US DEPARTMENT OF TRANSPORTATION

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PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

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GAS PIPELINE ADVISORY COMMITTEE

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WEDNESDAY
MARCH 28, 2018

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

PRESENT

DAVID W. DANNER, Chair
W. JONATHAN AIREY, Member
STEPHEN E. ALLEN, Member
RONALD A. BRADLEY, Member
DIANE BURMAN, Member (via telephone)
J. ANDREW DRAKE, Member
SARA ROLLET GOSMAN, Member
ROBERT W. HILL, Member
SARA W. LONGAN, Member
TERRY L. TURPIN, Member

RICHARD H. WORSINGER, Member

ALSO PRESENT

ALAN MAYBERRY, Associate Administrator for Pipeline Safety; Designated Federal Official
DRUE PEARCE, Deputy Administrator
CHERYL WHETSEL, Advisory Committee Manager
JOHN GALE, Director, Standards and Rulemaking
ROBERT JAGGER, Transportation Specialist
CHRIS McLAREN, Program Manager
STEVE NANNEY, Program Manager
SAYLER PALABRICA, Transportation Specialist

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

8:41 a.m.

MR. DANNER: All right, good morning, everybody. It is March 28th and Day 3 of Meeting 132 of the PHMSA GPAC Pipeline Advisory Committee.

I'm Dave Danner, I'm chairing the meeting today and we're going to be working almost focused entirely on repair criteria today.

So, I am just going to hand it over to Alan and Alan will tee up today's schedule. Alan?

MR. MAYBERRY: Okay, thanks Mr. Chairman. And for today we just have about I think ten more slides to go through as we tee up the repair criteria.

And we'll talk about how we're going to organize getting in a position for a vote. But before we get into that, I wanted to cover a couple of topics.

First off, I'll do a check from the Committee here. Is everyone doing okay? Is it

going at about the right speed?

I think there's been great discussion. I'm very pleased so far, just -- everyone's doing okay? I don't see any frowns so that's a good thing.

And as you know, this Committee is statutorily put in place to advise us, to advise the Administrator or the Secretary on policy direction.

And I think we've covered this and we've come a long way in the last couple of years of moving beyond trying to wordsmith text.

I mean, we're not -- your role is not to write text, as you know, but it's to advise us. And coming out of here -- and just to give you an idea, we will take the advice of the Committee.

And that's why we've worded it that we will -- you know, as we vote or you've voted, we've -- PHMSA will consider the input.

And we have to put it that way because there are a lot of things that happen after we

leave here.

Now, certainly, the advice of the Committee we take very seriously and normally, it kind of goes through that way but tweaks can happen and do happen as it goes through first -- you know, the first step will be we will be writing the Final Rule.

And that'll be the staff that you see here today.

And then from that point, it goes through a vetting process within PHMSA that's circulated through all Departments, obviously, the Office of Chief Counsel up through the Administrator.

And once it's signed off by the Administrator, the entire leadership team of PHMSA, including the Administrator, moves on to the Office of the Secretary for review.

And there are various offices within the Office of the Secretary that the rule will go through related to policy, related to budget and the like, as it heads beyond the Office of the

Secretary to the Office of Management and Budget, which is kind of the final hurdle, if you will, for significant rules such as this.

And the Office of Management and Budget will review the rules, and obviously a big component of that -- for good policy -- is the cost and the benefit. And that whole timeframe can take some months, as you know.

We've started this process, the NPRM -- back in 2011 for the ANPRM so it's taken quite a while but I don't think -- in fact, I'm sure the process going forward, as is probably obvious, won't be taking that long.

But this is a high-priority rule for us to get right. But, yes, the last step is the OMB before it comes back to PHMSA to sign the Final Rule. And then it ends up as a Final Rule.

The timing of that is just really hard to tell right now, but I would hope within the next year we would certainly have something finalized.

But I can't even predispose the

schedule because there were a lot of variables there as you can imagine.

And we're not the only game in town, there are other agencies there moving policies through the process and other modes of transportation within DOT for that matter.

Okay, so that was one topic. Any questions about that or about the process? Okay, many of you have been through this before. Okay, Rich?

MR. WORSINGER: Rich Worsinger, Rocky Mount. Alan, I just want to say thank you. I appreciate that you and your staff does value our input. It's obvious, the discussions we have here, the discussions we have in preparation, providing us with the slides ahead of time so that we can be prepared.

It's very clear to me and other members of the Committee that you do value our input, that it is a two-way exchange.

And I just wanted to say thank you to you, your staff for all your work, especially

burning the midnight candle in between the Committee meetings to tweak the things so thank you.

MR. MAYBERRY: I appreciate that feedback, Rich. Yes, if you look at the history of, you know, this whole process -- which is an amazing process -- we don't always get unanimous votes.

So, I think it's amazing we've had unanimous votes, which shows the good collaboration on the Committee.

But I know throughout time, the Committee may decide one way and we try to go that way but there is a history of varying from that, I just wanted to make you aware of that.

But thanks for that feedback, Rich.

The other issue I wanted to bring back up relates to just a matter of record-keeping. We had some discussion yesterday on what do we mean by TVC or traceable, verifiable and complete?

And as you know, we are going to

address that in the preamble as far as record-keeping goes.

We're not looking at rulemaking language for that, but I want to make sure that -- I really was going to open it up for input on this, but when we're talking TVC, it -- you certainly, as it came up when we issued our advisory bulletin in the realm that we've been talking, it was an issue related specifically to MAOP.

But really, when you talk about record-keeping, I mean, there's a matter of TVC or element of TVC in just about any record. And a record can vary depending on what you're dealing with, the topic you're dealing with.

So, in some ways, I kind of wish we weren't so focused on TVC but rather focused on what is a credible record for proving something, proving what you have.

Certainly, we found with the PG&E incident record that says you have 30-inch seamless pipe is probably not a credible record,

or there was a human error involved in that. Because there isn't a 30-inch seamless pipe.

But what is a credible record? You know, I want to approach it in sort of that vein but I want your input.

For instance, if we're talking record-keeping, if we're talking about pressure tests, certainly we would be looking for data related to what would go into a subpart J pressure test.

The test level tied to a line number, perhaps -- you know, there are a variety of data points that go in there. Perhaps the company, perhaps the individual did it, but not necessarily both.

Or if you're talking about a mill test pressure, there's certain mechanical properties that you're looking for in that. Or if you're talking about a close-interval survey, perhaps that would be tied specifically to a line number.

You would expect that, that you're dealing with maybe the month and the year or maybe just the year.

Or maybe, you know, if you didn't have the exact date, would that be a show-stopper? No, I wouldn't think so.

Would it be the company and the individual, or just the company or just the individual? I wouldn't think either one of those would make a big difference either way.

And it just varies depending on what you're dealing with. And I used to say this a lot, it needs to pass the common sense test. It needs to be common sense.

You can create scenarios for just about everything and what if it to death but it needs to -- you know, common sense needs to prevail.

But anyways, as we look to leave you today, at the end of today, and work towards writing the rule -- which would include preamble on this topic -- what are some thoughts you might have related to record-keeping that we need to consider?

I know I'm hitting you up cold with

that but if you had any thoughts on that, I'll take them and then we'll move on to our favorite topic, anomaly repair, for today.

Cheryl?

MS. CAMPBELL: So, I'm happy to throw a couple of thoughts out, Alan.

And I appreciate your view of a common sense approach, a practical and common sense approach, as an operator who has a number of records that might be almost complete, except for, say, maybe the guy's signature on the pressure-test record, right?

If I read some of this stuff to the letter of the law, you would say that's an incomplete record, right? We would like to think that it's not, right?

That it's -- if everything else is in line, that I have valid record-keeping for that MAOP, that piece of critical information.

So, I think the thing that will be a challenge for all of us is how do we make it clear enough so that the operators don't get

crossed wires with the states, right?

And you have some people say, well, this is what it says in black and white and this is the way I'm interpreting it.

So, I don't know if that's something that can be helped in the preamble or in some guidance or something, so that we can get to a practical level of record-keeping, right, credible -- define what a credible record is in a way that we don't spend a lot of time and energy arguing with each other over it.

And I'm not worried about getting a fine, right, because I'm missing a signature, right, on something like that. Now, if we think that that's a critical piece of information to make that a complete record, then okay, let's -- but I mean, I think that's where -- at least for the LDC segment, I think that's where a lot of concern is, is around how will it be interpreted by a lot of different people and -- over time as well, right, in a way that we can all have some certainty and say yes, we know this is -- and you

know me, I'm kind of a practical person.

I don't always like everything hard black and white, right?

But there are some things that, just, they generate a great amount of discussion and a lot of energy for both the company and the regulator that isn't necessarily energy well-directed. Maybe that's the way -- we have bigger fish to fry.

MR. MAYBERRY: Okay, thanks.

So, I think probably providing good guidance obviously, which we do on rulemaking, but a heavy focus on maybe helping guide the states as they implement this.

MR. DANNER: So, we have a couple other tents up over here.

MR. MAYBERRY: Who's first though?

MR. DANNER: So Andy was first.

MR. DRAKE: Andy Drake with Enbridge. I appreciate Cheryl's comment.

I think what we're really looking for is some sort of practical guide to the

enforcement folks on how to interpret this.

We've had a lot of discussion about TVC as far as MAOP. I do have to admit we had a conversation yesterday about it.

Is a single document acceptable? And Number 2 still seems to indicate we need something more than that.

But I think as we look beyond MAOP and you start talking about records, I think the question we flared yesterday was really what does that mean? And I appreciate your counsel here, your guidance, as something practical.

We're not terribly concerned about TVC other than maybe the variations of how it would be interpreted.

So, anything we can do to help give folks some guidance on that I think would be really, really helpful.

MR. DANNER: All right, Steve?

MR. ALLEN: Steve Allen, IURC. Yes, I have to agree with Andy and Cheryl on that. I think there needs to be actually guidance for

state inspectors.

I think documentation and records need to be substantive but we don't need to get into a situation where we have form over substance.

And I think that would probably be my only advice I guess or feedback to you is make sure whatever ends up into a rule is something that can be interpreted by regulators in such a manner that we don't have form over substance, if that makes any sense.

MR. DANNER: All right, thank you. John?

MR. AIREY: I have a suggestion that there be real caution on historic records and the nature of them.

Having worked on a few acquisitions of pipelines, the missing batches of data and files is occasionally a problem because of acquisition, a change in location of offices.

Stuff gets dropped and it's not readily available, and I just think there needs to be real caution on historic records.

You can't expect it to be at the level that going forward, it's going to be.

MR. DANNER: All right, thank you. Sara?

MS. GOSMAN: I'll just add my voice to thinking it's a good idea to clarify in the preamble this concept.

And I can see a reason why we might -- you might, decide that certain records are critical to understanding the safety of a pipeline and need more evidence that they are reliable and traceable and complete.

And those might be beyond those needed for this individual MAOP determination. But I think there has to be clarity about where we're go to going to apply that and where we're going to apply something else.

And if it's something else, right, do we have any standards around what that document is supposed to be? So, I think those would be my thoughts.

MR. DANNER: All right, Ron?

MR. BRADLEY: Ron Bradley from PECO, thank you Mr. Chair. So, I appreciate the conversation. I also agree that there should be a single record that could work here.

My sense is I think we've landed on the position at the gold standard of a pressure test as a winner.

We should be able to produce a pressure test and have it documented in the system somewhere.

I think the challenges from years ago are various but I think going forward, one record of a pressure test would make it happen.

MR. MAYBERRY: Yes, just to be clear, we agree that one record can be what's needed so we'll make sure that that's clarified in the preamble.

Okay, are we ready to move on? All right, if there's no further discussion, we'll conclude that. I appreciate that, that was very helpful.

We'll move on to repair criteria and

I'll turn it over to Mr. Nanney, Steve Nanney. Or, no, Chris McLaren.

MR. DANNER: So, yes, yesterday we had the review of the proposed notice and so now Steve is going to discuss the changes that PHMSA's going to propose to a specific repair criteria.

MR. McLAREN: Chris McLaren with PHMSA.

We have about 20 slides and some of them are quite in-depth, so finish up repair criteria and the summary of changes that PHMSA has proposed to the specific repair criteria in these next 20 or so slides.

So, this is the revised proposed repair criteria, showing on the left the repair criteria from the Notice of Proposed Rulemaking.

And on the right, PHMSA's current proposed repair criteria that has been revised for the Final Rule based on all the feedback we've received, and then the subsequent investigation we've done to this point.

There's about four slides, the first one's for immediate conditions. An immediate condition for an HCA and non-HCA would be when the PFP is less than or equal to 1.1 times the MAOP.

And that's the same as was proposed. Originally in the NPRM we had proposed dents with metal loss, cracking or stress riser.

We revised that proposal to be topside dents with metal loss, cracking or stress riser, unless the ECA demonstrates critical strain levels are not exceeded.

The third one was a metal loss greater than 80 percent, and that has remained the same.

The fourth is metal loss affecting a direct-current, low-frequency/high-frequency ERW, or an electric flash-welded seam. That's been revised to have metal loss preferentially affecting those seams unless the PFP exceeds 1.25 times MAOP.

The fifth one originally proposed was significant SCC and significant seam-cracking.

As we've revised our definitions, we have revised that repair criteria to be crack or crack-like defects greater than 50 percent wall thickness, exceeds detection limit of ILI tool, or the third criteria, the PFP is less than 1.25 MAOP.

And then the sixth one is any other anomaly requiring immediate action, and that would remain the same.

The next couple of slides cover scheduled conditions.

One of the scheduled conditions to deal with dents that was proposed for the Final Rule is bottom-side dent with metal loss cracking or stress riser, unless an engineer or an ECA demonstrates critical strain levels not exceeded.

The second one was regarding topside dents greater than six percent. Proposed for the Final Rule would be that topside smooth dent greater than six percent, unless the ECA demonstrates critical strain levels not exceeded.

The third one from the NPRM is a dent

that's greater than two percent at a girth or seam weld.

And in the proposed repair criteria for the Final Rule, we have dent greater than two percent at girth or seam weld, unless the ECA demonstrates critical strain levels not exceeded.

Originally in the NPRM regarding predicted failure pressures, for Class 1, that would be a scheduled condition of one year in an HCA if it was less than or equal to 1.25 in a Class 1, less than or equal to 1.39 in a Class 2, and less than or equal to 1.67 in a Class 3, or if the PFP was less than or equal to 2.0 for a Class 4.

And that would remain the same, and these are all schedule conditions for one year in an HCA, proposed two years in a non-HCA. Sorry about not clarifying that immediately.

As part of the looking at the Final Rule, we added a schedule condition for metal loss preferentially affecting the VCLF or HF-ERW in flash-welded seams, if the PFP is less than

1.39 MAOP for a Class 1 or is less than the reciprocal of class location factor times MAOP for Class 2, 3, 4 respectively.

Continuing with scheduled conditions which would be 1 year in an HCA and 2 years in a non-HCA area, the first one here is metal loss greater than 50 percent at a crossing or circumferential corrosion or girth weld. And that one would remain the same.

On the next two, PHMSA's proposing deleting them, the gouge or groove greater than 12.5 percent or a general corrosion area greater than 50 percent.

The fourth one in the NPRM was structured in that way, such that it was any indication of crack or crack-like defect that is not an immediate condition.

We've refined that to be crack or crack-like defect that is, 1, greater than 50 percent wall thickness, 2, the PFP is less than 1.39 times MAOP for a Class 1, or 1.5 times MAOP for a Class 2, 3, or 4.

So those are the scheduled conditions for HCA and non-HCA areas, and now we'll move on the bottom of this slide and the next slide to monitored conditions for high-consequence areas and non-high-consequence areas.

The first one is any bottom-side dent greater than six percent. The second one is a topside dent greater than six percent that analysis demonstrates critical strain levels not exceeded.

To continue on with monitored conditions, any dent greater than two percent of the girth weld or long-seam weld analysis demonstrates critical strain levels not exceeded was proposed in the NPRM.

And we've refined that for a dent greater than two percent at girth weld or long seam weld and ECA demonstrates critical strain levels not exceeded.

And this would be the same for HCAs and added for the non-HCAs.

Additionally, another condition added

is a dent that has metal-loss cracking or a stress rise, and ECA demonstrates critical strain levels not exceeded.

Another monitored condition added would be metal loss preferentially affecting those seams and the PFP is greater than 1.39 times MAOP for Class 1 or the reciprocal of the Class Location Factor times the MAOP for Class 2, 3, and 4.

And the last one added under the monitored conditions would be a crack or crack-like anomaly for which fracture mechanics analysis determined the PFP greater than 1.39 times an MAOP for Class 1, or the reciprocal of Class Location Factor times MAOP for Class 2, 3, and 4.

So, in light of public comments received at the NPRM and at the Committee Meetings, specifically the March 2 one, we suggest that the Committee consider a number of revisions to the proposed repair criteria summarized on the following slides.

One, PHMSA suggested to the Committee to add an effective date to 192.711(b)(1) to clarify that 192.713 is not retroactive.

And also, in 192.711(a), clarifying that pressure reductions be required for immediate conditions and in cases where repair schedules cannot be met.

PHMSA suggests revising 192.711(b) with the following, to avoid duplication, refer to 192.713 for repairs and pressure reductions.

Two, clarify that 192.713(a) applies to segments not covered under Subpart O.

For instance, 192.713 applies to non-HCAs, clarify that 192.713(c) is to replace the phrase, impairs the serviceability with a reference to the repair criteria in 192.713(d), and to revise 192.913(d) to clarify that the repair criteria apply only to onshore transmission pipelines.

PHMSA suggests revising 192.711(b) to also revise 192.713(d)(2) to strike the lower of and allow the pressure reduction to be the

calculated safe pressure based on the class location, one.

Or, 80 percent of the operating pressure, two. Or the third one, 1.1 times the PFP based on situational safety to public and operating personnel.

We would also require that operators document and keep records of the calculations or decisions used to determine the reduced operating pressure in the implementation of the actual reduced operating pressure for a period of five years.

We would also suggest the following revisions.

When anomalies cannot be repaired in a specified timeframe, clarify that the pressure reductions are required comparable to IM requirements in Subpart O.

Add notification requirements in 192.713 comparable to IM requirements, to require that operators notify PHMSA when, one, it cannot meet the schedule for evaluation or remediation

required under 192.713 and cannot provide safety through a temporary reduction in operating pressure or through another action, and also when a temporary pressure reduction exceeds 365 days.

PHMSA suggests modifying 192.713(d) and 192.933(d) to require that operators use the following assumed values needed to determine predicted failure pressure or pressure reduction when these records are not known or not documented in TVC or other records.

One, the specified minimum yield strength, assumed Grade A pipe, or determine the material properties under 192.607, or three, use the basis for the current MAOP.

Also pipe diameter and wall thickness use a basis for the current MAOP or determine the material properties under 192.607.

PHMSA suggests the following, strike the proposed definitions of significant seam-cracking and significant stress corrosion cracking in 192.3, delete the phrase any indication of from the repair criteria related to

cracking, combine the repair criteria for stress corrosion cracking and seam-cracking, and require that the PFP for all-time dependent cracking anomalies be calculated using the fracture mechanics procedure in 192.712.

PHMSA suggests adopting the below-crack repair criterion for immediate conditions, where crack depth plus corrosion is greater than 50 percent of the pipe wall thickness, where crack depth plus any corrosion is greater than the inspection tools maximum measurable depth, or three, the crack anomaly is determined to have or will have prior to the next assessment a predicted failure pressure that is less than 1.25 times MAOP.

PHMSA suggests adopting the below-repair criteria for one year in an HCA and two years in non-HCA conditions for repair.

Crack depth plus corrosion greater than 50 percent of pipe wall thickness, the crack anomaly is determined to have or will have prior to the next assessment a predicted failure

pressure that is less than 1.39 times MAOP for Class 1, or 1.50 MAOP for Class 2, 3, and 4.

And crack anomalies that do not meet either the immediate or one-year HCA, two-year non-HCA conditions, would be a monitored condition.

PHMSA suggests allowing but not requiring engineering critical assessment analysis for the following dent-related repair criteria in HCA and non-HCA areas: a dent with an indication of metal loss, cracking or stress riser, a smooth topside dent greater than six percent, or half-inch deep for a 12-inch pipe.

A dent greater than two percent or greater than a quarter inch on the 12-inch pipe, that affects pipe curvature at a girth weld or a seam weld, and dents analyzed by an ECA but shown to not exceed critical strain levels would be monitored conditions.

PHMSA suggests revising this immediate condition for non-HCAs as follows: allow ECA to analyze dent anomalies with indications of metal

loss, cracking or stress risers, and prioritize repair criteria as follows.

For an immediate topside dent that exceeds critical strain level, for that non-HCA two-year repair, it would be a bottom-side dent that exceed critical strain levels, and four, that monitored the defect that do not exceed critical strain levels.

PHMSA suggests deleting the following repair criteria for HCAs and non-HCAs, the gouge or groove greater than 12.5 percent wall thickness, and areas of corrosion greater than 50 percent.

Also proposed is revising 192.485(c) to include a reference to 192.712 for evaluating corrosion and proximity to cracks or crack-like defects, and for operators to make and retain records.

PHMSA suggests revising the repair criteria for corrosion metal loss affecting a long-seam in HCAs and non-HCAs as follows; allow but not require ECA analysis for the evaluation.

If the PFP is less than 1.25 times MAOP, the anomaly would be an immediate condition.

If the PFP is less than 1.39 times the MAOP for Class 1, or 1.5 times the MAOP for Class 2, 3, and 4, the anomaly would be a one-year condition in an HCA and a two-year condition in a non-HCA.

If the PFP was greater than 1.39 times the MAOP in a Class 1, or greater than 1.5 times the MAOP in a Class 2, 3, and 4, the anomaly would be a monitored condition.

And then continuing that discussion of the proposed revisions, we would insert the word, preferentially, to assure that this criterion would not be applied to small corrosion pits near long-seam.

It would only apply to corrosion along the seam that could lead to slotting-type, grooving crack-like defects.

In light of the comments we've received from the Committee, specifically from

March 2nd, we suggest the Committee consider the following definitions: accept the definition of wrinkle bend as proposed in the NPRM and accept the definition of hard spot with minor edits as follows.

Hard spot means an area on steel pipe with a minimum dimension greater than two inches or 50.8 millimeters in any direction, and a hardness greater than or equal to Rockwell 35 HRC or Brinell 327 or Vickers micro-hardness 345.

Thank you, sir.

MR. DANNER: All right, thank you.

So we are now going to turn to take public comment but I want to clarify basically, this is a lot of stuff so in order to make it orderly, we're going to break it into four buckets if you will.

So, we'll take comment on the first bullet up there. It's applicability, general provisions, pressure reductions, including notifications and pressure reduction assumptions.

