TRANSCRIPT OF PROCEEDINGS

U.S. DEPARTMENT OF THE INTERIOR
Bureau of Land Management
TRIBAL CONSULTATION
Proposed Revision Onshore Orders 3, 4 and 5
Dickinson, North Dakota
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Energy, Minerals & Realty, BLM
Billings, Montana

INTRODUCTION: JAMIE CONNELL
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OPENING REMARKS: AMANDA LEITER
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For Land & Minerals Management

PRESENTERS: RICHARD ESTABROOK
BLM Petroleum Engineer

MIKE WADE
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MICHAEL McLAREN
BLM Petroleum Engineer

P R O C E E D I N G S

9:10 a.m.

MR. JUDICE: So, good morning.

My name is Don Judice. I am the Deputy State Director for Energy, Minerals and Reality at the Montana-Dakota State Office in Billings. I'm also going to act as the facilitator for this Tribal Consultation meeting.

I want to personally thank you guys for coming in for this important meeting.

Some of the logistics that are going on, you should have picked up a packet that has the agenda for today, and the three regulations that these gentlemen will be discussing.

Logistics also about the building. If there are any issues where we need to exit the building, you can go out the way you came.

There's also exits here, that if you go out these exits and hang a left, you can get out of the building in that fashion.

But again, we're going to have an opportunity to share some information with you. It's going to be nice and cozy. There's not a big crowd for this, so we will have a chance to answer any questions that you do have.

I'll introduce Jamie Connell, who is our State Director, and she has some opening remarks.

MS. CONNELL: Well, hi, everybody.

I think we could welcome everybody individually, but I won't. We introduced ourselves at the back of the room.

Thank you for being here. We really, really appreciate it.

You know, we spend a lot of time meeting with the folks from the MHA Nation, and so I feel as if it's kind of almost a little awkward to have it set up like this. But that's fine, because, you know, hundreds of others might show up any minute, and we'll have to have room for them.

(General laughter.)

So first of all, thank you for being here. I understand there's quite a big event being held down Las Vegas with one of our -- for those of you that don't know, a member of the MHA Nation is competing in the National Indian Finals Rodeo in Las Vegas, and so -- a bronc -- roper. I was trying to find it on the Internet what his accomplishments were.

But anyway, Jesse's down there, and so a number of folks that we might have been able to meet with here today justifiably are down watching him compete, as well as going to meetings in Las Vegas.

So, thank you for taking the time to be here with us. We have a lot of information to share. And with the small size of the group, hopefully we will be able to answer lots of questions, and hopefully this will be somewhat conversational while we are keeping good records as we go through.

So, if there aren't any questions for me, I'm going to just move on and welcome all of you.

Are we going to do introductions around the room, do you think, or --

MR. JUDICE: We can do that.

MS. CONNELL: Since it's such a small group, I think we should.

MR. JUDICE: I'll then introduce now Amanda Leiter, who is the Deputy Assistant Secretary for Lands and Minerals Management Washington, D C.

MS. LEITER: So, thank you all so much

for coming out. I really appreciate it. Thanks, Jamie and Don for the introduction.

So, I'm Amanda Leiter. I'm the Deputy Assistant Secretary of the Interior, and I work principally on lands and minerals issues.

I really appreciate you all being here, and also taking the time yesterday to show Dylon and me around some of the Tribal minerals sites.

It was extremely helpful for me in particular. You know, being based in Washington, I don't see what this looks like on the ground all that often, so it was very helpful to get a sense of what the issues are on the ground.

So, over the past couple of years, as you know, the BLM has been working to update these Onshore Orders to address improvements in the technology, oil and gas technology. And the BLM initiated a Tribal dialogue on the Onshore Orders in 2011, and this is another step in that process.

The revisions are intended to ensure that we're accurately measuring the minerals as they are sold. And that's, of course, important for calculating royalties, which, as you know, are returned to the tribes or to the Indian, individual Indian allottees.

So, I think this is an important dialogue, and we really look forward to telling you a little more about what the updates are going to be, and then hearing from you any questions you have, any concerns you might have, et cetera.

And I'm very open to questions today. I do think we should do this as a pretty informal conversation. So maybe the next thing to do would be to just go around and have each of us introduce ourselves. Maybe tell a little bit what you do at the BLM or at Interior or for the Tribe, and we'll go from there.

MR. JUDICE: Great.

We will start here with Mike.

MR. WADE: Well, Mike Wade. I work for Washington office, although I physically sit in Denver as the Senior Oil and Gas Compliance Specialist, and one of the primary authors for 3173, which is site security.

MR. ESTABROOK: My name is Rich Estabrook. I also work for Washington office, but I am physically located on the North Coast of California.

My primary function is the lead for the gas pipeline reporter.

MR. McLAREN: I'm Mike McLaren. I'm a petroleum engineer in the Pinedale Field Office in Wyoming, and I'll be talking about what we are proposing for the oil management regulations.

MR. JUDICE: Travis?

MR. KERN: I used to work for Washington office. I'm at the State Office in Billings, Montana for the Bureau of Land Management in the branch of fluid minerals.

MR. JUDICE: And this is Travis Kern.

Chris?

MR. RHYMES: I'm Chris Rhymes. I'm an attorney advisor in the Solicitor's Office at the Department of Interior.

MR. FUGE: Dylan Fuge. I'm a Senior Advisor in the Director's Office. I'm the primary person in the Director's Office working on the Onshore Orders, and I serve a handful of other assorted solid and fluid mineral issues.

MR. TORRES: Gary Torres, Deputy

Division Chief of Fluids Minerals in Washington.

MR. LAMBERT: My name is Will Lambert. I'm a petroleum engineer with the Bureau of Land Management with the Washington office, but remotely located in Billings.

MS. FRIEZ: Good morning.

Diane Friez, District Manager for the Eastern Montana-Dakota District for BLM in Miles City, Montana.

MR. WICKSTROM: Good morning, Loren Wickstrom, North Dakota Field Office, Field Manager.

MR. JACOBSEN: Mark Jacobsen, BLM Public Affairs.

MR. DeVAULT: Chris DeVault, Inspection Enforcement Coordinator in the Montana State Office.

MS. NATION: I'm Darci Nation, the Inspection Enforcement Coordinator out of the Wyoming State Office.

MR. LYSON: Kenny Lyson. I'm Deputy Director of the MHA Energy with the Three Affiliated Tribes.

MR. HALLAM: Travis Hallam. I'm the

Pipeline Safety Officer for the Three Affiliated Tribes, and I also serve, help out with emergency response. Those are basically my backgrounds.

And many of you I've met from the Federal Partners meetings. And mostly what I do is beg the BLM to help us protect ourselves from the industry.

MR. MORSETTE: Daymyn Morsette, MHA Energy. Field Inspector.

MR. JUDICE: Thank you.

One of the things we like to start out with is, and I believe we will have an invocation done, and we will ask Kenny here to give us an invocation.

MR. LYSON: Okay. I appreciate everybody's time. It is our tradition in our culture to start everything out with a prayer. This is one of the things the tribes have done, so I feel honored that you asked me this.

(Invocation.)

MR. JUDICE: Thank you very much.

We will then -- oh, Amanda?

MS. LEITER: Yes.

One thing that I was supposed to say

that I forgot to say earlier is that the public comment period for these rules is still open until December 14. But, of course, we take comment from the tribe up until the point that the final rules are published.

So, you all should feel free to continue to weigh in in writing even after these meetings are over.

MR. JUDICE: That also brings to light another comment I'd like to share, is that if you would like a personal consultation where BLM could come to your Tribal chambers, talk with the entire Tribal Council on this effort, that offer is on the table, also.

So, just let us know before the end of the meeting -- but it doesn't have to be before the end of the meeting.

Any time here in the coming weeks that you believe that it would be important that you have something more personal that's at your offices in front of the Chairman and others, we would -- that offer is there.

MR. LYSON: And I think that would be -- you know, once we get everything here, we can take back to them and actually sit down to them, I'm sure they might want something like it. But I'll get ahold of you about that.

MR. JUDICE: Okay. Perfect.

MR. HALLAM: And when's the next Council meeting? They've got that one coming up pretty fast, right, like the 16th, I think.

MR. LYSON: I can't remember. I think so.

MR. HALLAM: So if we do, it would probably be pretty fast before we have our Federal Partners meeting, and that would probably be the 16th. So probably would be fast.

MR. LYSON: Well, Federal Partners is not until January.

MR. HALLAM: That's what I mean. It would before the Federal Partners that we would have it on the 16th.

And I think it is something they probably would like to do.

We will verify it.

MR. JUDICE: Well, verify. Let us know. That offer is out there for you.

MR. HALLAM: And I appreciate that offer.

MR. JUDICE: Absolutely. Okay.
MR. HALLAM: We appreciate it.
MR. JUDICE: So let's get started, then.
MR. ESTABROOK: Sure.
Well, my name is Rich Estabrook, again.
We got kind of a long presentation; a lot of PowerPoint slides, which I know can get really boring and dull, so I would encourage you to interrupt any one of us any time.
I would much rather have a conversation with you than just sit up here and go through slide after slide after slide. So, please, any questions, any comments, any time, please interrupt us and take advantage of that.
This is the outline we have proposed for this presentation. We are open to talking about any of these things in more depth or talking about other things.
But I was going to go through quickly about why these regulations are important; why we are revising them, and then I'm going to go through a discussion of what we are proposing to change for all orders -- there's three specific

orders that we're talking about revising, and I'm going to go through changes that are common to all of them, including a new proposed regulatory Part 3170.

I'll then turn it over to Mike Wade, and he's going to go into the specific things that we are proposing in 31 -- Subpart 3173, which would replace Onshore Order 3.

We have questions and comments. And of course, we'll take questions and comments after each part, but also, as I said before, stressing any time at all during our presentation, please jump in.

I'll then turn it over to Mike McLaren, and he'll talk about a proposed Subpart 3174 that would replace Onshore Order 4 about oil measurement. And I think that's specifically significant up in this area.

I'll wrap it up, and I'll talk about a proposed Subpart 3175, which will replace Onshore Order 5 on gas measurement.

So, why are these regulations important? And the bottom line is money.

These regulations will directly impact royalties going to both tribes and the federal government. So I thought I would just start with -- again, much of this I'm sure you already know, but I just thought I would start with how oil royalty is determined that goes back to Tribal leases, or allotted leases.

