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U.S. DEPARTMENT OF TRANSPORTATION
MARCH 28, 2012
7:00 A.M. CST
IMPROVING PIPELINE LEAK DETECTION EFFECTIVENESS

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>> JEFF WIESE: I am going to issue you a five minute warning and then we will get started. Check on the Webcast? We are good? Are we up and running? Thank you. Before we get going on this -- actually it has this section that we are going to be talking about. Good morning, everyone.

>> Good morning.

>> JEFF WIESE: How many of you were here yesterday? A number of you. You travelled all this way. (No audio). (Technical difficulties. Standing by.)

>> JEFF WIESE: People in the audience -- you will see that at the bottom down here. We have this Archean notion of creating dockets. If you go to regulations.gov, for example, the docket number, just remember PHMSA and 2012 and this is 0021. You will be able to get to most of the materials. You are also invited to submit things and to those of you who are watching the Webcast or otherwise tuned in we welcome your input. As the rest of the slide sort of makes clear we are really at the first stage of a process now. To develop the information we are going to need to conduct a study and to inform you and inform the U.S. Congress about the role that valves play. We want to understand the positive attributes as well as the challenges to some of these installations. So we will be looking really at both new and existing pipelines for this question. And not -- I will get to that in just a second

if you allow me, but I guess that this is the appropriate moment. We do have some folks here from the government accountability office. I would ask that they stand up quickly so that you as the audience can identify them. Thank you for coming in.

They got mandates out of this along with us and they are eternally grateful to us for it. But we have known each other for quite awhile and we continue to work well. The reason I introduce them I would like you to think about particularly for the application of valves on existing infrastructure, I think that that's going to follow largely in to the domain for the GAO report. The GAO is also taking a look at the operator's ability to respond in HCAs and obviously is one of the factors in considerations. Listed some other things that the Congress thought that GAO should consider here but I have listed Matt's -- sorry Matt, we listed your phone number and his e-mail here and encourage you to contact the GAO if you have information. Of course, everything that we develop here is intended to help inform them as well. They have the responsibility of reporting to Congress I think a year earlier than we do. So good luck with that one. We will be glad to help you as such as we can.

So at any rate today's meeting is going to be interactive. We are going to have panel presentations. We will have opportunities for Q and A. As I saw yesterday when we provided the index cards to people and we give them the opportunity to write their questions on an index card very few people will stand up. So those of you who were here yesterday I slipped a note to Linda to say always priority to anybody who is willing to stand up. Also worth to note the secretary has been Tweeting about this meeting and it generated quite a bit. I forget the numbers yesterday Bob. Over 500 kind of re-Tweets or responses, whatever you call it. My daughter would be humiliated right now. But there is a Twitter fall on the Webcast.

If you are interested in what people are saying about the meetings, people's presentations, you can dial in to that and see the Twitter fall. I do want to encourage you to stand up, use the mics, identify yourself and your affiliation. My usual warning that I give people because I have learned over many years to be a stern moderator and I have trained some of the others who will moderate stay on topic. This is really a study. We are here for one purpose only. We are not here to debate other issues. We are here to talk about the subject matter of the meeting. If you stray too far from that we will probably cut you off. The other warning if you are here to promote your business we will cut you off. It is not an opportunity for that. There is a clear role for venders and service suppliers. So it is not meaning to be disrespectful to these people but our purpose here today is to begin a study. Just fair warning on that one.

So for the Webcast attendees just a reminder you will see the e-mail address on the Webcast. If you want to address your question to somebody in particular, please do so. We need your input. So feel free. I will say that the moderators have some discretion here. We got a lot of questions. Oftentimes they are very similar and a moderator can roll up a bunch and say here is the general issue we are talking about. Finally I want to say we do have some venders that are out in the area around the corner and I would encourage you to visit them. I think it is very informative for you to be able to have an opportunity to talk with these people one-on-one if you have any questions about their technologies. We do not provide any endorsements for any vender. It is illegal for us. I will turn this over to Alan Mayberry. Alan is going to be your moderator for Panel 1. Alan is the deputy associate administrator for pipeline safety in the area of field operations and emergency support. Thank you, Alan.

>> ALAN MAYBERRY: Oh, I might need that.

>> You want me to give away this iPod?

>> ALAN MAYBERRY: Thanks, Jeff. Good morning. Today like yesterday we will use the panel format. We have three panels today. First one will be on focused on hazardous liquid pipelines and the topic today is automatic and remote control valves and understanding the application thereof. Similar to yesterday the -- we will have a lead-in from a federal perspective followed by the state perspective. Then an overall national perspective of liquid pipeline industry followed by two operators. So four panelists in all today. Each one has 20 minutes. I am very strict with the time. Remember that. And the topic today we gave the charge documents or the guidance we gave was to, you know, a couple of issues here to explore were the use of emergency flow restricting devices were commonly used, the experience with implementing and installing them. Obviously the cost issues were another factor. Environmental factors, internal operating conditions that impact the performance of these valves. We had a topic called "Do valves leak." Of course, there are two perspectives there. Dealing with leaks on the valves and shut off of the valves is the other. Is there a concern for increased risk of -- with installation of valves from a security standpoint and also from inadvertent shutoff. We will start off with Chris Hoidal, pipeline director of the Western Regional Office. I thank Chris for coming this week and he is joined by Wee Wen. He is an operations supervisor in Lakewood, Colorado. Without further ado, Chris. Chris, I assure you the other region directors will

have their opportunity coming up. (Inaudible) was here yesterday and paid his dues.

>> CHRIS HOIDAL: Good morning. I am Chris Hoidal. My primary job is to enforce the pipeline regulations. 26 inspectors enforcing regulations investigating accidents for the 12 western states. Key thing that occurred was 2010 we sent one of our inspectors to assist in the San Bruno accident. We assisted the California PUC and the NTSB, and one of the key findings of that action is emergency valves and the time it took to shut the valve and we quickly knew that NTSB and Congress would be giving -- sort of charging us with basically revisiting the excess flow valve issue.

Today I am going to talk a little bit about just the nomenclature, the word "excess flow valve", we got to get the semantics down and overview of the code requirements. We have code citations related to the placement and operation of AV valves and talk about emergency response and the Montana task force. That was something I entered in to the Montana governor's state agencies on accessing the conditions of the river crossings in Montana and how they are -- how they isolate the pipelines after a spill. And that all came about after the Exxon Mobil spill last July and what are some of the concerns with using valves, where to put valves and give an overview of what the state of the industry is.

So the primary purpose of my presentation is kind of just to frame what we are enforcing and what we are seeing in the field and I will let the rest of these guys fill in the gaps, but I will give an overview from a regulatory standpoint. AV, automatic valves are not used widely in the industry. This is where the pipeline will shut the valves. I don't see ASVs being used widely in the industry. You see remote control valves usually. Where information is gathered and the operator of the control system makes a decision to, you know, shut valves in a certain sequence and makes a decision which valve to shut.

Key thing with the remote control valve you have to have access to power. You have to have a communication network in place and in the West that could be problematic with some of the remote pipelines that we have.

I know. Another term that is used throughout the thing is emergency flow restriction device and if that we throw in check valves to function upon shutdown and when the backflow will shut and remote control. I mean that's not 100% of the time but that is what I put in that bucket.

Okay. So there is regulations. Despite what the latest mandate is and we have got mandates in '92, '96, 2002, 2006. Yeah. Every four years or so we are getting mandates to improve valving and valve operations but there is stuff in place. Under

Part 194 they have to calculate worst case discharge based on how long it takes to shut down the pumps and to -- basically based on where the valves are and how long it takes to actuate those things and calculate a worst case discharge. Under Part 195 we address valves under design construction and integrity management. Come back to 194, 105. It is the calculation, basically time to shut down the pumps. Time to actuate the valve and then the draindown from that valve down to the low point of the pipeline.

Under valve design requirements for pipelines themselves, it is pretty generic. It is sound engineering design, compatible pipeline material, indicates position of valve and market manufacturer data. If you comply to API 60 you are meeting all these requirements.

Now when you get to the actual construction, it gets a little bit more subjective. If you look at this, it says the valves have to be installed in a location as accessible to authorized employees. And also has to be protected from damage or tampering. I want to come back to that first one because you sometimes get in the valve accessibility but in areas like rivers or wide flood plains you sometimes have to be pretty far distance from the river itself and close to a road.

So while that may have been appropriate 40 or 50 years ago we might want to revisit that part of the regulation. Construction, this is a little bit more explicit where valves need to be placed. It doesn't talk about the actuation of those. Each line entering or leaving breakout storage tank area and here is a very subjective one. At locations that will minimize damage or pollution from accidental discharge. Get back to more prescriptive. Lateral takeoff from trunk line. At each water crossing more than 100 feet wide.

While that is a requirement it doesn't say how far it can be from the water crossing and then each (inaudible) holding water for human consumption. So this is from a design and construction standpoint this is what the current federal regulations require. Now under integrity management under 452i there is requirements for preventive and mitigative measures to be put in place. There is a lot of focus on assessment of pipeline and then assessing it with pays or tools, but one part of the regulation that people don't seem to focus a lot on is 195 452i which is preventive and mitigative and that kind of pulls in things like you are evaluating your pipeline from external forces, landslides and also talks about placement of EFRDs and leak detection systems.

These are the factors you are supposed to consider when you are putting in EFRDs. You guys can read it but basically it is look at the topography, location and nearest response personnel.

These are all things that should be considered when you consider where to put an EFRD and how to actuate it.

Okay. So we talked about the regulations. There is some regulations out there. As far as EFRDs most of that resides in existing integrity rule. Last September we had an emergency response. Mitigation preparedness and response and recovery. As far as EFRDs are concerned mitigation is where I can really help out. Making the size of the problem smaller, spill less or making the duration of ensuing fire or release of natural gas or liquids less. So we did talk about the need in our response forum for EFRDs in December.

Okay. Let's get back to the task force. It is to see what companies are doing in assessing water crossings in Montana. I am going to talk about Montana. There was 82 water crossings of hazardous in Montana. About 70% of those were trenched in. Where they were susceptible to scour. 30% are HED but regardless whether it is trenched they had to have valves on both sides of those crossings. And in the state of Montana and in Northern Wyoming we looked at the northern river basin, everyone had valves in place but the differences were how those valves were actuated. There were some that had, you know, remote controls. They had -- they were close to the river and had very limited discharge in to the rivers and other ones were some distance away outside the flood plain and they were manually controlled. The worst case discharges are the Montana study range anywhere from 200 barrels to 10,000 barrels and these are for similar things. Same topography. If I had to guess what the mode or what the frequent worst case discharge for these river crossings I would say it was around 2,000 barrels.

I want to go back to that one more second. I want to stress that all the valves on the upstream side of these river crossings were remotely controlled because they are in some remote areas but they had figured out some way to get power in them and equip them with some type of SCADA controls. So I can't think of an acronym for this Jeff.

>> (Off microphone).

>> ALAN MAYBERRY: TRC.

(Laughter).

>> ALAN MAYBERRY: Yes. Anyway, it is telling us it is pretty explicit. We have to go back and restudy. All the accidents that I have had in the last two to three years had some valve component. When I say a valve component either the valve failed or the wrong valve operated or there was improper maintenance on the valve which caused it to leak. They all seemed to have some valve component which was a little disconcerting. So we need to have a study done by January 2013

and I think the Montana governor's task force is a kernel, we can build around that but January 2014 we need to make a decision regarding the use of ASVs or remote control shutoff valves. Ten minutes. Got it.

All right. We have done studies in the past. We did a study in March of '91. And then we did another study in 1995. Obviously technologies have changed since then. You know, communications have improved. Being able to figure out some way to get power. So, you know, it is appropriate I think now to go back -- not appropriate. We have to go back and do another study. Rule making, we have taken a run at this a few times, '78, '87, '94 and 2010, but I have to be clear there is something regarding EFRDs in the existing legislation, 452i. As an enforcement person I got to tell you right now we have not focussed on that aspect of AMP as much as we should have. We have been focusing on running the pigs and removing the gouges and -- but I can say this for my staff in the western region is operators all over the board with how hard they have applied this part of the regulation of looking at preventive and mitigative measures, some have put a lot of effort in it and others have given it a cursory checkoff. That's one thing that my inspectors will be focusing on in the next few years until more or different regulations are put in place. And one of the things that really impressed me though was a lot of companies have taken this aspect of the regulation to heart and there is some really good best practices, at least in our region. There is build containment around valves. There is leak detection devices and leak detection cables, sensors, actually video cameras and things that have picked up any changes in the fluid levels in the valve. Companies are putting those in place. A lot of companies were concerned about if they had to shut the valves quickly or causing transient in the pipeline, a lot of have relief put in. Other companies put inhibitor switches where the valve starts to overpressure it stops it. Remote places in Alaska where they can't get power they put solar panels and nitrogen bottles and they will activate the valve. I think of cooking a pipeline and they have a middle (inaudible) close to the bottom of a volcano. They use nitrogen bottles and activate it with batteries and solar panels to shut those valves. They have to get a helicopter to go back out there and open them up again but they get them shut down in a timely manner. Here are some examples. If it is a good practice, this is Chevron valve pit in Salt Lake City.

This is the Exxon Silver Tip pipeline. You can see the relief bypass around the valve vault. They have one of these at each valve set coming down the mountain. This would allow them to shut down their valves as quickly as they want to. And here is a (inaudible). It is not the greatest picture but it shows the solar panel where the batteries and nitrogen bottles are installed.

So, you know, companies are doing -- they are trying to figure out some way to make things work. Now there is operational concerns. We are concerned about the operability to make the right decision on what valves to close. We have operators that close a valve and forget to reopen it and pump against it and rerupture the pipeline. And it happened a couple of months ago. Sometimes you get transient signals in the computer system that shuts the valve. There is inherent problems with the remote control valves. The second one is the problematic one. We are seeing improper maintenance of valves. They don't do maintenance or packing or gaskets and they don't seem to get sediment or sludge in the valve body and don't maintain them according to manufacturer specs. I don't consider that to be an EFRD issue as is a maintenance issue.

Here is another example. This is one -- this was a threaded O-ring which had it been locked down properly and over time just vibrated loose and caused a large release.

Again proper maintenance. Recognize the valve vault. This is a valve that they forgot to get the water out in a hydra test and popped the bottom off the valve. Thank God they had the vault there because it contained most of the product. Other concerns, cyber security threats, physical security threats. Getting power to certain areas, that's probably the hardest problem in the West. Fluid hammers, flow transient. You may not have a leak site big enough and what do you do about crossover parallel valves between parallel pipelines. I am sure you guys will address some of these, but these are concerns a regulator we have.

Okay. Prescriptive requirements, we have taken a run at this a few times. Very tough. I can at least say what we have done following an accident where we have prescribed where to put additional valves and how to actuate the valves. And this is what we have done on corrective action orders. We dictate where they should be. We will look at percentage volume and daily throughput. You can't say limit to 2,000 barrels because otherwise on the (inaudible) pipeline you would be putting a valve every 300 feet. We have done corrective action and also done some that are based on absolute number of barrels that can drain down after a pump shut down. And we do that in cooperation with emergency responders and city officials and local planners. And then also we have asked companies to look at risk based and HCA characteristics and couple that with OPA and make sure they do the analysis. One is an absolute prescribed amount. Other one is percentage of daily throughput and the other one is going back to look at the risks.

And obviously another thing we can do is have public comments through this workshop and comments through the registry and website.

Thank you.

(Applause.)

>> ALAN MAYBERRY: Nice job on the time. Next up to present a state perspective will be Don Ledversis, RI Division of Public Utilities and Carriers Gas Pipeline safety engineer. Don.

>> DON LEDVERSIS: Thank you, Alan. While he is loading this up I want to thank Chris for getting all those acronyms out there so I don't have to explain those. A lot of people were here yesterday looking for leaks and today when we get those leaks we will be able to shut them down hopefully. Anyone new in the room today that wasn't here yesterday? A couple of people. Great. Because you missed my presentation yesterday but I've got the first 14 slides again.

(Laughter)

>> DON LEDVERSIS: Okay. I work for the division of public utilities. State inspector and I am representing NAPSR. And we were established back in 1982. And just to blow our horn a little bit here, we have 52 state pipeline agencies involved in pipeline safety and we cover all the states and we don't do Alaska and Hawaii. The gas price in Hawaii was $4.53 today. We inspect about 78% of the 2.3 million miles of pipeline and we do have about 9,000 operators. We want to strengthen the state pipeline programs. And we want to promote the improved pipeline safety standards. If there is something out that's good that works, we are all for it. Adopt it and we will inspect for compliance.

Education, training, technology, always open for more education. We can't push that button enough I guess. And if somebody has built a better mouse trap, more than happy to see that put in effect. Had a lot of good research and development presentations yesterday. And this is our PHMSA partner. Basically we like to develop regulations that are fair, clear, unambiguous and consistent. Obviously hard nut to crack.

Costs associated with valves and maintenance, sometimes you get inadvertently closed and people pumping fuel up against them. But in the end if you shut it off and you don't get the product on the ground it makes things a lot easier for a lot of people. There is 15 states in the country that have liquid jurisdiction and those states are allowed to put out their own laws above and beyond the code. If you are in any of these states they may have these. On the state side we cover about a third of the liquid pipeline out there. So if you look at that list where is Rhode Island I am not on that list and I have liquid pipelines in my backyard. And I am concerned about them getting damaged and product leaking all over my state. This is one that we have that transports fuel, jet fuel and maybe some gasoline and it is in the right-of- way and everyone knew where it was during a construction project and unfortunately what happened here when this gentleman ripped it out of the ground, human error, this is a guy that was going to be starting work on a Monday for a company, decided to come in on a Saturday when nobody was there and practice digging so he would look like a hero on Monday and that's 2 million dollars worth of damage on the ground.

Now somebody shut a valve -- shut this thing down but the problem was it is fuel. It is gasoline and every time they went to get the soil out of the ground there would be a spark and it would catch on fire and they'd have to get the fire department there and this went on for many days. The product being transported, it was only a small landline, low pressure, made it very hard to clean it up. This is the other one we have. It is a Coast Guard jurisdiction line. They don't have to be members of Dig Safe in the state of Rhode Island. The company did have a Dig Safe valid number and didn't know it was there. He was digging and put a pretty big scar on top of it and he kept digging and hit the other one next to it. He hit both in one day. This is a case where not human error but just a bad set of circumstances. We didn't have any leaks that day on this particular job site but unfortunately six years later we had a third party again. This is a party that was working who knew exactly where the line was. So it is a case of human error maybe. So all different scenarios out there. Your pipes in the ground, it is going to be there for, you know, forever, after I am gone and basically there is people out there, third party damage it is always going to be your enemy. If you have a valve and shut that thing down and reduce the amount of product on the ground, that's what it is all about.

Okay. NAPSR, where do we stand? Basically we submitted comments in February 2011. I am going to go through those right now and you can find these on regulations.gov. You type in that code that Jeff told you about and you will be in to that. Our legal statement, we sent out a survey and not all our people answer these surveys. Some people have no interest and some people have a lot of interest. Basically if they didn't like the comments that were given and they want to go in a different direction, they are allowed to submit their own comments for their state. This is a photo that was sent to me, it is West Coast, it looks like a lot of money to do that. Once it is there it is there. If you have breakdown downstream of that, you will be happy that it is there.

I am going to go over the questions and our answers were pretty current. I think I am going to beat the 20 minutes real easy today and some of the answers were pretty quick and you will see where we stand. EFRDs, are there any practices or industry standards out there that talk about maximum spill volume and basically our constituents said no. And if engineering and design should dictate the installation of EFRDs, where they should go. Should PHMSA specify the criteria? In other words, we are going to tell you where to put it. Should PHMSA mandate the use of EFRDs in all locations? No. This is a question they were looking for statistics. So we incorrectly answered it. But what's the average distance between valves that are currently installed according to 260(c) and 260(c) is down at the bottom. It is kind of small. But it talks about the minimization of damage. This is already a code requirement where you have to take in and consider these things. And basically the way we feel about these average distances. We don't have the data to support it but proper location is far more important than average placement. Valves need to be installed where they do the most good and not on an average distance. I think we just missed that question.

Should PHMSA develop standards by which they develop valve spacing and locations? We believe this is being done in integrity management programs. If you are applying those programs properly, we think you will be on top of that. Should PHMSA specify maximum distance between valves and if so is there a magic number? The silver bullet? Cost benefits, we don't know about cost benefits. It is not our area of expertise but we are saying that maximum valve space should based upon consideration of the existing piping and environmental factors just as minimum valve spacing. So we are -- pretty much we are looking at it from an engineering and design standpoint and focusing on independent situations.

Should PHMSA prescribe additional requirements for locating valves beyond those currently described and we said no. Should PHMSA revise the standard in 260(e) to include narrower bodies of water? If so projected cost which we don't address. This is the regulation that Chris was just talking about in Montana where if you have a 100 foot that's at the high watermark, you have to have the valves. Where does the 100 foot come from? It is obviously a very rounded number. It was probably a consensus meeting somewhere many years ago when 200 was thrown out and 50 was thrown out and they came up with an average. If you go to these meetings that's how it works out. Is it the right number? You are going to say geez, that rule is not good enough. It is a tough thing. When you have 100 feet obviously there is going to be players on both sides there.

