to four that I think stand out. The integrity management slide indicates that the IMP effort has required an understanding of as much as possible about the facilities, and then overlay operating and performance histories, and at a decision point, bring all the subjective and objective information together. That was the beginning of it in many ways.

In a similar manner, exercising the effort of dissecting a job and all its particular duties and KSAs, knowledge, skills, and ability, and focusing the operator and the employee on what it takes was an important message. And so that particular thing goes out there.

I'll share an anecdotal story with you. A couple years ago, when I was a cadet engineer in Newark, New Jersey, the training program was extensive. It was six months, you'd go out in the field and ride with people and whatever else. And the OQ part of this slide is to recognize that there's a lot of aspects to a particular job, but also the OQ is to make sure that that senior operator, that senior technician that you are going out with doesn't give you any of the bad habits or at least you're aware of the bad habits when they're put upon you.

But again, in my training back then, I was -- one of my assignments was to go out with a serviceman, and we went out on leak calls, and he showed me how to find a leak with a match.

(Laughter)

This is the truth. And being out of college and being real smart, I figured hey, this is cool.

(Laughter)

And that story, that, you know, recollection, stays with me to this day.

And so in a lesser degree, what bad habits are some of our senior people sharing with our employees? And but for something like OQ, but for the dissecting and the methodical process that we've developed to teach everybody one good way, how do we guard ourselves against that?

The next item talks about documentation, and while a good memory is a gift, writing it down is something you can take to the bank. Here again, over the years as I've looked at records, there's probably equal number of fun stories that you have, but I'll share one. Looking for a main, I looked at the service card, the main record, and the dimensions to the location were very precise, you know, 62.5 feet. But it was off a railroad boxcar.

(Laughter)

And the person that did that, I'm sure, was you know, trying to be as good as they could. But it didn't sink in that records not only have to be accurate, they have to be reliable, duplicatable, and all that other stuff. And so the whole issue of documentation is coming to roost, and it's an area that we can do more on. Some folks still haven't gotten the memo, if I can share that with you. That will surprise you; won't it? Yeah. I don't think so.

My last example is taken from the Willie Sutton School of Management. You'll remember he was a 1930s bank robber. And he was asked once upon a time, you know, why do you rob banks? And his response is "That's where the money is." So it's no surprise to you when you look at that last item that identifying high-consequence areas, establishing risk profiles, and then doing a little bit more when it's indicated is smart. And I think we all are together on that.

But somebody actually had to put that on paper; didn't they? Somebody actually had to say that so that we all kind of get that same religion.

Well, opportunities first advancement. And I think based upon a couple of comments I've made, I think Congress understands this very well. I will tell you that I'm concerned about the reliance on technology in some ways. I read an article -- maybe some of you did as well -- about an individual driving with a Garmin GPS system, a little mapping device. They're terrific; right? Unless you get into downtown traffic, and then it's so busy that it locks up and it doesn't tell you where to go, and you're stuck in the middle of an intersection waiting for it to tell you make a left or a right. Well, this particular individual drove into a lake. He drove into a lake because the Garmin said there's a road there, and he just assumed, well, I guess the water is covering it. I'll take a chance. Hmm. Do we ever have employees that rely on technology and don't apply common sense?

How about this one? A little different from leak detection, but it's a true story. Had a guy, electric company, go out and auger through a six-inch plastic main. Now, that six-inch main was installed just a couple of years prior with directional boring technology, directional drilling, and that guy missed the old electric pole by inches, but he got it through there. I mean, he was real proud. He can -- boy, look what I did. He found a little loophole there, a little pocket to slide through.

What he also missed was the fact that electric companies occasionally replace poles, and when they replace poles, sometimes they lift up the old one and put it in the same hole, and oftentimes it's a bigger pole. And at the very least, what you do is you use a bigger auger. Once again, where's the judgment? And this is part of the human factor, and while the technology allowed them to do what they did, the training, the boots on the ground, the smart boots on the ground haven't done everything they can.

Talk about awareness of the public. You know, one of the most important early warning methods we have is that nose attached to the end of the pedestrian. And I don't think we use enough of that. We certainly send out those notices twice a year, and that helps. And we have a public awareness program. That's good. But so often we hear about people, oh, yeah, I smelled gas for weeks. And they never called in, they never do anything. So I'm not sure we are reaching the public the way we need to.

Now, we have a repair method with public awareness where we go back and test how are the results and so on, and I think that is the message that is an important one, that we have some sort of quality assurance in place so that when we do something, when we implement a program of some shape or form, that we go back and check it once in a while.

How about this? Price of gas being what it is, I put STP in my gas tank all the time. Maybe you do too. But first thing I do is I check my mileage, and I say how'd I do? Did I go from 20 to 20.6? What did I do? And I bet any one of you that does that probably, if there's a few engineers in here, you probably do the same thing. You probably measure how you succeeded. Do we do that with some of our other programs? Do we care? Do we get excited enough about other programs that we implement to measure how effective they are? Take your personal experience, apply it at work, and see if it doesn't help things.

So I think those are all important items. And then the final item is the -- the remote reliance. Well, I talked a little bit about that. My concern, again, we have the public and we have the local activity. As we get more and more remote devices, there's less reliance on hands-on stuff, and that's a concern.

So that last item, DIMP, if you will, encourages you to customize your program. Clearly, Arizona and Vermont have different climates, different impacts, and we have to appropriate solutions differently. And the DIMP program really allows us to customize that. See what's working for you. If it's working, terrific. If it isn't, change it.

Will Rogers, a humorist from a few years back in the railroad era, his comment is one of my favorites, which is you know, even if you are on the right track, if you're not moving forward, you're going to get run over. And that is so true in so many walks of life. I encourage you to apply that to your thinking.

Okay. Regulatory expectations. My third message. Grow the franchise. Listen. Natural gas is America's fuel. We all welcome it. We use it, want to use it, in bigger and better ways. However, if a black mark is attached to it -- think Fukushima -- if a black mark is attached to something, what happens? It will be the devil to pay. This is something we have to avoid and we have to do it together. I believe it will go a lot better if we work as a team. If we work this together.

Regulators are a voice for consumers and must be in touch with public sentiments. As issues emerge, it benefits the industry to communicate, consult, and cooperate. Playing "hiding the pea" is a failed strategy. Treating regulators like mushrooms, keep them in the dark and feed them manure. (Laughter). These are things that have happened. Are you shocked? They have happened. Occasionally, they still happen. It won't work. If we want to grow the franchise together, it has to be a team effort, gang. We have to do this together, and talk to us. Ask our opinion. Collaborative does not mean average, does not mean suboptimal. Collaborative in the long run is a more expedient way to come to good solutions, whatever they might be.

And I know my colleagues, my fellow program managers, we're all coming from the same school, which is you have got a lot of resources, and you've got to selectivize and be proactive in picking those projects and those things that deserve your immediate protection. Remember, sacred cows make great hamburger, and we are going to essentially go after some of those. It has to happen. Be prepared. Relax. Help. Be part of the solution.

Okay. What brought us together? Dangerously close, Alan. What brought us together today? Transporting gas and liquids by pipeline is one of the safest forms of transportation out there today. Congratulations. Well done. However, we are not pleased that through 2010, we had that many incidents which caused 378 fatalities and disrupted many lives and businesses along the way, resulting in $441 million in damage claims and fouling our environment to the tune of 2.6 million barrels of product spilled. We can do better, gang, and I would encourage you to take some of the story today and apply it back home. Thank you.

(Applause)

>> ALAN MAYBERRY: Thank you very much, Hans. Again, we're going to hold our questions to the end, but I ask that you please be thinking of your questions, and you know, in the audience, be ready to stand up to the mic, or if you'd rather not do that, write your questions on an index card, which will be provided. And then also, for those of you online, thanks for joining us. We also invite your participation, too, through questions as well. But we'll save it till the end.

Shift gears here a bit on perspective. Next we'll get the perspective of the interstate national gas association of America, representing the transmission interstate pipeline operators, and here representing INGAA is Pete Kirsch. Pete's the Senior Vice President, Midstream Technical and Compliance Services at CenterPoint Energy. So Pete, thank you.

>> PETE KIRSCH: Thanks, Alan, Linda, and the whole PHMSA team for putting this workshop together. Each of you are here for a reason. You have an interest in the subject. You have a passion for the subject. Maybe your boss said you had to be

here. I don't know whether in person or online. I'm glad to be here, and as Alan mentioned, I'm going to be offering up a natural perspective of gas leak detection from an INGAA perspective, so isle be speaking on behalf of INGAA.

Most of you probably are familiar with the INGAA organization, but in case there's a few of you in the audience that may not be, let me go over it briefly. INGAA stands for the International Gas Association of America. There are 27 natural gas pipeline operators. They operate about 200,000 miles of pipeline that represent close to two-thirds of the transmission knowledge in the United States. You can see on the right-hand side of the page the different member companies that are part of the INGAA organization. My company is CenterPoint Energy. I've been in this industry for close to a quarter century, most of that in operations and engineering field.

Back in late 2010, our INGAA board -- this was at the time that the ten-year baseline integrity management program was coming to a close. It was year eight of that program. And in the wake of several incidents, several tragic incidents, unacceptable incidents, the INGAA board came together and said how can we take pipeline safety to the next level? What do I need to do to get things moving in the right direction or further in the right direction? And they came up with some aspirational goals, and many of you have already seen this. I am not going to focus on each and every one of these except the very first one. To focus on a goal of zero incidents, a perfect record, the fatalities, the spills that Hans just mentioned, unacceptable. Right? I think we share that common message, that common goal.

All these other goals that are listed here right below the zero incidents roll up into that, engaging stakeholders, being transparent, using integrity management systemwide, continuously improving. All those things role up into zero incidents.

Well, the INGAA board didn't leave it at these guiding principles. They wanted something tangible to produce and to use these guiding principles, and they formed a pipeline safety task force, and out of that was born INGAA's IMCI effort. That stands for integrity management continuous improvement. Again, many of you have seen this slide. I've just got two more slides left on INGAA, then I will lead to leak detection, but I want to tell you where leak detection fits into the IMCI program. You can see there's a whole variety of subjects touching the integrity management programs. They go from transparent metrics, performance measures, to management systems, to storage, looking at preregulation pipe, R&D. You can look at all of these. Does anybody see leak detection on here?

No. It's not listed there specifically. However, we put it in the number 2 bucket, risk management. That's actually the effort I am championing. Risk management is where we're looking at expanding integrity management systemwide and applying those principles systemwide. It's also the bucket where we are looking at a fresh review to threats in the pipeline and how they interact with each other and best in class models. We feel that leak detection is part of the feedback mechanism that can tell us that yeah, we may be doing okay because there's no leaks or we're not doing okay because we have leaks, so it's a feedback recognition within our risk models.

