U.S. DEPARTMENT OF TRANSPORTATION

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PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

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GAS PIPELINE ADVISORY COMMITTEE MEETING

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FRIDAY
DECEMBER 15, 2017

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The Advisory Committee met in the Galleria Ballroom, Hilton Arlington, 950 North Stafford Street, Arlington, Virginia at 8:30 a.m., David W. Danner, Chair, presiding.

GAS PIPELINE ADVISORY COMMITTEE MEMBERS PRESENT
HON. DAVID W. DANNER, Chair; Washington Utilities and Transportation Commission
STEPHEN E. ALLEN, Indiana Utility Regulatory Commission
RONALD A. BRADLEY, PECO Energy
MARK BROWNSTEIN, Environmental Defense Fund
HON. DIANE BURMAN, New York State Public Service Commission*
CHERYL F. CAMPBELL, Xcel Energy Incorporated
ANDREW J. DRAKE, Enbridge Gas Transmission
SARA ROLLET GOSMAN, Pipeline Safety Trust; University of Arkansas School of Law
ROBERT W. HILL, Brookings County Zoning and Drainage, South Dakota
RICHARD F. PEVARSKI, Virginia Utility Protection Services LLC/Virginia 811
TERRY TURPIN, Federal Energy Regulatory Commission

RICHARD H. WORSINGER, Public Utilities, City of Rocky Mount, North Carolina
CHAD J. ZAMARIN, Williams Companies

PHMSA STAFF PRESENT
ALAN MAYBERRY, Associate Administrator for Pipeline Safety; Designated Federal Official
ELOISE CASTILLO, Economist
AMAL DERIA, Attorney Advisor
JOHN GALE, Director, Office of Standards and Rulemaking
ROBERT JAGGER, Office of Standards and Rulemaking
KENNETH LEE, Director, Engineering and Research
JANICE MORGAN
CHRIS McLAREN, Transportation Specialist
JANICE MORGAN
SAYLER PALABRICA, Office of Standards and Rulemaking
JAMES PATES, Assistant Chief Counsel for Pipeline Safety
DRUE PEARCE, Deputy Administrator
CAMERON SATTERTHWAITE, Office of Standards and Rulemaking
CHERYL WHETSEL, Advisory Committee Manager

ALSO PRESENT
TOM BUBENIK, DNV GL
CORINNE BYRNES, National Grid
THOMAS EAGAR, Sc.D., P.E., MIT
RICK KIVELA, Enbridge

ERIN KURILLA, American Public Gas Association

C.J. OSMAN, INGAA

LEE REYNOLDS, NiSource

C-O-N-T-E-N-T-S

P-R-O-C-E-E-D-I-N-G-S

(8:35 a.m.)

CHAIRMAN DANNER: All right. Good morning, everybody. We'll get started and called to order. This is day 2 of the Gas Advisory Committee.

And I am Dave Danner. I'm Chair of the Washington Utilities and Transportation Commission. And I will be chairing this morning's meeting as well.

This meeting is being recorded. So, just a reminder, speak into the microphone, both for the transcript, and for the benefit of Commissioner Diane Burman of New York, who had joined us on the telephone. Good morning, Diane.

MEMBER BURMAN: Good morning. Thank you.

CHAIRMAN DANNER: And again, this is --

MEMBER BURMAN: Thank you very much.

CHAIRMAN DANNER: Thank you. The transcript and presentations will be available on

the PHMSA website. It's Meeting number 127 on the eGov docket at www.regulations.gov. And the docket number for this meeting is PHMSA-2016-0136.

So, without further ado let's get back into the agenda. Yesterday we closed with discussion of three of the six methods that were listed there. I think yesterday we did pressure testing, pipe replacement, and alternative technology.

So, today we can start with the discussion of pressure reduction. And then we can get into ECA and small diameter. So, let me, I'd like to open the floor if there are any comments on those.

We have taken public comment on the methods already. So, take your time. So, what's that?

CHAIRMAN DANNER: Pressure reduction. Yes. Methods.

All right. You need to prime the pump a bit to get the conversations going. All right.

We have a tent card up already. So, Andy.

MEMBER DRAKE: I thought I'd just do some entertainment here while we get the slide up. You know, yesterday we were hurrying to close yesterday. And I just want to make a couple of comments about particularly the and clause that was going into some of these sections about the small diameter pipes.

I think we really need to be thoughtful about that. When we get below 30 percent SMYS the discussions that we've had historically in the Code was not eight inches and 30 percent. It was 30 percent, because of the leak-rupture threshold.

And I don't know exactly why we introduced the eight inch pipe. But I'd like to vet that out a little bit more deliberately. I really think that just as a flyer I don't understand.

The reason that was put into place at 30 percent was because of the pre-disposition to leak. And that testing wasn't going to help

identify manufacturing issues that would grow to failure, or construction issues that would service as a failure at that stress level.

And I don't want us, I just want us to be very clear why we're doing what we're doing. Because the eight inches is not in the Congressional mandate. It's not in the basis of the Code. And I don't understand its technical basis.

So, I just wanted to put that out there. We didn't really cover that yesterday in the discussion on the small pipes.

CHAIRMAN DANNER: All right. Alan.

MR. MAYBERRY: This all goes in the category of reflecting on yesterday. From our perspective, you know, we're looking for input on that. And I think we, Steve did cover the methodology for how that was determined.

But there, you know, we'd like input, you know, on that. So, if there's another way, either just go straight with 30, if that's the proposal. Or, you know, we're really looking for

feedback on that.

MR. GALE: Can I also recommend, Chairman, that, you know, that is what we're going to discuss under Method 5, which is the small diameter PIR. Can we just possibly just table that for now, if that's acceptable?

CHAIRMAN DANNER: Sure. That makes sense. All right. Chad.

MEMBER ZAMARIN: I'll wait until the Method 5 discussion.

CHAIRMAN DANNER: Okay.

MEMBER ZAMARIN: Thanks.

CHAIRMAN DANNER: All right. So, I guess right now we're going to focus on pressure reduction. Any comments from the Members? All right. Ready to move on? All right. Nothing on that --

CHAIRMAN DANNER: Nothing on that subject. ECA? Okay. Andy.

MEMBER DRAKE: Okay. I'll, I think there was a brief comment that came up yesterday about ECA. And I think it's worth noting. And

that, it may go back to some of Sarah's conversations yesterday about data.

If, you know, the assumption of fracture toughness at five and one foot pound is very, very conservative. And I think operators will have other data and other means of collecting more conservative numbers.

And I really think numbers -- Someone said something of 13 and four. Those are also very conservative, but a little more practicable. I'd at least like some discussion around what, how can we use 607, or some other way of creating caveats to use more practical fracture mechanic numbers?

Because that, those numbers are just going to basically create an unacceptable ECA on most pipes if you don't have the absolute numbers. So, there has to be some way for us to use alternative criteria that we have that's conservative, to fill in that blank.

And I just want to put that out there. I think those numbers at 13 and four are a little

more practical, and certainly very conservative.

CHAIRMAN DANNER: All right. Steve, do you want to respond to that?

MR. NANNEY: All right. Yes. We were planning to do that.

CHAIRMAN DANNER: Okay. All right. Moving right along then I think now we can talk about small diameter. Chad, you want to put your card up again and talk about small diameter PR?

MEMBER ZAMARIN: Thanks. Chad Zamarin with Williams. You know, I did recall Steve's presentation on the diameter and the grade. I actually may have misinterpreted it as meaning there was an or.

Because he presented that at smaller diameters, even at higher pressures, that they would have relatively small PIRs. And so, you know, I think it works as an or.

But, you know, and I think that's what the technical basis would support, that both at a low stress you have a very low likelihood of incident that would cause significant harm. And

even at smaller diameter, even at higher pressure you have a very small PIR that would not lead to likely impact.

And so, that's how I interpreted it. I may have misinterpreted it. When I read the language it does look like an and. But, you know, I would, I was comfortable with it if it was an or. And maybe we just need to talk through that. Thank you.

CHAIRMAN DANNER: So, it does sound like you're inviting some clarification. Anybody from PHMSA like to respond? Okay.

MR. NANNEY: All right. Yes. I believe it, Thad, I mean, Chad, I'm sorry. I believe it was a and. And I will consider an or, like -- And we'll go back and look at that.

MEMBER ZAMARIN: Thank you.

CHAIRMAN DANNER: Okay. Steve.

MEMBER ALLEN: Steve Allen, IURC. Just to kind of chime in on that. I think from a small operator perspective, and a state regulator perspective, I think an and would be awfully

difficult for the smaller operators. And awfully difficult for us to enforce. I think or is probably more appropriate.

MR. GALE: I just need to clarify something for the Committee. If you make that an or you're going to expand that applicability to above 30 percent SMYS. And I don't know if that's your intention.

MEMBER ALLEN: Could you say that once again?

MR. GALE: If you change that and to an or you're expanding the applicability of that method to above 30 percent SMYS. And I don't know if that's your intention.

I'm sorry, Cheryl. What I was talking about was actually in the reg sec itself, and the three conditions of the applicability in Method 5. We're pulling it up right now.

CHAIRMAN DANNER: Can you make that a little bigger for the benefit of some of us old guys? Not that old.

MR. GALE: Can we just put it up

there? It was my read that it would actually expand the applicability. And I believe we're trying to limit that applicability to below 30 percent SMYS. As long as that's the intention.

CHAIRMAN DANNER: All right. Andy.

MEMBER DRAKE: Andy Drake with Enbridge. I think this section in particular, I think we may need to -- We promised not to get into wordsmithing, right?

But the or/and thing I think we need to, maybe a little bit more separate discussion, right. I think you're right. We only expand it. But I do think there's a combination there that's a problem.

My comment actually becomes that somehow these very low risk pipes have become probably encumbered with as many obligations in this section as anything. They've got a lot of and, and, ands here, things they have to do.

And I would really encourage PHMSA to look at, many of these things are integrity management issues. We're going to do ECDA.

We're going to do IDCA. We're going to do leak detection. Those are all integrity management efforts that have to be saddled to pipes outside of the MAOP confirmation.

We can, again, we've had this conversation again. And it just of is a different design flaw. So, you know, we're kind of working our way through the document as we go.

But this particular section really illustrates that point quite a bit. That you've got a lot of integrity management issues tied up in here about how to confirm their MAOP. And that's not, I don't think that's what you really need.

You're going to get the integrity management discussions separately, when you talk about how to manage threats for 30 percent pipes in integrity management.

CHAIRMAN DANNER: Okay. Alan.

MR. MAYBERRY: I was just going to say, I know words like or/and matter. So, we get what you mean.

CHAIRMAN DANNER: All right. And, Steve.

MR. NANNEY: All right. Yes. Steve, Andy, Chad, we understand what you're asking. We will look at it. Again, as a, yesterday as we stated, on the other conditions that we need to look at under this particular Method, we had a number of things, as Andy alluded to, listed.

Please go back and, you know, we would appreciate on the docket anything there that you think are more important than others that we should consider going forward. And I think we had talked about that yesterday.

MEMBER DRAKE: To be clear, especially to my friends across the table here, I'm not advocating to get rid of ECA, ICDAs. I'm asking it to move to an integrity management section. Not to be eliminated. It just doesn't belong here.

CHAIRMAN DANNER: Okay. Sarah.

MEMBER GOSMAN: Okay. So, a couple of thoughts. I mean, I think my interest in keeping

these pipelines in this system, right, and working through how we actually get to integrity once we're in the system. So, back to this applicability question.

I think part of that is that I was looking through my slides to see what the mileage is on these types of pipes. But my memory at least is we're not looking at a large mileage here, in terms of the pipes that we're talking about right now. But I'd love clarification on that.

And then, I think, I've been thinking about this distinction between integrity management and these types of, what the National Academy of Science's Performance Based Regulation Report would call sort of micro means types of approaches.

And I think the thing about integrity management is that unless we put something very specific in the rules, what we're doing is, we're moving towards less specificity, right, more flexibility. But less of a sense of what this

actual method is going to mean.

And I keep going back to this issue that we still don't address things like Class 3 and 4 outside HCAs. So, that's a concern of mine.

You know, I want to make the point that we actually, just in terms of this whole piece of the puzzle, NTSB actually said, just get rid of the grandfather clause. And we aren't there, even with the proposed rule.

CHAIRMAN DANNER: All right. Thank you. Chad.

MEMBER ZAMARIN: Thank you. Chad Zamarin, Williams. I think the Con Ed comments yesterday were appropriate. I also heard this morning from someone at Washington Gas and Light that, you know, costs to replace pipe in urban areas, you know, can exceed $3,000 dollars per diameter inch mile.

I mean, it is very expensive to replace pipe these days. You know, we have, when the Code was written most of our transmission

pipe was in very rural areas. Today many of it, especially the low stress pipe, is in very urban areas.

And it just, I continue to say it just doesn't make sense to me to be spending, you know, the most expensive dollars on the areas where they give the least public safety benefit. And these are low pressure lines that we demonstrated though, you know, decades of research, don't have the propensity for significant failure.

I do think Steve's presentation yesterday showed that those were, even at extremely high pressures that wouldn't be, low stress lines have very, very small potential impact radius.

When you look at the types of pressures we're talking about, at less than 30 percent SYMS, they're very low pressure lines that would have, you know, de minimis potential impact radius.

So, my point is, almost irrespective

of the amount of mileage, it just seems like a disservice to be putting resources into investments that don't really contribute to increased safety. So, I continue to advocate for this section not being in this portion of the Code.

And following the Congressional mandate, and moving it to a filter, just as the Congressional mandate did on applicability in 192.624 A. I think that's where it would be most appropriate.

I think that's where the Congressional mandate, you know, frankly mandated that it should be. That this should apply to greater than 30 percent SMYS. And that was done for a very good reason. And I think when we start creeping beyond that, we aren't doing a great service to public safety. Thank you.

MEMBER DRAKE: Mark.

MEMBER BROWNSTEIN: So, let me take a step back. Let me just ask the basic question. What's the purpose of this section, the MAOP

section, writ large?

CHAIRMAN DANNER: Steve.

MR. NANNEY: Well, the purpose of Method 5 is what you're talking about?

MEMBER BROWNSTEIN: No. I'm talking about just 192.624. What are we trying to do here?

MR. NANNEY: Well, it's Methods as far as MAOP determinations that you can use as far as determining your MAOP, or confirming that it's safe to operate at that MAOP.

MEMBER BROWNSTEIN: Okay. And just for us civilians here, MAOP, again, just to remind me.

MR. NANNEY: Maximum allowable operating pressure. So, whatever the maximum pressure that the pipeline can operate. It's doing inspections, pressure tests. Whether it's a pressure test, an ILI, in line inspection, replacing the pipe, or the other methodologies that we've got here. Doing those to confirm that your pipeline is safe at that operating pressure.

MEMBER BROWNSTEIN: Okay. And so, the problem that we're trying to solve, as I understand it is that we have a certain amount of pipeline in the United States for which we don't actually know what maximum operating pressure is. And this is a set of provisions that are designed to help us get those answers. Is that right?

MR. NANNEY: Yes. It is where records are, have been lost, or have never been done, as far as pressure testing the pipes, and confirming the pipe wall thickness, grade, the things we were talking about yesterday.

MEMBER BROWNSTEIN: So, it seems to me that that's a very useful thing to do, right, to have some understanding as to what the maximum operating pressure is for pipe operating in the United States. Okay.

And then, what we're trying to do is come up with common sense methodologies to be able to do that. Okay. And you're providing a number of different ways to do that tailored to the size of the pipe, and the expected impact

area if there were a failure. Correct?