Okay. Should PHMSA consider a requirement for all valves to be capable of being controlled remotely? Every single valve out there has to be controlled remotely. Not all valves performance language, maximum response time for critical valves might help operators to determine where remotely controlled valves should be installed. Don't do it on every single valve. Do your due diligence and engineering and that's where they should be remotely controlled. Should we require installation of EFRDs to protect HCAs? This should be in the operator's. Present regulations are adequate. So we are taking a lenient stand on a lot of these positions. Valve spaces, pretty long question, what it gets in to it is the grandfathering, new construction, repair and replace. If a regulation goes in to effect is there some leniency on grandfathering? If I can't pick my line what happens? If I have a crossing casing, is there an exemption form? Can I get a waiver, all those kinds of things and our position on this is all exemptions whether grandfathering, you got to take in to consideration the size of the pipe, the amount of product involvement and release. And we are talking about infrastructure such as high voltage electric transmission in a common right-of-way. Electric generation, railroad, et cetera. We are concerned about HCAs. We are going a little bit further and looking at other areas. If you do have a valve requirement even if you think there is a grandfather situation there, we are pretty much hot on that one.

Cost impacts, we don't get involved in cost impacts. Basically I work on the rate side, too, and our commission has given in to anything that's safety related. We don't go down that road. We are spending 350 million dollars on cast iron replacement. You come in to our commission and you have a safety issue and you want to put in a valve and it is big money I don't see where you would be shut down. And that's it for me. Bought somebody a lot of time here.

>> ALAN MAYBERRY: Great.

(Applause.)

>> ALAN MAYBERRY: Thank you very much, Don. Okay. We are going to shift gears here a bit. You have heard two perspectives from government, federal and state. Next we are going to go to industry and for that first step we will have the national perspective representing the American Petroleum Institute, Frank Gonzales, who is a senior integrity engineer with Colonial Pipeline.

>> FRANK GONZALES, SR.: Thank you. I am a senior engineer with Colonial Pipeline Company. Today I am representing the American Petroleum Institute. I will also be able to answer questions with regard to my own personal

experiences at Colonial Pipeline Company but I don't have a separate presentation for my company's perspective.

I want to thank Chris for providing a very good definition of the various types of flow restricting valves or emergency flow restricting valves. For the purposes of my presentation here I include all of these various types of valves in the category of emergency flow restricting valves. So I don't need to go in to any more detail. And I thought that Chris provided a very good definition of each one of these types.

In the liquids pipeline industry what we have found from surveying operators is that the locations where EFRDs may be used to be most effective in hazardous liquid pipeline in near high consequence areas such as populated areas off commercially navigable waterways, actually mitigate consequences significantly. I use that word significantly because a lot of times in evaluations the amount of impact that's reduced is small compared to the total volume that's released throughout the -- all phases of the release event. And I will go in to that in a little bit more detail here in a minute.

Another thing that Chris touched on was the integrity management regulation folks done preventive and mitigative measures and we are about 11 years in to the integrated management being in place, and pipeline operators are still focusing on first preventive and then mitigative measures or actually both simultaneously, but what we find in doing our valuation that we get more risk reduction for our resource expended. It is best to prevent the incident from happening in the first place, intuitive. EFRDs are mitigative measures and they don't prevent incidents from occurring.

The experience that we have seen in pipeline operators is that for the liquids industry is that pipeline operators employ the consistent evaluation of high consequence area impacts. This was required by the regulation to take the data provided by PHMSA in what's the definition of a high consequence area and do the evaluation of how your pipeline could potentially impact those high consequence areas. That's a useful analysis in determining where EFRDs could potentially mitigate the impacts to those high consequence areas.

Completed projects to install EFRDs or add EFRD capability to an existing valve on pipeline systems where they have the greatest impact to reduce spill volumes in high consequence areas and lastly the evaluation process has further proved the value of spill prevention as I said rather than mitigation, and once you get in to the technical analysis this becomes even more pronounced.

I hope this slide helps explain that point a little bit better. If we break down the event of a spill in to four phases in from a liquid pipeline, the first would be the initial release while the pipeline is still running and it has not been detected yet. As we learned yesterday during the leak detection workshop that time varies because of several different factors and it is unique for each situation and each pipeline system.

The second phase would be continued release after the detection of the problem and emergency condition has been recognized. The control center personnel are taking action to shut down the pipeline and do that in a safe and orderly manner such that another problem is not created by not shutting the pipeline down in a safe manner. Third phase would be liquid depressurization. Liquid is somewhat compressible and after you shut down the pumps the line is packed. It is an industry term we use and that line has to be unpacked in order to reach an equilibrium at a nonoperating state. And during that time liquid is continuing to be pushed out of the breach of the pipeline wherever that occurs at.

And then finally the fourth stage is after all of the EFRDs have been closed, all the pumps have been shut down, every valve that can be shut down is shut down. Gravity takes effect wherever there is an elevation change. If there is elevation on the pipeline that is higher than the location of the breach and gravity will force product out of that breach in the pipeline. And this is -- and this fourth phase is where EFRDs analysis have been determined to be effective.

The first three phases EFRDs are typically not employed because again safe mode shutdown of a pipeline, you just can't drive a valve shut on an operating pipeline safely.

So EFRDs in their evaluation, there are several challenges that an EFRD project would face before it is installed. Primary drawbacks or challenges I should say to the installation of EFRDs is that compared to a straight piece of pipe, a valve is going to add additional potential sources of leaks. There is the threaded fittings and flanges and seals involved in the stem -- stem seal rather. And so to an integrity engineer it is counterintuitive to install a piece of equipment that you are going to add potential for leaks. Our goal is to have 0 leaks. So any time we look at installing something that adds potential for leaks, that's -- that better have some very, very high risk reduction benefits to outweigh those potential consequences.

The larger of the two considerations and challenges facing EFRDs is what Chris also covered, inadvertent closure. If a valve is closed inadvertently and a rupture could potentially occur. EFRDs only mitigate consequences for rather large volume spills, large breaches in the pipeline. For the small seepers or drips or small leaks, small rates of leaks, EFRDs really don't come in to play because those leaks are typically identified and repaired by while the pipeline is still in service. The line is shut down and the area is excavated and made safe, but the EFRDs don't come in to play in terms of mitigating the actual consequences.

The other point I would like to make here is that the placement of EFRDs only affect a specific location on the pipeline in that you do a calculation and you recognize that there is a large significant draindown at a specific location on the pipeline and in the remote possibility that there is a large rupture in that section of pipeline you take your best calculated guess as to where that valve should be placed such that it would mitigate the draindown of product from that pipeline if the spill occurred downhill from that valve. And if, you know -- so it affects that one point in the pipeline and the region immediately around it. It does nothing to prevent spills anywhere else on the pipeline. So again when that project is competing against preventive projects that may effect the entire pipeline, it has got an uphill challenge.

In terms of cost of EFRDs, it ranges widely as you can imagine the cost of an EFRD and the eight-inch pipeline is going to be dramatically different than that on an 80-inch pipeline. So for existing pipelines a lot of the costs often are involved in the draining of the pipeline, cutting out a section of pipe and installing the new facility. Significant costs can also be involved in bringing power and communication to the site to make it a remote operated valve. And generally when you compare installing an EFRD on an existing versus a new pipeline, you are looking at two to three times the cost because of the factors that I just mentioned.

Operating costs would be slightly lower on a new pipeline because you are dealing with new facilities, new equipment, built some new standards and latest in technology in terms of reliability and leak prevention. But it is not significant when compared to all the other capital costs and the risks involved.

In general since the integrity management rule has been implemented spills along the right-of-way has been in decline. So when the likelihood side of the spill equation has been reduced and you look at the cost-benefit ratio, cost being resources and people and time and money, and the benefit being identified as risk reduction, if the risk reduction is reduced by the likelihood being reduced, then the project is less and less desirable again compared with preventive measures.

Environmental and operating conditions that could affect an EFRD, water tends to accumulate in product pipeline. A minute amount of water tending to exist and settle out in low places and valves need to be winterized to make sure that water does not accumulate in the body of the valve. Water in a valve can cause a number of problems. In extreme freezing temperatures that block of water can make the valve operate improperly. And if the water freezes, if there is enough water and it freezes hard enough it can actually cause the valve body to rupture and causing a catastrophic release of product. Starting up against a closed valve, high forces are required to open the valve and the motor operator may not have that capacity and therefore then operator would have to take other measures to balance the pressure across that valve in order to get the valve opened again.

And as I mentioned availability of power communication to remote operated valves is critical and there may be vulnerability to weather conditions. If you have a radio or a cellular or a satellite communication to remote operated valves and fog or clouds affect the availability of that communication, what that leaves an operator with is a test situation in that you don't know through communication what the status of that valve is. You have no reason to believe that it is -- that it is being closed while you are operating but you also don't know that because you don't have the supervisory status of that valve.

Other risks associated with valves and hazardous lines according to our API has been tracking spills on a voluntary basis through the pipeline performance tracking system. So we have ten years of data, from 1999 to 2009 and valves on the right-of-way on onshore pipelines accounted for 6 and a half percent of the number of leaks. Not a large percentage but it is the second most common cause or location of leaks on the pipeline system on the right-of-way. Second only to the pipe itself. Of those leaks the volume that was released from the valves themselves they accounted for 3.9% of the total volume. These are not a significant percentage. But they are significant obstacles when you are trying to achieve zero leaks on our system.

The potential benefit of risk reduction with an EFRD has to be able to overcome all of these obstacles, the cost, the additional risks associated with leaks and with inadvertent closures. To address the question about potential of vandalism and sabotage, while these events are rare they have happened in my own personal experiences working for liquid pipeline operators. In the 24 years I have encountered situations where valves have been tampered by I guess bored teenagers. Seeing what would happen if they unbolted bolts on a valve installation and when product started spraying out unfortunately they left and there was no problem but a large spill and a big mess to clean up. And we all saw in the newspapers where some less than intelligent person took a lot of shots at the TransAlaska pipeline and took enough shots at it and caused it to rupture. EFRDs a lot of times are placed above ground because operators want to visually inspect them and because they are in remote locations and above ground and they are in right-of-ways which are good hunting spots they are vulnerable to intentional or unintentional damage.

Cyber security is another concern for remote operated valves. You give -- you supply power and some sort of a communication to a remote facility and you introduce the possibility. It is remote and you know we use secure encrypted communication protocol, but if a motivated hacker wanted to I would hate to think what would happen if that was breached. There is certain things from an internal error from your own employee who is logged in remotely and uploading software that introduces a possibility of an error. Uncommanded operation of remote operated valves present risk of HL pipeline overpressure. We engineer everything we can to account for that possibility. Show some great examples of the pressure relief valve that bypasses the remote operated valve such that any high pressure is bypassed around that valve until that pressure drops and that relief valve closes. Timers on valves to make them close at a slow enough rate so they slow the pipeline down in a fashion that is not going to create a sudden spike but would slow it down -- close in a slow enough fashion that it would mitigate the surge going back upstream, but in any case as a pipeline operator you must account for the unexpected. And the highest surge is dependent on how fast the product is flowing through the pipeline and how much pressure is applied to that product upstream and in order to reduce that potential surge you have to reduce your pressure and flow rate and that impairs your operability of your pipeline and may impair your ability to meet your customer's needs on the pipeline. So there is a technical solution to deal with that but they become complicated very quickly.

And finally a few words about check valves. Check valves are used I wouldn't say commonly but they are used in hazardous liquid pipelines rather effectively. I enjoy them. I am a mechanical engineer and they are simple mechanical devices. And they allow flow to go in one direction and if the flow reverses the clapper, the mechanism that stops the flow in the direction that is not supposed to go in. When installed on an uphill side of a river valley that's an effective way to have an emergency stop flow device. They typically provide no power communication and some operators do have power and communication to them in order to hold the clappers up out of the way of the normal flow during steady state operations. This helps with the DRA and the safe passage of pigs, which happens to be one of the biggest drawbacks about the check valves in that they are not very pig friendly sometimes. Smart pig are instrumented devices, computers on board and sensors on wiring and check valves have this big metal that swings in the flow of product and sometimes the smart pig are damaged by the clapper of the check valve itself. Conversely some pigs whether smart pigs or regular cleaning pigs they can damage the sealing surfaces. When the check valve is called on to operate it may not operate as advertised because of damage.

I thank you for your attention.

(Applause.)

>> ALAN MAYBERRY: Thank you, Frank. You won the prize for being perfectly 20 minutes. So next we will have Kori Patrick who is the manager of operational risk management with Enbridge Pipelines. Kori is here to speak about Enbridge's perspectives on valves.

>> KORI PATRICK: Thanks Alan. Good morning, everyone. My name is Kori Patrick. I am representing Enbridge today. I am from Edmonton, Alberta and I've heard some complaints about the cold weather. I will take the complaint for that because I like to feel comfortable. It is my pleasure to present here on an operator's perspective. I'd also like to thank David Wier and Yang Ping Lee for helping me to gather some of the materials that I am going to present today.

For those of you who aren't familiar Enbridge Liquid Pipeline Systems extends from Northern Canada down in to the U.S. and now from Cushing down in to Texas. The CUA line as well but that's not included in the numbers that you see on the right-hand side. So total system is in excess of 15,000 miles of pipe and that's excluding our gathering system. Within that mileage we have just over 17,000 -- or 170 main line valves. Of those 974 are remote controlled and 772 hand operated and 110 check valves for the total system. And then I broke that out in to the U.S. only. Of the total mileage 48.6% of that mileage is in the U.S. and off of the total valve count roughly 52% of the valves are in the U.S.

Here is a picture of a remote controlled valve site where we have the actuator in the center with two pressure transducers on either side. I have included just a little table on average valve spacing. We don't consider valve spacing for liquid systems. I didn't place this here to show that we use this as part of our consideration but more so to illustrate in our larger diameter lines we have a higher volume of liquids that we are transporting. So we expect to see a higher level of mitigation and more EFRDs placed on the larger systems to protect against that potential volume coming out. So this was a check against that to see on average do we have more valves on the larger systems. And indeed we do in the U.S. for valves on systems less than 12 inches. Of course, the spacing is a lot wider.

So I will go through exactly how we consider our EFRD spacing requirements.

We have had quite an active program since 2009 in terms of valve placement and specifically this year and the years to come. These are projected numbers in 2013 but can see the amount of conversions and cut-ins have increased dramatically for Enbridge. This has been an internal decision based on our risk tolerance. And I will go through how we selected these valves and how we considered these moving forward. I have got a few pictures of just some of the existing valves. So here we have a manual controlled valve. That's either considered to be converted to a remote control system. We have developed over the years an intelligence valve placement methodology where we look solely at the installation of remote controlled sectionalizing valves. We consider in our engineering design standard a requirement that these valves close in the three minutes. There has been some talk of automatic control valves and as Chris mentioned these are not particularly considered in the liquids pipelines just because of the incompressibility of the fluid. If you rely on a control system or something that can -- to close the valve there is all the upstream systems that have to shut down all the pumps, the whole line has to be shut down before that can happen. And so you are really relying on the system itself to make that judgment.

And so we have restricted our valves to remote control. Again I will just talk on check valve issues. These were discussed by Frank as well but also they are not easy to test. You can visually confirm them because they are buried in the ground and then again issues with inline inspection tools and seals. So our volume out calculation considers a couple of elements. One is the initial volume out which is based on the design flow rate. We take ten minutes for the control center to detect the alarm, determine if it is a real positive alarm, whether or not they need to shut down the line. Once that decision is made then add an additional three minutes to close the valve. We consider worst case a full 13 minutes to get that valve closed as the initial volume out. You have the stabilization loss which is based on the elevation at that point which is the draindown volume that would come out. And as you can see from the diagram you basically have a siphoning effect. Any elevation that is higher than the eruption, you get the flowing out of the rupture. So here if we looked at the analysis on the graph, there is a couple of components here. There are a couple of lines on top. These represent HCAs. Blue may be a source of drinking water. We look at these areas to consider what the impact is on volume out.

And on the bottom here we have an elevation profile. So here we can see the highest elevation and as we move to the right the elevation is going down. So you can see with that elevation that the volume out, this drainout volume increases as we go down in elevation. So we consider here this line of potential valve location. If we place a valve there, we basically change the volume out profile. We reduce the volume out and this would be the new volume out profile over the HCA. We are protecting those HCAs from this additional volume or mitigating that volume by placing that valve there.

So this is what we -- how we started doing this analysis in 2006. We built upon that by looking at a couple of different factors. And I will go through these four different graphs to kind of go through the calculation of different ways of looking at volume out. First of all, the effectiveness where we take the average volume reduction for an HCA, times it by the HCA length and then multiply that by HCA type score. So we could score it or give it a multiplier based on the risk associated with that HCA. So this is in effect a consequent scoring for the valve placement. Another way to look at it is efficiency. Chris mentioned there is several ways of looking at volume out. One is a percent reduction of volume for a given HCA again times the HCA length and divided by the total HCA length that's covered by that valve.

Two other factors, total volume out and average volume out. So if we look at this graph again this is a similar view. We can then calculate what's the total area. So that's one way of looking at it and then we can take also the average difference between these two lines and eventually those lines converge as the elevation profile changes.

If we look at the first one, effectiveness, what we did is we then looked at the effectiveness over our main line system. We took a cutoff to determine how big of a program we wanted to tackle. Of course, you can't tackle the whole system all at once. So we kind of just picked a spot along the curve and took that as an initial plan to tackle these valves.

And how that's done is it is through several iterations through the software that we developed but we would look and see plot the effectiveness over the length of the line. And so this point here, these two points would be the highest effectiveness. So, of course, we would place the valve there. Once we place the valve the effectiveness then would drop at that point. So you would end up with a new profile and you could just continue on and continue placing valves until you drive your effectiveness right down.

Recently in 2010, 2011 we took in some other considerations. There is a lot of talk about risk assessments. So we wanted to incorporate a little bit more of that. So we started to consider company identified risk case scenarios. These would be more region based where the regions would submit where their biggest worries were. Top risk areas, focus on major water crossings and also the intelligent valve placement program. So we considered a little bit of everything to see where we go.

So now we consider kind of in steps fixed valve spacing for HDPE pipelines. We look at fixed valve threshold for water crossings and valve placement to protect major water crossings not previously addressed, valve efficiency and then special cases.

So for implementing these projects we identified requirements. We kind of do the analysis for the line to see where these -- where we see valves being necessary. Our engineering groups then do field verification where they actually go out and do a site visit and they start to talk to the landowners or look at power requirements, communication requirements and see if they need to adjust where we indicated the valve should go to see where an actual fact we can place it. And then we begin to execute the project.

There are several different considerations when we consider the optimal locations, constructability, power availability, the terrain, availability of land and, of course, the location of the existing valves. Here is a picture of a set of valves that -- new valves that were ordered. So they are being transported out. These are large gate valves. These are then sent to a fabrication shop where on either end we attach pressure transducers and these would be welded on to the body of the valve. They are cutting away the existing line and installing and then weld this section in. The whole process of planning this activity could be up to a year in terms of engineering assessment, planning activities, obtaining the equipment and then installing it.

And we are waiting for the appropriate time to install those valves. In terms of costs, we are showing a little bit higher cost than what Frank showed as an industry and I think it was partially because we are including some of the upfront engineering costs that would be involved. Some of the additional communication costs that we are putting in for these remote valves. It is far more expensive to put it in to an existing system than it is in the new construction. That's probably three times the cost to do that. And, of course, it is almost three times the cost to do a cut-in versus converting an existing manual valve. So, of course, we want to do the conversions first.

In terms of valve performance, just coming back again to check valves, really comes down to maintenance. It is a little bit harder to maintain even though we like the idea of the check valve. RCVs, remote control valves are usually below grade. There is debris that can get in the seal and actuators fail, power communication loss and it comes down to the maintenance and keeping on top of it. The manual control valves there is less failure modes but require a person to be present. Can also be difficult in cold weather operations, accessibility, things like that.

Here is one example of a communication failure. Here is an existing valve site and it is hard to see but there is an existing communications tower here that's about 30 feet tall and this valve location is situated in between two facilities. And at one point during its life cycle the communication was switched from one facility to another and was later discovered that that communication was not occurring properly. That the height of the tower was not appropriate. So they -- the communication guys came in and did an assessment and determined that the tower had to be four times as tall. They installed a 120 tower to get communication to that remote valve site.

In terms of actuating times, there is some differences in the type of valve. Of course, check valves are immediate based on the pressure drop. Remote are three minutes. There are fast closure systems available in the market in terms of if you have a nitrogen bottle system, these systems are quite a bit more expensive. And, you know, we have looked at them. We have considered them for different areas. At this point in time we don't have any fast acting systems in place. These systems can close a remote control valve in 20 seconds. So you are basically essentially cutting down that three minutes to a 20 to 30 second time interval.

Manual control valves are really dependent on how fast you can get a person to the valve site to close it and depending on accessibility can be 30 minutes to several hours to even days.

Human factor issues, for any of our remote control valves it requires a human trigger. The operator has to identify an event and make the decision to trigger the valve closed. Our control center operations gets lots of practice through regular valve functions tests. That means through regular maintenance and twice a year required to function these valves. So they plan these activities. Manual valves are also regularly functioned by operations. So whenever we do a dig or repair on the line they use these manual valves to isolate. They are planned activities. The largest issue there might be through communication, making sure that the correct valve is being functioned and operated. Making sure that they have access to the site. And this is just addressed through experience and practice.

So I have covered off most of the issues. Enbridge's position is that we -- that remote control valves can reduce the impact of an unplanned release by reducing the draindown volume.

So thank you very much for your attention. I will turn it back to Alan.

(Applause.)

>> ALAN MAYBERRY: All right. Thank you, Kori. Okay. Now we are at the portion of the panel for questions and answers. In the room here we have two mics. As Jeff had mentioned when you step up to ask your question, which I don't see a line yet, but please state your name and your affiliation. And those online, there are instructions on the Webcast for submitting your question by e-mail. And for the timid ones in the group we do have cards available to write your question. And then we will address those in order. Also for the questions, I mentioned this yesterday, if we don't get to questions that are submitted we will answer them and post them online. Post them on the docket for this meeting.

We had a few of those yesterday. So any takers? Anything from the web yet? There we have a taker.