So, with regards to that first bullet,

are there any public comments?

MS. BYRNES: Good morning, Corinne Byrnes, National Grid. I believe this is appropriate for that section.

It's a comment on -- the assumption stated that scheduled conditions are allowed to grow until they become an immediate condition.

And the associated slides, Slide 173 through 174 show trends in immediate repairs, however, it does not provide detail on the nature of the defects that fall into that category.

In some cases, it may be possible that these may be newly acquired damages such as third-party damages. It's also possible that maybe operators are reporting conservatively.

So, I think we need a little more information before an assumption is made on trends of immediate damages that have grown over time.

Also, identified defects may not grow at the rapid rate suggested by PHMSA, especially for low SMYS pipe with minor to moderate pressure

cycles.

I know that at our company, pipelines that are baseline-assessed and then re-assessed using in-line inspection are compared side by side to determine if previously-identified anomalies that may have been under monitored classification have grown since the baseline.

In most cases, any growth of the anomaly has been minor if at all.

Defects that may be picked up through external corrosion direct assessment are usually repaired at the time that they're found because it requires an actual excavation.

We believe that the existing repair guidelines for corrosion defects adequately address the threat of corrosion defects up to 60 percent of wall thickness.

Also, there's a new category for corrosion found at crossings, which, sorry, probably should be removed as a criteria because it's a redundant requirement that's already in the existing regulation.

Thank you.

MR. DANNER: All right, thank you.

Are there any other comments with regards to the first bullet up there, applicability, general provisions, and pressure reductions?

That is the end of the public testimony with regards to that first grouping. So, I'll turn it over to the Committee.

Any comment from the Committee Members with regards to this first grouping? Well, we might be out by noon.

All right, no tents are up. Why don't we, then, turn to public -- all right, so -- All right, timeout.

MR. GALE: Mr. Chairman and Members, for this area, you can see the different suggestions as summarized from Chris and Steve's presentation up here.

They've required us to put it on three different slides because it's so long, this area. So what we're recommending is that we break the

three slides into basically two votes.

But also, as you can see here, these are the topics we're covering so we want to make sure you guys are comfortable, that you've had adequate time to deliberate in these areas.

MR. DANNER: Okay, Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I just want to make sure I'm clear here so, Steve, I'll ask this, or Chris.

When you say -- where is it up there -- pressure reductions, I think it's the second bullet, pressure reductions would be required for immediate conditions and in cases where repair schedules cannot be met, what you're really saying, I think, is even in immediate conditions, there is a response schedule for immediate conditions.

As long as you meet that immediate condition response schedule, you're okay. It's not that just because you found an immediate, you have to do a pressure reduction.

Is that right?

And then in that case, it would read the same, it would be the same effect. It would be required in cases where repair schedules can't be met, immediate or scheduled.

Is that the same intent as what you're trying to do here?

MR. DANNER: Steve?

MR. NANNEY: Steve Nanney with PHMSA.

What we are proposing is to give the operator, as far as looking at a safe pressure for doing the immediate, if you're not doing it -- even if you're doing it immediately based upon what you're seeing for your ILI results, you may have to take a pressure reduction before you put people out there.

And we've noted that in our wording, we would note that.

And we've given, as we've seen in some of the comments, several options that you can take to look at as far as what those safe pressures -- realizing maybe operating below that pressure to begin with so there's no pressure cut

or anything because that's what you were operating at.

So, we've given several options.

One would be if it's something unknown in an 80 percent pressure cut, a Class Location Factor pressure cut or a 1.1 pressure cut, we've got various options built in based upon some of the comments and everything.

So, I hear what you're saying and again, we've got wording based upon what you're seeing in the log, you know, and what you're actually looking at for you to have to make a decision based upon the code-wording and what you're doing at the time, and how long it's going to take you.

In other words, if an immediate's going to be a month or two months or 30 days or five days or one day, if you see my point. And the wording is set up that way.

MR. DANNER: John?

MR. AIREY: Jon Airey, I just have a minor question.

The requirement to go to lower pressure immediately concerns me a little bit if you're in a peak day condition zone on a transmission facility. That's the only concern I've got.

MR. DANNER: All right, other comments? Okay, John, it was your understanding that we would take these votes up?

MR. GALE: That's correct, Chairman.

We would have two votes on this first topic area, so this first vote would be on these two slides together and then we'll tee up another slide, and of course, if there's any need for any discussion, we can have that as well.

MR. DANNER: Okay, very good.

So, with the slide before us right now, is there any comment from the GPAC Members? If not, we are probably ready to entertain a motion.

Steve?

MR. ALLEN: Steve Allen, IURC. Similar to the voting language from yesterday,

the heading here, does that need to be adjusted to reflect that there's additional voting language to follow?

The way it reads is, okay, the NPRM is fine so long as these changes are made. But there are more changes to be made after this.

MR. GALE: Well, it does specifically say, remember, Alan, that it's regarding repair criteria applicability, general provisions, and pressure reductions.

So we are trying to zero it in to that topic.

MR. DANNER: All right, thanks for that question. All right, any other questions? All right, again, has anybody prepared to make a motion? Cheryl?

MS. CAMPBELL: I'm happy to make a motion, thank you.

The proposed rule is published in the Federal Register in the Draft Regulatory Evaluation with regards to provisions for repair criteria applicability, general provisions, and

pressure reductions, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made.

Add an effective date to Section 192.711(b)(1) to clarify that Section 192.713 is not retroactive.

Clarify in Section 192.711(a) that pressure reductions would be required for immediate conditions and in cases where repair schedules cannot be met.

Refer to Section 192.713 for repairs and pressure reductions to avoid duplication in these sections.

Clarify that Section 192.713(a) applies to segments not covered under Subpart O, i.e. non-HCAs.

Clarify Section 192.713(c) to replace the phrase impairs the serviceability with reference to the repair criteria in Section 192.713(d).

Revise Section 192.913(d) to clarify that repair criteria apply to onshore

transmission pipelines.

Revise Section 193.713(d)(2) to strike the lower of and allow pressure reduction to be the calculated safe pressure based on class location or 80 percent of operating pressure, or 1.1 times predicted failure pressure based upon situational safety to public operating personnel.

Require that operators document and keep records of the calculations or decisions used to determine the reduced operating pressure in the implementation of the actual reduced operating pressure for a period of five years.

MR. DANNER: All right, thank you very much. Is there a second?

MR. HILL: Robert Hill seconds.

MR. DANNER: Thank you. All right, any further discussion before we go to a roll-call vote?

All right, hearing none, let's take a roll-call vote. Cheryl?

MS. WHETSEL: Okay, Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?
MR. DANNER: Aye.
MS. WHETSEL: Diane Burman?
MS. BURMAN: Aye.
MS. WHETSEL: Sara Longan?
DR. LONGAN: Aye.
MS. WHETSEL: Terry Turpin?
MR. TURPIN: Aye.
MS. WHETSEL: Cheryl Campbell?
MS. CAMPBELL: Aye.
MS. WHETSEL: Andrew Drake?
MR. DRAKE: Aye.
MS. WHETSEL: Ron Bradley?
MR. BRADLEY: Aye.
MS. WHETSEL: Rich Worsinger?
MR. WORSINGER: Aye.
MS. WHETSEL: And Chad on the phone? Okay, Jim Airey?
MR. AIREY: Aye.
MS. WHETSEL: Robert Hill?
MR. HILL: Aye.
MS. WHETSEL: Sara Gosman?

MS. GOSMAN: Aye.

MS. WHETSEL: Okay, the motion passes, thank you.

MR. DANNER: All right, thank you very much, and just to clarify, I think that was John. You said Jim but we'll call him Jim. All right, so moving on to part 2 --

MR. GALE: Mr. Chairman, there's one more vote that has to occur.

MR. DANNER: No, that's right.

MR. GALE: On this first bucket here.

MR. DANNER: All right, so take a minute to read this next one.

MR. GALE: And just to be clear, it's just one page, that's all. I see our Member who likes to put forward the motion has left us.

MR. DANNER: Yes, so taking volunteers for anyone else who has eyesight sufficient to read that?

Robert, would you be willing to make the motion? Would you be willing to make the motion? Thank you.

MR. HILL: Do you want me to read this now?

MR. DANNER: Would you please?

MR. HILL: The proposed role as published in the Federal Register and the Draft Regulatory Evaluation with regards to provisions for repair criteria applicability, general provisions, and pressure reductions, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made.

When anomalies cannot be repaired in a specified timeframe, clarify that pressure reductions are required comparable to IM requirements, Subpart O, and notification requirements in Section 192.713 comparable to IM requirements, to require that operators notify PHMSA when they cannot meet the schedule for evaluation and remediation required under Section 192.713 and cannot provide safety through a temporary reduction in operating pressure or through another action, and a temporary pressure

reduction exceeds 365 days.

Modifies Section 192.713(d) and 192.933(d) to require that operators use the following assumed values needed to determine predicted failure pressure, PFP, or a pressure reduction when these values are not known or not documented in records.

Specified minimum yield strength, the SMYS, assume Grade A pipe, or determine material properties under Section 192.607, or use basis for the current MAOP.

Pipe diameter and wall thickness, use basis for current MAOP or determined material properties under Section 192.607.

MR. DANNER: All right, thank you very much. So, I'll let the record reflect that Robert Hill made the motion.

Is there a second?

MR. WORSINGER: Rich Worsinger, second.

MR. DANNER: Thank you very much. Okay, any discussion on this slide. All right,

if not, Cheryl, we'll go to a roll call?

MS. WHETSEL: Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan?

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin?

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell?

MS. CAMPBELL: Aye.

MS. WHETSEL: Andrew Drake?

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley?

MR. BRADLEY: Aye.

MS. WHETSEL: Rich Worsinger?

MR. WORSINGER: Aye.

MS. WHETSEL: Jon Airey?

MR. AIREY: Aye.

MS. WHETSEL: Robert Hill?

MR. HILL: Aye.

MS. WHETSEL: Sara Gosman?

MS. GOSMAN: Aye.

MS. WHETSEL: The motion passes.

MR. DANNER: All right, thank you. So, can we put up the slide with the four buckets?

So, I think we're now going to turn to public comment with regards to debt criteria, including ECA allowance and non-HCA anomaly types.

MR. GALE: And Chairman, if you allow, we're also going to put on -- this is only one voting slide on this.

So, it might help the discussion so they can see the topic areas that we're going to put the voting slide up early so that the public and the Members can see the topic under consideration.

MR. DANNER: That's good, thank you. All right, and so this is the voting language with regards to debt criteria?

MR. GALE: I'm verifying right now.

While we wait, we can thank those people who did bring the donuts today for continuing National Donut Day.

Are we good? Okay, we're good, Chairman.

MR. DANNER: Okay, so this is one slide with the voting language for debt criteria. Is that correct?

MR. GALE: That is correct.

MR. DANNER: All right, thank you, John.

All right, so we are now going to open it up for public comment on debt criteria and you see the language before you. Go ahead, sir.

MR. CHITTICK: I'm Dave Chittick with TransCanada Pipelines, and to do with the engineering critical assessment for the strain level for dents, operators like TransCanada and others, we have proven analytical methods to calculate the strain on our dents.

And today we're implementing those

outside of the HCAs. We're very pleased to have the opportunity now to apply those practices inside of HCAs.

And I just want to confirm that on an earlier slide, there was a reference to Finite Element Analysis, and I just want to clarify that FEA is not needed for many of these assessments.

It is needed in certain assessments but just looking to verify that just basic strain analysis is sufficient.

Thank you.

MR. DANNER: All right, thank you. Is there other public comment on this slide? Okay, hearing none, I'll open it up to the Committee for discussion.

MR. GALE: Steve would like to respond to that.

MR. DANNER: Yes, I was going to ask Steve if he would do that. Steve?

MR. NANNEY: Steve Nanney with PHMSA.

Just to reply to the comment we got on denting, the answer there would be yes, we agree

with the gentleman from TransCanada's comment that Finite Element Analysis would not be required on all dents.

MR. DANNER: All right, thank you for that clarification. Is there other public comment or other Committee comment on this slide?

All right, hearing none, are we prepared to vote? Is there a motion -- oh, Sara?

MS. GOSMAN: I just have a quick question. The critical strain levels here, are these determined on a case-by-case basis?

MR. DANNER: I think that's a question for Steve Nanney.

MR. NANNEY: This is Steve Nanney with PHMSA. The answer would be probably yes. It may be that some were put in a bucket, but the answer is yes.

And right now, as you I think know from the code, anything over -- there's a number of cases where if it's over six percent, it would require engineering critical assessment or analysis, whichever way you want to term it.

And what we were doing here as we went through in the slides, we wanted to put a framework around it.

We agree with industry's comment that we think we needed to put a bucket around it and allow it in other places.

And I can show, and the reason we thought that, we went back and looked at the history on the gas lines versus the liquid lines as far as dents.

And I think sometimes, the gas lines get caught up in the liquid bucket because the liquid lines are pressure cycling a heck of a lot compared to the gas lines. So, you will have, in dents, more cracking.

And what we found is it's sort of like the other day, I think we had a couple of stats and somebody said, well, maybe one or two of them, one was offshore and somewhere else.

But we had gone through the stats on dents for gas lines, and the incidents on liquids, from about 2002 to 2017, there were

about three and a half incidents per year.

The gas lines were more -- and again, somewhere between a half and less than one per year, and they were very minimal. So, that's why PHMSA is proposing this.

We agree, I think it's one of those where stats matter and so we're trying to put that into the code with what we're doing here.

MS. GOSMAN: Thanks for that clarification.

MR. DANNER: Thank you. I know we turned to Committee comments but I see that we have one more public comment with your indulgence.

MR. TOMAR: Thanks for the opportunity and thank you, Steve, for the clarification and for incorporating the fact that mechanical damage-related failures in gas lines are much less frequent.

My comment was --

MS. WHETSEL: Excuse me --

MR. DANNER: Can you identify

yourself?

MR. TOMAR: Sorry, Munendra Tomar from Kinder Morgan. My comment was about the ECA and the language around it.

I really appreciate and agree with the framework that you've provided in the slides as to what this should look like.

However, in that framework, you do mention two aspects of the ECA, one is the critical strain and the other is the fatigue life.

But in the criteria, it doesn't seem to allow for that so if we can consider leaving the framework as sort of a guidance.

And in the criteria limiting the language to say allow engineering critical assessment, then the framework kind of defines what comprises ECA.

And what that also does is there's a lot of work going on in PRCI industry and also on the European side with EPRG.

Some of the methods are FEA-based,

some of the methods are more analytical-based, some are critical strain only, and some do look into the fatigue life.

So, I guess keeping the language, just suggesting that an ECA is an option rather than defining the critical strain level as a criteria does give the operators the ability to incorporate the latest and greatest in science and technology as things develop.

Thank you.

MR. DANNER: All right, thank you.

All right, so turning back to the Committee, is there any comment on what you've heard or any reaction to the public comments you've heard?

So, Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I think the last comment was very good. I'm sitting here trying to think on the fly how we'd change that fourth red dash to pick that comment up.

Steve, if you have any ideas?

I don't think that certainly is counter to the direction thematically we're trying to do here, but I don't know if you have any thoughts on how to pick that up wording-wise.

MR. NANNEY: Steve Nanney, PHMSA. I don't right now. We're going to take into account the comments we've heard today.

My personal thought is it's not needed to be in there.

MR. DANNER: It's not what?

MR. NANNEY: My personal thought would be it doesn't need to be added, but if you wanted to add, just say consider FEA analytical type of reviews based upon the type of situation you encounter.

And we understand what that's pointing us to take a look at and everything. And I think that would help summarize it.

MR. DANNER: This is Dave Danner. I think that would be useful if we just added that to the fourth bullet and just say PHMSA will consider alternatives to ECA including FEA.

Where did it go? Should that be a separate dash or should it be part of the fourth dash? Yes, all right, that's great.

All right, thank you. Any other comments from the Committee? Andy?

MR. DRAKE: I'm willing to propose a motion.

MR. DANNER: All right, that's great.

MR. DRAKE: Voting language for repair criteria Paragraphs 192.485(c), 192.711, 192.713, and 192.933.

The proposed rule is published in the Federal Register and the Draft Regulatory Evaluation.

With regards to provisions for dent repair criteria, they're technically feasible, reasonable, cost-effective, and practicable if the following changes are made.

One, allowing but not requiring ECA analysis for the following dent-related repair criteria, HCA and non-HCA, dent with indication of metal loss, cracking or stress riser, smooth

topside dent greater than six percent diameter or 0.5-inch deep for diameters less than nominal pipe size 12 inches, dents greater than two percent diameter or greater than 0.25 inches deep for nominal pipe -- for diameters of less than nominal pipe size, 12 inches that affect pipe curvature at a girth weld or seam weld.

Dents analyzed by ECA but shown not to exceed critical strain levels, that would be monitored conditions. PHMSA will consider language to accommodate alternative ECA methods such as FEA.

And two, revise the immediate conditions for dent anomalies with indications of metal loss, cracking, or stress risers in non-HCAs as follows.

Allow an engineering critical assessment to analyze dent anomalies with indications of metal loss, cracking, or stress risers, and prioritize repair criteria as follows.

To immediate topside dents that exceed

critical strain levels, to your bottom-side that exceed critical strain levels, and monitored defects that do not exceed critical strain levels.

MR. DANNER: All right, thank you. Is there a second?

MS. LONGAN: I second.

MR. DANNER: All right, thank you. So, we have a motion before us and second.

Is there any further discussion before we go to a roll-call vote? Okay, hearing none, Cheryl, we're ready for a roll-call vote.

MS. WHETSEL: Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan?

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin?

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell?
MS. CAMPBELL: Aye.
MS. WHETSEL: Andrew Drake?
MR. DRAKE: Aye.
MS. WHETSEL: Ron Bradley?
MR. BRADLEY: Aye.
MS. WHETSEL: Rich Worsinger?
MR. WORSINGER: Aye.
MS. WHETSEL: Jon Airey?
MR. AIREY: Aye.
MS. WHETSEL: Robert Hill?
MR. HILL: Aye.
MS. WHETSEL: Sara Gosman?
MS. GOSMAN: Aye.
MS. WHETSEL: Okay, the motion passes.
MR. DANNER: All right, thank you very much. Okay, all right, so we're now going to move into the third one, which is cracking criteria.
And we don't have a Staff presentation on that?
MR. GALE: No, Chairman, we do have

two voting slides which we think will help the discussion from both the public and the GPAC as well.

MR. DANNER: Okay.

MR. GALE: And we're pulling it up here shortly.

MR. DANNER: Okay, so we're going to put up the voting language and then we're going to take public comment on the third bucket.

MR. GALE: It's coming up shortly. There we go.

MR. DANNER: All right, so take a moment to read that and then we will take public comment on cracking criteria.

MR. OSMAN: CJ Osman with INGAA. I have sort of a minor comment and this slide is very helpful so thank you.

On the second sub-bullet on the second bullet about predicted failure pressures and when to schedule responses for cracking anomalies, I just want to make sure we understand what the intent of this, or will have prior to the next

assessment language, really means, and if that's intentional.

Because what we're talking about in this second bullet here is doing a calculation for scheduled anomalies at a pretty conservative --

MR. DANNER: Okay, you are on the right side?

MR. OSMAN: Yes, the right side, sorry, the right side, Slide 22, second section, Bullet 2 where it talks about the crack anomaly is determined to have or will have prior to the next assessment, et cetera, et cetera.

So, those factors, 1.39 and 1.5, upon which you'll be scheduling anomalies are fairly conservative.

And then when you look at the state of crack analysis today and the models and methods that we use, to then add to that a requirement to look at what it might be before the next assessment, based on 1.39 or 1.5, that's going to loop in the majority of crack anomalies that are

out there, probably the vast majority.

I think what might be the intent here is to look at anomalies that might approach the immediate response condition, the 1.25, prior to the next assessment.

And I just want to get some clarity from PHMSA and from the PAC on what the real intent is there, and what the cutoff is for forecasting into the future about what a crack might be.

So, thank you.

MR. DANNER: All right, thank you.

MR. CHITTICK: Dave Chittick with TransCanada Pipelines.

Building on some of the comments CJ was just making, TransCanada, we have extensive experience with crack in-line inspections for gas pipelines.

We've completed over 200 inspections with this new and evolving technology, so we have learned a lot about this technology.

And there were some comments earlier

yesterday or the day before about this technology is evolving and is not quite mature.

To a degree, those comments are fair if we're looking at the low-level readings that the tools are detecting.

We're implementing this technology looking for cracks that are of concern, and these are cracks that are six inches long, greater than 50 percent through the wall. And this technology has no problem finding those cracks.

Where we're challenged with this technology is the features that it reported with 10, 15, 20 percent depth.

But if you now take all of those features and grow them out to your next assessment period, that will lead to a lot of digs.

And that may actually discourage people from implementing this technology, which is not what we want to do.

So, we really don't want to have a condition that says you need to dig to 1.39 for

up to seven or 10 years out there and do that within one year or two years. That's just not the optimal approach.

I think what's more appropriate is the year in which the feature would cross over that barrier should be the area in which you do the dig.

And another factor here, when you hurry to do digs, you drive up the cost of doing digs. Having opportunity to plan these things out really helps optimize the costing of the program. Thank you.

MR. DANNER: All right, thank you very much.

MR. JOHNSON: Dave Johnson with Energy Transfer.

My comment applies I think here and to the next section when we talk about the corrosion defects as well, but I thought I'd go ahead and get it on the table here.

And it has to do with the predicted failure pressure ratios that are suggested in

here.

There are several places throughout these slides where these ratios are stated and they are related to the Class Location Factors. And this is one of those places on the right-hand side, I think.

What seems to not have been considered here is the ability of operators to utilize what's commonly referred to as the class bump, that is pipelines that have met certain conditions can operate at a higher design factor than would normally be designed for their class location.

So, you can operate at a design factor of 0.72 in a Class 2 area, and 0.60 in a Class 3 area.

And if you apply the reciprocals of those, strictly as the Class Location Factors to any of these pipes, say, a pipe that was designed with 0.72 design factor that's operating that way in a Class 2 area, if you apply the Class 2 factor to it, the pipe itself will not pass,

regardless of whether it has a defect in it.

So, I'd suggest that we carefully go through all of this and one approach would be to change all of the references to Class Location Factors to something like Applicable Design Factor, which then would allow the 0.72 in a Class 2 area and a 0.60 in a Class 3.

MR. DANNER: All right, thank you. Go ahead?

MR. TOMAR: Munendra Tomar, Kinder Morgan.

My comment is about the requirement for a crack anomaly to be an immediate indication if the predicted failure pressure is less than 1.25 times MAOP.