MR. NANNEY: That's correct.

MEMBER BROWNSTEIN: Okay. So, it seems to me that, right, in that context -- Because, you know, part of what I was getting a little confused in is that yes, absolutely, we want to make sure that we have provisions to make sure that once pipe is in place, and we know what the maximum operating pressure is, that we have procedures in place to maintain integrity over time, integrity management, SMS. That's all great stuff. Okay.

But that speaks to me, that says to me though that we still have a first order question, which is what's the maximum operating pressure on the pipes? Right? So, okay.

So, you know, I'm confused why then we're getting so hung up. I mean, on these particular methodologies. Because I'm not hearing necessarily, I wasn't hearing necessarily that the methodologies are, you know, impracticable, or difficult, or too expensive.

What I was hearing is that in fact much of this activity should just simply be put into, you know, what I'll call process management provisions.

And it sort of struck me that maybe we're losing sight of what we're trying to do with this set of provisions here, which is get some fundamental answers that I think any common sense person would expect we'd have answers to, right.

So, I'm a little lost as to what the real issue is here with these provisions.

CHAIRMAN DANNER: All right. Alan.

MR. MAYBERRY: I'm really trying to -- We're attempting to thread the needle. Because if you look at the, take the NTSB recommendations for instance. It says, eliminate the grandfather clause. So, that's the full universe of what's out there.

You have our gas transmission rule that addresses the grandfather clause, which gets almost the whole thing, or a good bit of it. It

introduces a new term, MCA that probably sums it to where you're getting the riskiest stuff out there.

And then you have the mandate that specifies, address it in Class 3 and 4 and HCA. So, a further subset of the full universe of what's out there that has its own documented --

It wouldn't be that you don't know the MAOP. It's just whether in some cases perhaps that's the case. But in most cases it's a record keeping issue.

So, I think --

CHAIRMAN DANNER: Alan, please speak into the microphone.

MR. MAYBERRY: The challenge here, or the discussion is about, you know, if you look at what happened on the PG&E incident, that involved a line that had a higher stress level.

And certainly, you know, I think we all agree that lines like that, and what was, we now know about that is risky, is the riskiest. But when you look at the full universe of

transmission, it goes from 20 percent up above, you know, up to 72 percent.

There's a varying risk in what you're dealing with. Certainly, you know, and there's been discussion of the leak rupture boundary that, right around 30 percent and above, where you go from where, you know, on the issue of the pipeline would be a leak versus a rupture.

And that's what specified in the Code. So, really a lot of the debate is, you know, really applying some level of risk, a sliding scale to what you're really concerned about, to address the issue of record keeping in establishing MAOP.

And so, the discussion here is well, you know, below 30, or at least the point being made is less, and that's what in the mandate. Maybe we should be less concerned about that, and really focus on the area that, you know, it's the type of pipe that we dealt with in California, and other, you know, types of issues, ruptures we've had out there.

MEMBER BROWNSTEIN: So, if I can ask a clarifying question, Mr. Chairman?

CHAIRMAN DANNER: Yes, you can.

MEMBER BROWNSTEIN: Is it that below 30 percent there's a small probability, or maybe no probability of rupture? Or is it that below that pressure a rupture that would occur would be unlikely to be sort of catastrophic, on the order of a San Bruno event? I'm just trying to understand which, how we're thinking about this.

MR. MAYBERRY: Well, there have been ruptures below 30. But you can't really characterize from this. It can certainly be smaller. But I can't really characterize it would be less impactful. Because you just don't know. But --

MEMBER BROWNSTEIN: So, you're saying --

MR. MAYBERRY: It depends on the number.

MEMBER BROWNSTEIN: So, we're saying that the, that there's a low probability of

rupture --

MR. MAYBERRY: Much lower.

MEMBER BROWNSTEIN: -- below those pressures? Is that right?

MR. MAYBERRY: It has happened, but lower.

MEMBER BROWNSTEIN: Okay. But you could have a situation where pipe is leaking, you know --

MR. MAYBERRY: They tend to, there's tends to be --

MEMBER BROWNSTEIN: Because of the --

MR. MAYBERRY: -- because of the rupture or leak --

MEMBER BROWNSTEIN: -- rupture.

MR. MAYBERRY: -- below that point, yes.

MEMBER BROWNSTEIN: Okay.

MR. MAYBERRY: Do you want to add anything to that statement?

MR. NANNEY: Okay. Just to add something, at our next meeting, on the 104

incidents that we have up, we will break out how many were below 30 percent.

I probably know the answer now. But I want to look at it before I just throw a number out to the group, and everything. But we'll get back to the group at the next meeting.

And it's just like Alan said, one is, it's a lot smaller increment of the ruptures, the leaks are that. Plus, when you look at eight inch and smaller, the smaller diameter pipe, the volume just is not there to create the same type of problems, as if you've got a 20 inch, or 24 or 30 inch volume. I mean it's many times more volume, even at the same pressure, with the bigger diameters.

MR. MAYBERRY: If I might, I have one other point. It hasn't been mentioned yet. But maybe implied. But we, and our challenge in threading the needle is applying the cost benefit that we must apply in our rulemaking.

So, certainly if we had gone the full extent of the full universe of grandfathered

pipelines, we just couldn't have passed cost benefits.

So, and certainly we're hearing of challenges to whether our economic analysis on, you know, even what we proposed. So, we're trying to find that sweet spot that --

Because NTSB does not have a mandate to only put out recommendations that are cost beneficial. Their concern is, you know, what they think is right.

But when it comes to really, okay, let's put this into policy, that's where we, that's where it really becomes a challenge. And it's not so easy as, well, this would be the right thing to do. But we have competing interests. And certainly cost is a major one that we need to consider --

MEMBER BROWNSTEIN: Yes.

MR. MAYBERRY: -- you know, as we look to making sure that the costs that we are putting on the regulated industry is really being put to the most effective use to --

MEMBER BROWNSTEIN: I certainly do appreciate that. I would note though that the next incident that does occur, right, the NTSB recommendations will be sitting out there. And the judge, right, the measure of effectiveness will be, how far did PHMSA go in implementing those recommendations?

And I can guarantee that the representatives of those communities will want to know that you did everything possible. And so, we better make sure that we get this right. That's all.

MR. MAYBERRY: Yes. And I like to think that, you know, and this is incredibly great conversation. I think it does point to the due diligence that our staff has exercised in really researching this issue, to really find that right balance. So, but totally appreciate that.

CHAIRMAN DANNER: All right. John.

MR. GALE: John Gale, PHMSA. I think it's important to point out something regarding

the 30 percent SMYS issue, and the statutory mandate.

What you have on the screen here on Slide 40 and 41 are the two different provisions that are contained in the statute relative to this mandate. And they correspond to the different applicability paragraph within 624.

This is not talking about the first applicability, which was the in-service incidents, but to one, bad records. And it's, the applicability is Class 3 and 4, and all HCAs. And then untested pipe, which is the third applicability statement.

It is correct that under the third applicability statement it mentions 30 percent SMYS. But I want the Committee to note that under the second on, on Slide 40 there, there is no mention of below 30 percent SMYS, or above 30 percent SMYS.

So, if we were to adopt a requirement that accepted below 30 percent SMYS that would not be in accordance with that mandate.

CHAIRMAN DANNER: All right. Andy.

MEMBER DRAKE: That's a great point actually. Getting ready to make that. To Sarah's point earlier, I think when we look at this, to make the determination about 30 percent is about records, which is about, what that section's about.

You have to have records to even determine where you are on this scale, which kicks you back to 607, which is one of the questions you're asking. So, that's important.

I think 30 percent, this is a great conversation. It really is. And I agree with Mark. We need to get this right. Why are we doing whatever we're doing? Better have good logic that holds up.

I think Steve's right. There's a good report from Kiefner & Associates that particularly vetted out what family of events have happened below 30 percent. The vast majority of that was outside force. You know, you have other things loading on the pipe that

caused them to rupture. I think we'll find that when we get to that.

I think the other, there's very few when you start to differentiate down to that. But I think there's a handful that were corrosion. And they were very extensive corrosion. That should have been caught with ECDA or other protocols, which is why I think they're advocating for these low stress pipes to do those technologies.

And I'm just advocating for those technologies. Put them in IM, because that's where they belong. And that's sustainable beyond just doing integrity, or beyond doing your MAOP confirmations.

I think the thing that I heard, that caught my ear, and I can appreciate it. This is hugely complex with say, or intricate may be a better word. And how these mechanics work is important for us to understand.

But what we're talking about is all pipes and HCAs, Class 3, Class 4, and MCAs, which

we haven't even gotten to MCAs yet, are subject to this filter, in the discussion that we're having on this table. And that doesn't mean that's exclusive. That's just the most logical place to start.

When we did integrity management so many years ago we started HCAs. It was never written that that would be the end. It was just a start. And we're sort of at the second charge here. So, now we're going to have HCAs, Class 3, 4, and MCAs in this discussion.

And when, I appreciate that we're not getting rid of the grandfather clause completely. I don't know how to actually do that. I think that was a discussion we had a year ago.

What we are doing, and we're trying to be very deliberate about it is, eliminate the clauses that create the risk, which is about untested pipes, and pipes without documentation.

And so, I hear what you're saying. Yes, you're right. We're not eliminating it. But we are eliminating the clauses that create

the risk, which is appropriate.

And we want to be very deliberate. Are we being effective in that, which is this conversation we're having right here, which is a great conversation. And I think we should create a lot of transparency on this, because this has to be sustainable and practical, which is your sweet spot.

CHAIRMAN DANNER: All right. Chad.

MEMBER ZAMARIN: Chad Zamarin, Williams. One thing I want to go back to is, when we talk about cost benefit I do think that this will be an area that if we don't get it right is going to be heavily challenged.

I think that the, you asked about practical. I think the message is that the requirements that are being proposed for less than 30 percent SMYS are not practical. And that it would drive operators to pipe replacement, that is --

And the problem with that is we're talking about the least amount of risk with the

heaviest amount of cost. I mean, this is where there is de minimis risk.

You know, I was in the meetings that led to why the legislation was written the way it was. And it was to ensure that we were putting the resources towards preventing the next catastrophic accident. And it was recognized that that would be done by focusing on pipeline greater than 30 percent SMYS.

And the sad challenge is that if we open it up to everything we actually shift the heaviest cost burden to the least safety benefit. And that's just not I think a good way to craft this regulation. I think we need to stick with the intent of the mandate.

And I understand NTSB's, you know, recommendations. But I also think NTSB wants us to focus on investing the resources that we have in the areas that will have the greatest impact on reducing risk.

And so, I continue to promote us thinking hard about, you know, creeping beyond

the Congressional mandate. Because I just don't think the benefit is there.

CHAIRMAN DANNER: So, maybe -- All right. So, I'm sorry. Cheryl.

MEMBER CAMPBELL: Yes. I want to ask, Steve, when you bring that split back I would ask that we bring the split on the root cause as well, so that we can, you know, we can see what the cause was.

My recollection of the report was, as Andy's, is that they were not manufacturing or construction issues. They were more, you know, the outside force or corrosion, things of that nature.

If needed, I think maybe we provide some clarity, right, in the integrity management section about, you know, dealing with some of those types of issues, right, in these lower stress pipelines.

I do think that a rupture in these pipelines is very, very rare, of the type that we're talking about. So, I mean, I would just

add my voice to the choir about that.

And then, I wanted to make sure I understood. Because, I mean, I think what we're talking about here is, operators believe that they know what the MAOP is on their pipes, or they would not be operating them at that pressure, right?

And for those where we might have some gaps in records, or were grandfathered -- I don't know if I like that term or not. But, I mean, it is the term we all use. I believe what we're talking about here is reconfirming that MAOP. Is that correct?

MR. NANNEY: It's confirming or reconfirming.

MEMBER CAMPBELL: Confirming or reconfirming.

MR. NANNEY: And let me say, I have seen operators, at least one operator that had, that did not know what their MAOPs, of an entire system.

MEMBER CAMPBELL: I'm sure that's

true. I'm sure you have, Steve. That's why we're here. That's exactly right. So, yes. I just wanted to be clear about that. Because to me that's what we're talking about here is, if you've got these pipelines, right, we're talking about reconfirming where you're at.

And either finding ways, right, to fill those record gaps, or finding a way to reconfirm the speed limit, if you will, right, that we're going to go at on these pipelines. So, that's all I've got, Mr. Chair.

CHAIRMAN DANNER: Thank you. Sarah, and then Mark.

MEMBER GOSMAN: So, one thing I want to bring up, I'm glad that John brought up the different statutory mandates. Because I think that's important in understanding this 30 percent SMYS issue.

And then, the other thing that I want to talk about is the fact that we have a catch all alternative methods provision here. So, I think it might be really helpful to work out what

that particular low SMYS methodology might be.

But we also have a rule that is designed so that if that's too onerous, or it doesn't match the particular set of issues that operator has, they can go to PHMSA and put in the alternative.

And I think that's a really critical part of this rule. And it's really critical as it gets to cost. Because with that kind of provision you avoid the situation in which there are high costs across the board. Because they're not specific to the particular operator.

CHAIRMAN DANNER: All right. Mark.

MEMBER BROWNSTEIN: So, just an observation, and then a question. You know, I take Cheryl's point. But by the same token, just because a company is doing something doesn't mean that they know, okay.

I used to do environmental compliance for a utility. And so, whenever the operating guys came back to me and said that they believed something, right, my radar always, you know, my

light always went off, right.

A lot of tribal folklore in the business. And I think what this provision is designed to do is sort of get away from tribal folklore, and get some real data on the table, which serves everyone's interest. So, and I don't get the sense that anyone's disagreeing with that.

I want to unpack this because, you know, we heard from the public comment yesterday that as a consequence of some of these, this provision, you know, some companies would be sort of forced to just simply replace pipe. And that would be very costly, particularly in populated areas where it's difficult to excavate and do that work.

I'm just trying to understand what the relationship is between doing this kind of testing on the one hand, and the concern that if they were required to do this they simply wouldn't replace pipe.

I don't quite, I just don't understand

that. And maybe I'm misunderstanding the nature of the comment that we heard. But I'd like to better understand that.

CHAIRMAN DANNER: Are you --

MEMBER BROWNSTEIN: Yes. So --

CHAIRMAN DANNER: Is that directed at --

MEMBER BROWNSTEIN: There seems to be, I mean, we could ask the person from Con Ed. But it seems to be that you all understand what she was talking about. So, I just want to better understand from, what that's all about.

CHAIRMAN DANNER: All right. Cheryl.

MEMBER CAMPBELL: Yes. I'm happy to provide a little information about that. Frankly, we have replaced some pipe, right, as opposed to trying to do the testing that PHMSA has in the proposed regulations.

And what you end up with is, it depends, frankly, it depends on each unique situation. So, some of them might be a single line feed into a remote area.

So, you can't just take a line out for a couple of weeks to do MAOP hydrostatic testing. Because you have no way to maintain service to those customers. And, you know, I have a lot of mountain communities. You can't just shut a mountain community off for two weeks, right.

And if you find something on the pipeline while you do that testing, let's say you blow it out and you've got to do some repair work. You're down for even longer. So, sometimes you can maintain service, sometimes you cannot. So, it just depends on the situation.

Other times, by the time you cut in valves, and prepare the line for testing, because you have to cut out a lot of obstructions and stuff, so you can dry it appropriately, et cetera, you've spent more money than it would have cost you to replace it.

