U.S. DEPARTMENT OF THE INTERIOR
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PROPOSED REVISIONS OF ONSHORE ORDERS 3, 4, AND 5
PERTAINING TO OIL AND GAS

MEETING FOR THE TRIBES
DECEMBER 3, 2015 - 9:00 A.M.

PUBLIC MEETING FOR ALL STAKEHOLDERS
DECEMBER 3, 2015 - 1:00 P.M.

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MS. LIZ O'BRIEN: Good morning. Thank you so much for coming this morning. My name is Liz O'Brien. I'm going to facilitate the activity this morning and again this afternoon.

We thank you for being here. You are a very special crowd. I don't need a microphone, I hardly ever need a microphone. But I think you can all hear me, yeah?

Okay. That's terrific. This morning, I think, because of the level of attendance, what might be a really good idea is, don't feel so formal that you have to wait to ask a question or interact. We're quite open to the interaction. So stop us, interrupt us, do whatever. Okay? Just don't swear at us.

Also, this is a proceeding that, because we want to capture all the information, we have -- we are lucky enough to have Lynette as our court reporter. So she is going to make sure that this -- we capture every bit of information so all the

information can go back to the powers that be who are making the final decisions for this.

Your input is invaluable. We had a meeting -- it feels like last night, but I think it was a couple of days ago -- in Durango, Colorado, and gleaned a lot of information from participants there. So we're hoping that that will also happen here.

The morning session is going to go from -- is supposed to be 9:00, it is time now 9:30, from 9:30 until noon, or whenever, you know, you've had your input, questions, whatever, satisfied.

I'd like to introduce Sheila Mallory, who's the Deputy State Director for the BLM. And she is going to introduce you to all of our experts here.

I will say this, though. These are the experts from the BLM. You guys are the experts on everything else. So as much participation as you feel comfortable with, that would be terrific. So thank you, and thanks for coming. Sheila.

MS. SHEILA MALLORY: Invocation?

MS. LIZ O'BRIEN: Oh, I don't know. Nobody -- do we have an invocation?

MR. RICK FIELDS: I can do it.

MS. LIZ O'BRIEN: Well, would you like to come on up and do that?

MR. RICK FIELDS: I can.

MS. LIZ O'BRIEN: That would be great. Thank you. You want to introduce yourself?

MR. RICK FIELDS: Sure. Hello. I'm Rick Fields. I am the Acting Field Manager for the Oklahoma Field Office. I would like to thank you all for coming today. I'm also a citizen of Cherokee Nation. So, O si yo. Thank you, too.

So, with that, let's just bow our heads briefly as we have an opening invocation.

Today we ask the Creator to look down favorably upon us. Bless us with wisdom and guide us in our conversations as we look to wisely choose the course of action and give input on this.

We'd also like to ask at this time to give us remembrance for those who are affected by the tragedies yesterday in California. And ask that we have blessings on all of us as we travel about, too, to and from our homes. And we just ask that you reach out and touch upon us and give us that which we need to successfully complete our day.

We ask this in the Creator's name.

MS. LIZ O'BRIEN: Thank you.

MS. SHEILA MALLORY: So, as Liz has just said, I'm Sheila Mallory. I'm Deputy State Director

for New Mexico, Oklahoma, Texas, and Kansas. Try saying that really fast. And I'm here today to welcome you to our Government-to-Government Commission on Onshore Orders 3, 4 and 5. Onshore Order 3 is Site Security, Onshore Order 4 -- boy, a tongue twister -- is Oil Measurement, and Onshore Order 5 is Gas Measurement on Tribal and Allotted Lands.

I want to start by introducing some folks out of our Washington Office. And also, again, thank you, Rick Fields. He's our Acting Oklahoma Field Manager. So, if you have any specific questions related to issues in -- for these Orders related to a separate consultation, please, reach out to either Rick or myself and we can help you with that.

I also want to introduce Dylan Fuge. He is the Senior Advisor for the Director Neil Kornze.

I also want to introduce Steve Wells.

MR. STEVE WELLS: Good morning.

MS. SHEILA MALLORY: He is the Division Chief for Fluid Minerals.

And then Karen Mouritsen, she is Assistant Director, who will be getting us started this morning after I finish my introductions.

So, first off, Rich Estabrook. He is

our petroleum engineer. He will be explaining the proposed changes and what's common between all three of them.

Rich will be followed by Mike Wade. He is with Inspection and Enforcement with the Washington Office. And he will be covering Onshore Order Number 3.

And then finally, Mike McLaren. Lots of Mikes today here. He will be covering Onshore Order Number 4.

So with that said, I again thank you for coming.

Oh, also Rich Estabrook, he will be rounding out the discussion -- Did you know that?

MR. RICH ESTABROOK: I did.

MS. SHEILA MALLORY: Okay. -- of all the rules themselves and with a review of the provisions on Onshore Order Number 5 on Oil and Gas Measurement. He is like Obi Wan Kenobi of all this stuff.

So at this time, I'll turn it over to Karen Mouritsen.

MS. KAREN MOURITSEN: Okay. Thank you, Sheila.

And I'm Karen Mouritsen. I'm in the Washington Office. I'm the Deputy Assistant Director

for our Energy and Minerals Directorate. And so, Steve and Mike and Rich and Mike, we all work in that group on regulations and policy guidance for our oil and gas program.

And so, we really thank you for being here. As Sheila said, we're working on rewriting these regulations. This is really important, because it's been several years, more than several years, 1989 when they were promulgated, right? And technologies have changed, as you know, since then. And we have -- I'm sure you've heard about this, too. We've had various auditors looking at these regulations and our practices and saying, you know, we really ought to update things and get them more in line with current technology.

And the whole reason for all of that is accounting for the amount of oil and gas production that's just really important for everyone, because that goes to the revenue that we all get, both the Federal Government, the Tribes, the Companies, everyone. So it's a really important subject.

And we're going to -- these guys are going to give you their presentation and then -- and explain it and discuss it with you.

We would really like you all to give us

comments on the regulation, the proposed reg text. The Preamble, which is the part that explains all this, and part of the documents we've published, there is the Environmental Analysis, which we've had comments on; there's the Regulatory Impact Analysis is one of the documents published which would be -- you can get online. And that's the part that talks about our assessment of how much it will cost to implement these things, both for us and the companies, public.

So, we want you all to ask questions and give us comments on all of those documents. So that is just kind of background. And I think that's everything.

So just thank you again for coming and I hope you all can participate and give us your input.

MR. RICH ESTABROOK: Thank you. My name is Rich. And just to reiterate what Liz says, we have kind of a formal PowerPoint. But please, ask questions whenever you have one. Don't wait until the end. That will also make the morning be a lot more pleasant for us, to have a conservation, rather than just sit up here and do death by PowerPoint.

This is the proposed agenda of what we have prepared. And again, interrupt us any time, anything

that comes up. If we use an acronym you don't understand or there's questions on anything, comments on anything, please, please, interrupt us and ask.

This is what we have prepared. We're going to go over why these regulations are important, why we are revising these regulations, these Onshore Orders.

I'm then going to talk about changes proposed that are common to all three; Site Security, Oil Measurement and Gas Measurement, and then we're going to talk about the new regulatory structure that we're proposing. Part 3170 is going to be proposed to be a brand new part of the 43 CFR Regulations.

I'm then going to turn it over to Mike Wade, who's going to talk about subpart -- Proposed Subpart 3173. That one replaces this Onshore Order 3 covering Site Security. We have questions and comments at the end, but again, don't wait until the end, please.

Mike McLaren will then cover Proposed Subpart 3174, which will replace Onshore Order 4. And then, as Sheila said, I'll round it out with 3175, and that's the gas part of it. And 3174 is the oil measurement one. I'll round it out with 3175, which will replace Onshore Order 5, which will be

requirements for a -- technical requirements related to gas measurement.

So why are these regulations important? And in one word, your money. These regulations affect Tribal royalties and Federal royalties, too.

How royalty is calculated is pretty much the same for Federal and Tribal. There may be some very minor differences to that, this actually applies to onshore and offshore production.

Royalty on oil, and this is the royalty coming back to the Tribe or to the Allottees, equals the royalty rate on the Tribal lease, times the volume of oil removed from that lease in a given month, times the dollar value of that oil.

Now, one of the things that goes into calculating the dollar value of the oil is the API gravity. That's basically the density of the oil, the quality of the oil. That's not a direct multiplier in the royalty equation, but it does affect value, which is a direct multiplier.

The royalty rate is set in the lease terms and normally it is a fixed value. There are some of these sliding scale royalty rates around, I believe, in Oklahoma especially. But, for the most part, the royalty rate is a fixed percentage. It's set in the

lease terms. It has nothing to do with these Onshore Orders. We're not going to be discussing royalty rates here.

The dollar value of the oil is actually not determined by the Bureau of Land Management, it's determined by the Office of Natural Resources Revenue. It's not something -- we do not deal with the dollars and cents. We deal with the barrels and API gravity for oil.

I'm sorry about the colors. This -- each projector is a little bit different. This is what happens. The blue and magenta are really dark and hard to see.

But Onshore Order 4, and to some degree Onshore Order 3, currently have a very direct effect on the volume of oil, a very direct effect on the accuracy of the measurement of that volume and the recording of that volume that go on there on the report forms. So any changes to Onshore Order 4 and Onshore Order 3 will have a very direct effect on, not only the volume, but, ultimately, on the royalty.

Onshore Order 4 also has requirements relating to the API gravity. So again, for oil measurement, the quality of the oil is not a direct multiplier, but it does affect the value. And the gravity and quality and volume are the things that the BLM is responsible for. And quality and volumes are what the changes in these Onshore Orders are all about.

Okay. Moving to gas. Gas royalty is very similar. It's the royalty rate on the lease -- you're going to get a set number monthly -- times the volume of gas removed from that lease in a given month in Mcf -- millions of thousands, of thousands of standard cubic feet -- times the heating value or the quality of that gas, and then again times the dollar value of that gas. As with oil, our royalty rate is set in the lease terms, has nothing to do with these Onshore Orders. The dollar value of the gas, again, is not determined by the Bureau of Land Management, it is determined by the Office of Natural Resources Revenue or ONRR.

The volume of gas removed from a lease is a direct function of Onshore Order 5 and, to some extent, Onshore Order Number 3. The provisions of Onshore Order 5 are here to make sure that that volume is accurately measured and properly reported. Onshore Order 5 also talks about the heating value of the lease. Although, as I will talk about it later, it doesn't talk about heating value very much, at

least not currently.

What I would like to point out, I will discuss this a few times as I go through here, that both volume and heating value have the same weight on royalty. In other words, if an operator was to report a volume 10 percent in error, that's going to cause a 10 percent in error in the royalty that comes back to the Tribes. If an operator reports a heating value that's 10 percent in error, it's going to have the exact same effect on the revenue. That means you'll get a 10 percent error in the royalty that comes back to you.

Now just some statistics here. This is oil production. This is across the country for the Tribal leases. This is in millions of barrels. And starting in 2004, all the way up through about 2010, productions from Tribal leases was pretty constant at around 10 million barrels per year. You can see that starting a little bit in 2010 and a very definite trend through 2014, that's the latest data that we have, oil production has increased steadily and dramatically. And that's primarily due to the Bakken development in North Dakota, the Fort Berthold Reservation.

Oil price has fluctuated considerably over

the same time period. In 2004, oil was running about $35 per barrel. It peaked in 2008 at over $90 a barrel, took a dive in 2009, and the last couple of years it's been averaging about $90 a barrel. We all know that in 2015, or late 2014 and 2015, oil has taken a nose dive. But we don't have that data here.

So if you take from my oil royalty equation, if you take oil production and multiply it by the price, you get royalty that comes back to the tribes. And that looks like this. Again the magenta line is not showing up very well. But from 2004 to 2010 roughly, Tribal royalty -- actually the royalty scale is over on the right-hand, sorry for the confusion. But from 2004 to 2010, oil royalty is about $100 million per year.

Since 2010, we've had this dramatic increase in royalty. And in 2014, there was $850 million in royalty that came back to the Tribes. And a lot of this is Fort Berthold up in the Bakken formation in North Dakota.

Gas production looks a little bit different. Gas production from 2004 was about 300 Mcf, millions of Mcf. And it's had kind of a steady decline down to -- through 2014 it's been about 240 million Mcf of gas from the Tribal leases.

Gas price has fluctuated. I've given the scale for gas, now over here on the right side the gas price, the wellhead price. In 2004, gas was running about $4.50 an MMBTU. MMBTU is millions of BTUs. You actually get paid on BTUs on the thermal value of that gas.

Had a big spike in 2008 to over $8 an MMBTU. Very similar to the oil spike, it took a dive here in 2009 and we've never really recovered from that dive in gas price. In 2014, gas price is just over $4 an MMBTU. In 2015, it's also dropped. I know in some areas it's down to $2.50 or $3.00, in that area.

So again, as with oil, if you take production in Mcf and multiply it by price, you get royalty that comes back to you and the royalty now looks like this. In 2004, about $200 million per year, and in 2014 it actually hasn't changed that much.

So, why are we revising these regulations? Before I talk about specific reasons, I want to talk a little bit about what exactly we're proposing to do.

So currently, we have Onshore Orders 3, 4 and 5, which, as we heard, are -- were promulgated in 1989. What we're proposing to do is create a new regulatory subpart.

I should mention to you that the Onshore Orders are, I think, unique to the federal government, because they are the only -- the only uncodified, unpublished regulations that I'm aware of anywhere in the federal government. There may be others, but I'm not aware of them.

So the Onshore Orders have the weight of regulation, but they're -- if you look in the 43 CFR books or the regulatory books, you can't find them. You can get them online from our websites. We have old copies lying around, but they were never published. So they are very strange in that way.

What we're proposing to do is create a new regulatory Subpart 3170 that would contain all things related to the production and measurement. Within that overall subpart, there would be some things common to all measurement-related activities, like common definitions, recordkeeping, bypass and tampering, variances, appeals and enforcement. Those are common to all measurement things, they would be in one place.

Under this Part 3170, we would then develop -- or we are proposing a new Subpart 3173. 3173 would replace Onshore Order 3 and it would cover

things like site security. And site security generally means seals on valves. That doesn't prevent theft, but at least you can identify it.

FMP, which means Facility Measurement Point -- Mike, will get into all this when he talks specifically about 3173 -- commingling and off-lease measurement.

We're also proposing a new Subpart 3174, which would replace Onshore Order 4. And it would be the nuts and bolts of oil measurement, very specific technical requirements for oil measurement.

We're also proposing a new Subpart 3175. It would replace Onshore Order 5, and it would also replace statewide Notices to Lessees for electronic gas measurement. And I will talk a little bit more about that when I get into Onshore Order 5 at the end. And all of those things are related to gas measurement. So 3175 would be the nuts and bolts of requirements for gas measurement.

So, why are we revising these orders? Well, as Karen mentioned, they were last -- actually this is not entirely correct. They were not last revised in 1989, they were promulgated or developed in 1989 and they have never been revised. So they're 26 years-old, which is not necessarily bad that they are

old, but, because they are old, that's resulted in a number of things.

For example, our current orders or regulations do not address new technology or incorporate the latest industry standards and practices. As Mike McLaren will talk about in 3174, the old techniques for oil measurement that are recognized in the current Onshore Order 4 are oil measurement by manual tank gauging and by what's called a LACT, a Lease Automatic Custody Transfer System, using very old technology of positive displacement meters.

Many companies are going to Coriolis meters for oil measurement for a number of reasons. And that is not even addressed in the current Onshore Order, we have no requirements for that.

There is also gaps in the existing orders that need to be addressed. And one huge example of that is regulations relating to the heating value determination for gas. As I have showed in that equation, volume and heating value have the same effect on royalty.

Now in the existing Onshore Order 5, I think there is 25 specific requirements relating to the accurate measurement of volume. There is one, and

only one, requirement relating to the heating value determination. And that requirement is that you have to determine heating value, period. We have no requirements on how you sample for heating value, where you sample for heating value, how you analyze the sample or how you report the heating value. And that is a huge, a huge gap in our existing regulations or orders that we're attempting to fill.

Also again, as Karen mentioned, we need to respond to various reports and audits. I'll start with the middle one there. The Government Accountability Office oversees our agency to make sure we're doing our job. And they did a report in 2010 that pointed out that we are not -- we are not doing a very good job of accounting for oil and gas volumes and qualities. And they recommended that new regulations be developed to replace the existing Onshore Orders that are so old.

The Office of Inspector General, the bottom one there, kind of the same thing. They have done numerous audits and investigations and they are pretty consistent with the GAO that our regulations -- part of the reason that we're struggling is that our regulations are so old they are just not applicable anymore.

The top one is the Royalty Policy Committee. It used to be a charter advisory committee under the old Minerals Management Service. In 2007, they did an exhaustive study of the whole department, onshore, offshore and the royalty collection function, and they came up with 110 recommendations of things that our department needs to do to improve our oversight of measurement and production accountability. Of those 110 recommendations, 12 of them were very specific to volume and quality measurement, including the need for updated regulations.

The bottom line is we need to revise these orders to include measurement accuracy, reporting and accountability.

So I'm going to now go through a couple of things that are common, that are going to be common to all three proposed subparts.

First of all, in the existing Onshore Orders for each requirement, for example, for gas measurement you have to inspect the orifice plate on the gas meter every six months. For each requirement there is also an enforcement action. If we find a violation, is that a major or a minor violation. And it tells you what the category is. It tells you what the corrective action should be and the time frame in

which the operator has to correct that, correct that violation.

Now the problem has been with including these enforcement actions in the Onshore Order is that they were never intended to be set in concrete. They were never intended to be absolute, because, when it comes to enforcement actions, a major violation specifically is one that is substantial, immediate and adverse. So, what may be a major violation on a high producing well could be not a substantial issue on a low -- on a very low volume well. But this has been widely misinterpreted by both BLM and industry.

And so what we're planning on doing or proposing to do is actually pull those enforcement actions out of the regulations and we would develop an enforcement handbook that would go into a lot of detail about how different violations should be viewed and it would discuss all the extenuating circumstances and the things that our inspectors in the field should consider before assigning a major or minor label to it or assigning a corrective action or time frame.

The current Onshore Orders, there is only one immediate assessment. An immediate assessment is

where an inspector goes out, finds a violation, they can issue an immediate fine for that violation. There is only one currently in Onshore Order 3 and it deals with federal seals.

What we're proposing are, I believe, 27 new immediate assessments scattered throughout the three Onshore Orders. They would be a thousand dollars each. They're not intended to be punitive. They're intended to be -- they cover something called liquidated damages. And I'm not a lawyer. I have never really understood what that means. But that's what the intent is.

The current Onshore Orders leave technical reviews or variances of alternate meter technology or procedures up to the individual field offices. This has caused a number of problems, especially for industry, I will say, because there's a complete lack of consistency of these approvals throughout the -- throughout the BLM.

For example, in Wyoming there's a devise to replace orifice plates that is called a V-Cone meter. And there was a company pushing these V-Cone meters in Wyoming and they went to one office and that office said, sure, they are fine, go ahead and use them. Another office in another field office right

next door said, yeah, you can use them, but here's a list of conditions that you have to abide by. Another office said there is no way you're using those in our office. So huge inconsistencies and other issues.

What we're proposing is that we would develop or initiate a new Production Measurement Team where all these reviews for alternate measurement devices or procedures would be sent to this Production Management Team at the national level, they would do a review of this to see if that technology was appropriate for measurement on Federal and Tribal leases, they would develop conditions of approval for that technology, and then they would list that approved meter technology or procedure on a website. So an operator, or the BLM, could go to a national BLM website and just look at the pick list for the types of equipment that were approved and they could find out exactly what makes and models, very specific, equipment has been approved.