>> I wrote over it, Chris. Jason from Marathon Pipeline. Great job all of you. Very good representation. My question revolves around the definition of EFRD. If you look in the code it talks about protecting high consequence areas that would infer that not all ROBs would be EFRDs. And then the second part is manual valves -- can manual valves really be considered EFRDs, considering your draindown is probably going to occur in maybe 20 or 30 minutes and you may not get there to close the valve and reduce the volume?

>> ALAN MAYBERRY: Okay. You want to start with that, Chris?

>> CHRIS HOIDAL: I typically would consider a manual valve to be an EFRD. Particularly it take so long to get out there and actuate it. So that answers the question. What was the first question again?

>> The first one was involving ROBs that do not protect HCAs, would they be considered an EFRD since they do not protect an HCA?

>> ALAN MAYBERRY: Chris, speak in to the mic better.

>> CHRIS HOIDAL: I could consider them an EFRD. They want us to have EFRDs to drive down the consequence, you know, opposed to an HCA but just because you don't have an HCA there doesn't mean it is not an EFRD. I would consider a controlled valve to be an EFRD whether it is in an HCA.

>> ALAN MAYBERRY: Anyone else from the panel want to take

a stab?

>> FRANK GONZALES, SR.: With respect to whether industry EFRDs are typically evaluated relative to high consequence areas you look where risks are highest and that's where you want to put your mitigative resources first. However, I would not exclude a valve from being an EFRD if there was no impact or potential impact to a high consequence area. What was that your question? Manual valves. Most operators I believe do not take credit for manual valves as an EFRD. Speaking for Colonial if the situation is such that a manual valve is close enough and the response time is short enough, meaning that it is very close to a location where we have staffed facility 24 hours, then we may take credit for that but with the appropriate response time for a manual valve.

>> ALAN MAYBERRY: Okay. Okay. Another one here in the audience.

>> Mike from SoCalGas. This question goes to the last speaker. I think you had 1500 valve tests per year. What percent of those did you get a positive closure on first time through and do you have somebody stationed at the valve just in case?

>> KORI PATRICK: I don't have the data to tell you what percentage of valves are properly functioned first off. I would hope that it is a very high success rate. When those activities are planned we do have crews on the valve site confirming that they are closed. You don't rely on the computer system in place to confirm that for you. You do have a man on the ground confirming that that valve is actually functioning, yes.

>> Thank you.

>> ALAN MAYBERRY: Okay. And if you would please make sure you speak in to the mic so we can all hear you.

>> Victor Karrero. Kori, this question is for you. You mentioned that your standard for closure time is three minutes on your main line valves. What is the reasoning for keeping that three minutes? And how do you mitigate for inadvertent closures for those valves?

>> KORI PATRICK: I think the three minutes came from just the fact of the pure number of remote control valves that we have in place. That's probably an average closure time where some valves may be four minutes. Some may be faster. So we -- it is -- to be honest, I don't know if it came from the value manufacturers themselves in terms of the size of some of these valves being quite large and the time it takes for the actuators to close fully the gate. In terms of your second question, inadvertent closure, that can happen. And I think it has happened in our system where it inadvertently closes. One of the things that is easy to detect on a liquid system, the

control center can detect. They have protocols in place to shut down the system, shut down the pumps upstream of the valve and be able to prevent a pressure spike in the system.

>> Thanks.

>> ALAN MAYBERRY: Okay. This question is for Jeff Wiese but Jeff is not here. I get the short straw on this one. Could you specify the procedure, the timetable and the deadlines for reporting to Congress on the outcome of studies regarding leak detection and valve automation requirements? We have not drawn a blank on exact timing but I would say a year. And Jeff had mentioned this at the very beginning. It is in our statute. But a year to produce the studies after -- we have a year from the statute. The statute was January of 2012. So be January of 2013.

And, you know, just to elaborate and Chris did an excellent job of discussing our mandate, presenting our mandate, we are -- we are doing this in a very methodical way and producing the report. And there are some caveats in the regulation that determine our path forward on it but if further changes are mandated. You can see the history. We have tinkered with this part of the regulation a bit. I imagine we will tinker with it some more informed by the study and other input. But it is -- obviously there is some caveats in there on how we go forward and how we proceed. Yes. We have a question here in the audience.

>> Yes. My name is Lyle Welch with American Invasion. I have a couple of comments basically. Regarding the automation of the valves, there has been much improvement in the cost, size and reliability and torque, output speeds controls and communication for the automation packages. And so operators need to be proactive in updating their older opinions of these systems and do a comprehensive feasibility study before deciding. We see that occurred in a couple of instances with clients just not updating themselves with the latest technology out there in order to harm themselves with their best decisions for these options.

Also regarding fixed links of the water crossings, 100 feet, the AC analysis currently in use could be used to determine which water crossing would require the number and type of actuation packages for valving based on the type and the extent of HCAs affected since this is a primary concern of the HCA identification process anyway. So it would make sense to logically try to look at the impact on each individual basis instead of going with just like you said earlier just an arbitrary fixed link of 100 feet. We have that already in process with customers and the information is already available for HCA impact. Thank you.

>> ALAN MAYBERRY: All right. Thanks. I imagine on the next panel regarding technology we will talking a bit about the first part of your comments there. Next question from the web is really to our operators related to costs. What part of your valve cost is just valve operator versus communications related? Could you give a breakdown essentially on the cost? Valve operator, your communication package. Kind of rule of thumb there or you don't want to touch it?

(Laughter).

>> ALAN MAYBERRY:

>> FRANK GONZALES, SR.: Just so I understand the question quickly is the breakdown of valve operator and communication associated with that?

>> ALAN MAYBERRY: Now I am interpreting, but says what part of your valve cost is just valve operators and communications related. You have valve and operator and extension and mechanism up top there.

>> FRANK GONZALES, SR.: In my experience for Colonial we have a lot of large diameter valves. Our largest line are 36 and 40 inch diameters. Those can be rather expensive valves. The cost of bringing communication in to a site where an EFRD would be effective is usually or can be very high because you are typically looking at very remote locations where we don't have any existing communications or power. If you have to run power communication for a mile, that's all on your nickel and that can exceed the cost of the valve itself and the installation. So, you know, it varies with each situation. Sometimes power is readily available next to a road or something like that. But I guess that's the best answer I can give.

>> KORI PATRICK: Yes, I guess I will echo that and just say that I would predict that over half of the cost is going to be coming from the human resources and just the manpower required to do these installations. And the equipment itself would be less than half of the overall cost.

>> ALAN MAYBERRY: Okay. Next question. Right here.

>> My name is (inaudible). I have a question about the streamdown volume calculation. I wonder in the EFRD study whether in future studies you include the standard -- different company when they talk about streamline volume they are talking about the same thing.

>> ALAN MAYBERRY: I am sorry, it should include the -- the study?

>> Standardized calculated streamline volume.

>> ALAN MAYBERRY: Well, the study will -- if you have input related specifically to standardization, would you please place that on the docket? And the intent is to be a thorough study. So if there is input you have that would be relevant to

that end, please include it.

>> CHRIS HOIDAL: Can I say something? I am always leery of -- when it comes to evaluating risk I am always leery about standardizing how you assess risk, but it is a little bit -- from an enforcement standpoint when you have two pipelines traversing the same HCAs and the amount of drain worst case discharge, magnitude of 10 or more. Well, we can't standardize everything. There ought to be some range that the operators need to address. All things equal it is a huge difference in what is people's acceptable consequences.

>> ALAN MAYBERRY: To the point in your slides on the variation and draindown. Any other questions? Going once, going twice. None from the web. We are five minutes early. We will have a 15-minute break. It is 40 minutes after. 5 minutes up we will reconvene. Thank you.

(Applause.)

(Session in break until 10 a.m. EDT)

>> ALAN MAYBERRY: Okay. If everyone would please take your seats.

Okay. Before I kick off panel number 2, I thought I would reiterate why we're here today, and it's in follow-up to a question that came up in the last Q&A session as far as related to our mandates, PHMSA's mandates, and what the schedule is. And I didn't really get the whole story there. Jeff had covered it in his remarks, but we're here to talk about the part of the statute, Section 4, that -- relative to automatic and remote control shutoff valves. Specifically Congress had directed us within two years to issue, if appropriate, requirements for shutoff valves for new constructed -- newly constructed lines.

Along with that -- it's a little bit convoluted, but along with that, the GAO was directed to, within one year, to perform a study on retrofitting pipelines with remote-control valves.

Then there's a third aspect of this outside of congressional mandate relative to the NTSB recommendation post-San Bruno to look at the use of remote-control valves in class 3 and 4 areas.

Now, what PHMSA is doing, there's a lot of work in motion right now. Number one is what we are doing today. But we have commissioned a study on this project, and that's been a topic of discussion here. We are rolling all these up into one, and our goal is to have a comprehensive study that covers construction and existing pipelines, and our goal on that is to finish that within a year, so -- and that will help inform the policies we develop going forward and also help us comply with the mandate we have, which the time -- the Bogie on that is two years from the date of the Act, which is January of 2014.

Okay, with that, we are going to shift gears for panel number 2. Panel number 1 was liquid pipelines. Number 2 will be natural gas pipelines. Again, similar pattern. We will start with a federal perspective and move on down to state perspective, two government perspectives, then get a national perspective from industry along with two operators' perspectives.

Again, we're looking at the capabilities of valves and the application of valves for natural gas pipelines, just similar to what we did for liquid pipelines.

Without further adieu, I'd like to introduce our first speaker today. Jeff Gilliam is Director of Engineering and research at PHMSA, and without further adieu, Jeff.

>> JEFF GILLIAM: Thank you, Alan. I wanted to add a little context today, a little bit about -- I'll go back to the leak detection just briefly, but then a little context. What are we talking about when we are talking about automatic and remote control shutoff valves? Are we talking about replacing valves? No. We are not talking about replacing valves. Most of these systems are already pigable; right? All we need to replace is the top part of the valve, which is the actuator, and add some communications. That's what we're talking about.

I want to make sure that we also understand that this little $200 phone here has more technology in it than is required to necessarily monitor a valve, require it to open and close, and do the communications. This little $200 phone.

Now, that's not an industrial version. It's not in a class 1, div 1 enclosure which you need, which adds some cost. But it's not hundreds of thousands of dollars. Okay? We are talking about a few thousand dollars maximum. I just want to make sure that's clear. $200 phone. I want to make sure we get that.

Now, what I'll go through today is three key things. I am going to talk about the automatic remote control shutoff valves and some specifics. I am going to talk about the San Bruno incident. And I'll talk briefly about the study.

Public safety and environmental stewardship are paramount. Right? That's really what our goal and objectives are. Recent accidents necessitate a comprehensive study on installation of automatic and remote control valves. This, as Alan and others have alluded to, Congress has mandated us to do this study. That's what we're here to really vet out is some of the scope of work for that and some of the recommendations from NTSB.

Also, I think we should be aware of the study requires that we analyze the technical, operational, and economic feasibility play a role in determining ASVs and RCVs. Again, it's a $200 phone. Use of ASVs and RCVs depend on a pipeline system and needed capabilities to make those determinations.

Here's a good example. I've heard a lot of talk about footprint. Here is the footprint. Okay? The valve site is already there. There isn't a lot of additional requirements there. You may add a little building depending on what part of the world you are in, if you need climate control, et cetera. You may need a little $10,000 concrete building with AC in it, right, to maintain the equipment. We all understand that. Again, that's not that big of expenditure. I want to make sure we understand this is the footprint for the most part, top of the valve. You can add a little stand over here with a solar panel and an RTU, and that's your communications most times. We're talking about adding these where? In populated areas. Facilities, power, phone, et cetera, are available, readily available there. It is not going to cost you thousands of dollars to get those facilities.

Now, it's different for liquid. Liquids ACAs are different from gas. Remember, we are talking about gas here. I want to make sure we are very clear about that.

What are we looking to do there? We are looking to get the signals derived from pipeline sensors for pressure and flow. Guess what. That's very important for leak detection. It would be nice to get that at these additional locations. And that will help us in our response for failures, et cetera, when they happen. Signals cause an automatic closure, right, and we are talking about automatic shutoff valves now, so the automatic shutoff valve will depend on the sensing of the pressure and temperature at that location. It doesn't require human action. As far as gathering the signals for leak detection, that's really more for an RCV.

Here is the RCV. Here is talking about you can do that many different ways. It can be pneumatic, electric, gas-powered actuators. It can be operated from a remote location, of course. And it does require human intervention, decision making. It's very important -- and one I've heard and seen a lot in accidents, and I want to make sure this is clear -- is that controllers a lot of times are utilized as dispatchers. They are not controllers. A controller should have the ability to control the facilities. That means they initiate startups, shutdowns, and not necessarily start-ups that's unmanned. I'm not a big fan of that. But shutdowns in emergencies, they should have the authority to do that.

Typically what happens is they dispatch a crew to verify, hey, did something really happen or can you go out and check the valve? If they are dispatchers, they are not really a controller. That's the reason data and some of these inputs are very important. Technology is a good thing. I realize it's really changed a lot of our lives, but we need to utilize it more in the industry.

Preventive and mitigative measures. One of the key aspects of integrity management was always 935(a), and it talked about adding ASVs or RCVs where necessary. Unfortunately, most operators did not. Some operators chose to do that, but in the eight years I did inspection, I never found one. Okay? Not one that did that. So maybe they need a little more incentive.

As far as the minimum considerations, we are supposed to look at swiftness of leak detection, shut-down capabilities, yada yada, and location of nearest response personnel. The biggest argument, right, was that we had people that could go out and operate the valve within an hour. As we've seen in recent accidents, typically that doesn't happen. I think it's probably a 50/50 if it actually happens that timely.

Required distance from valves. This is a big issue here. And why so? Okay? Are we advocating adding more valves? No. However, historically, some operators have had their class 3 and 4 areas expand. Right? Those areas didn't necessarily, upon interpretation of the code by some operators, require them to install additional valving to maintain the spacing, particularly in class 3 areas. So now if you have some spacing that doesn't necessarily meet this requirement that's in the code, maybe there's a good spot where you should be considering automatic control valves or remote control valves to limit the consequence; right? Because that's all we're doing with here is limiting the consequence.

Valve requirements. 192.179(b) talks about the valve and actuator must be really accessible and protected from tampering and damage. They are all within fenced closures, generally, or vaults that are secure. So tampering -- I will say this. You can never prevent someone who wants to do damage. You can never prevent that. You can secure it, you can have it locked, et cetera, but if someone is determined -- just like if someone is determined to break in your house when you're gone, they can do it. Same thing with a valve. It doesn't matter if it has an actuator on it or not. Right? If they want to get in there and do damage to that valve or crank that valve handle by cutting off the chain or lock or whatever is on it, they can do that. So we don't need to fret about that aspect.
That's a known hazard no matter what.

This is something we might want to consider and into dell. What if we actually had blow-down valves that could be opened and vent the gas during a catastrophic rupture, as long as it was in a proper area that wouldn't initiate additional fire or problem, right, that would necessitate the quickest blow-down of the line.

Here are some standard calculations and information; right? It talks about the most conservative formula, which is here, and this is the worst-case scenario. This is based on if there was a failure at the mainline valve. So you have the entire valve section to vent from one direction. Okay? So if it's somewhere in the middle or somewhere else, those times are in -- you can cut those in half generally.

So if you get down here to the class 3 and 4, that's what your times are looking at, 15 minutes, less than 10 minutes. Okay?

Now, it doesn't matter how big that line is, believe it or not. It's dependent on distance. When you do the calculations and you do the math, it doesn't really matter how large a diameter that line is. What matters is the valve spacing and how quickly the valve is closed.

This is San Bruno, and we're all familiar with this. I can't tell you if this was actually 15 minutes in or an hour later. I think the picture probably would have looked very similar because the gas source was not cut off. Right? So just be aware of that. I'll get in some additional information on that..

The emergency response forum we had in December, there are key points. Everyone's goal, of course, is always public safety, but they had some issues with the valves and were they above or below ground? Do they know that? Do emergency responders know that? Have you sat down and talked with them? Is there single or two-way feed or looped lines? Do these looped lines have the crossovers open? This is a good place to point this out.

Engineers all know that when you have the crossovers open, it increases efficiency. Okay? That means you can get less horse power to drive the same amount of gas. You get a chance to make more money. I understand that. I think that's very prudent operations. However, when we're in HCAs, perhaps that's not the best mode of operation, particularly if you want to facilitate closure and gas sources into large-diameter lines. Right? Because the main thing that the difference in diameter does do for you is it has more stored energy, which means it's going to have more radiant energy that's going to be produced into the community.

Now, here's San Bruno. Here is a little schematic. 414 feet, that's the PIR based on a 32-inch diameter line operating at 400 PSI.

This second line is at the edge of the outer edge of all the homes that was destroyed, basically, burnt to the ground. The 414 divided by .69, which is our little number for gas in our formula, equates -- changes that number to 600 feet. So that's somewhere in between here. So is that where the PIR maybe should be? I don't know. But the valve closing may have reduced some of this damage out here because the extent and the time frame that the fire burned and the fact that the line actually ran in this direction along this street and there was a prevailing wind, so maybe the heat convection over the duration of the fire caused additional damage.

Now, this is strictly from the NTSB website, just so you know. This is isn't PHMSA created. This is from the NTSB. This 803 feet is really the extent of all the homes that experienced damage from this fire. Now, you can't read these little numbers down here at the bottom, but basically, there's about a hundred homes that are affected. So was this a good spot to have an automatic and -- or remote control valve? I don't know. I'm going to ask you some rhetorical questions, and you can add some comments later.

But I did do a little math. So since this is a 30-inch line at 400 PSIG, this 942-foot diameter circle is actually from -- and I have to get my notes here -- 36-inch line at 1440. And the green line is actually from a 42-inch line at 1440. Now, as you can see, the impact is significantly larger. So does that mean -- remember, this is 414, the original 30-inch line. Here is the 32-inch line. So would that be a good spot to have automatic remote control valve? Do these newer, more high-pressure lines that could have a higher impact, should they have these valves? All we are talking about is adding an actuator and communications. Again, it's not that expensive.

So is this scenario where we would want to consider that? I think that's something we need to discuss.

The next issue with the NTSB investigation was the heat. And this is straight out of the report. The heat and radiant energy directly proportional to the rupture time. That's key because they are saying the longer it's burning, the more -- this is what they're saying -- is the more radiant heat that's going to be out there and cause secondary fires, which is what I think a lot of the damage was associated with.

The allowed fire -- it allowed the fire to spread, which led to an increase in property damage. Pressurized flow resulted in an intense flame front and prevented emergency responders from accessing the site. And emergency responders were unable, basically, to respond. They just had to wait until the fire -- which for their safety is appropriate -- they need to wait till the fire source is turned off.

Is an hour -- is that -- is that acceptable? Is an hour acceptable? And I think you have some others talk about is a half hour? I think even if you had a remote control valve, you are still going to have about -- in this area -- 30 minutes of flame. So 30 minutes of flame would have done potentially less damage than an hour and a half worth, which is about what we had. So that's -- that's the contention, and that would be the purpose to have an automatic shutoff valve or remote control valve.

NTSB further said that the fire would be smaller with fuel flow -- if the fuel flow was removed -- excuse me -- and this would have limited damage. That's what they're saying. It's not what Jeff Gilliam is saying or PHMSA is saying. That's what the NTSB is saying. This study is going to look at some of that. We are going to try and look at some of the fire science. We understand the original CFR work that was done. We understand it was based on more of a candle flame and not necessarily the flames you could have potentially produced here with this fire. So we are going to look at some of the fire science and some of the other issues associated with that. I think that's extremely important that we understand the science, not -- and I don't have any predetermined answers, and I don't think anybody else does, but it needs to be based on engineering and science.

The recommendation regarding from NTSB was basically they say we should require automatic shutoff valves in high-consequence areas in class 3 and 4. I think that depends. I think there are some areas it is appropriate and there are areas it may not. I think there is something to study. Hopefully we'll come forward and clarify for us.

This is the advanced notice of proposed rule making. There is some requirements in there about valve spacing requirements, requiring block valve installation in new class locations, requirements for ASV and RCVs, and then we're also asking operators to reevaluate the economic feasibility.

I mean, technology has really changed. It's changed dramatically. I can tell you a little story, and I'll be brief. One is when I first came in the industry, I was sent out with this old-timer, we'd call him, to take you around the right-of-way and show you the ins and outs; right? Very knowledgeable guy. Taught me a lot. However, I see this individual with two or three missing fingers, and I wonder do I really want to do it the same way? I'm not sure. But I want to watch and learn for certain. So we want to keep that in mind.

The other story there is on technology. When I came into the industry, I didn't even have a computer. Now, that's not what I had in college, but I didn't have a computer. The only one that had a computer was a supervisor, right, and he barely knew how to turn it on and off. But be that as it was, the rapid change of technology is tremendous. Again, there's probably more technology in this phone than there was in that computer when I went to work. So there's -- our world has changed, and I think it's time for us to try -- or my recommendation is that we should consider trying to incorporate some of that technology into our operations.

Pipeline safety, regulatory certainty, and Job Creation Act of 2011. This is key. If appropriate, the Secretary should require by regulation the use of ASVs and RCVs. This requirement is based on the following: Economic feasibility, technical feasibility, and operational feasibility. Right? We're going to look at all those different aspects in the study.

The Act also goes on to talk about we should consider -- the GAO should consider the swiftness of leak detection, pipeline shutdown capabilities, location of nearest response personnel, and of course, the cost, risks, and benefits of installing ASVs and RCVs.

This is the -- this is the key piece. All these things need to intersect. We get that. Okay? It can't be, you know, put the blinders on and not use any intelligence here in decision making. We're not advocating that.