Royalty is the royalty rate on a lease, which is usually a fixed number, times the volume of oil removed from that lease in a given month, times the dollar value of that oil.

You multiply those three things together, and you get the royalty check that eventually goes back to a tribe or an allottee.

The value is affected by API gravity. That is the quality of the oil, the density of the oil. It's not a direct multiplier in the calculation of royalty, but it does affect value, which affects royalty ultimately.

The royalty rate, as I mentioned before, is a set number in your lease terms. It's something that these Onshore Orders do not get into. That's a whole different subject, and so we will not be discussing anything to do with royalty rate here.

The dollar value of the oil is not determined by the Bureau of Land Management. As you know, it's determined by the Office of Natural Resources Revenue. Again, that's a whole different thing that these proposed regulations will not cover.

Onshore Order 4, and to some degree, Onshore Order 3 specifically talk about the accuracy of volume measurement and the proper reporting of volume measurement. So, any changes to Onshore Order 4, and specifically and to some degree, Onshore Order 3 will directly affect the volume of oil that's reported on which royalty is ultimately due.

Onshore Order 4 also covers the measurement and reporting of API gravity. Again, not a direct multiplier for royalty, but certainly a factor.

For gas measurement, it's very similar. Royalty on gas is the royalty rate on the lease times the volume of gas removed from that lease in a given month, Mcf being thousands of cubic feet, times the heating value of that gas, times the dollar value.

As with oil, the royalty on gas is set in the lease terms. That's not something that these Onshore Orders are relevant to. The dollar value, again, is determined by the Office of Natural Resources Revenue, not us.

Onshore Order 5, and to a lesser extent, Onshore Order 3, however, do set standards which determine the accuracy of gas measurement and the proper reporting of gas measurement.

Onshore Order 5 also talks about the measurement and reporting of heating value.

Unlike API gravity in oil, the heating valuing of the gas is a direct multiplier of royalty.

One of the things I will talk about a little bit as we go through here, if an operator is to report volume, let's say they were 10% in error for some reason, mismeasured, whatever, the royalty is going to be 10% in error. It's a direct effect.

The exact same thing is true for heating valuing. If the heating value was determined 10% in error, it's going to have the same impact on royalty as value measurement.

This becomes kind of significant, as I'll get into the gas measurement a little bit, because the current Onshore Orders have a fair number of provisions dealing with volume, but one, and only one, provision dealing with heating value.

Just some statistics. These are oil statistics. This is oil production in millions of barrels, and this is all Tribal leases.

You can see from about 2004, all the way to about 2010, the oil production from Tribal leases was pretty consistent, about 10 million barrels per year.

Starting 2010, and continuing at least through 2014, there has been a tremendous increase in oil production. And that actually, most of that increase is due to this area right here.

So in 2014, oil production went from 10 million barrels previous to 2010, and now we're up to a little over 50 million barrels per year.

If you look at the price of oil, this is the U.S. average crude price. It's been jumping around a little bit.

In 2004, we were running about $35 per barrel. We had a big spike in 2008, up to over $90 a barrel. Had a drop the next year. And for the last couple of years, it's been around $90 per barrel.

And now we all know that in 2015, it's taken a big crash. But, I don't have the statistics for that yet.

So if you take oil production, and you multiply it by oil price, you get royalty.

So, this is Tribal royalty. From 2004, we were running down around -- I'm sorry, the scale for royalty is over on this side. I'm sorry for being a little bit confusing here.

In 2004, oil royalty is down a little bit below $100 million per year. Now, it kind of was pretty consistent again until 2010. But in 2014, Tribal royalties on oil were up to almost $850 million. So it's been a huge increase in royalty over the last four or five years.

Again, most of that royalty increase is due to production and development in the Bakken in this area.

If we look at gas production, it's got a little bit of a different story. Gas production in 2004 in millions of Mcf, with around 300 MMCF in 2004, and we've had kind of had a steady decline, and now we're down around 240 MMCF.

The gas price looks like this. And I'm going to use the scale over here on the right-hand side for gas price. It's been jumping around a lot, too.

In 2004, it was about 230 -- or excuse me. In 2004 it was about $4.50 per MMBTU. Had a huge spike in 2008, over $8 in MMBTU. And currently in 2014, it is at $4.

And I think in 2015 in most areas, it has been down around $2.50 or $3, something like that, I believe.

If you multiply production times price, you get royalty. Royalty on gas currently is around -- I'm back to this scale now. Royalty on gas is now around $190 dollars per year.

So, why are we revising these regulations? Before I go into why, I want to talk about exactly what we're proposing to do.

Are you guys familiar with the Onshore Orders?

MR. HALLAM: A little bit, yeah.

MR. ESTABROOK: A little bit. Okay.

You?

MR. LYSON: A little bit.
MR. ESTABROOK: Okay.
So currently we have Onshore Order 3, 4 and 5. 3 is site security. 4 is oil measurement. 5 is gas measurement.
Onshore Orders are kind of -- I think, I don't know. I think this is true, the Onshore Orders are unique to the Bureau of Land Management oil and gas program. I don't think there's analogous type of regulations anywhere in the federal government like an Onshore Order.
An Onshore Order is a regulation. It went through the full promulgation process back in the late Eighties, but it's not published anywhere. You can't go to a 43 -- the regulation book, you can't find it. It's not there.
So, they are listed on our websites. And, you know, people have old copies lying around that are printed, but they were never officially published. So it's a very strange thing.
What we are proposing is to develop a new Part 3170 within the 43 CFR regulations.

And Part 3170, would be all things measurement.

So in that Part 3170, one of the things it would contain is things that are common to anything related to measurement.

So, for example, definitions, record requirements, prohibitions on bypass and tampering. How we're going to deal with variances, appeals and enforcement. All that stuff is going to be common to all things measurement, and so that would just go in the general Part 3170.

Under Part 3170, we would also propose, or we are also proposing a new Subpart 3173, which would replace Onshore Order 3. It would cover topics such as site security, which the current Onshore Order 3 does already. That's tank ceiling mainly. Accountability.

FMP, it's a new proposal that Mike Wade will get into called a Facility Measurement Point, so we can actually track which meters are used to determine royalty, which we can't do right now.

He will cover commingling and off-lease measurement, neither of which we have much requirement on.

We would also propose a new Subpart 3174. It would replace Onshore Order 4, and it would deal specifically with the specifics of oil measurement. And Mike McLaren will get into that here in a little bit.

We are also proposing a new Subpart 3175. It would replace Onshore Order 5, and it would also replace the statewide Notices to Lessees for electronic flow computers that are unique to each jurisdictional state.

So, Montana, for example, has a Notice to Lessees specific to the operation of electronic flow computers. I believe it is NTL 2008-1. Is that right?

MR. McLAREN: 2007.

MR. ESTABROOK: It's 2007-1, okay.

And again, all those topics are specific to gas measurement.

So, why revise these orders?

First of all, the first bullet item is a little bit of a misnomer, "last revised in 1989". Actually that's not true. The Onshore Orders were developed, promulgated in 1989 and have never been revised.

The current orders do not address new

technology or incorporate the latest industry standards and practices.

For example, Onshore Order 4 dealing with oil measurement talks about manual tank gauging and LACT, positive displacement meters, and that's it.

Now, many operators, maybe even most operators up here, are now using Coriolis meters instead of positive displacement meters. Not even discussed in Onshore Order 4.

Of course, in 1989, Coriolis meters were in their infancy, and not used for oil measurement.

There are huge gaps in the existing orders that need to be addressed. And I'll give an example on the gas side.

As I mentioned earlier, there is one, and only one, requirement in Onshore Order 5 dealing with heating value, how to determine heating value.

And that is equally important to royalty determinations volumes. So there's a huge gap that we have virtually no requirements for how you determine heating value, when it's tremendously important.

Also, we need to respond to various reports and audits questioning the adequacy of our regulations. I'm sure you are familiar with some of these agencies.

The GAO, the Government Accountability Office. They oversee how well we're doing in our job.

In 2010, they issued a report coming up with numerous recommendations on how the BLM has to improve our process to ensure accurate measurement and proper royalties basically with numerous recommendations, and those recommendations included revising and updating our regulations on measurement.

The Office of Inspector General, another oversight agency for us, again has done numerous investigations and has come to the same conclusion that one of our main problems is that we don't have up-to-date regulations that we can enforce.

The top one there, the RPC, that's the Royalty Policy Committee, it was a federal charter committee talking about royalty policies.

They were under the old Minerals

Management Service, and they did an exhaustive report in 2007 about the whole Department of Interior's oil and gas program, including onshore and off-shore and the royalty collection function, and they came up with 110 recommendations of things that the Department needs to improve to make sure that we can ensure tribes and the public in general that we are doing our job to ensure accurate measurement and proper reporting.

MR. HALLAM: I apologize for interrupting.

MR. ESTABROOK: Sure. No, please.

MR. HALLAM: And I may be jumping ahead into your slide presentation of what will probably come up later.

But because you have positive displacement, and now you said you have different type of metering devices, will this discuss calibration and testing of the meters?

MR. ESTABROOK: Yes.

MR. HALLAM: Okay.

MR. ESTABROOK: Yes.

And Mike will get into that in some detail in the 3174 section.

Great question. Thank you.

Of the 110 recommendations in the RPC report, Royalty Policy Committee report, 12 of them dealt specifically with BLM's measurement function and our lack of ability to ensure good measurement because we don't have the regulations to do so.

So again, there's a number of reasons why we feel we need to revise.

MR. HALLAM: And the reason I bring that up, is I explained it in emergency response, we used to do ammonia loading where I worked, and we had to totalize it. And that would be off on railcars, you know, sometimes 70,000 gallons. It's ridiculous the volume, and it can swing either way. So a lot of time we were forced to deal with overloads and underloads.

But I know calibration, you know, miscalibration can occur, and that's the only reason I was asking, because I've experienced that many times in the past.

MR. ESTABROOK: Okay.

Yeah, no, that's a huge deal.

And in the oil site and the gas site

both, a lot of the proposed regulation business calibration, or they call it proving for oil, making sure that that meter is accurately -- is properly working and is accurate, usually by comparing it with a certified test device.

So, yes, we will get into that.

Good question.

MR. HALLAM: Good to know.

I think on natural gas, it would be pretty easy for calibration to get miscalibrated or something like that because of the properties.

MR. ESTABROOK: Yes. That's correct.