Given the requirement for an immediate and as Dave mentioned earlier, the cost of an excavation skyrockets if it's an immediate versus a scheduled condition.

On top of that, we do take into account tool tolerance; our predicted failure models are conservative. So, there's layers over

layers of conservatism in even the calculation of the predicted failure pressure.

On top of that, having a further conservative criteria for scheduling an immediate dig I believe makes it more onerous than it could be.

So, just for the consideration of the Committee, if we can discuss this and see if this is still appropriate? Thanks.

MR. DANNER: All right, thank you. Is there any further comment on the cracking criteria?

Okay, hearing none, I'll turn it over to the Committee. Do you have any comments or any response to the public comments?

Okay, all right, so what we're going to do, we're going to take a short break right now and then we'll come back and we will start the Committee discussion on the cracking criteria.

So, it is currently 9:58 a.m. and we will be back here at 10:10 a.m.

(Whereupon, the above-entitled matter went off the record at 9:58 a.m. and resumed at 10:33 a.m.)

MR. DANNER: Okay. We're going to be back on the record. I would like to just let everyone know we've been joined by the Deputy Administrator, Drue Pearce, so good morning.

MS. PEARCE: Good morning.

MR. DANNER: And now we are going to begin the Committee discussion on the cracking criteria. So as you can see, there's some new language on the slides in front of you. Who wants to start the discussion? Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I appreciate the break. These are -- at first, I think it's important to frame this discussion. This whole section about cracks is brand new, so, you know, we haven't been looking at any kind of response criteria for cracks. The whole thing is a brand new discussion. This is all a value add, so to speak, to the industry, and so there's a lot of trying to sort out what

does this mean.

I think part of the conversation we had the other day I'd like to bring back to help also with the perspective, and that is the tools that we use to look at cracks in gas are on a vertical developmental curve right now. So they're getting better, we're making better use of them. We also know better, quite frankly, than to get a conspiracy of optimism going here about their ability to look at size and discriminate small features. So having really aggressive numbers here is interesting, but what's relevant is we can't practice some of that because it's just not where the tools are right now.

So I think as we look at this, I'd start at the top. When we go to an immediate event, you know, one of the things we're trying to incentivize people to do is not use simple solutions for complex problems. We need to be looking at tool tolerance. We need to be looking at colony crack length, not just crack length.

We need to be considering realistic growth rates and things like that.

When we look at all of those things, we would typically come in at a 1.1 as an immediate. And what is an immediate? An immediate is something that is urgent, it's pressing. It's something that represents a significant encroachment on the confidence interval and needs to be addressed in a very tight time frame. If you've done all of those considerations, 1.1 is an appropriate number. If we're not going to do all those things, all right, well, then maybe 1.25 is the right number. But I think what we're trying to do here as we institute something new is: what behaviors are we trying to create in the industry?

If you go to 1.25, I think what you're going to do is get a gamesmanship thing going on where people don't look at tool tolerance, they don't look at colony length, they're not doing the things you want them to do so that they don't have to dig up half of the earth. And that's not

the right behavior that you're trying to incentivize.

So, you know, if we're going to do 1.25, okay, I think people will start discounting tool tolerances and other things, which is probably not where you want to go. I would actually opt for 1.1. It is an appropriate level if you're doing this correctly with tool tolerances, colony length considerations, and things like that. That's actually better engineering. That's actually better practice. It's also congruent with how you handle corrosion anomalies. So we'll just try to get in that same rhythm of prudent practice.

The other thing that I would say is or we'll have, prior to the next assessment, that little paren there taken out. What you're trying to do with urgence is you're trying to figure out is it urgent right now and deal with it. If it's not, then you go down to the scheduleds, and the scheduleds is where what you're trying to do in the scheduled. So my recommendation is take that

paren out. To me, you've got conservatism on conservatism here. These are things that are supposed to be dealt with immediately, so growing them is down in the next category.

In the next category, what you're trying to do here I think is try to figure out, you call it a predicted failure pressure, we call it FPRs, you know. But I think a number down there of a 1.39 number is about the right number, but it needs to be calibrated to the design criteria. I think Dave had a good comment a few minutes ago. Not class. Class is not the right answer. It's the design criteria, and you want to set that.

What that number is trying to do is trying to tell you, based on the growth rates and unity plots that you're doing, that number actually does consider growth and is telling you these are the ones to watch inside this time frame before the next re-inspection. So I agree with the striking of that "or prior to the next assessment." That's the purpose of that number.

That is what it's trying to do. And I think operators should be obligated to do some sort of unity plot verification to make sure what they're finding is lining up with that. I think that's prudent practice.

I don't mean to be sounding like I'm just tearing this to piece. I think this is a really important juncture that we're at. You're trying to institute something new and what behaviors do you want to come along with that?

So, you know, my recommendations for this right away would be taken the parens out. I don't think they help in either place. Get the numbers to line up with your design criteria, which I think we're pretty close to that. And I think the real question here is if you're going to stay, I would encourage you to go to 1.1 and then add things like operator should consider tool tolerances and things like that. I think that's really important here. But if we're not going to do that, I think 1.25 can work. It just has to have the parens taken out. Thank you.

MR. DANNER: All right. Thank you. Is there any other comment on the language before you? Cheryl?

MS. CAMPBELL: Cheryl Campbell, Xcel Energy. Thank you, Chair. So I think Andy makes a lot of interesting points and, again, just like we were talking earlier in the week about fracture mechanics, I mean, this is not my area of expertise. I'm just going to admit that. But I think that ensuring -- I agree, by the way, that this is new, right? I mean, we've all found some cracks and some features. The operators have found cracks and features in their pipelines, and I can remember standing next to one one day staring at it going, gee, I wonder what we're supposed to do with that. So, I mean, I get where you're coming from, Andy. This is kind of new, and we're trying to drive the right behaviors for the operators and the technical teams. How do we deal with that?

So I like adding some, maybe some additional words that talk about some of those

expectations. I mean, you should be thinking about tool tolerances and some of these other things, right, when you're thinking about growth rates.

I also agree with the comments about immediate. I mean, if it's immediate, then, boy, we better be out there taking care of it if we're that concerned about it. So I would agree with I'm not worried about "will have prior to the next assessment." It doesn't feel like that belongs there.

As far as -- I also, by the way, agree about the design conditions or the design factors. I think that makes more sense to me from a technical standpoint than using the class, and I do think it forces the operator into thinking about the class because is it not true that the design factor already takes the class into account, right? I mean, that's my recollection from long ago that the design factor already takes the class location into account. So I think that simplifies it and makes it a

little more straightforward. And then, you know, give people the ability to repair within a time frame as long as you're outside of that sort of immediate category.

MR. DANNER: All right. Thank you. Any other comment? Andy?

MR. DRAKE: This is Andy Drake. I just want to follow up on one point, and I want to be clear on this. I'm talking about an either/or here with the 1.1 and tool tolerances. I'm not talking about adding tool tolerances, colony considerations, growth mod-ing, and stay at 1.25. I think what that's going to do is actually dis-incentivize people from running this tool, especially given the developmental nature of the tool. People are not going to take that risk of running that thing and having to jump over this humongous hurdle.

So I think you're trying to land here in a place that incentivizes people to do the right thing but not punishing them inordinately for what they find, but keeps this in front of

them and manages it appropriately.

MR. DANNER: Sara?

MS. GOSMAN: I'm wondering if PHMSA could expand a little bit about the basis of the 1.25 versus 1.1.

MR. DANNER: Steve?

MR. NANNEY: Yes, this is Steve Nanney with PHMSA. I guess I need to put this closer. What PHMSA did is on the 1.25, the 1.39, the 1.5 are, it's just like our public comment was. I'm going to start there and just build into your question.

When you say Class 1 pipe or whether you say Class 2 or 3, that means you've got a design factor based upon that class and that also means that you would have pipe diameter wall thickness grade attributes based upon that. From Class 1 to Class 2, the reason the question was asked and we added the comment in red was because if you have a class change from 1 to 2, you've had a pressure test in the past at a certain amount to be able to do that. And so that design

factor would not change if it was a 0.72, which is, 1.39 is the reciprocal 0.72, and they're both interchanged depending upon how you're using them. That pipe wouldn't change. That same wall thickness and grade would be still there, so that's why we clarified that. We thought it was clarified in the notice, and we'll make sure we clarify it.

As far as getting to the 1.25, what we did when we were looking at this, there's criteria in an ASME document called STP dash, I think it's 01. I may be hitting me up right here to remember. And it's on stress corrosion cracking, but it deals with how to deal with cracks as far as what the pressure failure ratio should be. And it has a 1.25, it has a 1.39 or 100-percent SMYS. And what we tried to do is look at the categories and the timing that it had of when you need to be doing those repairs and be consistent with it is what we were trying to do.

And so that's how we got the 1.25. That's how we got the 1.39. You know, we're

always open to listening to additional information, but that's how we got it.

MR. DANNER: All right. John?

MR. AIREY: Steve, Jon Airey. Could you comment on Andy's suggestion of going to 1.1 in that first section? It made a lot of sense to me, and I'm just curious about your comment about it.

MR. NANNEY: Again, this is Steve Nanney with PHMSA. Again, PHMSA would have to go back and look at that to see if we agree or disagree. The one concern I would have on the comments is on tool tolerance and usage of tool tolerance. Even though operators are doing integrity management and uses of tool tolerance, PHMSA finds a lot of times that they're not using it or they're misapplying it. So I hear what Andy says, but we would have to go back and evaluate that fully before we would consider it one way or the other.

MR. AIREY: Let me follow up on that if I could. What if we just made the change to

1.1? It seems to me that that's a reasonable trigger for immediate action, and we left out a discussion of tool tolerance which I think Andy was also proposing, and it would avoid that issue that you're concerned about.

MR. NANNEY: Putting the 1.1? Well, again, on other occasions, have stated how using dent tools, whether it's an EMAT or whatever type tool, is a developing technology, etcetera. So, again, before PHMSA would consider anything other than 1.25, we would have to look at what the Committee suggests and look at the various concerns before we would consider it.

MR. DANNER: Andy?

MR. DRAKE: This is Andy Drake with Enbridge. For the record, I agree with Steve. It's an either/or. I think the tool is in a learning curve, and people need to be deliberate about understanding the tolerances that they have. But I think the point is trying to shape the right behavior, which I hear you're trying to get people to go this direction, consider that

tool tolerance, consider how to model these cracks effectively. And then, once you do that, then you should be looking at this in the accurate lens of what is it you're trying to do in an immediate, what is an immediate? An immediate is something that's really getting close, and we need to deal with it right now because you've taken a really good look at it and you know it's close. Well, if you do that, then 1.1 is right. But if you don't do the other things, I think you need a little margin, and I think that's the point of what Steve is trying to do.

So I see it as sort of an either/or proposition myself. I just wanted to be clear.

MR. DANNER: All right. Sara?

MS. GOSMAN: Sara Gosman. I'm trying to think through this issue of sort of gaming the system a little bit through tolerances, and I guess my concern is, you know, we aren't putting anything specific in here around tolerances, so that's already something I think that can be

different, I suppose, based on the operator.

Here we actually have a particular threshold, and I wonder whether that doesn't apply to any sort of situation in which you're going to set a threshold. I mean, that is the incentive could be for somebody who isn't going to do the full, go above and beyond is to pull back based on other safety factors. So that's just sort of one comment/question about whether this applies here, whether it's sort of a broader problem.

And then I guess the other question I would have is back to data. Do we know what we're looking at in terms of 1.1 versus 1.25, in terms of numbers, right? I mean, a sense of the scale here of the differences for purposes of immediate conditions. Is this an issue around we're suddenly going to be getting a ton more anomalies between that 1.1 and 1.25 or not, or do we even know?

MR. DANNER: Andy?

MR. DRAKE: This is Andy Drake. I

think the relevance -- your question is the right question. I think it has a little twist to it, and that is actually all we're really talking about here is time to respond. What you're saying is, urgently, I have to get out there if it hits this hurdle rate, you know, 1.1 or 1.25. If it doesn't, if it's not urgent, then it's scheduled.

So now the real question becomes: what's the likelihood of something between 1.1 and 1.25 growing to be a problem before we get there? And that, I think, is where the unity plots come in. The operator, as long as you've got tolerances and things adequately considered, we're not seeing things break out of those models, which is good. I mean, that's actually a very good confidence builder that the response times on those unity plots are getting people out there fast enough that, if they dealt with tolerance and they've got the right assumptions in the models about colonies versus crackling, that they're responding on a schedule that is

commiserate with that threat. Does that make sense? It's not so much the numbers.

What ends up happening is you move a lot of anomalies that can be managed successfully with time into a very urgent response situation, which is expensive, frustrating, and not terribly productive. And that's all you're trying to make sure you understand as an operator.

MR. DANNER: All right. Sara, then Cheryl.

MS. GOSMAN: Thanks again for helping me understand this. So am I correct then that, ultimately, this is about what the safety factor is? That is the sort of underlying assumption here relates to whether the particular safety factor as represented by 1.25 or 1.1 is important enough to move on immediate versus scheduled? And that seems to be an assumption built into then this conversation. And I'm listening to PHMSA say they have, you know, they're supporting this through an ASME report, and I'm just wondering -- I'm trying to figure out whether

this is an issue of practicality, an issue of differences around whether the risk is significant enough, some combination of those things, and a sense of the scale -- all of those things combined. And it's just I'm lacking clarity on why this is so important to go from 1.25 to 1.1.

MR. DANNER: All right. Andy, do you want to respond to that?

MR. DRAKE: This is Andy Drake with Enbridge. I think all we're really talking about is: what is urgent, and how accurately can we portray or define urgency? If you use tool tolerances and these other things, I think you have a much better sense of the shape and sensitivity and urgency of the anomaly. If you don't do that, then this more globular criteria probably gets you to the same place.

If you go to 1.1, you have to bring in these other considerations, which is, I think, prudent from an engineering and operations standpoint. But you're not losing track of the

other anomalies. You actually are, you have a better lens. You're looking more accurately at the world and you're making better choices about what is really urgent and then what needs to be scheduled.

With a fuzzier look or a more globular look, you're kind of cleaving this a lot more conservatively because you're not looking as accurately about what is urgent. But you're not dealing; you're not not dealing with it. It's just is it urgent or can I schedule it, and I think that's the difference is if you look at it more accurately you can probably schedule it because you can see it better or you're modeling it better. If you can't, then I think you might move it to where you deal with it more urgently. But it's not that you're not going to deal with it. I think that's the key. You will deal with it; it's just can you see it precisely enough to plan it versus just doing a lot more of them at one time.

And I think there was a comment made

earlier that doing a lot more of them urgently is not productive either. You know, that just puts a lot more work in a very, very expeditious period of time, which is not helpful for a lot of other reasons if I know better. That's the difference.

MR. DANNER: All right. Thank you. Cheryl?

MS. CAMPBELL: Thank you. Cheryl Campbell, Xcel Energy. I was just going to, I want to expand on that point that Andy made there about the urgency. I think that we're interested in making sure that the items that are urgent are in that category and that we are responding to them appropriately. I'm actually okay with having some that aren't urgent in that category, too, right, because you want to err on the side of caution here, right?

I think what makes people crazy, operators crazy in particular, and, frankly, the communities that we live in at times may be more for the LDC group, Andy, than the interstates.

But when you start having a lot of things that you're calling urgent in that urgent category and they turn out not to be, right, then, A, it's very, very expensive and, B, it's very, very disruptive. So if I'm having to get emergency permits and then I'm digging next to a big road or a highway, I've got all kinds of road issues, I have everybody and their brother mad at me because I just impacted their commute, I mean, it's really pretty amazing how quickly that sort of can spin up on you.

So I think it's an interesting balancing act. Again, we want things that should be urgent in that category and a little beyond. But we don't want so many things in that bucket that we are disrupting a lot of things around there. You can only go ask for emergency permits so many times from the same community, frankly, before they start not believing you.

So, I mean, I think that's Andy's point of what we're trying to do is where is the right line to draw because I agree we will deal

with these issues. The question is do I deal with them in a very short period of time, or can I be more thoughtful about how I schedule dealing with these things?

MR. DANNER: All right. Thank you. Rich?

MR. WORSINGER: Rich Worsinger, Rocky Mount. First, let me use the same qualifier Cheryl did. I am not an expert in any way on transmission and cracks and all this, but I still think that I have some points that need to be considered.

Many of APGA's members are fed by a single transmission line. And it's critical that that line have the pressure that's needed to serve these various LDCs, especially during high load like the winter. And I'm concerned that that line could have a pressure reduction that is not actually needed that could affect the ability of that LDC downstream of that transmission line to serve its customers.

To build on Cheryl's point, it

certainly is easier to do scheduled work than emergency work, especially if you can schedule that work in the shoulder months, either spring or fall, not in the high usage months, depending upon the system, of course. And I guess a question that could be answered either by PHMSA or by Andy, maybe both: is this mature enough to be able to be brought into regulation using these tools, this evaluation? There seems to just be some concern over what value you use, and I'm wondering if this technology has matured enough to be considered, especially if it's going to take a line, a pressure reduction and a line that could negatively affect the ability to serve customers.

MR. DANNER: All right. Andy?

MR. DRAKE: This is Andy Drake. I think we are at a place where the tools -- you know, yesterday I was talking about a thing finder. That was three years ago. I think the algorithms and the assessment criteria and the tools themselves have developed quite a bit where

they're actually very good at finding critical size cracks, and I think that's really important.

But down below a certain threshold, we almost mask that off because it's not able to discriminate or size consistently and accurately below a certain size. But it can find critical things fairly consistently and accurately. And I think that's just where the technology is which is okay. We should use the part that's working, but be conscious of the noise. When we start trying to grow little things, we don't even want to look at the little things because we're not even sure they're real, which is really the conversation that's happening here.

So I think we're moving forward in the right direction. We're truly at the front of the ship here. I mean, this is all brand new. The technology is evolving, and I think that's part of the conversation is: how do we set this up for success where we're not dis-incentivizing people to do this because we create a hurdle rate so high but actually shaping the right thinking as

they got into using these tools and how to accurately assess what they're finding.

MR. DANNER: All right. Other comments? All right then. We have some language before us. I'm not seeing any proposals for amendments to that language right now. Alan, why don't you go ahead?

MR. MAYBERRY: I guess what we're looking for is if the Committee could provide edits to this where you think it ought to be, and then we'll take it and consider it. And that's I think where we are right now.

MR. DANNER: All right. Andy?

MR. DRAKE: Andy Drake with Enbridge. As a minimum, we're typing as we're watching here, so it's sort of real-time thinking. But I think in the third bullet on the immediate stuff at the top, the material in parens is not necessary and it's kind of counterproductive. It is immediate or it is not immediate right now, and that paren needs to come out.

When you get down to the next section

where you're talking about scheduled anomalies, how we deal with "or could grow to an immediate condition 1.25 or less prior to the next assessment" is really what you're trying to accomplish with what we call FPR, you call it PFP, of 1.39. I had it in my mind that it was kind of okay with taking the paren out like you've done and then just leaving it at 1.39, but I'm trying to figure out what we're trying to accomplish with the next.

I think 1.39 accomplishes what you're trying to say with that new red stuff below because that's the unity plot. That's what you're trying to achieve there. So, you know, I would probably take that part out, and I think you're pretty close. I do think -- yes, the design criteria, we did take the words class -- well, there it is. Yes, you still have class in there. I think you want to take the class stuff out and talk about commensurate design criteria for 0.72 design factor, 0.5 design factor.

The class isn't the right reference.

It's the design factor that you want to switch out there. Now I think you're done dialing in on what is the thing designed to do and how is it responding to that, not the class. It's kind of interesting you've got this class bump stuff going on, and it throws everything off. Does that -- sorry. I'm trying to keep up with you on the redline stuff.

MR. DANNER: All right. While we're waiting, Cheryl, do you want to weigh in?

MS. CAMPBELL: Sure. Thank you. Cheryl Campbell, Xcel Energy. So I would ask, I would ask probably PHMSA and the Committee both, I mean, this is kind of my sense of what we're trying to do here. You know, I'll go back to what Andy was talking about earlier. That top part really is about are we defining those items that we should be taking immediate action on, right, we should be responding to immediately and taking care of.

And then, once you get those taken care of, okay, so now I've responded and I have

another group of anomalies let's say. So now which of these anomalies -- how do I deal with them, right?

So I think you're intention, and I'm asking for clarity, I think your intention is that we, operators, are paying attention to those anomalies, we are making sure we understand if they're going to get -- and I'm not going to use the right words -- if they're going to get serious before I'm supposed to be assessing again and I'm taking action. I mean, I think that's what we're trying to say here is take care of the stuff that's immediate and then be watching the rest of them and understand where they're at and how they might be changing, and do something about them before they become a problem. Is that where we're trying to -- I mean, that's my sense of what we're trying to talk about here, or have I just totally misunderstood?

MR. DANNER: Alan?

MR. MAYBERRY: I mean, that's basically it is deal with the immediate but then

be aware that, you know, be aware of your system essentially that you're able to snag the others before they become critical size. You know, I think, historically, you know, looking at what's happened out there, when failures have happened, you know, we often hear that, well, I allied that in the recent past. I'm just speaking anecdotally. It could involve a variety of types of flaws or anomalies, but it's just essentially know your system and be able to be in a position to know that you need to take action to repair a feature before the next, you know, before it grows to a critical size to fail.

MR. DANNER: All right. Sara?

MS. GOSMAN: Sara Gosman. It looks to me like what we're trying to do is essentially use (d)(1) here as the standard for that last crack anomaly, so that's the one that says 1.1, right? Am I right on this? Okay.

So in that paragraph, there's a discussion of the records that are needed and what happens if the records are not available.

So I'm wondering if proposal here includes all of the information about those records, as well, or if the proposal is simply to go to 1.1.

MR. DANNER: All right. Does anybody want to respond to that? Andy, do you have a response to that?

MR. DRAKE: I don't know if I do or not. My card was up for something else. But I think the records for this are in 712 under fracture mechanics modeling. And, you know, the discussion we had yesterday about toughness assumptions absolutely weighs in here, and that was why it was so important to get some of that because you may not have those records because so much of the system doesn't have toughness tests, what is that assumption, plays into this discussion.

So I think we have kind of, we're sort of closing down the size of the gap through all these conversations over so many issues over so many days. We're sort of getting down to we've already talked about toughness, we've already

talked about some of these other pieces, and now we're getting to leverage them. So I don't think the records issue will -- I don't think that's a big problem here because how we assume the lack of records has been kind of dealt with. Well, I mean, that's what we talked about yesterday.

Before I move on to my issue, I just want to make sure that answered your question.

MS. GOSMAN: So I guess to be more specific, I think you've answered my question, but just to clarify, so the language in (1)(i) there, would you be willing to put that entire language into the bullet point that we're talking about now?