PHMSA is conducting the study. I don't think I'm going to go through and -- ought aspects, but I will tell you we're going to look at all the things that's mandated by the Act, and we're also going to consider the issues that NTSB has brought up to us during the study. And I go through the different aspects as far as talking about the cost, the technical feasibility and operational feasibility, but in the end, ASV concerns, okay, the known issues. For automatic shutoff valves, pressure fluctuation sincerely a problem. Historically it's been a problem. You can get some false positives and inadvertent valve closures. We know that. I think some operators have learned how to engineer around that, but others may have historical, if you will, bad experiences, so they are hesitant to engage in this technology again.

The technology, I believe, today is much better than it was 20, 30 years ago.

Physical and cyber security threats. Yes, they exist. We all live with that. Do I think that that's a possible threat for these valves, no, I do not. There's always the physical, like we talked about earlier. Anyone can get into a valve site and do damage if that's what they decide to do.

Technology requirements. Technology is very limited. Right? Pick up my little phone here again. So the limited -- limited to larger leaks, to a dead band for smaller problems. You can see parallel lines and crossover valves, those do eliminate the effectiveness of ASVs. We need to be aware of that. That's why it's important to understand those operations.

RCV, the controls here. RCV control room issues, operator fatigue, operator's ability to recognize a situation that requires a response and require permission to do so. That's key. Again, the operator or I should say the controller must be able to control.

Physical and site -- the same type of things are there, and again, the same issue with parallel lines do affect the effectiveness.

Here's the final considerations. And we are looking for your input. Thank you very much. Again, it's a $200 phone. Thank you.

(Applause)

>> ALAN MAYBERRY: Great. Thanks, Jeff. For our second government perspective, we'll reach to the state governments, and Jim Hotinger from the Commonwealth of Virginia. Jim's the Assistant Director, Division of Utility and Railroad Safety, at the Virginia State Corporation Commission. Jim, again, will offer the state perspective. So Jim.

>> JAMES HOTINGER: Thank you, PHMSA, for inviting me to give our perspective. I appreciate you all coming. I appreciate those that are listening, and also, I thank Ledversis for introducing you to (Indiscernible) so I don't have to go through all that. So that's a bonus.

That's why we're all here is instances like San Bruno. Carlsbad. Even incidents that happen in rural areas. That's what bring us here. It's these things that drive the public's attention and brings that focus to PHMSA, brings that focus to the state, and brings that focus to the operators as well.

So they asked me to speak to the considerations for valves and such from a state perspective, and so essentially, I broke it down into four sections. We have the siting, installation, maintenance, as well as the other considerations. And these four area would want you to think of them as disparate considerations. They all should be thought of as concurrent. Because you may make a decision based on siting, but then if you look at the valve choices, the installation of them prevents you from using a particular location. So all of your decisions you make relative to the valve selection, actuator types and such, really need to be based on all of the factors that I'm going to bring out today.

For example, siting, distance between valves. We all know what the regulatory requirement is for the valves. But as Jeff brought out, we have the consideration of future growth. Should you think of, well, this might be a class 2 area now, but I foresee this is going to become class 3, so maybe I need to space my valves a little closer. Or there could be something within that area that says hey, the topography here limits this.

I want to reduce the impact. I want to make it easier for my crew. So I'm going to reduce the spacing distance.

The juncture of the pipeline limits you as well. Obviously, the choice would be to put the valves in straight lines of pipe, nice flat, level places, so that's one of the considerations as well. And of course, the locational accessibility. Can I get to it to install it, maintain it, operate it if I need to?

And many people think of transmission lines as those big cross-country lines, but they are not. From a state perspective, for example, this is in southwest Virginia. This feeds a high-security federal prison. That's an 8-inch line, runs across the ridges. It's about 11 miles long. That's transmission. The valve considerations for this are much different than the valve considerations for those 36-inch lines in 1440. This line they worry about the strip miners covering up the line so they protect it from the blasting of the strip mines. They have other considerations here, but they do need the valves. They do have customers on the other end. This is the single feed. So they also have to think about what type of valves I need here.

In Virginia, we also have marine environments. This pipeline goes underneath the Chesapeake Bay for several miles, and that particular beach is located on a lovely military, secured facility. So again, that looks like a wonderful place to put a pipeline, but the siting issues all right accessibility issues because of security create interesting considerations for gas companies to have.

Here's this -- they are doing a dig, this is along 495 here in northern Virginia. Again, considerations about the impact of this. How do I access that? All come to play. We are not just talking about the pipelines running across a rural area. And this pipeline, this transmission pipeline, as you can see, it runs down the median of a divided highway here, and also northern Virginia.

So the valve considerations on that rural line going to that prison are much different than the valve -- the considerations for these, the siting, the placement, the distances and so forth. So don't just focus on thinking of transmission lines as these big cross-country lines. We have them here in our urban areas as well.

When we look at installation, we have to think about, you know, the manufacturer may have some specific requirements as well as the direction of flow. You know, from a manufacturer, they talk about -- I copied this out of the installation procedures. They talk about making sure that the valve is full open when you weld it and to protect it from weld spatter, but also the temperature. Temperature is very important, so you have to have the means to ensure that you don't overheat that valve, the seats, and damage them during the welding process.

On a smaller pipeline in Virginia, we did have a problem where they did weld on -- it was only an eight-inch line, but when they welded the valve, it was too close, and they overheated it, had to cut it out and replace it. Pay close attention to what the manufacturer requires.

Also, think about your direction of flow and placement. This may look interesting to some of us, but these things happen in the real world. We see these kinds of things out there. You just shake your head. You know, we laugh at this. But guys, this is serious. This is a valve to control the flow of a pipeline, and you install it in this manner? How that happens we don't know, but it does happen.

And you know, what do you do? You know, we have to move beyond this kind of thing. I mean, you laugh about it, but think about what this implies. Somebody didn't think. We've seen filters installed backwards. How good that? We've seen filters installed on the wrong side of valves. I mean, so when you are doing the installation, make sure that you follow the manufacturer's guidelines and you make those appropriate considerations for and valve and its needs and your needs relative to operating and maintaining that valve moving forward.

You know, each type of valve has the -- has different maintenance requirements as well each actuator has different maintenance requirements, which requires -- both of those require your own operation maintenance procedures, requires your OQ training, requires procedures for all of that to be sure your people are capable and qualified to operate these.

You look at some of these valves, this is a basic valve with just a wheel, but they talked about the ports. That's the drain port. This is the port to bleed. These are the sealant ports. For example, in some of these ball valves, you have the ability to inject emergency sealant in them to seal it if you can't get a gas-tight shutoff. And it seals it. But what you need to also understand is when you use that sealant, you then have to flush it out and replace it with the appropriate lubrication so that it operates primarily in the future. And again, that's something often forgotten in procedures, manual, OQ, okay, if I have to do this I have a procedure to do it, but I may not have a procedure to say, okay, now that I used this, I need to flush this out, I need to relube it, and I need to make sure that the valve assembly is cleaned and operating appropriately.
Again, these things look simple, but there's a lot to these.

This is a fail close. Now, that's a big spring on it. This was a spring-operated one. You can see it takes kind of a large spring with a valve that big to close it, and it can be manually reopened. You have to -- there's basically a hydraulic jack that jacks the spring back into place, and you set the trigger. But again, fail open, fail close, fail last, those are all considerations of what you want. Relative to ASVs, obviously, they're fail close. And the ones that I've seen in use generally are going to single customers or just a few customers and were in locations where it was imperative that the customer not be over pressured or opportunities for incidents were greatly reduced.

Here is a standard valve that you see. It's automatic. We've got the hydraulic cylinder on the back side of this thing. This is on a facility in Virginia. This transmission line runs from northern Virginia down into Virginia Beach. And again, with each type of these actuators and each type of the valve, you have your challenges, your processes that need to be developed and followed to ensure. And every one of them fits a specific type of siting. Fits a specific type of installation. And so as I said when I started, you need to make considerations for each of those issues.

Here on another pipeline, you have the actuators here, and this is actually used as the gas from the pipeline to actuate. And one of the advantages of this one is if they lose power, they can still use the gas models to close that valve. That's one of the reasons those were selected. The company wanted that additional protection of, okay, I lose electricity, whatever, I can still make this valve work.

And lastly, this shows you -- this is installing a compressor station. There's an outlet to the compressor. Here's the valve. Here's the blow-downs on either side. This shows you topography. Obviously, it's a little bit of an uphill to the compressor station, but they are maintaining the height of the valves at the same place because they are going to cover this up. So look, imagine having to maintain this valve when it's that deep. If you have to dig that thing up. Again, that's a siting consideration, my depth of cover. How am I going to access this?

On the distribution side, I saw a distribution valve that ended up being 32 feet deep. They ended up creating a bypass around it and creating a new one that was a whole lot shallower because they knew there was no way to dig a hole deep enough to effectively use that valve.

When you use blow-down valve, you are blowing all kinds of gas and crud down those seats. You need to be sure after you use them that you have a procedure to inspect those valves and maintain them properly to ensure they will seal off properly and you didn't destroy the seats, you didn't destroy the ball itself if there's a ball valve.

You know, other considerations we get into. We have, you know, the requirement with good remote valves for electricity or communications. Some places are doing that with solar backup. We have cellular communications now, but of course, that depends on the availability of towers to reach out. You have fail open, fail close. The pipeline pressures and differential pressures, as you heard with the liquid. Sometimes if the differentials are great it's hard to make that operate. You have solenoid valves, whether you want to limit switches, manual overrides. And this goes back to maintenance. We have one operator now, their actuator failed, and they can still manually operate the valve because it has a manual override.

If they didn't have that, then they wouldn't have been able to continue to operate that valve. And now as a result of that actuator fall you're, they are looking at their procedures for the manual process to make sure that their crews do know how to operate that valve manually should the need arise and not overstress the valve.

In addition, we've seen -- relative to maintenance, we've seen things as innocent as bushhogs clearing right-of-way mow the bleed valves off. And that's not good because then you have to dig down to the valve to replace that section of piping. So while we think about tampering and damaging facility, remember to think about all the little pieces, parts that affect the operation of that valve. It's not just the valve assembly, actuator, it's also the bleed ports, rain ports, any of those things that can damage the operation of that valve, you need to take appropriate steps to ensure that they're not damaged and do not prevent the valve from being operated should you need it.

Another consideration is field reparable. We've had one operator install some valves, they got a good deal on them, and after they did that, they found out basically they cannot work on them in the field. They have since replaced them over the years as they got the money and gotten rid of them, but you don't really think about that. Make sure that if you are using those valves, especially in remote locations, they are field reparable. And along with that, if they are field reparable, should you have an inventory of parts to repair them?

We have an operator right now with a small transmission line, it's only an 8-inch, where they had to declare an SRC because they didn't have the parts to fix a failure. So they are having that part being manufactured so that they can install and make the repair. And if they just had an inventory of that one piece, they could have avoided the whole safety-related condition/issue.

So think about when you're choosing these valves, selecting these valves, and you decide on you are going to make field repairs, not only to have the procedures and processes, but keep the parts necessary to make those repairs so that it doesn't become, well, I can have them flown in from Texas or I can have them flown in from Vermont or wherever the manufacturer is because they may not be available. The manufacturer may not have the parts either.

And also things like filters. We've seen some valves on smaller lines get so they couldn't operate because of debris in the line because they didn't install filters, and filters are not that expensive, and they do a good job of removing the trash and debris that would prevent the operation of the valve itself.

But what I want to bring this down to a close with really what we're talking about is the stored energy. Your consideration as you're making decisions how much stored energy you are willing to lose if you have to blow down the pipeline to work on it, or conversely, the instance line San Bruno, how much stored energy you are willing to allow to escape and potentially create thermal energy and affect an incident.

Here, this particular incident happened in Virginia. So I pounded that ground and assisted PHMSA in the investigation of that. I'm very familiar with this.

You can see the pipeline runs this way. See this burn here was created mainly because you had more pipeline this way than you did that way, so this pipeline burned out before this one did, so more heat was pushed down in this direction.

But I look, there's a house 1200 feet away up this hill, where the vinyl siding was melting. 1200 feet away. It can -- thermal energy, once you've transitioned from the pressure energy and you're now into the thermal energy, the heat and mass transfer, that's where we talk about the San Bruno, as he pointed out, relative to the thermal damage. Once you start feeding fuel, once this field caught fire, it was going to continue to spread until it could find no more fuel. So your potential impact radius could be much greater than calculated based on the situation that exists, and those -- you need to think of those considerations and perhaps do some thermal modeling of the radiant energy effects.

How many of you all own a Jeep Cherokee? That tells you how much aluminum is in a Jeep Cherokee because basically, the only thing left is the iron or steel. There's the spare tire rim. It had alloy wheels, so they're right here. That's puddles of aluminum. This was about 200 feet away from that rupture. If I go back, there's the rupture, and that Jeep Cherokee is right there. And you can see that even some of the thinner sheet metal also was burned up and destroyed. That's why it's vitally important when you're making these considerations to look at your potential impact rate.

I drew this 415 feet because mathematically, it's like 415.xxx feet, so I made it 415. But to his point, there was damage here in this area, and they talk about prevailing wind. There may be a horizontal component to the PIR that's not being considered by your calculations, by the transfer of that thermal energy once these become ignited. Make those considerations when you're evaluating whether or not I need a valve in a particular placement.

Think about this. If this catches fire, is there going to be additional fuel sources that will create additional radiant energy and make the situation worse? Because the jet effect, which you can clear see here, from the two nozzles that were created by the other end of the pipeline, sure they make most of the heat go this direction, but as you can see, the fuel source, the dry fields and so forth, allowed that to propagate, as well as at San Bruno, you had, perhaps, the homes burning creating additional damage out in these areas here, but again, it's a consideration that needs to be made when you are sizing these valves and such. And making your determination how far apart they are.

And I will tell you most emergency responders will tell you they like to be there and be on scene and ready to fight a fire in 15 to 20 minutes because they have to arrive on scene, they've got to set up their equipment, they've got to put on the CBAs, do whatever is necessary. If you use that as a guide -- I'm not saying that it's absolute -- but to have a fuel source eliminated within that time frame, when they arrive and get set up they are ready to fight a fire and don't have to wait for someone to turn a manual valve ten miles away and wait for the gas in the pipeline to burn out and so forth. If the fuel is already dissipated from the pipeline, they can start fighting the fire, and they would be greatly appreciative if you would use that as a consideration as well.

So in summary, one size doesn't fit all. When you're looking at your valve considerations, you have to look at all of the factors concurrently. Don't look at them independently and in isolation. They can all have an impact. So I can't stress enough with the urban environments we have here in Virginia as well as the rural areas we have, we do work with our companies, and we do ask them these questions, as they will probably tell you. We ask them very pointed questions about how they determine their valve spacing and selected the valves that they're currently using.

And the same is true across the states. In the states I spoke with relative to the valve considerations and so forth, they also had the same issues. It really boils down to minimizing the impact of the incident should you have a pipeline rupture, which comes down to very simply how do I reduce the amount of stored energy that's available should that pipeline rupture.

I appreciate the opportunity. I thank you for listening to me. And I know there will be an opportunity for questions later.

(Applause)

>> ALAN MAYBERRY: Great. Thank you, Jim. Going to shift gears here a bit. And by the way, let me take a moment to say -- I've been we miss in mentioning this to the speakers -- I've been remiss in mentioning this to the speakers. This computer is Bob Smith's, and for some reason it beeps, but I assure you it doesn't mean the trap door is getting ready to open. (Laughter). For that, let me stand a little bit differently.

It's a good government-issued computer. Okay. Time to shift gears a bit here. You've heard the government perspective. Now we will start with the national perspective from industry. And here to represent the interstate natural gas association of America is Larry Hjalmarson. He is with Williams Gas Pipeline, where he is the Vice President of Safety Environment and Pipeline Integrity. So without further adieu.

>> LARRY HJALMARSON: All right. Now I'm going to be paying attention to that beep. I was ignoring it till then.

Well, I'm pleased today to give the natural gas transmission pipeline perspective on this important topic of valve automation. I'm representing today the 27 INGAA members shown here.

This is a familiar slide. You just got to look at it for ten minutes. I am going to show it to you for a few minutes as well. I came into this industry 35 years ago. I worked the first 27 years of my career in the gathering and processing side of the business. And I came into the gas transmission part of the business eight years ago. When I did, I had an idea about safety, that the pinnacle of safety in the gas industry or the greatest safety challenge in the gas industry I thought at that time was a gas processing plant.

Picture a small refinery, very complex, more than 200 control loops, pumps, compressors, distillation columns, a concentration of people where, if something went wrong, the hazard was great. We honed our safety skills to a very high level. We applied process safety management and all that goes with it. We got really good at our procedures, all of our practices. We kept those facilities safe because our lives depended on it. I thought that was the pinnacle of safety in the gas industry.

One thing we had there, though, as a backup, if something went wrong, was what we called the "emergency shutdown system." So if we had a gas release in the middle of the plant, our instructions were to flee. Get out. Right now. As we leave, press that emergency shutdown button that looks something like this. Block in the plant. Depressure it. And then we gathered at a safe place on the outside of that fence and decided what we were going to do next.

I arrived eight years ago to the gas pipeline side of the business, and I saw our pipeline next to people's homes, next to apartment buildings. I understood the amount of energy flowing through our pipeline and the tragic, catastrophic consequences if our pipeline were to fail, and I asked where is the emergency shutdown button? How do we protect these people? And the answer was there is none. We cannot shut that pipeline down fast enough to protect people. People are in grave danger even if we shut those valves instantly.

Here at Appomattox, Virginia, 2008, quiet Sunday morning, our pipeline ruptured. People were just sitting down to breakfast. Two homes quickly caught fire in the first minutes of this event. Ten minutes later emergency responders arrive. They see two homes engulfed in flames. They make the only natural assumption, that there must be at least five fatalities. Fortunately all right people escaped, narrowly. They fled from their homes as their homes were catching fire. Some were injured, several with serious burn injuries.

We cannot shut those pipelines down fast enough. We have to keep these pipelines safe. We cannot have a failure. The fire department can't protect the people at that point. The gas pipeline companies can't protect them at that point. I wish we could. But we can't.

There are ways to protect them, more effective ways. Certainly, the integrity management program is far and away the best way. These principles, as we apply them, we are going to avoid failures, and that's the best way to protect people.

PIPA, another great set of guidelines, Pipeline Informed Planning Alliance, gives communities ideas on how to construct near our pipelines and do it in a way that keeps people safe.

Common Ground Alliance, fantastic program, call us before you dig. Don't dig near a pipeline without calling us.

Valve automation certainly has a place, and I'll talk about where that place is, but that's not the best way to protect people.

Our INGAA companies gathered last year, and we set down guiding principles. First and foremost, we've got to prevent these kind of failures. We are aiming at zero failures. These are all wrapped up in a culture of safety, an attitude of relentless, continuous improvement, of applying integrity management principles systemwide, not just where it's required by law, and then certainly, engagement with stakeholders like we're doing today. We need to talk about these important topics. We need to understand each other.

INGAA's commitment is this: In populated areas, class 3, 4, and HCAs for the larger diameter pipes greater than 12 inch, we are committing to a one-hour response, whether it be with a person or with automation.

Smaller diameter lines, we are taking them on a case-by-case basis. They don't always pose the same hazard. Some of them do. We are applying what's called incident management, assessing that risk and doing the appropriate thing. Probably a lot of valves with 12 inch and under will also be automated as a result of this.

Class 1 and 2 we're not proposing any change there.

Industry perspective, give a summary, we set in place a task force, incident management continuous improvement, to get better at this. Most of the efforts were at prevention. The team I was assigned to -- and we have a number of team members in the room today -- we were the only ones working on the consequence side, on the emergency response side. We asked how do we protect people? Certainly, it's on the probability side of the equation. We've got to prevent these failures. Even if the valves close immediately, people are in grave danger.

We attended or put on, hosted a number of emergency responder workshops to engage that group of stakeholders in these questions. What they told us in those meetings -- we had one in Dallas in April, one in Houston in September, and we participated in PHMSA's workshop in December. Had he told us that the keys -- they told us that the keys are planning, preparation, communication, awareness. They told us that prompt valve closure certainly can mitigate property damage.

Our team hired a consultant to show us the rate that gas depressures upon a pipeline rupture depending on when you can close the valves. And we did this for various pipe diameters. This one shows a 30-inch diameter pipeline, eight-mile valve spacing, and if the valves close at 10 minutes, 30 minutes, 60 minutes, or if they stay open. You can track those lines down. There's two lines down at the bottom that I want to point out. The red line represents a heat radiation coming from that if it was ignited. Where an emergency responder in full turnout gear could enter the impact area for a few minutes but then would be forced to leave not due to injury but due to just exposure from the heat. Then the yellow lines represents where they can get into that impact area and work on a continuing basis.
Okay? So that yellow line is really the line we're trying to get to in an emergency response.

I want to point you now to the very top of that curve up on the upper left, and that actually goes off scale. I changed the scale so you could see the bottom part of the graph better. But just the top of that graph is 7 billion cubic feet a day. When I saw that figure, I knew it would be a big figure, but I didn't know it was that big. That's an awesome amount of gas. That represents about 10% of the United States consumption on a daily basis for that instant.

People that experience a natural gas pipeline rupture, it overwhelms all of their senses. It's earth shaking. It's ear-splitting. It sounds like a jet aircraft engine. The heat is intense. It's a scorching level of heat. The volume of gas is terrific. And I want you to notice that all of the lines line up together at that point. And people are fleeing at that point. Really, in those first minutes is where the impact to people is great. It blows up, it's on fire, and they're escaping. And within five minutes or so, typically -- and there are some exceptions that I'll talk about in a minute -- but typically, they're gone by that point.