Nine INGAA teams put together nine action steps, and it kind of coincidentally came out with nine steps. They didn't necessarily correlate with the nine teams. Some of you may have seen this already. I am not going to talk about each and every one of these; however, I wanted to talk about just a few of them.

The first one is applying risk management outside of HCAs. That's a big one for us. Right? Because only 4% to 6% of pipeline mileage is actually within HCAs. That's depending on whether you are talking about INGAA members or gas transmission across the country, including non-INGAA members. This came out of the NTSB recommendation on the San Bruno incident. We want to make sure we have the right methodology.

The fourth one will be a topic that will be talked about at tomorrow's workshop dealing with valves and emergency response. Anybody see leak detection on this one? No. Right answer. Thank you. It's -- it wasn't a trick question. But we put them in these following categories, and actually it falls within the risk management beyond HCAs because, again, it's part of the feedback loop. It falls within improving threat assessments and threat mitigation in our risk models. Again, the feedback mechanism that leak detection provides for us. And management systems, part of management systems is having that feedback loop. So it's part of the IMCI effort. It may not be a specific effort, but it's built within it.

Let's move to leak detection. I mainly wanted to focus on three themes and leave you with three themes today. The first is prevention. We want leaks not to develop to start with. I think that needs to be our number one goal is to prevent leaks. We spend a lot of our time, energy, resources into that. We also know that things don't go perfectly. Sometimes things are not within our control. We want to be sure that we design our operations, we design the pipeline itself such that if there is a leak, the consequences are mitigated.

Secondly is leak detection itself. We, as an industry, we value it and we support it.

Even if we get to zero incidents, we still need that feedback mechanism that we don't have leaks occurring. So we want to be sure we have robust surveillance methods and technology that we're using out in the field.

And then lastly, that new, workable leak detection methodologies and technologies are welcome, and I think they're needed. In my opinion, I don't think there's been anything too revolutionary we've had over recent years involving gas leak detection.

Okay. Let's talk specifically about prevention. And you might ask why I'm harping on prevention when this is a leak detection workshop, and it's mainly because I really think it's because we spend so much time and effort and energy and dollars on trying to prevent it. And it's trying to get past the incidents we've had in the past, we need to get here. We are going to continue to focus on prevention.

It starts with design and construction of the initial pipeline and hydrostatically testing it as a check to make sure there are no leaks and we have a quality pipeline to start with.

IM programs -- I use IM a lot. Excuse me. Integrity management programs we utilize. That's another proactive way to make sure we are not going to develop a leak. Pipeline replacements. We have programs to replace pipelines, and this is so the pipeline doesn't have a chance to develop leaks or one that could be developing leaks, we have programs to replace pipelines. Our O&M programs of corrosion control, damage prevention, all those things are preventative measures to make sure we don't have leaks.

Then R&D, something else we do, research and development, looking at new materials, looking at new designs, looking at new construction and operational methods and improvements so we can try and prevent leaks to start with.

We know things don't go perfectly; right? As I mentioned, things aren't always within our control. So we want to be sure that we can mitigate any leakage that's out there or the consequences of the leakage that may occur. And some of the things I've listed here are proactive, and some of them are reactive. A lot of these, actually, are mostly reactive. Obviously, once we detect a leak, we can isolate the segment, shut it in, repair and replace that segment or that portion that's leaking.

We can drop the line pressure. That will help minimize the consequences for a short while.

Green areas. This is actually a more proactive one for leak mitigation. This is where if a pipeline is crossing a parking lot, we have periodic green areas to mitigate the risk to any buildings.

Mercenary response plans and public awareness. These are programs that we are designing basically to help mitigate the consequences of a leak if it occurs.

Leak detection itself, there's not too many revolutionary things that are here. We do have surveys that we do, line patrols, area patrols, that are doing visual or actually instrumented -- excuse me -- detection with instruments. I'll use that word instead. We use three of the five human senses quite a bit: Sight, sound, smell. We still rely on those quite a bit. You know, whether they come from employees or from the public.

SCADA systems. I put a question mark by this one. We fully realize that the NTSB has put out a recommendation in regard to SCADA systems, that transmission operators should have their SCADA systems employed with tools to recognize and to pinpoint leaks and their location. That's a huge challenge. We are nowhere near that yet. Practically speaking, it's a huge hurdle to come across, and we realize that given the challenges of trying to detect natural gas, given its compressibility, given the false readings that you can get from decaying vegetation, et cetera.

R&D. We'll talk about that here in a little bit, but R&D is another element of detection that we use to try and improve our detection abilities.

Let me just take a quick moment to talk about ruptures versus leaks. This is for gas transmission lines. Ruptures can often be a large consequence or a larger risk than leaks. I think most -- that's probably common sense to most folks, but I just wanted to point that out. Leaks don't necessarily serve as a precursor for ruptures or for these high-pressure transmission lines. Whether a pipeline is going to rupture, whether it's going to leak, depends upon a variety of factors. A big part of that is the percent SMYS it operates under. We want to work toward preventing Not only the leaks, but we want to make sure the line doesn't rupture as well.

Definitely we value and recognize the benefits of leak detection. Listed some of the obvious benefits of leak detection. It minimizes safety hazard to the public and to the communities. We truly want to protect the public. We truly want to protect the communities. And we truly want to protect the environment that we operate in. I speak that with all sincerity. Our hearts are in the right place on this one. I think we share common goals with the regulators and probably most everybody in the audience and on the Web. We want to protect public number

Protection of the environment itself I just mentioned. That is basically release of methane to the atmosphere. Methane is believed to be a greenhouse gas and more potent than carbon dioxide. We want to minimize loss of product. We are moving energy, so if it's going out in the atmosphere, we're basically losing energy, so it saves energy because we don't have to replace that. Minimize loss of unaccounted for gas, which effectively saves money for the customer and/or the operator. But again, I'm harping back to let's prevent the leak from developing in the first place.

Moving more toward new technology and R&D, there's actually, in my opinion, been a few revolutionary methods in the last few years. There are a few studies out there. Jeff talked about a few of those, those are good. PRCI doing some studies dealing with right-of-way monitoring. That deals more with encroachments and ground services, but an element of that is gas leak detection, and Mark Piazza is going to talk about that little more later. PCI has a few studies, but you'll find as an industry most of them deal with integrity management, which deals with prevention. Which I think is where the party needs to be, but we still definitely value -- I don't want to discount leak detection because we definitely value it.

There is one other technology that came to light in late January. PG&E had announced a new technology they were using from Picarro. This is a device that gets mounted inside a vehicle, has sensors outside the vehicle, and you drive down the street. It's a supersensitive methane detector, and it can weed out gas from a pipeline versus gas from other sources, decaying vegetation, manure, that sort of thing. It's something we will keep an eye on, but that came out late January.

Management process, they need to be in place for leak protection so there is overlap, redundancy in what we do out in the field and in the office.

Then new methods in technology needed to take leak detection for gas pipelines to the next level. They're definitely needed. As I just mentioned, there's not a whole lot of programs that are out there that are dealing solely with gas leak detection. So we welcome any new technology out there that's workable for the stakeholders involved.

Whether we can get there with SCADA, that's the NTSB challenge for us. We need to try and do that. I think it makes sense for us to try and do that. It's going to be an uphill battle, but I think we fought uphill battles before, and we can make it there.

Detection of gas just directly out in the field, whether by air or on the ground, something we need to be sure we are continuing and look for new technology that can help us with that, and other methods to manage leaks as well where we have an open mind on that.

So again, I mentioned I wanted to talk about three subjects -

- prevention, let's not have leaks to start with. We value leak detection and want to continue when we get to zero incidents -- not if, I said "when" we get to zero incidents. Lastly, we welcome any new technologies that are out there for leak detection.

Last slide is who knows what next month is? And don't say April. Safe Digging Month. And Jeff stole my thunder. It is National Safe Digging month, and we want to put a plug in for that as well because, obviously, we are a large stakeholder in that process and in that program, so be sure to communicate to all your friends, your neighbors, to your coworkers, those folks that you know about, 811 and what that means. That's all I have. Thank you all.

(Applause)

>> ALAN MAYBERRY: Thank you, Pete. Moving right along, the next speaker on the agenda actually has the ultimate excuse not to be here. Chad Zamarin is a recent -- very recent new father, and Chad, best wishes to you and the family going forward. But very ably representing Chad and NiSource today is Mike Futch, a Pipeline Engineering Manager with NiSource Gas Transmission Storage to give the perspective of NiSource.

>> MIKE FUTCH: Thank you, Alan. I appreciate the opportunity to come speak to you guys today. What I'd like to do is spend some time together giving you a brief overview of how we kind of view what we consider a wholesale approach to leak detection for transmission assets that we operate. And then talk to you a little bit about some of the traditional and nontraditional Tools and strategy that is we see in the industry and that we're using within NiSource gas transmission and storage, speak a little bit about the opportunities that are there and touch on some of the limitations for some of the tools and strategies that we're incorporating. And then moving to an NGT&S, NiSource Gas Transmission and Storage case study, where we can speak a little bit more about what our perspective as an operator is from leak detection using technology.

We're using a platform that incorporates some leak detection and FLIR systems in a helicopter, and I've got some visuals I'll share with you and talk a little bit about how we're using that to respond and detect leaks. And then follow up with how we see that feeding the integrity management lifecycle.

To begin with as an overview, obviously, leak detection is a requirement. There are sections of the code that require us to inspect our pipelines and do leak surveys. Some of those depend upon what percent SMYS you are operating the pipeline. Some of them are class location dependent. It is a descriptive mode of operation. It is not something that can meet every need in the pipeline. There's minimum safety requirement. I know that we've talked a little bit here today about what we do when we find a leak. There's discovering the leak and also characterizing the leak. Some of the leaks that we discover are merely monitored, some are scheduled for repair, and some are obviously immediate repairs.

I think it's also important that we talk about semantics when we talk about leaks. There are, obviously, two different kinds. There are leaks and there are ruptures. The tools and the strategies that we incorporate to locate those and to respond to those are different and unique, and for the most part what I am going to focus on today are leaks. I don't want to focus on the upset conditions that are ruptures. Those are obviously highly reactive and oftentimes are found as a result of a phone call, as you all well know.

Emergency preparedness and response. When we think about leak response and integrity management, we're talking about a three-legged stool with people, process, and technology. I've also heard several of the speakers talk about how important the people are into the process, and I couldn't agree more. If you've got three legs of the stool and they are all different lengths, you are not really well aligned and integrated, and it's the people that really feed the process. So as we look at compliance requirements, those really feed more and speak more to what the process is, what are the minimum safety requirements that we perform.