MR. DRAKE: Okay. Which bullet point are we talking about now?

MS. GOSMAN: Number three under the immediate conditions.

MR. DRAKE: Okay. So number three about immediate response criteria based on 1.25. So what would we add to that?

MS. GOSMAN: The language in (1)(i).

MR. DRAKE: Okay. (1)(i). Can you just read me that?

MS. GOSMAN: Am I looking at the right place, 713(d)(1)(i)?

MR. DRAKE: I think (1)(i) is metal loss. So we're talking fracture mechanics, which is 713.

MS. GOSMAN: I apologize. Hold on.

MR. DRAKE: Everybody is scurrying about looking at their codes back here. This is kind of fun.

MS. GOSMAN: There's the same language in this one. Okay. So 933(d)(1)(i). So let me back up here. So what I want to be able to understand here is, and if I'm getting it correct, and I apologize my voice is leaving me here, but if what we're trying to do is essentially apply this general standard, we had something specific for cracks before that related to significant ones. We're now going to apply, as I understand it, at least for this particular bullet point, this 1.1, as opposed to 1.25 for

cracks, then, if we're going to do that, are we also going to include all of the information about records? Because it seems to me that then we want to be really careful about making sure that we have documentation that supports that particular decision in the same way, I mean, if we're going to do it for that general one, I would assume we would want to do it for the cracks.

MR. DRAKE: I'm getting a lot of help here, which is good. I think you're exposed to it, which I think -- not exposed to it. I think you're accountable to follow it in 712, which is good. So I think you're accomplishing what you want, but I would be hesitant to add it here also, rather than point to it. I mean, if we want to point to it, that's fine. I just don't like where you repeat sections of the code in three or four different places because I think you end up getting out of sync of how it applies.

I think you just want to point to it in context in its entirety. But I think that

it's there is the point. You're accountable to have those records to make that choice. Is that fair, Steve?

MR. NANNEY: I was not listening, to tell you the truth.

MR. DRAKE: I appreciate your candidness about that. I didn't mean to catch you off guard.

MR. NANNEY: I was reading something. Don't take offense. It wasn't that I was not trying to -- what did you say?

MR. MCLAREN: Yes, you would be accountable for those records. And I think the beginning of the discussion started by looking for 192.710 of pipeline assessment Section D data analysis, where all of the requirements are taking into account tool tolerances and accounting for other uncertainties and then doing unity plots and making sure that you're performing that integrity assessment correctly. Maybe there might answer your question. Thank you.

MR. DRAKE: This is Andy Drake with Enbridge. I think in answer to your question, as far as I can tell, the intent is to require the operator to have that data to make these decisions, and that is referenced in these 700 sections. I don't have a problem with that. I think that's appropriate. We're just arguing or talking through how to mechanically make sure that happens, but I think the intent is clearly there to make sure that happens.

MR. DANNER: All right. Sara?

MS. GOSMAN: Sara Gosman. I think what I'm interested in doing is, however the language is, is being sure that the language that is in (d)(1)(i) there -- now that I've got the correct section, 192.933 -- that that language concerning records, right, and the TVC records and the documentation that supports this kind of determination, that that language, if found in another place, we could certainly reference it. But, like, the fact that we have that specific language in that one paragraph, I would want to

see similar language as it relates to cracks because then, again, if I'm understanding this correctly, we now have a section that specifically references this set of documentation, but we're going to bring cracks down to that particular section without that set of safeguards around documentation.

MR. DANNER: Okay. So we want to add to that bullet that we would add a cross reference or cite to that section of 192.933? Okay. The way I see that, though, that Andy's concern about not picking up and repeating code language in multiple places is not addressed, so we just want to reference it. Oh, Ron, I'm sorry, I didn't see your card was up.

MR. BRADLEY: Thanks, Mr. Chair. Ron Bradley, PECO. So just sort of listening and absorbing this conversation, I like the concept of, I mean, it's what we do in the business. I like the concept of having an immediate repair criteria, whether it's transmission or distribution. It's not the same, but we do have

criteria that are immediate, then we have schedule, and then we have monitor only, and then we're in the same condition with this.

I think what I'm listening to is us trying to figure out what immediate is. If we set the bar to a place where the risk that we mitigate has us chasing something every day, then everything is immediate and nothing is immediate and we find out that we have our resources doing things that don't really mitigate against the risk. And that's a challenge, and that's a challenge no matter what side of the business you're in. We want to make sure that, if there's anything that needs to be addressed immediately, that we're out there, we're taking care of it, and we're mitigating the immediate nature of it, either permanently or taking some action that, you know, in transmission, you're going to do something permanently. In distribution, you can do something permanently, or you can defer based on where the actual levels of the gas are.

All along, we're documenting that. I

mean, so what I'm challenged with what we're trying to do today is listening to the public with the input, listening to the Gas Pipeline Advisory Committee with the input, and then walking away and trying to operationalize it in a way that puts resources in the right place. And I think that's really hard to do. I think we're going to have to take the advice of the Committee, and that's my ear. My ear is listening for that because if we write something here and then go away and then -- Andy, I love the thing finder thing. I got the image of it, but if we go out and start popping holes all over the place and don't add value, that's not a good thing because the real leak could be happening right around the corner and we need to go focus on what we got to focus on. Just a comment.

MR. DANNER: All right. Cheryl, your tent was up.

MS. CAMPBELL: Thank you. Thank you, Mr. Chair. Cheryl Campbell, Xcel Energy, and I'm just reading the last bullet there under the top

section, "material necessary for correcting defects." I would encourage us to consider, you know, pointing, referencing your point, Chair, referencing a piece of code that's already there, right, rather than lifting, rather than lifting and repeating here. That makes it easier in the future to kind of keep it all, right, to kind of keep it all straight, as well, rather than redoing it. So that's really all I wanted to support was the citation, as opposed to adding specific language.

MR. DANNER: Okay. Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I'm trying to keep up with the typing. I see -- first of all, I wanted to declare to Sara: we're in agreement. You need to have the records there that are appropriate. But when we talk about what we're referencing, I think we need to remember we voted on this yesterday, so it wasn't that long ago. That section we should be referencing is not 607, it's 712. That's what's applicable to here. And I think if we

want to go back and look at what we talked about yesterday. I mean, I'm fine with that, but that's what fits here. You don't want to do all of 607 every time we do a crack. I mean, that's going to get to be really a lot of, you know, machinations. You want to do 712 here.

And I think, I'm not trying to do anything other than connect the conversation we had yesterday to this conversation, which I know we deal with a lot of stuff, but that's the appropriate reference that goes there.

MR. DANNER: Okay. Are we there? Okay. Oh, your tent is up again.

MR. DRAKE: On a separate issue. I think, you know, again, I'm trying to keep track of the editorial stuff that's going on here real-time, but we talked about class, and I would offer this as a blunt instrument solution, rather than switching over to design factors, is where you have 1.3 times, it's the second bullet under scheduled and it says 1.3 times MAOP for Class 1. I think if you put Class 1 and 2 in there you

accomplish the same thing. It's a little bit more of a course cut, but you kind of back into it because it deals with the class bump. And what you're really saying is 1.39 is the sizing criteria for Class 1 and 2 design factors. And 1.5 times MAOP for 3 and 4, what you're really saying: is when you switch over to the Class 3 and 4 design factors, you can't have a commensurately big crack. It has to adjust to deal with design factors. And so you're sort of cutting it in two sections.

I think that's an alternative way of dealing with this, because I'm appreciative of the complexity of trying to reference design factors in here. But if you just group it in Class 1 and 2 and 3 and 4 at 1.39 and 1.5, you accomplish virtually the same thing.

MR. DANNER: So what would you have the sentence read?

MR. DRAKE: Where it says in parens "for Class 1," I'd just say "or Class 2." And then it says "or 1.5 times MAOP for Class 3 and

4." You accomplish the same thing. You're just sort of demarking that when you get into the thicker materials you don't want to use a 1.3 ratio. You don't want to allow a crack that big, and you're just sort of setting a stage gate that says, okay, we switch over to a smaller or more intense criteria. That's just an alternate way of doing it because I can appreciate, I was watching you guys' brow wrinkle and you're trying to figure out how to do design factors on this, and I think that accomplishes the same thing.

MR. DANNER: Okay. So I just want to raise the fact that, once again, we've got a reference to TVC here, and I believe we parked the definition of TVC yesterday. So we're going to have to revisit that after we approve that. Steve.

MR. NANNEY: I was waiting until the mixture got into the milk, I guess. The comment I'd like to make on what Andy just said was I really think adding that Class 2 and the 1.39 is not quite what I would suggest that you consider.

I would say our Class 2 that has Class 1 design pipe in it would be my thought there, would be more appropriate.

MR. DANNER: Andy, do you want to respond other than to wave your arms?

MR. DRAKE: Yes, it's hard to get that on the record, I'm sure. This is Andy Drake with Enbridge. I was just trying to cut a design -- where do you want to worry about getting a bigger crack? If you want to cut it at 0.72 design factor, that's okay. You just had to deal with the class bump. I really think it becomes a bigger problem when you get to the Class 3 and 4 design factors, 0.5 and 0.4, because you're now allowing a pretty sizable crack.

So I don't want to get into splitting hairs with you, Steve, but that was my intent. It was just create some differentiation that people can see pretty easily.

MR. DANNER: Steve?

MR. NANNEY: Again, I would suggest to the Committee that you consider it being Class 2

where it's changed and the pipe hasn't changed out. And the reason there is the 1.39 is times MAOP for Class 1 is tied into the 100 percent of specified minimum yield strength. In evaluating whether it's a pressure test or using this for monitored is more what you need to be looking for. Class 2 is one that we had selected the 1.50 as being, I realize it would be 1.67 if it was 100-percent SMYS, but as a compromise of it being thicker wall and everything, but with the Class 1 being thinner and you having cracks in it, which means that it's low toughness and everything. And the same thing with Class 2. I just think it would be more appropriate to be in the 1.5 area. And I realize the Committee can do what it would like to suggest, but that's just a comment.

MR. DANNER: So if I can clarify, you had suggested, so you'd say for Classes 1 or 2, when it involves -- what did you say? Class 1 pipe?

MR. NANNEY: When there's Class 1 pipe

in the Class 2. In other words, it's been a class bump would be one of the colloquial terms that we use.

MR. DANNER: Okay. And then you'd say 1.5 time MAOP for other Class 2 and 3 and 4?

MR. NANNEY: Yes.

MR. DANNER: Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I don't have a big problem with that. I guess just the fracture mechanics side of me is peeking out here, and that is this cracking problem diminishes as the thickness gets heavier. So the need to be super precise as we get into the heavier wall materials is not as pressing as it is on Class 1. And I guess, you know, my only thought here is: is the juice worth the squeeze, this incredible level of precision as we get into thicker and thicker materials, because I was just trying to create a step that didn't allow a big crack to exist in heavy design factors.

If we feel, you know, strongly that we've got a lot of data, I don't know about a lot

of data where we're having cracks that are encroaching on this on the thicker material. Is that a problem, Steve? I mean, are you seeing problems with this, just for my own insight? Because as we get to thicker materials, this conversation and volume of issues should be deteriorating.

MR. NANNEY: We will look at it as we get more data, but until we do we should get it as close to the 100-percent SMYS as we can. So, again, I just recommend to the Committee that you consider the higher number for Class 2. The Committee can do what you would like to suggest.

MR. DANNER: Well, the recommendation right now has "consider" in big red letters at the beginning. And I think my own view of it is let's just put it on the table that for Classes 1 or Class 2 that involves Class 1 pipe and then 1.5 times MAOP for other Class 2 or Classes 3 and 4. And I think that you have said that you would go back and look at how much of a problem it would be simply to say Classes 1 or 2, and we'll

just trust you to do that.

MR. DRAKE: This is Andy Drake. I agree with that. Steve, I trust your judgment on this. I mean, if you've got data that shows we're having Class 2 cracking problems, well, all right, if we want to cut it that fine. If this doesn't hurt us, at least let's consider it.

MR. DANNER: Does that work for the Committee? Okay. All right. Andy?

MR. DRAKE: In the interest of moving forward, I'll make a motion.

MR. DANNER: I'd appreciate that.

MR. DRAKE: All right. Voting language for repair criteria, paragraphs 192.485(c), 192.711, 192.713, and 192.933. The proposed rule is published in Federal Register and the Draft Regulatory Evaluation with regard to provisions for cracking repair criteria are technically feasible, reasonable, cost effective, and practicable if the following changes are made: strike the proposed definitions of significant seam cracking and significant stress

corrode and cracking in paragraph 192.3; delete the phrase "any indication from the repair criteria relating to cracking"; three, combine the repair criteria for stress corrode and cracking and seam cracking; four, require that PFP for all time-dependent cracking anomalies be calculated using the fracture mechanics procedure in paragraph 192.712; revise the definition of hard spot to read as follows: hard spot means an area on steel pipe material with a minimum dimension greater than two inches or 50.8 millimeters in any direction, and hardness greater than or equal to Rockwell 35 HRC, Brinell 327 HB, or Vickers 345 HV10; consider the below crack repair criteria for immediate conditions: crack depth plus corrosion of greater than 50 percent of pipe wall thickness, crack depth plus any corrosion that's greater than inspection tools maximum measurable depth, or the crack anomaly is determined to have a predicted failure pressure that is less than 1.25 times MAOP. PHMSA to consider 1.1 times MAOP for immediate

conditions after tool tolerance has been field verified and applied; clarify through a citation that material records necessary for evaluating crack defects are determined and documented in accordance with 192.712; consider the below cracking repair criteria for one-year HCA and two-year non-HCA conditions; crack depth plus corrosion of greater than 50 percent of pipe wall thickness; the crack anomaly is determined to have a predicted failure pressure that is less than 1.39 times MAOP for Class 1 or Class 2 with Class 1 design factor pipe or 1.5 times MAOP for other Class 2, 3, or 4; and crack anomalies that do not meet either the immediate or one-year/two-year conditions would be monitored condition.

MR. HILL: Robert Hill, second.

MR. DANNER: All right. It has been moved and seconded. Any further discussion before we take a roll call vote? All right. Hearing none, Cheryl, we're ready for a roll call vote.

MS. WHETSEL: Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan?

MS. LONGAN: Aye.

MS. WHETSEL: Terry Turpin?

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell?

MS. CAMPBELL: Aye.

MS. WHETSEL: Andy Drake?

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley?

MR. BRADLEY: Aye.

MS. WHETSEL: Rich Worsinger?

MR. WORSINGER: Aye.

MS. WHETSEL: Jon Airey?

MR. AIREY: Aye.

MS. WHETSEL: Robert Hill?

MR. HILL: Aye.

MS. WHETSEL: Sara Gosman?

MS. GOSMAN: Aye.

MS. WHETSEL: Okay, then that carries.

MR. DANNER: Okay. Motion carries. All right. So we are going to go into public comments on the fourth grouping, which is corrosion/metal loss criteria, including ECA and anomaly type. Do we have any public comments on that last bucket? Okay. Seeing none.

MR. JOHNSON: Nice try, Mr. Chairman. Dave Johnson, Energy Transfer. To kind of continue in the corrosion aspects, the same discussion that we've just been having on class location versus design factor, one of the aspects that, again, has not been considered on this is there doesn't seem to be any consideration of alternative MAOP pipelines. So what this boils down to is the two design factors that are typically allowed in a Class 1 area are 0.8 and 0.72. The reciprocals of those are 1.25 and 1.39, which are numbers that we've been talking about. But in a Class 2, it's possible for an operator to have design factors of 0.8, 0.72,

0.67, or 0.60, and they have all of their corresponding reciprocals that, again, range from 1.25 up to 1.67. And then in Class 3 locations, it's possible for an operator to have design factors of 0.67, 0.60, 0.56, and 0.50, again with their corresponding reciprocals.

So I think if, you know, particularly if we continue to talk about just class location and the factors that are associated with the class location, we miss the so-called class bump or pipeline that is operating at typically one design factor notch higher than would be designed for its class location, and maybe it was intended but this completely ignores the alternative MAOP pipe which operates at about 11-percent higher design factor than the traditional design factor.

So I think there's just a lot of clarification that needs to be done here because, as an operator, we have to deal with all of this. And if there are gaps or uncertainties or things that are mutually exclusive, where pipeline that has undergone a class location change and is

operating at a higher design factor is subject to a factor that makes even pristine undamaged pipe unacceptable in that location is just not appropriate. Thank you.

MR. DANNER: All right. Thank you.

MR. WARD: Good morning. Darral Ward, Boardwalk Pipelines. Boardwalk shares the desire to drive the immediate repair count down in HCAs. In the slide deck, PHMSA asserts that changes are necessary to a criteria for scheduling corrosion anomalies in order to reduce the number of immediate repairs.

Boardwalk evaluated some immediate repair data for HCAs since 2010 and determined that approximately 90 percent of the immediate repairs were actually due to dent anomalies with any indication of metal loss. Rather than changing the corrosion criteria, we believe PHMSA has proposed separation of top side and bottom side tents with metal loss, and PHMSA's new dent with metal loss ECA will allow operators to appropriately prioritize dent anomalies

warranting immediate response. Thank you.

MR. DANNER: All right. Thank you.

MR. DIAL: Gary Dial with Enbridge. Based on what Boardwalk said, we reiterate what they've said. We've done an analysis as well, and over the last three years our review has come back with a 90 percent repair rate of immediate anomalies due to dent anomalies, as opposed to metal loss. And we support, rather than changing the corrosion criteria, believe PHMSA's proposal separation of the top side and bottom side dents with metal loss, and PHMSA's new dent and metal loss ECA will allow operators to appropriately prioritize dent anomalies warranting immediate response. Thank you.

MR. DANNER: All right. Thank you.

MR. CAREY: Good morning. My name is Patrick Carey. I'm with Kinder Morgan. Like Enbridge and Boardwalk, we did an analysis of our data on immediate response from a time frame of 2012 to 2017 and had very similar results. And we support what PHMSA has been doing in the way

of updating the response criteria for the top-side dents, and I'd like to offer a different model to consider when you're going through this, and that would be the plan to check cycle.

When you look at the results that we show, which are, in our case, 84 percent of the immediate responses were due to dents with an indication of metal loss, the updates that we've made or have been proposed for top-side/bottom-side dents will help to address and get better clarity on that particular data, rather than trying to change the corrosion data that would be associated with the slides -- I think it's 170 to 176 under the revised deck.

So we haven't given that a chance to take a look and see what it does to our immediate response and really, when you look at that particular model, we've gone through the plan of the original HCAs. We've done the re-assessment on a fair portion of that, and our time frame was '12 to '17, so we were outside of that re-assessment window or the initial assessment for

the bulk of the HCAs. So, you know, let those changes that were reflected in the bottom-side/top-side take effect and get us some better data before we start trying to make some other changes.

As a side note, when we looked at the data, we did not see anything that was a 1.1 or below 1.1 response criteria. So it was something that, you know, while that would may be an assumption that you'd make when you see that data rising and the fact that people are letting the anomalies grow to the 1.1 level, that's not the case. And, again, we didn't have anything that fell into that criteria. Thank you.

MR. DANNER: Thank you. Before you go, could I just ask you, you said 84 percent, the other 16 percent, could you tell me what those were, and can you give me some idea of the actual numbers?

MR. CAREY: We had one particular one; we had one particular line that did have some interaction of a different threat type that one

line represented 11 percent of the data. So we had a total of 143 immediate responses over the course of 3,500 miles of HCAs in that five-year time frame. Again, 11 percent or I guess that translates to about 14 or 15 of the immediate responses were on that one particular line.

The other 5 percent were some miscellaneous results; I don't have the details on those.

MR. DANNER: All right. Thank you. Yes, sir?

MR. OSMAN: CJ Osman with INGAA. I had a few other data points I'd like to share that may help inform the discussion on this topic. Several folks have already covered some of the concerns around whether the immediate response data is appropriate to reference and to try to respond to here.

I think the other important thing to look at is the actual incident data. What's good about the incident data is we can really drill into what caused the different incidents. And if

we look at the corrosion incident trends going back to 2010, over 70 percent of those incidents occur on lines that have not had in-line inspection. These requirements talk about what you do after you perform in-line inspection and then respond to those anomalies.

So I don't think changing the anomaly response and repair criteria is going to have a major impact on internal/external corrosion incidence. So I think that's important to consider, too, in looking at whether it really makes sense to change the corrosion and metal loss response criteria.

Also, on a related note, there's a criteria proposed to a requirement related to metal loss affecting the long seam. And we went back and looked at data from 2010 to 2017 and found zero corrosion or environmental corrosion metal loss incidents affecting the long seam of high frequency ERW pipes. Those pipes are not known to be particularly susceptible to this type of corrosion, so based on that incident review

and our knowledge of this type of seam, we don't think high frequency ERW pipes should be included in the response and repair requirements related to metal loss preferentially affecting the long seam. Thank you.

MR. DANNER: All right. Thank you. Are there any other public comments on this topic? All right. Seeing none, open it up to the Committee for -- oh, should we go ahead? Okay. So we are going to take a lunch break right now. It is 11:49. We'll come back at 1:00. So see you all then.

(Whereupon, the above-entitled matter went off the record at 11:49 a.m. and resumed at 1:12 p.m.)

MR. DANNER: All right. We're back on the record. We're going to continue our discussion of corrosion metal loss criteria. I'm going to turn it over to Alan.

MR. MAYBERRY: Okay. Thanks, Mr. Chairman. If you recall, where we left off was on corrosion. We had ended with public comment

before we took the break, the lunch break. Over that time, we've done some tweaking of the voting slides just to be a backdrop for the Committee discussion, some tweaks based on the comments we had heard and just really for the Committee's consideration as you discuss corrosion.

But I'll turn it over to Steve. Do you want to go through what we -- yes, we'll warm it up here.

MR. NANNEY: This is Steve Nanney with PHMSA. I'm going to give you a minute or two just to look at slide 24 and 25. What we tried to do was, based upon what you have already voted on, we went back and did a QA/QC to make sure we were not missing anything because we had added some things based upon discussion in the other voting slides. So we did make sure.

Also, a few of the comments we heard from the public side and also the Committee side, we made sure we were explaining what we had there on the slide. So we'll give you a minute to look at that.

And then also on slide 24, the information in red is informational, and we'll drop that after the vote. But we wanted you to know what we were meaning there.

MR. DANNER: All right. Was Steve going to walk us through it, or is --

MR. NANNEY: This is Steve Nanney with PHMSA. Just to tell you what I was trying to do was get some of the slides where I could read them. So, anyway, I have contacts and I've got one for mono-vision, so sometimes it makes it a little difficult when the writing is real small. Uh-oh. And it's real hard to read when the slide disappears.