So, the bottom line of why we want to revise these orders is to improve measurement accuracy and improve reporting and accountability. That is our primary job when it comes to oil and gas measurement and the whole royalty side of it.

Office of Natural Resources Revenue will take hopefully these improved measurements and reporting, and they will process the royalty checks.

So, now I'm going to go start in with things about what is general, the changes that we are proposing that would affect all three subparts.

Currently in the Onshore Orders, and again, you may have seen this if you read through them, there's a bunch of things you have to do. You have to seal the tank, the sales line valve, for example.

And then for each provision, there is an enforcement action, whether -- if we find a violation, if we find a seal that was not there, not in place or is broken, is that a major or a minor violation? What is the corrective action, and what is the time frame for correcting that?

And every single one of the provisions for Orders 3, 4 and 5 are structured that way. Here's what you have to have to do, and here's what we are going to do if we find that you didn't do that.

Now, the problem with that is that the enforcement action was never intended to be an absolute.

So, let's say for a broken seal, it might be a major violation. That was sort of the recommended. The intent of that was to be a recommendation of the gravity of that violation, of how severe is this. The corrective action, the time frames were intended to be recommendations.

But both industry and BLM have misinterpreted that to mean it's an absolute. If there's a violation and if it's X violation, then it has to be major or minor, whatever is stated in there, and that was never the intent. There's always circumstances.

To be a major violation, it has to be an immediate issue; something that you have to fix right now. It has to be substantial. It's got to be substantial, meaning significant, and it's got to be adverse. That there's something bad going to happen if they don't fix it. So, immediate, substantial and adverse.

And whether it meets those criteria has got to be determined on a case-by-case basis.

For example, if you went to an oil tank that had virtually no oil in it and hadn't been used for a while, and the seal is broken, well, it's a violation still, but does it really climb to the level of immediate, substantial and adverse? And that's a decision that has to be made based on the circumstances.

So, what we are proposing to do is remove the enforcement actions from the regulation, and we would develop a new enforcement handbook that our inspectors would use, and it would go into great detail about the circumstances for each provision in the proposed regulations.

We would go into great detail about, okay, on this case, this might be a major, and in this case, it might be a minor, and here's what you should consider for corrective actions and time frames.

We feel it would give us more flexibility and really get to the intent of situational determination of immediate, substantial and adverse, and not just make it a locked-in thing.

Currently the Onshore Orders, Onshore Order 3 specifically has one, and only one immediate assessment, and that's if a federal seal is broken.

What we would propose is that -- I believe we would add 27 new immediate assessments scattered throughout Orders 3, 4 and 5, and they would be added to each subpart. The idea, they would be $1,000 each, and they could be assessed immediately by our inspectors.

And the idea was not to make these things punitive. They will be to compensate the BLM for what's called "liquidated damages". There's attorneys in the room here that could explain what that means, because I really have no idea. But that's the intent of that.

But they would be $1,000 each, and we would add $1,000 per violation, and we would add 27 categories of things that we could impose an immediate assessment on.

MR. MARSETTE: Do you got to have that dart in there, too, or just the seal?

MR. ESTABROOK: Mike, you want to take that one?

MR. McLAREN: Yes.

It's still effectively sealed.

MR. MARSETTE: With the dart or not the dart?

MR. McLAREN: Yes, dart to be effective.

MR. MARSETTE: Because if you don't have the dart, you can open and close it.

MR. McLAREN: That's right.

MR. MARSETTE: So it would break the seal.

MR. McLAREN: It would not be effectively sealed.

So, yes, the darts are still required.

You still use the same basic technologies or terminology that says defective seal, so as to prevent operations of the valves.

MR. ESTABROOK: Is that one of your immediate assessments still? If it's not effectively sealed, do you remember?

MR. McLAREN: Yes, it is.

MR. ESTABROOK: Okay.

So if they did not have an effectively sealed valve, not only would that be a violation, perhaps major, if it was a big time, but it could also be $1,000 immediate assessment on the site, on the spot.

Another thing we're proposing is -- well, currently under the Onshore Orders, if an operator wants to use some other measurement procedure or some other measurement device, they come to the local field office for approval.

The problem that we have been having

with that is one of consistency.

For example -- and I'll give a Wyoming example, there was a device called Wafer V Cone Meter that was proposed in Wyoming, and they were marketing it very heavily maybe 10 years ago. And actually, it's a decent device if used properly.

So they went to one field office in Wyoming, and the field office said, "Yeah, that's okay. You know, you can use that device."

They went to another field office in Wyoming, and that field office said, "You can use that device, but here's a whole list of conditions of approval that you have to comply with. You can't just do whatever you want. It's got to be under these conditions if you use it."

They went to another field office in Wyoming, and the field office said, "There's no way you're ever going to use this device in our field office."

So, tremendous inconsistency of reviews. You know, a meter is a meter is a meter, and it seemed to us that if a meter is good enough to use at a federal or Indian lease, it should be the same all over the place.

So what we're proposing is we would establish a new Production Measurement Team that would be -- I don't know where they would be located, but they would be reporting at a national level, and they would -- any variance request, request for alternate technology or alternate procedures would go to this Production Measurement Team for review, and the Production Measurement Team could recommend it for approval.

And how this would work logistically is that a manufacturer may submit a new meter to this Production Measurement Team, or an operator could, we don't really care, and they would have test data with it, and this Production Measurement Team would do a very, very thorough review of this device. And it may be fine the way it is, or it may be fine if operated within these strict operating limits.

If the Production Measurement Team thinks it's worthy of approval, with or without conditions, it would go on a national BLM website as an approved piece of equipment. So, any operator or any inspector, or you guys, you could go to this -- if you saw a piece of equipment in the field you didn't recognize, you could go to this pick list and see if it's on that pick list. If it's on that pick list, you're good to go as long as you're operating it within those conditions. If it's not on that pick list, then it would be a violation.

We think that this would provide -- one thing, it would provide consistency, because once that thing -- if one operator, let's say here, had a new meter they wanted to do, once it's on that pick list, it's available to any operator across the country.

So this would provide, we believe, a lot of really good consistency. We would ensure that we would get very good reviews of the data, because that Production Measurement Team would be focused only on doing this data review.

MR. HALLAM: Now, when you're saying this, are you talking like a verification team, or are they just going to have Daymyn come in and say, "Hey, I have this meter. It does this", and take him at their word versus any type of insurances that is what they say it is?

MR. ESTABROOK: Oh, no. That's a -- great question.

This team would be specialized in looking at test data and the data for these meters.

So, I have done some of this already with like this Wafer V Cone meter where the manufacturer in this case, they were working with an operator. They wanted to use this meter, and we required them to do a whole slew of testing at an independent laboratory.

And we worked with them for a long time, because they would do the testing, and then there was some weird stuff in the testing, and we'd make them do more testing. It went on for quite a while.

We did an exhaustive review of the testing, all the data, and determined under what conditions would this meter provide the same level of accuracy as an orifice meter, for example.

MR. LYSON: And do you consider environmental conditions, too, with that? I mean, because some of them need to have like housing in them, or are they durable just to be outside on their own?

MR. ESTABROOK: No. No. Environmental conditions in that way, absolutely. Because part of the standard testing is you do baseline testing under ideal conditions. The lab does this.

And then you do influence testing, where you put it in a temperature chamber to see how it handles minus 40o up here, or 100o; how it handles vibration; how it handles high pressure versus low pressure.

So, yes, all those things would be taken into consideration, yes.

Excellent question.

The other thing that we believe this Production Measurement Team would do is through the process, is it would provide longevity to these regulations so we don't get into the situation that we're in now with, you know, for gas measurement, the only thing Order 5 talks about is chart recorders.

With this approach, we could keep up with new technology without having to rewrite the regulations every time. So, we think that's also an added benefit, because 26 years from now, who knows what's going to be out there, and we don't want all the work we put into these things, we don't want them to become obsolete in five years, like Order 5 was.

Orders 4 and 5 are purely a cookbook. Here's the list of things you have to do to get accurate measurement; this, this, this and this.

And that's not horrible. There are no performance goals. There's nothing stated in Order 4 and 5, what accuracy are we trying to achieve here? What is it that we're trying achieve? It's just a cookbook.

And cookbooks are fine when you are talking about a specific technology. You know, gas is my main thing. So Order 5, there's's cookbooks on how to operate chart recorders, or the differential pen should read, and how you should calibrate chart recorders. And that's okay.

But the problem is, when electronic flow computers came along, the cookbook is irrelevant now because chart recorders don't have pens, or electronic flow computers don't have pens.

So, what we're proposing, is we would each Onshore Order 4 and 5, we'd keep the cookbook approach because some operators like that approach because they just want to know what they have to do. They don't want to do their own analysis. They just want to know what they have to do. So we're going to keep a cookbook approach.

But we're also going to establish performance goals in Orders 4 and 5 so we know what exactly it is we're trying to achieve. How accurate do we want this measurement to be? That's the goal, is X percent accuracy, and our ability to verify the measurement.

The performance goals in Orders 4 and 5 are -- and we will get into this a little bit more -- are intended to balance accuracy, accurate measurement with economic considerations from the operator.

So typically in Orders 4 and 5, what you'll see is for higher volume meters, there's stricter accuracy tolerances than for lower volume meters.

This performance goal approach, combined with the Production Measurement Team, we also think would provide tremendous flexibility for operators in getting new technology, because this would give the Production Measurement Team the goal of what they would be looking for when they review that meter. Can this meter meet the accuracy goals stated in Order 4 for oil or Order 5 for gas? That would be the criteria that the Production Measurement Team would be looking at in their review.

So again, for new technology, as long as it can meet the performance goals stated in each order, then go ahead, we would approve it, maybe with conditions, and this would provide tremendous longevity for the regulations.

Part 3170. This gets into the actual regulations now, proposed regulations. I'll go through a couple of things that are proposed that would affect all three subparts.

Now, right now, our Onshore Orders only apply to operators. We have no authority -- actually we have no regulatory authority over purchasers or transporters or pipeline companies.

So here's the scenario that we come

into on a somewhat frequent basis. We're going to audit a Tribal lease. And I'll use gas, for example.

We're going to do a gas audit on a lease, and we write a written order to the operator saying we need all this information - volume statements, calibration records, gas analysis statements, all the stuff that goes along with a gas audit for this time period. We need all this information.

And the operator says, "Yeah, but we don't own that meter. The pipeline company owns that meter. We have nothing to do with it."