Failure recognition. We're using some technology to detect leaks that is not otherwise discoverable just by visual methods or with the human eye or human nose, particularly when we're talking about unodorized assets.

So in the world of a fully integrated integrity management plan and response when it comes to leak detection, there are the people, so you're talking about your public awareness program, you are talking about your emergency responder training. These are the people that are the not necessarily boots on the ground because they don't work for the pipeline operator, but these are the people that live around our assets every day and have the highest frequency for interaction and potentially noticing an upset condition or something that's out of the normal condition that might tend to indicate a leak or something that is counterproductive to the integrity of the pipeline.

So taking all of these things into perspective, the process we follow as part of the compliance requirement and the tools that we use to detect leaks and the people and the -- that participate in the integrity management lifecycle, including operations technicians that work out in the field, all come together and kind of provide an "all of the above" solution for leak detection.

So speaking a little bit and briefly about what is a tool or a strategy for leak detection, obviously, there are traditional and technology-based solutions. You can do it from the air. You can do it from the ground. You can do a foot patrol. You can do visual. You can do instrument. We have SCADA alarms that will show us where we have a large pressure drop somewhere. Oftentimes we have to go out and actually verify those conditions before we can actually respond to a rupture or a leak.

We have emergency responder training and public awareness. We use these traditional and technology-based systems for NiSource Gas Transmission and Storage to cover approximately 15,370 miles in 13 states and the District of Columbia. About 1500 miles of that are class 3 and 4 assets, and we employ, as I stated earlier, a nontraditional Technology-based solution and a helicopter to sense leaks, and we have five people in a department, our aerial patrol department, that take care of this, and patrol about 140,000 miles annually.

Opportunities. I think the opportunities, again, are for a fully aligned and integrated integrity management plan. If you think about the different pieces of the puzzle that we're putting together -- and we're talking about leak detection. We'll talk about public awareness first. What does public awareness do for us? It supports early detection of both large and small events. People that live next to the pipeline see it every day. If anything changes, they are going to know it first. Aerial patrol. Obviously, we can't walk 100% of the pipelines. It would take too long, and you just don't have the horse power to do it, to even meet the minimum requirements. So what we do is we fly on our fixed-wing platform and our helicopter platform. It enables us to get coverage across wide remote geographic regions.

There are places where it's inappropriate to try to do it with an airplane or a helicopter. There may be canopy issues, there may be residential issues, there could be issues, as mentioned earlier, near a major metropolitan area where you simply can't fly. That's where foot patrol comes in, and you can do both visual and instrument from foot patrol. You can also do a combination of instrument and visual. One of the things that we'll talking about later as part of the NiSource case study is how we do incorporate that combination to offset errors that may be attributable to either the instrument or the person.

Then there is the emergency responder training that supplements detection and improves leak response.

Line break signals is a hot topic these days, and it's going to feed into the SCADA and control room management at NiSource. We do have a control room, and we do employ SCADA, but it operates in a more conditional mode off simple alarms. And people managing the controls in the control room level and communicating openly with the people in the field to respond to signals.

Limitations. It's heavily reactive. When you talk about leaks, you are not talking about going out and doing something proactive. You are talking about responding to inputs. We find a leak and respond to it. It's also difficult to cover 100% of the pipeline. If you look at some of the technology that I'm about to show you that we're using in our helicopter platform and you think about where our footprint is, we operate a very reticulated system. It's not a mainline transmission asset up in the northeastern part of our system. It looks like a spider web. So it's often not feasible to use a patrol plane with a fixed-wing system. So what we have there is a helicopter.

As you beginning to think about loading the helicopter operating platform with technologies that would support a leak detection, you have to also consider what are the logistics, what are the capabilities of the platform that you are putting this on, and you know, how are you going to cover the terrain that's involved?

One of the things that we struggle with a lot is that we've got a very tight window of fitting all the instruments on our helicopter for detecting methane, and having the ability to operate the helicopter over a wide geographic region without having to constantly plan around refueling and in a way that doesn't upset the ideal conditions for leak detection. You can imagine the wind influences of a helicopter flying about 30 knots 100 feet off the ground once it makes its first pass. If it has to come back and look for something it picked up on the first round, you may run into situations where you have difficulty picking up what you picked up the first time.

It's labor intensive and subject to human error. A good example of human error we encountered is we had the helicopter fly over, and we sensed something on our leak detection system. We circled back around and turned on our forward-looking infrared system, discovered an indicator of a leak coming out of the ground, and we called back to the operations folks and said we got a leak out here that's at a certain point on the system. Need you guys to come out here and fix it. The guy that was on the phone said we fixed it yesterday.

Now, that is a good example of had you not had that technology in place, you could have had that human error play into a situation where he thought he had already fixed a leak that was really not the leak that we were talking about.

Weather dependent. When you start talking about putting these platforms out there, these technologies on the platforms, you are going to be subject to maintenance issues and you may not always be able to fly the route you want to fly and capture the conditions that -- and capture the situations and conditions that are favorable for the technology. It's also regionally influenced because the platform that works well in Appalachia may not work well in Nevada.

So the NGT&S experience, NiSource gas transmission experience, is that prior to 2007, we had two company-owned fixed-wing aircraft and one contracted helicopter. In 2007, we purchased a jet ranger helicopter to replace the portion of contracted services. And in mid 2008, the helicopter patrol area expanded.

In 2009, we formalized our aerial patrol program, assumed operational and scheduling responsibilities. The helicopter is outfitted with a forward-looking infrared system, thermal imaging camera system installed on a helicopter, and in August 2009, class 3 and 4 instrument patrol areas were added to our helicopter patrol.

In January of 2010, we added our leak detection system, and it is operational on the helicopter today. And in June of 2010, we installed the eye-move immersive camera system, and it's, again, operational on the helicopter platform today.

This is a picture of our helicopter. This is -- what's the call signal there? Delta gulf 10G. Vital part of our instrument surveys for class 3 and 4.

Obviously, natural gas is odorless, invisible, and combustible, so how do we use this platform to detect methane as we're flying over? Here you see a camera system. It's belly mounted on the helicopter. It has an array of cameras that can give you a 360-degree panoramic view. We also have equipment on the helicopter that logs its flight path so we can directly correlate the images we capture with this camera system with GPS technology.

In the backseat, which is the instrument on the right, is our Apogee direct sample information. Sniffer I call it. It has a hole in the belly of the aircraft where it has a forward and rear-facing sensor capture system, and it detects methane. And on the front of the helicopter, we have an infrared imaging camera, which is our FLIR. If you've ever seen natural gas coming up out of the gas, I've got some of this material on video, it actually looks like black smoke coming out of the ground, so you can imagine doing an instrument patrol in this helicopter, you are flying over at about 30 knots 100 feet off the ground in very mountainous terrain, going up and down, and you get a signal on the instrument that says you are detecting methane consistent with transmission gas. You don't know where it is, but you do have a signal, you come back and turn your forward-looking infrared device on and hone in on it. That's exactly what happened when we found the leak and called in to the operator. He thought he had already repaired that leak, but he hadn't, and we knew for a fact it was there. So they came out.

We also have the instance where these guys call and they say we think we may have a leak on a particular line. And rather than have those guys spend two or three days walking the pipeline to find out where that leak may be, we flew over very quickly in a matter of 30 minutes and located -- that we did, in fact, have a leak and had the guys out there repairing the leak that day.

Another area where this comes in to effect is if you have a major upset condition. If you can imagine experiencing a failure on your pipeline and you have emergency responders on-site, your operations personnel have mobilized, and they've shut that valve section in. One of the things that we always do is we mobilize this helicopter, and we have them fly the valve section, both upstream, downstream, and the valve section where we experience the failure to make sure we don't have any other leaking events or preliminary updates where we might have another major upset condition.

This is a close-up picture of the forward-looking infrared system on the front nose of the helicopter. Although we have three fixed-wing aircraft and one helicopter, we only have the helicopter presently outfitted for some of these leak detection systems. Our current state will not be our future state. I think we're on the cusp of some great things at NiSource, and I don't expect that we'll be finished anytime soon as we improve these technologies. If we had this ability to put these technologies on all our platforms and increase our platforms, you can imagine the real-time indication of leakage that we could enjoy.

So what does this all mean? It means in the world of integrity lifecycle management, we are approaching an "all the above" solution. There is no one right answer for all pipelines. It requires a fully aligned and integrated approach using people, processes, and technology. The tendency can be to try to overcompensate with technology, but at the end of the day, if you don't have the right people trained with the knowledge they need to make decisions using the right information, you are not going to be where you need to be.

So leak detection is a very important part of our integrity management lifecycle. Our drivers are risk, compliance, and opportunity. We use the people that we have in the field, the processes in our procedures and O&M manual, and the tools we employ on this helicopter to capture data every time we go out, and we take that data, characterize the leaks, fix the leaks, feed it back into our GIS model, which also is bolted to the back end of our risk tool, and we try to use that to plan our work management and our maintenance planning lifecycle.

So in summary, it's very reactive at the incident level, but it is a leading indicator as we learn more about our asset performance. Thank you.

(Applause)

>> ALAN MAYBERRY: Thank you very much, Mike. Our second operator perspective will be from El Paso Pipeline Group, and here to represent El Paso is Reji George. Reji is the Manager of Pipeline Risk Management. So Reji.

>> REJI GEORGE: Good afternoon. Let me begin by thanking PHMSA and PHMSA staff for allowing El Paso the opportunity to come and speak on this important topic. We prepared about 20 slides, so in the interest of time, I'm going to skip over a few slides, so as we go through this presentation.

This slide talks about the purpose of El Paso. I am going to skip over that. I'll emphasize one point in our vision statement. One of the primary goals we have as a company is to be the neighbor to have. We tie all our integrity efforts to this important vision. So when we look at leak programs and integrity management efforts, we tend to think that the better we are at doing this, we become a better neighbor to folks around us.

My goal as part of this presentation is to give you a very broad overview of all the things that El Paso does in terms of tools and procedures to find leaks and mitigate those leaks. I'm not just going to focus on ruptures. It's important, but we want to look at the broad category of leaks, whether it's a small leak at a meter station or a leak at a compressor station or a pipeline leak.

We also want to address some of the considerations that Bob Smith had put together to prepare this presentation.

We operate about 38,000 miles of pipe across the country, and based on where the pipe is and where the assets are, our philosophy and procedures might be slightly different. For example, our habits and procedures in the offshore environment is a little different from what we would do in an urban area like Houston.