Okay. Just starting, again, what we were showing here is revise the repair criteria for scheduled conditions regarding the predicted failure pressure as follows. And in the note, what we wanted to make sure we conveyed and as one of our slides showed, if operators run an in-line inspection tool and they find anomalies in the class locations below the pressure failure

ratios, PHMSA would not want these conditions to be monitored and expects them to be remediated in the one or two-year interval based upon them being either HCA or non-HCA before the reassessment interval. In other words, what we're trying to do is what this next red bullet is if you look at B31.8S in ASME, Figure 4, it allows metal loss corrosion to grow to a pressure failure ratio of 1.1 before the remediation threshold. And if you look at, if you're in Class 3 or 4, they have design factors of 2.5 for Class 4 and 2.0 for Class 3. And if you go back to the Figure 4, it's the middle line is the one that says allows above 30 percent but not exceeding 50 percent. It's that line going there down to 1.1.

And the thing that we're trying to make sure is that we just -- and I heard the operators that got up and spoke earlier that they were not doing that and also that, of their immediates, they were between, like, 10 to 15 percent of the number that we're seeing is what I

heard based upon the three or four that we had to get up and say because, like we had said earlier, PHMSA gets immediates, but the data we get we cannot tell if they're dents or if they're metal loss or something else and everything.

So what we were trying to do is, again, if you're in a Class 3 or 4 area where a new pipe should be 2.0 or 2.5, we don't want them to be allowed to just continue growing down to 1.1. In other words, when you run the ILI tool, we want there to be a cutoff that if it's below that, you just don't let them continue growing to 1.1. When you do it, there needs to be a point where you go out and have to do remediation. You wouldn't have to do it immediately, but we wouldn't want it to fit in the monitored and go seven years or five years and not be touched is the point we're trying to make.

Also, if you go in and do in-the-ditch remediation, you know, something like that, it should be based upon the class location of the MAOP, I mean, if you dug the pipe out and you

look at it, you know, those type of things.

So I guess that's the item that we've got there. I just wanted to explain it. And if you would, let's go to slide 25. Mr. Chairman, would you like to allow questions before we go to the other slide, or do you want me to go through all the slides first and then come back?

MR. DANNER: Well, how many slides do we have here?

MR. NANNEY: I think it's three total.

MR. DANNER: Why don't you --

MR. NANNEY: Two. Two slides. I'm sorry.

MR. DANNER: So this is it?

MR. NANNEY: Yes.

MR. DANNER: What's in front of us? So, yes, why don't we, if there are any questions for Steve. Okay.

MR. NANNEY: Okay. Going to slide 25, again, the items there that we've covered before, we would revise the repair criteria for corrosion metal loss affecting the long seam in HCAs and

non-HCAs as follows. And, again, we would add the word "preferentially" to assure that this criterion would be applied to corrosion pits near a long seam. It would only apply to corrosion along the seam that could lead to slotting type crack like. It would not -- it would not apply to corrosion along the seam. That's worded incorrectly there. It would not apply -- not only apply, it would not apply.

What we're trying to do there, and we've heard what everyone has said, we're not wanting where it's just very minor corrosion that touches the weld seam or something, that, because it touches it, that you have to go and remediate it or do something. So we thought that was a good feedback that we had gotten.

Also, the next item was delete the following repair criteria for HCAs and non-HCAs, which from past meetings we've heard is a gouge or a groove greater than 12.5 percent wall thickness and then the area of corrosion greater than 50 percent. And then last is revise

proposed Section 485(c) to include reference to Section 712 for evaluating corrosion in the proximity to cracks or crack-like defects and for operators to make and retain records.

MR. DANNER: Okay. Again, any questions for Steve? All right. Andy?

MR. DRAKE: I want to set some context. You know, I think we're hearing things kind of funny and I want to make sure we get that right. And, second, I'd like an opportunity to come back to facts, so we'll get the facts in a second.

First of all, the conversation we were just having about cracks, we don't have a Figure 4 in cracks, okay? Like we were saying in that conversation, this is all new. So we're at the front of the ship here. I can't reference the work that we have in the existing ASME documents because there is no Figure 4. So that's where the conversation has evolved into design factors and other things, trying to figure out some crude tools. We also know that the sensitivity of

those tools isn't as sharp and the data we have isn't as precise and clear growth rate modeling around cracks as it is for corrosion.

So the point is a lot needs to be ears-up conservative, and that's why we were trying to pick one to two-year criteria, that's why we were trying to pick design factors, give operators some clarity of what to do in this unchartered water. We're trying to define some hurdle rates that are practicable so that people will actually go in the water with the tool, but that's not, I would be careful -- well, not careful. I don't agree to extend this to corrosion, and so I just would stop there.

The conversations we were just having I don't think come over the transom here very well and apply. And so I'm happy to stop there if we want to debate that for a few minutes, but I would like to kind of go on to facts about why. I think it's really important. So I don't hear anybody throwing their tent up right away.

I think this is really important,

really important to get the facts right. We are making a very, very significant decision here, and I want to make sure we're clear on what the facts are. Let's go back to slide, I think it's your 74, 174. I had in the pre-read materials 172. It's one of the repair criteria showing gas transmission incident history. It shows this uptick in the incident history. That's all incidents, all incidents. Well, that's interesting. What's relevant is what of that has anything to do with corrosion, which is what we're talking about here?

When you look at the data, the vast majority of the reason for the increase is because of equipment failures and releases from things like relief devices, OPP, O-rings, things like that. Equipment failures, breakdowns. That's what is causing a lot of that uptick. We also changed the criteria, which caused that to flash a little bit earlier.

CJ made an interesting comment that also is interesting. Of the corrosion piece,

which is going down, 70 percent of that is related to segments that are not pig-able. Okay. What does that tell us? It tells us it has nothing to do with the response criteria that we're currently using because they're not getting evaluated to that criteria because they're not getting pigged.

So is the response criteria broken? Not by anything I see so far. It looks like it's working pretty good actually.

I think when we get into immediate repairs, which was the next slide, we see a tick up, which was your slide 175 I think. You see a tick up. You know, it's miraculously coincidental that that also coincides with the infusion of high-res tools and, as people back here were saying, the finding of corrosion inside dents.

Again, that doesn't indicate that, one, the things we're doing aren't working. I think they're indicating things that we're doing are working. We're getting better at seeing

things. We're using that data to make better choices. It doesn't indicate that the repair criteria is not working or that the systems are coming unraveled. And I think this is really, really important to set the context around this discussion for public. The public, we have an obligation to advance pipeline safety. Are we or are we not? Let's use the data and the facts to figure out are we making progress or not, and make appropriate changes to the things we're doing. Someone said earlier PDCA. Let's use management systems here. Use the data to inform the choices that we're making and focus our energy in places that need to make big changes in the improvement of pipeline safety. This tells me: that's not the place to put our energy.

I think, you know, we can kind of keep going on here about the facts, but I do think it's important to probe into this and understand what's underneath this, before we just decide at 50,000 feet to make a huge course change on something that's actually working for us.

So I just want to pause there for that and kind of let folks percolate on that for a minute. And I'm glad to take questions on it, but I really think this is the foundation of making a choice.

MR. DANNER: All right, Cheryl and then Sara?

MS. CAMPBELL: Thank you, Mr. Chairman. Cheryl Campbell, Xcel Energy.

So, I have -- I echo what Andy said. I mean, I can't remember the last time I had a corrosion failure in a transmission pipe.

The tools have gotten so good at finding corrosion, we are -- it is a true statement, we are seeing more, but I think it's more related to the tool tolerance and the ability of the tool than it is that, you know, we're struggling with -- we're waiting to repair.

So, I guess my question that I have is, are we basing this change, this feels like we're -- you're asking us, Steve, to be more conservative, I think, in making repairs for

corrosion based anomalies.

And, it feels like we're doing that based on those graphs that showed the anomaly up tick or the failure up tick. And, if that's true, then I would like more information on what's causing those failures and those incidents to make sure that they are corrosion related.

And then, to Andy's point, that we are reacting appropriately to those changes, right, in setting criteria that work for those changes.

Because I'm -- I guess I am not convinced that operators are waiting to make repairs and allowing them to become immediates.

MR. DANNER: All right, Sara?

DR. LONGAN: Thank you, Mr. Chair. Sara Longan, DOI.

On slide 174, I had almost immediate questions yesterday when we first saw this slide. And, I think that it tells an important story, I just don't know what the end of that story is.

For example, the light green line, I had also questioned whether that was all

incidents or whether those were incidents that mattered and led to corrosion?

So, as a suggestion, I don't have a problem with still looking at that green line, but maybe an additional line showing those incidents that actually mattered or that led to corrosion, I think is a very important addition to the slide.

Furthermore, it wasn't clear to me how PHMSA got to the orange line of significant incidents which seems almost extremely flat to me, or flat to me.

So, what's the delta and how did the green line turn into the significance line, if it did? And, how should we be considering that in terms of being the need to be conservative as we're looking at the repair criteria?

MR. DANNER: All right, Andy and then Steve?

MR. DRAKE: This is Andy Drake with Enbridge.

I think, you know, I want to, you

know, there's -- this is a lot of good stuff. We really need to figure out what's working for us and what's not and what we need to do.

PHMSA's proposed some really good changes here and I don't want to get too distracted and not recognize that.

But, when you're talking about 1.1, industry assumes everything grows to 1.1. Can you show Figure 4 up there? That's your slide 172. There you go.

That is currently in ASME. That was developed back when the HCA or the integrity management document was developed. It helps us give time-based responses to corrosion.

What that is assuming is, once you size an anomaly, you're predicting its growth over time. That growth over time was a Battelle model that used a very aggressive corrosion growth rate to define conservatively an appropriate response time before it crossed that 10 percent safety margin threshold.

So, there's a lot of conservatism

built into that. And, no, we're not waiting until everything grows to 1.1. That is not appropriately reflected in what's happening.

The model is providing conservative criteria based on aggressive corrosion rates from a from a known sized anomaly off a log as to when you would encroach on if you used the aggressive corrosion -- experienced the aggressive corrosion rate before you got to 1.1.

What it was trying to do is a question that I have and I don't understand why we're doing this is, in essence, what we're doing here is we have -- we are being told that corrosion growth needs to be managed since that when you pig the pipe, everything that you find that's within a certain response criteria basically has to be managed within one or two years.

That's not appropriate. We have no data that shows that that's -- that this slide right here is not working exactly as it was intended to work, very conservatively.

Instead, what we're trying to do is

say, no, everything need -- everything that you could find out here needs to be dealt with in one to two years.

And then, basically, you wait years three, four, five, six and seven until you re-inspect and then we do it over again. That is -- that's just not appropriate.

I think this is functioning and it's going to create an incredible unnecessary consequence to producers, suppliers, the transmission system, dealing with things in this real lumpy fashion when, if we use our engineering insights and knowledge, we are -- we can deal with this conservatively and spread that impact out which is, I think, appropriate for everybody around this table.

But, I -- that's, in essence, what's happening with the proposal we're looking at, just to be very honest. You've taken a large volume of the anomalies and moved them down into one and two years and everything else is going to wait until it gets to seven.

So, you've got a lot of work to do in the first and second year, then you don't do anything for five years. Then, you've got a lot of work to do for one and two years. And then, nothing to do for five years.

That just doesn't -- it's not real inspirational that we're not smarter than that. I mean, we have data, we have this, we have a lot information from the corrosion anomalies. This is a lot different than what we're talking about with cracks.

This is pretty evolved technically and the growth rates are in a much smaller window of volatility. And, I think we should use that. It's working for us. I don't understand why we would change that.

MR. DANNER: All right, Steve?

MR. ALLEN: Thank you, Mr. Chair. Steve Allen, IURC.

Back to, I think it's your slide 174 and back to Sara's comments or questions, I just need some clarification.

The orange line, significant incidents per 10,000 HCA miles, is that significant incident as defined in 191?

MR. NANNEY: Yes.

MR. ALLEN: Okay. And, then the green line, the leaks per 10,000 miles of HCA or 10,000 HCA miles, is there a breakdown on what those leaks are caused from?

I mean, because if that's all corrosion, that tells me one thing. If it's a mixture of a lot of different reasons, that tells me something else.

So, and, frankly, as I look at that, we're looking at what an uptick to 80 leaks in 2017? Is that what I'm reading? But, I don't know how many of those were --

I'm sorry, no, leaks per 10,000 HCA miles? Okay, for 10,000 HCA miles.

And then, I guess, why has that kind of crept up over time? Is that -- did I hear Andy say that's because we're better at finding them? Or, what?

MR. NANNEY: I don't think a failure would be because you're better at finding them. I think it would be because it failed.

MR. ALLEN: And, I'm sorry, a follow up. The leaks and the failures, I guess, I just would be interested in knowing what the breakdown is. Are 50 percent of them corrosion related or all they all corrosion related? Or, any of them, you know, third-party?

MR. DANNER: Oh, and Steve?

MR. NANNEY: We have the data on our website. I mean, the percentage on corrosion is somewhere, without having it in front of me, is probably around 20 percent or so.

But, and like some of the other comments on relief valves, they -- depending upon what time frame you look at them, they are probably -- they could be probably about 9 percent.

If you break it out in another separate years, it might be 15 percent.

But, I've got a list in front of me

that's about 9 percent of it.

But, again, I would say 10 to 15 percent would be those type things, in general, of incidents across the system.

And, like I said, corrosion, metal pipe, weld failure, those type things are going to probably be somewhere around 30 percent. And, to give you general 35 percent, somewhere in that range.

But, the key point and the reason PHMSA has this fraught up, again, I hear everyone say that the tools are better and everything and we've got better systems which means we should have better CP and we've got better monitoring and everything.

And, I guess the key point is, you know, if you're in a Class 3 area or in a Class 4 area, is there a point where we shouldn't let it, per the Figure 4, continue growing before we go do a repair. That's the part we wanted to talk about and that we have on the table is, should we let it continue growing to a 1.1?

I mean, right now, you could do that, but do we really want that to stay as part of the code that you could do that?

Or, is there some point that an operator goes and fixes it because, you know, other things that are factored in the 1.1 is, you know, you've got overpressure protection that, depending upon what your operating pressures and percentages are could be set 4 percent to 10 percent above your MAOP right there.

So, there's other things you need to think about to take into account. And, that's all we're trying to do is have a discussion and take a look to make sure what we're doing there is the right thing. And, if we aren't doing a mini anomaly repairs --

And, like I heard, only 10 to 15 percent are corrosion related as we're trying to get an idea of what that would mean.

MR. DANNER: So, Andy?

MR. DRAKE: This is Andy Drake with Enbridge.

I appreciate that, Steve. That's really the point. There's a lot of things on that slide that's not a corrosion slide, that's an everything slide and there's all kind of stuff in there.

The key that we need to be extrapolating out of there is the corrosion piece getting better or worse? Is the criteria that we use to manage it and respond to it effective or not?

And, that's almost impossible to conclude from that slide. But, what we know is, that there's a lot of other things in there.

I think, you know, the other thing, if we can go back to Figure 4, I'm trying to do my cross counting here to your slide 172.

I think that when you look at that, if you see the three lines, three lines are designed to do what you're talking about, Steve. It's not every type of design factor, every type of situation would respond to 1.1, there's three different lines to deal with different sizes of -

- different levels of stress to deal with.

You wouldn't want the big safety factor pipes to encroach on 1.1 just because they can. That's not the point, that could be a very significant defect. That's what those three different lines are intended to accomplish.

And, I think they are working very well is the point.

So, I keep coming back to the same question I asked in our teleconference meeting on March 2nd. What is driving this significant change that we're talking about? Is there a problem with what we're doing that's not working?

Is there some facts or data that's saying, we need to double up on the corrosion factors and respond to everything within one to two years? It's like, wow, that's a big deal, especially in the context -- and why there's a lot of energy on this conversation is, we're getting ready to take the obligatory response from HCAs to HCAs and MCAs which is a huge increase in millage so people are going to be

accountable to respond to this.

Now, if we're going to do that, so we're going to quintuple the amount of pipe or more than that even, the amount of pipe we're going to deal with and we're going to all of a sudden do everything in one to two years, that's not going to happen, folks.

I mean, let's just stop and think about where we're -- what really do we need to be doing here?

MR. DANNER: Cheryl?

MR. CAMPBELL: Thank you. Cheryl Campbell Xcel Energy.

So, as I'm listening to all of this, I don't -- I think our intentions are probably very closely aligned in that we don't want these corrosion anomalies to grow to a point where they're an issue. Right?

I mean, we would like to respond to them prior to them being an issue.

To your point, Andy, we don't necessarily want to codify -- codify I guess is

the right way to pronounce that, the one to two year response time. But, I hear you, Steve, when you're saying let's not let them go for too long.

So, what is the right path forward? Because, I mean, Andy's right, we are -- as we move into MCAs and beyond the ACAs, we are going to see more anomalies that we need to respond to. How do we find that right place? Right?

And, by the way, I do believe that the current corrosion processes work really pretty well. But, as we move this forward and expand the purview, how do we find the right place and can we not sort of shove it all into that one or two year when we know we have more time?

We know, based on the data we have, that we have more time and we can be more thoughtful and plan-ful about how we do our repairs still wanting to make sure we get it done before we have an incident, though.

MR. DANNER: Okay, anyone else?

Sara?

MS. GOSMAN: So, the industry folks

around the table, I'm just wondering, you know, I feel like we keep coming back to this world of trying to decide why we're not driving down incidents as much as we might have expected we would through IM?

And, you know, we've had this GAO report, right? So, this is one part of it. It doesn't explain all of it, right? But, it is one part.

So, if this is not the problem, what do you think is the problem here? If it's not the fact that we're not repairing things earlier, I guess I would say?

MR. MAYBERRY: Andy? Sorry, the Chair left.

MR. DRAKE: Andy Drake with Enbridge.

I think when you look at the incident rate, there's so many things in there, it's almost impossible to discern that from that level. That's a 50,000 foot summary of data.

I do think that the material, when I look at it, the trends that I see that are going

up are equipment failures and material issues. Those are what's on the rise that we need to be watchful of.

Not that I want to dismiss equipment issues, but, I mean, when we're counting relief devices opening up, that's kind of what they're designed to do. So, I'm not going to freak out about that, I'm more worried about what's causing them to open up.

Is it an operating issue, you know, a controls issue?

But, it's not going, I hate to say it, it's as worse as it's going to get, it's not going to get much worse than what it is. That's what the device is designed to do.

So, that's, to me, not the biggest priority of our -- my focus right now. It is putting a lot of energy into that.

I think we're seeing things, as C.J. said, of the corrosion data which this -- that is a subset of that greater incident data, which is a much smaller line, as Steve is alluding to, 70

percent of that data is stuff that's not getting pigged.

So, that's really illustrative of the need to get the lines pig-able which is what's extending the MCA definition really does is it tries to drive people to get their pipes more pig-able because it's quite burdensome to try to do some of these other things on wide sweeping miles of pipe.

And, I think that will get those miles subjected to that Figure 4 criteria, which is what we want. It's not broken; I think it's a natural growth and evolution thing. That's what we're trying to do with MCAs is get those pipes in here.

And so, I think that's where I think our energy should be going. I don't see any data right now that would compel me that Figure 4 is broken. I haven't seen anything, anything that would say that.

And, I know how much energy went in to developing that. And, it is a very conservative

position.

So, I just keep -- I had this question last time on the phone is, I just want to see the data that would say what's rationalizing us not staying with this? Or, what's wrong with it?

You know, and I haven't got an answer yet on that.

I do think, too, the last conversation, we moved the reassessment interfolds, if you remember in the last meeting on MCAs down. Why? Because I'm using that figure.

If I'm not going to use that figure, I want to re-vote on the MCA re-inspection interval, period. I mean, we -- I'm serious. These all fit together. We're starting to make assumptions that I'm going to fix things over time based on those growth rates and that's going to make sense. So, we should shorten that inspection interval up to line up with that diagram.

Well, if I'm going to have to fix

everything I can find in an extraordinary -- and an incredible safety factor in the first one to two years, then let's revisit the re-inspection frequency. They fit together.

And, I think the other thing that I just want to put out there is just as a data point, right now, we have 180 days between when a pig comes out of a trap and when we have to make discovery, when we have to get the results in and make a decision.

And Hurricane Harvey really illustrated how close to the edge we are with the current load on the system. We had to file a blanket waiver for the industry to get data provisions because everybody was within two weeks of not meeting that 180 days.

That just tells you where the load is on the -- on tool availability, vendor technical capacity with 6 percent of the system being under rule.

When we increase this, I think it's prudent for us to consider some extension of the

180-day discovery, just inside the rule. Or, you're going to get a flood of waivers because everybody's going to be up against 180 all the time.

And, I'm not proposing, you know, a year or some big number. But I think we should talk about. I mean, what's an appropriate number? This is back to the bell curve thing.

I mean, okay, we just quadrupled or quintupled the size of the stuff exposed to this. The vendor load is going to be pushed on the 180 days. So, how many waivers do we want?

You know, I think there's some place we should be preemptive or proactive to talking about that.

MR. DANNER: All right, Sara?

MS. GOSMAN: Again, thank you for helping me understand more. I think then the second question I have is, you know, when I think about risk-based systems, it seems to me to make sense to be more conservative as you increase the potential for consequences.

And so, when I look at the class locations, I'm looking over here at Andy, but I mean to look at everybody, when I look at the class locations, what I understand that to be doing is tier-ing, right, safety factors by the consequences.

So, maybe these numbers are not right, but I'm surprised that, if what we have right now is one number that extends across and we're going to extend it across even further to MCAs, that doesn't look, to me, like a responsive to the sort of risk criteria as it relates, again, to consequences unless we think that 1.1 is so conservative already that it doesn't matter if it's a very populated area versus one that's not.

MR. DANNER: Do you care to respond to that, Andy?

MR. DRAKE: This is Andy Drake with Enbridge.

That's what the three lines represent. That is increasing conservatism, each line.

MR. DANNER: All right, any other

comments?

Oh, Andy? Okay.

MR. DRAKE: Just finish the sentence, when all -- a lot of what we're talking about here is how to evaluate a log.

The last point that, well, yes, the last point up there, that is how we do it, the red dot over here, in-the-ditch remediation should be based on classification and MAOP.

It is all the designs factors are fully taken into effect because you're physically measuring it and you take into all the safety factors when you're actually physically measuring it.

So, there is some certainty that you actually, when you're in the ditch, you actually deploy all of that.

What you're trying to do here is set up some criteria for response and investigation. Does that make sense? There's like staged gates of things that are happening, that's -- they're different, in the ditch, everything is plugged in

physically.