But our regulations, our Onshore Orders only apply to the operator. So the operator goes to the pipeline company and says, "Hey, BLM's doing this audit. They're asking for a whole bunch of records that we don't have because it's your meter. Can we have those records?"

And the pipeline company, for whatever reason, can say, "Nah, we're not going to give them to you." That does happen.

Our only enforcement action is to the operator. So, we write a violation to the operator for not providing this data when it's not even their meter.

What we're proposing is that recordkeeping requirements only would apply, or could apply to purchasers and transporters through the royalty settlement point, which is it FMP, or the point of first sale, whenever comes first.

So now in this scenario, we send that written order, we could send it directly to the pipeline company for their meter, and if they refused to give us the data we're requesting, we could take enforcement actions directly against the pipeline company, or the purchaser or transporter.

MR. HALLAM: Now you're saying transporters. You are talking rail as well as well, then, right?

MR. ESTABROOK: It could be rails as well, yes. Yes.

The statutory authority for us, and the reason actually we're limited to recordkeeping is the Federal Oil and Gas Royalty Management Act of 1982 actually gave the Department of Interior specific authority to go -- they are keeping records of actions through the royalty settlement point or the point of first sale, and so we've had the statutory authority since 1982, but we've never implemented it with regulations, and we are proposing to implement that now.

Now, this is a relatively minor thing. But all the orders have a variance section in the back of each order, of each Onshore Order. They are pretty similar, but they're not quite the same, and they're also pretty general.

What we're proposing is that we would have one section on variances in Part 3170 that would apply to all three subparts, and we would increase the guidance on how you request variances, and how we would review them.

And with that, I'll turn it over to Mike Wade to talk about 3173.

Before I do that, any additional questions on the overall stuff?

And we will get into the specifics of each subpart here in the next section.

MR. HALLAM: What about feasibility, how simple is it going to be for the industry to transfer over to these regulations?

MR. ESTABROOK: That's an issue. We're

proposing some pretty long phase-in periods, especially on the gas side.

So for gas side, for example, depending on the volume of gas that meter measures, they could have between six months and three years to get up to speed on the new regulations.

MR. HALLAM: Because I know that's going to be an issue with the State, because when I spoke to the Governor about putting SCADA on produced water lines, and said we have to consider feasibility, that was one of their main issues.

MR. ESTABROOK: Yeah, we have considered that in our -- in the website where all these regulations are located, there's a thing called a Regulatory Impact Analysis, or an Economic Analysis that goes into what this is going to cost industry.

We're open to comments from industry or anybody on that exact aspect of this, how feasible is this.

MR. HALLAM: Okay.

MR. ESTABROOK: Okay.

All right, I'll turn it over to Mike.

MR. WADE: Thank you.

Okay, as this was pointed out, the Part 3173 is proposing some more guidance on off-lease measurement, commingling and FMP, as well as some additional items in the site security section itself.

Currently, for example, there is absolutely no guidance in the regulations for off-lease measurement commingling other than you have to request it, and BLM may approve it.

We have proposed some new procedures for the operators applying for off-lease measurement commingling. Basically they're in line with the IM that was issued a few years ago for proposal.

So, the companies have seen these. They're not totally new to the operators for requirements. We have been using them for a while.

This is when the BLM was planning on approving commingling as it stands right now. Three situations.

Where there is real royalty impact to the allocation. Three Tribal cases, all with the same royalty rate, going to the same tribe. That's an easy one to approve because the percentage of 10 or the percentage on 100, you're still going to wind up with the same dollar value. So, those are a piece of cake to deal with.

The next one would be properties that would qualify as low volume for commingling, which we have some definitions in both the oil and the gas sections for low volume.

And then finally, for extenuating circumstances that the operator would come in and explain to us the problems. Why do they absolutely have to have this, and explain it to us. It may be something along the lines of we need to commingle these two separate unit PAs, because the lower one provides the gas lift, if you will, energy, to produce the upper hole, the other participating area. So there could be those type of situations. But they're going to have to come to us and explain those to us and work with us.

The way BLM was anticipating proposing this is that when a company comes in requesting a Facility Measurement Point, FMP, we would review existing older commingling and off-lease agreement approvals to see if they come into compliance with current standards.

If they don't, we would work with the operators first to try to see if we can find alternate ways to bring them into compliance, get enough documentation, et cetera, before we told the operator, no, you're going to have to go back to an on-lease measurement or some other less desirable for the operator alternatives.

But we want to work with everybody to get them there, but we also have to be able to answer the question from the tribe and from other Congress that, "Well, why did you approve this?" "Where's your justification?" "What was your reason?" Some of those that we do not have now. So we need to have those, and this would give us that capability to actually answer those questions, "Why did you approve this, and how are you verifying that I'm getting the volume and the dollars I should be getting?"

MR. HALLAM: Okay.

And then like Kenny just pointed out, extenuating circumstances, would that carry over to where we won't be stranding minerals, too? Would that be a consideration?

MR. WADE: That very well could be some

of the extenuating circumstances.

MR. LYSON: We've got a situation right now where there's two operators. And, you know, on ours, we got the lake that's six miles wide in the one area, and they're both trying to enter into it.

So we got them both coming in. We're going to meet with them and see which is going to be the most beneficial. We're not going to leave anything out there.

So, that's kind of one of the ones we're working on now, so...

MR. HALLAM: Yeah.

MR. WADE: That would be possibly for the drilling and production. This would be on the commingling side.

MR. LYSON: Oh, just the -- yeah.

MR. WADE: This is commingling and off-lease measurement.

The drilling APD, that type of development issues are handled separately from that. This strictly would be the --

MR. HALLAM: But we do understand the extenuating circumstances for environmental concerns. Because Kenny and I, we both kind of come up with an idea that we presented to Lynn Helms, as well as the North Dakota Petroleum Council that they're both in favor of, and that's on gas capturing, basically allowing for condemnation or eminent domain, whichever way you want to reference it, when it puts the environment at risk.

And what we had was a really deep, difficult corridor to go through. And with all the physical properties of gas, it would have collected in there if there ever was a leak.

MR. WADE: Mm-hmm.

MR. HALLAM: And there was this very simple short, it was like a 70-yard right-of-way we needed through an existing road where there would be no associated hazard by going through there. But the landowner wasn't giving that consent, so it was forcing them to go into a really difficult terrain.

And that was one of our issues, that the very simplest route was the safest and easiest for everybody is this, versus pushing it into a really unnatural -- well, you saw the type of structure where we were in yesterday. It was essentially putting them to that type of structure versus flat land.

So, I think we're going to be in agreement on that extenuating circumstance, because that's one of the things we sort of pushed for. And the State has said the same thing, is that it's one of the very few good ideas thief had lately, so they really liked that idea.

And it was basically Kenny's. I'm just sort of piggy-backing off of him.

MR. WADE: Well, we don't care whose idea it is. If it's a good idea, it's a good idea. Let's use it.

You know, right now, the current order applies to sales and allocation meters, and measurement relating to royalty payment is not even consistently defined or tracked.

What we are proposing would be to apply measurement for royalty. So, meters that do not impact the royalty.

I can give you numerous examples. If you have a measurement point or a meter on each of 10 wells, and then out there further on, you've got an on-lease central gathering facility, that's not commingling. We only need the one meter out there at the central location, central facility.

Those others would not need to be dealt with unless there was truly a commingling situation that had to be dealt with. But if it was on the same case number, that would be an example of where we could use affecting royalty and not have to deal with all allocation meters. And then, of course, BLM tracking the Facility Measurement Points, FMPs.

Right now, where an operator thinks is what they're using for royalty reporting and issues may not be the same point that the inspector has gone out and witnessed the meter calibrations on, or tank sales, or whatever it may be. They may not be the same.

So, this would get us all on the same page as to where royalty is going to be determined.

Run tickets right now are only required for tank sales of oil, and includes some seal numbers, some dates on, dates off, for water draining, but very minimal real information. Date on, date off for seals, and a real generic reason why.

What we are proposing is some additional requirements for things like water draining and hot oiling, et cetera, that would require an opening gauge, if you will, and a closing gauge before they drain the water, as well as some information about who took the seal off, and what times, so we'd have a little better, more detailed information and be able to better track what was actually removed or pulled from the tank.

And on hot oiling, if you have those types of situations, how much of that oil did you get back afterwards? You don't want to double count it. And that has created some issues for everybody when hot oiling is going on.

And then, of course, run tickets will now be covered and moved over to the 3174 for oil measurement that have site security.

End of month inventory. This is a new one also that is not covered in the existing Onshore Order.

We're proposing that operators will be required to maintain an end-of-month inventory.

If they want to call it

beginning-of-month inventory, that's fine, too, because the difference between the 30th and the 1st is not important to us. But we're just calling it an end-of-month inventory as a requirement.

No information related to royalty-free or beneficial use or used on a lease. All three are used interchangeably within the industry. There's no information required on that.

Order 3 is beginning to propose that the operators tell us if they're going to claim beneficial use; what equipment they're going to claim on; how are they going to determine that volume, and collect some btu, make model rating information, et cetera, so we can actually see without having to always request specific information on beneficial use on a case-by-case basis. We can automate some of that.

Also, if they are going to use a meter, that would be applicable to that for royalty-free. Some operators do use that for that purpose.

We are going to eliminate the self-inspection program on the site security plan.

With the added information on seal violations, or seals and a variety of other things, we are accomplishing that with the information they're going to be required to keep without going into extensive detail that says, this is a self-inspection program. This is all the information you have to have.

Right now, I think it's about two sentences for a self-inspection program. It gives the operator absolutely no detail as to what is and what is not. So, we wanted to eliminate that by increasing the amount of information available.

Then we have some very specific requests or comments in the drafts, things that we need more information on.

Right now, we put -- on commingling and off-lease measurement, to help us, we have set a 10% rate of return. Is this a good number? Is it a bad number? We don't know. We don't have good information to make that determination for that.

And that rate of return would be based on having to add new equipment, let's say an extra tank to a location in order not to commingle. Is a 10% rate of return on that tank a good number?

We're asking specifically industry and operators and everybody to comment on that number.

And then comments on our time frames for implementation. Current draft proposal has broken down the implementation into three phases - high production volumes with applying for the FMPs on existing facilities within the first nine months after the final date.

Medium level production, the middle third, if you will, of producing cases with the second nine months.

And then the lowest producing, the last nine months, or basically 27 months to apply for on the lowest end of the production.