Yes?

MS. MELISSA PEROS: Well, how long do you think it would take if a new meter came out to get through your team to be approved?

MR. RICH ESTABROOK: Good question. Now if we had a team in place, it would not be a -- first of all, it would not be a fast process. I have done a number of these reviews personally. And first you have to discuss what kind of testing you are going to require. You then have to do the testing. And then the review of that testing is pretty intense. You are wading through a lot of data and trying to decipher exactly how that meter performed.

So I would say -- to answer your question, I would say from the time an operator or a manufacturer submitted or requested an approval, it could be about a year.

MS. MELISSA PEROS: Is there going to be a manual or something that your team uses to determine how they test it?

MR. RICH ESTABROOK: Probably not. Again, this team would be measurement specialists that would know exactly the kind of testing that would be required. Okay? So this would apply to transducers and flow computers for gas measurement and for oil measurement and different types of measurement devices, like the waiver of V-Cone I mentioned or the Coriolis meters, anything, any equipment out there would go through this review, including existing equipment.

Now what -- and the other thing that this does is it -- we feel it provides longevity to these regulations. The existing regulations, one of the -- -- one of the main reasons we have to revise them is because they're obsolete. They only include measurement techniques and equipment that are being phased out.

This Production Measurement Team now would be able to continue and review new equipment and establish -- again, just put the new equipment on the pick list, even if it is not specifically mentioned in the new regulation. So we believe this will provide a tremendous amount of longevity to the regulations and make them fluid, rather than static.

Onshore Orders 4 and 5 are cookbook approaches to measurement. Here's what you have to do; A, B, C, D, E. You do all this stuff and you're good to go. But there's no performance goal ever stated in either Onshore Order. What is it we're trying to achieve? We have no idea. It's just follow this cookbook and you're good to go.

One of the problems with this approach, there is -- the upside is because some operators, especially the smaller operators, they just want to be told what to do and they'll do it. But the

downside is that the cookbook is only applicable to one technology.

For example, in Onshore Order 5, the cookbook only applies to the old -- the old circular chart recorders. It's a -- those mostly were developed in 1920. Because that only applies to that mechanical recorder, and so when you go to electronic flow computers, that no longer has any value. It talks about pens that draw on charts and had to have markings where those pens hit. Electronic flow meters, almost all we see now, they don't have pens.

So what we're proposing is 3174 and 3175 we'd still have a cookbook, because, again, some operators want that cookbook, they just want to be told what they have to do, but we would also explicitly state performance goals. Here is what we're trying to achieve, this level of certainty and accuracy. We don't want bias. We want to be able to independently verify it.

Again this kind of plugs in with the Production Measurement Team concept a little bit, because these performance goals is what the Production Measurement Team would be -- would be -- that would be the criteria for approval, the new techniques and new procedures. If you can show us

that you can use your proposed meter or proposed technique and still achieve these performance goals, you're good to go. It provides tremendous flexibility and adds to the longevity of the regulations.

In 3174 and 3175 we've made the attempt to have different performance goals based upon volume, the flow rate through those meters. And the idea here is to try to balance accurate and verifiable measurement, which are our goals, with economic considerations. So we give relief to operators operating very low-volume properties or very low-volume meters that simply couldn't afford to have all the bells and whistles on them that a high-volume producer could have.

Part 3170, this is the regulatory part of things that are common to all three subparts. This one is kind of a big deal. Currently Onshore Orders 3, 4 and 5 only apply to operators. So any violation, the incident of non-compliance always goes to the operator.

Now one of the problems is, let's say we're doing an audit on a gas meter and we sent a written order to the operator saying you must provide all this information about this gas meter; volume statements, calibration records, gas analysis. The problem is the operator doesn't own that meter. In many, many cases that operator does not own that royalty meter, it's owned by a purchaser or a pipeline or a transporter of some sort.

So the operator gets this notice from BLM that they want all this data and the operator then has to go to that pipeline company and say BLM is auditing us, can you, please, provide this information. And the operator -- or the purchaser or pipeline might just say no, we're not going to provide it to you. This has happened.

So now, the operator is in violation of our written order to provide the information, even though it's not -- the operator has no control over it. Our only enforcement action then is to write an incident of non-compliance to the operator for not following our written order.

What we're proposing in 3170 is that requirements for recordkeeping only, not for meter maintenance or anything else, but for recordkeeping only, would also apply to purchasers and transporters through the royalty settlement point or the point of first sale, whichever comes from first. So now, if we're doing an audit on a meter that a pipeline

company owns, we can go right to that pipeline company and say we want this data. And if they don't provide it to us, we can take enforcement action directly against that pipeline company.

We've actually had this authority, this statutory authority, since 1982 under the Federal Oil and Gas Royalty Management Act. It has been a late -- I'll call it a latent authority that we've never implemented before. We're proposing to implement it now.

Part 3170, currently the actual orders, each Onshore Order has a section on variances. They are similar, but there are some differences in them. What we would propose is that we're going to pull all the variance language and put it in one place, that overarching part 3170, and we're going to give a little more guidance on how an operator would request a variance and under what conditions we would approve it.

And with that, I will turn it over to Mike, unless there is any questions about what I -- Yes, please.

MS. MELISSA PEROS: Can I ask question about variances?

MR. RICH ESTABROOK: Sure.

MS. MELISSA PEROS: So when you move the variances all into one section and you kind of set out how it's going to work, do you expect that there are going to be a lot more requests for variances based on your new regulations?

MR. RICH ESTABROOK: I don't think so. And part of the Production Measurement Team is that, if someone requested to use a new type of meter which currently would be considered a variance, that wouldn't be a variance any more. That would actually be an approval by the Production Measurement Team. So all those things that used to be variances would no longer be variances.

So I don't -- I'm actually thinking there would be less. And also, we've kind of tightened up the conditions under which we would approve a variance to some degree. So I'm guessing fewer variances.

Anything else before I turn it over to Mike? Okay. Mike.

MR. MIKE WADE: Make sure I turn it right side up. Okay.

3173, Site Security, is involving Site Security Measures, Facility Measuring Points, Commingling, Off-Lease Measurement and several other

topics. Those are the big ones that seem to be the big, hot-button issues, if you care to think of it that way.

Currently Onshore Order 3 provides absolutely no guidance for commingling or off-lease measurement; how you obtain it, what you need to submit, et cetera. The proposed has the procedures and requirements that the operators and others would need to comply with the order in question; off-lease measurement and commingling. We have added some standards in there that we would work with.

Basically, we -- the BLM would have no problem with applying for commingling where there is no impacts to royalty measurement. If you have multiple leases, all with the same royalty rate, the same payee, commingling those would have no impact on royalty. Royalty rate 12 percent on 100, 12 percent of a thousand. The dollar value is still going to be the same. It would be the same number of dollars. So those would be a piece of cake to deal with.

Properties with low volumes. Sometimes due to volume issues, the need to commingle in order to maintain production comes into -- applies. So we look at the low volume and have the operators look at those as a reason for commingling.

And then lastly, extenuating circumstances; environmental concerns, there could be numerous extenuating circumstances where we could look at it for approval.

Those would be the three main areas that we would be concentrating on for commingling approvals.

MS. MELISSA PEROS: I have a question.

MR. MIKE WADE: Yes.

MS. MELISSA PEROS: Sorry. For the extenuating circumstances, are you guys going to define that?

MR. MIKE WADE: No, we're not -- Under extenuating circumstances, the operator has got to come to us and say here is my situation. And since there is such a potential wide variety of issues that could impact this, to try to define the cookbook with every single possible combination of extenuating circumstances is a crystal ball. And we don't have one of those.

MS. SHEILA MALLORY: Would an example be helpful?

MR. MIKE WADE: An example? Okay. Yeah, that might be a good one. An example would be for downhole commingling. Okay? In some instances a

downhole commingling for different unit participating areas, in order for production from an upper zone to actually get up the wellbore, we need to commingle to use energy from the lower-producing formation to actually help raise the oil and/or gas to the surface so it could be produced. There would be -- that's an example of one of the types of extenuating circumstances. But it also qualifies under -- possibly under the low volume as well. They could fall under one or the other of those, depending on specific details, which that could vary.

MS. MELISSA PEROS: Well, how can you -- how are you going to keep it consistent so that, say, a Tribe in Oklahoma gets an exception and a Tribe in California has the same situation but they don't. Is it going to be one team that does it? Or how are you going to make sure there's consistency?

MR. MIKE WADE: In part, through the handbook. And there is very specific information that the operators need to submit. And this would be the operators that would submit it, not so much a Tribal, unless they happen to be a Tribal owner, lessee, et cetera, where they own the rights. So there would be, you know, some of that type of issues to deal with.

But from a perspective of the operator, inside the proposed rule is specific information they need to submit. You know, not -- a simple statement, well, what we need to do this for this reason, give us some numbers, or give us some science, you know, explain it to us so that we can mix it for verifiability, if you will.

MS. MELISSA PEROS: Okay.

MR. MIKE WADE: Okay? And currently our planned proposal would be to review existing Commingling Agreements where the operators submit their requests for a Facility Measurement Point. Nobody would be shut down or there would be no impact like that just because the new regulations come out.

Next, Order 3 applies to all allocation meters and sales meters, and measurement related to royalty measurement is not even considered. It applies to everything. What we are proposing to do is to apply it strictly to royalty measurement. If it impacts the royalty, then we need to have verifiability on this.

And to track where the Facility Measurement Point is, right now, in many instances where the BLM inspector goes out to inspect, they think they've inspected where the operator is actually measuring

for royalty purposes, come to find out when they do the additional work, the operator is using this point over here. I expect it over here, and we may not have agreement as to where this point should be. This will require the operators to submit information, tell us where it's at, so that we can all be working with the same points for sales.

Right now Order 3 requires run tickets, but only for sales by tank. And then there's the issues with seal numbers; date on, date off, and a reason. That is it for seals, for water drains, hot oiling, other types of operations.

We are proposing to add a little more tight requirements for water draining, hot oil operations, et cetera. Some of those requirements that we're proposing are things like what was the volume in the tank before you broke the seal, what was the volume in the tank when you put the new seal on there. That's the sum of the additional information we're asking for, not just a seal number and a date.

And we're moving run tickets on that side over to 3174 with the oil measurement. So that would be removed from 3173 and actually moved over to the oil measurement side for the run tickets.

Right now Onshore Order 3 has nothing as far as end-of-month inventory, beginning-of-month inventory, how much fluid is out there. We're proposing the operator would be required to accurately measure an end-of-month inventory every month and retain those records.

Currently there is no information in Order 3 for royalty-free use, used on lease, beneficial use. Interchangeable term, but the same concept. We're proposing in -- to require the operators, when they submit their site security diagrams, to include some additional information if you're going to claim royalty-free beneficial use on a particular case. And that would be the makes and models, BTU ratings, how you're going to calculate it, if you're going to measure it. If you're going to measure it, give us some information. If you're going to calculate it, how are you going to calculate it from the equipment manufacturer's rating. Something that's verifiable.

Currently there's a requirement for a self-inspection program in Onshore Order 3 and for a site security plan for the operator for each case or for a group of cases that the operators must maintain. We're proposing to remove those completely in that. The additional requirements for seal records and other records will accomplish and fulfill

the requirements of the self-inspection program. If you're out there writing the numbers down and doing these records, you'd be doing the same thing you would be doing with the self-inspection program.

We are asking for very specific -- in the draft asking for information from operators and anyone wanting to comment on these three areas here. We've got a proposal for a 10 percent rate of return. We're requesting for on commingling, especially at the very low volume wells, we don't know if that's a good number or not. We are specifically asking operators and everyone to give us feedback on that 10 percent rate of return.

And what that entails would be, if you put a tank out there and it costs $20,000, how long is it going to take you to put -- to get the price of that tank back and still make a profit. Not the total price of the well, counting drilling. This is the new equipment or changes that you're required to make and that 10 percent rate of return. Don't know if that's a good number. Operators have not supplied us -- been willing to supply us with what they considered appropriate rates of return.

Comments on time frames, volumes and thresholds. Currently we're proposing, for example,

on the Facility Measurement Points, to take the highest producing one-third of the properties and those are due within the first nine months. That would be due after the first nine months of the effective date. The middle third, based on volume, nine months after that. And then finally, the low producers, nine months after that. So, 27 months. Is this adequate? Is it not good? Too long? Too short? The volumes, do we need to have a fourth level in there? We would like firm information and input on our time frames and our implementation for that. So, we are asking very specifically for comments on those areas.

Questions?

MR. STEVE WITTER: Yeah. On that last one there, the reason for that time period is because the BLM is going to have to approve every one's FMPs?

MR. MIKE WADE: That's not the only one. But the reason also is because the operators have to apply for it. How long -- they have an operator -- a large operator --

MR. STEVE WITTER: Yes.

MR. MIKE WADE: -- with, you know, 9,000 cases, how long do they need?

MR. STEVE WITTER: And they would be

requested through the E-Commerce part of the BLM or through electronic permitting?

MR. MIKE WADE: Oh, that is our hope and intent, would be to, when the companies are applying and requesting for an FMP number, to do that through our E-Commerce electronically. Those of you who are -- have been introduced to the new version of Atlas 2 for APDs, if you have any information on that, which you will soon get it, if you haven't already had it, something along -- similar along those lines. An electronic application process. So help speed it up and make everybody's job easier.

But, as I said, as long as these are drafted and not actually developed, that standard and that ability yet, that's our intent is to have a electronic application process automated as much as possible, but we have to have the rules before we can build it so that we're not building something that's useless to everyone.

Other questions? Yes, sir. Nothing? Okay. Well -- Oh, yes.

MS. LIZ O'BRIEN: I have one. How long does this group have to comment on these proposed revisions?

MR. MIKE WADE: Okay. Right now all three of the Orders have an extension or availability for comment through December 14th, but not for the Tribal. The Tribal has right up until we publish them final. We can take your comments and concerns any time. So the public, we'll stop theirs December 14th. And all the Tribal representatives, you have right up until we're done, all the way through.

MS. LIZ O'BRIEN: And Mike, how do they do that?

MR. MIKE WADE: One of the ways you can do that, if you want one-on-one consultations with -- contact your state office here or in New Mexico, contact your local field office, and they will work with you to help set up whatever we need to get you one-on-one consultations.

MS. LIZ O'BRIEN: Okay. I'm just going to keep going here.

MR. MIKE WADE: Go ahead.

MS. LIZ O'BRIEN: When does the BLM think they're going to wrap this up?

MR. MIKE WADE: Depending on the number of comments we receive from the public, you know, that will be one of the determining factors as to how long it will take us to process all of those. Can't give you -- can't give anybody a firm date on that. We

get a million comments, probably it would take longer than a thousand.

MS. LIZ O'BRIEN: Thank you.

MS. DARLA McMILLAN: I have one.

MR. MIKE WADE: Yes.

MS. DARLA McMILLAN: If Tribal is going to be allowed to submit comments up until time for it to be published, how is that going to affect any potential changes that we might need to make?

MR. MIKE WADE: Unknown? Then it will have to be addressed as -- if and as those occur. The Tribal's government to government is a working government to government. You always have to take those things into account when and if it happens. Just we'll have to play that by ear on that, on that question.

MR. STEVE WELLS: And if I -- Steve Wells, from the Washington Office. And so, I work with Mike. But the Tribal tribaling -- or Tribal consultation with the government to government means that's it's always open, it's always fluid. But realistically and obviously, if we send it to the Federal Register, you can provide comments and then we would have to decide whether or not was that a show stopper.

Given it was written in 1989, we don't really want to go through this right away. But these CFRs will allow us to update for industry standard changes. With that, we do feel that with the outreach that we're doing, we're getting a lot of technical comments already. We hopefully won't have any show stoppers or surprises. But we do realize that people are always in that dialogue and that people continue to work with the local offices. And that part doesn't change whether there's a rule out there or not.

But we do know that there are a lot of things that have to be updated from the '80s. So this has to be done.

And like Mike said, a lot of these comments are going to be very technical, so it will take awhile to get through. But it won't be like our fracking rule. That was tremendous public participation and a lot of digression and a lot away from what the rule really was. This is really just the nuts and bolts of doing production measurement.

So hopefully, it will be a much more narrow-focused review and analysis, but it will take time.

MR. ROBERT MARTIN: I just got a quick one

on the end-of-month inventories. And that's going to be required?

MR. MIKE WADE: Yes.

MR. ROBERT MARTIN: Is that something just to verify with the end-of-month inventory in our programs or does that have something different to do?

MR. MIKE WADE: It will aid us in overall production accountabilities and volume accountability for that. And since it's already required, as you pointed out, on the GARVS inventory. Hopefully there would not be a significant impact on any of the operators. They already have it.

MR. ROBERT MARTIN: They are doing it.

MR. MIKE WADE: They are supposed to already be recording it on ONRR. So now, it's just a matter that they would actually keep those records and we can inspect them.

MR. STEVE WELLS: Now Mike, would be there be a threshold or would that be for all records?

MR. MIKE WADE: That's for all records. All records have to be maintained and inventory is required for all Federal or Tribal production.

MR. STEVE WELLS: On all of it.

MR. MIKE WADE: Yes, sir.

MR. ROBERT MARTIN: Is that on actual

production on Tribal property or how about -- obviously in common with other offshore properties?

MR. MIKE WADE: Well, for inventory purposes, inventory that involves Federal or Indian, we have jurisdiction on it regardless of where it's located. If you have private property and that's where the tanks are physically located, but the oil is coming from Tribal or Federal, from a measurement volumes perspective the bureau has jurisdiction and responsibility on those volumes.

MS. LIZ O'BRIEN: Mike, do you have an e-mail address for comments?

MR. MIKE WADE: Yes. Those E-mail addresses for all additional comments and stuff, Rich will point those out on the last slide, I believe.

MR. RICH ESTABROOK: Yes.

MR. MIKE WADE: We have all that available on the last slide to make sure there's additional contact information available that identifies us. If you need to or want some one-on-one consultation. Contact the local state office or field office and work with them and then we'll work with you to make the necessary arrangements to get what you need for one-on-one consultations.

Okay. I guess I can turn it over to Mike

McLaren.

MR. MIKE McLAREN: I'm Mike McLaren. I am talking about what we are proposing for the technical changes for the new Proposed 3174 regulations.

So, as Rich stated, the current Onshore Order 4 has no performance. And as stated, it's a cookbook. You're either going to manual tank gauge or you're going to use a Lease Automatic Custody Transfer System.

So we're proposing three tiers of performance standards, uncertainty levels. So if you're producing and you're measuring more than 10,000 barrels a month, we're proposing an uncertainty of plus or minus .35 percent. If you're middle tier, if you're between 100 barrels a month, less than that 10,000 barrels, we're proposing a plus or minus 1 percent uncertainty measurement. And then for the very low, 100 barrels or less than 100 barrels a month, plus or minus 2.5 percent.

And where we get these from, that plus or minus .35 percent is based on an uncertainty analysis using a LACT System, with a positive displacement meter in the current Onshore Order 4.

The middle, the plus or minus 1 percent, is based on the uncertainty analysis of manual tank

gauging on a 400 barrel tank and that oil's removal was approximately 250, 300 barrels out of that tank, a typical load out.

And then the lower 2.5 percent is manual tank gauging, pulling 40 barrels out of a 100 barrel tank, any low volume.

In the current Onshore Order 4, it references industry standards that were in place in 1989. Okay? We're proposing to incorporate 21 current industry standards into -- the ASTM Standards, the Tables 5A, 6A.