So, it's, you know, you try to do the cost benefit on each individual segment, and determine if you think you can test it. Or, and sometimes it depends on its vintage, right, and

how old it is, and what kinds of construction issues you think you might have in those areas. Sometimes it's just more cost effective for our customers to replace those lines, rather than try to do a test on them.

CHAIRMAN DANNER: All right. Chad.

MEMBER ZAMARIN: Thanks. Chad Zamarin, Williams. I also want to point out, because I don't want it to be heard that this is a do nothing approach.

When we were working on this we committed on the interstate side of the industry to addressing all pipe, even outside of HCAs, by 2030. One of the reasons, and the majority of that, 90 percent by 2020.

One of the reasons why we in the interstate side said that is because in particular for low stress pipelines, low flow pipelines, it's very hard to use advanced technologies to do alternative assessments.

You can't put an in line inspection tool in most of these lines. Most of them are

not piggable, or they don't have enough flow to move a tool through the line.

So, what you end up with is, remember, this is the very lowest risk pipe in the inventory. And we're talking about reducing the pressure of the pipe.

We're talking about requiring an external direct assessment, which is a series of surveys and analyses that must be done above the ground and around the pipe.

We're talking about doing an internal corrosion direct assessment, which is an analysis of the pipe in many different fashions, to determine whether or not it could have the potential for internal corrosion.

We're talking about developing and implementing procedures for non-destructive testing, for examinations and assessments for cracks and crack like defects.

We're talking about monthly patrols at intervals not to exceed 45 days, weekly patrols in Class 3 areas. We're talking about instrument

and leak surveys. These are ands. You have to do all of these things.

And I'm just telling you as an operator, you're going to look at that, and you're going to say, that is incredibly difficult to do on these lower stress lines.

And so, when we were working as a community on what makes sense for the legislation we always said, look, we get it. We want to get everything covered. But we've got to start with the things that make the most impact.

And we've also got to recognize that as you start dealing with smaller diameter, lower stress, and unpiggable pipelines, that we continue to work on technology that will make it more feasible to do that at a cost effective manner. And so, that was, I just want to make clear that was the goal at the time that we did this.

And so, but I think, when I read this I was pretty shocked. If you look at the other sections, we kind of loaded the most onerous

requirements on the least risky segments, that are the most difficult to assess. So, I just think we need to rethink that.

CHAIRMAN DANNER: All right. Andy, and then Steve.

MEMBER DRAKE: This is Andy Drake with Enbridge. I think that's a very good point. The thing that strikes me, and we talked about this yesterday, was what we call DIM, Distribution Integrity Management.

There are, I brought that up on purpose, because I think it actually interlocks with this conversation pretty intensively. That we deliberated over this when we did gas transmission integrity management, and distribution integrity management.

Because this leak rupture threshold, which isn't a sharp line, it's a grey area where you decidedly start to get away from the capacity kind of rupture, is a big deal. It's, what threats, how do threats manifest themselves?

It's different as you move across that

regime. So, construction and manufacturing threats become much less of an issue. Outside force, third party damage, other things become more relevant.

And how do you confine them is also different. Most of these low pressure pipes don't have enough driving force to move a pig. So, that's good, the fact, that's good to know.

And the fact that they're predisposed to leak, rather than fail, gives us a different tool to use. We ramp up one of our leak detections that we would run.

I think the thing that's relevant here, that I learned as we were going through the distribution integrity management rules some years ago was, the histogram of distribution of mileage. If we look at where these pipes are, these are pipes in residential areas. They're down in, you know, urban areas.

They are not prone to failure. But there's lots of them, lots and lots of them. So, if we don't get this right, we can suck a lot of

pipes into this requirement, where there's not a lot of value. And I think that's what we were hearing yesterday.

You know, there's thousands and thousands of miles that large diameter pipes. There's hundreds of thousands of miles of small diameter pipe. So, understanding the threats that they create is important. And not just trying to throw everybody in the same bucket. The threats don't manifest themselves, and the tools don't work the same.

So, understanding that differentiation is a big deal, especially as you start to encumber the small diameter pipes, because of the number that's involved in it.

And I think that's kind of what I'm hearing from the audience is, if we're not careful, and they draw this line into the small diameter pipes, that we just drew a lot of pipe, and a lot of energy into this discussion, where there's not a threat. And I think that's really why this conversation is so important, to make

sure we understand how that manifests itself.

CHAIRMAN DANNER: All right. Steve.

MEMBER ALLEN: Steve Allen. And yes, I think Chad verbalized what I was trying to say earlier about, as a state regulator it would be easier to enforce an or, rather than an and.

It does get back to kind of resources, I think, for the, say the small privately owned LDCs. You know, there could be a pretty significant amount of effort that goes into complying with this rule. And perhaps not enough customers to spread those costs over.

And likewise, with the municipal operators. While most of those are not under state jurisdiction for establishing rates, they have the same problem. They have to go their Town Councils and try to come up with, you know, the tax to go ahead and, or the rates to go ahead and pay for that. And there's going to be a lot of pushback.

And as such, you know, it's going to be difficult to enforce for, you know, some of

the state regulators, state pipeline safety regulators. And I just wanted to thank Chad for saying what I wanted to say in the first place.

CHAIRMAN DANNER: All right. Thank you. Ron.

MEMBER BRADLEY: Ron Bradley, PECO. So, just weighing into the conversation as well. I think is a really interesting and a good conversation about this subject, specifically the smaller SMYS kind of pipe, the pipe closer to 30 percent and lower.

The question that came up, I think you heard the public comment about Con Ed were, or companies that may have to replace a lot of pipe. It's good that there are alternatives. That's the first thing, and I would like to say that.

It's good to see some opportunities for just sort of picking something that will work to help us confirm MAOP where we didn't have good records.

And I do understand that there's got to be a company out there, or two, that really,

really don't know what the MAOP. But I know, I believe most of us have a knowledge of it. And when some of this pipe when in place, you know, just over the years just didn't do a good job of maintaining records.

Today we're in a place where a lot of our records are automated, go into databases. We're at a whole different place today in this kind of technology era.

But in a world where we had to move records from building to building, place to place, I think some of those records got lost. That's obviously what I believe happened.

Now, in the case of why would I have to, if put against these parameters, replace a section of pipe? It could be that it is feeding specifically to a large customer. And either I have to work sometime to take that customer off line. Or maybe I can find a way to leverage my right of way, and put pipe in. It could be that.

I think these are all case by case. And I do not believe the first thing that we

would do, or many companies would do would just be invest the capital into installing the new infrastructure.

I think you'd want to figure out what you have in your infrastructure with some of these other alternatives. But there are cases where I could see where the best alternative would be just to put in pipe, and replace it.

CHAIRMAN DANNER: All right. John, and then Sarah.

MR. GALE: Thank you, Mr. Chairman. John Gale again, PHMSA. Another nuance to point out on the applicability of these provisions. And that's the issue of the MCAs. Not that I'm looking to get into the definition of MCAs. That will be at a later time.

But if you notice that the applicability of MCAs only comes into place in two areas. And it does not come into play under the area of bad records. And that's to be consistent with the mandate.

So, it's a little bit of this nuance,

part of this rule. But we did bring in the concept of the MCAs. But we only apply it to the "grandfather pipe".

And we only apply it to the area of history of failures attributable to defects and incidents. So, in the area of lack of pressure test records, it's only HCAs, Class 3s and 4s, which is consistent with the mandate.

Now, you still have the ability to come up with a method that's less onerous than things like pressure test, et cetera. But to be, to cover the mandate we would be obligated to come up with a method to address those pipes.

MEMBER GOSMAN: So, I'd like to know, do we have stats on the mileage and number of operators that are going to be affected by this set of pipelines that we're talking about right now?

MR. GALE: If I, on the slide to your left, Sarah, there at the bottom you see we estimate that approximately 8,089 miles of gas transmission pipe would be subject to 624. The

breakout, if I recall, if roughly 3,000 miles or so of grandfather pipe.

MEMBER GOSMAN: And then, about how many is 20 to 30 percent SMYS?

MR. GALE: I think our preliminary estimation is less than 1,000. Might be close to 500 miles right now. We're still working on that number. But I think that's --

MEMBER GOSMAN: Okay. So, I think that's a really important number here. Again, thinking about cost. And do you have a sense of how many operators are going to be impacted?

And I don't want to minimize the impact on specific operators, right. But when we think about cost benefit analysis, and particularly what we're trying to do is, you know, sort of look broadly at costs, and compare them broadly against benefits.

MR. GALE: Yes. I don't have that number right now, Sarah. We'll see if we can work on that.

MEMBER GOSMAN: Okay. And then, I

think I'd be, I'm interested. I see a lot, like just in terms of numbers, right, and a lot of requirements on this particular number 5 Method.

But I'm not sure where the cost, the concern about cost is coming from. If there's a particular, and is it the patrols, right? Is it the fact, I mean, when I read this, I, you know, there's -- Yes. So, I'll leave it there.

I'd love to hear more about, you know, if you could identify the particular areas that are of concern. So, maybe we could focus on those, rather than a sort of general discussion of cost.

CHAIRMAN DANNER: All right. Ron, and then Chad. Ron.

MEMBER BRADLEY: My comment, Ron Bradley from PECO. My comment was specifically about, you know, some companies may have the decision to replace, right.

So, in all cases with transmission there are Code requirements around preventative maintenance we have to do. And I think that

happens regardless of whether it's new or an existing pipe that we reconfirm or confirm the MAOP for.

So, I don't see a big issue with cost. We're going to have to do leak survey at a routine cycle. We're going to have to do circuit patrols, or line patrols at a routine cycle.

We're going to have to apply cathodic protection effectively at a routine cycle, and do all the checks on reactive fires and test stations. All of that stays. I don't see that changing.

I just think that there are times where if it's unpiggable we're going to have to do some work. We're going to have do some capital work. We're going to have to install launchers. We're going to have to -- I don't think those are issues. I think you build those into your work plan.

And you make your, you build a transition plan. And you move yourself to a place where you do have piggable lines, and you

do have the right kind of technology to do disruptive or non-disruptive tests to collect the information you need. I don't think I have an issue with that.

MEMBER ZAMARIN: Chad Zamarin, Williams. Having worked at a company that had quite a bit, I'm not there now, but had quite a bit of low stress pipe, I will tell you that much of it is in areas where it's very difficult to excavate. It's under concrete roads or sidewalks.

So, the idea of performing external corrosion direct assessment, internal corrosion direct assessment, digging up the pipe to do non-destructive testing, or destructive testing, you know, is very challenging.

And frankly, I think those are the two methods that are the, that we're kind of relying on the most for, you know, this segment. And, you know, the mileage may seem like it's not a big number.

But if you just extrapolate some of

what heard, you know, 500 of pipe, we can be talking about $5 billion dollars of investment. Do we want to invest $5 billion dollars to solve a problem that really doesn't exist? I mean, I think putting that $5 billion dollars towards the areas that are greater risk is a lot more important.

And you just start, and the problem with, you know, these areas is, the more of these things we tack on, you start loading, you know, investment into areas that aren't really attacking the greatest risks. So, it's real money. And it's, and I think we want to make sure the money is getting the most benefit.

I would also is, and this isn't maybe proscriptive. But the Code serves as kind of a beacon for how we operate outside of just the proscriptive regulatory areas, the applicable areas.

So, typically when we write, you know, when things like this become Code, they become a standard that is referenced for how we manage

things outside of HCAs, outside of, you know, Class 3 and 4 areas.

And so, you know, we look to the Code for being a, you know, smart approach to balancing the risk, and the issues on a pipeline with the requirements of what you should do.

And I just again worry that we're kind of shifting practices to an area of very low risk that are high cost. And I think we're, you know, we're causing some concern.

I do want to address one thing. And we heard some talk about not having MAOPs known on pipelines. That would be a compliance violation with existing regulations.

We have to have MAOP established on every pipeline by current Code, either through a documented grandfathering of the pipe, we've heard about that process in the late '60s, or through traceable, verifiable, and complete records for pressure tests that have been performed in accordance with Subpart J.

So, we're not, I mean, there may be

operators out there that we've seen that don't know their MAOPs. They would be in violation of current regulatory Code.

So, this is about, the intent of this requirement was for those pipelines that have their pressures established, their MAOPs established or grandfathering through that late '60s process, which I'll tell you is a, you have to have a documented process that, and we have records that date back to the '60s that show the pressure, you know, charting and documentation that was done to establish those MAOPs. We're talking about reconfirming MAOPs on those pipelines.

So, I know we're worried about, you know, some of the circumstances that we've talked about. But the Code requires a known and documented MAOP for every pipeline today. I think we're totally comfortable with every pipeline has to have records that reliable and verified.

And I will tell you, you know, we've

been working since San Bruno to go out and verify all of our records on both, you know, grandfathered and pressure tested pipe. But I just wanted to make that point. Thank you.

CHAIRMAN DANNER: All right. So, Rich.

MEMBER WORSINGER: Rich Worsinger, Rocky Mount Public Utilities. I think we're missing something. And it really was brought up yesterday, comments of the public.

That we're taking the smallest diameter pipelines here, the ones with the least risk, and we're requiring additional, we're requiring more actions on that than we are on the larger diameter, those operating over 30 percent SMYS.

And my suggestion here is, instead of making it an and, make it an or. It's either the ten percent pressure reduction, or those other methods. Not the and. I mean, I just, I'm kind of confused. I know, Steve, this is something you guys are going to go back and look at.

But why requiring more actions on, as you pointed out, the potential impact risk of these, because they are smaller diameter, the volume of gas if they were to rupture is much less. So, I'm just, I think that's something we have to go look at.

CHAIRMAN DANNER: All right. Andy.

MEMBER DRAKE: Andy Drake with Enbridge. I want to try to provide some clarity about my comment earlier about mileage. I think that's relevant here.

I do think that you're asking how many miles are exposed to this. And the comment earlier about the disproportionate amount of small diameter miles is mostly a concern about what miles are exposed to these filters that we're talking about?

It's not that 100,000 miles would come into the rule. It's just that there's a big pool of pipes there. So, as we move the criteria around, more, there's a flash volatility to that big volume, big pool that could come into this

rule.

I don't know the basis for the numbers that PHMSA's showing up there. I've seen some different numbers. I'd like to see that. I think that's fair for you, as well. It sounds like we share that interest in understanding the breakdown.

But you asked, you know, what was driving some of that? And I'm kind of projecting a little bit from some of the comments from the audience, based on that understanding of how big that pool is. That if the filter moves around it's, you're, a lot of things can end up in there.

But I do think it does come back, as Chad said, it comes back to risk. What is it that we're trying to manage here? And an understanding, what is the threat that those pipes create? And how do we manage that threat, which drives back to DIM.

They still need to define their MAOP. They still need to have records, which is a new

obligation for them. If they define that they're below 30 percent SMYS we know that there are certain threats that start to wane. Okay. That's what this is trying to deal with.

And they still have to go through integrity management, DIM, even as we adjust it here. So, I think it's really important that we keep that clarity as we walk through this discussion, or we end up putting I think unintended consequences. We put a lot of energy into places that's not doing anything.

It sounds good. But I think they're still obligated to know their MAOP. They're still obligated to have data to make that prediction. They're still obligated to manage the asset, which is what we're trying to get them to do.

And the big pipes, which is where the rupture threat is, aren't in that class. That's primarily where the concern is. So, I think it's worthwhile to get some more of the numbers to get clarity about that. But I still think it comes

back to understanding how these things link together to solve a problem.