As the fire progresses, we're really talking more about property damage at that point, and we want to -- we want to hasten the point where the firefighters can get in there and put out those surrounding fires. Sometimes one home is catching the other home on fire if it was a densely populated area, or that radiant heat might cause yet another structure to catch fire.

We surveyed some recent valve closure times. You can see it's quite a range. This is during actual emergencies. About half of them we respond and get the valves closed in less than 60 minutes. About half of them it takes longer. We're committing, as INGAA companies, to be on the left side of this, to be no greater than a 60-minute response. We believe that serves the emergency responder needs.

We studied an incident. Closing the valves is just one aspect of this. This flow chart of an emergency response starts with a rupture. On the left side are the pipeline company response. On the right side are the emergency responder response. Connected initially by the 911 dispatcher, and then as soon as possible thereafter, forming incident command and a unified command where we're coordinating with the emergency responder handling this incident.

On the left side I would point out the first box identified a rupture. That takes a finite amount of time to recognize the rupture's happened. Secondly, the order to close valves can take a finite amount of time. We want a bias for that gas controller to not have to call somebody for permission. Not only that, we want them to be more inclined to shut the valve quickly in the event of emergency. Don't wait. Get it closed.

Then we want to reach the valves. If it's a matter of electrons flowing, it's almost instantaneous. If it's someone driving to it, that will take some time.

We want to close, lock, and tag valves. I say lock and tag because thee automatic valves, we don't want them to inadvertently go open. We've got to disable the valve to protect the emergency responders going into that impact area.

Then you evacuate the path. So you get the valve shut, now the gas is depressuring. Those are the main stages of emergency response.

Then the emergency responders over on the right side are able to enter, mitigate, and put out the secondary fires.

This is the exception I was talking about. Put a slide in here particularly for this. There are a lot of facilities that have people with limited mobility, could be a nursing home, a detention center, and part of incident mitigation management is to identify those areas and make special provisions for them because they've got to get out quickly, and it's very hard for them to do that at that point. Certainly, preplanning and preparedness. I think PIPA comes into play here too. Facilities like that probably shouldn't be next to our pipelines. And then the IMP and the risk model. If we -- those in our risk model in our existing IMP models, we need special provisions, extra efforts to make sure nothing ever goes wrong next to those facilities.

Valve types and numbers. Roughly 30,000 of these. We are in the process of counting them. I wish I had had that for you today. We'll have it soon. A mixture of automated control valves, remote operated valves, manual valves, and I won't cover that because I think it's been covered about a hundred times in the last two days.

Recent experience since the IMP rule. Very simply, one of the team members told me this, and I thought he was exactly right. If we apply IMP rules like it's supposed to, like we're intending to, and we reduce these failures, there will come a day -- and we can see it in the future -- when we will never have to operate one of these valves in an emergency again because we will eliminate failures.

New pipelines tend to be fully automated. We have an example of that up there. Older pipelines tend to be a mix.

Cost to automate, about 80,000 to 200,000 for an existing valve to automate it. To install a new valve, half million to a million, depending on if it's an open right-of-way or in a city. Maintenance costs, about $500,000 per year. Benefit really is about property damage. Typically does not protect people. I pulled this figure off of PHMSA's website. In the past 20 years of significant gas transmission incidents, there's been about $1.4 billion in property damage. And keep in mind that even if you shut the valve immediately or within ten minutes, there's still pretty significant property damage that happens. So probably the benefit's going to cut into that.

I will say this, though, too. Homes don't equate to dollars. If you are a homeowner and you've lost your home, it's a lot more important to you than dollars. It could be priceless heirlooms that can't be replaced, priceless to you. Wear and tear. These valves are normally used for maintenance. We'll use these valves a thousand times for maintenance before they are ever used in an emergency. They are mechanical devices. They can fail. This has been talked about a lot over the last few days, so I won't cover this anymore. I'll skip.

Valves can leak. We had a failure in Alabama in December. This is a picture of that. One valve on one side didn't seal off completely. Now, it didn't inhibit the emergency responders from getting in there, but this is the next morning. We had to put that fire out with a fire extinguisher, use an evaporator and get that gas away before we could begin working in that area.

Intermediate valves do improve blow-down times, but there may be more practical ways to do that. Remember the flow chart of emergency response. But just for comparison, I did include some graphs. So if we shut the valves immediately, which, as I said, isn't really practical, with 15-mile, 8-mile, 5-mile valve spacing, you can see the blow-down time. And remember, we are trying to get to the yellow line there at the bottom. So 15-mile valve spacing, about 23 minutes to blow down. 8-mile valve spacing, about 10 minutes. 5-mile valve spacing, about 5.5 minutes.

Security concerns. As have been mentioned, vandalism, tampering, cyber attack. We think these are manageable. These are existing problems that we deal with every day.

Inadvertent closure is, I think, a much greater consequential thing and more real, something we've all experienced in the industry. These are complicated systems. We could cut off flow to a major metropolitan area. That can take weeks to relight. Picture the dead of winter and you shut off the gas to a number of residences. We can actually create a worse problem or a worse hazard. People die sometimes in those situations, elderly people, when their house has no heat.

So automated valves have their place, probably more often on the long-haul part of the pipeline where the consequence isn't so great if they inadvertently shut. The closer you get to the market area, I think there's more tendency to use the remote operated ones where somebody has to decide and shut that valve so you don't have that inadvertent failure. You also have a lot bigger pressure swings the closer you get to the market area, so if you have a pressure sensor, that tends to make it prone to fail.

We surveyed our companies, and yes, we have these kind of failures. Here's kind of a table or a graph showing that.

In summary, we intend to protect people. Valve automation does not change the outcome for people in a major rupture in those first catastrophic minutes. Preplanning, preparedness, PIPA, incident mitigation management, these things all certainly help. The most certain way to protect people is a strong integrity management program.

We also intend to protect property, and that's our INGAA commitment, to get these valves closed promptly, be it manually or with automation.

We invest where there's a clear safety benefit. We can rally our employees around causes where we see we're really making a difference. As companies, though, we get hesitant, we get less supportive if we don't see the benefit. And as I said earlier, we want a dialogue on these topics. Thanks.

(Applause)

>> ALAN MAYBERRY: Thank you, Larry. Next we'll have an operator perspective. Representing Spectra Energy, we have Andrew Drake, the Vice President of Engineering and Construction Technical Services. Without further adieu, I'll pull your presentation up, and it is all yours.

>> ANDREW DRAKE: I think it's appropriate to follow Larry. Larry is chairing the what we call Team 7 of the INGAA initiative on pipeline safety. I think it was a good presentation to maybe frame some of these discussions. I think following San Bruno, the INGAA board did sponsor an initiative to advance pipeline safety. I am the chairman of that initiative. We report directly to the Board.

It was very clear that our charge was -- and our underlying principles were -- a commitment to get to zero -- zero -- incidents.

Primarily, you know, of the ten teams that we have on that initiative, nine of them precisely are focused on how to prevent, which is appropriate. I think when we see the equation, we see more energy being deployed positively on prevention, the ability to get to zero is the key focus there. I think one of the teams was focused on explicitly looking at incident response and valves, and Larry chairs that.

I think that, you know, Larry provided a good context of that effort. You know, it's been a big effort, a tremendous effort really focused around listening, listening to other stakeholders, trying to learn from San Bruno and other incidents. What is it that is driving, you know, opportunity to improve here, figuring out how to characterize and fingerprint that opportunity.

It's a complex series of activities. The coordination with the emergency responders is critical, obviously. That's been logical. We've reached out to that community very explicitly to try to hear what they need.

My role here is really just to provide context and tangibility and examples in application of an operator. How does that validate or substantiate or quantify some of the things that Larry's talking about? In particular, you know -- and I'll be very frank here -- we are the pipeline that operated the -- that was involved in the incident at Edison, New Jersey. Now, that was 18 years ago. It's very sobering to be involved in those incidents, but I think it's an incredible opportunity to learn as well, and I think we have to embrace that opportunity, even if it's a little bit scary to stand up here and talk about not being perfect and having some things that we see as opportunities to do better, as an operator, as an individual, and as a company, and as an industry for that matter as well.

Just to give a little bit of context as to who is Spectra Energy, this is the somewhat obligatory system map. I think it shows very quickly you can see we have facilities all over North America. We're not just U.S. We have several companies in Canada, a big distribution company in Ontario. We have significant processing facilities out west. We have significant processing facilities in the United States. We move about 10% to 12% of the gas that moves in the -- in North America. We move about 10% or 12% of that volume. We're probably the largest storage facility, storage operator in North America and the largest gas processor in North America.

This is a little bit more specific to the U.S. assets, just to kind of give scale and tangibility. I won't deliberate on this, but it gives you a little bit of a feel for who we are and what kind of facilities are involved in our asset.

I think an interesting part of what are we -- what are the regulations saying and why do they say it, where did this come from? I used to be chairman of ASME for three terms, and during one of the terms, we actually were involved in the integrity management initiatives ten years ago. The first generation of integrity management we'd call it, 1.0. We went back and asked the ASME elders -- we called it the Emeritus report -- we went back and asked the elders who wrote the original code back in 1950, what were you thinking about, literally? Then we just stopped talking and asked them point by point by point.

When we asked them about valves, it was very interesting. You know, you don't know what you don't know. I didn't know that's where that came from. The original criteria certainly was to support operations and emergency response. We've heard that from many different speakers this morning. The interesting thing was valve spacing specifically was designed based on road spacing, to facilitate access and response. I thought about it a minute, and they went through it very deliberately. Section roads, county roads, how far apart are they in rural areas, you know, subdivisions, and urban environments, and they literally had gone through and modeled that.

And the goal is to get valves near the road so that you could close them. And well, shazam, that seemed to make some sense. It was a component in their consideration of design. At Spectra Energy, we use, certainly, the guidance criteria provided by DOT based on that ASME legacy, but we close them up to really hit the core of providing ready access to get there as quickly as possible.

I think the other issue that comes into play, and someone brought up a few minutes ago about parallel lines. Well, when you look at our service map in the U.S., we primarily provide gas to the northeast. We bring gas from many market areas, but we service Philadelphia, New York City, and Boston. We are in heavy urban environments. We are bringing large quantities of gas. That's the end of our system, so we are dealing with multiple lines. So it's very normal for us to have multiline rights and multiline right-of-ways into these urban environments. That adds a complexity. You know, Jeff brought that up. You've got crossovers. You've got to deal with that. It's an added complexity. I think it's something to keep in the equation here.

The other thing is, obviously, one of the design considerations -- and I think we've gotten through that hurdle over the last few years -- is we've got to have these valves, these mainline valves have to be fully opening, typically ball or gate design, so that an inline inspection tool can get through them. That fosters the lessons learned ten years ago. We are going to do internal inspections to facilitate prevention, the valves can't get in the way of that. So we're working as an industry to get through that.

This is a -- an aerial photograph of one of our mainline settings in Pennsylvania. It's very common for us. This is a four-line right-of-way, and I know you can't really see all the valves, but there's 11 of them. There's four mainline linear valves, and then there's 7 crossover valves. These are not little valves. We're not talking about 2-inch valves. We are talking about 24-inch and larger crossover valves, full size. That doesn't mean they all need to be open. You know, it's something to think through. It's not just so easy as to say well, we are just going to put something on this one valve and be done and walk away from here. No, no, this is much more complex than that.

I think, you know, we look at the physical equipment. I think Larry did a good job of staging out the series of events that happen, and I think it's helpful to understand in those series of events that happen, there's different kinds of equipment that play a role in that function. Incident recognition is a big deal. If it takes 30 or 40 minutes to recognize you have a problem, everything else is downstream of that. So getting that figured out and getting gas control, enough equipment and cues and alarms and savoir-faire to figure that out quickly is a big deal. I think that's why Larry has taken this with the team. Don't just focus in on one answer. If it is a series of 12 activities and you pick on one, any other of the 11 can cause the issue to continue. You've got to deal with the whole train.

Actuators is one of the train events. Once you've identified an event, you have to actuate the valve. We've talked different kinds of valves here, others have. To me, there's really three different kinds that you are really looking at here. You are looking at fully manual, which is geared to close. I've got this picture on here. I think it's got 12 to 13 different valves on there. That is a fully manual valve. You've seen them before. They've got the wheel on the side, and it's hand driven. These are also all manual valves, very quick to close. But that one is many cranks of that hand wheel to close the valve. It's designed to close line pressure and accommodate human strength. So you are talking many, many, many rotations of this thing to close a valve on a big valve.
On a 30-inch valve, maybe 700, okay, round and round and round and round to close that valve.

Once you are there, you are going to have to deal with that value, so you are in that series of activities.

The next level of actuation is gas-driven manual. Now, this is where you are using gas pressure to drive an actuator to close. That's that guy right there. That tank right there has gas pressure in it, and it fuels that actuator right there to close that valve. That's a big valve. That facilitates it.

Actuators, when you have an actuator on a valve, it can close a valve in two to three minutes. Bam. It just drives that valve, stem and screw assembly. That's an important element in all of this.

The next piece is fully automated gas driven. Now, we talk about automatic control valves and remote control valves. Automatic control valves, there's no human intervention here. This is just a set of sensors that are looking for either rate of change, rate of pressure change, or a low-pressure sensor. The old ones used to be just rate of change, and they could get fooled. We had those on our system up in the northeast, and unfortunately, they closed one day when it was really cold, and that was really, really bad. You can ask anybody in Boston. They still remember that. Now they are using low-pressure sensors, and they are integrating with the two signals. The problem is there's still no human intervention, and in market areas, it's not really hard to replicate that and confuse them again because low pressure on a cold day in New York, they pull hard, it can drop down that low, and it can close them again. So I think that's something to be cognizant of. They are not an end all. There's place where is they fit and there's places where it's dangerous.

The other thing you can do to make it work is you can set the sensors low so that they don't trip under operating conditions. The problem is that then you're masking failures, that it actually could break and it won't go off because it doesn't understand that that's not just the rate of change that an operating situation would -- the fingerprint of an operating situation.

Remote controls use telemetry. It involves pressure sensors and telemetry to send a signal to gas control or someone off-site to look at the bigger picture to see if there are other signals that are sensing pressure drops, and then they actuate the valve remotely, okay, and it uses those gas-driven manual -- those actuators, those gas-driven actuators, to close those valves. Each have pros, each have cons.

Design considerations. This was really a series of questions we were asked by PHMSA to try to address in our presentation, I think. For actuators for gas, they're gas driven. The gas is primarily clean. It's not if there's not a high dew point gas. This is a pretty simple equation. There is some dew point considerations. We use mist extractors to minimize freeze-up and discharge in the event we have two phase flow or some liquids in the line, water. I think the other point came up earlier, don't install these in floodplains. That's not a good idea. That should be one of those intuitively obvious things, IQ test, but you get fooled. You know, you are near a river, seems like you are supposed to have river isolation valves, you put it down there, and the next thing, the Mississippi River is about a mile wider than it's supposed to be. The valve is in there somewhere. That's something we have to think through ahead of time.

Temperature is a consideration for solenoid ratings. It's not really a problem. It's something to make sure you understand and deal with in the design.

I think an issue that catches people off guard is when you put telemetry on these things, you now just installed a gigantic lightning rod. That's pretty interesting. You need to keep track of lightning, do continuity checks to make sure things are still functioning.

There was conversation earlier about remote transmitters. If people have hugely bad intent, they are going to do bad things. The point is make it a little bit higher hurdle, keep the mischief at least to a minimum, and do what you can that's reasonable to protect the sites and minimize unintended operations. Most people don't really have that kind of hard-wired bad intent. They're more mischievous than anything.

But I think this slide, frankly, can be a quick focus slide. This is Spectra Energy's automation criteria, and I think the key here -- I put up the end points, and I know everybody is reading very quickly and wondering how did you get to these decisions? How did you get to these criteria? That's the right question. How did we get to those decisions? How did we get to those criteria? Because that's very germane.

When we looked at ACVs, we talked a little bit about the issue in Boston, we continue to look at ACVs. We have ACVs on our systems. We're just very conscious about putting them in a place where they work well and are predictable. Typically, outside the market area, typically on long-haul mainlines across the mid continent, they work very well there. That's a good application.

The new technology does help a lot, and it helps widen their bandwidth of application. You just have to be careful not to overextend them.

RCVs, where we use them. We use RCVs where the response time is above an hour. I think as Chris Hoidal mentioned, valves are an important part of our prevention and mitigation efforts. Automation of actuators and valves is one element of the incident response P & M considerations. In a series of activities in a series of attributes. We have to kind of break that down and look at that very deliberately.

The choices on response time and automation are a product of an overarching incident response perspective. Most -- as Larry pointed out, most of the time damage happens very quickly. It doesn't mean that time is not important. Time is important. We just need to work hard to characterize where is that and work on those areas. Areas where it's not the case that time is not irrelevant, but time is not a big change in the fingerprint or footprint of impact.

And we really need to look at coordinating the time with incident responders. That's why so much conversation went into meeting with the emergency responders. How does this affect getting access to the area? How does this affect us -- you know, how do we, synchronizing with them, affect the net effect of what's happening on that site?

When we look at Edison in particular, the background of this incident was beyond -- certainly, it was third-party damage where a landowner was not using one call. A lot of other things were going on there. Not a good situation with that landowner.

But the bottom line on the valves, the valve closure took over 90 minutes. That's unacceptable. The personnel got on-site in less than 30 minutes. They were there. They were working to close the valve. The valve site was very, very close to the incident. So there was a huge pressure differential across the valve. The bottom line that happened at Edison was the line pressure fell below the pressure that was needed to drive the actuator. So there wasn't enough energy in the pipe to close the valve. So now they're into manual mode. And the pressure differential across the valve was actually so high that the valve would not seat. It would not seal. It basically arrested on the seats halfway closed. It couldn't physically close because of the pressure against it.

And so what did we learn on valves with regard to what happened at Edison? What we have done is installed pressure tanks, storage volume bottles -- and you saw one in the launcher barrel on the green pipe -- volume bottles have been added to the actuators. They're separate from the line. There's a check valve between the line that feeds the actuator and the line so that it can't depressure when the lines depressures. And so they're not driven by line pressure directly. That separates that event so that we have certainty of actuation.

We also discharge multiple crews to secondary up and downstream valve sites upon notification of the incident. In addition to the incident site dispatch and in addition to primary valve location dispatch. When you look at us, you think of New York City, think of Boston, think of Philadelphia. We have very reticulated pipelines, so our folks are in and among a host of pipes that are spread out. They're not linear into those markets, obviously. They look like your hand. And so our people are spread all around there and trying to get to those valves is a key consideration in how we design the systems in those areas.

Response criteria and equipment selection has been revised to deal with where are our people? Where are the valves? How quickly can we get there? And we've applied a RCV technology on a host of valves since Edison where we see the need to facilitate emergency response, and it's tied to our SCADA system and gas control.

This is really, you know, a little bit of context. Spectra Energy, how many values do we have? 2800 system mainline and crossover valves. Our crossover valves adjacent to class 3, 4, and HCAs is 1700, most of which are gas actuated and close access to personnel due to the nature of our reticulated pipelines and our market area focus.

We have about 200 valves that we have put RCV equipment on, and we have some ACV equipment out there. Primarily we use RCVs. We have about 250 valves that will require automation to meet the INGAA commitments, so the INGAA commitments are a step up even from the criteria we use, which is not a regulation that there's no other criteria pressing us to be at an hour. It's self-imposed. Many other operators don't have that criteria either, so many others will have be higher than us to get to the INGAA criteria.

Not to be argumentative, but just a scale. If we move from 60 to 30, there will be 1200 valves that we are obligated to put RCV equipment on. So that kind of just shows the scale of where are our people is really -- how close are our people, and how do they fit into the emergency response signature?

I think that this slide really is intended, as much as anything, to not say all or none on accelerated response. It's here to show that we need to characterize where is secondary effect and where is impact -- where are impact created by limited mobility? So that where do we need to accelerate response to address that signature?

The PIR is not an end-all. It's a good start. I mean, it was a good start to try to figure out what is the impact zone of a failure? And it's been based on a lot of incidents over time. But the model had some basis of people's ability to exit the area. It was not a delineation between damage and no damage. It was an impact to people and a certain amount of heat fluctuating, survivability. We need to help keep that in mind as we look at this so we can figure out how to use it constructively.

This is another -- you know, this is just another way of looking at the slide I just talked about about valves. You see the impact is very high on the number of valves. The good news is cost is easy to quantify. It seems like to be a gap, I don't know if it's as low as $200. Certainly, Larry's slide says it's much higher than that. The good news is it's pretty easy to deliberate that and vet that out. Maybe we need a workshop to clarify that. It's pretty easy and straightforward.

In conclusion, I think most of the damage and injury occurs very quickly. Valve spacing and closure will not significantly alter the physical impact in most situations. More issues to consider on that, though, I think to help fingerprint that.

An order-of-magnitude increase in impact will occur to shift INGAA criteria to 30 minutes or "all" valves. I don't think anybody wants to do all. Response time, coordination with emergency responders seems like the right thing to focus on. It seems like the right combination of events.

The operating people in close proximity to valving are an important element in the solution and in incident response.

I think the key three things to walk out with, in my mind, are there are issues beyond physical impact which are difficult to quantity that need to be considered and addressed, and we need to put some energy to that, to fingerprint that secondary effect. It's important to improve, create consistency, and provide certainty of incident response in high-consequence areas, and we're committed to that. We need to continue to vet out and characterize secondary impact for inclusion in accelerated response criteria, and we're trying right now through the INGAA effort to strike an appropriate balance, and we are committed to that. Thank you, Alan.

(Applause)

>> ALAN MAYBERRY: Thank you, Andy. Okay. Our final speaker on this panel will provide the operator perspective again. Today we have David Chittick, who is the Director of Pipeline Integrity Engineering and Asset Reliability at TransCanada.