Is this a good number? One-third? Should it be something else? Too short? Too long? Comments are more than appreciated on that.

And with that, any more questions? Comments? Concerns?

MR. HALLAM: When you were saying on that 10%, were you talking about capturing as

well, or is it pertaining to something else?
MR. WADE: This would be for off-lease measurement commingling.
MR. HALLAM: Okay.
MR. WADE: Any additional equipment that they might be required to put out there because we disapproved off-lease measurement commingling.
MR. HALLAM: Okay.
MS. CONNELL: Do you guys have a clear understanding of what he means by "off-lease commingling"?
MR. HALLAM: Yeah.
I just didn't know if it was limiting to that, or if that 10% was going to carry over that, if you can't get to that point, then you are not required to capture it.
That was my concern.
MR. WADE: No, this would have nothing to do with the capture and --
MR. HALLAM: I just wanted to make sure that was part of the --
MS. LEITER: This is just eligibility for commingling, when you're allowed to do it.
MS. CONNELL: I would just add a

comment.

If we end up going in to meet with the Tribal Council, I think in the presentations, when we get back to the very beginning of each of these sections, I mean, it's so easy for us to get caught up in the middle of some of these terms. And, you know, the average person has no idea what the word "commingling" means in the context. It sounds like a word from eighth grade English class.

So, let's just keep that in mind, because it sounds as if we are going to be invited to go out--

MR. HALLAM: Because these guys are going to be really sharp on it.

Kenny would have a better understanding. How well is the -- is it just the Natural Resources Committee, or will the whole Council have an idea on that?

MR. LYSON: I would think if we just bring up to the Council, I would think that -- we will invite the Natural Resources Committee. They would be the main ones interested, but I'm sure the Chairman would show up, too, if we do set that meeting.

MS. CONNELL: Okay.
We can just do a little bit better job of giving -- because even if they understand it, it doesn't hurt for the one person who might need a little bit of introduction of kind of what this means from a layman's purpose.
Because I mean, these guys work in oil and gas all the time, but --
MR. LYSON: Yes.
MS. CONNELL: -- there are members of the public, and members of the representatives for the tribe who would appreciate -- and some of us who might appreciate a little more beginner information regarding some of this complicated stuff.
Thank you.
MR. HALLAM: We can definitely work on stuff like that.
MS. LEITER: But we should -- I mean, we have time now.
If there are questions about what we have gone through, you all should feel free to -- you know, if there was something we failed to introduce or some terminology that we weren't clear about.

MR. HALLAM: Well, I think I asked plenty of questions during the --

MS. LEITER: Okay. Just making sure.

MR. HALLAM: I'm just wondering, you know, like Kenny brought up, we have two different versions of our Tribal Business Council.

You've got your Natural Resources Council, which consists of three members, plus whoever wants to join, that deals with this basically all the time, and then you've got your full Council of seven.

And what Kenny was mentioning, one of the options might just be the NRC, which the Chairman and others can attend if they would like, a more simplified version that just deals with this type of issue versus our general TBC, where it goes across the radio and probably wouldn't be as good, you know, to have that discussion. This would make more sense for -- it would be more specific to that topic.

MS. CONNELL: Yeah.

MR. WADE: Right.

MR. HALLAM: And they would also tend to have a better understanding of it, then.

MS. CONNELL: Right.

MR. WADE: Well, that would help us, if you do schedule something like that, to let us know what types of audiences we can anticipate, because then we can design our PowerPoints for the audience itself.

We anticipated on this one that most of our people that would be showing up would be people out of industry or pretty knowledgeable about what we were talking about to begin with.

But without having a good feel for who was going to be, and what level of experience or knowledge they might have, as you can see, this could very easily turn into an all-day item just for one of the orders to cover enough basics so people would understand.

MR. HALLAM: Yeah.

MR. WADE: So we would need to -- I would really ask that we have some idea as to what level we need to build our presentation.

MR. HALLAM: I think the NRC would be -- do you agree, Kenny? Would be the better one.

MR. LYSON: Yeah.

MR. HALLAM: Because you wouldn't have

to change anything. Everything you're addressing would be basically speaking the same language with them, and as well as the attendees would, you know, have the same understanding) so it would work best to have an NRC meeting).

And we can see about getting you on the 16th. I don't think that would be too much of an issue, would it?

MR. LYSON: I can find out for sure).

MR. WADE: Well, we will have to work on some of those schedules. There's a lot of things.

Anyway, I would like to give it over to Mike McLaren next for oil measurement).

MR. McLAREN: Have you guys had a chance to read what we have proposed for the 3174?

MR. LYSON: No, I haven't).

MR. HALLAM: I just got the notice so, no) I apologize).

MR. McLAREN: Okay.

I'm mainly going to cover the big picture changes, not the fine details of it).

I think Rich stated the current Order 4, it's cookbook) you either manually tank gauge it, or you run through that Lease Automatic Custody Transfer using a PD meter. It's one or the other.

And so we have three tiers of performance standards that we proposed there. Again, these are based on the manual tank gauging and running through a LACT. And it's also, as Rich stated, for new technology down the road, what would we compare it to.

So this is what we would be comparing it to.

I'll put some numbers out here. We're hoping to get comments on it.

If you got a meter out there, it's more than likely going to be a LACT or Coriolis. If you're measuring more than 10,000 barrels a month, we're looking at an uncertainty of plus or minus .35%. That's based off of the current Order 4 calculation of the LACT system with a PD meter under the current requirements.

If you're between 100 barrels a month and less than that 10,000 barrels, we're proposing plus or minus 1%. That is based on uncertainty calculation of a manual tank gauge pulling about 200 barrels out of a 400-barrel tank, it comes to about 1%.

And then based on the 2013 form that Rich held, we had a suggestion for a third tier, a low number.

We came up with 100 barrels a month. And pulling about 40 barrels out of a 400-barrel tank, the uncertainty was about 2.5%. So, we threw that in as a third tier.

MR. HALLAM: And you said currently, there isn't that requirement?

MR. McLAREN: Currently there's no performance standards in the Order 4. It's either you go in, and you manually tank gauge it, or you run it through the LACT with a PD meter.

MR. HALLAM: What do you think the accuracy is on that 10,000 barrels a month currently?

MR. McLAREN: Well, that rate there, that .35%, was based on the calculations of a LACT system with a PD right now in the current Order 4.

MR. HALLAM: And that's what I mean, that's about what it is right now?

MR. McLAREN: Yeah.

It was actually plus or minus .32, okay, so we went to .35, a little play.

And we're hoping industry, or you guys can come in with a different calculation maybe with a different number. Give us something to look at. But we're pretty comfortable with that.

MR. HALLAM: I like that number.

The only thing I would say, you know, me personally, would be a .5% for. You've got 2.5, 1, and a half.

MR. McLAREN: Yeah, but --

MR. HALLAM: But I like that number being more accurate.

MR. McLAREN: Yeah.

We didn't just pull those numbers out. We based those on actual uncertainty calculations.

MR. HALLAM: And if that's a standard, I like that idea.

MR. McLAREN: Yeah. Well, that's what we are asking in there.

We are specifically asking in the preamble, what do people think of it? Is that a good number, or are they bad numbers?

Currently the Order 4 has references to the industry standards of 1989. Obviously part of our agenda would bring us up to date.

So we're proposing to incorporate 21 of the current API standards, and two ASTM standards, which is the Table 5A(6)(a).

Currently in Order 4 for the tanks, it requires the thief hatch or vent line valve.

Kind of modified that in our proposal. Along with the thief hatch, we would require a pressure-vacuum relief valve set at inlet/outlet pressure greater/less than thief hatch settings.

And if you have vapor recovery, then, of course, you wouldn't need that.

Also in there, we're stating the condition we want these tanks in. So we're not saying, "Here's a tank." "Here's some equipment." We list equipment, but we also are very clear in there, we want these tanks to maintain pressure-vacuum integrity. We want that integrity held.

The current Order 4, it randomly points out the requirements for manual tank gauging.

Okay, we had a suggestion early on in

this that why don't we put those requirements in a sequence.

So we proposed, based on the API 18.1 standard, a sequence for the manual tank gauging, as well as the technical requirements for each activity in that sequence.

Currently the Order 4 requires two consecutive gauges within one-quarter inch.

API updated their 3.1A standard in 2013. Their current standard now requires two consecutive identical or three gauges within one-eighth inch. So part of updating to the current industry standard practice, we have proposed that.

The current Order 4 requires tank calibration tables, okay. Typically they have been quarter inch. Well, API changed their gauging standard to eighth inch.

So we proposed, if we're going to gauge to an eighth inch, we would want the strapping tables to match.

The current Order 4 for the LACT system, it requires the automatic temperature, or automatic temperature gravity compensator, and a PD, positive displacement meter.

We propose to eliminate, to prohibit the automatic temperature compensator, or the automatic temperature gravity compensator, and require the electronic temperature averager.

The automatic temperature compensator, it adjusts that totalizer reading. There's no raw data.

So if we're going in to verify that totalizer, we don't know if it was adjusted properly by the automatic temperature compensator. So, we want raw data. We want to be able to verify that that totalizer is correct.

We are proposing as well to allow the Coriolis meter in the LACT system in lieu of the PD meter.

And as I said, the current Order 4, you either manually tank gauge, or you measure by the LACT.

We have also included the Coriolis meter as a stand-alone meter. So, if you don't want to have the full-blown LACT, with Coriolis, you can have the Coriolis as a stand-alone meter. But we have some requirements, of course, for that.

We proposed to maintain the same 8400 pulse per barrel resolution that the PD meter currently has.

We have some requirements for reference accuracy, influence effects, stability, acceptable pressure drops.

Again, we need that non-resettable totalizer.

For the proving, we want to verify that meter is zero before you prove it. Make sure that's within the manufacturer's specifications, because if it's not, you have to re-zero it and then re-prove it. So we want that done before you prove it.

We want the Coriolis to be able to make the determination of net-standard volume. The computer is definitely capable of doing that. We want that to be done.

We have kind of thrown out there for the API gravity. Do we want the Coriolis meter as it determines the density to average it between run tickets, or do we want to have a composite sampler, and you do the conventional determination? We have got that out there. We're hoping for comments on that.

And we have some on-site display requirements that we would need to do our audits on it.

And then, of course, we would require the audit trail requirements of the quantity and transaction record, the configuration log, the event log, the alarm logs.