When you look at the leak detection practices for El Paso, we take a very layered approach, and what we have is a lot of years of experience melded with technology advances. So as many of you have spoken before, our gas control center does a lot of monitoring. I don't think we have the latest and greatest tools like many of you have spoken today about modeling the leaks, but they do a very good job of managing and monitoring for pressure drops and other things that can tell us there is a problem.

We also spend a lot of time with aerial patrols. Almost every segment of pipe that we have on the system is monitored at least once every five weeks. Some of the urban areas are monitored every two weeks. So we have a visual look at our assets at least in a five-week interval.

We also spend quite a bit of time walking and driving, looking for leaks. When you look at some of the maintenance work that we do, whether it's at the meter station, mainline valve, or at a compressor station, the work that we do involves a look for leaks. So if you get those things right, we believe that we can manage some of the leaks from growing into bigger problems.

We also have worked with aircraft equipped with leak detection devices.

In most of the cases, we work with a vendor to make this happen. And we also believe that sections of pipe where we have injected odorant helps us find some of the leaks early so we can fix the problem before it becomes a bigger problem.

Here is a picture of one of our aircraft in our aviation group. They spent quite a bit of time looking for leaks. And here is an example of some of the problems or type of problems that they can tell us, and so when you fly the system, you are looking for spots on the ground that could be indicative of a problem that we should follow up and take care of.

This is an image from one of our aircraft that's equipped with a FLIR camera. We have a program that's focused on compressor stations. So we look at every one of our compressor stations at least once a year just to see what the problems are that are visual and easily identifiable from the outside. Keep in mind this program in itself does not fix every leak at the compressor station, but it gives you a good feel for how things are maintained at the compressor facility. And the follow-up and the follow-up loop that we have with operations ensures that the problems that are found are fixed, and the next time you go around to the same facility, you hopefully will not find the same problem.

This layering process that we have, what we are trying to do is to create an environment where we find some of the smaller leaks early before it becomes a bigger problem. And the benefit that we have by doing that is it creates a culture where leaks are not acceptable, where there's a small leak or a larger leak, we want to emphasize to operations, we want to emphasize to our engineering group, we want to emphasize to gas control that every leak is an important item that needs to be taken care of.

It's quite possible you look at a leak and say it's not a major leak, but it's still indicative of the habits and practices of a company on what happens and what choices are made when you find a leak.

When you look at the science of leak detection, we have to be very open to new technology, but at the same time, we have to take into consideration the advantage that we have as operators of years of experience. So we have to temper the new science with operational knowledge that we have. So when a vendor reports a leak in an area where there is a concern about methane, we have to ask ourselves, it's not a leak until we go and identify the problem and say it is a leak. So the way we work the vendors is they'll report leak indications to us. We'll follow up. We'll check. And we will say that is a leak or not a leak.

We also are very cognizant about new technology blind spots, where it's a weather problem, high winds, snow, water on the ground. All these problems create blind spots for new technology. So we have to be very open and understanding of those problems.

While we do all these things, we also have to be knowledgeable about what we think is a standard. Most technicians will tell us that their flame ionization unit is the standard. And we sometimes struggle with that. A vendor would report a leak to us, flying at say 500 feet, and our technicians will go and not find the leak. And we struggle with the aspect of thinking where one technology trumps another technology in terms of follow-up. So in cases like that, we always take into consideration another set of tools to go find the leak to verify that either the leak exists or it is a false positive that the vendor reported.

In terms of external factors, what we tend to do is we tend to look at all the issues at play. So when you look at what could cause a leak, it could be a third-party damage that caused a leak or a small problem on the pipe. Or it could be our own practices at a meter station, where we did not take care of maintenance and there is a tubing leak that slowly builds up over time.

The options at play for managing this problem is different and has to be different. So what we emphasized through other procedures and through our own manual is to have a varied approach. You deal with the problem, provide the right solution so that the problem goes away, regardless of what the problem is in terms of the problem spectrum that you are looking at.

Once a leak is identified, mitigation could include the following steps. So if you look at a large leak, it may require us to close a mainline valve. As part of our tool set, we have several mainline locations where we have it equipped with auto close valves. And I'll cover that in a few slides, give you some more details on that.

So when you look at some of these actions, some of the larger actions only apply to pipe body leaks. When you look at the type of leaks that we find, a large percentage -- and I am talking about 60%, 70% of the leaks that we find -- are not in the pipe body. It could be a tubing line, it could be on the crossover piping, it could be at other things that are outside the pipe body. And the corrective action to a large degree is very simple. You are looking at greasing valves, tacking bolts, simple steps that can fix the leak. But you have to identify the leak, and it tells you a story.

There's a picture of a mainline valve location that's equipped with auto close valves. So when you look at a location like that, what we do is we are set up at this location to automatically close the valve if there is a large pressure drop. The challenge for us is we have to get the math right. We have to say the pressure has to drop by a certain amount in a certain window of time, and if that happens, the valve closes. The problem with having tools like this is if you make a mistake, everyone is going to have a big problem with that. If you make the right choice, everyone is happy. And we have a lot of locations where it's equipped with devices like this, especially in our class 3, class 4, and ACL locations where we are ready if a failure happens. And it happens without the involvement of gas control.

Once a leak is identified on the main line, the next step is to remove gas from the pipeline segment of interest, repair the leak, and the last point I think is very important, we have to reflect on what happened. Regardless of what the leak is. Whether it's a meter station, a compressor station, on the main line, or at a main line valve. Because in my view, every leak has a story. There is a causative story behind it. And understanding that causative story will help us create better practices going forward.

This isolation discussion is quite challenging for us, and I'm sure it's challenging for most operators when there isn't a big failure. So what we try to do is the first step is to close the valve and isolate the supply source, and then you think about all these other factors, try to look at the size and the location of the leak, impact the neighbors and customers, location of the valves to isolate the leak, look at where your blowouts are. In general when you have segments of pipe operating at a thousand pounds that are five to ten miles long, it's not that easy and quick to evacuate that section of pipe.

We also put a lot of credence to greenhouse gas consideration. Our objective is not to blow all the gas into the atmosphere if we can help it.

As I mentioned before, we have portions of the pipeline system equipped with auto close values, and we an active program to add more of these devices in the system. These devices are time and pressure drop based, and that's basically the control process. Some of those locations are tied to gas control, and all our new locations are typically tied to gas control, but we do have locations where gas control does not have a direction connection to that location. But keep in mind, closing a valve does not prevent the leak, but it helps start the corrective process.

One of the questions that we had was regarding how soon can you stop a leak if you have all these technologies at play. And based on our experience, it all depends on where the location is. You know, when we look at the tools at play, the quickest way to solve a leak is automate all the valves. The cost for that that we see is 40 to 75 thousand dollars per main line valve. You add an auto close device, you add a communication package, in theory it's possible, but it still does not stop the leak. It stops the leak from the short-term. It does not prevent the leak from forming, but it closes the valve.

When you look at additional maintenance cost, I think that's another question that we had, and we are trying to answer. What we were saying is if you install these devices at a mainline valve location that you're already maintaining as part of your maintenance practices, additional cost is minor. But the more of these devices you install in the system, the greater are the chances you make a mistake and you close a valve without the correct set of information at play.

In terms of technology advances over the last several years, we have been involved with a lot of things. We have purchased imaging cameras. We have purchased handheld devices. We have worked with vendors who have leak detection instruments. We have explored the idea of adding some of those devices into our helicopters and fixed-wing aircraft. What we see is a lot of opportunities to improving when we find a leak and how quickly we can find a leak.

We've also spent some time with efforts from PRCI and other research groups into developing a better solution to some of the challenges that we see in terms of finding leaks.

In terms of concluding remarks, what I see is there isn't one solution. We mentioned a series of things that we can do, and so we tend to look at it from a holistic perspective. We have to continue to eliminate factors that create leaks. So our emphasis should be to get to a point where we have no leaks and no ruptures and no failures. And a big element as part of that goal is to have an active public awareness process. We have to stay engaged with advances in technology because we think that there are solutions that we can use, even improve what we have today.

When I look at the El Paso system, we do a lot of things, but I think we can do more in the future in terms of bettering what we have for leak detection.

We also have to and need to spend a lot of time focusing on lessons learned. As I mentioned before, if you have a section of pipe and every compressed station has a leak, it tells you a story about that section of pipe. It tells you a story about the local management in that section of pipe on what the culture is. If you have the same circumstance at meter stations, it tells you a story about that section of pipe and saying maybe they don't think leaks are that important. So we have to put a lot of emphasis on lessons learned and ensure that it is very good follow-up for every leak that's reported, whether it's at a meter station, at a compressor station, on the body of the pipe, or on our mainline value of locations.

Every time we have vendors fly our system -- and I think this year we probably have over 500 miles of pipe that's flown by the vendor -- we look at the data and we wonder why didn't we catch that leak? What is it in our process that is preventing us from catching that leak? And that is something that we have to reflect on every time we look at data.

When we look at last year, we few several thousand miles of pipe, and every time we flew the system, we found leaks. And some of those leaks were minor. You would call it in the category of yeah, if we went to that meter station on time, we would have found that leak. But it still remains a fact that leaks were found, and we had to follow up.

thank you for your time.

(Applause)

>> ALAN MAYBERRY: Thank you, Reji. The last speaker on this panel is Rick Lonn, who represents AGL Resources, to give an LDC perspective. And Rick is the Director of Regulatory Compliance with AGL.

>> RICHARD LONN: Thank you, Al. I appreciate the opportunity to come and speak today, although I feel a little bit like an endangered species as an LDC. And I understand we're about 15 minutes ahead of time, so I'll see if I can get us back on schedule.

(Laughter)

All right. Let me start with the obligatory who are we slide. AGL Resources is an LDC. We now, with the recent acquisition of Nicore Gas, now the largest gas in the nation, pure gas, not gas and electric combo. You can see we operate in many of the states in the nation, and several of those are distribution. Basically, everything east of the Mississippi is LDCs, and everything west is storage.

Today, since I get the opportunity to go to a place nobody else has been able to go, leak detection is extremely complex for LDCs. It's a completely different animal here. The piping systems, the mileages are higher. Just in our systems, we're about 90,000 miles of pipe. Extremely congested areas, everything from downtown Atlanta to, you know, the suburbs of Chicago now to parts of New Jersey. And so obviously, the issues are related with leak -- leak detection and dealing with your leak systems are very hard. The variety of pipe materials, gas loads, take your pick. I mean, we are talking an extremely, extremely dynamic system here in that regard.