CHAIRMAN DANNER: All right. So, at this point I think that everybody, I think a number of views have been expressed. I think we've had a very good conversation. And I don't know that, I don't see this conversation driving towards a particular consensus.

And I'm wondering, Alan, I should ask your advice on this. Should we table this discussion right now, and move on? Or do you want to keep going for another hour?

MR. MAYBERRY: Well, I don't have a flight to catch, so I'm good. No. I would suggest we table it. We were just site boring here a second ago. And, yes, I've mentioned maybe if we could get a proposal.

I would table it now. And then, if between now and the next meeting if some suggestion of an alternative approach, if you guys could consider that, we'd look to bring it back, post it to the docket. And we'll consider

that.

I mean, we've heard a lot of comments here. We'll consider it as well. But I would just suggest that if we could get an alternative suggestion to, you know, bring it back.

MR. MAYBERRY: Well, just --

CHAIRMAN DANNER: Okay. Andy, and then Mark.

MEMBER DRAKE: Andy Drake. I think one thought I'd throw out there as we button this up, and just a thought that kind of struck me as we're looking at this.

With all the energy you're putting into 624, is it appropriate to consider leaving, you know, making more changes to 619? I think 624 actually deals with this issue.

And I think you may be in a place where you can leave 619 alone, because you're dealing with the problem here. And I just throw that thought out, because I think that, recognizing the obvious, how much energy you're putting into 624.

CHAIRMAN DANNER: Mark.

MEMBER BROWNSTEIN: Well, I just wanted to observe, I mean, there were some factual issues, there's some facts that we wanted to get out on the table.

I don't, people can propose whatever they want. But for me, you know, there's some threshold issues that we want to better understand. And then, it makes it easier to evaluate this, or any proposal anyone puts forward.

So, I don't think it's a matter of just simply coming up with, you know, alternative proposed language. It's, there's some, right, there's some questions that have been asked. And those answers are important to then understanding how to best proceed. That's all.

CHAIRMAN DANNER: Okay. But I think that those questions are on the record, unless you think there's, there are factual questions that have not been asked. Okay. Alan.

MR. MAYBERRY: Well, I was just, we'll

bring, yes, I mean, we'll bring back, I think we have some data to bring back on the leak rupture boundaries. So, we'll bring that. I think that will help inform.

But, you know, that's a data point. But in addition to that, if there's a suggestion, you know, we're all ears in the meantime. But we'll consider it at the group, next meeting.

CHAIRMAN DANNER: All right. Steve, last word.

MR. NANNEY: This is Steve, okay. There's --

CHAIRMAN DANNER: Yes.

MR. NANNEY: Just one thing. And to help clarify. Is if you go and you look at Method 5, and I, and then, and there's been a lot of conversation about putting it into integrity management or not.

And the reason, when we were looking at this originally, we didn't put it in integrity management is, we weren't trying to expand integrity management.

Because if we put it in there, number one, there would have been a lot of Class 3 and 4, and even HCAs that were originally not in HCA, that would have been put in there.

And if you go look at the methods that we're talking about, if you look at the external corrosion direct assessment, that is integrity management. When you can't run an in line inspection, you can't pressure test. All these things that we are talking about, that cost a lot of extra money, this is alternative measures when you can't do all of that.

And then, like the internal corrosion direct assessment is when you do have wet gas, and you have situations to where you're going to have internal corrosion.

And at the end of the lines, hopefully these are lines that have dry gas. And it's going to the, very close to going to the customer. And hopefully that's going to be very minimal. So, really what this is, is those type, direct assessment, indirect

assessment methodologies that's already in integrity management.

And then, as far as if you look at the wording in there for cracking, and those type things, is if you have reason to believe you've got those issues, you do something about it. And that's exactly for those threats, what you would do under integrity management.

And then, the one that I'm hearing, and I think PHMSA, prior meetings have said, we would be opening to listening. And everything would be on patrols, and those types.

It's like I think what Mark said earlier, is that the number of those or some things like that. And then, the thing there, when we originally wrote it is, we said, well, this is in Class 3 and 4.

There's going to be a lot of one calls. You're going to be out there anyway, probably every day. Is, what can we do to make sure it's being checked?

Now, whether it should be weekly, or

monthly, or quarterly, you know, that's something I think, you know, we would definitely want to hear, see input.

And why, and then, if you go back and look, if you do the ECDA methodology, one of Sarah's concerns has been on material documentation. But when you go do ECDA you'll have to do what has been her concern on verifying your material. So, it all wraps in. What we've put in there had wrapped in.

And like Alan said, and we've all, we're open to listening to different ideas, and trying to get the best result. But I just wanted to give everybody an idea of how we came up with that. And again, we're all open to listening, getting better ideas down. So --

CHAIRMAN DANNER: All right.

MR. NANNEY: And anyway, before we took a break I just wanted to get that out.

CHAIRMAN DANNER: Yes. Thank you. I don't know that we're near break yet. The, but there were a number of factual questions that

were put forward. And I hope that you'll be able to get some information, and share it with the Committee members before we gather again.

Okay. So, the next item is fracture mechanics. Are we ready to move on? You want a break?

CHAIRMAN DANNER: Let's take a vote. Who wants a break right now?

(Laughter)

CHAIRMAN DANNER: All right. All right, everybody. Ten minutes, come back.

(Whereupon, the above-entitled matter went off the record at 9:45 a.m. and resumed at 9:59 a.m.)

CHAIRMAN DANNER: Okay, are we back on the record. All right, Sara.

MEMBER GOSMAN: So I really think this was a great discussion. I just don't want to lose track of the issues around material documentation and process, and the provisions as we go through each of these methods how that's going to apply.

So I think that we're going to come back after we've had some more data and talk about these sets of issues. But I just want to make sure, I'm sorry to sound like a broken record here, but just make sure that we continue to have that discussion, because it's, yes, it's a critical discussion for me.

CHAIRMAN DANNER: Okay. Excellent point, thank you. Chad.

MEMBER ZAMARIN: Chad Zamarin, Williams. I just wonder if maybe before the next meeting we could have a, I know we talked about a flow chart and I think that's difficult to do for the whole code, but maybe if we can map how 624 and the various sections tie to 607 and make sure that we're comfortable that we've got it wired the right way. I think that would be helpful for the next meeting. Thank you.

CHAIRMAN DANNER: All right. Thank you. And, Andy.

MEMBER DRAKE: I'd like to second Sara's comment. I really think that this, it is

very intricate what we're going through and helping could be very clear, flow charts would be good, but helping to be clear what kind of information we need that cues us back to 607 here, from MAOP.

I mean, we were talking about it. It's just deliberate in here. So I think that would be, I think that's important for that clarity.

CHAIRMAN DANNER: All right. Thank you. Any other comments? All right. So we're moving on now to fracture mechanics, Item Number 3. And I would like to turn to the folks behind me, see if there's any public comments regarding fracture mechanics.

MS. KURILLA: Hi, Erin Kurilla, APGA. Actually, I'm not making comment on fracture mechanics, but just want to make a quick comment to get it on the record because it's not listed as one of the public comment sections up there. It pertains to 619(e) that was included in the slide deck. And John brought it up on the side.

We, the industry, appreciate some simplification of 619(e). However, I kind of have a multi-folded comment here where I actually agree with Andy's earlier comment, that I don't actually think it's necessary to include 619(e) in the code. Really all it does is point operators to requirement in 624. I think if you are applicable to 624, you have to do 624. You don't really need a code section to point you there.

Furthermore, I think that the word notwithstanding is actually incorrect. And I'm smiling because people who know me best know that I get really obsessed with this word. Notwithstanding means, in spite of. So I read it and I'm not a lawyer, but I pretend to be one sometimes, that it actually says in spite of all the requirements in A through D you should do 624.

So I think that's the wrong word. And I will offer written comments after the meeting, but I believe the best way to actually resolve

all of this is in 619(a), to actually simply state that you are to set your MAOP via one of the 619 methods or via 624. So, just want to get that on the record and will file written comments to that effect. Thank you.

CHAIRMAN DANNER: All right. Thank you very much. All right, no other comments? All right. Let's, any discussion by the Members? Okay. Moving onto item Number 4, which is, help me out.

MR. GALE: We have no comments on fracture mechanics?

CHAIRMAN DANNER: No.

MR. GALE: Okay. Well then we could actually move on to discuss of the strengthening IM assessments, which was our next item on our agenda. But the sick house here to my right is trying to debate who has the voice that can talk to us.

CHAIRMAN DANNER: I'm sorry, I didn't hear that.

MR. GALE: Yes, the sick ones to my

right is trying to figure out who has the voice who can talk to us right now.

CHAIRMAN DANNER: Okay. Okay. All right, so item Number 3, strength of assessment requirements.

MEMBER ALLEN: The slide number is sitting different than mine.

Whoops. I'm controlling one, but not the others.

Okay just to, the other items we've got on the agenda for today as far as we can get. Number 1 would be 192.493, industry standards for ILI. And there's three standards there we will go through. 192.921(a) again, expand assessment methods allowed throughout. 192.923(b) and 927 is internal corrosion direct assessment. 923(c) and 929 is stress corrosion cracking DA.

Appendix F is guided wave ultra-sonics. And as we had stated earlier, that is trying to put into the code in Appendix F the requirements that's the 18 points that we've been using for ten years now for operators on the gas

side and the liquid side coming into PHMSA to be able to use like for case crossings and things like that.

And one thing only, on the guided way that was the criteria we came up there was based upon a research project we had. We worked with industry to come up with the 18 points that are, and to my knowledge there hasn't been an incident or an issue from using a guided wave the past ten years that it has been employed.

And then the last is 192.150, passage of internal inspection devices. We'll go through that. Well my control won't work. Okay.

The first item we'll go through in the strengthening standards would be the issue or the item to go through is the current regulations are solid on a number of issues of the impact the quality of effectiveness of ILI.

And based upon input that we've got from industry and others is we're looking at incorporating by reference three industry standards, API standard 1163 for inland

inspection systems qualification.

Also ANSI/ASNT for ILI-PQ, inline inspection personnel qualification and certification. And also NACE SP 0102 for inline inspection of pipelines.

We propose to also to clarify that operators must consider uncertainties in reported results in identifying and characterizing anomalies in 921(a)1, and to limit the use of direct assessment only the segments that cannot be inspected by inline inspection tools in 921(a)6. And the basis for this was a petition for rulemaking submitted by NACE in 2009.

Our next slide we'll go back through for these proposed changes. Comments that we got on record, this is a summary of them. Many commenters supported the proposed changes. Commenters suggested that the rule should reference the latest versions of the standards, which we agree.

And again, PHMSA agrees that the most recent versions of the standard should be

referenced. And we would handle that upon if it is agreed upon and voted upon to include these.

Recommendations of the standards should not be requirements, and PHMSA believes the recommendations in these standards are important to realize the safety benefit of the standards.

Also, a comment we got was that inclusion of a ASNT ILI-PQ standard applies to employees of ILI service providers. And the comment was it is unnecessary to incorporate it by reference since API 1163 requires that providers of in-line inspection services ensure that their employees are qualified according to ASNT ILI-PQ.

And PHMSA's comment on that was according to API 1163, the three reference standards have been developed to enable service providers and pipeline operators to provide rigorous processes that will be consistent to qualify the equipment, people, processes, and software that's utilized in ILI inspection.

The next item, or comment we got was exclude requirements contained in API 1163 which is the inline inspection systems qualification standard, Section 11, quality management system. And again, PHMSA believes that the required conformance with the quality standards will enhance pipeline plan safety.

Can you get the other slide to move? Something's happened. You're leaving it there? Okay.

The next comment that we got was ILI vendors may not be able to meet the 90 percent tool tolerance specified in the referenced standards. And our comment there was that the referenced standards are consensus industry standards. And PHMSA agrees that the industry committee that developed this standard, that the tool performance standards are needed and achievable.

Also another comment we got was to relocate 493 requirements to a different subpart. And you can see the subparts there that are

listed. Give me one second, I've got to get a cough drop.

I'll finish it.

I think we need a doctor.

(Laughter.)

MEMBER ALLEN: And I think Drue's come in and sit over here by me, and she's gotten it also. So, anyway PHMSA believes that 493 is an appropriate place for this requirement, since ILI would be required for both HCAs and non-HCA pipe segments.

Also, a comment we got was to restore the reference to B31.8S in 192.921. And PHMSA comment there is that we believe that the industry standards in 493 are better than B31.8S for this. And also we note that currently 921(a)1 only requires that operators follow B31.8S, Section 6.2 in selecting the appropriate ILI tools and does not address how the assessment is performed.

MEMBER ZAMARIN: Another Commenter stated that in 192.921(a)1, acknowledged that

some of the listed activities to verify tool performance were typically performed after anomalies are characterized.

PHMSA commented that we do not intend the language in 921(a)1 be interpreted outside the usual practices for performing the listed activities as outlined in standards incorporated by reference in the new 943 at 493.

A commenter disagreed with adding explicit requirements for a no objection letter for notifications of using other technology. And PHMSA comments that as we have in previously, that the no objection letter in responses to other technology notifications is the usual existing practice that has been implemented, what we consider, very successfully since the inception of the integrity management rule.

Thank you, Mr. Chairman.

CHAIRMAN DANNER: All right, thank you very much. So now let's take public comment on industry standards for ILI. Go ahead, sir.

MR. REYNOLDS: Good morning. My name

is Lee Reynolds. I'm with NiSource. We're primarily a distribution company, but we do own and operate approximately a thousand miles in transmission line in seven states.

In regards to the consensus standards, or the incorporation by reference in PHMSA in its, I believe it's a change in its practice on previously incorporating, especially new ones, of consensus standards into the regulations. Previously it had been that you shall follow the recommendation, I'm sorry, follow the requirements.

This go around in the last year or so, especially with the gas transmission storage rule as well as in this particular rule, is now codifying that to incorporate that the operators are to required to follow the shall statements as well as the recommendations, which is concern because I'm probably one of quite a number of folks in the room that are working on the various consensus standards organizations such as NACE, ASME, and others. And these typically standards

are international standards as well.

The concern on these, my concern specifically, is in regards to with PHMSA moving towards now incorporating into the federal code the should statements, my concern is is that for those who participate on the consensus standards, will there be an effort that may be to those folks really, really strongly think about how much should statements now should be incorporated or placed in those consensus standards. Probably in concerns of that those eventually will be, you know, incorporated into the US Code.

So I think we may find there may be some concerns around limiting then maybe the effectiveness of these consensus standards on a path forward basis. For example, in regards to the API, the three documents that NACE, the ASNT and the API documents, the three for specifically for 192.493 that's being proposed, if you tally up there's 234 shall statements. So those will be and I think industry overall are in agreement that those would be incorporated as must be

required.

But historically the should statements is left to the operator what makes sense, you know, for their operations. In that case, for these three documents there's a total of 231 should statements.

So that is a concern now, especially dealing with our contractors, because these standards are meant to provide those flexibility of the shoulds based on certain situations that are applicable to their systems.

Also from an industry perspective, it's not clear on how PHMSA it will be treating the may statements. In these three documents there's 179 may statements. So would PHMSA be considering those to also be considered recommendations. Thus, we shall follow those.

So I urge the Members of the GPAC Committee strongly consider the path forward on incorporating the, you know, the mandates of all the recommended statements in these consensus standards.

Again, primarily is the concern is that we will start to see maybe really people thinking at the table when their writing these, around placing those should statements on a path forward basis into these consensus standards.

Thank you for the opportunity for the comment.

CHAIRMAN DANNER: Thank you. Others who wish to address this topic?