Currently the Onshore Order 4 requires a pressure-vacuum thief hatch or a vent line valve for tanks. We're expanding on that a little bit. And we need a pressure vacuum thief hatch, but we're requiring the relief valve, vent line valve standards and where we're wanting it. And we're very explicitly stating there the condition we want on these things. We want a pressure vacuum and integrity on the tanks.

So it's kind of implied in Order 4, the equipment is there. It's kind of implying you're maintaining a pressure vacuum, but it doesn't state it. So we're stating the condition we want these tanks to stay in.

The current Order 4, it's very random in the tank gauging section. It did list the requirements you needed to do, but it doesn't give you the proper order or sequence of events to do it. So we're proposing the sequence of events for the manual tank gauging. And we're still including the requirements for each one of those sequences. And this is based off of the API 18.1 Standard, the sequence that's in there.

The current Order 4, it requires two consecutive gauges within 1/4th inch. We're adopting the current API 3.1A standard of two consecutive identical gauges or three gauges within 1/8th inch.

The current Order 4 requires the tank calibrations tables, but no instruments specified. We're taking that requirement and expanding it to proposing to break it down from 1/4 inch to 1/8th inch increments to match the gauging standard in 3.1A.

The current Order 4, the LACT Systems, it requires a Automatic Temperature or a Temperature Gravity Compensator. It only allows the use of a Positive Displacement Meter, a PD meter. What we're proposing is to prohibit the Automatic Temperature Compensator, the Temperature Gravity Compensators and require the Electronic Temperature Averager. And we are now proposing to allow the Coriolis meter in lieu of PD meterd. We propose to use it.

And we're -- we want to prohibit the Automatic Temperature Compensators is, it adjusts and corrects for the temperature at the totalizer. So that totalizer is already a corrected volume. And we have no -- we had no raw data. We can't verify that totalizer, that it automatically corrected it, properly corrected it. So we need some raw data to do our verifications.

The current Order 4, it allows manual tank gauging or the measurement through the Lease Automatic Custody Transfer System. But that's it. So we still have the manual tank gauging allowed. We still have the Lease Automatic Custody Transfer, but we also have a section in there to allow stand-alone Coriolis Measurement Systems. And we've added some proposed requirements for the Coriolis Measurement System.

We're going to retain the same 8400 pulse per barrel that the LACT Systems have now. We have specifications for the Coriolis meter, including the referenced accuracies, influence effects, stability of the meter, the fluid, the pressure drop. Again,

we want a non-resettable totalizer that the standard PD meter has now and the LACT system.

Again proving, we want to identify that the meter zeroed before proving. It's a process on the Coriolis where you stop flow through it and assure that it's recording zero flow.

We want the Coriolis to -- through the tertiary device to determine the net standard volume. It has that capability.

We have two proposals in there for determining the API gravity, whether it be from the Coriolis itself determining an average gravity through the flow, through the monthly run ticket period, or a composite sampler and do the conventional determination that way.

We have some on-site display requirements of the raw data that we need; pressure, temperature, and whatnot. And we had the requirements for our audit trail there; Quantity Transaction Records, configuration log, event log and alarm logs.

Currently in Order 4 the requirements for the LACT proving is -- it's equal or greater than 100,000 barrels, proved monthly or quarterly. We took a look at that, and what we're proposing is for a LACT system or Coriolis Measurement System to prove

every 50,000 barrels on the totalizer, or quarterly, whichever would come first.

And we had a 50,000 barrel run and we did a statistical analysis. At what volume would the cost to prove equal the potential overpayment or underpayment on royalty due to meter factor changes, and that 50,000 barrel is the number that that worked out with, using an average proving cost of $550.

The current Order 4 in the proving section, it has no standards for prover sizing, no standards for the fluid flowing conditions that you're proving, and it has no standards for the minimum number of pulse generated on a proving run.

So we're proposing the minimum/maximum fluid velocity to be used for prover sizing, we're stating a normal flow, pressure, gravity. We want to prove at normal conditions. In there we've proposed it to define what's normal. Basically we proposed 10 percent of a normal pressure, 10 percent of a flow rate and plus or minus 5 degrees of API gravity.

Let's say you're using a small volume prover, it's not going to generate 10,000 pulses, it's going to generate a couple thousand pulses. So if you're generating less than 10,000 pulses, we're going to do compulsory pulse interpolation.

Measurement tickets. There is no current requirement for a measurement ticket for a LACT system, only for the manual tank gauging.

We're proposing to generate a measurement ticket after proving and at the end of every month for a LACT system or a Coriolis measurement system.

Kind of winding this down for the oil measurement. In the Preamble discussion, we're specifically asking for data, numbers. Our three tiers of uncertainty, are those reasonable? And we're hoping if someone has a different number, they are going to submit an analysis, a justification why a different number would be good.

We're asking for data, field data, test data on the automatic tank gauging, sort of a hybrid tank measurement system.

The proposal for the composite sampling system on a Coriolis meter. What we're proposing for the standard water deduction, if you don't have a composite sampling system, we would say you would not make a sediment water deduction from the volume. How would you determine the sediment water if you didn't take a sample and do it like that. So we're asking for data from people, is that a good approach.

You know, say would it be up to the operator to decide, do you want to buy a composite sampling system to take that sediment water deduction or do you want to not spend that money and record zero, not take a deduction. We're asking for input on that approach.

We're asking for ways to effect a Meter Factor Determination. If you have variable flow rate, fluctuating pressures, temperatures, what's the best way to address that. Would it be an average meter factor proving it in different conditions? Would it be a dynamic meter factor where you would have a calculation where a flow computer would automatically trip and change that meter factor based on the flowing conditions? We're looking for some input on that.

And that is technical changes we're proposing for the oil measurement. Do you guys have questions?

MS. MELISSA PEROS: The industry standards that you're incorporating, are you incorporating them by reference?

MR. MIKE McLAREN: Yes.

MS. MELISSA PEROS: Or are you incorporating them by -- by reference. Okay. By reference.

MR. MIKE McLAREN: We are incorporating them by reference.

MS. MELISSA PEROS: Do you intend in the future, should they change, to change that to incorporate the new ones by reference?

MR. MIKE McLAREN: Yes.

MR. RICH ESTABROOK: Yes. That's what we're hoping. Part of that Production Measurement Team, part of its responsibilities would be to constantly monitor. We do intend to give you a guide, the working committees, in the spring and the fall, so we know what they're work on. We sit in on the working groups. And that is the intent, that it will be dynamic. As they change those, we'll go back and look at the changes to say do we want to incorporate these changes.

MS. MELISSA PEROS: Thank you.

MR. MIKE McLAREN: Okay. Thank you. With that, I will turn it back to Rich.

MR. RICH ESTABROOK: Okay. Let me ask a question before I wrap this up. How we are doing on time? Are we all right?

MS. LIZ O'BRIEN: I think we would like to take a break, a 10 minute break.

MR. RICH ESTABROOK: Good.

MS. LIZ O'BRIEN: Is that okay?

MR. RICH ESTABROOK: Yeah. It is good for me actually.

(A break was had, after which the following:)

MS. LIZ O'BRIEN: Rich, you're up.

MR. RICH ESTABROOK: Okay. The last thing that we have prepared is a discussion over the proposed changes to the Gas Measurement Regulation, Subpart 3175.

MS. LIZ O'BRIEN: Rich, can you pull up -- speak up just a little bit?

MR. RICH ESTABROOK: Okay.

MS. LIZ O'BRIEN: Thank you.

MR. RICH ESTABROOK: Existing Onshore Order 5 only addresses orifice plates and old mechanical chart recorders. And the mechanical chart recorders first came out in 1917, and they have been around for a long, long time.

We address Electronic Gas Measurement Systems through individual notices to lessees that are unique to each jurisdictional state. So, for example, Oklahoma is under the jurisdiction of the New Mexico State Office. So, the New Mexico State Office has a notice to lessees that addresses

Electronic Gas Measurement Systems, which I believe is NTL 2008-01. And each -- each -- Colorado has their own NTL, Montana has theirs, California has theirs, they're all -- they're all identical except for Wyoming.

In the Proposed 3175, we would maintain orifice plates as our primary measurement device for gas. We like orifice plates, because they give a reasonable level of accuracy. They have been thoroughly tested and vetted for decades and they provide the ability for the BLM to independently verify them from beginning to end.

Proposed 3175 would also approve mechanical recorders, just like Order 4 does -- or Order 5 does currently, with some restrictions that we'll talk about.

3175 would approve Electronic Gas Measurement systems, basically incorporating a lot of the provisions of the statewide notices to lessees. And it would also give specific guidance for alternate measurement and flow conditioners.

Order 5, just like Order 4, has -- is a cookbook. It has no specific stated performance goals. It does have three tiers of requirements that kind of gets to that idea of tiering things based on volume or flow rate, and I have a little graphic in my next slide.

Proposed 3175 would establish four tiers of performance standards based on flow rate.

So, this is Order 5. This is the existing Onshore Order. Here on the Y axis is the average monthly flow rate in Mcf per day. If you're above -- if your meters measures more than 200 Mcf per day on a monthly basis, then all 26 requirements in Onshore Order 5 are in effect. If you're flowing less than 200 Mcf per day, you no longer have to have a continuous temperature recorder. And if you're less than 100 Mcf per day, you no longer have to operate your Deferential Pressure pen in the outer two-thirds of the chart and you no longer have to comply with our Beta ratio limits, which are .1 to .7 -- .15 to .7.

The Proposed 3175 would expand on this concept and have four different tiers of -- four different categories based on average monthly flow, and we would have a name for each of these categories. If you're flowing more than 1,000 Mcf per day, then that would be called a "Very High Volume" FMP, Facility Measurement Point.

If you're flowing between 100 and 1,000 Mcf

per day, or if that's what the meter is measuring, that would be called a "High Volume" FMP. If you're flowing 15 to 100 Mcf per day, that would be a "Low Volume" FMP, and meters measuring less than 15 Mcf per day would be called a "Marginal Volume" FMP.

Now the idea with this categorization, and I will go through what the significance of this is in a second here. But the idea is that for Very High Volume FMPs, measuring a lot of volumes, there's a lot of royalty being generated by that meter. We're going to have very tight restrictions on that meter to make sure that it is operating very accurately, because any errors in measurement from a high volume meter have a very significant effect on royalty.

Those tight restrictions, however, come with a price tag. And what we would propose is, as we go down in volume, the risk of mismeasurement and its effect on royalty is decreased. And so, we're proposing these tiers to give some -- the operator some economic relief, so they don't have to meet the really tight restrictions for the Low Volume or the Marginal Volume FMPs.

So, our proposed performance goals in 3175 include uncertainty or accuracy for both volume and heating value, bias and this last, very important

category, which is verifiability. One of the most important things for us is not only accurate measurement, but verifiable measurement. So whatever meter we choose or approve must be independently verifiable by the BLM. We have to be able to verify from beginning to end that the volumes measured by that FMP, by that meter, accurately represents what actually flowed through that meter.

So for Very High Volume FMPs, we are proposing a Volume Uncertainty or Accuracy of plus or minus 2 percent, a heating -- H-V is Heating Value, a Heating Value Uncertainty of plus or minus 1 percent. We would not allow any statistically significant bias in that meter, and the meter would have to be completely, independently verifiable by us. Orifice plate meters can achieve that.

If someone were to suggest an alternate meter design, and it would show it to the Production Measurement Team, these are the criteria that the Production Measurement Team would be using to assess that meter and whether or not it's applicable or usable on Federal and Tribal leases.

For High Volume FMPs, the Volume Uncertainty would be reduced a little bit to plus or minus 3 percent, a little less restrictive. Heating Value

Uncertainty would be reduced or increased, however you want to look at it, to plus or minus 2 percent. Again, a little less restrictive. Again, we would still not allow any statistically significant bias in that meter, and it would still have to be verifiable.

For Low Volume FMPs, we would not have an Uncertainty requirement or Accuracy requirement. We would still require no statistically significant bias and we would still require verifiability.

And finally, for Marginal Volume Wells, less than 15 Mcf per day, there would be no Uncertainty requirements, there would be no bias requirements, but we would still require the measurement to be verifiable, independently verifiable by the BLM.

Order 5, this gets back to the industry standards. Order 5 adopts AGA Report No. 3, one and only industry standard. The AGA, that's American Gas Association, Report No. 3, the 1985 version, which deals with a primary device, orifice plates, and flow rate calculations.

Now, one of the problems with adopting such an old standard, 1985, is this has been updated numerous times since 1985 for good reason. For example, in AGA Report No. 3 (1985) there is a thing called a tube bundle, tube bundle or straightening vane that you put upstream with an orifice plate sometimes to help -- to help even that flow out to make the flow uniform going through the orifice meters to get better measurement. The placement of that straightening vane is actually really important.

1985 AGA Report No. 3 was based on some very old data. So if we put that straightening vane where AGA Report No. 3 (1985) tells them to put it, new data suggests, data done -- data recorded after 1985 suggests, that that's actually going to bias the measurement by 1 or 2 percent.

So in this example, our -- right now we can only enforce this version, 1985. So for straightening vane placement, we're actually enforcing bias on measurement, because we're requiring operators to put that in the exact place where they shouldn't put it, based on the data.

In the Proposed 3175, we'd be adopting new API, American Petroleum Institute, and GPA, Gas Processors Association, standards covering the primary device, orifice plates, covering Electronic Gas Measurement Systems, covering flow rate, volumes, and heating value calculations, and covering gas sampling and analysis.

Current Order 5 has no inspection

requirements for meter tubes. Meter tubes are the straight lengths of pipe upstream and downstream of a orifice meter. API recommendations are very strict about meter tubes, because if that meter tube has got scale build up, or is out of round, or if it's got a lot of rust, it's going to affect the measurement accuracy. And because it does affect measurement accuracy, we feel that they ought to be inspected now and then. Current practice is to never inspect these. Most meter tubes that I'm aware of have never been inspected for the life of the well.

The frequency of meter tube inspection would be depending -- would depend on the classification of that meter; the Very High, High, Low and Marginal.

Marginal Volume FMPs, we would still never require an inspection. The assumption here, these meters are measuring such low volumes that any additional cost would basically make them uneconomic.

Low Volume FMPs, 15 to 100 Mcf per day, a visual inspection would be required once every five years. A visual inspection can be done with a device called a bore scope. The ones I'm familiar with, they are a fiber optic device. You can run them down through a pressure tap and look through a little view finder and actually look inside of the 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 ten years. A detailed inspection would require complete disassembly of that meter tube, going in with a micrometer and miking all the dimensions looking for scale, looking for surface roughness issues, and making sure that it complies with all the standards in API.

Very High Volume FMPs would be once every year for visual inspection and once every five years for a detailed inspection.

Of course, if a visual inspection on any one of these categories showed that there was something wrong in that meter tube, there's excessive scale build up, there was some damage, it could kick it in to require a detailed inspection to fix that problem. Given consistently very few requirements for these Low Volume wells, and the requirements tighten up as the volume goes up because of the risk of mismeasurement is much more significant to royalty.

In Order 5, mechanical recorders, the old chart recorders are automatically approved. That's the only thing that's automatically approved.

In Proposed 3175, the mechanical recorders

would be restricted to only those meters flowing less than 100 Mcf a day. And the reason is, because the accuracy or performance of a mechanical recorder is really not very well defined. And if you can't define the accuracy or performance of a meter there is no way that you could even do an uncertainty or accuracy determination, which is required. Uncertainty and accuracy is required for higher volume meters.

I talked about this one at the opening. Currently under Order 5 there's one and only one requirement for heating value, heating value which has an equal impact on royalty as volume. And that one and only one requirement is that the BTU, the British Thermal Unit value of that gas, has to be determined at least once per year and that's it. We have no requirements currently on how you sample that gas, where you sample that gas, how you analyze that gas, or how you report that gas. This is a huge shortcoming in Onshore Order 5. And this was pointed out in every single one of those reports, the Royalty Policy Committee, OIG and GAO reports.

So, we're proposing to increase our requirements for heating value determination significantly in 3175. I'll start with sampling

frequency.
The sampling frequency would be changed as follows: For Marginal Volume FMPs, we would not change it. It would still be just once per year. For Low Volume FMPs, it would be twice per year, once every six months would be a fixed sampling frequency.
For High Volume FMPs and Very High Volume FMPs, we're proposing something a little bit radical. For High Volume FMPs there would be an initial sampling frequency of once every three months. But, once we get enough samples to do some statistical analysis, which is usually about five samples, we would look at how variable that heating value is from sample to sample. If that heating value is very consistent from sample to sample, that means basically that there's very -- there is little going on. You have good accuracy from that heating value. You can actually reduce the sampling frequency in that case to once every six months, for example.
However, if that -- those five samples, those previous samples, we do a statistical analysis and that heating value is all over the place, which it is quite often, there is something going on there. The accuracy of that is not good. So in that case, we could require an increased sampling frequency to

compensate for that variability. Up to weekly samples, if that was required, to achieve our overall heating value uncertainty requirement of 2 percent.
The same thought process would hold for Very High Volume FMPs. There would be an initial sampling frequency of once every month. Based on historical heating values that we get from those samples, we could then adjust that sampling frequency to meet an overall heating value uncertainty goal plus or minus 1 percent. We could adjust it up or we could adjust it down based on how scattered those values are.
Kind of continuing, there's a possibility that in some meters the heating value varies so greatly that even weekly sampling is not going to be enough to meet that plus or minus 2 percent or plus or minus 1 percent uncertainty limit. In that case, we could require that a composite sampling system or online gas chromatograph would be required and that would take care of that variability.
Also, we're proposing a new database called GARVS, Gas Analysis Reporting and Verification System. All gas samples used for whatever determination would have to be entered into that database. They could be key entered or they could be downloaded from another electronic system, like

Flow-Cal or something. The GARVS system would be maintaining and storing all the compositional analysis from each sample and it would also be used for the statistical analysis to figure out how frequently they have to sample to meet the uncertainty requirements.
Currently Order 5 has no requirements for a sample location or method. It has no requirements for gas chromatographs. A gas chromatograph is a thing that is used to analyze that sample to figure out what components are there; methane, ethane, propane, butane and all of that.
Proposed 3175 would require the sample probe to be located 1 to 2 times dimension "DL" downstream of the primary device. Dimension "DL" is the minimum required straight length of meter tube downstream of the orifice plate in the API, API standards.
So, for example, if you go into the table on the API standard and dimension "DL" is 8 inches, which means you would have to be a minimum of 8 inches of a straight meter tube downstream of the orifice plate, the sampling probe would have to be located between 8 inches and 16 inches downstream of the orifice plate.

Now this is just a proposal. And this is one of the things that we're asking for data on. This is kind of out there, because this actually goes against API and GPA standards where orifice sample probes should be located.
But the issue is this: API and GPA standards are all based on sampling perfectly -- perfectly clean gas with no liquids in it whatsoever. And the reality is, we don't have that situation very often. The reality is, we have some liquids going through our orifice meter, which you're not supposed to have, but there is no way to avoid it in many cases, especially at lease level measurement. When you have that situation and you put your sample probe way down far from the orifice plate or at another location, we have other standards as well, you're not going to get those -- you're not going to see those liquids getting into your sample and they will be unaccounted for.
The goal, the thought process here, is that by placing the sampling probe really close to the orifice plate, as gas goes through that orifice plate and accelerates and becomes very turbulent, our thought process is that any little droplets of liquid that are sitting on the pipe wall or somewhere else

are going to get picked up and that high velocity, turbulent flow can actually be picked up by that sample probe. The gas sample then will be able to account for those liquids that are flowing through the meter that are currently unaccounted for.