MR. HALLAM: Okay, when you are saying -- well, maybe you will get to it again.

MR. McLAREN: No, go ahead.

MR. HALLAM: Verification of meter prior to proving and the test thing, is there going to be like an annual calibration date?

MR. WADE: I think that's even next.

It is.

MR. HALLAM: Okay.

MR. WADE: So, currently the Onshore Order 4, talking about LACT proving.

If you are equal or less than 100,000 barrels a month, you prove the meter quarterly. Every three months, you would prove the meter.

And if you are greater than that 100,000-barrel threshold, you would prove it monthly.

What we proposed is proving for the

LACT systems and for the Coriolis Measurement System, to prove it every 50,000 barrels on the totalizer reading. Every time that totalizer increases 50,000 barrels, you need to prove it, or quarterly, whichever would come first.

Now, we came up with the 50,000-barrel threshold as we did a statistical analysis at what volume flowing through that meter would cost to prove it potentially equal to the royalty overpayment or underpayment based on the meter factor changes.

And when we ran that, 50,000 barrel was the number we came up with. And that was based on an average proving cost of about $550 at the time we did that analysis.

The current Order 4 proving requirements, there's standards in there for prover sizing. So you could be using an oversized prover, which would put an artificial back pressure on the system.

There was no standards in there for proving conditions. Obviously we want to prove at normal conditions, but that wasn't a requirement in the current Order 4.

And there's no standards for minimum

pulses during the proving. How many pulses are you going to generate on a proving run.

So, we proposed minimum/maximum fluid velocity parameters, which is based on the prover sizing. That's out of the API 4.2 standard.

We have stated we want you to prove at the normal flow rates, normal pressure. We want the normal gravity fluid going through there.

And we define "normal" as pretty much plus or minus 10% of a normal flow rate. If you are within plus or minus 10% of that normal flow rate during proving, yeah, you're okay. That would be a normal.

The same for pressures. The same for temperatures.

Gravity, we would propose plus or minus 5o for the fluid.

We're seeing a lot of the small volume provers. Okay, a small volume prover generates 2000, 2500 pulses on a run.

Okay, if you're going to use small volume prover, we'd propose to require pulse interpolation. We want to count those partial pulses that's being generated in the proving notes.

Currently, there's no measurement ticket requirement for a LACT system. Our current requirements are fair tank gauging.

So, we would propose to generate a monthly measurement ticket after proving and at the end of every month for LACT and Coriolis Measurement Systems.

In the preamble discussion, like I said, talking about the volume uncertainty, we want feedback from industry, from you guys.

Are the volume thresholds good? Are uncertainty numbers, are they okay?

We're hoping everyone is going to take a look at their operations and do their own analysis and see if those tiers are good, if that works for everybody.

We're looking for some test data on the automatic tank gauge systems, any kind of hybrid tank measurement. I know it's a big deal up here in this area with the volatile oil that you guys do have.

Are there other ways to sample other than getting people on top of the tanks in the feed patches? Are there other ways to determine temperature?

Automatic tank gauging, are there other ways to take the gauge ratings? We're looking for data on that. We want to see what you guys, what you can give us.

We're looking for our proposal on the composite sampling system on the Coriolis meter for -- I got density readings, obviously, but sediment water determination.

If you don't have a composite sampling system, how would you determine sediment water in that fluid?

What we proposed in there basically, if you don't have a composite system, we would not allow you to deduct the sediment in water.

So, we're looking for are there other ways to determine sediment in water other than in actually taking a sample and doing a grind-out?

We're looking for some ways to address meter factor determinations on available flow rates, pressures or API gravities.

If you've got a range that's a normal, how would we address that? Are you going to take multiple meter factors at the different conditions and average them? Are we going to do a thick curve, a dynamic meter factor that the flow computer would automatically in the net volume calculation take the flow parameters and adjust the meter factor accordingly?

You know, we're throwing that out there. We want some input on that. What would be a good fit for the regulations?

And that's pretty much what I have got for oil.

Anything you can think of?

MR. HALLAM: I like it. I like the idea of what you're doing.

MR. McLAREN: Okay. Good. Thank you.

MR. LYSON: I mean what we're going through here, too, I mean there's -- you know, some of the guys from industry, I'll discuss stuff with too, you know, and kind of get some feedback from them.

MR. McLAREN: Okay. Thank you.

MR. ESTABROOK: So, before I start the 3175, I probably got another 20, 30 minutes worth of presentation for this. Do we need a break?

MR. HALLAM: I wouldn't mind stepping

out.

MR. ESTABROOK: Okay.

How about 10 minutes?

MR. HALLAM: Yeah, that's fine.

(Whereupon, a short recess was taken.)

MR. JUDICE: Okay, lets get started.

MR. ESTABROOK: Okay, the last presentation material we have is about the proposed Subpart 3175 for gas measurement.

Onshore Order 5 has requirements for orifice plates and mechanical recorders only.

Because electronic gas measurement systems are so common, and have been for a while, starting in 2004, we started kind of getting around the Onshore Orders a little bit, and each State Office issued a Notice to Lessee, which is a form of regulation specific to their jurisdiction on electronic flow computers.

Wyoming was the first office to do it in 2004, with all the other State Offices did NTLs between 2007 and 2009, I believe.

All the State Office NTLs are exactly the same with the exception of Wyoming. It's a little different because it was kind of the prototype. So it covered electronic gas measurement to fill in a huge gap left by Order 5.

Proposed 3175 would continue with orifice plates as the primary gas measurement device. We've talked about verifiability a little bit, but we believe orifice plates provide a reasonable level of accuracy. They're very well understood. There's more data on orifice plates than any other type of gas meter out there. And most importantly, perhaps, is that they provide complete, independent verifiability by us as to the measurement.

With an orifice plate meter, you can verify that measurement from beginning to end at every step of the way. There is no magic boxes to deal with. Everything is completely verifiable.

Proposed 3175 would also continue the approval of mechanical recorders, but with restriction, as I'll get into in a little bit.

We would approve approved electronic gas measurement systems. We would also have specific guidance for alternate measurement and flow conditioners. Flow conditioners are associated with orifice plates. And I might talk about that a little bit.

As with Order 4, there are no overall performance standards given in Order 5. It is a cookbook of how you operate an orifice plate meter with a chart recorder, and that's it.

If you look at the requirements of Order 5, it does imply that there's three tiers of requirements, depending on volume. And I got a little graphic I will show in the next slide.

In proposed 3175, we would continue this tiered approach that Order 5 has currently, but we would propose four tiers of performance standards based on average flow rate.

So let's look first at -- this is the Onshore Order 5.

This is the average monthly flow rate along the Y axis here. And for meters measuring more than 200 Mcf per day, average, all 26, whatever there are, requirements in Onshore Order 5 are in effect.

If you are below 200 Mcf per day, if your meter measures less than 200 Mcf per day, average, you know longer have to have a continuous temperature recorder. Again, this is the current requirements.

If you are below 100 Mcf per day, your meter measures less than 100 Mcf per day, you no longer have to operate your differential pressure pen in the outer two-thirds of the chart, and you know longer have to comply with our Beta ratio limits, which are .15 to .7.

The proposed 3175 would continue with this concept of tiered requirements. We are proposing four tiers, and they would have a name.

So, if you're flowing over 1,000 Mcf -- if your meter measures more than 1000 Mcf per day on a monthly basis, that would be called a very high volume FMP, or Facility Measurement Point.

If it measured between 100 and 1000 Mcf per day, it would be categorized as a high volume FMP.

Between 15 and 100 Mcf per day, it would be called a low volume FMP.

And less than 15 Mcf per day, it would be marginal.

And the idea is with these performance standards is to try to balance accurate measurement with economic reality.

So, for the very high volume FMPs, we are going to be very tight with our requirement, because a little bit of mismeasurement is going to have a big impact on royalty.

But being very tight with requirements has a price tag to it. And as you get lower and lower volume, the risk of royalty impacts becomes less because you're dealing with less volume.

And with lower volume FMPs or lower volume meters, some of these, especially the marginal volume ones are right on the economic edge of not being able to legitimately afford improvements.

So, we've tried to balance, again, accurate measurement and economic reality.

We have proposed performance, specific performance standards for these categories as follows:

We have an uncertainty performance not only for volume, but also for heating value. We have a performance standard for bias, statistically significant bias. Bias is if that meter reads -- always reads a little bit high or always reads a little bit low.

And this last category is really important, and this is our verifiability. That's the BLM's ability to independently verify every step of the measurement so we are not dealing with some magic box out there that we have no idea how it works, and they just give us a volume. That's unacceptable to us. That's not verifiable.

So, for very high volume FMPs, we are proposing a volume uncertainty of 2%.

A heating value, this will be average annual heating value uncertainty of plus or minus 1%.

We would not accept any statistically significant bias in that volume measurement, and every aspect of the measurement would have to be independently verifiable by us.

For high volume FMPs, the volume uncertainty would be plus or minus 3%. The heating value uncertainty would be 2%. No statistically significant bias, and again, everything would have to be verifiable.

For low volume FMPs, we would do away with uncertainty requirements. However, there still could be no statistically significant bias in the measurement, and it would still have to be verifiable.

For marginal volume FMPs, the only thing we would require is that it has to be independently verifiable.

At this level of production, they are legitimately on the economic edge of being able to afford any improvement for that meter.

Order 5 adopts 1, and only one, industry standard, and that's called AGA Report No. 3, the 1985 edition.

And AGA Report No. 3, talks about orifice plates only, and it talks about how they are installed, and how you calculate volume or flow rate from an orifice plate.

Now, there's some odd things, because we are stuck with this 1985 version that we have to enforce. That's what's in Onshore Order 5.

I'll give you one example of what this leads to.

As you probably know, with an orifice plate, you need straight runs of meter tube both upstream and downstream of that meter to make it read accurately.

There's also a thing called a

straightening vein or a tube bundle that you can install inside the upstream meter tube to reduce the amount of length that you need.

The '85 requirements for the placement of that tube bundle were based on some pretty old data.

So, if you place that tube bundle, the 1985 AGA Report No. 3 tells you to place that tube bundle. It's very specific. You have to place it right here, a certain distance from the orifice plate.

If you do that, new data suggests that you are actually biasing your flow rate, biasing your measurement by a couple of percent.

So right now, we are stuck enforcing a standard that we know -- we know results in bias in measurement, which is one of the things that we're trying to avoid.