MR. KIVELA: Hello, Rick Kivela with Enbridge. I wanted to express a concern that was raised yesterday about a --

CHAIRMAN DANNER: I'm sorry, could you speak more closely to the microphone?

MR. KIVELA: Yes. I wanted to express a concern that was expressed yesterday as well about the limitation on using direct assessment to non-piggable lines. When it comes to stress corrosion cracking direct assessment as was commented yesterday, it's a very valid tool for screening lines that have never experienced stress corrosion cracking before, but they are

susceptible to that threat.

So I would encourage PHMSA to consider the use of SCCDA to still be a valid assessment method. This is especially concerning given the advisory bulletin that PHMSA issued earlier this year on deactivation of threats.

In that advisory, it stated that the threat of SCC should always be considered active, even though that would cover pipelines that consensus standards have identified as not having the SCC threats.

So given the proposed requirement in the rule and that advisory bulletin, operators would be forced to run SCC ILI tools in lines where the threat doesn't even exist. Thank you.

CHAIRMAN DANNER: All right, thank you.

MR. OSMAN: Good afternoon. C.J. Osman from INGAA. Couple of comments related to the use of ILI here. I just want to make sure that in looking at this rule, PHMSA allows operators to select a tool appropriate to

evaluate the specific threats to the pipeline that are of concern.

And specifically, PHMSA is proposing that the ILI tools that are used to comply with 192.921(a) be capable of detecting material, cracking, crack like defects, hard spots of cracking, as well as corrosion, deformation of mechanical damage.

This is really a comment related to just drafting, but words do matter. The way that a propose regulatory language is drafted, it can be implied that an operator must utilize an ILI tool or a series of tools that are capable of detecting all of these threats in all situations.

Currently, operators select ILI tools to identify the specific threats that are of concern for the segment, for the specific segments in question. So I want to make sure that is retained and discussed by the GPAC.

Additionally, PHMSA is proposing in this section that persons qualified by knowledge, training and experience, must be used to analyze

the data from the ILI tool. Of course, data must be reviewed by knowledgeable individuals.

However, we're a little concerned that PHMSA's proposed language under 921(a) here is duplicative and confusing in light of existing OQ requirements in IM under 192.915, as well as a proposed revisions to 192.423 that are also being discussed in this section.

So I just want to make sure there's clarity there and there's one qualification requirement and not different requirements in different places. So thank you.

CHAIRMAN DANNER: All right, thank you.

MS. BYRNES: Good morning. I'm Corinne Byrnes from National Grid. I have a comment relating to limiting the use of ECDA as an assessment tool to only those pipelines that don't, that are not ILI capable.

I spent about 13 years of my career in National Grid performing and overseeing ECDA assessments throughout our territories.

I believe a lot of this recommendation comes from the NTSB gas transmission pipeline safety study which stated that unlike ILI and pressure tests in which the integrity of the entire pipeline segment is examined, direct assessment methods, including external corrosion direct assessment, internal corrosion direct assessment, and stress corrosion cracking direct assessment, says only the integrity of selected pipe areas where the operator suspects a problem.

Therefore, direct assessment provides information only about the threats that the operator is specifically looking for and locations where the threats are suspected. And it also states choosing to use direct assessment for a pipeline segment therefore requires justification for assigning of very high risk to corrosion threats.

As we know, this is really not entirely true. ECDA, in particular, is a four step process which can be and is typically done over an entire pipeline segment, not a specific

area.

ECDA is a four step process which includes pre-assessment using knowledge about the pipeline and the history of the pipeline, historical data, feasibility, survey records, indirect inspections using highly accurate and sensitive inspection tools to do an overland inspection of the entire segment. Direct examination of locations where you suspect that there may be an indication.

And this to me is the step that the NTSB report was calling out. And I think there may have been a misunderstanding about how this tool is used.

And then a post-assessment, which includes analysis of data collected to assess the effectiveness of ECDA and to determine reassessment intervals. So I request that the Committee review that section under 192.921(a).

CHAIRMAN DANNER: Go ahead, sir.

MR. BUBENIK: My name is Tom Bubenik at DNV GL. I wanted to comment on one of the

slides that talked about the confidence interval for inline inspection tools at a target value of 90 percent.

Ninety percent is an aspirational goal. It's one that many of the tools that are out there today would not meet. Some would, but many would not. I think you've already got in the planed regulations the requirement to take into account the tolerance on the inspection tools, and I would encourage the Committee to maintain that, taking into account the tolerance, but to loosen the requirement for 90 percent confidence.

CHAIRMAN DANNER: All right, thank you. Any other comments? Okay, I'll turn to the Committee. Any discussion on industry standards for ILI? All right, Andy?

MEMBER DRAKE: Andy Drake with Enbridge. I think we heard some good comments from the public. Particular couple that resonated with me was on slide 118 you were talking about can't use DA on piggable segments.

I do think the SCCDA issue needs to be deliberately considered on how to create caveat for that.

The SCCDA in my opinion is working more reliably than in my inspection tools on DA for gas pipelines. And I think in combination, I think Rick mentioned that in combination with the advisory bulletin we got, we must consider SCC active everywhere. We know that's not right. And we need to create the technical caveats and criteria around when SCC is active, which is very clearly recognized in industry standards.

So the bulletin kind of throws everything into the pot, and that's not helpful. We're doing now what we would be required to do SCC investigations on pipe that we just put in yesterday without the pipe coded pipe. That's not constructive. And so I think we need to just dial that in a little bit.

I do appreciate the comment about 90 percent tolerances. I just think we need to be deliberate with that, which you know not all

tools are at 90 percent on all threats.

And so I think we need to be a little bit more careful as we marshal a broad sweeping threshold of tolerance for all tools. But in general, very supportive of this direction that we're going. I think the standards are a good step for us.

CHAIRMAN DANNER: All right, thank you. Sara?

MEMBER GOSMAN: Sara Gosman. So on this set of issues, I just want to make the point that whenever we consider these standards, we need to think about whether the public has access to them.

And so in just reviewing this, I note that the API standard that we're talking about, 1163, is available on the web site for $131.00. And the ANSI standard for 48 for non-members. The NACE standard is available to the public in their reading room.

And I think I'd like to make a process point that, you know, if we're going to be

considering standards like this for adoption in the rules, it's not just the adopted standards that matter for public understanding of rulemaking, it's the proposed ones.

In fact, I would argue that maybe it's more important because that's the set of issues where the public comments. And I think it's critical that we have those available.

And then as to the question of requirements versus should, so I think this points out a difficulty in adopting these kinds of standards. That is they're really not written as enforceable standards in the way that a regulator would write them.

So in terms of how we might address that, I think the thing to do would be to go to the standard and individually decide on the provisions that are important to the safety goal instead of adopting it wholesale including terms like should, because even when you say these are requirements in the regulation, when you go up to the text of the standard and it says should, I

think it's just confusing as a regulatory matter. Thanks.

CHAIRMAN DANNER: Thank you. And I had a question about that too. It's really a legal question. Can you incorporate by reference a standard that is not publically accessible except at costs? Would that meet the requirements of administrative law? So I would pause at that question.

Okay, Cheryl and then Chad.

MEMBER CAMPBELL: Thank you, Mr. Chair. I wanted to make a comment about the use of direct assessment and having done, and I'm just going to state publicly that I tend to have a preference for ILI for a variety of reasons, but recognize its limitations as well as the limitations of DA.

So I think my comment is really more around encouraging us to not necessarily take tools out of the toolbox, but maybe provide clarity where needed around when those different tools might be applicable or pointing people,

right, in the direction on how to evaluate that.

I think it's, you know I've been through a lot. My company has been ILIing since 2008, and I spent more time at an interstate pipeline prior to that where that is what we did regularly. It's interesting the things I've seen throughout my career, right, where we found and not found with the different tools.

So they have continued to improve. I have seen it happen more rapidly in the last five or ten years, which gratifies me greatly. But, you know, I'd like to have more tools in the toolbox, right, with maybe some standards or some help for operators to understand when the right tool should be used as opposed to removing a tool from the toolbox.

AS to SCC and SCCDA, I agree having seen some interesting readouts from use of those tools that suggest that I have cracks that are an inch wide in my pipelines when clearly I did not. You know we got a ways to go on that.

And again I appreciate how quickly the

technology is moving forward, but, you know, the assumption that it's active everywhere is a difficult one for operators to deal with on a regular basis.

So you know, I think we have to find an interesting balance. We need to allow the technology to move forward. We've also got to be clear about operators not missing those threats, right? And not forgetting about certain threats on certain pipelines.

So I think it's a tough balance to write in code, Alan. I really do. I get the challenge, but again would encourage us to have a broad view of the tools in the toolbox.

CHAIRMAN DANNER: Chad.

MEMBER ZAMARIN: Chad Zamarin with Williams. I think my only comment is I would ask that we look at adopting the no objection letter language that we approved in 192.607 in this section as well. Thank you.

CHAIRMAN DANNER: All right. Mark?

MEMBER BROWNSTEIN: So the questions

with regard to adopting the standards by reference has got me thinking a little bit. What happens, just as a factual matter, what happens when an underlying standard that's being referenced is changed by that body?

So for example, we were you know referencing a certain API standard or for that matter an ASME or whatever, what happen when that standard is changed?

CHAIRMAN DANNER: So I can tell you at the state level, you do incorporation by reference at a regular period. So you're constantly updating. So on an annual basis we have a rule making for incorporation by reference.

So if we are referencing a CFR and that CFR changes, we have adopted the new CFR on an ongoing basis. But I'll turn it over to John and John can address that for PHMSA.

MR. GALE: Sure, sure. Thank you. John Gale, PHMSA. Mark, what we do is we adopt a very specific addition. We adopted, for example,

addition five for a given standard. We can't just adopt a standard and any subsequent additions. We're not allowed to do that per federal registration requirements.

So if there's a revision, we have to go through another rule making exercise and propose and then adopt it. I'm going to real quick, I'd like to discuss real quick the availability issue because we have a requirement under Section --

I'm sorry. Regarding availability, we have a requirement actually in our statue under Section 24 of the 2011 Act to make statements available to the public for free. And we do that when, ever since the institution of that requirement.

We either make it available on the internet. We make it available through what we call a take-it take-it program where you can call us up and get access. We work with the SDOs to make most of these available. And in some cases, if we have to, we'll get copies.

But we do, when we publish rules at the proposal and at the final rule stage, try to make them available, or make them available to the public for free of charge.

MEMBER BROWNSTEIN: Okay, thank you.

CHAIRMAN DANNER: So let me follow up on that because I think this morning we were referencing particular standards. My guess is Sara went on the internet to try to find them and what came up was you could have it for $85. How does the public know that it can get around that $85 charge by going directly to you?

What kind of outreach, because I don't think that the standard setting organizations are letting people know that because they like the $85.

MR. GALE: Sure. Again, John Gale again, PHMSA. Actually in the rule, you know we'll actually have a section now in the rules that, an IBR document and we'll talk about availability. And on our web site we talk about availability and where folks can get to that

information and try to point and direct them to that information.

CHAIRMAN DANNER: Okay. Sara.

MEMBER GOSMAN: So yes, and I think I'm very glad that the Pipeline Safety Act has a provision in there that requires standard setting organizations to make these standards available once they're adopted.

But the issue here is that this is still in proposal. And so as far as I, I mean I went on the PHMSA web site. I looked at your list. You list is of the, of IBR. And it doesn't include these proposed ones.

So I think that that is an issue that perhaps isn't dealt with in the statute. I completely take your point that, you know, somebody could individually contact you and get a piece of paper. I just think that's not really how the public sort of engages with these types of processes anymore.

And if they can't find it online, they're probably not going to be able to find it.

And I thank that's, just as a matter, I mean, this is an ongoing issue in the administrative law community about whether, you know there is fair public notice and comment as it relates to standards that are not publicly available.

But at the very least, I think, you know, if the standard setting organization knows that their standard is about to be adopted, that's a good thing for them to have it adopted.

They should make those available to the public for notice and comment. And it shouldn't just be the public comment period, you know, of the 30 days because we're still discussing this particular rule. It should be through this process as well.

MR. GALE: And thank you.

CHAIRMAN DANNER: John?

MR. GALE: Yes, John Gale again, PHMSA. Thank you again for that information. We're committed to making those standards available, not just after the final rule, but also at the proposal stage so the public does

have the information they need to effectively comment on those rulemakings.

So I guarantee you, I'm going to personally check into availability of those standards regarding this rule and at the proposed rule stage. And if it wasn't available, we're going to try to make them available as quickly as possible.

CHAIRMAN DANNER: All right. Alan?

MR. MAYBERRY: Just to reinforce that point. Yes, we'll take a look at that. I think that's very important, especially as we're in the proposal stage.

Just a general comment, taking a step back on what we're trying to accomplish here though. Related to EDCA and the different DAs, you know, really what lead us here, here again is an accident where an operator used or relied on ECDA where they probably should, they should have relied on something else. And that's really what we're after.

You've got to use the right tool in

the right location. Our goal here is not to limit the ability to use the best tools. So we've heard comments, we've gotten comments on the docket as well and we'll take that up for consideration as we come back, you know, with something to vote on here.

CHAIRMAN DANNER: All right. Thank you. John your card is still up. Are you? Okay. All right. I see no further cards up. Are we ready to move on to 921(a)? All right.

Expand assessment methods allowed for IM. Are there any public comments on this provision? Oh, are we going to have a briefing on? We're done with ILI for now. Is there --

MR. MCLAREN: Excellent. Within the strengthening assessment requirements, the second item is to expand assessment methods allowed for integrity management in 192.921(a), 506 and Appendix F. The issue is the current regulations are silent on the use of certain integrity assessment methods that are acceptable assessment methods.

PHMSA proposed in the MPRM to add the following methods as allowable assessment methods, spike hydrostatic pressure test, excavation and in situ direct examination, guided wave ultrasonic testing conducted as described in Appendix F, and the limit the use of direct assessment to lines that are not piggable.

The basis is that the operator should be able to take credit for integrity assessments conducted using methods that are not explicitly listed in the current rule without the need for submitting a notification.

One commenter proposed that language under 921(a)1, which is to require persons qualified by knowledge, training, and experience analyzed ILI data, is duplicative and confusing in light of existing of operator qualification regulations under IM 192.915, as we've heard commented also here today.

And PHMSA agrees that the language in 921 regarding qualification of persons is duplicative with existing code requirements in

915(b) and proposes to withdraw this duplicative language.

Another commenter requested that clarity on apply one or more of the following methods for each threat to which the covered segments is susceptible. At least one assessment may be required for each threat. Current proposal would virtually mandate the assessment of all nine threats.

Clarify that every ILI assessment does not require crack tool, and that tools are driven to be identified or driven by the identified threats under 921(a)1 and 937(c)1. PHMSA's response is that the list of allowed methods in 921 does not drive with which methods must be used in any particular circumstance.

Selection of assessment methods is identified as part of the operator's threat assessment. If the pipeline is not susceptible to a particular threat, then the operator is not required to conduct an integrity assessment for that threat. The proposed rule would not change

that approach.

Another commenter stated that PHMSA's proposing to add requirement on the detection of anomalies which many ILI tools cannot meet. For example, hard spots, environmentally assisted cracking, and girth wells.

PHMSA's response is that the existing regulations already require an integrity assessment for all threats to which the pipe is susceptible. There is at least one integrity assessment method considered suitable for any threat, and that is hydro testing.

A commenter supported a spike hydro test only for time definite cracking threat, such as stress corrosion cracking. The requirement for spike hydrostatic testing for materials and constructural related defects should be deleted. A pressure test to 1.25 MAOP for class one and two and 1.5 MAOP for three and four is adequate to address those threats.