We would allow four spot sampling methods: The fill and empty method, the helium pop method, the floating piston method, and portable gas chromatograph.

We would include requirements for the calibration and operation of the gas chromatographs. Also, we would require a more detailed gas analysis, the C9+, that is nonane plus, if the C6+ plus analysis was greater than 0.25 mole percent. Does that make any sense whatsoever?

I will explain quickly. What you do, a gas chromatograph breaks the gas and organizes it by -- well, gas is methane, ethane, propane, butane, pentane and heptanes, hexanes and so on. Now, the gas chromatograph organizes and sorts those molecules out and it figures out how much of each molecule is in that gas sample.

So a normal C6 analysis is the standard industry term. In C6 analysis it can identify specifically, there's little -- it's all done

graphically, and there is little peaks that show up for different components. So that the normal analysis picks up the C1, C2, C3, C4, C5 very easily, there is a little peak for each one. Anything greater than hexane just comes out as one big blob. So if that big blob is greater than .25 mole percent, which is starting to get significant here, then you will be required additional analysis that would separate out hexane, heptane, octane, nonane and get a more accurate sample.

Order 5 has no requirements for BTU reporting. Proposed 3175 would. And this one is somewhat significant.

There are a bunch of different ways you can report BTUs. You can report BTUs as gross or net, you can report them as real or ideal, you can report them as dry or wet or as-delivered, you can report them to one of at least four different pressure bases. And I think if you multiply that out from a single gas sample, you can come up with as many as 60 different BTU values for that single gas sample. Which one do we use?

Right now, we have no requirements. The operator can use whatever they want to. If they want to use the one that gave them the lowest value, they

could use that one and we would have no enforcement.

We are going to define which conditions they report under; gross, real, dry, which is a significant one and highly controversial, 14.73 at 60 degrees Fahrenheit.

I'll just mention this one a little bit. Dry, wet and as-delivered have to do with how much water vapor is assumed -- assumed to be present in that gas sample. Water vapor doesn't burn and it takes up space. So the more assumed water vapor you have in a sample, the lower your heating value is.

It is still fairly common industry practice to report BTUs on the wet basis. Without going into too much detail, if they’re reporting BTU values on a wet basis, they're assuming that that gas sample is saturated with water vapor at 14.73 psi and 60 degrees Fahrenheit. If your meter happens to operating more -- at a higher pressure than atmospheric pressure, which most meters do, not all, they are deducting -- they are reducing the heating value for water vapor that cannot physically exist at that meter. You and us are getting underpaid. And this is common practice still. So we -- we believe this one is horrible and we're proposing never to accept a wet value.

Order 5 and the statewide notice to lessees for electronic flow meters have no requirements for independent testing of transducers or flow computers. All transducers and flow computers are accepted. The notice to lessees in New Mexico, it's in NTL 2008-1, does have an uncertainty requirement and accuracy requirement. The BLM has developed a tool which makes it fairly easy for our inspectors to enforce that uncertainty requirement. However, built into that tool -- I should say the transducers especially have a heavy effect on that uncertainty calculation. The accuracy of those transducers is critically important to the uncertainty of that, the accuracy of that meter.

The BLM calculation tool that we use right now uses the manufacturer’s-stated specifications for accuracy as the basis of the calculation. However, the manufacture's process for establishing those performance standards is basically unknown. Most manufacturers have a proprietary method of determining uncertainty or performance of their transducer. It's not transparent, it's not public. We don’t really know what some of the numbers even mean or how they were determined.

What we’re proposing is requiring any

transducer used on High or Very High Volume wells and any flow computer used on a High or Very High Volume FMP, I should say, would have to go through a defined testing protocol, be publicly available, it's right in the proposed reg, transparent testing protocol.

The Production Measurement Team, that we talked about earlier, would be reviewing the test results from those transducer and flow computer testing and developing a list of approved devices.

Now, this would be done on a one-time basis. So if an operator, for example, submitted a transducer, a Fisher MVS205, for example, to the PMT -- they went through the testing protocol and the results of this testing protocol were sent to this Production Measurement Team, the Production Measurement Team will look at the results and, if they thought it looked good, after their review it would go on a list of approved equipment.

Once it's on that list, no one else has to do it. Once it's on that list, it's available for everybody to use. And that would be how it would work for all the devices at the PMT. The PMT would review it, one time shot.

Just to wrap up then, as with 3173 and 3174, the Preamble contains specific requests for data and

comments. And the reason we do this is because for these things on the list, and this applies to 3173 and 3174, we are kind of putting stuff out there that we just think it might be a good idea that we would like to try, but we don't have a lot of information on it.

So, for example, in 3175, we would like some information about how much it's going to cost industry to do those testing protocols on the transducers. We don't have a good -- a good handle on what that costs. So we're specifically asking for comments on that.

We're asking for comments on whether five transducers constitutes a statistically representative sample. You can't just -- in my opinion, you can't just take one random transducer and send it through testing and base all your specs on that one transducer. It could be your -- it could be a high-graded one, it could be a really good one that performs really well. It could be a horrible one that doesn't perform. So we're proposing that the testing protocol would have to be done on five randomly selected transducers off the assembly line. Is that good? Looking for comments.

There is very little information out there,

requirements or standards, for these on-line gas chromatographs. We're looking for data and comments on what standards, if any, we should incorporate.

For example, API just published API 22.6, which is a testing protocol for gas chromatographs. We should be able to incorporate that.

Data showing the water vapor saturation, this gets back to that dry, wet, as-delivered issue. There is another -- another water vapor saturation assumption that I didn't go into in much detail. There is dry, which means there is no water vapor, you're assuming no water vapor, water vapor can't be detected by gas chromatographs. I believe that is why you have to assume something.

Dry equals no water vapor, wet means it's ridiculous, physically impossible value that we would reject. The third one is the as-delivered, which is an assumption that the gas is saturated with water vapor at meter pressure or temperature, it's physically possible.

If you do a dry heating value, you're assuming no water vapor. If you're doing this as-delivered, you're assuming it's saturated. But the truth probably lies somewhere between those. Those are the two end points. The truth probably

lies somewhere between those.

We don't believe tribes or the public should get any value reductions for assumptions of water vapor. We believe that's why we want the dry. That's the highest heating value you can have.

If industry wants to use that as-delivered number, which will lower your heating value and your royalty a little bit, not as much as wet, but a little bit, we want some data to show that that's a legitimate assumption. And so, we're asking industry for that data. We actually have some already that has some very interesting results.

Data showing correlation between sampling probe placement and composition. This gets back to our proposal for the one to two times downstream, the DL length. We'll just throw that out there. That's based on not much. That's based on hearing some discussions at API meetings.

For example, at one API meeting there was a discussion where it was actually a V-Cone meter, not a orifice plate, but they were taking gas samples fairly far downstream of the orifice plate meter and getting a one BTU value, or downstream of that V-Cone. As they took samples closer and closer to that V-Cone the BTU value was climbing substantially.

But I haven't seen any published data on this, so we're looking for that.

The cost of retrofitting orifice meters to meet the eccentricity requirements, that's -- again that was something we didn't have a good handle on.

Chart integration companies, we are proposing that they would have to go from a 1985 calculation to the latest calculations for volume and flow rate. Chart integration companies have been around for decades and we don't know what the economic impacts would be, if any, on those chart -- on the few remaining chart integration companies. So we're looking for data on that.

I talked about the C6 and the C9+. We're looking for data on whether the .25 mole percent is a good threshold.

And finally, we're looking for ways in which clean sample cylinders can be sealed. API requires that when you go out to take a sample the cylinder has to be -- go through all this rigorous cleaning and steam cleaning and process. But the thing that occurred to us is how does the inspector looking at this operation know that -- know that that had just be cleaned and not been contaminated somehow. So we're looking at ways to seal that so that when you

open it, however you open it, you break some kind of a seal.

And that's -- that's all I had. I am totally open to questions. Just for your information though, this is a -- this is a site where you can submit comments. Regulations.gov is also other information here. There's our Economic Analysis is there, our Environmental Assessment is there. For 3175 there is a Heating Value Variability Study there on which our heating value or gas sampling requirements are based on that.

These PowerPoints will be available and posted at this site here. You can also mail comments.

Any questions on 3175? I know it's really -- I know it's really technical.

MR. LEGION BRUMLEY: I have got a question, Rich, on the production team. How do you envision that team? Going to be a group of individuals together working on the variances, or is it going to be individuals across the nation working on it independently and then coming together and trying to coordinate that decision?

MR. RICH ESTABROOK: I'm not -- that's a great question we haven't really resolved yet.

To me -- to me the Production Measurement Team would have to be a permanent, full-time team, because I think the workload, especially initially, is going to be huge. Now, you know, relocating people is problematic for a number of reasons. So I don't know logistically how we would do it. But I think we would need a dedicated team of two or three people to work on this stuff and pretty much nothing else.

MR. STEVE WITTER: You talked about collecting all the gas analysis into a new data base. Is that going to be under BLM or under ONRR? And will it be initiated --

MR. RICH ESTABROOK: It would be under that and available to ONRR, is what we're proposing.

Any other questions?

Liz or Karen, do you want to --

MS. LIZ O'BRIEN: Is there -- is there a phone number where, if anybody has any questions after they go back and talk to constituencies, is there a live person to talk to somewhere?

MR. RICH ESTABROOK: Yes. In fact, each subpart has a contact person in it.

MS. LIZ O'BRIEN: And that's on the website?

MR. RICH ESTABROOK: It is on -- it's in the

regulation itself. If you go to regulations.gov, you can pull up the actual Federal Register notice and the contact information there. The contacts are sitting right here, by the way.

MS. LIZ O'BRIEN: Perfect.

MS. KAREN MOURITSEN: Their phone numbers are right on that first page of the Federal Register notice for each of these. I just looked at them.

MS. LIZ O'BRIEN: Karen.

MS. KAREN MOURITSEN: Okay. Well, thank you all for coming and for the good questions. And I'd just say it again, we really hope that you will go back and think about these things and give us any comments, especially in the areas where they noted we particularly need comments. But really, anywhere else, any other aspects of it. So, please, do. We need the comments. We need the input.

And these questions were good here, too, also. So, feel free to come and listen to this again at 1:00 o'clock, if you want. You're welcome to do that.

(Morning session ended.)

PROPOSED REVISIONS OF ONSHORE ORDERS 3, 4, AND 5

PERTAINING TO OIL AND GAS
PUBLIC MEETING FOR ALL STAKEHOLDERS
DECEMBER 3, 2015 - 1:00 P.M.

MS. LIZ O'BRIEN: Good afternoon. What a gorgeous day in Oklahoma City. Whoa. This is the warmest I have been in, I don't know, two weeks.

My name --

CONFERENCE OPERATOR: This is the operator. Did you want to begin?

MS. KAREN MOURITSEN: Yes. Yes, we are ready to begin the meeting.

MS. LIZ O'BRIEN: All right. We're having a little phone-in issue. We have got some people who couldn't make it today, who, after everybody in the room has spoken, we're going to take phone-in calls. So that's what we're trying to organize now and I have no idea how to do it. So there you go.

Anyway, my name is Liz O'Brien. I'm the facilitator for today. I'm an independent contractor. I do not work for anybody anywhere anyhow.

So we have experts that can deal with all your questions and issues and why the changes to the current rules. We've got plenty of people in the

room to help you out with that.

We're going to take a break. It's going to, you know, if you need a break, wave to me. Otherwise, I will decide when it is. It will be about halfway through the afternoon and it's only going to be about 10 minutes.

There is going -- this is going to be repeated about ten times this afternoon, and that is that the cutoff for comments on these particular rules is December 14th. It's been extended. My understanding is it's been extended a couple of times before, but this is a pretty firm date. So if you don't want to speak today, you know, if you have public-speaking fear, just send your comments and we're going to give you addresses and e-mails and ways to do it and people to call. So there's several different ways to do this.

Does anybody have any questions before we begin? If it is a technical question, you don't need me. Anybody have any questions before we start?

Okay. Are we -- is Sheila doing this, Karen, or are you?

MS. KAREN MOURITSEN: Well, I will start. Okay. Hello, everyone and thank you for coming. Is this -- Am I talking holding it close enough?

My name is Karen Mouritsen. I'm the Deputy Assistant Director for Energy, Minerals and Realty Management for the Bureau of Land Management in our Washington Office. And so, I work in an office where we work on policies, such as this one. So I really thank you all for coming.

I'd like to introduce the BLM people who are here, and then we'll get started here. To -- let's see, some of the people from our Washington Office that are here are Steve Wells, who is the Division Chief for our Fluid Minerals Group, our Oil and Gas Group in the Washington Office. Dylan Fuge, who is a Senior Advisor to our Director in our Washington Office. And our experts here, who are going to talk to you about this rule, Mike Wade, who works in our Inspections Program, Mike McLaren, who is a petroleum engineer; and Rich Estabrook, a petroleum engineer for our office.

So thank you all for being here. And as you know, we want -- we have put out these draft regulations on oil and gas measurement and we want your comments. We want your comments on the regulatory text. As they go through the presentation, they're going to point out some areas, some very specific things that we would like comments

on from you all. But we want comments, you know, on anything really. Even, you know, the specific things and anything else.

There is a -- the Preamble, the explanatory section of these regs, we'd like your comments on. We have an Environmental Analysis. There's also a document called the Regulatory Impact Analysis that goes through the costs that we think these regulations will cost to implement them, both the costs for the government to implement and the cost for producers to implement. And so, that's on the websites and described in the Federal Register notice. So we'd like your comments on that, if you have ideas on how we calculated those costs or think we need additional information.

And as our facilitator said, December 14th is our comments due. The Federal Register notices and the press release all have the places where you can send your comments in. The Federal Register notices also have these guys' names and phone numbers, if you want to contact them for more information. So, you know, there's is lots of ways you can get your information to us.

I did just want to introduce why we're here. Probably you all know this. But these regulations were last written or were written in 1989, I think it was. As they're going to point out, there are some parts of them that are pretty out of date. The technology has changed. The referencing things, standards, are out of date. So that's one reason we're doing this.

We have also had a number of groups do audits of these regulations in our program, which Rich will talk about a little bit, but they have all said, look, BLM, you need to revise these regulations.

And we really want to ensure that we're adequately accounting for the volumes of oil and gas, and that goes to the revenue, it goes to the royalties we collect, and it's so the Government and the Tribes get the proper amount of royalty, but it's also -- you know, it could go both ways. So we don't want the producers paying more than they owe either. So it's for everyone's benefit to measure this accurately.

Our court reporter is just taking down everything so that we can make sure we capture everything you all say. And we'll look at that as we look at the other comments, everything she gives us.

So and then, after the 14th when we get

these comments, we'll look at everything, and we really want to look at these comments, as I said, and try to figure out if we need to make any changes to our proposed reg and, you know, if so, what they'll be.

And we're just going to move forward as quickly as we can to work through that, but I don't have a exact date. It will depend on how many comments we get.

So, I think that's about all the introduction. And shall we just -- you want to start, Rich?

MR. RICH ESTABROOK: Sure. Okay.

Well, thank you. Again, my name is Rich Estabrook and I'm going to do part of the presentation here today.

So, this is the presentation outline. I'm going to go through why these regulations are important, I'm going to talk about why we are revising these Onshore Orders, then I'm going to cover changes that affect all three orders or proposed modifications of the orders, and a new Proposed Regulatory Part 3170.

I will then turn it over to Mike Wade, who will talk about the specific proposed changes to

3173, which will replace Onshore Order 3.

Mike McLaren will then talk about 3174, which will replace the Onshore Order 4, the Oil Measurement.

I will round out the presentation discussing Subpart 3175, which will replace Onshore Order 5 for Gas Measurement.

MR. STEVE WELLS: Hey, Rich, would you keep it a little closer so they can hear?

MR. RICH ESTABROOK: Okay. Is that better?

MS. KAREN MOURITSEN: No.

MR. STEVE WELLS: Keep talking.

MR. RICH ESTABROOK: Hello. Testing.

The way we have this organized -- maybe I can get the other mike.

MS. LIZ O'BRIEN: Try the other mike.

MR. STEVE WELLS: That doesn't sound like it's working.

MR. RICH ESTABROOK: How about this? All right.

The way we have the presentation or the day organized is that we're going to get all the presentations out of the way right up front, and then the rest of the afternoon is your guys' comment and ask for questions for clarity. So I hope that works

out okay.

For the one in Durango, we ended up taking a break after the end of our presentation. We'll just kind of see how it goes. So with that, let me just kind of jump into this.

Why are these regulations important. And I think this is going to be information that you all know very well, but I just thought I would throw up some equations here, kind of start with equations.

Royalty on oil is calculated by taking the royalty rate on a lease -- which is usually a fixed number set in the lease terms. Twelve and a half percent is very common for Federal leases -- multiplying that by the volume of the oil removed from a lease in a given month, and then multiplying that by the dollar value of the oil, and you multiply those three things together and you get the royalty that's due for that lease for that month.

One of the things that goes into the calculation of value is the API gravity or the oil quality. It's not a direct multiplier in the royalty calculation, but it does affect the value.

Now the royalty rate is set in the lease terms and it has nothing to do with Onshore Orders 4 and 5 or 3, 4 and 5, and I'm not going to be talking about that aspect of the royalty formula today.

The dollar value of the oil is established by the Office of Natural Resources Revenue. It's not our agency that does that, it's a different agency within did the Department of Interior that establishes the dollar value of the oil.

Onshore Order 4, and to some degree Onshore Order 3, has a direct bearing on the accuracy of measurement of oil volume and the proper reporting of oil volume. So the proposed changes to Onshore Orders 4 and 3 will have a direct impact on the accuracy and reporting of the volume of oil on which the royalty is due. Onshore Order 4 also impacts the determination and reporting of oil quality, the API gravity.

For gas, the equation is similar. Royalty is the royalty rate on the lease, times the volume of gas removed from that lease in a given month, times the heating value of that gas, times the dollar value. Again, royalty rate is established under the lease terms. It has nothing to do with the Onshore Orders we're discussing today.

MR. FRED YOUNG: Lease rate, the royalty rate, did you say it was 12 1/2 percent on crude oil? What is it on gas?

MR. RICH ESTABROOK: It's normally 12 1/2 percent. Indian leases the royalty is different and it can vary, I believe.

MR. FRED YOUNG: Okay.

MR. RICH ESTABROOK: The dollar value of the gas, just like with oil, is not established by the BLM, that's established or verified by the Office of Natural Resources Revenue.

Onshore Order 5, the BLM's responsibility is about ensuring accurate measurement and proper reporting of volume on which royalty is due and ensuring the accurate determination and reporting of heating value, which also affects royalty.

One thing I want to point out in this equation is that both royalty -- or, excuse me, both volume and heating value have an equal effect on royalty. So, if volume was reported or measured, let's say, 10 percent in error, that's going to cause a direct 10 percent error in the royalty due on that lease.

Likewise, if heating value is measured or reported 10 percent in error, that will also result in that same 10 percent error in royalty paid. So volume and heating value have equal bearing on the royalty that's out there or paid for a lease.

Why are we revising these regulations? Some of this has already been mentioned. Before I get into the why, I just want to go over specifically what our proposal is.

Currently, we have Onshore Orders 3, 4 and 5. The Onshore Orders, as far as I know, are the only -- they are very unusual. And I don't think any other program in the government has a similar thing as Onshore Orders.

Onshore Orders are regulations. They have full force and effect of regulations, but they are not published anywhere. You can't to go a regulation book, a CFR book, and find them. They are not there. They're on our website, you people have copies floating around, but it is uncodified.