>> DAVID CHITTICK: Thank you, Alan. I'm pleased to be here to have the opportunity to present TransCanada's perspective, practices and experiences with isolating pipelines. TransCanada's been in the business of building and operating pipelines for over 60 years, and we have 15 pipeline systems, 8 of which are in the U.S.

In the end, the objective is always the same. We're -- safety of the public, protection of the environment, and to minimize the risk. Firstly, we do this through minimizing the potential for failures in the first place. And then secondly, minimize to the extent that it's possible the impact post a pipeline failure.

There's our obligatory map. The system is an extensive system. We've got over 40,000 miles of gas transmission and just over 2,000 miles of the liquid pipeline there, the Keystone, and about 380 billion cubic feet of storage.

The systems -- the age of the systems are quite different, and the means by which we achieve isolation is different on each of the systems, and I'll go over a few examples of those.

I wanted to start by just a little bit of a refresher on risk. This will build on Larry and Andy's presentations. But risk -- risk is a measure. The potential to incur undesirable consequences or losses, and typically probability times consequence. The consequence that we're concerned about is the thermal effects should the releasing gas ignite. We start out with when there is a pipeline failure, there's the outflow of the gas. It's quite considerable to begin with. It's -- it's -

- typically you'll have -- depending on the diameter of the pipeline, you'll have a mushroom cap can develop. The gas will rise up, will rise up because of its buoyancy, will also rise up because the gas underneath it will push it up.

Ignition if it does happen can happen anytime after the rupture. If it happens shortly, there will be the fireball, then just followed by the burn that happens. But as to the probability of ignition, there's a graph there that shows that the probability is a function of the diameter and the pressure. So for an example, a 30-inch pipeline at 800 PSI has about a 50% chance of igniting. So a small-diameter pipeline, very, very low likelihood of igniting. So yes, if there is a failure, the next step is is it going to ignite? A number -- a good number of pipeline failures do not ignite. We can have large-diameter failures where they do not ignite.

Now, the concern is do you have the thermal radiation? You're concerned about are there people and are there homes out there. So in the U.S., approximately 94% of the pipeline systems are rural, so that is to our advantage. The codes are more stringent where there is the population, and the integrity programs are more stringent why we have population.

Okay. Talk a bit about isolation plans. So isolation plans are developed for all of the high-consequence areas. And we achieve -- obviously, we achieve isolation by closing of valves. The valves involved will be the upstream/downstream block valves reason will be crossover valves, could be lateral valves, and I've got some drawing to illustrate that in a minute here.

But TransCanada, we rely primarily on the local controls. Now, this would be with actuators installed on the valves, and our current standard is to rely on low-pressure sensing, but on some of the older pipelines, we have the rate of pressure detection, and so should we detect low pressure, should we detect a drop in pressure, we will close those valves. That closure happens quite quickly.

When you do have a release, the pressure in the pipeline -- sorry. The pressure -- the gas depressurizes very quickly. In a typical valve section on the downstream side, you will be down 50% within -- in under ten minutes, and that's important because that allows us to detect -- detect that the release has happened.

And on top of that, we would have the ability to dispatch people and do the manual control, but our primary means to achieve isolation is through the automatic local controls.

Now, we do also have remote control. This would be a telemetry package with a controller, and we do not rely on these as frequently. We always want to rely on the local sensing of the pressures. Now, we do have some instances where the consequence of a false shut-in are very significant. On some pipelines, they're feeding power plants, et cetera, you cannot afford to have a false shut-in. You will always have false shut-ins from line break detection. We've got one pipeline where we're predominantly feeding some power plants. What we've done on that pipeline is every valve site has a telemetry package. Every valve site when we sense, locally sense that a line break may have occurred, it initiates a closing sequence, alarms that to gas control, and then gas control has a short period of time by which to override the local controls.

As to the detection of line break, fortunately, the detection can be done quite quickly. If it's -- the pressure drops quite quickly, we'll get -- calls will come in to gas control, and typically in under ten minutes, usually, and depending on where your pipeline system is, high-consequence areas, of course, there will be people around there, we will always get a call -- typically get a call within ten minutes. Also we'll detect through the SCADA system. So it typically takes six to eight minutes to detect it through the SCADA system. Of course, there are always changes happening on the system that can mask it, but the good thing is it's detectable quickly.

Going to just show a couple examples of some of our pipeline systems. This is our newest pipeline system, the Byson Pipeline built in Wyoming, in North Dakota. There's a 303-mile pipeline system. There's 20 mainline block valves. There's no high-consequence areas along this pipeline. There's a photo. Every site has a gas hydraulic actuator sensing line pressure with automatic shutdown.

So we also, on this pipeline, there are three sites where we do have the remote control ability. One of those is because we have a -- along the system here, there's a good elevation change, so there is the potential to have an over-pressuring, depending on the flows, so at that site where there's a relief valve that could open, we have a telemetry package there to allow alarming of that to gas control. Then there's also two sites that we're in the process of analyzing because of access issues, we are looking to put the remote packages in there.

The other system -- one of the other systems is the gas transmission northwest up in Idaho and Washington/Oregon. It's 1351-mile-long pipeline, two me dominant main lines there, a 36-inch line and a 40-inch line. There's 90 block valves along this pipeline system. The first line was installed in '61 and predominantly gate valves there.

The photo down in the bottom left there was -- it's not the easiest to see, but it's a pneumatic motor. So when we took over this pipeline in 2004-2005, part of the additional preventative, mitigative measures for the high-consequence areas, we did an analysis of that, and we weren't convinced that that valve -- that that actuator could close a 36-inch gate valve against a high differential pressure, so we went in in 2006 and 2007 on either side of all of our high-consequence areas, and we upgraded the actuators to the other photo there, which is a gas hydraulic actuator. So considerable expense to do that. You can see it's -- what's also of interest in the picture there is it's a gate valve, so the larger the gate valve -- when you put a gas hydraulic actuator on a gate valve, it starts to look a little bit like a space shuttle.

What was interesting was those -- the tanks there typically are mounted up -- mounted on the actuator itself, which is what we had done initially, and then we had some local homeowners complaining about the unsightliness of the whole installation, so we off-mounted the gas hydraulic tanks.

The rest of the pipelines -- or the rest of the valves on that A line are reliant -- have the manual -- the pneumatic motors.

On the B line, which was installed in 1994, ball valves, 100% of them have gas hydraulic actuators, all of them with the local line break sensing.

I'll just quickly go into our largest U.S. pipeline is the ANR pipeline, just 10 thank you 500 miles. Diameters range from 2 inch to 42 inch. Predominantly parallel lines here feeding two lines, sometimes three lines. There's actually -- there's 765 high-consequence areas on that pipeline. That 900 block valves is only referencing the high-consequence areas.

Along this pipeline, all the actuators have -- all the valves ten inches and above have actuators. The actuators have pneumatic controls that will shut them in. Typically, they are the rate of pressure devices, but as we -- these devices have proven to not be as reliable and as effective as the low-pressure sensing, so when we do have the issues, we're changing out the rate of pressure and putting in low pressure. And for the smaller valves, it's manual control.

Just referencing, there have been a lot of studies done in the past looking at the effectiveness and the value of controls, valves and that. The conclusion from the past studies are installation of automated valves does not reduce the initial impact. That's been talked about. The real -- the concern is the initial outrush of the gas and the potential for the ignition of that, the damage -- the damage all happens in the first three to five minutes.

The time of valve closure may have an effect on property damage and risk to the emergency responders after the initial impact.

Now, it's always -- it's -- these are conclusions that were all studies done ten years ago. Good opportunity to revisit these studies and see if similar conclusions are landed today.

The question was what are we doing? What has the HCA IMP rule, how has that affected us? So the rule is you must take additional measures. If you determine -- complete a study, and if you determine that the effects of an automatic shutoff valve or remote control valve would be efficient, then you should do that. So we've completed that study, and -- in our high-consequence areas, and we've concluded that the application of automatic valves will not minimize the initial impact. Unfortunately, As it is, there's no way to minimize the impact -- to minimize the initial impact. But we did recognize that there was the potential to minimize some secondary impact, typically property damage and reduction of risk to the emergency responders, so we've developed plans to ensure all of our high-consequence areas that we've got line break detection on these.

So we're in the process of doing this. We've prioritized it to identify sites with limited mobility.

This is just an example, one example on our ANR system where off there in the top right there we've got assisted living home, so clearly that would be a site with some limited mobility challenges. We completed our isolation plan study for this, and this goes to the -- you know, the complexity and the challenge. There are eight valves that need to -- we need to ensure will close to achieve the isolation for this -- for this high-consequence area.

So just a little bit as to where our current practices are. So today we install actuators on all valves that are greater than 12 inches. We install it on smaller valves if the valves needed to be swung more frequently. We install low-pressure shutdown on all of the valves. We found these to be very reliable.

Looking at six of our -- six recent releases that we've experienced, five -- in five of the six instances, the isolation happened in under 20 minutes. That's due to when you do have a release, the pressure of your gas is dropping very significantly, and you're able to sense that drop in pressure and isolate it. Typically you can do this more quickly than you can do this through gas control.

We do do remote control, but it's driven by a need for operations, depending on the configuration of the pipeline, if you need to be swinging sections in and out, we'll do remote control where it's necessary for a hydraulic point along the pipeline system, just data for the pipeline to assist gas control and operating the pipeline. We'll do it where we have access issues. And also we'll do it where we need that higher level of reliability where we're feeding critical loads, ensuring that a false shut-in doesn't trip it.

Actuator travel time just through that one, actuators are very effective. We can achieve a travel time of approximately one second an inch. We can probably do it faster, but that's typically how we calibrate the actuators too.

Cost. $500,000 to drop in a large-diameter valve in a new pipeline. It costs a million dollars or more to drop that into an existing pipeline. Everything is more expensive if you go back to do it the second time around.

To put an actuator on an existing valve, of course, depending on the diameter, but 50 to 100 thousand dollars is what it costs to put an actuator onto an existing valve. You wish -- and I wish this all the time -- I wish things didn't cost as much money as they do. Sometimes I struggle with what they do cost. But just the cost of the actuator alone, that's just the starting point. Now you've got -- you've got to get crews and contractors. You've got to deal with valves that are old valves and mating actuators to old valves. It's quite -- the cost can add up quite quickly.

Putting in remote telemetry onto an existing valve will raise that cost to $150,000 to $250,000. So the valve is already there, but to now go -- to go in and put an actuator on that and then to put a telemetry package in on that is $150,000 to $250,000. And it can be higher.

I wish -- I wish it weren't so expensive. I think there may be opportunities to bring the cost down. But I think success -- success would be had, which we've never had, if we could bring the cost down to $50,000, I would be -- I will be shocked. We've all done work with solar panels and stuff like that, and they're just -- you cannot rely on them. They just are a target for attention. People want to steal them. People want to shoot them. We've never been able to rely on solar panels. It's never as easy as we would want it to be. And operational costs not that significant, $5,000 a year.

Okay. Just kind of wrap it up here. So in the U.S., we've got 15,000 miles of pipe. We've never had an incident, never had a pipeline failure in a high-consequence failure. You always knock on wood when you talk about this. But truly, the objective is to ensure the safety of the public, the safety of the land owners, safety of our employees, and we -- our best ability to achieve that is a commitment to the reduction in the probability of a release.

Engineers have the ability to affect the probability of failures. We're doing this -- relentless pursuit of zero incidents. We are committed to this. Integrity management programs. The continuous improvement that comes from the integrity management program, technology developments. All operators are involved, associations are involved in the pursuit of new technologies, improved technologies. We clearly see -- we're in the process of implementing new technologies. We can clearly see how these new technologies are going to affect a reduction in the failure frequencies. It's quite exciting. Then also a great effort into public awareness and damage prevention, minimizing -- doing all we can to minimize the potential for unauthorized excavation.

Okay. Committed to the reduction in the consequence of the release. We understand it. We don't -- we don't want to take any false sense of security, but if there's anything we can do to minimize the initial impact from a pipeline failure, that's where the damage occurs, that's where the most significant damage occurs. We cannot achieve that. What we can achieve is a reduction in the damage that comes post the initial release, and we achieve this through a combination of automatic controls, remote controls, and our operations people. And we're already doing this, prioritized on our identified sites with limited mobility.

That's it.

(Applause)

>> ALAN MAYBERRY: Okay. Now we're to -- we have a few minutes for questions. And for those of you on the webcast, there are instructions there for you to submit questions. And those of you in the room, we have cards and we have two microphones. So I guess we'll start with -- David, did you have a question?

>> It's more a comment.

>> ALAN MAYBERRY: Oh. Yeah --

>> Yeah, it's a question.

>> ALAN MAYBERRY: If there's a question.

>> There's a question in here somewhere.

>> ALAN MAYBERRY: Is it your age? Okay. Go ahead.

>> My name is Dave Johnson. I'm with Energy Transfer. We are a natural gas transmission operator with, I think, about 20,000 miles of transmission.

In this morning's panel, again, primarily related to the gas transmission, this latest panel, I know we're going to hear some more about valves this afternoon as well, but I've heard some things that I think we need to go back and revisit because I think that this -- this is part of the process that involves PHMSA, it involves the industry, it involves the public, it involves the GAO. And for this to move ahead reasonably and correctly, I think there are some things that still need to be sorted out.

I think what I heard this morning so far are some comments about the potential impact radius and how that -- how that works or doesn't work. I think I've also heard some statements that indicate that it's really not consistently understood what it is, what it is not. So that's one thing that needs to be sorted out.

I've heard what I think is about a three order of magnitude difference in the costs for valves and their automation. So that needs to be sorted out because three orders of magnitude, you know, factor of a thousand is pretty big.

I've heard some comments and seen some data presented based on the spacing between valves, but I think we also need to -- to be clear here -- and those are fine. I'm not arguing with the calculations. But we need to be clear that the current gas transmission regulations in 192.179 do not have a valve spacing requirement. It's a valve proximity requirement. So attributing a spacing -- an inferred spacing for class location is probably not the accurate way to do that.

>> ALAN MAYBERRY: How much more do you have?

>> Not much.

>> ALAN MAYBERRY: Okay.

>> This is all pretty basic kind of factual information, and I think that for us to go ahead as a group on this subject with the PHMSA, the industry, the public, and the GAO, we really need to sort this out and come to a common and consistent understanding of the facts and the bases. And we need to be able to clearly communicate those to the public so that their expectations are -- are somewhere within the bounds of reason. So thank you.

>> ALAN MAYBERRY: All right. Thanks, Dave. Let me take one question from the Web here, switch to the Web here. Recognizing -- this is for the panel. Recognizing importance of response time, what technology is available or can be developed to remotely verify alarms? You want to take a swing on that? Has to do with response time. What's there to verify alarms?

>> What I want to say there, Alan, if we are talking about available technology, maybe we should wait till the next panel where the experts and SMEs are going to discuss that technology.

>> ALAN MAYBERRY: Right, but you guys -- it seems like you may have had a thought anyway on that.

>> Just that a gas controller will be looking at their screens, looking for pressure drops, and then oftentimes that call from the field is an important call. Somebody says hey, there's a big rupture here. And so you add those two together, and they quickly shut the valves.

>> ALAN MAYBERRY: Okay. Thanks, Larry. Who was next, between you two? Go ahead.

>> I think so, Alan. Thank you. My name is Darren Moore. I work for El Paso Corporation out of Houston, Texas. We are a

natural gas transmission operator primarily, operating over 38,000 miles of pipeline.

My comment is directed mostly toward the Government Accountability Office. We heard a number of discussions an hour or so ago talking about the potential impact radius and how it's calculated, what it does, what it doesn't do. There were a lot of misrepresentations in that.

I was the primary INGAA developer, industry developer of the PIR. I sat in dozens and dozens of hours of testimony to docket discussing the PIR. I look around the room right now, and I see, I think, one OPS representative in the room who is privy to those discussions in 2000. The reason I say that is we don't remember well as an industry what the PIR does and what it does not do. It did not account for build-on fires. It did not account for wind direction. We could not model those things well because they're specific to the geography around the failure site itself.

We focused on fatalities and injuries and heat flux, not on property damage, when you built the PIR. You are going to have to discuss internally the PIR when you consider valve spacing and valve closures, et cetera. To do that, you need to fully understand what the PIR is. To understand it fully, given what we have in the room today and our remembrances, you're going to have to go back to the docket, I think, in 2000 and read the hundreds of pages of testimony, whether it's scientifically based, whether it's verbal transcripts, you can read what I said, what Jeff said, particularly what Mike Israni said with OPS. He was here yesterday. I am disappointed he is not here now. You may want to talk to him as well.

But to understand all this well and to make the right recommendations, you need to fully understand the PIR because it's the basis of what we're talking about. You saw the circles. The circles were not representative of what we talked about in 2000 really at all. I will just encourage you to look at that data because it does matter quite a bit in this discussion. Thank you.

>> ALAN MAYBERRY: All right. Thanks. Over here.

>> Arnold Blue with Quantum Dynamics. I just want to remind everybody when you've got to do the planning for your valve closure, you've got to account in wintertime for things like hydrate formation. That's going to be really, really important in the colder climates. I'm sure the guys at TransCanada thought of that. But since we're discussing planning, that is something that possibly should go into the codes.

>> LARRY HJALMARSON: We're usually talking about pipeline quality gas, very low amount of water, typically don't have hydrates forming in our gas.

>> Yes, but they form in the valves. This would be a problem with valve closure; wouldn't it?

>> In our experience, my experience, it's never been a problem within the valve. We have experienced some failure -- some issues in the past with water collecting around the valve stem and freezing, and then, of course, you try to close the valve, you can't turn it. And we address that through we install some tubing and we put a glycol water mixture, but we've never had a problem of liquids within a valve.

>> Okay. Thank you.

>> ALAN MAYBERRY: Yes.

>> I'm Keith Ibis with PPIC, and I think you're correct when we wanted to talk about physics. I talked yesterday about myths, perception and perceptions. If we stick with the actual values, the reports that have been done, there's probably about 10 or 15, over half I managed. Then you'll see that the -- it'll figure out with the diagrams. So the destruction is at the beginning, and as Larry pointed out, that's something that really bothers us. And it drops off very dramatically as we've pointed out in the other diagrams too.

So I think to make sure we all have the right idea, we should stick to the physics part.

>> ALAN MAYBERRY: Okay. Rick?

>> Rick with Accufacts. I just wanted to reinforce the comment made earlier about the PIR. We are going to get an opportunity later this week. Parties will be under oath discussing that. And I just point out that the PIR -- if PHMSA could post on this docket the docket number for the PIR discussions, because I think a lot of people in this room understand what the PIR is, but there are a lot of people who are misapplying the PIR, from my perspective. And that's what's getting people in trouble.

But I think if you get the docket availability, docket number out, that will just help -- instead of reinventing the wheel that was spent back in the year 2000 -- I represented the public during that period of time. Some members of the public. And it was clear that the PIR was never meant to be a siting tool. It was a screening tool for integrity management. I think a lot of decent people in this room understand that. Unfortunately, In the heat of battle with lawyers in the room, you know, facts -- and again, not to criticize lawyers. They are trying to do their job. But it's easy to misinterpret what the intent was, and that's what we need to start.

>> ALAN MAYBERRY: Thank you. Go ahead, Larry.

>> LARRY HJALMARSON: Yeah. You know, like I said, I'm new to the transmission business. But following that Appomattox failure, I was just curious, went out and measured, did it with

aerial photo of that charred area. Jim pointed it out where the grass was charred. That was almost exactly the PIR.

Now, the thing I would comment there was I could also look out beyond that and see trees that were exposed to the fire, and I could tell that those trees also suffered heat damage outside the PIR, so some damage can happen outside.

And then I mentioned that there were two homes that caught fire inside the PIR. There was a third home inside the PIR that did not catch fire. It was badly heat damaged, you could tell. So it is an approximation.

I think it's a pretty good one, though, because you know, certainly at Appomattox, that was where the greatest damage was.

Then at San Bruno, what happened there was fire spreading, and so that becomes more of a -- yeah, secondary fire rather than, you know, the initial cause of the exposure. Although there could have been homes, because of the exposure in that case too, continuing to burn. So it is an approximation, but a pretty good one, I think, my impression of it is. So my compliments to those, whoever developed it, and I know Darren and others developed those.

>> ALAN MAYBERRY: Okay. Thank you very much. I think that will wrap up our question-and-answer session. I want to make a couple of announcements. Well, first off, let me say thanks to the speakers. I think this was a great panel. Brought a bunch of relevant affection to bear on the topic at hand, and thank you very much for taking the time to prepare and give your presentations today.

Also, thanks to you for tuning in on the webcast and then all of you, again, for being here.

I wanted to make an introduction. I may have missed him. Is Tim Butters still here? Our deputy administrator was floating around a few moments ago. He may be out in the hall. Tim Butters, Deputy Administrator for PHMSA, is here.

Also, the comments on the docket. The docket will actually open on Friday for this workshop, and the -- it will be open for 30 days. So I want to make that announcement.

Okay. We'll break for lunch. We'll come back at -- what does the schedule say? 1:30. There are eateries, restaurant selections. There's a list on the desk up front. And enjoy your lunch.

(Lunch break until 1:30 p.m. EDT.)

>>: We are going to get started in just a couple minutes. If you would, come on in and have a chair. I appreciate it.

(Please stand by for the PHMSA Panel 3 session: Valve Capabilities, Limitations, and Research.)

>> JEFF WIESE: They get carried away. Sitting outside.

Good afternoon, everyone. I go to the radio voice and Alan Mayberry, could you please come in and sit down, please?

Good afternoon, everybody. Welcome back. I hope you had a nice lunch. Difficult to find a place in easy walking distance. I guess you did need the 90 minutes.