PHMSA's response is that the notation in proposed 921(a)3 about spike hydro test being

suitable for crack defects does not require spike hydrostatic test in any situation. Rather, it merely communicates the situation where spike hydro test would be suitable such as any crack defect has the potential for growth during pressure testing.

Spike hydro testing is an integrity assessment method for any crack or crack-like threat, and the rule would not require a spike hydrostatic testing exclusively to assess cracking threats.

Another commenter recommended striking the language in 921(a)7 regarding the no objection letter. Concerns with efficient timely reviews or allow an operator to proceed with the new technology if a no objection letter as noticed to PHMSA is not received within 45 days prior to the plan to use the other technology.

PHMSA commented again that the issuance that the note objection letters is consistent with the longstanding practice for notifications under integrity management.

An industry commenter objected to restricting direct assessments to only non-piggable line segments. However, CPUC, the California Public Utility Commission, commented that direct assessment must always be supplemented with other methods such as inline inspection or pressure test.

Further, NTSB urged PHMSA to ensure the regulations that result from this NPRM address all elements contained in safety recommendations P15-18, 20, and 21 regarding upgrading lines to be piggable and prohibit direct assessment.

PHMSA responds that removing the restrictions on the use of direct assessment only if the line is not piggable would not be responsive to the intent of the NTSB recommendation. Direct assessment should be considered only when better methods are impracticable.

PHMSA supports the NTSB goal of increasing the percentage of lines that are

piggable and minimizing the use of direct assessment, but believes a mandatory prohibition on the use of DA would not be cost effective. Thank you, Mr. Chairman.

CHAIRMAN DANNER: All right, thank you. Now I will entertain public comments. Are there any commenters on this section?

MS. KURILLA: Hi, Erin Kurilla, APGA. I just want to make a comment on that last slide concerning direct assessment. It's the industry's position that, and I'm kind of reiterating a couple of the other public comments from the last session, is that DA is an excellent tool when identifying the threat of corrosion on a pipeline.

The concern that you see trying to be summarized by the public, written comments, is around the language that PHMSA used in 192.921, and also 710 when we get to the other assessments outside of HCAs, is that the operator is required to eliminate the possibility of using any other assessment method, and pressure testing is always

an assessment method.

And so each and every time an operator wants to use DAs specifically to find corrosion, they would have to prove that pressure testing is impracticable. And that just puts an odd burden on an operator to prove their use of a great tool to identify a specific threat. I don't think that's the intent, and I like the last bullet from PHMSA.

But, just want to put that on the record. That I think we agree with PHMSA's intent, but just are little concerned with the code language. Thanks.

CHAIRMAN DANNER: All right, thank you.

MR. OSMAN: C.J. Osman from INGAA. Just two quick comments, first one related to 192.506, methodology for spike testing. We recommend that the spike test pressure be conducted to a minimum of a hundred percent SMYS as opposed to 105 percent of SMYS as currently proposed.

There has been, as was mentioned in previous days, there's been several opportunities for research on this topic that have validated 100 percent minimum SMYS requirement.

Dropping the minimum SMYS percentage from 105 percent to 100 percent, while the minimum impact on the margin, but will drastically reduce the likelihood of pipe damage during the spike test and increase the mileage that could be included in a single test, therefore increasing the effectiveness of that tool.

Also in this section, PHMSA should specifically address time dependent cracking as the threat managed by spike testing, such as stress corrosion cracking.

And then separately on Appendix F with respect to the use of guided wave, current industry practice employs the longitude in the signal only as a spot check to the exposed areas where there is a collar is installed as opposed to in all cases.

PHMSA has proposed procedures that would require both the torsional and longitudinal in the signal to be used, and that could inhibit the use of guided wave. Also, PHMSA has prohibited the use of guided wave on shorted casings. We think the GPAC should discuss that because there's value in using guided wave on shorted casings. So, thank you.

CHAIRMAN DANNER: All right, thank you. Other comments? It appears not. Could we open the Committee conversation? Andy?

MEMBER DRAKE: Andy Drake with Enbridge. I think a couple of comments that resonated with me. First of all, this is very good section. I don't have a lot of comments here. I think just maybe some fine tuning.

We've certainly had a carpet bombing of discussion around spike testing. Not to continue that, but I think that it's relevant to, and we talked a little bit about this yesterday, be cautious about a required 105 percent hydro-test. I think that you're looking for effective

separation, if the operating stress is lower than 72 or some percent, you're going to get the separation.

You do have to deal with things like elevation in the real world, so you deal with the hydrostatic head. If we don't, 105 percent is going to be above any test that this material has ever seen. So that's an effective test. A hundred percent is also going to be above anything these pipes have seen.

It just starts to create a little bit more practical solution. I would encourage PHMSA to look at how do you create some caveats to consider that separation and then deal with elevation a little bit more practically.

I would also caution unintended consequence. A whole time of 30 minutes. I know you need to stabilize a test to make sure you haven't happen to have any significant pressure problem, like a leak or a rupture. But the last thing you want to do is hold that pressure for very long, because what ends up happening is you

start growing sub-critical time dependent defect, or time independent defects, or time dependent defects.

And that's not what you want. You don't want to grow the sub-critical cracks. That's where you actually create all these things of making this situation actually worse. So you want to grow them, get them out of there quickly and then drop the pressure down.

I think there's other studies that are out there. I know Tom Bubenik's out there from the corner, him and, but ten minutes is a little bit more of an industry standard. It really is just trying to avoid an unintended consequence.

So I'd just encourage trying to look at that. I think there's been a lot of research done on that and I think that would be actually quite constructive.

And the comment about guided wave UT is relevant. That tool is actually very important in our tool belt right now to deal with unpiggable segments, and we need to be able to

look inside road crossings and things with this tool.

Not having that has resulted in a large number of special permit technical application requests. And PHMSA, I know you guys are aware of that. You certainly have that in your inbox quite a bit.

But key to make that technology practical is look at all those waivers and technical applications that have been made over the last couple of years and try to incorporate them into the standard as best as possible and make this really practical, not just a perfection exercise because you're going, what if you do that we're going to end up with more technical waivers being submitted because we can't follow the standard. So I think that's just a pragmatic comment.

CHAIRMAN DANNER: All right. Sara?

MEMBER GOSMAN: Sorry. I wonder if PHMSA could address two issues that I've heard that I'd just like more information on. One is

the issue of spike testing as it relates to damage to pipelines in the 105 percent. And then the other is the issue is whether there are benefits to direct assessment when there are piggable lines.

CHAIRMAN DANNER: Okay. So we're holding our list of questions. So, Chad?

MEMBER ZAMARIN: Well, I can help also with that maybe. But my one suggestion on this section is 192.921(a)3 on spike testing. You might want to consider, like you did with guided wave, just keeping it as a reference to 192.506.

I think the, I get a little concerned with the kind of implication of kind of listing all these potential threats that are trying to be addressed. And when you read 506, I think it does a good job of talking about time dependent threats being, you know, something that stress corrosion cracking is typically used to manage.

So I just think it might make better sense not to kind of do that in two different places and potentially send mixed messages.

Maybe just building on what Andy described, there are two kind of practical issues with spike testing. And he said it but just to provide some context.

There is an upper limit at which you would want to test the pipeline. You don't want to go very far beyond yield because you can enter plastic deformation, which is permanent damage to the pipe. So what you're doing is you're going to above the specified yield of the pipe, but you have to make sure you don't go beyond its actual deformation point. You don't want to expand the pipe. You don't want to cause damage to the pipe.

So what we do is we set a minimum test pressure, and then we basically have to design the length of the test section to ensure that the lowest elevation point, because of the head pressure of water, it's going to see a higher pressure. So you need to make sure that the lowest elevation point doesn't witness a pressure that's too high.

So you're setting the whole test section for a minimum test pressure, which will be experienced at the highest elevation point, and then you're designing the length of your test section to ensure that you don't exceed some upper bound at the low elevation point.

And what that means is when that limit is narrow, so if 110 percent is your max and 105 is your minimum, you only have a five percent band within which to design a test section. And what that means is, you need more test sections.

You have to cut up your pipe more frequently, you have to deal with water management, you have to dispose of more water. If you have a larger band, you can have a longer test section because you have a larger variation due to elevation of the pipes.

So that's why it is important. We do worry that by going to 105 percent as a lower bound, you really can't change the upper bound. We typically try to keep the upper bound, you know, at around 110 percent. It significantly

limits the amount of flexibility you have for test section length. So you'll end up cutting up your pipeline into multiple test sections.

I hope that makes sense. Typically, 100 percent is a commonly used approach. But I think Andy's point also is, if a pipeline is operating at 40 percent SMYS, I'm not sure it's valuable to take it all the way up to 100 percent SMYS. I mean you can, on a 72 percent SMYS pipe, you're you know that's typically how we design it.

But I don't want to over complicate this section, but you might want to leave some flexibility. The goal is to achieve a sufficiently high enough pressure to expose defects, get off that pressure quickly because what Andy described is you don't want to grow the smaller defects that aren't failing at that pressure, because that's why it's a spike test. You want to go to a high pressure for a short duration.

If there's anything that would fail at

that pressure, have it fail and identify it. But you want to get off that pressure as quickly as possible because you don't want smaller defects being exposed at a high pressure for a long time and starting to grow.

So that's the theory behind spike testing. So the two issues of trying to create as much of a window as possible to better design test sections and then not spend a lot of time at that higher pressure.

And you know get off that higher pressure back down to, what we then do is go down to the standard eight hour test where, you know, we monitor for leaks and for other, you know, other potential issues on the pipe. I hope that helps.

CHAIRMAN DANNER: All right. Andy?

MEMBER DRAKE: Thanks, Chad. That was great. That's kind of frightening that you have two metallurgists just sitting next to each other, but you know. But I think it's a great question. It's been something that's been

deliberated over a lot, a long time.

I'm a big fan of high pressure testing and setting a big margin. I just think that becomes a practical limit, especially when you deal with elevation. It becomes literally so tight a band because you're up against the absolute strength of the pipe.

I have no ability to deal with elevation change, which makes it impractical. I can't do that. So I think that's part of it. The other piece is the spike test. I know a lot of people have heard about this. Why is the spike test.

There's a family of defects that you look at that will fail time independent. So as you bring the pressure up, they just fail it out anytime. They go right to failure.

The ones that you want to watch, which is why you don't stay up there, is there's a whole other series of sub-critical defects that grow but stop. But when you de-pressure, the front end of that crack collapses and that little

tough spot that stopped the crack is now gone.

So when you bring it back up in operating pressure, it now can start moving again at a lower pressure which is called the pressure reversal. And that's what we're trying to manage here because when you're dealing with cracks there's a whole family of them out there. Big ones, little ones.

And that's why you don't want to hold it up at that pressure. You want to get away from that pressure as quickly as possible to avoid the unintended consequence of these little ones growing and stopping, but now they're just bigger than they were before.

And that literally is the mechanics of the test. And so both of those things together create the concern about creating a problem, an inadvertent problem damaging the pipe. People said damaging the pipe during the test. That's explicitly why that test was designed to do that.

CHAIRMAN DANNER: Okay. So, let's see, there's a slide up there. Shows where the

105 comes from. One of the questions that I had is there's a slide 131, or it's 131 in my book, it's different up there. But it says that DA should only be considered when better methods are impracticable.

And the question I had is what kind of showing does and operator have to make that other methods are impracticable before they can start DA? What kind of record keeping, or what kind of burden of proof do they have?

And I see Steve's card is up. So I don't know if you want to answer that one or if you want to answer the one before.

All right, go right ahead.

Just don't lose sight of the one I asked.

MEMBER ALLEN: Bobby, put 59 back. I just wanted to give a little comment there. Is this slide again, well hold on until we get it up, is this slide here shows and number one, if you've got cracking issues in weld seams and you look at the red line, the 105 percent in, and if

you go on over you'll see a number that's a 0.8 and a 1.0. And you know your normal 90 percent or 1.25 test would be right in between the eight and the one.

And the point is, is if you had a test there, that test is not going to be high enough to effectively test for most of the defects you would see in low frequency ERW. And the key is, is what is that sweet spot. Sometimes, and the reason at the time we selected to come out and with the 105, if you look, it covers the majority of the issues.

Now realizing, like we had said yesterday, is depending upon the type defects threats you're looking at, we would expect, and what Chad or Andy or a combination of both would say, in the 100 percent or 1.39 times MAOP or 1.5, you know, I think we all discussed all of those yesterday, would be the flip side because if you got pipe that's operating at 50 percent SMYS, there's really no reason to bring it up to 100 percent or 105.

So what we would do is go back and adjust that language to take care of those different type parameters. As far as, switching, as far as the time interval, I've seen research anywhere from ten minutes, fifteen minutes to an hour.

The latest that we got on the low frequency ERW is that there's not much difference in the 15 minutes to an hour, or the 30 minutes to an hour, but the key part is whether any of those that need to be stabilized before it starts.

So I wouldn't agree with three minutes or five minutes or something like that. But we're arguing around the edges or we're talking about the edges. We're not very far apart is my point on what everybody's saying.

So, and like we said yesterday, we'll go back and look at this and when we come to the next meeting, we'll do just like we've done at the other meetings and propose something.

CHAIRMAN DANNER: All right, thank

you. Any other cards up? Sara?

MEMBER GOSMAN: So in looking at 506, there's an alternative technology or alternative technical evaluation process. So I'm just wondering if some of the concerns that have been raised here can be evaluated through that process, if that was the purpose of that or there was another reason for that?

CHAIRMAN DANNER: Yes, Steve?

MEMBER ALLEN: We've tried in most of these areas is it's like the congressional mandate and also NTSB, is to be open to other technology. It's just to give the avenue that we don't have to go through a special permit type process.

That if an operator, if a service provider comes to an operator with a better methodology for us to be able to review it, and timely get back to the operator. So that's why that's in there.

CHAIRMAN DANNER: Go ahead. Sara?

MEMBER GOSMAN: Okay, so just to

follow up on that. It seems to me that there might be some technical issues that need to be worked through in the language.

But to me, what this provision looks like is exactly what I would hope, which is a set of requirements that would work, hopefully, in most situations and then a catch all provision that says if it doesn't work, come to PHMSA, give us your information. And if we have a problem with it, we'll object. So I think that's a good system.

CHAIRMAN DANNER: All right, Steve?

MEMBER ALLEN: And we're doing that as we'd said yesterday, in other areas like using the emap tools in inline inspections. There's been several operators to come to us that we were through or have worked through using those on their systems.

And methodology is what I, what it allows us to do and it's similar to what we did on guided wave UT, we actually go through that process and get what we're going to put in the

code or proposed to be going into the code later based upon going through working through the issues individually with each operator based upon their threats and how they plan to use the technology.

CHAIRMAN DANNER: Okay. Other comments on this topic? Sara?

MEMBER GOSMAN: The other question I had related to direct assessment was that, again I heard, if I understood the public comment correctly, there was an issue around whether we should be using direct assessment in piggable lines or not because of some benefits. So I just wondered if PHMSA or anybody else here could address that issue for the record.

CHAIRMAN DANNER: Cheryl, do you want to address that or --

MEMBER CAMPBELL: Sure, I can provide a little bit of insight on that. ILI tools are really great at a point in time. So, you know, when you run the tool, here's what the health looks like of that asset.

DA is really good at external corrosion, for instance and it can give you some insight and some guidance into where you might be developing the corrosion problem whereas the ILI might not be able to tell you, you know, where that might happen in the future.