MR. DANNER: All right, so, I am -- I haven't heard from everybody. I'm getting the sense that the Committee is not prepared to adopt this language today.

Is there anybody who has a contrary view who wishes to communicate that?

MR. MAYBERRY: I don't know if you can indulge me, Mr. Chairman.

If the Committee has a recommendation, I think, you know, whether it's to working within what's up here, although I think I understand, I think we heard the position or, as the Chairman was saying, you know, what option do you recommend?

MR. DANNER: So, Andy?

MR. DRAKE: This is Andy Drake with Enbridge.

I think there's a lot of good material here. I mean, if we wanted to try to make a motion, I'd ask for just a few minutes because I'm going to get a lot of help otherwise and

that's probably not really the turbulence that we need around the table.

But, I don't, you know, I think the crux of where I am is, trying to make this practical. I think we're expanding integrity management significantly, which is a great thing. It is a big step forward.

I don't see anything that's compelling me to change off Figure 4. I don't, I don't see any data, I'm not aware of any problems that we're having. The criteria was very deliberately put together with very conservative measures on corrosion growth assumptions.

I think it's working. As we apply a lot more pipe to it, I think that's actually quite helpful, if that's working, keep using it, especially not to make everything go down to a one and two year response time.

So, I could probably fashion some language around that, I think.

MR. DANNER: All right, I think what we'll do, Andy, is let's take a -- it's 1:57,

we're going to come back at 10 after.

MR. DRAKE: All right.

MR. DANNER: And so, that'll give everybody time to have their side conversations.

(Whereupon, the above-entitled matter went off the record at 1:57 p.m. and resumed at 2:24 p.m.)

MR. DANNER: All right, we are back on the record.

As you can see, there's some amended language in front of us. Andy, do you want to, I think you may have had something to contribute to this, so maybe you want to explain it.

MR. DRAKE: I don't know if I can take full credit for this, but I'll make a motion, well, maybe people can now read this, is there any comments or concerns about what has been typed up here in the break? I mean, that's fair, as people are coming back in.

MR. DANNER: So, why don't -- I would appreciate it if you would just explain the practical effect of where this moves the ball

from what the status quo is today.

MR. DRAKE: The intent here is to maintain Figure 4 and institute it into this section with 713.

And then, to do the same thing for HCAs and non-HCAs that we have been doing in HCAs as far as response criteria to corrosion anomalies.

There is a proposal at the bottom to basically increase the discovery period by 60 days. That's just a proposal to try to give more time for people to deal with the volume of inline inspection reviews they're going to do.

I think the driver behind the, really, the third bullet which is, I think, where the crux of the issue is around, we have put a lot of time and energy into Figure 4.

We think Figure 4 is very, very conservative. It has demonstrated that through its performance, through the baseline inspection period for HCAs.

I think using that is, one,

conservative as proven; and, two, a great deal of continuity for industry and others about what we're doing in responding.

I think the thing that adds value is, Figure 4 is designed to look at corrosion anomalies and project their growth with the corrosion -- conservative growth rate over a period of time and provide a response for investigation graduated over time for different severity rates or severity, you know, defect severity.

What's being proposed was that we, in essence, would evaluate a log and end up remediating the actionable anomalies in one or two years, which is an incredible burden which I can't see any data that supports that.

MR. DANNER: So, just put it -- if you would explain to me, though, because my understanding was with the note that was put up there that basically excluded all the ILI, I mean, how much volume are we talking?

I mean, is this really a lot of holes

that need to be dug over what the current system is?

MR. DRAKE: I think it is going to be a lot of holes to be dug. A lot of folks have been inspecting pipes outside of HCAs as they pig HCAs, which is good. That's prudent.

A lot of folks have not; a lot of folks have not made their pipes pig-able. I think as you extend this rule to include HCAs -- MCAs, it will create a business case and a driver to people to make their pipes pig-able, which is absolutely what we want because the sampling frequency is much higher with the pig than with DA.

It's much more physical or closely aligned with assessing defects than DA is, particularly for corrosion.

And so, I think you are going to pick up a lot of volume which is good, that's the point of this exercise, you know.

And, they are now obligated to remediate them to the standard, which they were

not before, which is all good.

So, yes, I think there will be a significant increase in volume.

MR. DANNER: Okay. Other comments? Sara?

MS. GOSMAN: So, at this point, I think this has been a great conversation. I would like to ask that we take bullet point three on slide 26 and separate that out into a separate motion.

Because, I would like to vote yes on the remaining part, but I am going to vote differently on that particular part.

MR. DANNER: Okay, Cheryl?

MS. CAMPBELL: Thank you. Cheryl Campbell, Xcel Energy.

So, I think what I'm trying to understand and I -- so, this will -- this is more of a question than anything else.

You know, I heard what Steve was saying and I understand we've got, and again, we're not talking about making rules for the

people in this room, we understand that.

We've got some people that are probably more willing to push it, shall we say, right, and let anomalies grow a little bit longer than people may be comfortable with.

But, we're also trying to make sure that prudent operators that are out there working and making their lines pig-able, getting the data, right, trying to do the right thing, they have the time and the resources to respond appropriately.

So, I guess my question is, these changes, does that help us do that? Does that help us give clear direction to operators that might be allowing things to --

And, the example we were talking about at break were operators that were allowing in Class 3 and 4 allowing anomalies to go until they got, you know, pretty close, right to the edge, right, would be one way to talk about it.

Does it give them that clear guidance to act sooner while still providing the operators

enough flexibility to go be --

Because I just don't want to get a bunch a stuff jammed into one or two years.

I agree with Andy, as we pull in MCAs, we're going to see more anomalies. We have to. I mean, we are continuing to do new pipe every year.

And, as I shared with Sara and Steve, I have not seen a drop off in my number of immediates every year, but it's not -- I'm not seeing them on the pipe that I've assessed before and I've reassessing. I'm seeing it on the new pipe I'm pulling into the system -- into the program. Right?

So, and that's exactly what you want me to keep doing. Right? So, I'm looking for clear direction to the operators that might be pushing it too far, but allowing other operators that are out there leaning forward the time to work this appropriately and not try force them into very short time frames that might be impossible to meet.

MR. DANNER: And so, the language that is up there on the right side, you thought did that?

MS. CAMPBELL: I'm not sure. I'm asking the question.

MR. DANNER: Okay, does anybody want to respond to Cheryl's question?

So, your question has gone unanswered.

All right, Andy?

MR. DRAKE: I found it an awkward position to respond to that. But, I think that the code obligates people and so the ASME standard to evaluate the corrosion rates in your unity plots.

And, if you're aware of anything that indicates that this is growing faster than the assumptions on those models, you're obligated to go investigate it at a shorter frequency.

And, I think that's the only breakdown that I can think of. Where we're really getting hung up is we're not seeing incidents where this isn't working.

But, the -- there is a safety net behind that and people are obligated to do unity plots and check to see if they are finding corrosion growth rates that are more aggressive than what that model would indicate. And, if so, then they're supposed to shorten those frequencies up.

But, I mean, that's the best I can answer your question. They are not falling into that safety net, or at least I'm not aware of it.

MS. CAMPBELL: Well, and, I'm just thinking about the conversation I had, Andy, and I'm -- so, it feels like somewhere along the line then that there might be a disconnect with people's understanding.

And I don't know if it's the operators or PHMSA about how the chart, you know, the AMSE BS31.8 and the, you know, the different things all fit together and should all work and how an operator should respond and what those obligations are already in the code.

I'm not trying to disagree, I'm just -

- because I thought the safety net was there as well. Right? But, I'm just wondering if there's some misunderstandings or we're not all interpreting it the same way is the only conclusion I can come to based on all the different things I've heard.

And, I don't know if PHMSA's got a thought on that.

MR. DANNER: All right, Alan?

MR. MAYBERRY: And, I was just kind of reflect on a few accidents I've seen related to corrosion or general corrosion.

But, you know, they involve other factors as well like shielding, for instance. That seems to be an issue that dogs us, but, you know, how do you address that?

You know, is an operator doing their close interval surveys?

You know, we saw what Appomattox, an incident there that was pretty dramatic that involved that type of issue where you had a good reading nearby but that, you know, involved the

corrosion program, not necessarily how you assess the corrosion.

You had system bill West Virginia, there again, probably a shielding issue there, but again, involving general corrosion, those types of things are tripping us up.

I can think of numerous others that involve general corrosion. But, you know, it's just -- it's a variety of factors. But, I think it really points to the fact that we need to focus on this area certainly continue.

And, you know, obviously, we've, you know, we're going to take the information we've received however the Committee decides to vote on this and go from here and, you know, see what we need to do.

But, I think the experience out there shows that we just all need to be vigilant at, you know, all tools are there to, you know, assess and prevent accidents related to corrosion, we need to make sure we're using all the tools as well.

MR. DANNER: All right, any other comments?

(No audible response.)

MR. DANNER: All right, so, we have a motion on the right side. Sara, you asked for it to limited to those three, so perhaps you want to make this motion?

MS. GOSMAN: I think --

MR. DANNER: Oh, I'm sorry.

MS. GOSMAN: It's two pages.

MR. DANNER: Oh, it's two pages, all right.

MS. GOSMAN: All right, yes, that seems appropriate.

Okay, voting language for repair criteria Sections 192.485 , 192.711, 192.713, 192.933.

The proposed rule is published in the Federal Register and the Draft Regulatory Evaluation with regard to provisions for corrosion metal loss repair criteria are technically feasible, reasonable, cost effective

and practicable if the following changes are made.

Revise the repair criteria for corrosion metal loss affecting a long seam in HCAs and non-HCAs as follows.

Insert the word preferentially to assure that this criterion would not be applied to corrosion pits near long seam. It would apply to corrosion along the seam that could lead to slotting-type, crack-like defects.

Delete the following repair criteria, HCAs and non-HCAs -- is that gouge -- gouge or groove greater than 12.5 percent WT wall thickness -- thank you -- area of corrosion greater than 50 percent.

Revise proposed Section 192.485 to include reference to Section 192.712 for evaluating corrosion in proximity to cracks or crack-like defects and for operators to make and retain records.

Revise the repair criteria for scheduled conditions regarding the predicted

failure pressure as follows.

PHMSA will apply similar predicted failure pressure factors to alternate MAOP pipelines based on class location/design factor.

In-the-ditch remediation should be based on class location and MAOP.

Change discovery period for non-HCAs from 180 to 240 days.

MR. DANNER: All right, thank you.

Is there a second?

MR. HILL: Robert Hill, second.

MR. DANNER: All right, is there any discussion before we go to a roll call vote?

Andy?

MR. DRAKE: I think you have to do the Steve Allen comment here since we've exempted the other stuff. You have to probably put that up in there in the beginning.

The anomaly response -- that anomaly response criteria has been exempted from or excluded from this discussion.

MR. DANNER: It's actually -- it's my

understanding that we are going to put that up for a separate vote.

Oh, I see. So, we need the --

Yes.

MR. HILL: The second agrees with that.

MR. DANNER: All right, then, I think that we have an agreement that the motion has been modified.

All right, with that change, are we ready to go to a roll call vote?

What's that? What? I'm sorry, I can't hear you.

MS. WHETSEL: Okay, y'all ready for a vote?

MR. DANNER: I think now we are.

Is there --

MS. GOSMAN: Chair, do you want me to amend my motion or is what we've done for the record --

MR. DANNER: Oh, I thought we were --

MS. GOSMAN: -- sufficient?

MR. DANNER: I think, well, yes, why don't we just verbally just say that we have added to the preamble there that after the words loss repair criteria, we put comma, but excluding the anomaly repair timing, comma.

MS. GOSMAN: Okay.

MR. DANNER: Okay? I think that --

MS. GOSMAN: So, with regard to my motion, it is with regard to provisions for corrosion metal loss repair criteria, but excluding the anomaly repair timing.

MR. HILL: And, the second agrees.

MR. DANNER: Okay. So, we have the amended motion before us then.

And, if there's no further discussion, Cheryl, can we -- oh, I'm sorry, Andy, I didn't see you.

MR. DRAKE: Since we're splitting this, I just want to make sure; there was another issue that we wanted to broach. I don't know which section it now fits in, so I'm asking for an interpretation by Steve or somebody.

The greater than 50 percent wall thickness issue about being a whatever it's called for road crossings and river crossing and girth welds, is that in this piece or the next piece?

MR. NANNEY: I think we've already voted on it. It was in the one before lunchtime.

MR. DRAKE: Not for corrosion, we did cracks, we did other things, I mean, but --

MR. DANNER: All right, Andy, we're going to check on that.

(Whereupon, the above-entitled matter went off the record at 2:41 p.m. and resumed at 2:46 p.m.)

MR. DANNER: All right, we're back. So, John, can you explain the response?

MR. GALE: Yes, so, we -- yes, Chairman. We have slide 167 from the presentation from yesterday up on the screen right now which brings up this issue.

And so, at the time, we did not recommend a change to this. So, if this is the

appropriate time to bring up that discussion to change it. So, that's why the voting slide didn't have anything on there to actually recommend any kind of change.

We were going to be adopting it as we proposed.

MR. DRAKE: This is Andy Drake with Enbridge.

This -- I just didn't know which section this was -- is in the vote that Sara's proposing or is in the next discussion?

We can have it here. I think this is -- actually, I would like to think this is actually a pretty short conversation.

We talk about using depth as a trigger to creating, you know, for brook crossing and welds and things like that, that if it's 50 percent or more through the wall that we would now have to repair this, you know, within one to two years.

I think that this kind of fights engineering logic that we've used for evaluating

defects, and I just want to make sure I'm clear on why we're doing that.

What we're worried about is depth and length and width and the stress that the pipe is under.

I'll give you an example where this creates a problem for me. I have a river crossing right now. It has a 50-plus percent through wall anomaly that is a pit. It's an HDD crossing. There are on other anomalies on this crossing.

The FPR this pipeline operates at 33 percent of SMYS. The FPR failure pressure rate is 3. So, it is three times the MAOP.

The, you know, this thing isn't going anywhere. It happened because when we installed the rectifiers were installed incorrectly and were anodic at that little anomaly. And, it's a pit that's deep but not long or wide.

This would require, because it's a river crossing, now I have to go out and replace the river crossing for a pit. I can't believe

that's what we're trying to do here. But, that's going to be what happens.

Now, I know there are issues with road crossings and people aren't responding appropriately. I'm fine if we set an FPR rating of 1.75 or something.

But, if it's that bad, based on depth, width, length and stress that you need to go get this. But, just picking out depth I think is going to create an unintended consequence that's not constructive dealing with the problem. Characterize the problem and deal with it.

I think girth welds is a whole other -- not another thing, I mean, I don't know what -- I don't think depth, again, is the issue there. I think there's another problem with girth welds. Frankly, the Delmont incident taught us a lot about circumferential modeling. FPR calculations aren't real good at picking that up, neither is depth.

I think we need to figure that out and doing just depth is a disservice. And, I don't

think you're solving the problem.

I'm not just saying that we should dismiss that, but I think you should solve the problem. This does not solve the problem.

My recommendation is, get away from just using depth, acknowledge FPR ratings which is everywhere else in the code for evaluating anomalies and set a threshold. Okay? That's appropriate.

This is like a piece of an answer and I don't know what was driving this. For cracks, I'm in a different place because of some of the comments we made earlier, where we are with the tools, how the cracks grow, how we model them is a lot less understood. But, for general corrosion, that, I think that's just prudent, frankly.

So, that -- I apologize for bringing this, but we were so focused on Figure 4 when we broke that's where we put all the energy.

MR. DANNER: So, do we want to just put a bullet in there asking PHMSA to review this

section with regard to --

MR. MAYBERRY: Wouldn't you add this section to the slide? The voting slide we had just in case this --

MR. DRAKE: I think you just -- if you added a bullet that just said, ask PHMSA to evaluate the use of FPR ratings and an FPR threshold. I think that solves the problem.

I just think --

MS. GOSMAN: That's fine with me.

MR. DRAKE: -- thickness is not -- thickness is interesting but it's not the problem.

MR. MAYBERRY: Yes, okay.

MR. DRAKE: It's just a data point.

MR. DANNER: Okay. So, yes, if we could add that.

MS. GOSMAN: I don't -- I'm glad you raised it. So, I want to make a second amendment to my motion.

(Whereupon, the above-entitled matter went off the record at 2:50

p.m. and resumed at 2:54 p.m.)

MR. DANNER: Okay, Andy, does that language address this? Okay, so, Sara, you want to modify your motion again?

MS. GOSMAN: I'd like to amend my motion to include additional language after change discovery period for non-HCAs from 180 to 240 days.

After that, PHMSA will evaluate the use of a predicted failure pressure rating thresholds for remediation schedules of anomalies at a crossing of another pipeline or --

MR. DANNER: Or at an area.

MS. GOSMAN: Or -- sorry.

Or at an area with widespread circumferential corrosion or is in an area that could affect a girth weld.

MR. HILL: And, the second approved of the change.

MR. DANNER: All right, thank you.

Okay, so, we have an amended motion and a second to the amended motion.

Anything further before we go to a voice vote on this or to a roll call vote?

(No audible response.)

MR. DANNER: All right, Cheryl, we're ready for a roll call vote.

Oh, Steve, I'm sorry.

MR. ALLEN: A bit of clarification here as there's been a lot of discussion on this.

We removed the controversy that we have been going back and forth on for the last hour and a half out of this particular motion, is that correct?

MR. DANNER: That's correct.

MR. ALLEN: And, we're going to pick it up on another --

Thank you.

MR. DANNER: That's right.

MS. WHETSEL: Okay, we ready for a roll call?

MR. DANNER: Okay, Cheryl, we're ready.

MS. WHETSEL: Okay, Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan.

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin? Terry Turpin had to leave.

Cheryl Campbell?

MS. CAMPBELL: Aye.

MS. WHETSEL: Andy Drake?

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley?

MR. BRADLEY: Aye.

MS. WHETSEL: Rich Worsinger?

MR. WORSINGER: Aye.

MS. WHETSEL: Sorry.

Jon Airey?

MR. AIREY: Aye.

MS. WHETSEL: I'm going to really mess your name up, I can see this.

Robert Hill?

MR. HILL: Aye.

MS. WHETSEL: Sara Gosman?

MS. GOSMAN: Aye.

MS. WHETSEL: Okay, the motion carries.

MR. DANNER: Okay, thank you.

So, now to the other part of this motion which is on the right side. So, before we get a motion, does anybody want to speak to this?

All right, Cheryl?

MS. CAMPBELL: So, I'm wondering -- thank you, Cheryl Campbell, Xcel Energy.

I'm wondering if it would be helpful to the Committee if we walked through an example using this chart so that we all understand how conservative or not this is?

Because, I don't think the chart is self-explanatory. And, I do think it takes some experience and understanding of the assumptions behind it.

So, I would ask --

Yes, I would ask -- that's the chart we're talking about, right?

ASME B30 -- Figure 4, right?

So, I'm just asking us if that would be helpful.

MR. DANNER: Any sense? I'd certainly be interested. So, there we go.

Okay, so, before we go through that exercise, Steve or Andy? Steve?

MR. ALLEN: Yes. Thank you, Mr. Chair, Steve Allen, IURC.

I agree. As everyone was huddled up here earlier at the break, I was delving through B31.8S, the 2004 version and looking at Table 4 trying to get my head wrapped around this.

And, I have been to Oklahoma City through some training, realizing I am an accountant, okay, I need help here because I don't feel comfortable on voting on something I don't understand or have an appreciation for.

So, I think what Cheryl is saying makes an awful lot of sense. I want to see the

delta between what we're doing today and what is being proposed in the NPRM regarding additional conservatism.

And, I am interested in the increase in the number of digs. I mean, because, this does have to be practicable and cost effective as well.

So, but, I just want to get my head wrapped around and I need some help. So, thank you.

MR. DANNER: Okay, thank you.

Andy?

MR. DRAKE: This is Andy Drake with Enbridge.

I've asked Mark Hereth with P-PIC to sit up here next to me. We were heavily involved in the development of ASME's B32.8S document when it was written. And, between the two of us, I think our memories can serve to get -- answer any questions that come up on this document.

But, I do think that -- listening just to the conversations at the break, how

misunderstood this is and how -- and, maybe that's part of the problem, Steve, it's people aren't using it correctly, too.

This document was developed to help provide clarity about how people should interpret inline inspection results and predict over the reassessment interval the need to go investigate them. Okay?

So, what it's telling you is, based on three different curves, based on the SMYS level which is back to basically design factors, if you want to apply that.

We're looking at corrosion growth modeling. The corrosion growth model that was plugged in here was basically based on a half-inch material corroding at, I think, 11 mils per year.

Normal -- when you look at the bell curve of distribution of corrosion, that's extraordinary on the bell -- on the tail end.

Nominal corrosion rates in the two to four range. So, you're at 11 mils per year.

That's what this is based on. That's just data.

What you're trying to do is, as you look at the different stress levels, is predict out if this anomaly, based on those corrosion growth levels, was to cross that seven year or whatever the re-inspection frequency that you're setting is, if it crosses that line, then you have to go look at it on that schedule.

So, you're basically assuming the defect that you have, you project it on those growth rates, and if it crosses -- where ever it crosses those lines is when you have to go inspect it.

So, you know, you can see the different response curves. I mean, a defect that's at 30 percent of SMYS would basically be projected out to require a seven-year re-inspection if it crosses at 1.5. Does that make sense? If you follow the 30 to 50 percent line, the middle line out, you would be at 1.5.

So, if it gets to 1.5 or be predicted under those aggressive corrosion rates to get to

1.5 in seven, you have to go inspect it before you re-inspect.

MS. CAMPBELL: So, Andy, can I just ask a clarifying question around that? I'm not trying to be -- right?

When you say 1.5, you mean a predicted failure pressure that's 1.5 times the MAOP?

MR. DRAKE: Yes.

MS. CAMPBELL: Okay, thank you.

MR. DRAKE: Fifty percent safety margin. So, that's a big safety margin. But -- and, it's dealing with the different stress levels. It's trying to pick that up.

I think the other thing that it does, it was intended to do, is it picks up the different stress levels and predicts them over time. So that you're actually dealing with things that are in between 72 percent and 50 percent, in between 50 percent and 30 percent.

You're trying to model the entire population over a very long period of time so that you keep all of these anomalies kind of in

front of you from a growth modeling perspective.

It's not a cliff. It's not a binary solution like you do a model now or you wait a long time. No, you keep track of them all.

And, the obligation to the operator is, as you're digging these up, you're supposed to do unity plots. Unity plots are telling you, are you on a different curve than this?

You can't use a less conservative curve but you're obligated, if you find data that tells you you're on a different curve, to reevaluate that log run and go adjust all those response criterias to get back out on the right time frame.