So what we're proposing to do, and one of the things we're proposing to do, is to take these uncodified regulations, the Onshore Orders, and develop a new subpart under 43 CFR. CFR is Code of Federal Regulations. Part 3170 would contain everything that has to do with production and measurement. And that would include definitions, recordkeeping, statements about bypass and tampering, variances, appeals and enforcement. These are common to anything that relates to production and

measurement, so they would be pulled out and put into one -- in one place under this Part 3170.

Also, Part 3170 would contain the new Subpart 3173, that would replace Onshore Order 3, and it would deal with Site Security, FMPs, which is a Facility Measurement Point, commingling and off-lease measurement. And Mike Wade will be getting into the specifics of that here in a little bit.

Part 3170 would also contain a new subpart 3174. This would replace Onshore Order 4 and it would deal specifically with the specifics of oil measurement. And Mike McLaren will be getting into kind of the nuts and bolts of that proposal.

We would also have Subpart 3175. This would replace Onshore Order 5 and would also replace the statewide notices to lessees for Electronic Flow Computers. As you may or may not be aware, every jurisdictional state within the BLM has a NTL that covers Electronic Flow Computers. And those would all be replaced by this new Subpart 3175. And all of these things deal with gas measurement.

So why revise these orders? Well, for one thing, the bullet says last revised in 1989. That's actually not correct. The orders were promulgated or developed in 1989 for the first time and they have never been revised. So they're 26 years-old.

The current orders do not address new technology nor incorporate the latest industry standards and practices. For example, Coriolis meters, which are now commonly used for oil measurement, are not addressed in Onshore Order 4. Again, Onshore 4 was developed in 1989.

There is gaps in the existing orders that need to be addressed. For example, Onshore Order 5, the gas measurement one, has one and only one requirement for heating value determination and that is that BTU content must be determined once per year and that's it. There is 24 or 25 regulations or provisions for volume side and only one for the heating value side.

As my equation showed, both the volume and heating value are equally important in the calculation of royalty. So there's a huge gap in our heating value requirements. We have no requirements for how you sample, where you sample, how you analyze or how you report heating value.

We also need to respond to various reports and audits that Karen mentioned. The GAO, the Government Accountability Office, did a -- they oversee us to make sure we're doing our job. And

they wrote a report in 2010 that found numerous deficiencies in our regulation of oil and gas management program. And one of their recommendations was to update our Onshore Orders.

The Office of Inspector General is another agency that oversees how we do our job. And they have written numerous reports showing deficiencies in our ability to regulate the measurement, insure accurate measurement and proper reporting.

The RPC, the top bullet there, is the Royalty Policy Committee. It is a chartered advisory committee under the General Management Service. And, in 2007, they did an exhaustive study on the Department of Interior's Oil and Gas Management Program that included onshore, offshore and the royalty collection people. And they found -- or they had 110 recommendations of things that the BLM or the department has to do to fulfill our responsibility, our fiduciary responsibility to ensure accurate measurement and proper reporting.

Of those 110 recommendations, 12 of them dealt directly with measurement, volume and quality, and a lot of that was you need to update your regulations on record.

So, the bottom line is why revise these

orders. Because we want to improve measurement, accuracy, reporting and accountability.

So I'm going -- now going to go through a couple of changes that would be common to all three proposed subparts; 3173, 3174 and 3175.

In the Onshore Orders, if you're familiar with Onshore -- how many in here have reviewed the existing Onshore Orders and are familiar with them? Okay. Good.

For those of you who are familiar with the existing Onshore Orders, each Onshore Order has a number of provisions. And after each provision there's a statement whether that's a major or a minor violation, what is the corrective action and what is the time frame for that corrective action.

Now both BLM and Industry commonly misinterpret that enforcement, major/minor corrective action time frame, as being absolutely mandatory. And that was never its intent, because, the determination of a major violation, we must find that that violation is substantial, immediate or adverse.

Now a major violation for a tank seal, for example, would be appropriate for a big tank. But if you have a little tank out there that gets filled up every three months and there's two feet of oil in it,

maybe that seal violation doesn't meet the criteria for being substantial. And so, it could be a minor violation.

So what we're proposing to do is remove those enforcement actions from the regulation itself and put them into a handbook. In a handbook we can go into a great amount of detail providing what circumstances are required for a violation in order to elevate it to a level of major. We're hoping that will eliminate a lot of the existing confusion about what constitutes major or minor and what the corrective action and time frames have to be.

The existing orders have one immediate assessment. There is where an inspector can go out and identify a violation and immediately assess a dollar amount, a fine basically. The proposed regulations would implement numerous immediate assessments that would be added to each subpart for something called liquidated damages. The attorneys in the room can explain what liquidated damages is. I don't really understand it, but that was the -- that was the idea. Each immediate assessment, the proposed dollar value for each immediate assessment, is a thousand dollars across the board for each.

The current orders, if you want to do

something different, if you want to use a different meter or a different procedure, you have to go to the local field office and ask for a variance. The problem with this, and I have heard this from the industry actually, is that there's a tremendous lack of consistency and how that variance is processed at the field office level.

I can think of an example in Wyoming where there was a new type of gas meter that was requested. One office basically said, fine, go ahead and use the meter. Another office in the same state reviewed it and said you can use it, but with these conditions. And a third office got the same request for the same meter and they said there's no way we're using it in our office.

So, what we're proposing is that we would establish a new, national level Production Measurement Team to provide meter device approval at a national level. We believe, for one thing, this would remove the inconsistencies with field office-to-field office variance reviews and conditions of approval.

How we envision this working is that a new technology would be -- the data for this new technology, it could be a piece of equipment, it

could be a procedure, would be submitted to the Production Measurement Team, the Production Measurement Team would review the data and determine whether or not it's appropriate for use at Federal and Indian Facility Measurement Points. And if it was appropriate, it would be put on a -- listed on a BLM website under a hit list of that type of device.

Once somebody submits the data or request and the BLM approves it, let's say that one operator decides that they want to use this new technology and they submit the data for it, once that happens and it gets posted on our website as an approved device, anybody can now use that device without additional approval. Again, we believe this would tremendously increase the consistency of review. And the other advantage we see to this is that we're providing a mechanism for us to accept new technology without having to rewrite the regulations.

For example, one of the difficulties of Onshore Orders 4 and 5 being so old, Onshore Order 5, for example, doesn't even discuss Electronic Flow Computers, it's chart recorder and orifice plates. Well, if we have this Production Measurement Team, new technology could be submitted over and above what's in the -- what's in the Proposed 3174 and

3175, it could be reviewed by the Production Measurement Team and it can be approved. Thereby, we believe it would increase the longevity of the regulations and make them much more dynamic and much more adaptable to new technology.

Orders 4 and 5 both take a simple cookbook approach. Here is the cookbook of how you measure gas; requirement 1, requirement 2, requirement 3, just do those things and you're good to go. But there are no performance goals. There is nowhere in Onshore Orders 4 and 5 does it say, here's what we're trying to achieve with all of these cookbook items.

What we're proposing is that we would establish, in addition to we're going to maintain this cookbook approach, or proposing to for certain technologies, like orifice plates and Electronic Flow Computers and PD meters and Coriolis meters, so we're going to retain a cookbook approach to some extent, but we're also going to explicitly say what our objective is, what is -- what are we trying to achieve in terms of uncertainty, verifiability and other things.

The idea of the performance goals would be to balance accurate and verifiable measurement with economic considerations so the performance goals,

like we'll see from Mike McLaren's presentation and mine, are geared to volumes. So lower-volume meters have fewer or much less restricted requirements than higher-volume meters.

So we believe, in addition to the Production Measurement Team that I just mentioned, we believe this will also result in a much greater amount of flexibility for operators and manufacturers. If someone proposes a new meter to us, for example, and it goes to the Production Measurement Team, these performance goals are what that Production Measurement Team is going to use to approve or disapprove of that device. So as long as you meet the expert's uncertainty and verify -- your ability to verify that technology, you're good to go, you'll get listed on the website and no further approvals are needed.

Part 3170 has proposed changes common to all three orders. One change is the current requirements that all the orders apply only to operators. Right now we have authority only over operators. We inspect against the operators. Any violations we find, we go to the operator.

Well, one problem is, and I hear this a lot, is let's say we're doing an audit on a specific gas meter and so our auditors will send a written order to the operator for the lease on which that gas meter is located requesting information, volume statements, logs, calibration statements, all that stuff, and the operator says, well, that's not my meter, that meter's owned by the pipeline. So the operator goes to the pipeline and they say can you provide us information, the BLM is doing an audit and they are requiring us to submit it, and the pipeline company could say, no, we're not providing that information to you.

Well, our only enforcement action is to write an incident of non-compliance to the operator. We have no authority currently over purchasers, transporters and pipeline companies.

What we're proposing is to actually -- actually actively -- statutory -- statutory authority we already have through the Federal Oil and Gas regs, and for recordkeeping only, recordkeeping requirements would also apply to purchasers and transporters through the point of the royalty supplement point, which basically means the FMP, or the Facility Measurement Point or the point of first sale, whichever comes first.

So with this, when we do an audit, for

example, we could go directly to the purchaser or transporter, if they happened to own the meter that we're auditing, and request that information that we need for the audit. And we could take enforcement actions directly against purchasers and transporters.

Currently, the Orders have a variance section specific to each order. They are similarly worded, they are not identical. What we would propose is to remove the variance section in each Order or each subpart and put it in the part itself, Part 3170. And also, we would further explain how you would apply for a variance and how we would review it.

And with that, I will turn it over to Mike Wade to discuss the requirements of 3173.

MR. MIKE WADE: How is this working right now? Can you hear okay?

MS. LIZ O'BRIEN: We can hear you across the room and the block.

MR. MIKE WADE: Thank you. That is the intent.

Okay. Under 3173, the proposal is to -- some of the new areas are Off-Lease Measurement, Commingling, FMPs and, of course, Site Security.

Currently Order 3 has absolutely no guidance or requirements for commingling, off-lease measurement. And we were proposing some direct procedures for commingling and off-lease measurement, and to -- methods for providing the information to us for approval.

Specifically, what the BLM is looking at in the proposal is, first off, any instance where the commingling has no impact on royalty, all Federal, all Indian, ownership or interest rates, et cetera, no problem. We can do those. They almost -- almost a rubber stamp, if you will. I don't like that term, but it's relatively simple, straight forward to take care of. No impact on royalties.

Then we have the Low Volume exceptions for commingling. If you have Low Volumes, there are reasons to commingle it and make it more economical to approve commingling.

And then, finally, we have exceptions based on extenuating circumstances. Those can vary all over the place. But you have that ability to request commingling approval for those, but you have to justify it.

The BLM was planning and proposing to review existing commingling and off-lease measurement

approvals at the same time as you request the FMP number so as not to cause dual applications, extra work. Try to minimize some of that.

Order 3, currently it applies to all sales and allocation meters, all the requirements for the gas measurement applies to all those meters.

Royalty measurement is not even discussed in Order 3. And we would propose to apply it, the new regulations, only to those points where royalty is actually determined and also for a Facility Measurement Point.

A lot of you are asking why do we need a Facility Measurement Point. We've had many instances where we've done production accountability or where the inspectors have gone out to witness meter calibrations, et cetera. Come to find out six months later, the meter we witnessed or the meter we started working on is not the meter the operator says is their selling point. And we have just wasted tons of time for the operator, tons of time for us and accomplished nothing in return. This will make all of us working from the same location for sales and for royalty purposes.

Run tickets are currently in Order 3 for Oil Measurement, and including some additional information on seal numbers, water drains, et cetera. All that's required now on the water drain, for example, is date on, date off, seal number, basic reason, drain water. No other information.

What we are proposing is that the documentation for like water, hot oil and et cetera to include some new information on your part. How much was in the tank before you broke the seal, how much was in the tank when you finished draining or when you got ready to hot oil, how much did you leave in the tank, how much did you actually remove.

Also, we would be moving run tickets into 3174 with the oil measurement, which Mike McLaren will talk to you about later.

End-of-month inventory or beginning-of-month inventories are currently not required. Very much a useful and necessary piece of information. We're proposing operators do an end-of-month inventory and maintaining the records.

We have no requirements in the Orders right now for royalty-free, also known beneficial use, used on lease. All treated basically the same, have the same meaning. What we are proposing is to add some requirements with the site security diagram from the operators to provide us, if they are going to claim

beneficial use, give us some information. How are you going to determine that volume, what methodology are you going to do. Are you measuring it with a meter, are you basing it on the equipment BTU ratings, et cetera. Tell us how you're doing it so that we're all on the same page.

Currently, we have a requirement for a self-inspection program in Order 3 and for a site security plan that you have to -- that the operator's supposed to maintain under the Order, too. We are wanting to eliminate those. With the additional information on water drains and all the other requirements, that will totally replace that, so there's no reason to have those requirements and this as well.

Things that we would like specific comments on, if you could provide it to us in that. As mentioned in there is, on the commingling side, we have a 10 percent rate of return number. Basically that would be in relation to the equipment that you would add. If you did not get the commingling, the new piece of equipment, is that 10 percent a good number? Is it a bad number? Is there a better way to make that determination? We basically need more information from the operators and the people that

have to do this work.

We're asking for comments on time frames and volume thresholds that we're using for implementation. Current basic proposal in general says five producing cases would be required to report or request their FMP number in the first nine months. Middle third producing cases, this is based on an annual monthly average, would have the next nine months. And then the Low Volume, Very Low Volumes would have the final nine months or 27 months just to request the FMPs. Is this too long? Are our volumes thresholds too low? Too high? We needed more information on what the operators think so we can do a reasonable time on the implementation without too much difficulty.

And I will now give this over to Rich or, I'm sorry, to Mike McLaren.

MR. MIKE McLAREN: Hello. I'm Mike McLaren. Can you hear me okay? There we go.

I'm Mike McLaren. I'm going to talk about the proposed technical changes for the Subpart 3174, the Oil Measurement.

As Rich stated, currently in the Onshore Order -- currently in Onshore Order 4 there is no overall performance standards stated. It is a

cookbook. You can use a LACT system or manual tank gauging. So what we've proposed are some performance standards for uncertainty. It's basically being proposed three levels of uncertainty. If your meter is measuring more than 10,000 barrels a month, we're proposing a plus or minus .35 percent uncertainty. If you're measuring between 100 barrels a month and less than 10,000 barrels a month, we're proposing plus or minus 1 percent uncertainty. If you're less than 100 barrels a month, we're proposing plus or minus 2.5 percent.

And where we got these numbers from, the top one, the plus or minus .35 percent is based on an uncertainty calculation we did using the LACT, current LACT system under the Onshore Order utilizing a Positive Displacement meter.

The middle layer, the plus or minus 1 percent, is based on the uncertainty analysis using manual tank gauging on a 400 barrel tank. And for that number there, that was withdrawing two-to-300 barrels out of that 400 tank when you're trying to load out. And then the bottom tier is for a low producer. And that was calculated, I believe, it was 40 barrels out of a 400-barrel tank.

The current Order 4, it references industry standards that were published in 1989. We're proposing to incorporate 21 of the current API standards and two ASTM standards.

The current Order 4 requires a pressure-vacuum thief hatch or a vent line valve for tanks. We're proposing, along with the pressure vac and thief hatch, we were proposing to require a pressure vacuum relief valve set at inlet/outlet pressures greater or less than that of the thief hatch.

Also in the proposal, we're stating what we want the condition of that tank. We want it to maintain pressure-vacuum integrity. It is implied in the current Onshore Order 4, but it's not stated. We're explicitly stating the condition we want that tank to be in.

The current Order 4, it has requirements for gauging sampling in random order. What we've proposed is in Order 4, we're proposing the sequence for manual tank gauging, along with the requirements for each sequence. And that's based on the current API 18.1 standard.

The current Order 4 requires for the manual tank gauging two consecutive gauges within a quarter inch. We're proposing the current API 3.1 standard

of two consecutive identical gauges or three gauges within 1/8th inch.

The current Order 4 requires tank calibration tables, but no increments specified within the quarter inch of the actual gauging. We're proposing 1/8th inch increments for the tank table to match the gauging requirements of the API 3.1A.

On the current Order 4, LACT systems require a Automatic Temperature Concentrator and Automatic Temperature Gravity Compensator and only allows the use of a Positive Displacement meter. We're proposing to prohibit the use of Automatic Temperature Compensators and the Automatic Temperature Gravity Compensators and require the use of the temperature -- electronic temperature averager instead. And we're proposing to allow a Coriolis meter in lieu of the PD meter, if the operator chooses to do so.

The current Order 4 requires measurement by tank gauge or Lease Automatic Custody Transfer, LACT, systems. So we're keeping the Automatic Tank Gauge and the LACT system requirement in there and we also have a section proposed for a Coriolis Measurement System, a separate section for a stand-alone Coriolis Measurement System.

And we have a few requirements that we propose for the Coriolis Measurement System. We are proposing to maintain the 8400 pulse per barrel for the minimum resolution. We have some specifications, including reference accuracy, influence effects, stability, pressure drop. We want the Coriolis to have a non-resettable totalizer, like the PD meter has. In the proving of the Coriolis, we want to verify the meter's zero prior to approving the Coriolis meter. We want the Coriolis meter to be able to determine net standard volume.

We've got -- a couple of options were proposed for gravity in the Coriolis Measurement System where there'd be a composite sampler, friction and gravity or the average gravity as determined by the Coriolis meter during the flow between run tickets.

We have a list of some on-site display requirements, which is basically the raw data; the pressure, temperature and flow rates.

And for the audit trial, we would -- we're proposing the requirement of Quantity Transaction Records; configuration log, event log and alarm log.

Current proving for a LACT System, if you're less than or equal to 100,000 barrels, it's

quarterly. If you're greater than 100,000 barrels, it's monthly.

We're proposing proving for the LACT and Coriolis Measurement Systems to prove every 50,000 barrels on the totalizer or quarterly, whichever would come first. We came up with that 50,000-barrel number doing a statistical analysis of the volume threshold that the cost to prove could equal the royalty overpayment or underpayment based on the difference in meter factors between provings.

Currently Order 4 in the proving section has no standards for prover sizes, no standards for proving conditions and no standards for pulses during a proving run.

We proposed minimum and maximum fluid velocity for the prover sizing. We would like the proving to be at a normal flow, flow rate, normal pressure, the normal API gravity.

And, if you're using a small volume prover, you're not going to get 10,000 pulses on the run, you're going to get couple thousand or 2500. And so, if you're using a small volume prover or getting less than 10,000 pulses per run, we're proposing to require a pulse interpolation.

Currently there is no measurement ticket requirement for a LACT system. We're proposing to generate a measurement ticket after proving of either the LACT system or the Coriolis Measurement System and at the end of every month.

So winding down the oil measurement, in the Preamble discussion we're specifically asking for data and comments on the volume uncertainty levels that we've proposed. We explained where we came up with our numbers. If you guys don't think those are reasonable or if your calculations show a different number, we would like to see that.

At the time we drafted the rules, we had no data on the Automatic Tank Gauging systems, any kind of type of tank measurement. We've got a few since this has been published or proposed, we're hoping to get a lot of field test data, a lot of input from you guys on the use of Automatic Tank Gauging for possible inclusion into the final rule.

We proposed our composite sampling system on the Coriolis meter. For sediment in water determination, what we're proposing is, if you don't have a composite sampling system, then we wouldn't allow deductions for sediment in water, because we wouldn't really be able to determine if you didn't do a sample analysis. We're asking for input from you

guys, is there other ways to determine sediment in water, other than sampling. We would definitely consider it.