And so technology, obviously, like you saw with the liquids this morning, that's something that's really just not here yet for us as an LDC, and the other part of it is -- and this is where LDCs are different from a lot of the interstates in that regard -- is that leaks are a reality of our life, probably much more so than for our transmission pipeline. We find leaks on our systems, leaks on other operator systems. You've got areas where two gas LDCs are running down the same street. And you've got leaks on your end-use customer systems. And you know what? Every one of them is a potential for something going wrong in that regard. So understand that for an interstate focusing on large diameter makes all the sense in the world. But for an LDC, I got to focus on that half-inch pipe every bit as much as I've got to focus on may 36-inch pipe, so that's why we have a fundamentally, I guess, different approach.

All right. Did I say it was complex? You know, some of the proactive identifications, the way we attack leaks. Let me say it this way. Certainly, as the code requires, we do our initial pressure testing. We follow the code, we have our ongoing leak surveys. That is certainly the first, first level of defense for an LDC. We are all over these systems. We have pipe that ranges from cast iron installed about a hundred years ago up to pipe that we put in two weeks ago, state-of-the-art polyethylenes. Every bit of it is a material that was put together by a human, and it has the ability, eventually over its lifecycle, to leak. So we will pursue with those leak surveys, and we go down that path.

The nature of the beast as well is that the public does not differentiate. If there is a -- an incident in a customer's home, they really don't ask the guy, the reporter, was that the gas company's facilities or the customer's facilities inside the home? So we make sure, since we have thousands of people, honestly, on the street every day, working and lighting up appliances, turning on new customers, tongue off old customers, that we are well trained and have proper turn-on procedures. And as part of that, we are looking for leaks, obviously, in every customer's home before we safely establish that service.

So as you can see, the magnitude of opportunities is in the extreme for an LDC, and certainly it varies by the size of the LDC, but the points are consistent and common that we're at the end of the line here. It's the most complex end of the system, and there's just a myriad of things that you have to attack.

All right. So in that regard, what I would tell you is one of the recent regulatory enhancements that came down the pipeline, DIMP, in that regard, is probably our best friend, and that's why I'm going to go with this presentation. When you are dealing with a situation like this and you are dealing with -- a system of this complexity, you've got to use the data that you've got to identify trends and figure out where to go because, really, as I said, it's unrealistic to expect that there will be no leaks on an LTC, so the best thing you can do is try to figure out where they are going to be and get after those and then be proactive repairing the ones you've identified as well.

The last part of what I would say the triad of things we have on this page is certainly odorization. We call it the last line of defense. I mean, we put the smell in the gas for a reason. And you've heard several other people talk about it. Homeowners are an important part of this defense mechanism. If they don't know what they're smelling, they don't know to call. If we haven't publicly educated them, then they won't call us as well. So this all rolls in together.

I would tell you that in our public education program, we looked at the data, this one particular message is the one that has most resonated in the public. When you get right down to it, ask them all the questions in the surveys, do you know what natural gas smells like, and do you know who to call, you usually get the most positives of any answer in that regard. That's the message we have been preaching the longest, so certainly keep preaching.

All right. So how can a distribution operator improve their LDS strategy? And in this regard, as I said, I am going to go down this DIMP pathway here. You truly have to know your system, not think you know your system. And this is where DIMP has done us the favor. What you are looking at here is a representation of all the different places we hid integrity data as related to our pipeline systems.

In the old world -- a lot of it was automated, some of it was on paper. Obviously, some of it sat between the two ears of the individual in question. And we had to pull all of this together and now utilize it in the best way that we knew how. So a lot of opportunities there.

And if you're going to do this, the way we have approached it, anyway, is automation is the key. You're not going to get there picking people's brains. You are going to have to use the data. You are going to have to do the best you can to make the data right. And you are going to have to pull it all together, and from that, run a true risk-based approach to your distribution management.

So a little history. The dates you see out here, these are the five systems I would tell you that ultimately play into our leak management, ranging from, obviously, our GIS system at the top of the page, which is where we store our DIMP data when you get right down to it, to the dispatch systems and the work management systems for our service and distribution folks; our compliance tracking systems, where we enter leak data that we find through our surveys and make sure it gets out and done on time; and then the leak survey automation systems that we actually capture the data in the field.

When you see two numbers, we're already into our second generation on those systems, but all of these together kind of help us -- those are some of the source systems where you pull them in together, and we ultimately get to that DIMP data.

Now, obviously, this was a huge increase in data DIMP required of the industry to better know our system. And obviously, with data, you always have concerns when you're going to increase it, and you can see some of the automation concerns up there. Ultimately, increase data capture in the field was going to be hard on the field folks. You know? They are not computer technicians. They are guys that fix leaks. They're guys that repair appliances. Right? So ultimately, there are more chances as well when you are capturing data for the guy in the field to not necessarily get it right either. Obviously, this automation would require additional office review as well, because to be honest, we get tired of looking at things like plastic corrosion, things of that nature.

Anyway, the way we try to address these concerns is certainly to improve those data capture processes. And we try to do that by putting in place logic within the systems, drop-downs that ultimately wouldn't allow you to do, to pick things that made no sense in the system. To try to help the guys in the field, and ultimately, better training for the guys in the field, so ultimately, the better the data, the better the analysis. Ultimately, the better the analysis, the better we approach it as it relates to renewals, how we are going to attack repairs, equipment replacement, things of that nature.

All right. So where we went was we ultimately wanted to to get standardization on our data folks. As you can see, this is just an example of one screen off our work management system. Just pure use of pick lists wherever possible in that regard. Let's remove confusion from the guy's life in that regard. Ultimately, we used that even on the leak survey side in how we do it. We came up with these coding systems so that when the leak survey technicians out there, there's a three-digit code of where exactly that leak might be on the meter set or where it might be in the yard or where it might be versus the curb ultimately so that this all can be driven much more easily and efficiently from a computer perspective or from a systems perspective and help in the analysis as well.

I can now look at all of my leaks on my service cogs or I can look at all the leaks on the meter itself or I can look at all the leaks within -- you know, right up against the house. Take your pick. But the idea is to be able to cut and slice the data as many different ways as possible to help us do the right thing, if that makes sense.

To help the guys in the field further, we've even gone so far as to put out there what the definition is for the DOT or PHMSA's breakouts of types of leaks. You know? I take it for granted, being an engineer, that everybody else stays up at night and reads 192 as well. That's probably a bad assumption. But for the guys in the truck, if they want to know what's supposed to be in materials in Wellsley, so be it. We've put it out there so they can read it and they can make the right choice based on what they see on the pick list.

Excavation damage, which is certainly our biggest risk in an LDC, same sort of thing. Help us help us. Tell us what happened out there on each of those excavation damages so we can focus our resources on finding that leak before it happens. That's a little bit different there because when you are looking for an excavation leak before it happens, I am looking for something with six wheels and a guy behind the wheel of the a backhoe. I am looking for the individual, not the spot.

Anyway, the idea is to try to use all of that data as efficiently and effectively as we can.

Now, at our company, the way leak system integration was done -- and is done today -- ultimately, you can see we got our leaks from two different systems. Our leak survey system, which we call ELROY. And if you are a Jetson's fan, you'll get that one. Next generation will be named after the dog. And from our CIS 911 call-ins. They channel in to our WMIS system, going through the leak scheduling system, and ultimately that's where it existed before DIMP. But after DIMP, we now took all that data, pulled it into our GIS system, put the leak data into this aggregated area so we can use it all and come up with ultimately, as you see at the end, a risk score that will help us in that regard.

So in this risk management approach, ultimately, we are talking about the likelihood of failure as well as the consequences of failure laid out against all of the leak data we have pulled into our system. If you go to far and you look at the map there, you can see just the color coding of the segments within the system, we can tell where we probably ought to be focusing our efforts there, those nice little red ones. Thank God there's not too many.

But when I talk -- we talked about consequences earlier today. I heard somebody ask about consequences. We've even gone so far in our consequences trying to figure out where the hospitals, the schools, and everything are relative to this, and the consequences change based on the surrounding buildings.

So what do you do with this data? How do you use it? This is -- I'm going to quickly go through about three or four slides here to show you how we can take the data and use it. This data is just some sample data from one of our states ultimately. You'll figure out which state it was in the following slides because I wasn't smart enough to remove the cities. But ultimately, you take the same data and you can cut it six different ways, you can use it to your advance to really understand it. Now, you look at this slide and you go jeez, yeah, that makes sense -- I hope -- that you look at the leakage per mile -- and this is based on all data we've got, so it's multiple years of data -- but the plastics we put in in the '60s, guess what. They leak more. There's a surprise. The newer it gets, the less it leaks. Actually, it makes me feel good.

But the ability to manage leaks and work leaks -- now, you take that same data, and let's focus in on that vintage, that old plastic. You take a look at it. I've cut it by service center. This is in Georgia. Like I said, I wasn't smart enough to remove the cities here. You can see at one end of the spectrum, there's a small town in south Georgia that's got a higher rate than anyone else, and they go on down. So you use that data to go focus in on that area.

We go in even so far, we can do it by the city limits itself if you want to look at it in a different cut.

You want to take it one further, we go down to a gridded area, about 2500 feet per side, and these are -- out before 40,000 grids, these are the top counts in the state. If I were worried about where to go and do accelerated actions, let's go out there and accelerate our leak surveys, let's go out there and figure out where those segments are and renew them, that's where I went right there. You can see a couple things that jumped off the page and they have been removed. You know? So this is using data as effectively and efficiently as we can to focus those resources.

That's my last slide coming up. There you go. All right. So understanding this approach, our idea is that you take the data and run your system. Certainly, we talked about educating your customers. They are key. They've got to understand that they have a gas system around them, what to smell, what to call. Right?

Emergency response, another key part. You know, we run live drills with them. We keep trying and trying to educate them. We do fire training and these kind of things. And in both of those cases, you are dealing with third parties that it's important to get to, but after that is what we do ourselves. You know, we take that data, and of course, we schedule leak repairs, the idea being let's fix the leaks where we're not going to be able to quite replace the system yet because there is ultimately a fundamental fact of life that you can't replace a system for free. And the regulators -- the state regulators, the commissioners, understandably don't want the rates to be too high, so you have to find a nice sweet spot and balance.

We use accelerated actions, as I indicated before. When you see a trouble spot, let's quickly go out there and leak survey it, and let's make plans to address it. And then from there, you go to a focused infrastructure replacement, which is tied to that accelerated action. Let's go hit those spots. Then ultimately, by the end of the day, I think you float over to a blanket infrastructure replacement, like cast iron and bare steel.

And kind of, you know, in this kind of approach that ultimately you work your way from new plastic or from a new pipe all the way through the one that's a hundred years old and coming out at the other end of the system.

So that's kind of the way we attack it, and like I say, we use data as heavily as we can because of the complexity of it, but with that, I'm done. So thanks.