So, the point is, is even if you're conservative, there -- that was the safety net. As you're doing your digs, as you're digging these up from the first year, the second year, the third year gathering data, if that data is telling you that pig run was off or that corrosion growth rate is off this model, you have to recalibrate the entire log and recalibrate

your entire response criteria.

And, I think the point is, is this was intended to be very conservative and address the different stress levels so that you don't get small anomalies -- you don't get big anomalies growing on Class 3 and 4 pipe because they have this huge wall thickness.

You're trying to get them where a higher FPR is the standard for that response and to avoid just that.

Now, I do think the whole point of this conversation, people are not using this right. You know, they're staying down on the lower line. Well, that's not the right answer.

If you are at 50 percent, you know, if you're at 40 percent of SMYS, you can't be on that lower line.

And, I think the point is, we're not -- the other part is, we're not seeing anomalies when this is deployed. People are inspecting and deployed, we're not seeing this breakout.

So, I don't know, Mark, if I --

Any other questions? But, that basically is how this is used. It actually predicts, based on hostile corrosion growth, from where you are right now to where this anomaly would be, when do you have to go look at it?

And, you're obligated, based on the other data that you find on that log run, to do unity plots to make sure you're on track. And, if you're not on track, you need to make an adjustment.

MR. DANNER: All right, Steve?

MR. ALLEN: Thank you, Mr. Chairman. Steve Allen, IURC.

So, I was trying to go back to the language that was originally proposed where it talks about different RFPs, the less than or equal to X number for each class. I don't know if we can go back to that or not. The original proposal, okay.

And then, my question is, is can you compare then what this graph on the left is to what that proposed language that they had before?

Does that make sense what I'm asking?

Okay.

So, Mr. Chair, may I?

MR. DANNER: Yes, Steve, go ahead.

MR. ALLEN: So, again, I'm looking for a comparison of this table here on the right to the chart from B32.8S, Figure 4.

MR. DANNER: Okay, Steve, do you have more? Your tent is still up.

MR. ALLEN: That's right.

MR. DANNER: Okay.

All right, okay, we have a guest, so please identify yourself.

MR. HERETH: I'm Mark Hereth from the Blacksmith Group.

So, to address Mr. Allen's question here, if you take the first one there of 1.25 which was the proposed level for Class 1, if you go and look at that on Figure 4, since this is Class 1, it would be above 50 percent of SMYS.

When you look at that 1.25, it puts you just right in front of that seven-year

interval. But, it put -- it's just in front of it.

If you look at the 1.39 in Class 2, that's also, that's 60 percent of SMYS is that a Class 2 design factor.

So, you would go up to 1.39 just below the 1.4 and you would read over and that would put you beyond that seven-year period.

So, the one thing that these -- this curve does is it forces you to actively be looking at anomalies year in and year out to know where you are on that curve and to be checking against that conservative corrosion growth rate.

When you simply repair things to a threshold, it leaves the option for people to walk away. And, that's not what we -- that's not your intended -- that's an unintended consequence.

The 1.67 in Class 3 would be between the 30 --

Yes, it'd be the 30 and 50. So, it would be 1.67. So, you go put to 1.67 which is

just above the ones -- it's between the 1.6 and the 1.8 on that line. And, that goes beyond the seven-year.

So, the approach that this figure takes is that that takes you out to a response time. So, for example, the 1.67 would put you at a response time of, let's say, eight years.

But, you're constantly watching that eight years as you go along. And, if you find indications --

And, what the reference to Section 7, and Andy said this earlier, is it forces you to look at the corrosion growth rates if you have on an ongoing basis, and if you're inside that conservative rate, then you have to adjust that rate and reflect that in how you're responding.

So, what this does is it gives you the time to respond and then, typically, you're going to reassess for things that have large safety factor. You're going to reassess before you get to the time where it would grow to 1.1.

And, in that time that you have two

measures to look at that anomaly and say, has it actually grown?

If I go and repair that within one or two years, you take away the options to see if it's grown or not. You're assuming that it grows.

We have numbers of cases where you don't see growth. This gives you the opportunity to reassess and not have to make a repair.

Questions?

MR. DANNER: All right, Cheryl and then Steve?

MS. CAMPBELL: Thank you, Mr. Chair, Cheryl Campbell, Xcel Energy.

So, Mark, is it fair to say, I mean, what I heard Andy say originally was the corrosion growth rate behind this chart is assumed to be 11 mils per year.

So, what -- and that's -- that is three to five times sort of the midpoint on the bell curve of the corrosion that we see.

So, that's a -- that's an added safety

margin plus the 1.4 or whatever your factor is to the predicted failure pressure. And, I think that -- your point is, those are the additional safety factors that are on this.

Now, the question, are operators actually monitoring their corrosion growth rate and reevaluating where they're at and readjusting where they should be taking action?

I think that's the issue on the table, is that fair?

MR. HERETH: Yes, that's fair.

The other thing that I would offer is that they're taking tool uncertainty into account by using tool tolerances. So, you're taking tool tolerances into account, you're taking the corrosion -- conservative corrosion growth rate into account.

And, you're applying that to yield this safety factor. So, you have a lot of margin there. And, that's why we think we're not seeing the fact that this model fails as a cause for failures.

There are corrosion failures, but they're not because of this -- the failure of this model. So, the conservatism is there and Section 7 requires that the operator look at, through the use of unity plots and other mechanisms, and some of that, you're already built into the language that you voted on, is to have those measures that causes the operator to go and look and examine to make sure that they're making sufficiently conservative enough decisions to support the use of that conservative growth rate.

MR. DANNER: All right, Steve?

MR. ALLEN: Steve Nanney, PHMSA.

Again, just to make the point, is when you look at the lines, the middle line is for Class 3 and 4 applied. And, the red line from seven years going up is at the seven-year point.

And, I realized my vision's not that great, but I -- what I think I'm seeing, it is at about 1.5 at the seven years. And, that's for Class 3 and 4 areas and that's a pressure failure

ratio of 1.5.

When you design a Class 3 area and when you design a Class 4, a Class 3 area has a safety factor of 0.5 which would be equivalent to a pressure failure ration of 2 for Class 3 and 2.5 for Class 4.

And then, the point PHMSA is bringing up in doing this is, do we -- I'm not debating whether we've done it in the past. It started out in integrity management early on because, one, we didn't know what we were getting into; and then, how many anomalies and what the timing.

Now, just like Cheryl said earlier, what she's seeing in on new facilities. Well, if you go look at the HCAs, they're not growing very much. In fact, they're pretty flat in integrity management.

If you look at what we're proposing in this rulemaking to be under it, it's -- we've gone through the mileage, it's about 4,500 miles. So, we're not talking about 300,000 miles of pipe, we're talking about areas where they're

either in Class 3, Class 4 or you've got a certain amount of people around.

And so, the point that we were getting at, and in the -- is the areas on the left-hand side of the red line and the middle line that's sloping down to 1.1, should we let it grow to 1.1?

In my opinion, if you get down to 1.2 and less and you're in a Class 3 and 4 and you've got relief valves set at 4 percent above or 10 percent above and you're looking at tool tolerance and everything, is that really the safety factor you think you have? And, should you be letting it grow when the safety factors on new pipe is 0.5 or 2 and 0.4 or 2.5.

Also, in the evaluation criteria we use, we're adding 10,000 pounds to it. And so, if you've got one grade of pipe, if it's X52, in these anomaly calculations, you're using 62,000. So, you're adding like 15 to 20 percent onto that grade when you do it. That's the point PHMSA's bringing up.

That's why we wanted to have the discussion, and again, we respect the Committee's determination. But, we want you to understand why we're bringing it up.

MR. DANNER: All right, Sara, did you have your tent up?

MS. GOSMAN: No, I just wanted an explanation from PHMSA about the delta and I just got it.

MR. DANNER: Okay, all right, thank you.

Andy?

MR. HERETH: Could I add other perspective to address Steve's comment?

MR. DANNER: Yes, identify yourself.

MR. HERETH: Again, it's Mark Hereth from Blacksmith Group.

Steve, you make a great point with the noting that the Class 3 and 4 cross at exactly 10 years for 1.5 and they cross at 7 years for 1.39.

That was part of the design of this figure, actually. The basis for these curves was

actually work that was done by John Kiefner and I believe Brian Leis.

And, this was in the early 2000s. And, actually, it was Battelle data, the same people that did the ERW study that you guys have referred to over the past few days.

The Battelle data actually supported a re-inspection interval of about 12 to 14 years. What we did on the Committee was actually get conservative and use, for example, 10 years and the hydro testing basis there.

And then, for Class -- above Class 1 and -- which is the 1.39 and the 1.5 test in Class 3 and 4 which is the hydro testing basis there.

So, the interval could have actually been longer based on the data available. But, we actually got conservative, and this is to Cheryl's point again, of the conservatism that's built in.

We decided to move back to the 10-year interval and use the hydro testing basis as a

basis to establish this.

MR. DANNER: All right, any other -- Cheryl?

MS. CAMPBELL: Thank you.

I just want to make one further comment. I'm not -- I'm, frankly, not questioning the need to have the conversation or PHMSA bringing it up, I think it's a valuable conversation to have.

I think it's important for those of us on the Committee, myself included, to understand the chart and what's behind the chart and how conservative it is or is not. Right?

Where the weak points and the strong points are so that we can make an informed decision on what we think the right path forward is and provide that guidance to PHMSA.

And then, obviously, Allen, you and your team will take that into account when you think about what the final answer is.

So, I appreciate PHMSA bringing it up and I appreciate very much the conversation

around it.

MR. DANNER: All right, thank you.

Steve?

MR. ALLEN: Yes, Steve Allen, IURC.

Steve Nanney, there was point that you had made about when an anomaly reaches a point where the predicted failure pressure is, you know, 1.2 times MAOP, why would you not want to go out and fix it or address it?

I think you said something to that effect?

MR. NANNEY: This is Steve Nanney with PHMSA.

I think you misunderstood me. All I was doing was looking at the line up there. If you look at where the two bottom lines go into 1.1, cross 1.2, it you're going from 1.2 to 1.1, you would not have to do the repair until you got to 1.1.

That was the only point I was making is that you've got several years.

The other thing, if you look at the

red line at 7 for Class 1 and 2, where that crosses it's about 1.3. And, where it crosses for Class 3 and 4, is 1.5.

And so, the point PHMSA, you know, is trying to get on record, should we be letting Class 3 and 4 go all the way down to 1.1? Where we're using an R-string, something along that line to evaluate corrosion where you're adding 10,000 to the strength of the pipe and I realized that we're -- operators, some are, most are adding tool tolerance, should we be going down that close?

Should the number, like if we do a pressure test, it's 1.5 for Class 3 and 4 that you do a pressure test. So, in year 1, if you did a pressure test, it would meet that 1.5 that's on that red line.

If you did a hydrostatic test of a Class 1 and 2, it would be 1.25 would be what you would look at.

So, that would be the numbers if you did a pressure test which, at some point, we were

hearing that a lot of these would be pressure tests and not ILI.

We'll have to look at that in an RIA of which, but the ones that get a pressure test will do what the red line I think pretty much is showing when you do the pressure test. It's just of having the discussion of should we let it go to 1.1?

And, again, especially in areas where you've got high consequences and you've got a lot of people in 3 and 4, should we be getting that close when the original design is 2.0 pressure failure ratio and 2.5? That's the issue.

MR. DANNER: All right, Andy and then Allen?

MR. DRAKE: This is Andy Drake with Enbridge.

If the big concern is Class 3s and 4s, I do think this is conservative, but, you know, when we saw the proposal, it was for all classes, 1s, 2s, 3s, 4s, we're going to revisit the whole criteria. And, you saw an allergic reaction.

If the issue is there's a concern that this is not conservative enough for 3s and 4s, I'm fine with revisiting that with some issue.

I think people are misinterpreting this a little bit. I think there is extraordinary conservatism in two levels; certainly the corrosion growth rate and we've now collapsed the re-inspection intervals down, which it helps on both ends.

Which, in essence, puts us at 1.5, I would agree with you on that. Yes, 1.5 is a pretty big margin of error, especially given it's queuing up an inspection.

And, when I get to the ditch, I have to plug in all the safety factors. Okay? So, it's not like we're losing track of these.

But, if there is some concern that 1.5 is not enough in here, I'm -- I would be willing to entertain some discussion about 3s and 4s with some FPR rev limiter. Okay, I think that's reasonable.

But, when we start plugging in all

these miles in MCAs, most of these miles are going to be Class 1s and 2s. Now we're in another place.

I think it's -- it doesn't -- there's nothing here that's showing this isn't working in those areas. And, I don't know why we would change that and it's a huge issue, volumetrically, for the amount of response that we're going to make.

So, I would be willing to bifurcate that a little bit. If people are really wrapped around the axle about this isn't conservative enough in 3s and 4s, all right, I, technically, don't agree, but if -- to the will of the Committee, if people want to do that, all right, let's entertain some different conservatism for 3s and 4s.

But, I don't know why we would get away from this, certainly from Class 1s and 2s. It's proving, it's working; it's got double layers of conservatism in it. I see Steve shaking his head yes, so maybe that's some kind

of settlement here.

MR. DANNER: All right, Alan?

MR. MAYBERRY: What you just mentioned -- Andy, what you just mentioned, so you're suggesting further research on it or to maybe develop alternative language to address that conservatism?

MR. DANNER: Okay, Steve?

MR. NANNEY: Can I just -- and, what we've been looking at in the mileages that we've been looking at on the non-HCAs, the biggest portion of it is Class 3.

And, I think what I thought I heard, you know, would something here be for Class 3 and 4, a 1.5 or something along that line, I thought I heard you mentioning that and leaving the 1.1 for Class 1 and 2? Is that --

MR. DRAKE: I'd like to take a break before I agree to that because I don't want to get stoned when I walk out of this room.

But, okay, you know, not stoned like in Colorado, I mean --

(Laughter.)

MR. DRAKE: But, I think directionally, that's -- that makes some sense. I think that may address what Sara's worried about.

And, I -- and, we've got a lot of time committed as a Committee, and I'd really applaud the willingness of this group to work through thorny issues.

Well, this is a thorny one. And, unfortunately, it's last and everybody's trying to go home. But, if we can bear a few minutes, I think that this would be worthwhile.

I will offer this and then we can take a break, because I think this is actually just as important.

And, I think when we pass the red face test here, we need to add a bullet that operators should consider tool tolerance in this before they deploy Figure 4, I think that should be a requirement.

MR. DANNER: All right, let's take a

five to ten minute break, get back as soon as we can after you have consulted with folks.

(Whereupon, the above-entitled matter went off the record at 3:27 p.m. and resumed at 3:41 p.m.)

MR. DANNER: All right, so Sayler has put some language up there that has been discussed during the break. All right, wait a minute. So we are looking for one more edit. Okay, so who wants to walk us through this? Mark or Andy? Do you want to tell us what you agreed to? All right, Andy.

MR. DRAKE: The guest speaker is sitting back down again. This is Andy with Enbridge. I -- I think we have some good thoughts here. One, I do think we need to add the tool tolerance conversation. Let's quit talking around that. Get people to do this. It's consistent, it's appropriate, it's diligent. It helps -- it would also help to narrow down volatility, which is really what you're trying to do. People should have that. It -- that's an

expectation we should have.

So that -- let's, you know, as we throw the language up there. One thing I think that became clear in the conversations back here was, generally, a comfort with coming up -- differentiating to Class 3 and 4 with some FPR response criteria, I thought a very good conservative step that everybody agreed to -- so, I am trying to work from total consensus down to where there's a little bit of angst, just to be transparent -- that moving to response criteria inside HCAs, which is the vast majority, needs to be one year. So there's no -- figure 4 would not apply in the response criteria for HCAs. It's one year. Outside of HCAs is two years.

So there's nothing beyond one and two years in Class 3s and 4s for these criteria that we're talking about -- which is a big step. I think there was an initial energy around trying to settle and be all stack hands, and that went to 1.5 because that was a number that came up. And then a lot of people got very anxious about

uncertainties with what's happening in their systems. And they've dropped back to 1.39. And I am being as transparent as I can be without putting anybody in harm's way here.

So I think there's a lot of -- there's -- there's a little bit of split here about what is the FPR target? There's no split on tool tolerance. There's no split on using one and two -- HCAs and non-HCAs one year and two year as a criteria, which is, as you look at Figure 4, that's a huge step forward. And to Steve's point, you know, based on what people could be doing, 1.39 is at least a 20-percent safety margin on top of what we currently have, and you back-ended their maximum response time to one to two years. So I think that's -- no one is standing up to object, so I am taking that as -- that was -- that is the absolute most accurate reflection of the conversation back here I can get between the trade associations, not just INGAA, the -- all the trades.

So, I just throw that out there and

see how that responds, Steve. I mean, looking at you. I mean, you've had some concerns about this 1.39 FPR with tool tolerances and a one- and two-year maximum response time in 3s and 4s. Does that address the concern that you have?

MR. DANNER: All right, Steve?

MR. NANNEY: You said 1.39, or 1.5?

(Pause.)

MR. NANNEY: I thought 1.5 is what's up there, that's why I've -- I'm not catching.

MR. DRAKE: That was -- that was a first thought. And then as people started talking, I think they got very anxious about not knowing what that meant. And I think the point they felt like was moving the response time frame up to one- and two-years. As you look at figure 4, takes a ton of risk off the table. And then you're increasing the FPR from the bar -- the line, basically, from whatever that is on the line at one and two years up to 1.39, immediately. That's a lot of conservatism. And that -- so that's there on -- that's, just like I

said, that's -- I am just trying to be very transparent with what the conversation was back here. So that's how they ended up with 1.5 here was there was initial surge of trying to reach a consensus. And then there was a second of, wait a minute, we're -- we're not sure how big a hole we just stepped in. I mean, I am being very honest.

MR. DANNER: Steve, do you want to --

MR. NANNEY: This is Steve Nanney, PHMSA. Again, I think the 1.5 is -- is a better option, but the Committee can consider what they want and PHMSA will take that back and consider it whether it's 1.39 or 1.5.

MR. DANNER: All right, Cheryl?

MS. CAMPBELL: Thank you, Mr. Chair. Cheryl Campbell, Xcel Energy. So -- and again, for purposes of clarity for myself, if we put -- if we were to put a predicted failure pressure of 1.39 but also a one-year response -- and what I am trying to do is convert that into some kind of a risk profile, right? And -- and -- in my mind,

right? And I am probably -- I am probably thinking about it incorrectly, but it -- so I am basically saying my predictive failure pressure is 1.39 times MAOP, but I am also going to make sure I get it inside a year in an HCA. Is that -- is what I understood the -- and if I am outside an HCA, if it's still in a class 3 or 4, I will make sure I get it within two years.

So, I guess my question would be, I am wondering, off the top of my head -- probably a bad question -- what corrosion growth rate would it take -- might take some math, Andy, but what corrosion growth rate would it take to get from 1.39 to 1.1 -- which is the place, Steve, where you're very nervous in that one- to two-year time frame? Does that make sense? Steve is over there shaking his head up and down, right, because we're all interested in keeping it safe, right? And getting to it before we have a failure. So can we convert that into something that helps me think about the risk profile? So is that -- is that the 11 mills a year? Or is

that 20 mills a year? Or is it five mills a year? Can somebody -- can somebody tell me that?

(Pause.)

(Laughter.)

MR. DANNER: I think they're working on it.

MS. CAMPBELL: Someone is doing the math.

MR. DRAKE: It's like throwing a bone to a dog. You've got a bunch of engineers back there, and then -

(Laughter.)

(Simultaneous speaking.)

MS. CAMPBELL: I did see a bunch of them jump up and run to the calculators, yes.

MR. DRAKE: This is awesome; I've got something I can actually do. I mean -- yes, we can calculate that. Actually, we can pick 500-well pipe or something and calculate through it. It's pretty easy -- what that means. But I think the -- where you would be on the bell curve of distribution of corrosion growth would be 99.9999

-- I mean, you would be way out on the tail end. Because you would be talking -- you would have to be talking somewhere in the 16-plus mills -- 17-18 mills per year range of corrosion to get down that fast -- in one year. You'd have to take -- it would probably be much more than that to get off from 1.39 to 1.1 in on to two years means you're --

MS. CAMPBELL: And I think --

MR. DRAKE: You're losing a lot of millage. I mean a lot.

MS. CAMPBELL: Yes, and I just think that knowing that will help the -- A, the non-engineers in the room and B, the non-material science people in the room. You know, help us understand a little bit better about what we're talking about.

MR. DRAKE: I can do it; I got to get my calculator out.

MR. DANNER: Sara?

MS. GOSMAN: Can I ask for that calculation as well to go up to 1.5?

MS. CAMPBELL: Oh, you just had a whole bunch more people run back there to the calculator.

MS. GOSMAN: I know.

(Pause.)

MR. McLAREN: Chris McLaren with PHMSA. Just wanted to add a little bit of context around the corrosion growth rate discussion. While 11 mills can certainly be considered a conservative growth rate in many venues, the NACE 0502 provides more conservative growth rates as the NACE, sort of, gold standard of corrosion growth rates of 12 mills per year if there's CP applied in 16 mills per year -- if no CP in a shielded condition, thank you.

(Simultaneous speaking.)

MR. DRAKE: Yes, unmitigated corrosion growth rate is 16, just to be transparent. But that's -- we're supposed to have CP on our system, so --

MR. DANNER: All right, any further discussion here?

(No audible response.)

MR. DANNER: Apparently not. Other concerns? Other tweaks? Or are we -- Steve?

MR. ALLEN: Thank you, Mr. Chair. Steve Allen, IURC. I -- maybe I missed it, but did we hear what the -- okay.

(Simultaneous speaking.)

MR. ALLEN: Well, I -- I -- so, Cheryl, I think that that's a very, very good observation. And, Mr. McLaren, I think that also adds some parameters to the discussion as far as corrosion rate. You know, of 16, or what was it you said -- is 12 was the gold standard?

MR. McLAREN: NACE 0502 provides the standard of 12 mills a year corrosion growth rate when CP is applied. Or 16 mills per year corrosion growth rate when inadequate or shielding CP is -- is there -- not there.

MR. ALLEN: Okay, so then if we find out that the -- the mills per year is greater than 16 for this drop from 1.39 to 1.1, that does a lot for me.

MR. BRADLEY: Just to -- just to -- thank you, Mr. Chair. Ron Bradley, PECO. Just to get clarity, Chris, on the corrosion numbers. Are you talking about bare steel or coated steel cathodically protected -- when you say protected?

MR. McLAREN: Cathodically protected coated steel from NACE 0502, the ECDA standard. There are other numbers in ASME B-31-8-S which deal with soil resistivity. But typically if we want to stay within the NACE family of definitions, as we have so far, those are the ones out of 0502.