Ways to address meter factors. If you have variable flow rates, fluctuating pressures, different gravities, how do you utilize the meter factor? Would you average meter factors proving the different flowing conditions and average that meter factor in between provings? Would you pull up and calculate a dynamic meter factor with a flow computer or use a dynamic meter factor to adjust for the different flowing conditions? That's something we're looking for input from you guys on, on a way to address that.

And with that, I will turn it over to Rich.

MR. RICH ESTABROOK: Okay. We'll finish off this presentation with 3175.

Currently Onshore Order 5 approves only orifice plates and mechanical recorders. Order 5 is a cookbook on how to measure gas with orifice plates and mechanical recorders. We did address Electronic Gas Measurement systems with our statewide NTLs that, again, are unique for each state office jurisdiction. All the NTLs are the same, with the exception of Wyoming. Proposed 3175 would maintain the orifice plate as the primary method of measurement. We like

orifice plates, because they achieve reasonable accuracy and, perhaps more importantly, they are completely independently verifiable, verifiable by us. So we would still accept mechanical recorders with some exceptions or restrictions. We would accept or approve approved Electronic Gas Measurement systems, and we would have specific guidance for alternate measurement and flow conditions.

Like Order 4, Order 5 also has no performance goals. It's just a cookbook. And Order 5 has three tiers of requirements. Now I have a little graph that I'll give you in my next slide.

The Proposed 3175 would actually establish four tiers of performance standards based on average flow rate volumes. So this is actually what's in Order 5 right now. The average monthly flow rate is shown on the Y axis here. If -- if your meter is measuring more than 200 Mcf per day on a monthly basis, currently under Order 5 all the 26 or whatever requirements there are in Order 5 are in effect. If your meter measures less than 200 Mcf per day, you no longer need a continuous temperature recorder. And this is the current Order 5. If you are less than 100 Mcf per day, you also are exempt from the requirement of a DP, a Differential Pen, when logging

the outer two-thirds of the chart and you're exempt on the Beta ratio limits, the .15 to .7 Beta ratio limits.

Proposed 3175 takes this concept and expands on it a little bit, with these tiered requirements. We would establish four new categories of FMPs, or Facility Measurement Points, based on average monthly flow rate. If your meter measures more than 1,000 Mcf per day, we would call that a Very High Volume FMP. As I recall from our statistical analysis, about 1 1/2 percent of all of our meters would fall under this category right now. If your meter measures between 100 and 1000 Mcf per day, that would be called a High Volume FMP. If your meter measures between 15 and 100 Mcf per day, we would call that a Low Volume FMP. And less than 15 Mcf per day, we would call that a Marginal Volume FMP.

So for each category, there would be requirements specific for that category. And the idea is that for High Volume meters, like Very High Volume FMPs, a little bit of measurement error has a big impact on the royalty, because there's a lot of volume going through that meter. So, what we're proposing is we would be very tight with that, very restrictive.

Now that restrictiveness, of course, comes with a price tag. And so the idea is, as the volume gets less and less, first, the risk of royalty mismeasurement also becomes less and less, because it's just not handling that much volume. But also, we want to provide some form of economic relief as the volumes -- those meters measured get lower and lower. So we're very tight, proposing to be very tight with the very High Volume meters. As you get down to Marginal meters, we have got almost no requirements for that meter whatsoever.

The performance goals are uncertainty in both volume and in heating value. They also include bias or the absence of bias, and they also address something that we call verifiability, one of the very critical things, our ability, the BLM's ability, to independently verify every single step of that measurement. So that, if you report 10,000 Mcf is being moved from a lease in a given month, we can verify that, yes, in fact that is a reasonable number that represents the gas that actually went through that meter.

For Very High volume FMPs we are proposing an overall volume of uncertainty of 2 percent, an

overall annual average heating value of uncertainty of 1 percent. We would not accept any statistically significant bias and all measurements, all aspects of the measurements, would have to be verifiable.

For High Volume FMPs the volume uncertainty would be 3 percent, the uncertainty in average annual heating value would be 2 percent, we still would not accept any statistically significant bias and the measurement would still have to be verifiable.

For Low Volume FMPs, we would do away with uncertainty requirements altogether, we would still not allow any statistically significant bias, and the measurement would have to be verifiable.

For Marginal Volume FMPs, the only thing we would care about is some level of independent verifiability of your numbers.

These are the overall performance goals. The cookbook part of 3175 used these performance goals and this concept to figure out what specific cookbook requirements would apply to each category of meter.

Order 5 currently adopts one, and only one, industry standard. And that's AGA Report No. 3, and specifically the 1985 version of the AGA Report No. 3. And that talks about orifice plates and flow rate

calculations.

The Proposed 3175 would adopt the latest API standards covering primary devices, orifice plates in particular, Electronic Gas Measurement Systems, flow rate, volume, and heating value calculations and gas sampling and analysis.

Current Onshore Order 5 has no inspection requirements for meter tubes. Now API 14.3.2 goes into a fair amount of detail about requirements for meter tubes; surface roughness, roundness, obstructions and so on. We believe that, because API 14.3.2 has specific requirements for meter tubes, clearly it's an important thing to measurement, that we should be inspecting those meter tubes periodically to make sure they comply with API 14.3.2.

So Proposed 3175 would have some requirements implementing tube inspection, meter tube inspections, and the frequency would depend on the classification of the meter. So what we're proposing is this schedule: For Marginal Volume FMPs, we would not require any meter tube inspections. For Low Volume FMPs, we would require a visual inspection once every five years. A visual inspection would be probably with something like a bore scope. You

wouldn't have to disassemble a meter tube, you'd run a little fiber optic thing down through a pressure tap and then you can see what's inside that meter tube.

High Volume FMPs would require a visual inspection every two years and a detailed inspection once every 10 years. A detailed inspection would be complete disassembly of that meter tube and miking of roundnesses, surface roughness measurements and so on, enough stuff to verify that that meter tube objectively complies with the API 14.3.2 standards.

For Very High Volume FMPs, we are proposing a once per year visual inspection and a once every five year detailed inspection. Also, if a visual inspection identified a problem, that could jump it into a detailed inspection to correct that problem, to make sure it complies.

Currently in Onshore Order 5, which only discusses mechanical recorders, well, Order 5, the mechanical recorders are the only thing that it talks about. Proposed 3175 would still allow mechanical recorders, but only for those meters measuring at less than 100 Mcf per day. We do not believe that the performance, the uncertainty of mechanical recorders, is well enough defined to do an uncertainty calculation. And because High and Very High Volume FMPs have an uncertainty standard, there's no way we could do an appropriate calculation to determine if a mechanical meter -- mechanical recorder was meeting that standard.

As I said before, Onshore Order 5 has one, and only one, requirement for heating value, and that is that it's determined at least once per year. In the Proposed 3175, we would establish the following sampling frequency: Marginal volumes would maintain their once-per-year standard. Low Volume FMPs would have a twice-a-year, once every six-month fixed sampling frequency.

For High and Very High Volume FMPs, we're proposing something a little -- a little different.

Initially, a High Volume FMP would have to be sampled once every three months. However, once we have enough samples to do some statistical analysis, the frequency of spot sampling could either increase or decrease, based on the heating value variability of those past historic samples.

We put this in here because we realize that sampling frequencies are somewhat arbitrary. And in order to try to avoid arbitrary sampling frequencies, we went back to our overall performance goal of the 2

percent. And the heating value would be adjusted to meet that plus or minus 2 percent uncertainty of heating value.

For Very High Volume FMPs, the same principle would apply. Initially it would be once per month. Once we had enough data, enough samples to do some statistical analysis, we could increase or decrease that sampling frequency to maintain an overall uncertainty heating value of plus or minus 1 percent.

Proposed 3175, this is continued. If you could not meet the uncertainty requirement based on sampling, because you had to do it so frequently to get that to that 2 percent or 1 percent level, we would then require the installation of a composite sampling system or an online gas chromatograph.

Also, we are proposing that all gas samples, all gas analyses, I should say, that are used in the determination of royalty would be submitted to a BLM database called GARVS, G-A-R-V-S. That's the Gas Analysis Reporting and Verification System. This would be key entered or it could be downloaded from your software packages like Flow-Cal or whatever.

This GARVS system, among its function would be to do the statistical analysis and

figure out what sampling frequency is required to meet that 2 percent or 1 percent uncertainty.

Order 5 has no requirements for sample location or method, no requirements for gas chromatographs. But, post-3175, we'd have a few new things on this.

Now this first bullet point, I want say right up front, we're just kind of throwing this out there. And as you will see that our -- in our request for data, this is one of the things that we're looking for data on.

What we're proposing is that the sampling probe be located 1 to 2 times dimension "DL" downstream of the primary device. As you know, DL is the minimum length of downstream meter tube required under API 14.3.2.

Now this is in contradiction with the API and GPA standards for placement of the, you know, sample probes. And the reasoning is, again, we're open to data on this and other opinions, the reason is that API and GPA sampling standards are based on an assumption that you're at or above the hydrocarbon dew point and that basically you're free and you have no trouble lifting these. We're pretty sure that the

reality is that most of this lease level measurement there is some entrained liquids there. Hopefully not a lot. And we feel that sampling systems designed to eliminate those liquids, and this would include the use of membrane filters on the probe, would not adequately account for any entrained hydrocarbon liquids that are flowing through the orifices.

We think, perhaps, that by placing a sampling probe relatively close to the orifice plate would actually, because of the velocity and the turbulence coming right through the orifice plates, or however device, that might actually lift those liquids and put them into a aerosol state that we could then sample. And we believe that could be the way to account for entrained liquids going through the orifice plate.

As I say, we're looking for data on this. This is just a proposal.

Proposed 3175 would allow four spot sampling methods: fill and empty, helium pop, floating piston and portable gas chromatograph.

We would have requirements for gas chromatograph calibration and operation. And another proposal we have is that, if the hexane-plus analysis yields greater than 0.25 mole percent of hexane plus, that you would be required to get an extended analysis through C9+.

Order 5 has no requirements for BTU reporting. BTUs can be reported on a number of different bases. They can be gross or net; they could be real or ideal; they could be dry, wet or as-delivered; and they can be reported through a number of different pressure bases. I have never seen anything besides 60 degrees on the temperature side.

But what this means is that for a single sample you can actually -- I think, if you do the multiplication, for a single sample you can actually get 60 different BTU values potentially; gross/net, real/ideal; dry, wet, as-delivered; different pressure bases.

Right now we have no requirements for which one of those 60 you should be paying royalty on. So, Proposed 3175 would say gross, real, dry, 14.73 and 60.

Order 5 and the statewide NPLs have no requirements for independently testing of transducers and flow computers. Basically all transducers and flow computers are accepted. The problem with this is that the statewide NPLs already establish an

uncertainty standard for Electronic Flow Computers. The calculation or the tool that we use to calculate uncertainty in our uncertainty calculator uses manufacturers' reported performance specifications for transducers in particular as the basis of the uncertainty calculation.

We believe that a lot of that or some of those manufacturer specifications are based on proprietary, in-house testing methods. We believe that, in order for our uncertainty calculation to actually mean something, we should be using specifications and performance standards that have been tested and are transparent and are publicly-available methodology.

So 3175 is proposing that all transducers and flow computers used at High and Very High Volume FMPs must go through a testing protocol. The Production Measurement Team that I mentioned earlier would review the results of that testing and develop a list, a pick list of approved transducers and flow computers.

This would be a one-time shot. So, for example, if a manufacturer went through the testing protocol and submitted that testing to the Production Measurement Team, the Production Measurement Team did

a review of that and said this is an approved device and put it on the pick list, no one else would have to do it. Once it is done, it's done, and that piece of equipment is approved.

So specific data and comments requests from 3175. And just be aware, the Preamble gives specific or asks for specific information. The reason we do that is because we know we're putting something out there that we don't have a lot of information about. And we really are looking for data on this to help us decide whether it's a reasonable -- something that's reasonable, something that's unworkable. We really are looking for data to help us figure out how to deal with this. So a lot of these things, our -- these proposals are true proposals we're just putting out there.

So specifically, these things appear in the Preamble of 3175. What is the cost to industry for type testing transducers. We don't have a good feel for that. We're looking for some information.

What is -- and in the proposal we wouldn't just test one transducer and base performance specs on that one transducer. We want some kind of a statistically representative sample of transducers to do that testing on. In the Proposed Rule, we're

suggesting five is the magic number, but we have no idea if that's correct or meaningful.

Should we require standards for online gas chromatographs? There is not much out there, that I'm aware of, for industry standards on online gas chromatographs. So if there's other documents that we should be incorporating, we'd like to know about it. There is the new API 22.6. Is that appropriate for incorporation in this standard? That's a question.

The next one gets to the dry, wet, as-delivered issue. There's been lots of controversy about this. We currently, our policy is to require dry. Our proposal in the 3175 is to require dry. A lot of companies say, well, the as-delivered method is the more appropriate, because we know that there is water there. And the dry and the as-delivered, in my opinion, as-delivered means that it's an assumption, you have to make some assumption of water vapor, because it's very difficult to test for water. The as-delivered assumption is that that gas is saturated with water vapor at meter pressure and temperature.

So dry and as-delivered are basically the end points, the maximum and minimum amount of water vapor that can actually exist in the gas. Well, the truth probably lies somewhere in between those two points.

So if industry, if you want to claim that as-delivered heating value, we would like some data to show that that's a legitimate assumption. If we don't have that data, we would be leaning towards the dry, which we're proposing right now.

Data showing correlations between sample probe placement and composition, that's that requirement, the proposed requirement I talked about, that 1 to 2 times dimension DL, we're just throwing that out there. We're really looking for data on that, or anything, anything you have, because there is really nothing in the literature that I know of.

Cost of retrofitting orifice meters to meet the eccentricity requirements of API 4 -- API 14.3.2, again we didn't have a good feel for this one.

One of the things would be -- that we're proposing, is that mechanical recorders, chart integration and statements would also have to be done in the 1992 calculation method. We know a lot of chart integration companies have been around for a long time and may not have upgraded. We have no idea

what the cost for a chart integration company to go from a '85 to a '92 calculation.

And finally, data showing the difference between C6+ or hexane plus and nonane plus analysis as a function of the C6+ mole percent. Basically we're looking for the kind of data that would support or refute our .25 mole percent recommended to do an extended analysis.

I have up here -- that is the end of the presentation. I have up here, if you haven't seen it already, there's mailing addresses for comments. I would go to this site right here, this regulations.gov. Not only can you submit comments there, but you will also find a copy of the proposal itself. You will also find the Economic Analysis, the Environmental Assessment, and we did a study on Heating Value Variability, which is the basis of our proposed sampling frequencies, and that study is there as well.

These PowerPoints will be posted at this site right here, on.doi.gov, the bottom one.

MS. LIZ O'BRIEN: Could we just leave this up here in case everybody didn't get it yet? Leave that last PowerPoint up there? Thank you.

We would like to take -- I have a sign-up

sheet for speakers and currently I have 12 speakers. And the last I heard, there were 57 people on the phone. Now I don't know if all those 57 people want to speak, but we don't know until, you know, until we ask.

If you have not signed up to speak, please, do so. Let's take a 10-minute break, because it's about 120 degrees in here, and come back in 10 minutes and we'll start with these speakers. Thank you.

(A break was taken, after which the following occurred:)

MS. LIZ O'BRIEN: I'd like to start with the speakers now, please.

And we've done a little shuffling of speakers, so if you feel like you're interested in speaking, please, I'll ask again at the end if you'd like to. But thanks for coming back.

Our first speaker is Dave Curtis. Are you Dave Curtis?

MR. DAVE CURTIS: I am.

MS. LIZ O'BRIEN: Well, how about a microphone?

MR. DAVE CURTIS: Yeah. That would be great.

Good afternoon. Is that working?

MS. LIZ O'BRIEN: It is.

MR. DAVE CURTIS: My name is Dave Curtis. I'm with Anadarko Petroleum.

First of all, since I'm the first speaker, thank you all very much for taking the time to do this forum. This type of thing is important. It gives us all an opportunity to hear your thoughts and for you to hear, you know, what we're thinking.

Along those lines, again we appreciate the fact that 3 and 4 got extended, but I would like to take this opportunity to request that we get the same for 5. It would be my argument, I don't know about others here, but 5 is some of the most impactful rules to us with regard to current operations. And so, additional time to be able to review and, more importantly, collect the data that we've talked about in order to either agree with or refute some of these things. And even better would be to have, perhaps, some workshops where we could sit down and talk these things out. Sometimes when you're in a forum, we all lose something in the shuffle.

That being said, I just have a couple of questions and thoughts on a few things here. One was on the heating value variance versus uncertainty. It talks a great deal about leaving that uncertainty in there, and then it lumps variance of the heating value units.

We collect samples under a certain sample collection technique. We analyze it with the same instrumentation and we use the same calculations in reporting. The uncertainty is the same, regardless of the variability. So the two don't really tie in.

We have a high heating value well in Colorado that's getting major ambient temperature changes. We're going to see major variation in the heating value, but, truthfully, that has nothing to do with it saying that it's less certain.

So I'm not sure that that really tracks with one another. Does that make sense?

MS. LIZ O'BRIEN: Do you have a suggestion to add to that?

MR. DAVE CURTIS: Well, our suggestion's in there. You know, there's no real good way to collect data. As you start to get lower where economics don't support putting in a heating composite sampler, or a GC, we agree with you completely. When we get our major delivery points, that's where we start going in to putting in those composites and GCs just at a higher threshold, because it's not only just the

price of purchasing that equipment, for those of you who are running heated composite samplers, when you're running on rich gas and running that heater, those instruments do not work worth on a darn, so you spend a lot of labor on this out there trying to keep those operating. So when they're in remote locations, what we're even deeming currently as high volumes just doesn't become economically feasible. So, anyway, that was my thoughts on that.

C6 versus C9+, you'll see we did a study on this. We did a host of samples. And what we found is on our sample set, if you look at the repeatability specs cited by one of the major manufacturers, I won't say it here, their percent of heating value repeatability that they cite, on our study the heating value change between doing C6+ and C9+ calculation is actually, the average is about half of that repeatability. So it's well within the analytical deviation of the instrumentation.

We did have one outlier, and that's cited in our data. So we hope you take the opportunity to look at that, because I think that's important, because moving to C9 will have a major impact on us.

And then the last one I'll make comment, and I then will give it to somebody else, when you were

up there and you were saying about the dry, you said the dry versus wet, currently it would only be accepted as dry. And I just wanted to clarify, in the Proposed Rules it says dry or actual measurement. That still is the case, correct?

MR. RICH ESTABROOK: (Nods head.)

MR. DAVE CURTIS: Okay. I just wanted to verify it, because that threw me in a loop of somewhere where we were going.

So, anyway, appreciate the opportunity. And I'll turn it over to the next person.

MR. RICH ESTABROOK: Well, --

MR. DAVE CURTIS: Oh, yes. Please.

MR. RICH ESTABROOK: Well, no. For the record, I agreed with what you said. The actual is still in there. It is just realistically I can't imagine too many people are going to go out with a chill meter or a laser device on a well GC meter.

MR. DAVE CURTIS: I can -- I can speak for our company. Since this was brought up, I don't know, two or three years ago, we have implemented it and every one of our folks that are out there with a portable gas chromatograph, which is almost everybody on a federal property, is out there with an automated chill meter kit. And real -- we haven't been

applying it yet, but we've been collecting all that data.

MR. RICH ESTABROOK: All right. Thank you.

MR. DAVE CURTIS: And by the way, you are right. It shows a -- some degree of partial saturation, more than 50 percent. So it does kind of lend more towards a as-delivered value being more accurate than a dry, but it is some degree of partial saturation.

MR. RICH ESTABROOK: And is that data that you were going to submit with your comments?