>> ALAN MAYBERRY: Thanks.

(Applause)

Thank you, Rick. Okay. Now it's time to take questions and answers, so I'd like to open it up. Anyone in the room here with a question? If you do, there are two microphones in the aisles here. Or you can write your question down, which I have a few. No takers yet.

>> Alan, did you put those $5 dispensers by the microphones?

(Laughter)

>> ALAN MAYBERRY: Yeah, that's right. We can make change if

you need it.
(Laughter)
Okay. Here's a question from the audience. We'll give this to the group. Do operators track the amount of gas lost due to leaks on transmission? I think that's unaccounted for gas question. Does someone want to take that?
Okay. Do operators track the amount of gas lost due to leaks on transmission?
>> I'll try and answer that. Yes, for transmission lines, interstate pipelines, most interstate pipelines have a -- well, not a -- they're either going to have a tracker, where they track how much gas is basically going in versus how much is going out, and the difference is lost and unaccounted for gas. That amount of gas goes into a tracker that goes by the FERC for approval, and that's updated every six months or year depending on the pipeline system.
Some pipeline systems, however, go on risk on that amount of gas on what is in versus what goes out. To the extent -- they'll have a fuel charge of let's say call it 3%, to the extent they can manage below that, they make a little bit of money. To the extent they manage above that, then they lose a little bit of money.
>> ALAN MAYBERRY: Thanks, Pete. Hans?
>> HANS MERTENS: I'd just like to offer a slight perspective on that, and it goes back to the message I was trying to deliver about technology gets you so far, and then it takes people. I can remember some statistics a while back about lost and unaccounted for gas, assuming that's also part of the question, and that last and unaccounted for gas, I remember an Indian Pueblo had 34% unaccounted for, and then there was a small LDC in New York State that was making gas. And those statistics, they were on the books for multiple years in a row, and nobody got excited about that. 34% unaccounted for or 5% making gas. Either case, it's crazy; right?
So the statistics, the technology was there, it was giving us an answer, but who the heck was asking the question: What does this mean? So let's not lose sight of that.
I think Richard touched on it very nicely, thank you. That's the important part of it.
Alan, would you excuse me? Can I make one more comment?
>> ALAN MAYBERRY: Certainly.
>> HANS MERTENS: And I apologize. I had it on my list and forgot it. One of the things Bob Smith asked to us do was rate Congress. The question was rate Congress on the requests that they've made. And based upon my slide, I hope I gave you the impression -- and now I'd like to enforce it -- reinforce it -- is I think they've done a good job for us. I think they've

asked the right questions, they've pushed us in the right direction, and it's been a very positive -- not everything, but very positive in general, and that was the response I wanted to offer. Thank you.

>> Hey, Alan, you might want to make the point about our reporting requirements. We lowered the threshold for reporting for our gas loss.

>> ALAN MAYBERRY: Go ahead.

>> I don't remember the number. I just remember that we did.

>> ALAN MAYBERRY: I know we did. I just don't have the number either.

(Laughter)

I think Pete had a follow-up comment as well.

>> PETE KIRSCH: Yeah, I just wanted to echo a little bit what Hans just brought up with a company that has 40% or a large gain. Those questions do need to be asked for those types of anomalies, I would call it, and for at least on the interstate pipeline side, there's competition that drives companies to want to get their LAUF, lost and unaccounted for gas, down as low as possible. It's economic incentive. So companies, first off, don't want to have leaks is to start with, but secondly, there's economic incentive not to have a high tracker, high LAUF.

>> Thank you. Very enlightening panel. Several weeks ago many people were talking about essentially the shale gale and how this is potentially an economic Renaissance for the United States. And in those remarks, there was a consistent theme about transparency around shallow gas drilling. To get the support from all stakeholders. So I was just wondering if you might have any thoughts with regard to transparency of leak information.

And then also, one thought about the frequency of leak surveys. A lot of great points of discussion about how you go about surveys, but I'm curious to know about how the frequency of surveys -- and that is how that is evolving in your process. Thank you.

>> ALAN MAYBERRY: Someone want to comment on that?

>> REJI GEORGE: For the El Paso pipelines, our leak survey process is driven by what aerial control does and what gas control does, so we fly our entire system typically every five weeks. There's a visual inspection that is done. And some segments of the pipe, that inspection is done every two weeks. The gas control monitoring is around the clock, and we have segments of pipe that are odorized, so there is, to some degree, monitoring around the clock if somebody were to smell gas leaking.

>> ALAN MAYBERRY: Also, from the PHMSA perspective, we do require operators to report leaks on the annual report, and then

also, of course, reportable leaks. And speaking of transparency, that information is posted on our website. And then furthermore, you know, speaking of transparency, that's really why we're here. This group is an important data point for us as we look at our path forward. As we prepare a report to Congress, that's required by Congress, and then work on a path forward as to where we should go related to leak detection systems. Hans.

>> HANS MERTENS: Just one more comment on that because we sort of have a distribution/transmission ying/yang here. From a distribution perspective, I'd like to say two things. First of all, thanks to the Public Pipeline Safety Trust, who has encouraged transparency. You may know that that organization has rated all the states as far as giving information, as well as PHMSA, I suspect you've got a rating too. PHMSA did the best because they have a very good website, and it's all very open and so on. The rest of us are trying to catch up. But it's a pressure point, and we will get better at that.

Number two, as to what about this leak survey program, I appreciate that question. DIMP, if you would, encourages operators to look at what they have, improve what they have if they can. If you try something and it doesn't work, try something else. And DIMP allows you to do that. You have to justify it, you have to make sure that it does work, and you have the backup, but then go your own way, customize it. And I think that's going to be a very positive element.

>> ALAN MAYBERRY: Thanks. Next.

>> I'm Arnold with quantum dynamics. Just a general question. If FERC lowered down the allowances for measurable error, would that make a significant impact in your efforts to improve pipeline integrity? Because right now it seems like it's almost open-ended as far as the allowances for measurement error.

>> REJI GEORGE: From a measurement speck, you look at the best meters we have in the industry, probably the allowance is half%. The best meter system we can build is half a percent. What we are looking for in terms of losses is a lot less than half a percent. When you look city system, we cannot use a half-percent measurement system to find the type of leaks we are looking for. That is the difficulty. If you are strictly looking at mass balance, current technology does not allow you to get there. And we have tried that on the El Paso system in several segments of pipe just to see can we utilize some of that data to help us find leaks, and we have not been successful. But we have used that data to manage our LAUF numbers as well.

>> ALAN MAYBERRY: Let me sprinkle in a Web question, if I may. This one's for the panel. Could the panel talk about the

use of inline inspection tool data to identify potential leakage risks? This would be a question not to lean on the operator part of the panel, but can you speak to that? Yes, please, the operators.

>> MIKE FUTCH: Speaking from a NiSource perspective, we try to take every opportunity we have to collect data and information on the pipes. That includes when we run tools. It includes when we do bell hole inspections. It includes whenever we tie in new facilities to existing facilities. It includes when we fly the pipelines and when we do our instrument surveys and when we do our visual surveys. Every opportunity we have to collect information is a driver for us in that continuous cycle of integrity management.

So I think the obvious answer is yes, we do use tool results to try to show us where we might have an opportunity to improve our integrity management performance. I don't know that it would speak directly to whether or not we're going to have leaks. Obviously, it would show you where you've got some -- some room for improvement as it relates to internal corrosion or external corrosion, but speaking specifically to leaks, I don't think one tool with point you in the right direction independent of all the other factors that feed into your risk model.

>> I'll address that a little bit. I think if a company has multiple runs and they can trend the corrosion growth rates or if they see an indication where they have a significant increase of corrosion or anomalies over time, they can use that data -- and I won't say they can determine where leaks will happen because I think you are correct on that, but they might be able to trend an area of their system prone to leaks because of that aggressive corrosion activity, whatever the reason for that is. They would have to go out and investigate some of those anomalies and determine what's causing that.

We've seen that for AC interference, DC interference. In cities we've also seen that where you may have a system where the CP system isn't operating correctly or improperly. There is some advantage to having multiple tool runs over time so you can trend that analysis.

>> ALAN MAYBERRY: All right. We have time for one, maybe two more questions. Let's go to Dr. Keith Levis.

>> Hi. I was going to -- yeah, Keith Leewis at PPIC. Back to perceptions. Your R&D has been shown to be pretty fruitful, and we've talked about it this morning, and we have another session this afternoon. And I know that sometimes the value of your program has been doubled or tripled annually through cofunding, yet there's a perception out there that maybe we don't play very well together, and cofunding will no longer be accepted as part of the program. And I don't know if that is

just a misperception or if things have been straightened out over the period of time.

>> ALAN MAYBERRY: I think clearly -- thank you for the question. Related to R&D, clearly, in reauthorization, we've been given direction on how to manage cofunding. Certainly, we've learned a lot over the last couple of years. I think we'll take those learnings to work cooperatively and leverage the funding. The funding, regardless of the source. But you know, that's about all I can say on that topic. I don't know, Jeff.

>> JEFF GILLIAM: A little more information I can offer you is we have restructured the program. There will be cofunding. It will depend upon the type of research and what the specific project is, whether we choose to do 100% PHMSA funding because we feel like it's a safety-sensitive issue and we want to make sure there's full transparency around that, and I would say no perception of undue influence, and there will be other projects where we fund more than 30%. Obviously, Congress has a 30% mandate in there. But the program has been restructured so we have the option to do both, but there will be cofunding, and we look forward to doing that, and I think we can probably add a lot more context around that in July during our research forum. Okay?

>> ALAN MAYBERRY: All right. We'll take one more question in here.

>> Terry Boss from INGAA. I just wanted to articulate a couple things. The discussion about loss and unaccounted for, that is an accounting term of what goes in the system and what goes out, the difference between those two. As Reji articulated, there's accuracy in the measurement systems as compressibility in the pipeline systems, there's fuel being used, so that is a very rough number on that part.

Typically, PHMSA has been working on leaks, accounts for the amount of gas that goes through incidents and has that number out there, does not necessarily collect the data on small leaks, but they do identify when those leaks occur.

In the meantime, EPA is doing, under subpart W, an accounting, and I would argue probably one of the stiffest accounting mechanisms out there for capturing GHG emissions, and we're just completing that for last year and putting through there. So there's three different ways that things are being measured, but they are slightly different on how they put those things together.

>> ALAN MAYBERRY: All right. Thanks, Terry. I'll take -- I guess I'll read one question that was given to me on a card here. The subject of improving integration of data has come up today a few times, not to mention at the workshop we had last

summer. What is PHMSA/NAPSR looking for as a next stage of continuous improvement and integration?