Appreciate your coming back from lunch. I know a lot of people are probably trying to travel. By the way, we are adjourning reasonably early today. Hopefully people will still be able to catch flights out if they need to.

Good discussion this morning. Set the stage, but it causes me to kind of reiterate the reason that we are here today. Welcoming not only the people here but people on the webcast hopefully re-engaging them as well.

You know, we are really here to begin a process. We don't need to necessarily argue points of view and who is right on one decimal place or another.

We are here to start a process. You have an opportunity to provide your views, whether you are here in the webcast, wherever you are. We are going to be opening up the docket. The number I gave you earlier. You can easily, I think you can probably find it on our website by now.

>>: On the meeting page.

>> JEFF WIESE: On the meeting page. Anyway, there's a lot of opportunity for you to provide feedback to us on this subject. So at any rate, I know a few people came up to me during lunch and said they wish they could have made a point, wish they could have made a point. Plenty of time. Relax. Your input is appreciated. I don't know want you to feel like you're rushed.

With that we are going to continue the discussion this afternoon, discussing a little bit about valve capabilities and limitations, and what's happening in research. Great comment somebody made to me at lunch time. Where do we take it next with valves? How do we lower the cost of some of the valve applications? Hopefully we can tough on some of those things.

With that said, I played my Vanna White. I'll turn this over to Jeff Gilliam, Director for Engineering and Research, has a long history with PHMSA. And with that, no further ado, I'll turn it over to Jeff.

>> JEFF GILLIAM: Thank you, Mr. Wiese.

I will say I appreciate the passionate dialogue this morning. I think that's what we wanted to do is inspire comments and feedback. I think we have been successful at doing that. Please, remember that the docket will be up, I think Friday. We will be looking for those comments to come in and can be considered.

So first we have three panelists this afternoon. We are going to be talking about valve capabilities and limitations and the research around those.

Our first speaker up is going to be Rick Kuprewicz, the president of Accufacts Inc.

Okay. There we go, Rick.

>> RICHARD KUPREWICZ: Thank you. I was asked today to speak on two issues related to valves, the liquid and the gas. Very quickly I'll comment. I am going to restrict any comments to information readily in public domain. There are various efforts to get information out there. I find if I keep everything, if you look for it you can find a lot of information in the public domain.

With that caveat, some perspectives. I'm glad to see, I think it's important to understand this is a starting process to get the dialogue going. Otherwise you have the attorneys work it all out. That is not an efficient process, though it is one that you can use. General observations on liquid valving. Everyone is a valve expert I'm finding out. I think the important issue is to understand that in the dialogue -- it's not just liquid lines but also for gas lines. As you go through the valve discussion you move away from maintenance issues or valves for maintenance to a safety role. That's a big change. You need to understand that. When I as a perspective, as a person with experience in the industry and looking back at the public perspective, it's easy to miss this whole paradigm shift that needs to occur. A safety is a whole different issue. They demand what I call more process attention. You need to pay a little more attention to not only what are you going to do with it, what are you really trying to do with it and more important, how are you documenting the process? The culture changes weekly, monthly, yearly. There's die ma'am I cans, changes in companies going on all the time. You reinvent the wheel and that's a frustrating process.

I highly advise the industry as well as the public to avoid the scare propaganda tactics. While they may be successful in the short-term, the backlash from those when they are proven wrong can be very severe.

That goes for the regulatory effort as well.

I always try to advise folks, it's hard to do when you are under oath being yelled at. Suggest try following the laws of science. When in doubt as engineers, pull yourself back. Even a group of engineers can discuss whether or not the science or the basic fundamental principles are art or not. But normally most people will rationalize and figure out that the laws of science do apply. If you argue the repeal of the law of gravity, the burden of proof falls on you arguing that gravity doesn't exist.

Another observation, control rooms are getting more complex. Doing more with less stuff. We spent the last ten years working on developing the improvements in the control room management process, hopefully issues that go well beyond the fatigue issues. It's the equipment, folks. If you don't have the right equipment you can compound the fatigue factors and other factors associated with that. It's hard to do. It's not a yes or no answer.

The other thing is, there's a lot of anxiety I'm picking up here this morning from various players. About the costs. Well, as a representative often for the public, I often have said this over many years: Safety is not free. So if anybody is going to tell you they are doing safety for nothing, that's not fair to the industry, not fair to the public and not fair to the regulators.

The other side is, you need to be able to quantify why you're doing something. The argument of safety isn't a blank check.

On both gas and liquid pipeline you saw some of this this morning. It's pretty typical if you ever have been in a liquid pipeline emergency or gas emergency. There's four general phases. You have an initial, I'll focus on pipeline rupture based on my discussions yesterday. Leaks can be very dangerous. The ruptures are definitely attention-getting events. They fall into four phases. First is possible indications to a control center. And that could be either by SCADA or direct communication or whatever.

But there's this phase are trying to figure out: Do I have an indication here that I might have a real problem like a rupture? The second phase is involving, depending on the equipment and the control room organization as well as the operator training, analyze the decision of possible release. Okay, you start initiate removing power and initiating isolation and kicking in emergency response plans each company is supposed to have.

Then the phase 3 is you are actually closing the valves. I am not here to champion one valve over another. If you can get to a manual valve, that works just fine. As the line size gets up harder -- how many here have been in an emergency situation where you had to go out in the field and close a 36-inch valve?

Even with adrenaline pump you are not going to do it in three minutes or ten minutes, okay? Physics are going to work against you. RCVs and ASVs can help you on closing time for the bigger stuff. Hopefully they aren't seized up and you can close them faster.

You have the first three phase Z there. Now we get to the isolation to occur and then science takes over, right? For liquids, release is driven by terrain. And valve space. You can argue about some other details. But you can't repeal the law of gravity, okay? For gas it's the isolation blow down time set by the valve spacing, the initial pressure and the pipe diameter. We can have debates about what the exact numbers are, but they are not going to be -- you'll find there's general consensus coming together.

It's important to realize that an inefficient pipeline organization can cause phase one, two, three, any combination of those to be substantially longer than phase four, okay?

Focusing specifically on liquid valving now. Manual versus remote versus the automatic. Automation definitely shortens release tonnage because it takes less time to close bigger valves, get people to them and close them. That's not rocket science.

It has little I will packet on leaks. That's just the reality of it. The public may not hear it but that's the reality of most pipelines. Quicker closure is needed in many cases, especially if you have high gravity profiles. Look at it this way, we used to fill up the tankers in Valdez, a couple of barrels in a matter of hours. It's a matter of gravity which doesn't fail, not yet.

There is trade off here. Nothing is going to be perfect. Mentioned terrain, hydraulic profile. You saw indications of that, an approach that made a lot of sense following the laws of science this morning.

It plays a major role. So I think I heard some discussion this morning about let's go ahead and say valves should be seven to 8 miles apart. In the liquid situation it's highly terrain specific.

I think it's important on liquid lines to reiterate this. Valve automation should not create a surge risk. That should be obvious, but you need to do a surge calculation and know how to do it.

Right? Surge analysis. If you are going to retrofit or install on a new line a liquid valve or retrofit an existing line with valves, you've got to do a well-documented safety evaluation on surge. The Bellingham 1999 tragedy is a representative example of an initiation process that came about, again this is all in public domain, from very poor valving decisions for a series of failures drove them into an automatic shut down that put the high pressure surge into the liquid system.

The new pipeline operator that took over that operation developed a more prudent valve safety design. We will talk about the more details of some of that in my last slide.

Moving over to gas transmission valving. Emergency response priority is obviously something that has to be said but needs to be understood by all players. Especially priority on rupture. If you get over focused on just leaks in your organization and under staff or under coordinator under organize so that you can't adequately deal with a prudent response for gas transmission rupture, you're in big trouble because it's going to look bad.

These events are highly heat flux events especially in the early stages. If you have ever been in -- how many here have actually been involved in a gas transmission or gas release incident?

Okay. How many have been incident commanders?

All right. Incident command for gas systems takes on special meaning. All right? The gas company is in charge in the initial stages because they control the gas, whether they do or not is a different issue.

The last thing you want to get into is an argument with a battalion chief about who's in charge, all right? That's not the time to be doing it, during an incident.

The federal regulations are fairly specific here. It says maintain liaison, all right?

Especially for large diameter pipelines. Cutting off the gas supply is not going to hurt you. If anything has come about after the terrible tragedy at San Bruno, in California, they are going to add, they are going to exceed current federal regulations. That's fairly clear. They are going with automated valves. They are going to go beyond the federal regulations. What we are trying to discuss or clarify in front of a bunch of attorneys and judges is the approach to where should we put these valves, what size diameter lines, from my perspective. And whether they ought to be RCVs or ASVs. In California they set a 30 minute time for response. California has two gas transmission that have the most mileage, based on information given in testimony by other parties, that have the most mileage of high consequence areas in the country.

All right? It's important to recognize -- this is kind of what, I see some anxiety by a lot of people in the room here. Two types, at least two types of gas transmission systems. There's the main gas transmission system that can be interstate or intrastate that don't see a lot of variation in supply and demand. There may be seasonal changes. There's a second one, a local transmission system. A local transmission system is a whole lot different animal -- there are some similarities, they are a whole lot different animal than the typical gas transmission lines. If you're developing a one size fits all solution for valving, you probably have the wrong approach.

Talked about manual ASVs. Manual valves shorten release tonnage and time. The issue is: It's nice to get the valves closed but phase four may or may not be the leveraging issue here. We need to close the valves. You can definitely shut down or slow down the time.

Let me step back. I need to mention here. It has been misapplied. I have been getting calls from the public in California. You don't get to read about those in the papers. I don't interject into those. I know they are well meaning but they are violating the laws of science. I also have seen applications for FERC pipelines where people are taking creditor blow-down in a pipeline rupture, for blow down lines, okay?

I want to step back here a second. That violates the laws of science. It's illusion of safety. People mean well when they say let's go to blow down valves if we have a gas line rupture. I have a

36-inch diameter pipeline that is ruptured, 100-foot crater in it. Section of pipe is 100 feet away and blowing out of two full-bore ruptures. There's no way. I know you mean well, but opening up a six or 8-inch blow down line, the laws of thermodynamic are going to limit, the gas is going out the 36-inch holes, all right?

So I think it means well, but it's the wrong solution.

Close the isolation valves. The closer to the rupture, the better.

You just can't negate the laws of science.

Now, this is a document that has shown up in my sworn testimony in the San Bruno CPC filings. Based off of information from a GRI study in 1995. I found it to be fairly reasonable and rational. It kind of gives you the blow down time from this report, and I recommend reading it, for various valve spacings. It doesn't actually plot this. It gives you the data and you can plot it. It follows the laws of science and is basically a function of estimated blow down time for valve sizing and valve spacing.

The point I want to make here is, and this should seem obvious, the bigger the diameter of the valve, the bigger the valve spacing, the easier it is going to blow down, right? We recommended in our testimony to the PUC, somewhere around a class three, 8-mile spacing, none of this is cast in concrete. I don't care if it's 7 miles or 8.5. But around class 3, for a larger diameter pipeline if your goal is to get the triage in within 30 minutes, you are looking at around a 24-inch pipeline and larger, valve spacings of no longer, no greater than 8 miles. Now, again, the engineers can argue about what kind of actuator we want on those, but that's the laws of science.

You are welcome to calculate your own transient curve releases, but the relationship between large diameter and small diameter valve spacings, the relationships are very close no matter what you run.

Okay? Thank you.

I went all that time? Hmm.

Anyway, thank you. I think the issue is, RSVs and ASVs can reduce gas venting tonnage. Our position is, I'm not saying this is cast in concrete, but for various systems, a lot of them for the local transmission systems, around a lot of people like San Bruno and the San Francisco pen insure La, especially large diameter lines, 24 or greater, valve spacing of up to class 3 or maximum of 8 miles. You can have them shorter, whatever is more convenient, is rational. You will have reasonable blow down and the meet the goal of getting triage into the area within 30 minutes.

The issue of ASVs over RCVs, the ASVs if they are properly designed take the control room operator out of the response group. If you design them right you can have the response center intervene. But the control room has a lot going on there. It is difficult, as I mentioned earlier yesterday, to understand if you have a rupture that's real. The issue to me is on RSVs and ASVs, I'm not going to beat people with clubs. Some people like one or the other.

To me the decision is how complex is your control room? How do you feel about an RCV and the ability of the control room, can he be properly alerted? Is he trained? Is he knowledgeable about getting the right information? Don't put this all on the control room operator. If you have ever been one, that's what we call an operator setup. You have to be real careful here. I have a natural bias to go to a proper designed ASV. Am I going to sit here and argue you should never put RCVs in? No. Be careful about the approach. It is easier to convert an ASV to RCV than the other way around.

If you design an ASV, on the last slide here, that can make things hatch sooner. If you have the control room set up and the people rightly trained an RCV can work as well. You need to look at the San Bruno event. Not trying to point fingers to nobody. Not getting commands to close the valves from the, an hour plus, hour and a half, a lot of chaos, which is typical in an emergency, all right?

So bottom line is a properly designed, key word is properly, properly designed ASV on gas transmission systems that are large in diameter are definitely much faster and more responsive.

Okay. Let's get to the main issue here and then I'll shut up. Levels of safety for liquid and gas RSVs and ASVs.

A lot of stories about these valves closing on their own. Most of the time I hear conversations about ASVs with false closures. How many here have been in a control room where an RSV closed on its own?

Yes! So let's all put this in the right perspective here, folks. If you don't design it right, maintain it, put it in right, it's an illusion that RCV -- they may be less complex, less complicated but they can fail close, too. Liquid lines, it's in the regulations that you shall in your operating procedures deal with this. So I would suggest as you move forward if you are going to do something in guidance in terms of regulatory effort, you have to deal with automatic closers for RSVs and ASVs.

The N.T.S.B. used smart valve approach for these. Where you can do a lot of the logic thinking with PLCs if you want. They didn't define what a smart valve approach is. As you heard this morning, the technology, the apple phone has more than the space shuttle used to have. That's good and bad, but it's important that you go through the right processes when you are designing these things, whether it's ASV or RCV. You heard me talk about leak detection and other issues yesterday. It's important from a positive process perspective to never rely on a single source. Traditionally the industry approach is, we have always done it this way, we like it this way. We know it works. It's different for different companies.

I challenge you if you are going to design safety for the intent of being used in the event of a rare rupture, you follow the rules used on various other important designs, and that is two independent signals confirming a need to closure. It is not redundant. It has to be independent.

Let me give you a quick example of how a group of intelligent engineers can make a mistake.

The Space Shuttle Challenger had two redundant systems to prevent failure: Two O-rings. Unfortunately, they were both sensitive to common signal failure, cold. Catastrophic failure. You want independent. It is usually not going to be pressure. You can always design ASVs, most of you probably already do this. The control room operator can always say close. We are saying why don't you design it for him to say stop close. It is not hard. You can give hill some time. We recommend and this is something new to this industry though many of you have been applying these principles since Bellingham. A hazard ops team designs a process, looking at the components of the approach to avoid false closures and signals. This is something used in the chemical industries, but many of you are following the safety approach, if you are designing for safety you will go for two independent levels of pro effects, go through each equipment mode and see what can cause you to avoid the safety not working when you need it. You have to document it so it's thorough and ton appropriately and 75 years from now -- somebody five years from now can figure out what the design logic is. You can do fail safe approaches in ASVs or RCVs.

You have to say this, it's embarrassing but we found too many situations. Look, you're designing all this stuff in the heat of the battle. You forget to look at the system sometimes.

What would you rather lose, a tank farm or a pump station or a compressor station -- not that you want to -- or do you want to move that problem on to your main line where you might rupture?

I used to think a billion dollars was a lot of money, okay? You want to see how quickly you can go through a billion dollars, move a properly that you should properly deal with on something you control to a main line that goes into the public. And we have found situations. It is not that people are stupid. They just get in the rush of all this information coming at them and they forget to look at the system perspective. The regulations are very focused on protecting express sore stations. So we kind of focus on that and say wait a minute, you don't want to move your problem to a main line. That's all I have. Appreciate your patience. Thank you.

(Applause.)

>> JEFF GILLIAM: Thank you, Rick.

And I know you may have to leave a little bit early but I want to say thank you for coming out for the last couple days and helping us in these workshops.

Our next speaker is Joseph Summa, he's president and CEO of Technical Toolboxes.

And he's also going to be speaking along the same lines and subject matter.

>> JOSEPH SUMMA: Thank you, Jeff for allowing me to speak today.

Rick is always a hard person to follow in any case.

>> RICHARD KUPREWICZ: Did I put you to sleep?

>> JOSEPH SUMMA: No, you always keep everybody awake. That's for sure. The panelist charge, I put up the list of questions as far as what the charge was for each one of the panelists. And like Rick said, everybody is an expert in shut off valves. So I guess I'm up here myself.

I am not going to address every one of these six panelist charge points. I'm going to focus primarily on some of the new research outside of the United States that I'm aware of. There's a specific case study that may be of interest to some and warrants investigation by companies and the industry.

So this is an agenda of what I hope to accomplish in the next ten, 15 minutes. Just a quick introduction, discuss the objectives and just have a short discussion on risk assessment and risk sensitivity analysis and then go straight into the case study on sonic sensor technologies.

I am not an expert on the actual mechanics of the valve and closure, but on some of the sensor technologies I believe that we are not utilizing some of these sensor technologies to their fullest.

We will go into that particular case study and then on to some conclusions and recommendations.

As an introduction, both the gas and liquid Code of Federal Regulations requires sectionalizing block valves. The objective obviously is to contain the product flow from both routine maintenance and emergency response.

We have heard this on several of the talks. And most of the focus being on high consequence areas that there is a requirement to look at those high consequence areas and add additional safety precautions as necessary in ASVs, RCVs, than manual shutoff valves are part of that process. We also had a number of discussions here today about the unintended consequences of valve closure, whether due to circumstantial significances, mechanical, human error, whatever it is. There is some consequences. Surge issues and other issues that have a direct impact on safety, customer outages, costs and as we also both can -- as we both know, gas and liquid hydrocarbon closures are a different animal. They accomplish the same result but they are very different in nature.

On the risk analysis side, I am a firm believer that in any properly engineered solution you have to look at risk and what the consequence of an event occurring, and properly design a response with the backups, secondary backups, tertiary backups, whatever is necessary depending upon that risk.

If an operator determines an automatic shut to have valve or control valve would be a good addition to the area in, the Code of Federal Regulations require that the operator install that. In making that determination, the operator must consider the following factors that have been listed in a number of industry papers, the swiftness of leak detection, pipe shut down capabilities, the type of product being transported, the rate of potential release, the pipeline profile, potential for ignition and location of nearest response personnel. That's a long list of items to consider in risk analysis, but I think it's very important to understand that they all are combined together to make a determination as to the most cost effective solution for the operator and for the public. I think Rick pointed it out well. I mean, there is a cost to safety. It is not an unlimited budget. Even aircraft, no one would like to get on an aircraft that falls out of the sky, but there is a risk associated with that. It does happen from time to time.

What we need to do is be prudent and understand what new technologies can be used in order to minimize risks for the public as well as to optimize cost benefit for the operators.

Some of the research and technology I won't go into all of it, but ASVs, RCVs, MCV is getting cheaper, more robust, more reliable. This is a function of time. We are seeing improved SCADA information and technology upgrades which also assists in the process of closing off or sectionalizing pipe faster and quicker.

And the third point is the introduction of advanced sensor technology and software artificial intelligence have been lagging in the introduction into the pipeline industry. For what reason, I don't know. But there are some immediate benefits that can be generated by looking at this in much greater, with much greater emphasis.

So with that I'm going to go right on to the case study.

This case study is from Brazil. The company is Petrobras, the research center for Petrobras in which they have been investigating and testing what they call intelligent or smart line break detection systems for both gas and liquid pipelines.

The theory of the operation of this intelligent line break detection technology has been around for years. It is based on the detection of a pressure transient wave created when a sudden change in pressure takes place. The pressure transients propagate as sub sonic waves throughout the pipeline. In both directions.

And the walls of the pipe act as a guide for the pressure waves, allowing them to travel greater distances until they reach sonic sensors installed in the line. We have seen in the inspection world the use of long range guided wave ultra sonics, devices or technology that allows you to look for anomalies in a pipe from one particular location. This is based upon the same principle. When you have a leak or rupture you are going to generate a sound wave. That sound wave is going to propagate through the wall of the pipe as well as through the fluid itself. Obviously the more dense the fluid, the quicker it is going to move. It is going to move at the speed of sound in the material that it's propagating through.

So the theory of operations, sonic waves can be divided into frequency bands. The intelligent line break detection technology uses extremely low and focused frequencies that propagate over very long distances. Distances of 20 to 40-kilometers.

Propagation speeds depend upon the fluids, as we said. The density, viscosity of the fluid. It is going to react faster in a liquid line than it is in a gas line. But the speed of sound through that wall, pipe wall is going to travel at the same speed, whether it is gas or it is liquid.

So we are looking at the sonic waves that are focused in both directions up and down the pipeline. The system architecture for this, these devices. When the sound wave reaches the sonic sensors, the information is transmitted to the intelligent line break detection electronics which is responsible for processing and identifying the realtime incoming events. These FPUs employ several advanced techniques for signal processing and recognition, including filtering, pattern recognition, and artificial intelligence using neural networks.

There are two main architectures available that have been tested by Petrobras and Saduti. One is a standard architecture and one is distributed architecture, basically one being a remote control type valve and another being an automatic shut to have type valve. Here in the -- shut off type valve. Here in the shut off valve type mode, these acoustic sensors are spaced approximately 20-kilometers apart. And can sense a leak, actually a fairly small leak all the way up to obviously a major rupture they can hear very quickly.