MR. DAVE CURTIS: You know, because we were agreeing with yours, we weren't really going to submit it. But if you would like it anyway, we could.

MR. RICH ESTABROOK: I would love it.

MR. DAVE CURTIS: Okay. Yeah. We will put it together. I may send it to you -- send it off line, if they've already sent our comments. Well, it's not off line, but you know what I mean.

MR. RICH ESTABROOK: Thank you.

MS. LIZ O'BRIEN: Thank you.

Stormy Phillips. Hello again.

MR. STORMY PHILLIPS: Hello. First let me thank you for getting to follow you guys all over the

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country. It was very fun to drive from Durango to Oklahoma City.

MR. RICH ESTABROOK: You know we're going to Dickinson next.

MR. STORMY PHILLIPS: Yeah. I had a question for Mike. I will let you guess which one. Sorry, guys.

I just wanted to know the reasoning or justification that the BLM is using in requiring the sample point to be downstream of the Coriolis meter and upstream from the proving connections on a Coriolis Measurement System, which just isn't in line with normal LACT design?

MR. MIKE McLAREN: The sample point?

MR. STORMY PHILLIPS: Yes. In the component requirement Section 3174.10, section E, number 8, it says, the components must be placed in this order. And it places the sample point after the meter.

MR. MIKE McLAREN: Yeah. And I believe that does follow the sequencing in API 5.6. I will verify that, but that should have been following the sequence and that diagram in API 5.6. I will verify that.

MS. LIZ O'BRIEN: Does that request, could you put that request in writing?

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MR. STORMY PHILLIPS: Already done. Already over it. Yeah. Just trying to understand that, because when you look at your normal LACT set up, you normally have the sample point somewhere upstream of the divert valve, which is going to be upstream of the meter. So that could create an issue in which we're right back to asking for variances on all of the LACTs.

MR. MIKE McLAREN: Well, I will look at that, because I thought that sequence was following API 5.6. I will verify that.

You did submit that one?

MR. STORMY PHILLIPS: Yes, sir.

MR. MIKE McLAREN: Okay. Thank you.

MS. LIZ O'BRIEN: Thank you. Is that it?

Barry Balser.

MR. BARRY BALSER: Right here. Thanks.

First of all, I'll apologize. I signed in on the sign-up sheet and I thought it was the regular sign-up one and later discovered it was the speaker sign-up, so now I have to speak.

So one comment I guess on 4, there is not near as much information in 4 as there is in 5. Five goes in talking about all the requirements for

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testing of transducers, RTDs, all of that, there's no mention of that in 5 in 4. I'm not -- I guess in my mind I'm assuming the same thing applies, that somehow they will all have to be tested as well if they are on liquid. There's no mention of that, so that's a question we've been having and have been wondering.

There's also come up questions about the list of approved devices with liquid. How do you get on that list? Coriolis, for example, it's not being used now, it's not on that list. How do you get on that list? Is there a testing protocol? What's going to be involved for someone to get on the list for the liquid equipment?

On gas, you know, I feel for all the producers in here, because I think this is hitting them much harder than it does us, but we're also partners with them. In a way, we want to consider ourselves that. There is a couple of those that hit us pretty hard and then indirectly then it's going to hit them. And primarily the testing protocol of the transducers and transmitters.

The way I read that, the big one is the stability test. That's a 24-week test. The way that's stated, that says every range, every model,

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if you do range downs, every range down. I do not have the exact quote now, but we have estimates of that test running around half a million dollars for one range. We don't know facilities that can do this. We do know Southwest Research has a couple of large walk-in chambers. We know CC has a small one. We don't know where we're going to go if we have to go to an independent, third-party facility to test the sensors that you're going to need to use on your leases.

That's a six-month test. So once this becomes law, particularly in the economy we have today, we're not going to be going and investing money to begin this test until we know what the test is.

So, if testing is done, once it becomes law and we know what the tests are, and it's a 24-week test for every range, we have five models, for example, of one range, the 255 500, that is five different sensors that are going to be tested, with five of each, that might be a $2 1/2 million charge. Someone will be paying for that.

Not knowing the facilities, not knowing how we can get these done, or how we can get that done in any timely basis, particularly if the effective date is 30 days after this becomes law, we don't see how you're going to have equipment to put on your sites.

We would propose that some method be implemented that the manufacturers can do this testing. Whether that means a PMT, whether that means an ISO 9000, one auditor, someone can audit our facility. You can sit and watch us run the tests. Odds are we have better equipment than any of the labs do that would be doing this. We have many more chambers. We've got 13 chambers we can be doing these tests in. We don't know of anybody together that has 13 chambers.

We're open to that, but we believe there ought to be consideration that there be some independent that could audit us and say, yes, it's okay for you to do the tests. We'll watch you, we'll look at your test results, we will verify your test results. So that one is a very big concern of us.

I'd like to see that the calculations of the flow computer be allowed that way as well, because it will make it less expensive for everybody, and we're open to showing that to people. We don't -- you know, we don't want to just come back and have people see anything that's really proprietary. But following some test procedure and seeing the data

verified that our test equipment is precise enough equipment, we're very open to that.

One thing I just thought of now, one of our guys read through, I have not read through the details of trying to track when it says it supports different standards as a reference. There is one that's an IEC standard in there that appears that that stability test is DP and pressure. If that's the case, that's going to limit anybody that could do that to almost nobody, because there is very few facilities that are going to have environmental chambers that could run a DP and a pressure at the same time. We can do that, but it's going to be at ambient conditions on one device. Those are not the common thing you're going to go down the road and buy.

I think that is primarily mine. I appreciate the opportunity for this. I've got comments that I'm sure that will be filed as well. And appreciate it.

MS. LIZ O'BRIEN: So you are going to put those comments in writing also?

MR. BARRY BALSER: Oh, yes.

MS. LIZ O'BRIEN: Okay.

MR. RICH ESTABROOK: Barry, can I just ask?

Can I ask one question, because this long-term stability thing has been an issue for me for awhile. I was hoping 22.4 would address it, but I don't think they are.

MR. BARRY BALSER: No, very intentionally it is not.

MR. RICH ESTABROOK: You know that, the long-term stability test in the Proposed Rule was pulled pretty much from the IEC standard. Do you have any idea how -- is it a European thing? Or how --

MR. BARRY BALSER: No, I believe that's the Leon -- one Leon was referring to when you go look at that test. It lists the DP lying at elevated pressures. And accurate test equipment that can do 200 inches at 500 pounds is few and far between.

MR. RICH ESTABROOK: But do you know anybody who's implementing that IEC standard?

MR. BARRY BALSER: I don't know all those standards. I'm sorry.

MR. RICH ESTABROOK: Okay. Thank you.

MR. BARRY BALSER: Thank you. Thanks.

MS. LIZ O'BRIEN: Dee Hummel.

MR. DEE HUMMEL: Yes, sir. I was wondering if you could clarify how you determine the volume

thresholds. For instance, if you have got a well that's only generating a thousand --

MS. LIZ O'BRIEN: Sir, this has to go on the record. So you have to start over.

MR. DEE HUMMEL: Yes, sir.

MS. LIZ O'BRIEN: It's on.

MR. DEE HUMMEL: Yes, sir. I was wondering if you could verify how you determined the volume thresholds. For instance, in your scenario I looked at the other day, we had one well that flowed at a thousand Mcf for one day. How is that determined?

MR. RICH ESTABROOK: That is actually spelled out in the proposed rule. And I believe it would be an average. It would be a monthly average taken over the previous 12 months or the life of the meter, whichever was shorter, I guess.

MS. LIZ O'BRIEN: Is that an answer to your question?

MR. DEAN GRAVES: Rich?

MR. RICH ESTABROOK: Yes.

MR. DEAN GRAVES: There is one statement in there that says it may be yesterday's information in the Preamble. It doesn't make sense, but it's in there.

MR. RICH ESTABROOK: Okay. I'll take a

look.

MS. LIZ O'BRIEN: Can you do that again? This is for the record.

MR. DEAN GRAVES: Okay. I cut in, like I typically do. But in the Preamble there is one place where it says it could be yesterday's volumes, which doesn't make sense and it doesn't go along with the other part of it. What you said is exactly right, it's the last 12 months or the measurement at the end of the year, whichever is less. But again, there is some disconnect there.

MR. RICH ESTABROOK: Okay. Thank you. I'll check that.

MS. LIZ O'BRIEN: Thank you.

Fred Young.

MR. FRED YOUNG: Hi. Fred Young with Enterprise Products. And I will wait on the mike.

MS. LIZ O'BRIEN: Thank you.

MR. FRED YOUNG: I'm an engineering manager, but there's a lot of experts on measurement here and I'm not one of them. I have never claimed that.

We are going to submit written comments. And for the record, Enterprise is not a car rental company, we are the second largest pipeline company in America. We have about 49,000 miles of pipe and

we have about 25,000 gas meters and a significant number of them are on BLM land.

I have some specific comments, then I have some cost data that I thought went to your -- one of your comments you requested about numbers on the AGA's compliance.

And I'm going to use a word you don't like a couple of times, and that's grandfathering. But you're going to have to just sit down and not jump out of your chair. Okay?

First, we do thank you for this. And I understand why you want to update them, but we think they go -- the rules in general go past updating.

Our -- some specific concerns are the fact that, regardless of how your system performs, there is no allowance for using the existing equipment, i.e., grandfathering. There are unintended consequences to some of this on system -- on a entity's accounting systems that are going to take time to implement.

The time of this whole regulation to be -- set of regulations to be implemented is a concern. Cost is a big, big concern.

Obviously, we're in the transportation company and we think there is somewhat of a

discriminatory treatment of transporters because we're not an equity owner. And all the economic analysis was based on equity ownership. And in our case, there's no improved performance for many of these proposals.

And lastly, there is a risk of revenue loss to the Government, in our case, and to the Indian Tribes and the other equity owners.

So let me -- we're a publicly traded company, so I can't give you exact specifics. So I got -- I had this scrubbed and here is what I can give you.

We're a -- suppose there is a hypothetical transportation company with 100 gas wells, and I'm going to speak strictly to gas. Forty percent of the meters are going to have -- the meters tubes are going to have to be replaced because of either inspections or AGA non-compliance. A meter tube right now, shop value, is about $8000. We're running about a two and a half-to-one multiplier to install them.

There's another 40 percent of the tubes that are going to have to be modified. And because these things are out in less than high-populated, high-density areas, it turns out to be cheaper to

replace them with shop fab meter tubes than going out and buying them. So we're looking at of 100 meter tubes, 80 of them being replaced. That's a cost of about $2.2 million.

Those electronics, I talked to Mike about this, Mike Wade, a couple of weeks ago. Now our read of this FMP requirement, and I understand why you want it, is that the only way we'll be able to get to assure the FMP, which is not only the station and drawings, but on any document or report that you can get or might get or could want, is it will have to be redesigned to fit the computer. We also have to have our own tag meter in there to meet -- that meets the Instrument Society of America requirements and our own internal policies.

There's no -- we don't know of a single flow computer installed today that will accept an 11 character tag name. We have one that will do 10. But none will do 11. And none will take two tag names.

In addition, we have perfectly good working flow computers now that have been out of manufacture for a number of years. They will not -- we don't think they'll make it to the approved equipment list, because how are you going to -- how are you going to ask the manufacturer who doesn't make them to send them in for testing. So we're looking at 100 flow computer changes, which is about $875,000. Flow computers are 2500 bucks a piece.

We did do -- we have gone through this pretty stringently. The other pipe modification based on minimum pipe tubing sizes and blah, blah, blah. We think we're going to be spending about $87,000 on, this 100 meter company would.

Gas chromatographs, this company would have to -- would have to buy additional gas chromatographs because of the increase in the samplings. That is $70,000.

Personnel. It is going to take more people to do the inspections and run to catch the samples and to run them. So for this 100-meter company, that's about a 300 -- two people, 300,000 per year cost if they're fully benefited. They are going to have to buy vehicles. It is going to add another 4-wheel drive, three-quarter ton, whatever heavy duty truck, and that is $70,000.

We're going to have -- the company is going to have to buy a fluoroscope. They're 60 grand a piece.

The accounting system. This is not

the biggest cost, but it's a killer in terms of time.

The first FM -- if I read this correctly, the first FMP the company receives would have to be in compliance within 30 days. It's going to take two years to modify a mixture of major vendor software and homegrown software in accounting systems, because all the accounting systems, volume accounting systems, would have to be modified.

And at the end of the day, the total cost is about, for a 100 meter company, would be about $4.2 million.

An interesting thing is, if I talk now about Enterprise specifically, we measure the gain/loss on all of our systems. And we've looked at the last 12 months. BLM systems, we're within a quarter percent gain/loss systemwide. And we measure systems from the wellhead to -- all the way to Mont Belvieu in some cases. But on the BLM-specific equipment, we're within a quarter of a percent. So for $4.2 million nobody is going to get anything.

In fact, if you look at -- if there -- because measurement is inaccurate, it's not a direct, you know, you can't count 100.00 molecules yet. There is a risk of plus/minus that at the end of the

day, you know, in fact right now we're showing that we're over accounting for gas delivered from BLM meters. There is a chance that we would say, well, we got better measurement, we're not paying you as much, because the volume went down.

So, we would be out for this 100 company -- 100-meter company would be out $4.2 million and everybody could lose.

MS. LIZ O'BRIEN: Can I ask for a wrap, please, sir?

MR. FRED YOUNG: Yes, ma'am.

MS. LIZ O'BRIEN: Thank you.

MR. FRED YOUNG: Two things. There is safety concerns here because of the amount of repressuring and depressuring that goes on in the field while this work is being done. That's an increase in personnel exposure. And there is supply problems, because last year the BLM on BLM lands in New Mexico there were, I think, 920, give or take, wells completed. You all have 66,000 meters in service. How many of them are going to get -- how many meter tubes are going to get replaced? Who is going to make them? Who is going to install them? Who is going to house the people installing them? And who is going to provide flow computers? We're

going to all be scrambling for the same first one out of the box. And we don't see any way to support this that's worth that effort.

And I guess lastly, we would say, you know, we think that there should be some sort of grandfathering based on performance. I don't know. There is better ways to say grandfathering. Don't raise your hackles. But there ought to be credit given where systems that are performing well. And if the intent of the BLM is to have a database, it would be cheaper on everybody for BLM to develop its own server and database with the company information and well information and loop numbers so that BLM is on the same page with the producer, transporter, whatever, rather than however many entities there are developing their own systems. Thank you.

MS. LIZ O'BRIEN: Thank you. Would you like to respond to anything that was just said? Anybody?

MR. MIKE WADE: The only thing I would like to add, have you submitted this in writing to us? Or are you planning on it?

MR. FRED YOUNG: We are in the process of writing them right now.

MR. MIKE WADE: Thank you.

MS. LIZ O'BRIEN: Can I just add something

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to what you just said? Now I know nothing of what you're talking about, but what I think is important is that when you express your concerns generally, I think, if you have a solution, you probably ought to throw that at it, too, because they're looking for all the information that they can get and the solution might be helpful.

MR. FRED YOUNG: We are.

MS. LIZ O'BRIEN: Okay. Good. Thank you.

MR. RICH ESTABROOK: Let me just say, some of your numbers surprised me. And again, I hope we'll get this in writing. But basically you're saying you would have to replace 80 percent of your meter tubes?

MR. FRED YOUNG: That company did, yes.

MR. RICH ESTABROOK: Again not -- just talking about it here, but I'd be really curious as to what is triggering that.

MR. FRED YOUNG: A number of things. One, the -- remember we are -- we do measure within a quarter percent. Now when you inspect if you come out with and you don't meet all the exact criteria in terms of the smoothness or roughness, however you want to say, the eccentricity, if I can say that

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right, but the orifice plate, all of those things, that you now go into you don't meet it, you have to replace the tube, there's no question.

The other is when you go from the pre-'85 to the current AGA 3, you don't have the tube in there, there is a different in length between the two meter runs. And that is even more expensive, because now you've got to move the block house and you've got to figure out how to depressure more than just the meter tube. Does that make sense?

MR. RICH ESTABROOK: I think so. I would hope -- hope to get that specific information as part of your comments.

MR. FRED YOUNG: Okay.

MR. RICH ESTABROOK: Yeah. That would be helpful.

MS. LIZ O'BRIEN: Okay. Thank you.

Dean Graves. There you go.

MR. DEAN GRAVES: Thank you. Rich was hoping I wasn't going to talk.

Dean Graves with Devon Energy. And as you can guess, I have got a few questions and comments. Rich and I go back a way this a way.

Been reading the document, a lot of detail,

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Onshore Order Number 5, and varying grossly, and recently making sure we're putting our statements together.

And this is the scenario I'm having to tell my management. I've got a well that flows 101 Mcf a day, older well, heater tube was put there in about 2000, maybe a little later. The -- it's on plunger lift. I am making some liquids at the separator and dumping, worse during the wintertime.

To comply with the document, to comply with these documents and my experience with these documents, based on our experience with the NPLs, what has been proposed will become the law unless y'all make a change to it. That's the way it's been written.

So the way it's written right now to -- when this comes into effect, unless I change the meter tube and replace the meter tube, replace the EFM, I'm going to have to shut it in. I cannot flow it, because there's nothing been approved. I have to meet the approval list that the BLM will provide. There are zero meters on that. So, at this point, right now, when it becomes law and at the six months or 101 it would be 12 months, if there's not something there for this particular equipment that I

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have on the EFM, I shut it in. I will have to change the meter tube, because it will not meet the eccentricity requirements that are stated on the 2000.

Since I am making liquids, I am very likely over a quarter percent, C6+, I am also likely having a variability in my BTU greater than 1 percent or 2 percent. So I will be having to install a composite sampler, if not an on-line chromatograph on a 101 Mcf a day well to keep it flowing.

The cost of installing the tube, eight grand, as you all show in the -- as your document for your rate of return, is just a bare minimum. It didn't include the connection fee, that didn't include the work doing it, as Fred was saying. And the EFM, you add all that together, it's easily between 25 and 50 grand to make those changes right there.

The adding a C9 on-line chromatograph to comply with the requirement and the heating element, you may be upwards of 75,000 to comply there on a C9.

The -- then you add to it, I bring my data in to Flow-Cal, Flow-Cal or PPS, whichever one it is. I would not be able to supply you data because you will not allow that from the Preamble from the

Flow-Cal. And that's what the Preamble says. And so I've got to find a different way to get the data.

It looks like, the way it's written, that I will not be able to do editing, even this seems strange, but that's sort of the way it can be interpreted by an inspector of the data.

The other thing is, if my meter is connected by regular tubing and a manifold, I'll have to install a half-inch tubing and a half-inch manifold, I'm not sure how much those cost, because the existing 3/8ths will not be acceptable per the document.

The concept that Fred mentioned in his scenario is we see 80 percent-plus of our meters above 100 Mcf a day will have to be replaced. Meter runs, EFM. Right now, EFMs do not comply. The amount of data you're looking for, the size of the FMP, even though the FMP number is a good concept, the cost of putting this is going to be well exceeding the economic.

What we've also found is we get zero return on doing these. And the other thing that we see is the concept is to improve uncertainty. Very, very noble. Totally agree with the concept of uncertainty.

The BLM document in the Preamble calculates the Mcf a day -- 15 Mcf a day and the concept of rate of return of 15 percent, and a cost of equipment of 8,000. The cost of equipment is between 25 and 50,000, the rate of return is different than that, the 15 Mcf a day becomes very uneconomic. That's really an arbitrary number. The numbers above that is pure arbitrary, from what we could tell. There's no justification on how they're achieved.