I think I'll flip that first to -- Hans, you want to take a swing at that?

>> HANS MERTENS: Don't you think Jeff ought to answer it?

>> JEFF GILLIAM: What I would say there is, like we said last summer, a good system will have a geographical basis; right? They have GPS information on your facilities that allow for integration of multiple data streams, which includes ILI data, CP data, one-call information as far as where the one-call data is coming from. It will have your anomaly information. It should have your facility description, along with its data for the pipeline system itself, the size, the wall thickness grade, et cetera. If it's been hydrostatically tested, all the information that you would think would be necessary to evaluate the risk of a system should be able to be seen visually and be integrated all in the same context on the same screen. That's what we're looking for. That way you can analyze many things. I mean, having an aerial photography in the background and seeing a lot of anomalies and you see a pipeline as an example coming in and out of a power line corridor can immediately help you say oh, maybe I've got AC interference here because I got voltage pickup on the pipeline, and it's trying to exit once it leaves the pipeline corridor. That is a very common phenomenon that happens, and it's very previous leapt where you share these right-of-ways in the west and also in the east.

So that's just an example, and that's where I think our viewpoint is on that at this time.

>> ALAN MAYBERRY: I think one other point, along the lines of being a common theme today, specifically related to leak detection. I think some good examples have been brought out about how the moral of the story is don't put all of your eggs in one basket, and look at multiple systems and look at data from multiple systems in determining whether or not you have an issue.

Anyone else want to weigh in on that?

>> HANS MERTENS: I'm not going to follow up on that comment. I tend to agree with it. I think you captured it nicely.

With regard to integration at the distribution level, I think the information that state regulators are looking for is accurate information. I gave a story earlier about a measurement off the boxcar. Well, if that measurement makes its way into the data stream, garbage in, garbage out. You remember that old story. So there's this filtering and this clarification and so on and so forth. And so the integration of data, first of all, is it good data, is it relevant data, and making sure that you have that.

Folks, you know that a lot of the data at the distribution level, which was generated in the '20s, the '30s, and the '40s, and even more recent, is not good data. And so there needs to be a cleansing, and it needs to be fixed in some regards.

So the integration, the prime challenge that many of us see is accuracy, relevance of data, and making sure that it tells the story so that the conclusions that Jeff talked about can be reached.

So it's not a complete answer, but as much as time allows.

>> ALAN MAYBERRY: Okay. Thanks, Hans. We're going to go to break right now. It's four minutes after the hour. We'll reconvene at 19 minutes after. We'll do 15 minutes. Thank you.

(Applause)

(Session on break until 3:19 p.m. EDT)

(Please stand by.)

>> ALAN MAYBERRY: All right. If you would please take your seats and we'll get started.

Okay. Please take your seats. We'll get started. We will close the doors. Hey, Bob, do you want to catch this one?

Okay. We'll get started with our fourth and final panel.

Again we will follow the same format as the last panel. We will allow the presenters to talk and then at the very end we'll have a Q&A session.

So please, we value your questions. Consider them as you hear the presentations.

Panel 4, the topic is natural gas leak detection system capabilities and research. So there will be a high focus on state of technology in this afternoon's, in this last session here.

Again, we are looking at factors that you'll probably hear a theme that continued from the morning, even concerning redundant systems, capex and opex expenditures, how to address false positives, human factors, environmental factors and the state of technology and also where there are gaps in technology.

This afternoon we have five panelists. We will kick it off with the first subject matter expert, Richard Kuprewicz, president of Accufacts. sME number 1.

>> RICHARD KUPREWICZ: Oh, man, I have been called a lot worse. And I'm about to, too.

>> ALAN MAYBERRY: There we go.

>> RICHARD KUPREWICZ: Good discussions today about some of the

stuff. Some will be repeated. A lot of it does apply to natural gas and some of it doesn't. Let's go real quickly here. I want to comment most of my discussion this afternoon will be focused mainly on transmission. Ways glad to hear some of the distribution discussion. I think the important point is, most of you may not need to know, but a lot of the Web listeners may, transmission is an entirely different animal in many aspects than distribution. We may call gas leaks, the vast majority of the problem with transmission is high profile events that get everybody's attention and those are the ruptures.

The leveraging issue, from most of the public, not to down play the importance of leaks because some leaks can be very dangerous on the transmission system but the ruptures are high profile no matter where they occur and the consequences of them. Briefly touch on internal versus external as we did this morning. For liquids there's similarities but again serious differences regarding compressibility challenges. Transmission are more likely to have SCADA computers. Depending on the integration of the system they may or may not have SCADA computer systems.

I think it's important to realize and keep in perspective without alarming folks, it's a scientific fact that on most gas transmission pipelines ruptures can put more hydrocarbon tonnage into a neighborhood than any other form of transportation. Scientific fact. Understand that and then appreciate it. Not to be scared, but just respect it.

And remote rupture detection, even the high profile, blowing the pipe out of the ground events, it's harder to determine even remotely than it seems. That's something that you need to convey honestly and straightforward to the public. While you try to meet this challenge.

As I mentioned on the internal monitoring system similar to liquid but more of a problem with gas, the compressibility makes identifying via control center extremely challenging. Approaches, again I may get difference of opinion here, but across 40 years of various investigations and evaluations and looking at many different companies, mass balance has proven to be highly unreliable for many reasons. Pressure drop, the nature of a rupture, by the time you recognized pressure drop, it's probably way too late.

There's some discussion about the rate of pressure drop and then we'll probably talk about this -- not probably, we will talk about this tomorrow afternoon when we get into the valve discussion, for liquid and also for gas. Rate of pressure drop is a more commonly used technique for automatic shut down valves. There are challenges with that approach as well.

Again, especially if you've tied it to a single signal that triggers a valve that can be closed. You get into that signal, single signal approach and you've set yourself up. You heard this morning about the importance of having some sort of independency. If you want high reliability you don't link the systems together with a single pressure input data or point or whatever.

We believe more reliable approaches will be associated with monitoring for gas transmission is looking for flow changes. I think you'll find that will tend to be -- not always, but that will tend to be in most rupture scenarios a quicker possible indicator. Not the only indicater you want to use but may be one the second backup signals you want to be looking for. Again you have to understand how do you measure the rate and how reliable is it. Are you operating it beyond its intended design in terms of trying to determine flow changes.

More likely, especially in terms of valving issues, whether they be remote or automatic, you are going to look at the independency of independent systems, at least two signals coming from different sources that would say you really need to be looking at this. This is telling you you do have a rupture. Either you trigger automatic or the SCADA operator would say shut down.

I need to be very clear here, in the combination of indicators, complex transmission systems -- and there are some who are less complex. Many that are very complex. I'll just leave it at that, and the more complex the system, the more challenging and so again, rupture detection can be something that is very difficult to get to. And the term of a gas transmission operation, there's a high probability that you'll over load or distract the control center with way too much information. You go into the control centers for gas transmission, you find that many are getting false alarms, whether for rupture detection or leak detection or normal operations. This is an issue as I mentioned this morning, the control room management was trying to get a better gauge or guide into the operations of a pipeline.

You need to strip them out of these false alarms. It's setting everybody up. I think the key is if you are going to use SCADA computer systems or some related system that plugs into a SCADA system you want to be asking the question fundamentally, is the computer logic working for the operator or is the operator control center operator working for the computer?

And we see this all the time. In today's information age coming at

everybody with all this technology, we find that we suck our employees into working for the computer when we ought to be spending the effort to make the computer try to work for them.
It's hard work, by the way. It's not something they can say and go do. It takes a lot of effort. It is not unusual given past history to have field confirmation of field rupture before you start shut down especially on some of the more, shall we say, critical pipeline systems.
On the external monitoring systems, very similar to what I parroted this morning. There's various types of technical approach. What I call the sound frequency. You can give it a different name. A lot have been around in terms of developmental for many years. What may be changing is a different approach, how the data is interpreted or presented. Hydrocarbon detection is another way. Again, the gas has to get to the sensor and there's all kinds of ways. Once you decide to put a hydrocarbon sensor detector on a pipeline, there's all kinds of ways that they avoid that sensor. There are challenges with that. I don't say you don't say you don't consider that approach. But how you place it, where you place it. Various approach on fiber optics. They tend to be limited in their length which all the monitoring systems, that's a problem for longer transmission systems.
Where do you want to get the bang for the buck and you move into high consequence areas, which tend to be shorter. Not all of them but some of them are relatively limited in length. There are various fiber optic approaches that are very promising. Signal noise ratios are very screening. There's exciting stuff going on, especially with the military. I ask you as you look at the resources as an industry, look outside the box.
Challenges, limited pipeline length, signal noise ratios as I mentioned. If you get false alarms, if you get leaks, if you get a rupture, you have to decide we're going to treat this as a serious issue. Some of the external monitoring system in a catastrophic pipeline rupture where it blows the pipe out of the ground. It will snap the signal, snap whatever the device is. Some of them are built in so if it did break it will act as a signal. The problem is a guy digging with a shovel could be doing the same thing. There is a complication there.
Most likely you'll use the external monitoring systems in highly limited applications and those are the things you have to wrestle with.
Again I need to just mention here because I don't want to down play it, the aerial leak monitoring, you heard several times, for transmission and distribution leak monitoring. That has been around for several years in various forms. The Europeans may be one of them, I may be out of turn, one of the areas where that got a lot of use and then it came to the U.S. and that technology is playing

helicopter vehicle, that's been covered.
The advantage per leak detection, not, the aerial monitoring is highly effective, you can make it work. It's not realtime, however, but a good way to track it down. As you heard a lot of companies are finding that to be very cost effective.
The key in a lot of this stuff that we have seen in various aerial signaling, whether it be FLIR or whatever, is in the presentation software and the algorithms and that kind of stuff. You're looking at a lot of value and you have to get it down to something and the leaks aren't always pipeline related. Anyway, that's it for me.
(Applause.)

>> ALAN MAYBERRY: Thank you, Rick. Next, our next subject matter expert is Dr. David Shaw, managing director of Technical Toolboxes Consulting.

>> DAVID SHAW: Good afternoon again. I'm going to be following very much the sale philosophy that I used this morning in the presentation. For those of you who weren't here this morning, what I'm going to try to do is to go through all of the agenda items in the workshop program one by one. And of course, in 15 minutes there's no way I can address everything in a lot of detail. So I'll try to pick out a few of the biggest issues that I feel are worth discussing in each of those topics.
Please look upon this presentation as a way of trying to encourage discussion on these items, not necessarily as finalized observations.
I did also say this morning that I have the privilege to work with a large number of different pipeline operators. And I would say that half of them are natural gas companies. So let me start with this and it's kind of entitled with a view to people who see my morning presentation, but I did want to say in terms of flavor, what is different between gas leak detection and liquids leak detection, especially because there's a huge amount of overlap in the physical principles and the technologies that you use in both areas.
Now, there is internally based leak detection system in gas. And in that kind of environment you are doing the same thing. You are taking instrumentation, metering on the pipeline. You are building a model of what the gas should be doing in the pipe. And you are

comparing the actual measured state against that theoretical state of the pipe.