The proposed 3175 would adopt a new American Petroleum Institute and Gas Processor Association standards covering the primary device, the orifice plate, gas measurement systems, flow rate, volume and heating value calculations, and gas sampling and analysis.

Currently Onshore Order 5 has no

inspection requirements for meter tubes. The meter tubes that I've discussed, the proper length and construction and making sure that they're actually round and not full of scale or pitting, that's actually really important for the measurement, to ensure accurate measurement.

The AGA and API have lots of standards for those meter tubes. So we thought it might be a good idea to have operators actually inspect those meter tubes from time to time.

So, we are proposing that meter tubes would be inspected according to this frequency:

For marginal volume, the one, the very, very, low producing meters, we would not require any inspections. It's just too costly.

For low volume FMPs, we would require a visual inspection once every five years. A visual inspection is where you could open up a pressure tap and stick a little fiber optic tube down there, and you could actually have a view finder and actually look around inside that meter tube without having to disassemble it.

For high volume FMPs, we would require a visual inspection once every two years, and a detailed inspection once every 10 years.

A detailed inspection is where you would actually disassemble the meter tube completely, run mikes through there, and surface roughness measurements and do a very complete, detailed inspection to ensure that meter tube meets API specifications.

For very high volume FMPs, we would require a visual inspection every year, and a detail inspection every five years.

Again, that whole idea is low volume, low risk of inaccurate measurement or significant errors in measurement and economics. As we go up in volume, we become stricter or stricter with our requirements.

Currently Order 5 approves mechanical, old chart recorders. That's all it approves.

Proposed 3175 would still allow mechanical recorders, or chart recorders, but only for FMPs measuring less than 100 Mcf per day.

We do not feel that the performance of mechanical recorders is adequately defined to do a meaningful uncertainty calculation. Therefore, what we have on uncertainty standards for high and very high volume FMPs, mechanical recorders could not be used.

This is the heating value. Btu content every gas. Order 5 -- now this is one of the huge weaknesses of Order 5.

Orders 5 has one, and only one, requirement relating to heating value, and that is that you must determine the Btu content at least once a year. That's it.

Order 5 has no standards of where to measure the heating value, how to sample it, how to analyze it or how to report it. It's a huge weakness.

And again, I'll remind you that heating value and volume are equally important for royalty.

Proposed 3175 would establish a sampling frequency as follows:

If you are marginal volume meter FMP, you would still just have the once per year sampling.

If you're a low volume FMP, you would have to sample once every six months. That would be fixed.

High volume FMP would have an initial sampling frequency of once every three months.

And here's where we're going to throw in kind of a somewhat new, somewhat radical idea, but we think it gets to the goal we're trying ti achieve.

Once we do an initial sampling of every three months for a year, let's say, that would be four or five samples, once we have enough data of how the heating value varies -- every time you take a sample, you get a different heating value. We want to know how scattered that heating value is.

If there's a ton of variability from heating -- same sample to sample over that first year worth of data, the uncertainty in average annual heating value is horrible.

So what we would propose is that based on these initial samples, we could either increase or decrease the sampling frequency to obtain a fixed uncertainty in heating value of plus or minus 2%, which is one of those overall performance goals.

So, if the heating value is all over the place, we might say, three months is not good enough. You need to take a sample every two weeks.

Or, on the opposite end, if the heating value was consistent from sample to sample to sample to sample to sample, we might say, you know, you don't need do three months anymore. You can do six months. And we can change that if something changes.

For very high volume FMPs, there would be an initial sampling frequency of once per month. And we can adjust that sampling frequency after we have a statistically -- statistical information on that variability, we could adjust that up or down to achieve a heating value uncertainty of plus or minus 1%.

Sampling frequencies are arbitrary. And we wanted to take the arbitrariness, if that's such a word, out of this and make it so here's what we are trying to achieve, 2% or 1%. And we will adjust that sampling frequency to meet that performance goal.

Continuing on. If a meter was so erratic, with the heating value just jumping all over the place, if they simply could not meet our uncertainty standards -- there will be only for high and very high volume FMPs -- if they simply could not meet that 2% or 1% uncertainty standard by taking these spot samples, we would require an operator to install either a composite sampling system or an online gas chromatograph, and that would take care of that.

Also, what we are proposing, that all gas analyses be entered into a BLM data base. It's going to be called GARVS, or the Gas Analysis Reporting and Verification System.

Every gas analysis that an operator gets would have to be entered into this system. And this system would, among other things, do statistical analysis to figure out how frequently we need to sample to achieve that 2% or 1% uncertainty level.

Continuing with the Btu theme, Order 5 has no requirements for sample location or method. And it has no requirements for the gas chromatograph, which is the device that analyzes the sample to tell you what your constituents are, your methanes and ethanes, and propanes and et cetera.

Proposed 3175, this first bullet item again is kind of radical, and it goes against industry standards, actually.

We are proposing that the sampling probe would have to be between 1 and 2 times dimension DL downstream of the primary device, which is the orifice plate.

Dimension DL is the API standard for how much straight meter tube you need downstream of the orifice plate.

So, for example, if API standards said you needed 8 inches of straight meter run downstream of your orifice plate, the sampling probe would have to be located between 8 inches and 16 inches downstream of that orifice plate.

Now, industry standards, API and GPA, say that the sampling probe shall be mounted no closer than five times -- five times the pipe diameter downstream of a major obstruction, like an orifice plate.

What we're trying to do here, is we have a reality in the field that the API and GPA standards don't recognize. API and GPA standards for gas sampling all assume we have perfectly dry gas with no liquids in it whatsoever. And that's just not reality.

What we're trying to do is move the sampling probe closer to the orifice plate, so any in-train hydrocarbon liquids would be turned into an aerosol, basically a spray. As they are forced through the orifice plate, they accelerate. There's tons of turbulence. Any in-train liquids would be caught up in that spray basically, and they would be picked up by the sample probe.

So the gas analysis would include the Btu content of those heavier ends which have a lot of Btu content.

Right now, we cannot say that all of the Btu, all the molecules are being accounted for in gas sampling systems, because gas sampling systems are designed to keep liquids out generally. So, we're proposing this, and we're actually looking for data on this.

We would allow or retain four different spot sampling methods, and that would include the fill and empty method, which is by far the most common, I think; the helium pop method; the floating piston method and a portable gas chromatograph.

Now, we would incorporate our requirement for the calibration and operation of gas chromatographs.

Now, this is another one that we're kind of just throwing out there.

Are you guys familiar with gas chromatographs at all? Have you ever worked with them?

MR. HALLAM: (Shaking head.)

MR. ESTABROOK: A little bit maybe?

So, gas chromatograph, to me, it's almost magic in some of the ways it works, but they have these columns.

And these columns take, and they sort the molecules. So it sorts it by -- really light molecules, all the methane molecules are sorted, and then ethane and then propane and then butane and so on.

And then this stream of molecules comes out this thing called a column, and there's a device that measures how much there is in that.

So it measures how much -- if you look at it graphically, you would get a little blip for methane, and a little blip for ethane, and a little blip for propane. And the size of that blip tells you how many of those molecules are in that gas sample.

If you get a big blip, there's a lot of

that. If you get a little blip, there's not.
So, you get a blip for methane and a blip for ethane, propane, butane, pentane.
And then anything heavier than hexane comes out as one big blob.
And so you measure this blob, and you report it on the gas analysis as hexane plus. It includes hexane, heptane, octane, nonane, and everything hexane and heavier.
And that's reported as one number. And we think that if there's a significant amount of this big blob, the hexane-plus, that we could be shortchanged because we may not adequately account for the heavier molecules, the more valuable molecules in that hexane-plus blob.
So, what we are proposing is if you get more than 2.5% of hexane-plus, you need to do another analysis to figure out not only the hexane-plus, but each component within that hexane-plus - the heptane, octane, nonane. We think that would give us a more accurate Btu content. It's something else we're looking for data on.
Order 5 has requirements for Btu reporting. Proposed 3175 would establish

reporting requirement.

Now, from a single gas sample, you can get Btus report on a variety of different bases.

For example, Btus can be reported gross or net. They can be reported real or ideal. They can be reported as dry, wet or as-delivered.

They can be reported to a number of different pressure bases, and usually I have only seen 60o Fahrenheit.

So from a single gas sample, if I do my math right, you can get 48 different values of the heating value of that gas. 48 different values based on which of these they choose.

We're going to dictate which of these you have to report to - gross, real, dry, 14.73 and 60o Fahrenheit.

I want to talk a little bit about this one, because this one is confusing and controversial. This is dry, wet or as-delivered has to do -- first of all, it has nothing do with hydrocarbon liquids.

When I first heard the term -- years ago I heard the term "a wet Btu".

Have you guys seen gas analyses reports before, and seen what they report at?

MR. HALLAM: (Shaking head.)

MR. ESTABROOK: Okay.

Take a look at one of your gas analyses if you get a chance, and if they are reporting wet Btus, you're probably getting shortchanged in the royalty.

Now, when I first heard the term "wet Btu", I thought, oh, okay, they're including hydrocarbon liquids, so that should be a good thing.

"Wet Btu" has nothing to do with hydrocarbon liquids. That dry, wet or as-delivered has only to do with assumed water vapor content.

If they're reporting wet Btu, they're assuming that gas is saturated with water vapor at 14.73 degrees [sic] and 60o Fahrenheit. You are getting an automatic 1.74% deduction from your heating value if they are assuming that.

Now, if your meter is operating say at 100 psi and 60o Fahrenheit, it is physically impossible for that gas to contain 1.74% water vapor, and yet you're getting a 1.74% reduction in heating value, which means a 1.74 deduction in royalty value for water vapor that cannot physically exist at that meter. So, we are proposing to take care of that and require only dry.

Order 5 and the statewide Notice to Lessees. The statewide Notice to Lessees actually have an uncertainty requirement in them already. It's 3% if you're over 100 Mcf per day.

And we actually have a tool to enforce that uncertainty requirement. It's called an uncertainty calculator that our inspectors use.

One of the big contributors to uncertainty or inaccuracy in a meter is the transducer. That's one of the major contributors to inaccuracy.

And right now, that uncertainty calculator, when our inspectors go out, and they enter in all the information about that meter, it uses published manufacturers' specifications for the accuracy of those transducers.

And any transducer that's out there is automatically accepted. We have no acceptance criteria right now.