The reaction time is in seconds. So it is a very, very fast technology for alerting. The other advantage is that because it is traveling through the speed of sound with the speed of sound in that particular fluid and you have multiple devices, you can triangulate and know exactly where the location of that rupture or leak is.

Some of the other technologies don't allow you to do that.

The distributed toll is very similar. If you notice, all I'm adding here is a couple of cell phone towers or some communication devices that allow the sonic signals to go back to a central control room before the decision to shut the valves down are taken. These are again just sensors. You are using the existing valves, whether they are manual, remote volume, you are exchanging the sensor within those valves.

The intelligent line break detection system can detect and identify events in seconds, avoiding erroneous actions, mistakes that create unexpected situations such as pipeline shut-downs based on poor or partial information.

The important thing, I think, is that this technology has been around for a long time, but due to artificial intelligence, neural networks, you are able to take noise databases, footprints and be able to look and filter out lots of noise that are known type noises.

So the level of false alarms from a sonic device like this has been .9999 percent probability that when an event occurs, it is a real event.

Combined with other scientific principles, my colleague Dr. Shaw yesterday indicated that if you take two poor leak detection type technologies and add them together, you have much better response by adding two rather than having one mediocre system.

Here what I'm claiming is that by combining this sensor technology with another scientific principle, before a decision to shut that valve down could improve the likelihood that you are making the right decision.

And not creating unintended consequences.

Here is a picture, worth a thousand words. Up in the left-hand corner is the acoustic sensor. In the right-hand corner is the enclosure. The sensor is actually closed in that device. You can see it's clamped on to the pipe on either end of the shutoff valve and then connected to the actuator.

The only thing that you are changing is the actuator in the current valve to this acoustic actuator.

Whenever possible, pairs of sensors are used, observing adequate distance from each other. The installation of redundant sensors eases the   and -- filters out interference as well as improves the probability of eliminating any sound of, spurious sound signals.

Sensors are assembled in adequate enclosures to properly protect them from mechanical damage, from any theft, from any other issues that could cause them to fail without them failing for the intended purpose.

And as displayed, the earlier plans connect them to the process. Installation of the lines can be made using a simple hot tap machine without stopping the pipeline operation at all. Therefore this is a reduction in system costs and there are no production losses during the installation of these acoustic sensors.

Besides working as a redundancy, the installation of a pair of sensors allows them to be used as a phase detection filter providing the origin of events identification.

It is important to observe that the distance between the two sensors as they operate are complementary. So they are operating redundantly and that's what Petrobras has found to be the most reliable. The field processing unit, that's the electronics, the artificial intelligence, the neural net is responsible for the acquisition and processing of the signals. The field monitors the output of the acoustic sensors and executes a complex processing to properly identify the line break signal event. Discarding all the other operational interference.

This is the field processing unit that can be at the individual acoustic sensor devices and operate independently as an automatic shutoff valve or can then forward that information to a central control station to act as an intelligent remote control device providing the operator at the control center with additional information before the decision is made to shut down the pipe.

One of the main algorithms used in the fuel processing unit is artificial neural networks the artificial neural network is a system based on the operation of biological neural networks. In other words it's an emulation, emulating the biological neural system. The idea comes from the brain structure itself, more specifically the brain neurons.

Artificial neural network is a method to solve problems similar to the human brain behaving or learning. Computational techniques modeled on neural networks of intelligent organisms are able to create knowledge from experience.

These things are actually learning as time goes on. Each neuron or processing unit is able to send and receive information and is connected to all other neurons. They can also have a local memory. These, this structure works similar to the brain neuron where all the inputs are summed and there is an output depending upon the result of that sum.

So in conclusion and recommendations, I would just like to say that mechanical control involves, remote control valves require human intervention. No automatic control valve can be smart enough without human intervention, in my mind. Scientific principles are required to develop a fail safe operating procedure. You can never totally eliminate risk. Let's all be honest. We just cannot bring risk down to zero. And human factors when it comes to automatic anything, I think it's very critical. I happen to have had the opportunity to be an intercontinental ballistic missile launch commander with my fingers on the button for a number of years. And it was amazing to me that at the end of the day when that button was to be pushed it was going to be pushed by a human being. It was not going to go off automatically.

Yes, we had training. Yes, we were tested constantly. Yes, we were educated out the wazoo. Yes, yes, yes, it all fell on that last line of resistance, that human being that made that call. And all I can say is when you have situations like we are talking about today, I think that's the most cost effective, the best solution is to have a properly educated, properly trained, properly compensated person

that has the knowledge to make the right decision.
Thank you very much.
(Applause.)

>> JEFF GILLIAM: Thank you, Joseph. I wanted to point it, I was a little remiss that Joseph and Rick were both our subject matter experts in this area. I wanted to make sure I pointed that out.
At this point we are down to our last speaker, Dennis Jarnecke is the R&D manager and Gas Technology Institute, operator and developer in the technology research area.

>> DENNIS JARNECKE: Thanks, Jeff.
I guess it's me that is keeping you guys here from going out and enjoying the rest of this beautiful day in the D.C. area. I appreciate you hanging on and listening to this last group of panels and myself.
Let me give a little bit of an overview today of some of the research that has gone on over the past couple decades. Some of those research has been identified and referenced by others.
A little bit of the history of some of these remote control and automated valves. Some of the research funding that we have seen in our industry over the last couple decades.
Again, some of the overview of some of the research that has been conducted and is being conducted. And finally, maybe some of the future focus where we are looking at in GTI.
Pneumatically operated valves, concept dates back to the '40s where again as we were kind of sitting here today looking at how can we address the need for more rapid closure and shut down of the pipes, to address these pipe ruptures. And then as there has been advancements in the area of communications and sensor technologies, as those started being employed into these pneumatically controlled valves, we now have our remote controlled and automated shutoff valves. That's what got us here to these valves that, all the operators in some form or fashion use today in our systems.
Now we are talking about how we can make those valves better to make them meet the needs that we have here today.
I just want to remind all of us and I think many of us, many of the speakers before me touched on this, but these automated shutoff valves do not prevent the leaks from occurring. They will not minimize the initial impact. As Joe mentioned and others, we need to look at the risks in our existing system. You use integrity management techniques, identify those risks, make the necessary repairs and replacements of those pipes with the ideal goal -- I forgot who mentioned it earlier, maybe Larry, the ideal goal is to have no failures and we never have to use those valves.
As Joe just mentioned, we are going to have to use those valves.

They are going to be there in some form or fashion W that said, you know, there is a role for these valves, ASV and RCVs. That is to mitigate the additional consequences that occur and deploy a quicker shut down of those pipelines.

So if we look at the funding over the last couple decades, there has been over a billion dollars from basically some of my finding that I have gone out there to try to identify in the pipeline industry that really in the natural gas industry that have been focused to develop and enhance our industry and the piping infrastructure of our industry.

This funding peaked back in the 1990s and has been kind of on the decline ever since. If you look at GTI's predecessor PRI back in the mid '90s they were funding R&D for the pipeline industry, transmission pipeline industry probably in the maintain of about $50 million a year. Today those two organizations, maybe other collaborative organizations, it's somewhere probably in the neighborhood of less than $10 million per year.

What does that mean? I think what it means is we have to focus our efforts. We have to focus our R&D efforts, our development efforts smarter. We have to rely on PHMSA and others to help focus where we need, where those needs are. Where does the industry, manufacturers, operators, research organizations, where do we need to focus these efforts such as on sensor and automation technologies that many of us have been talking about here today to improve our systems overall.

So again also I think as Jeff pointed out with his phone, you know, look at other technologies. What else has been developed out there? How can we take those technologies and incorporate them into what we have here today? Don't necessarily don't reinvent the wheel if we don't have to, but deploy and employ other technologies.

In particular, GRI back in the days, where a lot of the collaborative funding comes today is from the OTD group made of 20-some utilities. This organization over the last, similar time frame has put a lot of R&D funds out there to develop technologies.

Next, here first before I go into some of those research areas, I believe this was an INGAA sponsored support. This is a snapshot from 2006 and the funding that was being directed to our industry.

And if you take a look at about the $54 million in 2006 that was directed to R&D in the pipeline industry, gas industry, it was about a fifty-fifty split between distribution and transmission. And then if you look at the further breakdown in the chart it looks at just transmission only. Of that $26 million in the transmission area, majority of that, 54 percent was directed at materials and design. And then 22 percent of that funding was directed at inspection technologies. Again showing where that funding has been. It will be interesting to see where it is today, which I have not looked that up.

Again we are going to talk a little bit about the history of some of the efforts that have gone on. There's been several of the speakers who referenced some of these old GRI efforts. Many of them were back in the '90s, again going back to the peak of some of that funding. There was a lot of funding and a lot of work that was going on.

One of those such efforts was looking at the assessment of the remote and automatic shutoff valves being deployed by the pipeline operators at that time.

Again, the question was asked, you know, how are they organize overall? Are they operating to our expectations? What are the problems with those valves, et cetera? This was all done both through field experiences and field evaluations along with simulation studies. In addition to what that showed, there was a major unreliability issue with some of these RSVs and RCVs. All of us have talked about that here today. That is with the false closures. You know, so that is a focus need that we saw back then in the '90s and we still see here today. As Joe and others mentioned we need to look at what are those sensor technologies being deployed. What are the other sensor technologies that can be deployed with those to improve this.

What the study back in the mid '90s did show and most of us would agree today, it did identify accurately actual rupture events and they did close. In some cases maybe the valves didn't close all the way, but it was able to accurately predict and close when there was a rupture. It's just the false closures is where the problem lies.

Based on some of the false closures, there was additional investigation into simulation modeling at that time. Those computers back then probably aren't as good as our phone is, as Jeff mentioned.

Again it looked at modeling the systems and how to apply line break and control systems.

Again, some of those results showed that the computer modeling that was created in that day based on some of the field simulations and evaluations, showed that the model was fairly accurate. One of the things, and it may be in the same realm that Joe is speaking, it did validate and showed that there is promise in some acoustic wave detectors. That probably sounds, when I was listen to Joe's talk here earlier, sounds similar to the sonic sensors being used down in Brazil today. Interesting back in the '90s some of this was looked at. I'm not sure if it ever went anywhere. Again these technologies need to be looked at and there are probably others out there as well.

In addition, there's been a lot of talk about the challenge of installing RCVs and ASVs in our system. Back in the '90s GRI and others looked at this issue. What are the problems from the operator's standpoint of installing these valves? Again we heard all these same things over and over. Lack of above ground and below ground space especially in the urban areas or HCA areas where these valves have more importance. The cost of installing these systems, especially on current piping systems where again even back in the late '90s it was identified that these costs can be as much as a million dollars per valve, again depending on the system at hand.

But these same studies also took a look at evaluating the benefits of the RCVs and ASVs, how they can reduce injuries and fatalities by addressing the follow-on release of gas if they were installed. Again there's benefits and obviously hurdles to overcome, back then and today.

Now looking at some of the stuff that is going on today, with some advancements in computational fluid dynamics. At GTI we are once again doing quite a bit in the area of modeling. Again this is based on regulations, unfortunate events that have occurred.

Leading to a need by the industry. So we are working with our clients and using more sophisticated models now to take into consideration various operator input, the valve types, closure times, pressures, ambient temperatures, gas loads, et cetera. And with the goal really looking at the rupture response. And in this work we are taking all various scenarios using a model to both generate simulated and directed responses, but I think what is important is not only are they looking at the shut-down time, what it takes to shut down that valve and stop complete blow-down of that pipeline, but it's also looking at, I think there's a couple folks who mentioned it here earlier, the BTU release. Focusing on more than just that, what does it take to blow down that line? Each line is not created equally. What is the pressure. What is the volume of gas in that line? Again, it's quite a comprehensive model that is really focusing on many, many different aspects and considerations in providing the operator, I think with much more knowledge and considerations when they are either redesigning an existing piping system or designing a new pieing system to take into account all those factors. Not just blow-down time but also BTU release and helping them determine how many valves, what types of valves should they put in their systems. Where are the placement of those valves? Where are the placement and number of sensors and full measuring devices that are needed to improve that response time.

So again, this is something that there's been a renewed need for it and basically because of recent events. But again I think let's use technology and some of the modeling that is out there today to our advantage.

In the area of valve design, you know, we are now looking at some of the issues that again we identified back in the late '90s. They still exist today and I mentioned them earlier. It's high cost. How do we deal with high cost?

The high cost of some of these systems are geared or driven by the large excavations, the need not only, the cost of the quilt but more so how you install those valves into the system and all the associated piping and sensors. In many cases you need by passes set up, fittings put on to shut off the flow of gas in order to cut in that valve.

The goal of this project or the project we have been working on, this initial project was focused more on distribution piping but we are also looking at and looking to apply it in transmission scenarios as well. But the goal of this project is really the development and evaluation of a valve that can be installed in natural gas piping system without shutting off the flow of gas. It may not apply to all transmission systems but earlier we saw a photo of some of the more maybe utility operated transmission lines. Some lines, there are transmission lines out there, smaller diameters in more urban areas. These may definitely play a role for some of these, what I call in situ installation valves.

Here are some photos at GTI where we are working with a company with a company called advance valve technology. Here is a smarter way of performing research and development. It is not necessarily reinventing the wheel but looking at other industries and looking to transfer some technology that they are deploying into the gas industry.

So in this case here, this valve is actually installed on to the pipeline without ever shutting off the flow of gas. So again, it just provides operators with another option when installing valves.

As I mentioned, the next steps in this is now to take it and look at higher pressure operating systems. So again, we are going to apply to higher pressure distribution and I guess lower pressure transmission piping systems. Again, another option in the tool box.

Again, my discussions, I think everybody's discussions here today point to several different areas of needs. Again, sensing systems to minimize the unintended valve closures. How do we look at maybe some of the sonic technologies tied in with the technologies that are used today. How do we make smarter systems to provide, whether it's the control room operator or the person in the field with more information to take actions that are required.

Looking at different options for converting some of the valves that are out there, converting them from RCVs to ASVs, et cetera.

Modeling, we are undertaking that right now. But let's utilize some of the improvements in computer modeling to better understand and design the systems that we have out there today.

More cost effective installations. Again I talk about the one valve that we are working on. Looking at names of advancing the -- means of advancing the technologies. Let's reach out to the valve manufacturers and challenge them to come up with new solutions and new modifications to their valves to make them more cost effective from an installation or overall installation standpoint.

And then again, challenge the manufacturers out there. If we have tight spaces, the design, the valve designs that we are using today, they have been the same for many, many years. How can these designs if possible be changed to accommodate some of the needs that we have today.

I guess finally I pulled together kind of a pipeline roadmap slide. I pulled some various kind of focus areas that I thought that we had put together for the OTD, operations technology group. A lot of these have the role in both distribution and transmission. I tried to focus on those more focused on the transmission. And broke them into overall groups.

We have materials shall. Some of the focus we are looking at is looking at new materials, nonmetallic materials, whether for rehabilitation or repair of some of our piping systems, some of the composites that are coming into play.

Sensors and automation, again from inspection tools to above ground pipe detection tools and even to help with the control of valves.

Third-party damage detection. We touched on that. Eliminate third-party damage to our pipelines. Again, that would help eliminate the need to actually operate some of these valves through those scenarios.

A whole slough of operational type activities. Again this is where some of the valve technologies fall under. Even looking at tracking our assets, better tracking our assets, corrosion, modeling for predictive failures, et cetera. Yesterday we talked about some of the leak detection efforts going on.

Finally, data. I believe yesterday folks talked about some of the data. As we learn more about our system and collect more data on our system, the challenge is always, how do you deal with that data, how do you manage it? We are looking at developing standards, developing better acquisition systems and allowing the operators to better manage the data that we have in hand.

So I want to thank you for your time.

(Applause.)

>> JEFF GILLIAM: Thank you, Dennis. At this time I would like to take a brief minute to thank the speakers who came out and made this possible for us. We appreciate folks taking time out of their busy schedules to do that.

Questions first? Questions, sorry. Any questions for our panelists?

Okay. The question is: Recognizing the importance of response time, what technology is available or can be deployed remotely to verify alarms? That's how I read that.

>>: I think some of the things that Joe was talking about. You want

to touch on that, Joe?

>> JOSEPH SUMMA: I guess the question was how do you reduce the response times. And as some of the discussions have been on closing the valves faster, but I think the decision, the quicker you can make the decision to close the valve, that's going to probably be your most effective way of reducing time. This case study that I just presented on acoustic sensors is just one of several technologies that could potentially provide that type of solution. So there are activities underway. There are other people, other countries that have similar problems and we can learn from others the same way that others can learn from us.

>> JEFF GILLIAM: Anyone out in the audience that wants to get up and ask a question? I know it's at the end of the day and we are probably all getting tired.

Is there anything else from the website any tweets or anything else?

>>: All this discussion about research, it's a good reminder that in July we'll have an opportunity to talk about it more and Joe, talking about your presentation in the case study with the Brazilians, it's a great opportunity to look at our program and the type of research we do and know that we can get into some of the case studies and look at the technology and address valves as much as has been done in the '90s. There will be more information in July when the federation notice for the R&D forum.

>> JEFF GILLIAM: Very good point.

(There is no response.)

>> JEFF GILLIAM: Well, seeing no takers, we will have the -- okay, we will have Alan Mayberry come up and close out our event.

>> ALAN MAYBERRY: Okay. Yes, we really are going to close. First off, just a reminder, we will post the presentations we hope by Friday, this Friday. It may be a week from Friday, but hopefully we will get it fray.

The public docket opens Friday. Please comment. It will be open for 30 days for public comments.

Bob mentioned the public or the R&D forum that will be a public event in July. Kind of ties in nicely with some of the things you heard here in the last panel related to the state of technology in valves and automation of valves. A heavy focus of that forum will be the topics we covered here today and yesterday on leak detection as well.

And another reminder, we mentioned this yesterday, but what is April? It is national safe digging month. So I want to put a plug in for that as well as mentioning, we are seeing a number of states jump on the band wagon. Most recently we got a message that the Alaska issued a proclamation about safe digging month in April.

Did we miss a question? I think we have one more from the audience. Would you please state your name?

>>: This is Stacy Gerard for P-Pic. The question I had goes back to some of the comments earlier on the range of views presented today on the costs for retrofitting valves, upgrading valves. The question I had was, do you have any kind of process in mind for rectifying that range of views?

I notice that you are only going to have the docket for this open for one month. I was wondering if maybe more time would give time to put more information out there on the views on range of costs for retrofitting the valves.

>> ALAN MAYBERRY: True, there was a wide range. As we do our study on the topic, that will really look, take a hard look at that.

Obviously we need a number as we go forward especially, if we decide on rulemaking. A number is very important for that, one that is credible. That needs to be a focus to have something that is hopefully not so wide ranging.

It is understandable. You heard described the number of environmental and locational factors on this. That definitely comes to bear. But you will see some variability. I think that's understandable in some cases. Yes, this is wide and hopefully we can zero in on this.

>>: Do you need to close the docket in a month?

>> ALAN MAYBERRY: We are obligated -- we may choose to extend it depending on the level of comments and if it's still active. We have that option. Even still, if we close the docket, it doesn't obligate us to consider the comments after that. We could, especially if it's a relevant document, but we are required to consider the documents in that 30-day period. If we need to extend it based on the activity, we'll do so.

>> JEFF GILLIAM: The only thing I would like to add there, Stacy, part of the charge for the research or the study is, they are going to look at the operational, technical and economic feasibility. They will be looking -- I know we had a wide range of response here, but there's other ways to go out and collect some of that data. I'm sure they will be doing that. They may go to vendors. Everyone in the industry knows who the vendors are. They know how they can price out equipment. We can get some of that information.

>>: Not to mention dockets in other states.

>> JEFF GILLIAM: Yes, dockets from other sources, other comments.

>> ALAN MAYBERRY: Let me highlight one other point that came out of here. We saw photos of San Bruno and discussions on the consequence of that failure, what the issues were relative to that.

I think consistent with that, really what we are after and what is expected is that we find ways to improve. The industry obviously, the record is safe, but whatever improvements we can make. Clearly on San Bruno there were short comes. If you look at our inspections and decision making that operators make on where to place a valve, there's that part of the regulation that requires the operator to be cognizant and to review factors, consequences of failures and ACAs on determining whether or not to place a valve.

We have seen variability in that whole analysis. It is not just San Bruno but in other areas where maybe there is little or no analysis or not very robust analysis. That is definitely an area to look at going forward.

I just wanted to make sure that was noted. I think we talked about that a bit. A lot of graphic pictures, but that's really a key fact that we are trying to point out of this.

I wanted to say thank you definitely to the speakers. I'm impressed with the speakers that we have had. Also to the people that put on this event. Bob Smith, who really ran interference with presenters and prepared a lot of guide material to Pat Landon, Joshua Johnson and Jim Merritt who have been here in the room and out front at the desk. Thank you very much. You guys did an excellent job.

Then also to the managers at PHMSA who stepped up to the plate. Jeff Gilliam and Chris Hoidal, I appreciate you guys doing that.

For all of you here and on the Web thanks for taking the time out of your busy schedules to be here to talk about this and listen to this important topic.

And yes?

>>: Use the Closing Slides

>> ALAN MAYBERRY: Oh, use the slides.

I wasn't going to do that, Bob.

This must be very important.

I think we talked about this yesterday. Just to follow through on this. You know, there are a lot of actions for all of us, all the stakeholders involved, from regulators. That's clear. I did highlight this yesterday, but for the benefit of those who weren't here, the stakeholders and regulators, the group that I represent or we represent who put on the event, the pipeline operators, standards developing organizations and research organizations. I mentioned the docket. There you have the link to it.

And I've covered thanks. There's the website on meetings. You can get information. We have that website on our R&D forum.

With that we will adjourn the workshop. Thank you very much.

(Applause.)

(The meeting concluded at 1:45 p.m. CDT.)

(CART provider signing off.)

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