Now, first of all, with liquids I would say that the technology of calculating that state is fairly well-known. In the case of gas, the very calculation itself is something that is quite difficult. The issue being compressibility and the fact that you get pronounced shock waves inside the gas in transient conditions.

It also makes the comparison itself between two states very difficult because in fractions of a second the measured State will change. So you have to be running calculations that are much higher level of granularity.

I will simply explaining why internally based, model based leak detection has a terrible, terrible reputation in gas pipeline industry. I will also say that it is not something that you completely ignore. I mean, understanding that these are the challenges that you have, there are successful realtime transient model based transmission systems out there for the bigger transmission systems.

While passing through I'll repeat something that Rick just said: There is a world of difference between big transmission systems and smaller local distribution systems. In fact, in between there are medium pressure systems which are sort of like city gateways and so forth.

The point being we are now talking about highly networked systems. That means that straight point to point balance types of things won't work at all. You have to go all the way to a realtime transient model. That means you have the added cost of expert operators. That very often is another missing link in the success of these internal LDSs.

On the flip side, external sensor based technologies rule in the gas world. So they are used much more often than they are in the liquids world. That's because quite simply when methane escapes, it is very volatile. It's very visible against the background and the atmosphere.

And so I put 50 percent, I would say it's much more than that. Probably 70, 80 percent of leak detection is done with sensor based technologies.

And these can be, as we will be discussing, hand-held, aerially carried and they can be permanently mounted. One thing I would like to point out, that the frontier is to save money and to increase response time by permanently mounting certain of these sensors in rights-of-way.

I will also say finally that -- I'll come back to this because gas companies are good at using multiple sources of information to detect a leak. Typically you don't have just one atmospheric sensor. You have a couple of principals going and you have foot patrols and you have called out crews as well.

So the ability to use multiple sources of information to detect a leak is quite advanced, actually, in the gas industry.

The reason for this is the gas systems are engineered from the beginning as typically they are engineered as safety critical systems. So they already have things like we heard this morning like automatic shut-off valves. They already have systems like dual levels of protection on the SCADA, when there is any.

So there is a large amount of redundancy already built in to the system. I should say backup in my language, meaning that there is a very low risk of failure of any one of the controller instrumentation systems on natural gas pipelines.

I think again what we are trying to do is we are trying to run multiple different strategies in parallel on the same pipeline. Using different physical principles and using different philosophies and integrating them into one common decision on when to call an alarm.

I am going to repeat what I started saying on the first slide. I think right now the state-of-the-art is to take sensors and either hand carry them or to fly them, and very often this is out-sourced. So you have service companies who do this for you.

I think one thing that really is a direction that gas companies should explore is owning their own sensors and placing them strategically. It's true, they won't be 100 percent reliable because wherever you place a sensor, the gas is bound to miss it. But at least if you've got this as your third arrow in your quiver, then you've got something which is permanently online. I do, of course, endorse getting a minimal level of communications on these pipelines. Right now a SCADA system is not mandatory and there are a large number of gas operators who operate without gas control, because quite simply their operations are real simple from an operational point of view.

For this one reason, for improving the safety of the pipeline, I think this is something that also every gas company should look at.

The final bullet, I think, is something we should really be thinking about. The pace of technological improvement in sensor technologies is dramatic. I mean, every year you're getting a new technology out. They are, there are, they are consistently more and more sensitive and tying -- they are attractive in this area and something that have to be thought about. Gas companies need to have a technical horizon which in my opinion is very, very short. Every year, perhaps, there should be a refresh of the kind of strategies with respect to technology as opposed to maybe liquids pipelines where three, four, five years might be adequate.

Now, handling false alarms is of course a huge issue. Back to my comments on the realtime transient modeling. It is the killer for realtime transient modeling because it tends to give rise to a very large number of alarms.

And I have the suggestion, I made it this morning. It should be a situation where you call alarms in an escalated manner. If just realtime transient modeling is giving you the indication of an alarm, it should go to yellow. If now also a couple of sensors are giving an alarm in the same area, it should go to orange. And if you send somebody out there and you've sent an inspection bull down the line and they are all agreeing it goes to red and that's when you tell the operator, the controller, I should say, to shut down the pipeline. This strategy of integrating different sources of information is very important to this particular issue.

Gas companies do have another benefit, which is that they are pioneers in the data integration space. We just talked about this now. They are partly because a lot of the LDCs are also utilities, they have been pioneering the GIS concept. GIS is just a tool. It doesn't necessarily have to be geographical, but it is an excellent way, excellent vehicle for integrating all of these different sources of information.

I also pontificated this morning about trying to take a risk based approach to detection. GIS is being used for risk assessment very effectively in this particular industry.

I am going to go to the who owns the LDS point on this slide particularly. I think that one place where improvement might be had is to have the gas operator, pipeline operator own the LDS themselves, out-source less, take responsibility in house a little bit more.

I know there are economic issues and so forth. Even from the point of view of being able to be very, very targeted with the technologies you use and for internal capacity building reasons as well it's good to take ownership of the inspections as far as is economically practical.

Naturally many, because they are highly networked and fairly complex, all the noise around the pipeline contributes to making leak detection more and more difficult. One of the areas we need to think about is the shale gas kind of development. In that kind of environment with literally thousands and thousands of gas gathering lines, I think we've got a big challenge in trying even with sensors to try and detect the leaks from the overall background noise of all kinds of other gases and all kinds of background natural biological gases and so forth.

I see these as big challenges. Of course, anything in a complicated production environment.

I will say one final thing. This is in common with liquids. It is still very difficult to detect small, small leaks. They are still dangerous F they are small and they persist, they are still hazardous. A number of technologies won't get past a minimum-minimum threshold, including acoustic sensors and other sensors. That's one area for fruitful research. Again, I think the

area -- very fruitful area of research is to keep, for example, the vehicle, the carriers for some of these sensors and turn them into much more practical and much cheaper alternatives.
I hope that that will give rise to some discussion. And glad to take questions afterwards. Thank you very much.
(Applause.)

>> ALAN MAYBERRY: Thank you very much. The next speakers will discuss research. And first up will be Dr. Kiran Kothari, who is -- I'm sorry, change the order. Yeah. We actually went through that really well before this.
The next one will be Daphne D'Zurko, the Executive Director of NYSEARCH and vice-president RD&D of NGA Association. Daphne will discuss research as far as what is going on at NYSEARCH. I understand you have a plane to catch.

>> DAPHNE D'ZURKO: Yeah.
Thanks to Alan and Bob and Kiran, thank you for switching with me. I do need to beg off after the talk here. I'm going to talk about research from the NYSEARCH perspective. This afternoon is getting complicated and we're switching back and forth from transmission to distribution, all of. That I like to make analogies. It's springtime, baseball coming. We have the American league and national league. We all play baseball. Today we're all about pipeline safety and continuous improvement in pipeline safety. We are all playing baseball. We have a development H, but in general we are all playing baseball. I'm going to talk about past, present, future with leak detection system that we have developed. To give you an idea who is involved, this NYSEARCH is a voluntary RD&D association, we focus on product development, testing, technology transfer, and commercial implementation.
And those are all elements of the R&D process. These are our members. Primarily they are local distribution companies. Some of these local distribution companies own transmission pipelines. Over the years we got very involved with pipeline integrity issue with transmission and as a result now we are involved with some transmission companies. But these folks have been involved with leak detection over the years under our voluntary program.
So this is sort of a catch all slide. I will go into these in more detail. Some of you are aware the remote methane leak detection that started with an RFP we worked on in 2000. And we got involved with physical sciences incorporated in Andover, Mass. Shortly thereafter Heath joined us and that's successful since 25. We looked at using RMLD for other things and partnered with Gas of France in 2006 to look at RMLD for mobile survey. We have been

involved in Bat El and others in acoustically pinpointing techniques. I forgot to mention I'm going to talk about successes, accomplishments, but also challenges. There are challenges in here and things we didn't do. I'll talk a little bit about them even though my point is, I guess, not everything is going to fit the application, but we have looked at a lot of stuff.

We did an RFP in 2007 to advance leak pinpointing. I wanted to underline pinpointing. Classification and location approach, pinpointing is getting the exact location even in dense, urban areas. The leak pinpointing process is not the same as the leak survey process.

We wanted to look at advancing a very good process with continuous improvement. We also developed a variety of test plans and we will hear more today from Mark Piazza and others about aerial detection. We considered that for the distribution and tested that. We looked at tracers and in inert gases, in the fluorocarbon -- you don't have to catch all this in the slide, but we are active with PHMSA in a technology that we found through the Oracle program and for years we have been looking for the ability to equate to to the accuracy and reliability of the human nose. The human nose measures down to parts per billion. For that application of measuring the mercaptans, most of the stuff we could fill is in the parts per million level.

Partnered with PHMSA to kind a mercaptan sensor that we like to call the smart nose.

Finally there's other approaches that we have. We are looking at quantum leap technology and active now in a low cost highly accurate methane sensor that may be held as an operator as they walk into a building or on their clothing, things like that.

In terms of the future, you heard about the card technology. Mark will go into that. We recent have gotten into discussion with Picarro and feel that's one of the things to evaluate. That's one of the future things we want to be working on. Moving into the advanced testing of our smart nose technology. We think we need to advance technologies for leak repair. I'll talk about that, as well as getting back into pinpointing.

So going back to 2000-2001, these are the original specifications, at least most of them were original and they held up over the years. There have been ground breaking technologies, I believe, in the distribution sector. Some of they will are getting a little dated, but it took us about five years to fully develop and test remote methane leak detection. The idea was to take the operator out of the plume, at a distance being able to remotely survey a leak. We are using laser based technology where you shoot a laser through the plume. It reflects back and you measure a signal. It is no longer a straight concentration measurement. It's integration through the plume, a PPM meter.

Initial vision, we wanted something down to single digit PPM. It's 5PPM meter sensitivity, it turns out. That worked well. The idea was to improve safety and help folks do more walking survey. The other thing that's really nice about the RMLD, it can get inside locked buildings. In the early experience with the job, we were doing pinpointing in Brooklyn and there were a lot of houses we could not get into. This tool is field rugged and really taken off. Proud of our partnership with Heath and Heath

***

***