So it's a little more forward looking in that respect as opposed to a point in time. So the way we view them is at times very complimentary, depending on what the threat is for our asset.

So they can be used, and I have frequently used them on the same pipeline. So it's, you know I keep going back to it depends on the threat, right? The right tools and the tool box for the threat. But I am also sensitive to Alan's comment about, you know, making sure you're using the right tool and you've evaluated the right threats for that asset.

And that's why I made my earlier comment about providing some guidance about when to use different kinds of tools for different

kinds of threats.

CHAIRMAN DANNER: Any other comments on this topic? All right, Alan.

MR. MAYBERRY: Did you say, yes, from my perspective ECDA is a good tool for if you're looking for corrosion, but it's not a good tool if you're looking, if you have a seams threat. And it's kind of what put us here is that issue there. In particular, you need to consider your threats before you rely on --

CHAIRMAN DANNER: You had to speak into the microphone, so. All right. I think that's all on this topic. Are we ready to move onto ICDA?

All right. Go forth.

MR. MAYBERRY: Got it. Okay. Topic C of strength and assessment requirements deals with internal corrosion direct assessment in 192.923(b) and 927. The issue is that the current regulations are silent on a number of issues that impact the quality and effectiveness of internal corrosion direct assessments.

PHMSA proposes to incorporate NACE SP 0206 by reference and supplement the NACE standard to address issues observed by PHMSA. The basis for this was a petition for rulemaking submitted by NACE International dated February 11, 2009.

For the MPR in comments on this, one recommendation was that the standards should not be mandatory. PHMSA says that recommendations in the standard are items operators should do and PHMSA seeks to codify that expectation as applicable.

Another commenter said that to include, that PHMSA should include reference to ASME B31.8S Section 6.4 in referencing Appendix B2. PHMSA responds that the ASME B31.8S is currently referenced in 192.927, but the NACE SP 0206 is a more comprehensive standard.

And PHMSA believes incorporating the NACE standard will provide improved and more consistent internal corrosion direct assessment results.

A commenter recommended that all proposed language be deleted and that an ICDA be conducted in accordance with NACE SP 0206. The version approved in 2006 with only those additional items that are currently contained in 192.927. PHMSA proposes to supplement the NACE standard with additional requirements to address specific issues that could adversely affect ICDA results.

Commenter recommended removing the proposed requirements to notify PHMSA 100 days before performing ICDA and clarify what is required in the notification.

PHMSA comments that for internal corrosion direct assessment, notification is only required for systems with electrolytes. Since the NACE standard only applies to dry gas system, notification in a procedural review is important to assure appropriate controls are in place when ICDA is applied to dry gas systems that contain electrolytes.

And this would be another technology

notification in accordance with 192.921(a)4 or 192.937(c)(4) and the contents of such notifications would be the same as currently required for other technology notifications.

Commenter recommended removing the second half of Paragraph C related to ICDA region identification. Commented that using descriptive wording requiring NACE SP 0206, defined DG-ICDA Regions prohibits operators from using additional criteria specific to the operator.

And PHMSA comments that the supplemental language on ICDA Region is intended to insure that each HCA within an ICDA Region as defined in the NACE standard has an integrity assessment performed.

A Commenter commented supporting the use of pipeline specific data, but stated there are many cases where conservative assumptions could be applied to certain list critical data elements. Also recommend that proposed language about the model validation be deleted and current 192.927(c)(4)(ii) language be restored.

PHMSA responds that model validation and data validation are important aspects of a quality integrity assessment. Thank you, Mr. Chairman.

CHAIRMAN DANNER: All right. Now we'll open it up to public comments. Do we have any public comments on ICDA? Apparently we do. Go ahead, sir.

DR. EAGAR: My name is Tom Eager. I'm a faculty member at MIT, one of the last people at MIT who teaches structural materials and doesn't study DNA.

One of my concerns as I read these reports is I'm seeing Charpy values of one, two, and three, and it seems to me that PHMSA should request a second significant digit when they report values that low. Anyone who studies pressures knows that when you read a gauge you don't read within the bottom five percent or above 95 percent because the gauge doesn't read accurately.

If someone tells me the Charpy value

is 2.2, then I don't know if that's one-half or two and a half. And that's a pretty big difference. If I'm going to be doing integrity assessments and calculations based on the measured values, I should measure them more precisely. It's not hard to do, you just need to use a smaller machine.

You don't use a machine the size of my desk, you use a desktop impact tester. And those are commercially available. And if we know we have toughnesses, or fracture energies of this value, that's what we should be using. We're using the wrong machine.

Having said that, we're also not necessarily in these models using the right parameter. The correct parameter back 110 years ago was the Charpy value. That's all we had.

Since 1950 when George Irwin developed fractured mechanics at Naval Research Laboratory, we've known that we should be measuring a fractured toughness. And we should do all that we can to start putting things in terms of not

Charpy values, but fractured toughness values.

Technology has improved over the last 60 years. NASA learned about fractured toughness in the 1960s when they had some failures of rocket motor cases. The civil engineers learned about fracture energy with the Northridge earthquake in the early 1990s.

It's time for the oil and gas industry to learn about fracture toughness rather than Charpy values. Let's move into the 21st Century.

CHAIRMAN DANNER: All right, thank you, sir. Anyone else who wish to comment on this item? Okay. Committee Members, discussion on ICDA? All right, I'm seeing none. We can go on to SCCDA.

MEMBER DRAKE: Thank you, Mr. Chairman and the Committee. The fourth topic under strengthened assessment requirements regards stress corrosion cracking duressed assessment within 192.923(c) and 192.929. The issue is that current regulations is silent on a number of issues that impact the quality and

effectiveness of SCCDA integrity assessments.

PHMSA proposes to incorporate NACE SP 0204 by reference and supplement the NACE standard to address issues observed by PHMSA. Petition from rulemaking were submitted by NACE International dated February 11, 2009 as this is the basis for this modification.

On to the MPRM comments. One commenter stated the NACE recommendation should not be mandatory. PHMSA's response is that recommendations in the standards are items operators should do and PHMSA seeks to codify that expectation as applicable.

Commenter also stated to include reference to ASME B31-8S, Appendix A3 for susceptibility criteria. PHMSA responds that the B31-8S is currently referenced in 192.929, but the NACE SP 0204 is a much more comprehensive standards and PHMSA believes incorporating the NACE standard will provide improved and more consistent SCCDA results.

A commenter recommended the proposed

language be deleted in SCCDA be conducted per NACE 0204 with only those additional items currently in 192.929, but PHMSA should not exceed those established industry standards. For example, the proposed rule would require a minimum of two above ground surveys and three direct examinations.

These additional requirements do not account for operators to utilize other sources of information, such as ILI runs to complement their SCCDA results. PHMSA responds and proposes to supplement NACE with additional requirements to address specific issues that could adversely affect SCCDA results. Operators that desire to deviate from assessment requirements could submit another technology notification to PHMSA.

Commenter commented requesting that PHMSA provide technical guidance and clarification. PHMSA responds that we will communicate additional guidance as needed during the rule implementation.

Commenter recommended the requirements

of SCCDA specify the assessments are required to be conducted in an area that is most likely to be subject to SCC such as within a compressor station discharge regardless of HCA designation.

PHMSA responds that integrity assessments must address high consequence areas. PHMSA will consider how to structure the rule to apply results to non-HCAs from non-HCAs to high consequence areas.

Commenter recommended that the NACE SP 0204 rather than the NACE RP 0204 was the appropriate nomenclature to use and should have been made the standard rather than a recommended practice. And PHMSA agrees and the number of the standard will be corrected.

Commenter stated the requirements for the spike hydrotesting requirements are covered within the proposed 192.506(e) and there is no need to repeat these requirements in 192.929(d)(4)(ii). And PHMSA concurs that the spike hydrotest requirements are redundant to the proposed 506(e) and will replace it with a

reference to 506(e).

Commenter stated that when calculating remaining strength until such a time that the requirement within 192.607 have been met or if the segment under evaluation is not subject to the requirements of 192.607, supportable found engineering judgment should be allowed.

And PHMSA concurs and agrees to address the gap pertaining to failure pressure calculations when data is not available. Thank you, Mr. Chairman.

CHAIRMAN DANNER: All right, thank you. We'll now take public comments on SCCDA. Do we have any public comments?

Apparently, we do not. Any Committee discussion on this topic? All right. I think we're ready to move on to guided wave ultrasonic inspection.

MEMBER DRAKE: Thank you, Mr. Chairman. The fifth topic around strength and assessment requirements regards the use of guided wave ultrasonic inspection as outlined in

Appendix F. The issue is that the current regulations do not acknowledge guided wave ultrasonic inspection, and operators are currently required to submit a notification to PHMSA to use guided wave ultrasonic inspection.

PHMSA proposes to explicitly allow guided wave ultrasonic inspection in the list of integrity assessment methods, and codify current guidelines operators use for submitting guided wave ultrasonic procedures PHMSA review in the proposed Appendix F or the 18 points.

The basis is after many years of successful application of guided waive technology for integrity assessments, notifications are no longer necessary in PHMSA's opinion.

A commenter stated that there are technologies other than the GUL Wavemaker G3 and G4 which should not be excluded. PHMSA's response is we don't intend to preclude the use of other equipment software providers besides Guided Ultrasonics Limited and specified in the proposed rule that operators may use equivalent

equipment and software with equivalent capabilities and sensitivities.

Commenter said that the requirements of both torsional and longitudinal wave modes in all situations introduces unnecessary complexity into the guided wave ultrasonic data interpretation process. Specifically, torsional wave mode is the primary wave made when utilizing GWUT. Longitudinal wave mode may be used as an optional secondary mode.

And used GWUT monitoring with a target of 0.5 to 0.1 percent cross sectional area with pipes up to 36 inches in outer diameter complimented with a leak monitoring system at the same location.

PHMSA's response is that the proposed rule allows operators to submit notification to propose different technical requirements other than those specified in Appendix F.

A commenter stated that numerous technical specification comments and suggestions that there were, to delete several provisions of

Appendix F. PHMSA responded the existing guidelines proposed to be codified in Appendix F have been successfully used since the start of integrity management and have evolved since then into the certain text that we use. Thank you, Mr. Chairman.

CHAIRMAN DANNER: Thank you very much. Now let's take public comment on guided wave ultrasonic inspection. Do we have any public comments on this section?

Okay, we have no public comment on this issue. Now committee discussion, Andy.

MEMBER DRAKE: Very briefly. We made several comments a few minutes ago when guided wave came up previously. Those comments apply here as well.

I think the lessons learned through all those waivers just need to be applied in developing the standard which is exactly what your comments said. So I just wanted to appreciate that and kind of connect the comment that we made prior into this section as well.

CHAIRMAN DANNER: All right. So noted. Any other discussion on this issue? All right. Let's proceed then to -- oh, I'm sorry. Chad I didn't see your flag.

MEMBER ZAMARIN: Thanks. Chad Zamarin, Williams. I'm like the no objection process guy. It's just a little bit of a different set of language that was used here. It refers to two different sections of the code. I wonder if that's necessary.

And 921(a)(7) we've already talked about, but 937(c)(7) looks like it has different language, don't know if that's intentional or necessary. Just might be something worth looking at between now and the next meeting. Thank you.

CHAIRMAN DANNER: All right, thank you. Any other comment on this issue? All right. Then let's move on to the next issue, passage of internal inspection devices. So, staff briefing.

MEMBER DRAKE: Making great progress today. Thank you, Mr. Chairman. On the sixth

topic, the passage of internal inspection devices in 192.150. The issues is the PG accident or incident at San Bruno, highlighted the weakness of direct assessment which is commonly used for impiggable pipelines.

PHMSA proposed to the existing 192.150 requires that each new gas transmission line or each replacement of line pipe valve fitting or other line component in a transmission line must be designed and constructed to accommodate the passage of ILI devices.

PHMSA proposed to establish minimum technical standards for this process by incorporating NACE SP 0102, Section 7 by reference. The basis for this are NTSB recommendations P-11, 17 from San Bruno and then P-15, 18 and 20 from the gas IM safety study which recommended that PHMSA require all natural gas transmission pipelines be configured so as to accommodate ILI tools with priority given to older lines, older pipelines.

A commenter recommended that PHMSA

revise the proposed regulatory language to allow operators to consider the best practices and NACE standard practice and implement those practices that are determined to be beneficial.

NACE standard SP 0102 should be a guidance document. Recommendations should not be mandatory. PHMSA believes that all the recommendations in the NACE standard are beneficial to achieve the desired safety goal.

Another commenter commented that adding new exception to 192.150(b) such as a replacement of line pipe or component need not be designed or constructed to allow the passage of ILI devices. If the inside of the pipeline is so obstructed by condensates or other solid material it cannot be removed, that it is very unlikely that the pipeline could ever accommodate the passage of an ILI device.

PHMSA's response is that the purpose of the rule is to upgrade pipelines to be piggable whenever components or pipe segments are replaced. Prior to conducting ILI, the pipeline

is cleaned of liquids and solids in preparation for the running of smart or intelligent ILI tools. Thank you, Mr. Chairman.

CHAIRMAN DANNER: All right. Let's see if there's any public comment with regard to the passage of internal inspection devices.

MS. KURILLA: Hi, Erin Kurilla, APGA. The second to last slide that where a commenter made the point that SP 0102 is largely a list of best practices made me pause, and I just want the Committee to stop and think about that before we kind of fly through this section.

I personally am not super familiar with 0102, but if it is, in fact, is a list of best practices, by codifying both the recommendations and the requirements of documents that meant to be a best practices document, it's kind of odd.

And I just think maybe I'd encourage the Committee to take a closer -- I don't know if we're going to move to vote today, but if we are, to take a little bit closer look at what 0102 is

before we say for all new or rehabilitated, I guess, transmissions pipelines that we require a list of best practices during the construction of those.

I just want to make us stop and think about that before we truck forward.

CHAIRMAN DANNER: All right, thank you. Other comments on this section? Committee discussion? Chad.

MEMBER ZAMARIN: Thanks. Chad Zamarin, Williams. I really like this section, but I do want to just make one comment. If we could go to the very first slide that introduced this.

I just want to note that, and I think Alan actually said this correctly. I think we need to be careful that we don't believe that the PG&E accident highlighted weakness in direct assessment. I think what it highlighted was the incorrect identification of threats to the pipeline based on bad data.

You know, I don't think anyone would

claim that external corrosion direct assessment was a tool that would be appropriate for a seam defect. So I don't think it was a failure in the tool, it was picking the wrong tool for the threat.

So there's a lot of discussion about the, you know, the quality and validity of external corrosion direct assessment, structural corrosion direct assessment, internal corrosion direct assessment.

I just think we've got to be clear that, I have no issue saying they're not good tools for seam threats. But I do think we need to be careful that we don't imply that that was an issue of the tool being the problem. That was an issue of picking the wrong tool for the problem. Thank you.

CHAIRMAN DANNER: All right, thank you. Any other comment on this issue? Okay.

So we have come to the end of our agenda for today.

The question we have now is whether

we, are there any of these issues that we feel that we have enough consensus that we could move forward on, clear the deck so that we can have a more focused discussion at the next meeting? And I turn it over to Alan for a little guidance on that.

MR. MAYBERRY: Yes, I think we're, just based on our perspective how the conversation's gone. It looks like we may have the ability to present to maybe an option of voting on maybe D, E, and F. Let me turn it over to John to kind of carry this.