So, the problem with that is that we were talking about accuracy and manufacturer specs a little bit on break, is we have no idea what those manufacturers' performance specifications are based on.

Much of the testing that manufacturers do is proprietary, and there is no transparency to it. We have no idea of what those numbers even mean actually.

What we are proposing is that all transducers used at high and very high volume meters would have to be run through a published testing protocol, which it's part of the 3175.

You would have to go through a series of tests. You would be submitted then to the Production Measurement Team, that test would be, and the Production Measurement Team would determine what the actual accuracy, the actual performance of that transducer is, so that when we do our uncertainty calculation, it would be based on real numbers.

Finally, as with the other Onshore Orders, other proposals, we have a number of things, some data that we're specifically asking for. For example, how much is it going to cost industry to do this type testing of these transducers? We don't have a good feel for that.

What we are proposing is that when they do this testing protocol, we don't think it's good enough just to grab a transducer off the assembly line and go test it, because they could feed us one that's really good.

So we're proposing that they would have to test five transducers to get a statistically representative sample that are randomly pulled off the assembly line.

We're asking for comments on whether five transducers is adequate.

We're asking whether we should incorporate standards for on-line gas chromatographs, which there really are not very many of, or if there's some other standards we should be incorporating, like API 22.6 which just came out.

Data showing water vapor saturation. There gets back to that assumption of dry, wet, and as-delivered.

Industry has gone to this as-delivered method, but they're still giving you a deduction of heating value based on assumed water saturation, but it's based on meter, pressure and temperature, so it's a little more reasonable.

But I'm not convinced that even that is a reasonable assumption, and so we're looking for data on that. We are proposing dry unless we get convincing data to show us that it is saturated.

This gets back to another one that I talked about, is our sample probe being between 1 and 2 dimension DL.

We are just throwing that out there, and we're looking for any kind of test data that might be out there to show correlations between sample probe placement and composition.

I can tell you one, the reason we came up with that, we couldn't find any research. And we attend the API meetings, the semi-annual API meetings.

And at that meeting, there was a couple people talking about this very issue. And one operator, I believe it was an operator, he said they had these cone meters, which wasn't an orifice plate, but they're similar, and they had a sample probe quite a ways downstream of this cone meter, and they took a sample from that sample probe and got a certain heating value.

They then moved up to sample probe that happened to be installed much closer to that cone meter, and the Btu value went up tremendously.

So we're looking for that kind of data.

MR. LYSON: Well, I mean with that placement like that, you're talking a lot of darn dollars there, too, then.

MR. ESTABROOK: Yes.

And that the potential is there is that -- in fact, the OI -- I think it was the Office of Inspector General asked me, he goes, "Well, how are you accounting for in-train liquids that are going through there?" And I was like, "We're not."

Another thing about that is, current industry practice allows you to put a filter at the bottom of your sample probe specifically to keep liquids out, and we are proposing that that would be prohibited.

So our goal -- we don't want to over represent the sample with liquids. We're trying to get a representative sample. We think if you have a filter there, or you're way downstream, it's not going to be representative, and we're not accounting for those molecules.

So it could be significant. We're looking for data on that.

The eccentricity, that's kind of a minor thing.

Chart integration companies, the second bullet there, I think most chart integration companies have been around for a long time, and they still do calculations based on the old 1985 method.

And we're asking for cost data for them, how much it would cost them to update. We have no idea.

This is one I also mentioned, a data showing this hexane-plus versus nonane-plus, because as function of C6 mole percent, we're looking for data showing that.

And finally, clean sample cylinders.

Right now, API and GPA, Gas Processors Association, have a ton of requirements for how to properly clean a sample cylinder after you have taken a sample cylinder. There is a steam cleaning thing, and it's a rigorous process.

But the question we had of how are our inspectors going to know whether that sample cylinder they're putting on our meter, or your meter, to take a sample, how do we know that's actually clean still and hasn't been opened?

So we're asking industry for ways where they could clean the cylinder and then put kind of seal on it so you'd have to break that seal in order to use it. And we haven't got any good ideas yet, but we're hoping we will when the comment period closes.

So, that is our proposals.

Obviously we will have an open discussion where everyone talks about. For comment submittal, this is where you would submit it.

These PowerPoints going to be located at this location (indicating).

And I would encourage you to go to this regulations.gov website. There's actually a lot of good information there for each 3173, 3174, 3175.

There's the regulations themselves, the proposed regulations, there's an environmental assessment. There's an economic analysis. And for 3175 there's also a Gas Heating Value Variability Study, which is the basis for our recommendations for the gas sampling frequencies.

And with that, we will take any questions or comments you have on 3175, or I think on anything at this point.

MR. HALLAM: On that cylinder you are talking about at the end there, you're talking on the collection cylinder itself --

MR. ESTABROOK: Yeah.

MR. HALLAM: -- not the tubing that you would simply purge out.

MR. ESTABROOK: Right.

The collection cylinder itself.

Because especially having your hydrocarbon consult themselves into the pores of the metal in those cylinders and become very, very difficult to remove if you don't go through this process.

MR. HALLAM: I mean, after cleaning, you want it sealed -- once it's cleaned and not used again, what's your concern?

MR. ESTABROOK: My concern is, for

example, most of those cylinders have a vacuum inside of them, or they're purged with hydrogen.

So, the gas tech comes up in his truck to do a calibration and a sample, and he pulls a cylinder out of the back of his pickup truck.

How do we know that that thing hasn't been opened and has now been contaminated with air, nitrogen, oxygen and all kinds of other stuff?

Or maybe it just came from another well, and it never was cleaned.

MR. HALLAM: Well, that would my more concern, whether or not it's been cleaned, not so much contaminated.

MR. ESTABROOK: Yeah.

MR. HALLAM: I'd like to see verification that it's gone through the cleaning, but once it's cleaned, I don't know if we're not overdoing it as far as putting a seal on the sampling bottle.

MR. ESTABROOK: Yeah, that's the kind of comments we're looking, so yeah.

MR. HALLAM: But I would like some form of verification that it has been cleaned.

MR. ESTABROOK: Okay.

Anything else, again on any one of our proposals here?

MR. HALLAM: Like I said, obviously for us, it's a huge improvement. Everything is benefitting us, but I think industry is going to take a different view.

MR. ESTABROOK: Yes, we think so, too.

MR. HALLAM: But I like it.

MR. ESTABROOK: Although industry has been overall very agreeable to the goals we are trying achieve. It's not so much maybe with how we are trying to achieve them.

MR. JUDICE: Well, with that, that concludes.

We will await to hear from you, Travis, Kenny, whichever wants to let me know about having a presentation done personally for the Chairman and others at your reservation. So let me know that.

MS. CONNELL: Don, I have just quickly a comment.

MR. JUDICE: Sure.

MS. CONNELL: Just on behalf of all of us here at BLM, first of all, I want to thank all of you guys for being here, because I know there's a hundred other places today.

But, you know, for us, particularly for Montana-Dakotas BLM, we recognize the importance of all of this stuff. And we have a number of PETs, or lead PET from BLM Montana-Dakotas, and we haven't all the tools in the toolbox to be able to be as directive as we would like to be to make sure that we have the proper royalties being paid.

You know, I think we've done the best job that we possibly could, but you can all do better.

And to know that our responsibilities for overseeing the Indian royalties for both Tribal and allotted lands, particularly at Fort Berthold, is a huge responsibility for us, and we take it very, very seriously.

And so whatever you can do to provide feedback. I appreciate that you're going to talk to industry, because they might tell you something that they might not tell us, and you might be able to interpret it a little bit different than even we would be able to. So if you could sort of feed that information back to us, we would greatly appreciate it.

MR. LYSON: And see, that would be something where I would like to -- you know, there's some of them I get along with that I'll talk and kind of discuss their, you know, thoughts and concerns, and then I would have that with me if I have you guys up at the Natural Resource Committee. That way we can kind of take it over there.

MS. CONNELL: Well, I appreciate that.

And our work with the Federal Partners meeting that we're going to have in January, I think that's another opportunity for us to be able to talk about this some more.

But, please know we really appreciate you being here and how important we believe that relationship between our organization and yours is.

So, with that, I'll turn it over to Amanda.

MS. LEITER: Yeah.

So again, I'll just reiterate what she said, we really appreciate your being here.

I probably won't be back -- I certainly won't be back if you guys are doing a meeting later in the month. I mean, I would love to come back another time, but I'm not going to be back later in the month if you're doing a meeting.

So to the extent you have, you know, concerns that you'd like shared with Washington, I'm happy to hear about them. We can do it in this big group, or I have time, you know, if you just want to talk for a little while after the meeting. That's fine as well.

I mean, I think this particular rulemaking is obviously just a very a detailed effort to make sure that we're understanding what the production levels are. And I think most of the comments that we're going to get are going to be pretty technical in terms of this device does or doesn't work. This is too expensive; this isn't.

But we're happy to hear sort of broader concerns as you have them as well. So I'm happy -- if you have stuff with the whole group, that's fine, or we have a little time left over, we can just talk afterward.

MR. LYSON: Well, I mean, I thank you guys for having us here. And it's very, very informational, you know. I mean the stuff we can take back and, you know, let everybody else know what's going on, I mean, that's very beneficial to us.

And like I said, thanks for having here.

MR. HALLAM: Well, one of the things I would say, though, is if you do meet with our NRC, they have meeting-induced ADD.

So, you're going to have to kind of condense these down to more on point. I mean, so you're going to have to kind of filter out what's going to be the stuff you really want to emphasize in there.

Because it's unfortunate, but we've seen in these meetings one after another, after another, and while you're doing the presentation, they're going to be saying, "Well, what about that Vikings"?

So, it's just the way it plays out.

So if you can kind of keep it to more a condensed their shock clock they have is 10 minutes, I think is their maxed-out attention span.

So, just something really brief and condensed would work good for a short presentation for them.

MR. JUDICE: Well, thank you. That's very helpful.

And with that, we will close.

And thank you, Fran.

(Whereupon, the meeting was concluded at 11:30 a.m.

REPORTER'S CERTIFICATE

CASE TITLE: Tribal Consultation Meeting
HEARING DATE: December 8, 2010
LOCATION: Dickinson, North Dakota

I hereby certify that the proceedings and evidence herein are contained fully and accurately on the stenographic notes reported by me at the meeting in this matter before the Department of Interior, Bureau of Land Management, and that this is a true and correct transcript of the same.

DATE: December 10, 2015

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