MR. BRADLEY: Appreciate it. I just -- I know we got calculations being done; I just don't want to scare the organization. I mean, when you -- when you -- we've traditionally gone back and looked at pipe -- obviously, there are one-offs that happen and there is shielding. But cathodic protection does a great job -- yes, or induced.

MR. DANNER: Are we close? Okay. In the meantime, Steve Allen. Oh, you're going to

wait. Okay. Well, while we are waiting, I just remind everybody that our next meeting is going to be June 12th to the 14th. So, for those of you who don't have your calculators out, get your calendars out. Okay, Andy?

MR. DRAKE: Andy Drake with Enbridge. While we are idling here, and his computer is sort of smoking, I am going to -- I thought I would throw out here a thought that Sara and I broached the other day. And that was, as the rule comes to a close -- knock on wood -- here at the midnight hour, I think it's appropriate for us to be conscious of our accountability to the public.

You know, the city of San Bruno is particularly affected by this and had a huge bearing in this discussion. And I think that it may be appropriate -- I think it's appropriate for some small group of us -- I am very committed to doing this, I think others are. I just offer this to the Committee. May be worthwhile for us to go and meet with the city managers and the

folks out in San Bruno and kind of close the loop with them about what have we been doing for oh, so many years? As industry and as committees and as government, did we hear them? Are we responding to them? Are we advancing pipeline safety? Are we addressing their concerns? I think this is a part of our accountability. And I just want to throw that out there for us to think about.

MR. MAYBERRY: Actually, I was thinking about that as we, you know, finish up here. You know, that's a milestone for this group, for the agency, for the, you know, hard work that's been done to close the loop on some policy matters. You know, and develop a path forward for, you know, policies that will prevent -- help prevent that type of incident. So, you know, I didn't want -- and I appreciate you mentioning that, Andy. I didn't want to lose sight of the fact that, you know, we -- we made progress here over the last few years. And I think we need to remember, you know, what it's

all about. You know, improving pipeline safety. Certainly learning from incidents that have happened, and most notably, you know, the eight fatalities and the victims and their families from San Bruno as we go forward, you know.

You know, it weighs heavily on me, I know the rest of us, that -- you know, this is a big deal we've done here. And it's a lot of good work that went into it. And so, you know, unfortunate that there was loss of lives. But it was, you know, out of that we have learned and are developing new, you know, policies for pipeline safety nationwide. So, yes, I would welcome something like that as well.

MR. DANNER: Okay, Sara?

MS. GOSMAN: So I wish I had thought of this idea. I've got to give Andy credit because that's a great idea and I really -- I think it's a terrific thing to do. I think we -- and I would say that I think that we should try to get everybody there. But if we can't do that, then we can't do that. But it seems to me that

we as a Committee can be there and responsive to the people who had this incident. And it's a different place than being here in D.C. and I think -- I think we should be able to explain what we've done, and I think we should be proud of a lot of the work that we have done on this rule.

MR. DANNER: So I would just like to say -- this is Dave Danner -- that I think it's a great idea, too. In my state, in Bellingham, Washington there was a fatal explosion several years ago. It seems like it's old history, but in my state, it's actually still fresh. So I have to imagine that in San Bruno it's very fresh. So I do think it's a good idea. And we should consider that.

MR. DRAKE: Actually, they're doing due diligence. They're actually comparing -- that they reached the same conclusion separately, which is good -- that's a good thing.

(Pause.)

MR. HERETH: This is Mark Hereth with

Blacksmith. Can I go ahead?

MR. DANNER: Right, you are recognized, sir.

MR. HERETH: Thank you. So a couple of us have run this independently. And we've gotten essentially the same number. So to go from 1.5 to 1.1, the growth rate that would be required in one year is 100 mills. So compare that to the 11 mills that we talked about before. So that's a very aggressive corrosion rate. To go from 1.5 to 1.1 in two years, which would be the non-HCA, that would be 50 mills. If we then look at 1.39 to 1.1, that would be 72 mills in the one year, and it would be 36 mills in the two years. So even at 1.39, we're -- in two years, we're three-times -- or, more than three-times that 11 mills per year growth rate.

MR. DANNER: And that's for a half-inch wall pipe?

MR. HERETH: When I ran it, it was for half-inch wall, yes. I used half-inch wall, 30-inch -- yes. X52 is what I used. Yes.

MR. DANNER: All right, thank you. Cheryl?

MS. CAMPBELL: Thank you, Mr. Chairman. Cheryl Campbell, Xcel Energy. I -- given that information, I would like to propose that we change that -- that predicted failure pressure for Class 3 and 4 to 1.39.

MR. DANNER: Okay. Any discussion on that? Sara?

MS. GOSMAN: I am just hoping for a response from PHMSA about the data that we've just heard.

MR. DANNER: Go ahead, Allen?

MR. MAYBERRY: We will consider it. We will consider -- yes. I mean, I've heard the -- the growth rate numbers, and yes, we will take it under advisement. Certainly we will take seriously the recommendation of the Committee and go from there, yes. Sorry.

MS. GOSMAN: Could I push a little bit and just -- I mean, does that cause, for example, Steve to change his perspective on the numbers

that have been proposed? And if so, why? And if no, why not.

MR. NANNEY: Steve Nanney, PHMSA. I am not sure going -- the one -- what I just heard, I don't really know that it makes sense to me one way or the other. The key is, is if you're in a Class 3 or 4 area, is, for that time frame, whether it's growing at five mills, 11 mills -- how -- how far below do you want it to go is the point. Because I think -- that's the key point, is do you -- do you want the 1.39 to go down to -- in this case, to 1.25 or 1.1? And I am not sure, what I would want to see, that it answered the question. But -- but the key is, is 1.39 fine versus 1.5? And again, just like what Allen said is -- we will take whatever the -- the Committee recommends and look at it and take it under consideration. I would have been more pleased if it had been 1.5.

MR. DANNER: Okay, Andy and then Allen?

MR. DRAKE: This is Andy Drake with

Enbridge. I think -- I can appreciate where we are. I mean, we are all sitting here learning vertically, on the fly. I would just throw out there a reminder that we took a very conservative model and we collapsed it. We accelerated the now assumption of corrosion wildly and we have collapsed the time frame for which we are projecting it to be reacted in to two years. And I think that's -- that's where the confidence really starts to drive up, is we are going to get on these quickly. You've taken tool tolerances out or into consideration. And we've jetted -- you know, jetted up the assumptions on safety margin and closed down the time frame. So I think we've got three or four dimensions of value that we're adding in this conversation. I don't -- I just want us to keep, like, looking at it one variable at a time. So I think when you look at them all together, the two-year commitment is a significant deal because that closes down volatility. So is the tool tolerance issue. It closes down the volatility, which is important.

MR. DANNER: All right, Allen?

MR. ALLEN: The only other thing I would add, I mean it's a positive step. So, you know, sometimes you get what you can. And, you know, but -- you know, it's in the right direction. It's -- you know, there's not too much difference, like Steve was saying. But, you know, we just have to take a look at it and see.

MR. DANNER: All right, Sara and then Steve.

MS. GOSMAN: So I am wondering if we could as a Committee ask PHMSA to consider revising these two sections within the framework of 1.39 to 1.5 based on information such as the one that we were just given. That is, rather than make -- excuse me -- rather than make the specific recommendation to PHMSA for a particular number, give them -- they've heard our discussion. They've given -- they've -- we've given them some helpful information. Give them a range and let them look at that.

MR. DANNER: All right, Steve?

MR. NANNEY: I wanted to ask Andy just one thing. You said two years, were you saying that you'd have to repair it in two years? I didn't catch one thing. I just wanted to make sure I didn't misunderstand something.

MR. DRAKE: The commitment that we made back here was HCAs would be remediated to respond to within one year, and non-HCAs within two years. So -- and I think that's the value add. I -- you know, I appreciate the -- you know, we send PHMSA back to consider this. I just think this is a very conservative position. And I would like to be -- you know, have that weighted appropriately as they go back. The growth rates we're talking about are astronomical, especially given the fact that we just committed to close the time frame way down, you know, and deal with tool tolerances. And I would like that to be considered as we go back.

There's a lot of good faith trying to happen back here, and I am trying to recognize that out loud here. Folks in -- on the operating

side, literally don't know how big this commitment is. But they're willing to make it, and that's good. And I appreciate that. And I just -- you know, we talk about trying to meet in the middle of the road on a lot of things. I think this is one of those places it would help people's anxiety drop down if we could -- if there was some due consideration of 1.39. So I am okay with this, I just want to go on record. I really think this is compelling conservatism.

MR. DANNER: All right, Steve and then Cheryl.

MR. NANNEY: I just wanted to say, it's appreciated and we appreciate the entire Committee taking a look and having the conversation because we think it's a safety item that was worth this -- of getting it on the table and talking about it. And again, thank you.

MR. DANNER: All right, Cheryl.

MS. CAMPBELL: Thank you, Mr. Chairman. Cheryl Campbell, Xcel Energy. So -- and I apologize, Steve, John and Allen if we were

not clear about that earlier. But that -- one of the reasons why I think people were saying how conservative this was was that, for HCAs, we were committing, right, in Class 3 and 4 to a one-year and non-HCAs in Class 3 and 4 are two years. So that adds one more level, right, of safety belts and suspenders. I think I now have like three belts and two pairs of suspenders on with this -- is what it feels like, Steve, right? But you know, to provide that guidance, right? To give you the tools that you need, right, to help operators -- let me put it this way, help operators understand what their obligation is. But also give people some certainly and some guidelines. And then I think lastly I would ask Mr. Allen if he would comment on this and how he feels about it from the -- from the NAPSR perspective.

MR. DANNER: All right, go ahead, Steve.

MR. ALLEN: Thank you, Steve Allen, IURC. Without speaking with my fellow NAPSR

members, I really can't speak for them, but I can speak for myself in that I do appreciate the education that was received this afternoon. Going from a, you know, potentially a seven-year cycle down to a one- or two-year cycle to rectify an anomaly, I like that. I think that's -- that's in the right direction. From an enforcement perspective, and I had mentioned this before. I think, you know, there might be some concern about, you know, perhaps some smaller operator is not having the level of expertise to perhaps understand all this, and maybe even comply with it. So with -- with any other change that comes about in pipeline safety regulations, part of our job as a state regulator is to help educate those operators out there that need help, and I think that whatever -- you know, not just with the conversation from this afternoon, but this entire rulemaking. I think the NAPSR members are going to need to work pretty closely with Zach Barrett's organization to make sure that we are delivering the right message to our

in-trust state operators so that they understand what the -- their responsibilities are and we can help them with some change management. So I don't know if that helps you or not, but this is big stuff and we're going to be held accountable for enforcing it. And I think -- I do think that the membership is going to recognize what a Herculean task this is going to be for some of our operators.

MR. DANNER: All right, Allen?

MR. MAYBERRY: You know, I can certainly appreciate the good faith, you know that you guys huddled up and came up with this. And, you know, to move -- the movement that happened. Related to what's up there now, and I am just trying to -- to just do a check on that -- that -- and I am not sure where you guys are. I mean, I kind of have a feeling where you are. But I would think you might want to add that -- that this would be, you know, it would be based on relevant technical information. Either way, you know, that it would have to land on a spot

that's based on relevant data, corrosion growth rates and the like, you know. You have a response to that, Andy?

MR. DRAKE: I think that's the fundamental underpinning of a lot of these discussions. And I think that's really the value of -- I know this took a while, and some of us has to go catch planes pretty quick, but I think that was the value of letting this churn and go through some models and examples, so we can get some context and tangibility to what's this means in terms of growth rates -- where are we on the standard? Where are we on the S standard? Where are we in these -- in these assumptions that we're making? In that interest, I am willing to make a motion -- and I will leave it as it's typed with the guidance that we've given.

MR. DANNER: All right, if there's no further conversation, Andy, why don't you make a motion?

MR. DRAKE: I would like to propose a motion that the voting language for repair

criteria in paragraph 192.485(c), 192.711, 192.713, and 192.933 -- the proposed rule is published in the Federal Register and the Draft Regulatory Evaluation with regard to anomaly repair timing provisions for scheduled corrosion metal loss. Repair conditions are technically feasible, reasonable, cost-effective and practicable if the following changes are made. Incorporate 192.933(c), i.e. ASME B31a-section 7, figure 4 into paragraph 192.713. Operators must consider ILI tool tolerance, account for uncertainty and accuracy on pipeline integrity runs or in-line inspection runs. Remove the PFP standards for Class 1 and 2 from the proposed 192.713(d)(3)(iii) and 192.933(d)(2)(iii). For Class 3 and 4, revise the proposed paragraph 192.713(d)(3)(iii) and 192.933(d)(2)(iii) to consider a PFP ratio between 1.39 and 1.5 based on the technical discussions, and the conservatism of the discussions of the Committee to date. Scheduled corrosion metal loss, repair conditions must be remediated in one year in HCAs

and two years in non-HCAs. And PHMSA will provide appropriate guidance to improve the understanding of and use of ASME B31.8, Section 7, figure 4.

MS. CAMPBELL: Mr. Chair, Cheryl Campbell, second.

MR. DANNER: All right, thank you. Is there any discussion?

(No audible response.)

MR. DANNER: All right, I just want to say, I really appreciate all of the discussion this afternoon -- all the work people had been doing. My only issue -- and this is why I will probably vote no on this, is just that I think I would like to take this information and just give it to PHMSA for consideration without a presumption that this is the best way to proceed. I would like them to be able to look at this fresh. But again, having said that, I do appreciate this work and thank everybody for a great conversation this afternoon. So with that, I think that we're ready to have a roll call

vote.

MS. WHETSEL: Okay, Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Nay.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Nay.

MS. WHETSEL: Sara Longan?

DR. LONGAN: Aye.

MS. WHETSEL: Cheryl Campbell?

MS. CAMPBELL: Aye.

MS. WHETSEL: Andy?

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley?

MR. BRADLEY: Aye.

MS. WHETSEL: Rich Worsinger?

MR. WORSINGER: Aye.

MS. WHETSEL: Jon Airey?

MR. AIREY: Aye.

MS. WHETSEL: Mark is not here.

Robert Hill?

MR. HILL: No.

MS. WHETSEL: And Sara Gosman?

MS. GOSMAN: Aye.

MS. WHETSEL: Okay, we have -- what do we have? Three nays and how many do we have -- and eleven.

MR. DANNER: All right, and the motion passes. So I think that brings us to the end of meeting 132 so again, we will be meeting again in June, 12th through the 14th. But I am going to turn it over to Allen. He's got a few matters to discuss before we adjourn.

MR. MAYBERRY: Okay, thanks Chairman -- Mr. Chairman. Is there anything for the good of the order before we wrap up?

MR. ALLEN: To the extent possible, can -- can PHMSA provide the Committee as much information as quickly as it can regarding gathering lines to help us to -- I mean, there's an awful lot there. And there's going to be quite an education to be had by many of us, and we would appreciate -- you know, even if they're just, you know, primers. You know, I just -- I

would appreciate any information as quickly as I can on that so I can get up to speed.

MR. MAYBERRY: Yes, we will get it. We will definitely help, Steve, in that area. We will do the briefings we've done, you know, be consistent with that. But to the extent you need other information, we can -- we can help. Cheryl?

MR. DANNER: All right, Cheryl?

MS. CAMPBELL: Yes, I -- I wanted to check -- and I know we've got some folks that need to get out of here for airplanes, but I wanted to see if we just wanted to put on the record some data around this 30-percent SMYS issue that we had talked about earlier in the week? Or if that is a -- if that is -- if that information is something that we wanted another time? I am asking a protocol question.

MR. MAYBERRY: I think it relates to the 30-percent issue. I think the Committee had sent us off to -- to, you know, look into that based on cost and benefit whether or not to

extend it -- coverage to non -- was it -- well, it's in -- yes, non-HCAs. Class 3 and 4 non-HCAs. So we will -- we had some information I was hoping to present, but we just need to -- we need to do our due diligence just to double check it, you know, before we come back.

MS. CAMPBELL: Okay.

MR. MAYBERRY: You know, I think we're -- we have a good idea on where -- where that may land. But, you know, we'll just have to -- you know, we will let you know.

MS. CAMPBELL: Okay.

MR. DANNER: All right, Sara?

DR. LONGAN: I will make this very quick because I know people are trying to get out of here. I had a comment about the language that you showed us earlier in the preamble for TV&C. And I promise, I can make this fast. But I was wondering if you could entertain some wordsmithing, and I apologize because I think it's important. Is that a yes? If we can go back to that slide we saw earlier?

MR. DANNER: So this is the language that we had up yesterday?

DR. LONGAN: It was the language that we had up first thing this morning.

MR. DANNER: Oh, okay. The -- so the --

MR. MAYBERRY: It was on the -- it had -- it had a reference to TV&C in it.

DR. LONGAN: I believe it was the very first thing we spoke of this morning.

MR. DANNER: Yes, I think it was the motion -- the first bucket.

DR. LONGAN: That's it. Thank you, I want to make two obvious caveats. One, I hold in high value the need for PHMSA to have access to as much information. I'm, too, on a very steep learning curve. I know a little bit more on day three, but this being my first GPAC, I need some more time. Regarding the language that's on this slide and the conversation I heard this morning, which was very helpful, I spent time looking at the slide decks from the past two and previous

GPAC meetings.

I caught the spirit of what PHMSA has said in the past and described as it relates to TV&C. But being a former state regulator myself, I understand that when this is enforceable or interpreted, even if it is in a preamble, ambiguity is not good. So when I read on the second bullet, document information confirmed by other, I am wondering who is to do that confirmation. And I offer if you would consider something different -- document information informed by other complementary but separate documentation.

Some clarity from PHMSA also would be nice because, from our exchange this morning, PHMSA said no, we're really just looking for one documentation. But when we talk about separate documentation, I was confused. And I am sorry; I should have brought this up earlier. But we moved on. And then I want to, just for the record, state that as I understand it -- again, going back to the spirit of the conversation this

morning and the slide decks that I have reviewed -- that that spirit, stated by PHMSA, is reflected in the third bullet that says, is finalized as evidenced by a signature. Because I believe the statements that industry has raised about acquisitions, about requiring a signature for someone who maybe has unfortunately passed away -- evidenced by a signature is important and I think, for me, accurately captures the spirit that PHMSA has said they want to work to get as close to TV&C as possible, but maybe not having one signature isn't going to cause the operator a big problem. So please consider those word changes, and again, thank you.

MR. DANNER: All right, thank you very much. Yes, that's consistent with some side conversations that I've had today. I mean, the -- the words traceable, verifiable and complete, to me, each have plain language meanings. And so whatever definition they have to come up with has to be consistent with that in my opinion. So, all right, is there anything else to come before

the Committee? Allen?

MR. MAYBERRY: No, I just appreciate that, you know, suggestion and clarification. So we will take a look at that, thank you, Sara. And then --

MR. DANNER: All right. Anything else for the good of the order, Committee Members?

MR. MAYBERRY: Well, I just had a -- I wanted to summarize where we are with the -

MR. DANNER: Oh, all right.

MR. MAYBERRY: Yes. Just, if you would, put the slide back up related to the rulemaking. I just wanted to remind you that we -- as I mentioned, you know, on day one as far as where we are going from here with this rule, which we've -- you know, so far I've moved through the process as one monolith, but it will be split into three. Two of them are up here. We already have what we call regulatory identification numbers. If you go to the DoT website, these are listed. And you can track on that website, you know, the status of these

rules. But, you know, these -- these three -- first, on the left -- I believe that is the -- let's see. Yes, that's the rule number one. That essentially covers, essentially mandates. A little bit beyond mandates, but essentially that's a mandates rule. The second one on the right screen is, you know, repair criteria as you see there -- a variety of other issues that are not so much mandate related, but related to other areas -- improvements to the code. And then the third area, lastly -- and by the way, let me back up one second. We are finished with these two. So, you know, really cliche. Give you guys a hand. How about? Nice work.

(Applause.)

MR. MAYBERRY: And way to go. You know, like I said earlier, this is a great milestone for policy making. And then lastly, we have the -- and not -- certainly not least, the gathering line, which would be a third rulemaking. We will cover that in the June meeting. So anyway, that's just a reminder of

how it's broken up.

And just -- you know, I want just to say, you know, on behalf of the secretary, the administrator -- you know, Drue Pearce who is here, Deputy Administrator, thank you. Appreciate your hard work over the last few years. And, you know, again, welcome to our new members. John and Sara, appreciate your involvement. You will -- you will soon come to know that, you know, this is no easy task. This is hard work that is in addition to your day job. So very much appreciate it.

And lastly, I wanted to -- this is a little bit of a test. What starts on Sunday? What's -- what does Sunday mean to you? Besides, you know, April 1st is April Fool's Day. Any -- not a trick question. And Easter.

MR. DANNER: Is it Fix-A-Leak Week?

MR. MAYBERRY: I want you to remember that -- and you all know this -- but Safe Digging Month starts April 1st. So, remember -- again, Andy is wearing his 8-1-1 pin. Contact -- thank

you -- because there are a variety of ways to contact 8-1-1. But yes, remember to promote, Call Before You Dig. Tweet it. If you would, tweet it out. I would recommend. I would commend you to tweet it at your respective organizations. So, Sara did you have?

MS. GOSMAN: Thank you. Sara Gosman. I wonder if PHMSA would be able to share the -- where they come out on two for one in terms of breaking up these rules. Because it seems to me that it's -- our jurisdiction is to understand these proposed rules and their cost-effectiveness and reasonableness. And we've now added a layer in which we are removing regulation in order to be able to propose the regulation. And I think that comes within the kind of things that we should consider, or at least be informed of.

MR. MAYBERRY: Thank you, Sara. What we can do is have at our next meeting a briefing on -- on that. You know, on the executive orders and how all this fits in. And you know, where we're headed with that -- and probably update the

Committee as we go forward as well. That is, you may recall, a department-level -- well, actually, it's a government-wide initiative, but certainly it's being managed at the department level.

MR. ALLEN: One other thing, and I don't know when you would want to do it. I had mentioned it, I think, in December and you acknowledged. It was the report that the Transportation Research Board put out last year talking about different regulatory approaches. I mean, I think that would be good to share with the Committee here. So, just to -- not to lose sight of it. I thought it was pretty good -- just -- and Ron, you were there? So it was -- it was good stuff.

MR. MAYBERRY: All right, we will plan for a breakout on that as well.

MR. DANNER: There is nothing else to come before the Committee today. We are adjourned. See you in June.

(Whereupon, the above-entitled matter went off the record at 4:33 p.m.)

C E R T I F I C A T E

This is to certify that the foregoing transcript

In the matter of: Gas Pipeline Advisory Committee

Before: US DOT

Date: 03-28-18

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