MR. GALE: Yes, if you just give staff just a second, we're trying to get some language right now to possibly get us a vote in D, E, and F, if that's acceptable to the Members. We're putting it together right now.

CHAIRMAN DANNER: All right. And while you're doing that, I do want to note that we did have some comment with regard to F about these are being best practices and what is guidance and what is mandatory.

MR. MAYBERRY: Chairman Danner, we're about to put up the language. We tried to capture the best we could and as efficiently as we could. We just kind of generalized the comments made by PHMSA staff and also by Member Drake and Member Zamarin.

If you note it didn't address right now, at least, the comment made by Ms. Kurilla on one 150. So if we need to make additional changes to this to address that, we're open to those suggestions.

CHAIRMAN DANNER: All right.

MR. MAYBERRY: This is trying to capture basically the proposals related to area 7, was it 7D, 7E, and 7F.

CHAIRMAN DANNER: Okay, so why don't we give the Committee Members a minute to read digest this.

MEMBER ALLEN: David?

CHAIRMAN DANNER: Yes, Steve.

MEMBER ALLEN: All right, just to give one bit of clarification on the part of

192.150 on ILI surveys. That is Section 7 in that particular portion. If you read the 151 language what we said is, in accordance with requirements and recommendations in NACE SP 0102, Section 7 and Section 7 is for new construction and it's planning for ILI surveys when you build a new line.

It's a list of things that you should consider and it's for planning for ILI surveys when you begin the system design for new pipelines. And it's a list of things, a recommendations that operators should consider and incorporate. It's a lot of mays and shoulds and things like that in it. So it's not all shalls or anything like that.

MEMBER BROWNSTEIN: Well that's -- so if I may, that's exactly I think the question that we're sort of -- so what's the, so at the end of the day, right, what you know what would you want to see, right?

Is the issue that you simply want to know that the operator considered these things,

or are you suggesting that these criteria that are in this are things that the operator must consider, right, because, that's the ambiguity. I'm just trying to understand what you were thinking.

CHAIRMAN DANNER: That the way that we've got it referenced and the way that it's actually written in the standard, it would be for them to consider. It's not mandatory because if you go and look at the standards, there's a bunch of shoulds and mays and --

MEMBER BROWNSTEIN: Yes, Yes, Yes.

CHAIRMAN DANNER: -- and things like that.

MEMBER BROWNSTEIN: Exactly.

MR. MAYBERRY: If I may, what we're saying is we're going to address that and pretty much leave the standard as is where the shalls or shall, they will be expected.

If it's a should it, they would need to consider it and if it's relevant they would do it, if not they wouldn't. In carrying out our

inspections we would look for that as we look at how they implement the standards. So that's, we had a little dustup related to this on underground storage that we're working through. But, you know, we --

CHAIRMAN DANNER: Okay. Steve your card is up. Okay, Sara.

MEMBER GOSMAN: So just a note as I read through Section 7. What I notice is there are a lot of shoulds and essentially considerations for, for this design. I think that when I read it as a lawyer, it's hard for me to see how this could be ever enforced.

Other than through, did you consider this particular issue which may be important, but isn't to me a requirement? So maybe it's about considering the issues in that section.

CHAIRMAN DANNER: So are you suggesting in that language be made more prescriptive?

MEMBER GOSMAN: I don't think I have the background to make that suggestion. But I

guess on the enforceability question, I think it could be clearer in the text if what we're doing here is using this may standard essentially to guide consideration of the issues that that perhaps could be clearer in the text of the proposed rule.

CHAIRMAN DANNER: All right. Steve?

MEMBER ALLEN: And Sara, just what you said, for them to consider this to get the best practices out there so that when they read the code, they know where to go to look for it. The expectation is that you have to put every item A, B, C, D in there, is to look at the shoulds and the mays in here and go applicable.

Now it would be to make your system piggable would be, but also in making it piggable it would give guidance on how you should do that so that later you don't get down the road and find out that it's not piggable.

CHAIRMAN DANNER: Go ahead.

MEMBER GOSMAN: So just one last bite. So the text says must be designed and constructed

to accommodate the passage of ILI devices in accordance with the requirements and recommendations in Section 7 of the NACE standard.

So as I read that, just to be clear here, what we're doing is we're requiring that lines be piggable right through, by ILI. But in terms of the design of those, we're directing operators to Section 7 of this NACE standard in order to be able to consider the issues. Okay.

CHAIRMAN DANNER: Okay. And I see a lot of nodding around the room. So it looks like that's how folks are interpreting this, is that right? Okay. It sounds like we have consensus then on these items D, E, and F. Is that the sense? Are we ready to entertain a motion. Sara?

MEMBER GOSMAN: Sorry, I just want to, when I read revised 923(c) and 929 according to the recommendations by PHMSA staff at the meeting. Are you talking about the recommendations in your slides?

Okay, thank you.

CHAIRMAN DANNER: Okay. Andy?

MEMBER DRAKE: Is there some, and I don't remember the comment coming out that strongly that ICDA had a list of concerns. Is there a reason why it's not included in this motion?

CHAIRMAN DANNER: John?

MEMBER DRAKE: I mean, C, D, E, F?

MR. GALE: Oh, if the members want to more, we are more than welcome --

(Laughter.)

MR. GALE: I agree.

MEMBER DRAKE: I'm asking --

MR. GALE: You give us a second and we'll do it.

MEMBER DRAKE: -- because I don't remember a great deal of comments or anything. I think people accept it as it was. I just was curious why it wasn't put in this motion. And I'm happy to make a motion actually, I think.

CHAIRMAN DANNER: Oh, I think Chad's

the motion guy, so.

(Laughter.)

MEMBER ZAMARIN: Oh, all right.

MEMBER DRAKE: We tag team.

MEMBER ZAMARIN: All right.

MR. GALE: Just real quick Andy. Would it be appropriate to create a bullet similar to the first one there for IDCA?

MEMBER DRAKE: Yes, I think so. Yes.

MR. GALE: Okay. All right. By the way, while we're waiting for this to be typed, I would like to thank the PHMSA staff to my left who do a very great job of, under a lot of pressure to get this stuff done and up on the screen the way they do.

MEMBER CAMPBELL: I do wonder though, Mr. Chair, if we should make a motion to separate the two meddlers just at the next meeting. Just saying.

CHAIRMAN DANNER: Yes, okay. Sara?

MEMBER GOSMAN: Also, if we could just clarify what we mean by revised the no objection

process as recommended by members at the GPAC meeting. For example, I notice there was a state notification provision in one of the no objection provisions that we looked at.

And I don't know, I mean I don't know if that was part of the concern here or not. Or if what we're really just talking about is the put in material, if after a certain amount of time, no objection letter is sent out, then proceed.

If that's all we're talking about then that's fine, then I can vote on that, but I'm just, it's the language is unclear to me.

CHAIRMAN DANNER: That was my understanding. Is there a need to clarify that language?

MR. GALE: No. The way we took it was, it would be very similar to language we developed for the 607 section. That's how I interpret it.

MEMBER GOSMAN: Okay, but the state notification provision remains in.

CHAIRMAN DANNER: Okay. All right. Andy?

MEMBER DRAKE: I'd like to propose a motion.

CHAIRMAN DANNER: All right. Wait a minute, Sara's flag is still up. Oh, all right. Now you may proceed.

MEMBER DRAKE: I don't want to violate Robert's Rules of Order, but the proposed rule is published in the federal registry in the draft regulatory evaluation with regard to provision of ICDA, SCCDA, requirements of guided wave ultrasonic testing, and the passage of inline inspection devices are technically feasible, reasonable, cost effective and practicable if the following changes are made.

Revise 192.923(b) and (c), 192.927 and 192.929 according to the recommendations by the PHMSA staff at the meeting per PHMSA slides. Revise the no objection process as recommended by members at the GPAC meeting per the recommended procedure under 192.607 and consideration,

considering the other recommendations made regarding made regarding guided wave ultrasonic testing process by Members Drake and Zamarin.

MEMBER HILL: Robert Hill, would like to second that motion.

CHAIRMAN DANNER: Okay. We have a motion and a second. Is there any additional discussion on the motion? All right then, I'll turn it over to Cameron to take the votes.

MR. SATTERTHWAITE: All right. And it goes just straight, jump right into it. The options are aye and nay or abstain. Andy Drake?

MEMBER DRAKE: Aye.

MR. SATTERTHWAITE: Chad Zamarin?

MEMBER ZAMARIN: Aye.

MR. SATTERTHWAITE: Cheryl Campbell?

MEMBER CAMPBELL: Aye.

MR. SATTERTHWAITE: David Danner?

CHAIRMAN DANNER: Aye.

MR. SATTERTHWAITE: Diane Burman? I don't know if she's with us right now? I'll go onto Mark Brownstein?

MEMBER BROWNSTEIN:: Aye.

MR. SATTERTHWAITE: Richard Worsinger?

MEMBER WORSINGER: Aye.

MR. SATTERTHWAITE: Richard Pevarski?

MEMBER PEVARSKI: Aye.

MR. SATTERTHWAITE: Robert Hill?

MEMBER HILL: Aye.

MR. SATTERTHWAITE: Ron Bradley?

MEMBER BRADLEY: Aye.

MR. SATTERTHWAITE: Sara Gosman?

MEMBER GOSMAN: Aye.

MR. SATTERTHWAITE: Steven Allen?

MEMBER ALLEN: Aye.

MR. SATTERTHWAITE: Terry Turpin?

MEMBER TURPIN: Aye.

MR. SATTERTHWAITE: It's unanimous. It passes.

MEMBER BURMAN: I'm sorry, I was on mute. I say aye.

MR. SATTERTHWAITE: Say again.

MEMBER BURMAN: I'm sorry. Aye.

MR. SATTERTHWAITE: Okay, thank you.

CHAIRMAN DANNER: Now it's unanimous. Thank you, Commissioner Burman.

MR. SATTERTHWAITE: Now it is completely.

CHAIRMAN DANNER: Okay. So the motion has passed. Thank you everybody. I'll turn it back over to Alan now. He'll tell us where we go from here.

MR. MAYBERRY: Thank you, Mr. Chairman. Wow, what a way to end with a bang here. Awesome. I think we over-achieved, we definitely did, getting that last vote.

I just want to thank everyone. I think the conversation is incredible. It's really what, you know, I think part of what makes this country so great and this process so great, the dialogue we're able to have, the different stakeholders on policies that really impact a lot of Americans. So really appreciate that conversation here. I find it very, very invigorating actually.

But a couple things. Well, first up I

wanted to thank our Deputy Administrator, Drue Pearce for sticking with us here until the very end. Thank you, Drue.

And, I wanted to talk a bit about the next steps. We are, as I had mentioned earlier in my remarks about trying to, you know, move with deliberate speed, you know, appropriate speed to get to the end game, which I do find that I see a light at the end of the tunnel. We're making great progress.

So were anticipating and I think you've seen a couple of dates out there. Next related to March, we're looking at the 26th through the 28th. Actually, looking at maybe making that a three day meeting. Possibly covering, you know hopefully we can get to a vote on 624 and wrap up. Yes, 624, which you know pretty meaty area that we had discussion on here.

And then perhaps on the third day we would stage gathering line. And whether or not that's full there or half day, I mean that can be something we discuss. But I think we need two

full days just to close up 624 and maybe a third day to add gathering. And that would be in person. And then followed up by June 12th to the 14th as meeting pretty much dedicated to gathering lines.

But before that, with the other topics we came up and discussed here today related to enhance assessments and some of the other homework I think that we needed to provide, we would propose a conference call in February time frame to, you know, close the loop on the rest of what we talked about here, but then also to report back to you on some of the data that we need to cover.

So I would throw that out to you. I think you've already seen those two dates, but then we were looking at that and another. I'm really hopeful that, perhaps, we could wrap this whole, I mean maybe it's wishful but you know you've got to grasp towards something and think positively in which I am very hopeful right now. I feel pretty good about this that we could

possibly wrap up by June. That would be my hope.

Lastly, I wanted to thank, you know, PHMSA staff. I know John had just mentioned Bob and Sayler. You guys are phenomenal at the controls over there. I really appreciate your work here.

And the rest, Cameron, John, who's kind of the running things from the reg program standpoint. Steve and Chris are main presenters on the rules, thank you so much. And of course Cheryl, our Advisory Committee Manager, who appreciate the effort. Let's give them a round of applause. Takes a lot of work to put these things on. Very much appreciate that.

MEMBER ZAMARIN: Hey, Alan?

MR. MAYBERRY: Yes.

MEMBER ZAMARIN: Can I just echo. This meeting was by far, I think we were better prepared. I don't know if the rest of the group agrees, but the quality of the materials and having them early, I think really helped us move quickly through the meeting. And I just want to

commend the staff.

I know the team did a tremendous amount of work. But I think one of the reasons why we moved so quickly through these materials was because we had them in advance. So I appreciate the good work that was done in this ready.

MR. MAYBERRY: Yes. I appreciate that.

MEMBER ZAMARIN: Thank you, Alan.

MR. MAYBERRY: Yes, I think we're getting there. We've made a lot of progress on preparing the Committee Members. And, yes, I agree and I've heard a lot of comments. Thanks, Chad, too.

You know the feedback on how we could improve things or suggestions either now or just drop us a line. I don't know. Like a, you know again welcome Ron. Ron first meeting here. I appreciate your engagement here as well.

MEMBER BRADLEY: I'll come back.

MR. MAYBERRY: That's a good sign.

MEMBER BRADLEY: Yes. I just, I would like PHMSA to work with the federal government on providing coffee at these meetings.

MR. MAYBERRY: We have that on the records. To do that. Thank you, I'll take that into consideration. And then lastly, Cheryl had a couple of housekeeping items and then I'll say one last thing.

MEMBER CAMPBELL: Yes, I just wanted to say a couple of things. There we go. I wanted to mention, we did mention a couple of times, you know we wanted some input on several items.

So I wanted to say we've had some conversations about where we should put these comments. And we are recommending that you put them both on the meeting page docket as well as the rule making page docket. And we think that way nothing will get lost.

Also I wanted to let you know, because I had a couple comments about the rosters not being updated. Our web site is currently under

construction or reconstruction, which ever one you want to call it. And we will get those things updated as soon as possible.

They are, however, in the package of materials that were provided to the Members and on the current meeting page, Number 127. You have to download the Member Portfolio, as what it's called and the updated rosters will be there.

For Members, I did update your current information. Hopefully I caught it all in the midst of everything. And you bios and I will be sending that back out. So if you could just help me with any typos or any errors I might have made, I appreciate it. I hate doing that to you. I know how busy you are, but it's helpful.

So again, thank you everyone. Ron, it's really been fun having you. You said you were having a good time, so. Everybody have a nice holiday.

MR. MAYBERRY: Lastly, I would just like to thank the public participants. That's

been my problem the whole meeting here. Gosh. No I just was thinking, you back behind me who can't hear me for being here.

Very much appreciate your involvement here as well and participation. I encourage you to come back as well. With that I bid everyone safe travels, back home. And happy holidays. Take care.

CHAIRMAN DANNER: All right. Thank you. Meeting is closed.

(Whereupon, the above-entitled matter went off the record at 5:24 p.m.)

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C E R T I F I C A T E

This is to certify that the foregoing transcript

In the matter of: Meeting of the Gas Pipeline Advisory Committee

Before: Pipeline and Hazardous Materials Safety Admin.

Date: 12-15-17

Place: Arlington, VA

was duly recorded and accurately transcribed under my direction; further, that said transcript is a true and accurate record of the proceedings.

Neal R. Gross

Court Reporter