We are -- the company has put together a document to show a suggested rate of return on how that could be -- not rate of return, but a calculation on how to do that to return that. And so, we're suggesting different tiers, tier levels, based on numbers, not just pulling numbers out of the air.

The other thing that we're seeing is the uncertainty concept. The uncertainty concept is equated -- in the Preamble, shows the justification on the 15 Mcf a day as if the uncertainty improvement is going to gain volume, gain revenues to whoever. Uncertainty is, if there's an error, it can go either direction. Okay? So uncertainty says there's a possibility of error. And so, if we're trying to achieve a 1 percent, or, in the case of 101 Mcf a day

a 2 percent uncertainty, that assumes that there's a 2 percent error, which there may not be. But, if there's an error, it could go either way. The true -- there is no true rate of return. No true -- nobody gains dollars by accomplishing this. Accuracy can be improved, but it gets to the point of exceeding the ability.

When you get to the BTU, you go away from uncertainty until you get to the variability is how it's all written. The concept of I've got a well out there that's making some liquids in the separator, my BTU will swing. If it swings -- at 101 Mcf a day, if it swings -- if it's showing 1150 and it swings 30 throughout the year, that means I'm going to have a composite sampler on or maybe an on-line GC.

MS. LIZ O'BRIEN: Mr. Graves, can you wrap up, please?

MR. DEAN GRAVES: I have to wrap up? I just got started.

MS. LIZ O'BRIEN: I know. It's frustrating.

MR. DEAN GRAVES: Okay. So the bottom line is, the way it is written, we will be shutting in, we'll have to, to comply, shutting in these locations, because we'll not be able to meet it. The cost of doing this is extremely expensive. The rate

of return for us is almost zero.

And so, we ask that you look at these things. We understand what you're trying to accomplish, we understand trying to get the accuracy, but when you start trying and get down to the nth detail, this is tremendous, what it means to us.

So, okay. I will hesitantly -- will quit.

MS. LIZ O'BRIEN: Don't throw that thing at me.

MR. DEAN GRAVES: They say I'm always that way. I'm sorry.

MS. LIZ O'BRIEN: Okay. Thank you.

Kathleen Sgamma.

MS. KATHLEEN SGAMMA: Thank you. Kathleen Sgamma with Western Energy Alliance.

And, you know, we really do understand what you're doing. We totally agree. We're -- you know, we all have an interest in accurately measuring our products. So we do share that goal.

However, it's hard to see right now with 2007 pages, and, yes, I'm that anal that I do count these things, of open regulations right now between BLM and EPA, with Onshore Order 9 coming, it's hard to look at some of these regulations and not see sort of a punitive nature about them.

We had asked for all of the Onshore Orders, including on Shore Order 9 coming up, to have overlapping comment periods. We do appreciate that Onshore Order 3 was reopened. However, when you really look at it, it was an extra 17 days for one of those regulations. So, I don't think we've got enough time for both industry and BLM to do what it's trying to do with this very complex, technical regulation.

So we would ask for not only more implementation time, but more time to respond to these, to these regulations. And I think, you know, your staff is feeling the strain as well.

MS. LIZ O'BRIEN: Thanks. May I interrupt you for a second?

MS. KATHLEEN SGAMMA: Sure.

MS. LIZ O'BRIEN: When you say more time, what are you talking about here?

MS. KATHLEEN SGAMMA: More time commenting.

MS. LIZ O'BRIEN: Right. But how long?

MS. KATHLEEN SGAMMA: Well, we had asked for 90 days of overlap for all the Onshore Orders, all four of them. That was probably -- I mean, I understand that might have been too much, but certainly 30 days of overlap with 9. I think we're

all struggling to understand these regulations. We're all struggling to understand how they would be implemented. We're struggling to understand, you know.

I think your point was a great one. And I would frame it, instead of grandfathering, as not being so retroactive. You know, you look at things like details like providing equipment numbers to the Facility Measuring Points retroactively. I mean, how many producing wells does BLM have systemwide? Something like 90,000, right?

MR. STEVE WELLS: 94,000 active wells.

MS. KATHLEEN SGAMMA: 94,000. I mean, it just is a lot of retroactive application or implementation that is, indeed, going to shut down production. It's looking at trying to track down hypothetical losses in royalties which will result in actual, you know, shutting in of royalties. So it's that being penny wise and pound foolish as we try to track down to a very specific degree.

And again, we all appreciate and understand the need to be accurate, but when we're chasing a few million, we are putting billions at risk.

So, that's kind of what we're struggling with right now. And it's been awhile since I read the GAO Report in conjunction with the first round, Onshore Order 3. But, I mean, was there -- was there a display of willful -- of willful -- is there evidence of willful, you know, cheating on measurement? Is there really a problem with industry really not reporting?

I think we try, our members try, to report as accurately as possible, to pay an equitable royalty. But again, we're getting to these very specific regulations.

And I appreciate, Rich, that you're -- you know, there is more performance-based standards in the new regs, but there is still a lot of that cookbook. And you look, is that cookbook really providing the value, especially when you're looking at the costs of that retroactively.

So, you know, we have a desire, again, to accurately measure, to make sure that we're bringing regulations up so that new technologies can be used and we will be flexible for the future, but we still see a little bit too much of that cookbook.

And I would like to bring up the issue of commingling, because I understand from the Durango

session that the idea there is to retroactively go back and cancel unitization agreements. And I'm trying to -- I'm really trying to struggle with -- or we're really struggling with understanding why, you know, that system of CAs would want -- you would want to upend that whole system, because, again, that's going to shut in quite a bit of production, again resulting in less royalties, not more.

MS. LIZ O'BRIEN: Kathleen, would you like that question to be --

MS. KATHLEEN SGAMMA: Yes.

MS. LIZ O'BRIEN: -- addressed by --

MS. KATHLEEN SGAMMA: I think so.

MS. LIZ O'BRIEN: -- one of these guys?

MS. KATHLEEN SGAMMA: That would be great.

MS. LIZ O'BRIEN: Okay. Who wants to take that one?

MR. RICH ESTABROOK: I think with the CA issue there was -- I think there is some -- a mass confusion.

MS. KATHLEEN SGAMMA: I'm sorry?

MR. RICH ESTABROOK: I think there might be some confusion on that one. So I think this was -- this was brought up in Durango and I just want to make it really clear.

So if you have a CA, a Communitization Agreement, and that Communitization Agreement has multiple properties on it, some Federal, some State, private, whatever, the production from that CA, even if there's more than one well, that's not commingling. Okay? That -- it's all based on the CA.

So commingling, from our definition, is the combining of multiple sources of prior-to-the-royalty measurement. A source is an uncommitted lease or a unit participating area, or a CA or a non-Federal property.

So again, if you have a CA, even though there's multiple ownerships in there, that's -- if you measure the production anywhere on that CA, there's no commingling that's happening.

Same with a PA, a Participating Agreement. You can have a giant participating area with 100 wells on it and 50 different property owners. If you measure once all that production coming from all those 100 wells, if you measure all of those measurement points right at that PA boundary, there's is no commingling, there is no flow meter requirement.

So I want to make sure that's really clear. A CA is a source. And as long as you're not combining that source with another source, there's no commingling and no approval requirement. Okay?

MS. KATHLEEN SGAMMA: Okay.

MS. LIZ O'BRIEN: That was a big question in Durango also.

MS. KATHLEEN SGAMMA: Yeah. And perhaps I had misunderstood the feedback from Durango, because I thought it was stated that many CAs would be rescinded as a result of this process.

MR. RICH ESTABROOK: Not Communitization Agreements, if that's what you're -- I am assuming that's what CA stands for.

MS. KATHLEEN SGAMMA: Right.

MR. RICH ESTABROOK: No. No. Communitization Agreements or units are great ways to avoid commingling.

MS. KATHLEEN SGAMMA: Okay.

MR. RICH ESTABROOK: Yeah. We would encourage them.

MS. LIZ O'BRIEN: Information.

MR. RICH ESTABROOK: Yeah. So -- and there was some confusion there.

MS. KATHLEEN SGAMMA: Okay. Because I heard

that was a hot topic of conversation. You know, when we read Onshore Order Number 3, we looked at it as, you know, almost a nonsensical result. And maybe it's the way it was worded whereby, you know, I mean, the whole point, obviously, is to bring together a multiple --

MR. RICH ESTABROOK: Exactly.

MS. KATHLEEN SGAMMA: -- a multiple ownership.

MR. RICH ESTABROOK: Yeah. We'll look at that and we'll look at clarifications, if that is confused, if the language is confusing.

MS. KATHLEEN SGAMMA: But why go back and, again, retroactively look at all of those agreements? You know, why not just move forward? I think that was one of our main comments and will be of all of these, you know, and with the reopening of it as well.

MR. RICH ESTABROOK: Okay. And, you know, we'll definitely consider that comment.

If I could just make a general comment. You know, we hear this -- we heard this a lot in Durango about how these regulations would shut down a bunch of wells and cause a lot of economic hardship. If that's what happens, then we have failed miserably in

these regulations, because we don't want that. That's exactly the opposite of what we want to happen.

So if that's reality for the producers out there, then what we need, because we're not -- I don't think any of the three of us up here are -- have ever been an operator, we don't know what you go through. If that truly is the case, excuse me, we need to know what are the provisions that are especially onerous, why are we they onerous, and can you provide -- and what would be really helpful is, can you provide a different, less-costly way for us to achieve what we're trying to achieve.

That would be enormously helpful to us, because I will state it flat out. If you guys start shutting in our wells because of these regulations, then we have completely failed in our mission. Our mission is to get revenue, the production of our oil and gas. Which, obviously, if we get less production and less revenue, that would be -- that would be silly. So --

MS. KATHLEEN SGAMMA: Well, we -- Sorry.

MR. RICH ESTABROOK: No, so I was going to say, so, please, help us, the non-operators up here, understand what is -- what are the onerous regulations, why they are onerous. Some data would be helpful of what is the cost, and the gain, and I think Fred is going to get that to us. And again, how can we achieve the goals we're trying to achieve. And that would be very helpful.

MS. KATHLEEN SGAMMA: Okay. And we certainly will in our comments. I think implementation time, especially if it's retro -- I mean, we would say don't go back retroactively for 94,000 wells. Let's look forward to the future. Let's make sure it's less prescriptive and more performance based. But I think there needs to be more time, if there is meant to be that retroactive element. I think we need a lot more time.

I think some of the comments on, you know, just -- on getting some of this equipment would certainly be a bottleneck, because there wouldn't enough manufacturer supply.

So certainly, we will comment. Appreciate the ability to provide comment today. I'm wondering if you can share a little bit from the morning session with the Tribes. Are they concerned about, you know, how this would affect development? Do they understand, you know, some of these shut-in issues?

MR. RICH ESTABROOK: The session this

morning was mainly a listening session. We honestly did not get a lot of feedback.

MS. KATHLEEN SGAMMA: And Durango, same thing?

MS. LIZ O'BRIEN: Not quite.

MR. RICH ESTABROOK: We got some feedback in Durango. And I think some of those concerns were shared by that as well. But that went sort of --

MS. KATHLEEN SGAMMA: All right. Thank you very much. I guess I hear you about saying put it in writing, but I would just add again, and, you know, perhaps, after being on the receiving end of lots of regulations just this year, not just from BLM, which is starting to feel like a, you know, an onslaught to us, that when we look at the time to implement this before the election next year, it kind of strains pejoratively to think about how that can all actually be done for some very complex regulations, in conjunction, of course, with Onshore Order 9 coming up, which will be a completely new set of requirements.

So we're feeling a little shell shocked. We're feeling a little bit as though, you know, when we do put things into our comments, like the hydraulic fracturing rule, we did see improvements

from the first draft, to the second, to the final, but still many things that, you know, make us wonder, you know, how can we implement this and how can we continue to operate on Federal and Indian lands. Thank you.

MS. LIZ O'BRIEN: Thank you. Kenneth Fairchild.

MR. STEVE WELLS: Do you mind -- Karen, do you want to respond or maybe --

MS. KAREN MOURITSEN: Oh, well, I'll just -- I'll just say, we do appreciate that you're making the comments and, like you talked about, the fracking rule, we did go through all the comments. We got a lot of them. But we went through them, and so, thank you for acknowledging that.

And we hear your point. Right now this is when the comment period ends. And it sounds like you all have thought through at least some comments. So, please, give us the comments you can. And thank you for doing that, for coming here, and we'll really look at them seriously.

MR. STEVE WELLS: Well, I can add to that. Hi. I'm Steve Wells. I'm out of the Washington Office. I work with these guys.

Just for a little more context, we've

glossed over it. It is in the Preamble, but why we're here today, too, is this has been going on for quite some time. 2013, we did a stakeholder forum. Rich basically conducted that. The idea was to get it out on the table, things we're looking at to address; measurement, accuracy, precision, those kinds of things. And we welcomed that feedback. That helped us guide this.

But if you go back even further, in 2007 there was a Royalty Policy Committee that had a bunch of recommendations for the Department of Interior, you need to do this, this and this.

In 2010, we had -- the Government Accountability Office came to us and said, you know what, with you need to tighten your standards out there. Well, we all knew that these regulations from the 1980s needed some help and we needed to update it. But they gave us specific guidance. The Office of Inspector General also chimed in. In 2011, the Department of Interior put on the High Risk Board production accountability.

So, it isn't just our decision here. We're trying to find the best fit, like Rich was talking about. How can we achieve these measures.

And I think the words we're hearing from some of the consultants here, Devon and others, and the pipeline company, is maybe the threshold should be changed. Maybe the phase-in period should be changed, and this is why, this is the economics, this is the impact.

Those are the things that we're asking for data on that you could provide to really help us out to make the best rule out there. But I don't think we can say we're just going to leave it as-is.

The reason we're on this high risk is because of these existing properties out there. The GAO was not so worried about what's going to happen with the new well that comes in in 2017. They are worried about the 23,000 producing properties out there and ensuring that we end up getting the proper royalty accounting, whether it's up or maybe it's down. We know that it can go either way on these errors. But the idea is it should be accurate, it should be defensible. We should have documentation. When we do these audits, we can defend it.

So there's a lot more to it. I know we have kind of glossed over with some of the slides or background and in the Preamble, if you want to read through all of those documents. But we do explain a little bit more of how we got here and really how

important it is to have that kind of feedback and the data, if you can share data.

This was a Proposed Rule based on what you've told us from 2013. So we're hoping that our final rule will incorporate the things that you say, you know what, you guys were close, but you need to do this much or do this differently. And we're willing to hear that.

So that's why the Proposed Rule is out there. We're trying to give you as much time as possible. But we've had some very good comments.

We had an outreach at the API Meeting so that we could explain some of these things and get comments. We have been getting comments in from some of the companies already. So we've had some very good stuff already. But anything else that you can provide between now and December 14th would be awesome. Thank you.

MS. LIZ O'BRIEN: Thank you. Ken.

MR. KEN FAIRCHILD: Ken Fairchild with WPX. Everybody is hitting on gas measurement and --

MS. LIZ O'BRIEN: Ken, can you speak closer to the mike?

MR. KEN FAIRCHILD: Sure. Everybody is hitting on gas measurement, and I deal with a lot of

oil, on the order of 3500 run tickets per month, and that's a lot of gauging, a lot of technical work that goes on with that.

The thing that concerns me is this changing the tank strappings from a quarter of an inch to an eighth of an inch. I did some little calculations while you all were talking.

On a 12-foot diameter tank, that's either a 210, normally it's a 210, or a 400 barrel tank. That's 1.77 -- excuse me -- 1.667 barrels per inch if it's a perfect cylinder. If it's on a quarter-inch gauging, the accuracy is 99.76. To go to an eighth inch is 99.88. Yet, on your LACT meters, and, unfortunately, you went through that slide too fast for me to write it down, but I recall a .35 percent accuracy on a 10,000 a day LACT unit, 1 percent on a thousand and 2 percent on 100.

Now you asked where did I get those percentages on my LACT tank straps. The average load ranges from 170 to 175 barrels on a single truck. Then there is other trucks that will actually pull -- they have a little tandem, and they can do 280. That's where you are, Wyoming or out in New Mexico, DOT regulations. So, you can see if it's a 280 barrel, that goes -- the accuracy is phenomenal,

better than your gas measurement. I mean, Dean is right.

And the other thing is, I can take anybody in here and he and I can go walk up on a tank, we can both gauge and, I guaranty you, we will not get the same gauge within an eighth of an inch. And so, if you're sitting there worrying about that eighth of an inch, might be high one time, might be low the next time, let's flip coins, guess what, it is going to even out and be very accurate.

You know, I don't see where this kind of thing is gaining the BLM any extra revenue for the U.S. And to go out and strap a tank in Wyoming for a quarter inch is $3,000 per tank. I've got 600-plus tanks on Federal lands. So -- and this is at current prices, because I don't know what they're going to charge me to go out there and put in 4 gallons and measure it, 4 gallons and measure it, 4 gallons and measure it. But $1.8 million? For what? What are we getting?

And let's go to thresholds, because that was brought up. Our wells start out, especially these unconventionals, they'll start out 2 and 3 million a day, a thousand of barrels of oil a day, they are on rapid decline, very rapid decline. Within six months, it will be at a half of that rate or even lower. I don't think anybody here will argue that.

So, what criteria? Where is the threshold? That threshold, we're moving through the thresholds very quickly. So you're asking me to go put all this, all this equipment, all this expense on a brand new well that's going to be down there in the very low range in a very short time and now I have to maintain that equipment with techs. It's, you know, it's crazy.

And then back to somebody said grandfather. I have -- I say I am responsible for, probably, 150 very-low volume wells that are scattered all over New Mexico, can't afford this. So we'll end up shutting them in, unless it saves us the acreage that's critical for development, and now you've lost that revenue and you will never get it back. I'm done.

MS. LIZ O'BRIEN: Thank you.

MR. MIKE McLAREN: I think that --

MS. LIZ O'BRIEN: Oh, sure.

MR. MIKE McLAREN: What we need then -- what we did is implement the current industry standard of API 3.1A.

Now if we can get comments with data saying don't do that, that's what we want. Again, we just

looked at the current industry standard when we looked at that. That's where that eighth inch came from.

So, please, submit that data in your comments. If we can get data saying eighth inch isn't feasible, we are definitely going to consider that.

MR. KENNETH FAIRCHILD: Good. Because it's not enough. I mean, you're going to have to shut these wells in. I mean, these wells, that will take me, you know, six months to pay out restrapping these tanks from all the tanks that we sell from on that location.

MR. MIKE McLAREN: Right. And I think we can justify, if we're not going to follow industry standard, we can justify that with your comments. But I can't honestly propose a rule that's not following an industry standard with no justification.

MR. KENNETH FAIRCHILD: Right.

MR. MIKE McLAREN: So I appreciate your comment. Thank you.

MR. KENNETH FAIRCHILD: Okay.

MS. LIZ O'BRIEN: Okay. Thanks very much.

I don't know whether if I'm supposed to sing this next line.

MS. KAREN MOURITSEN: I think you could just say it.

MS. LIZ O'BRIEN: There is an operator somewhere and we are ready to take questions from those on the phone.

CONFERENCE OPERATOR: If you would like to ask a question, to ask a question, please, press star 1, please, un-mute your phone and record your name clearly when prompted. One moment, please.

If you would like to ask a question, please, press star 1.

MS. LIZ O'BRIEN: Hello?

MS. KAREN MOURITSEN: There will be a little bit of a delay here.

CONFERENCE OPERATOR: I'm showing no questions at this time.

MS. KAREN MOURITSEN: Okay. So are we coming back to --

MS. LIZ O'BRIEN: Is there anybody that would like to speak that has not spoken? There's got to be one of those. No? All right. We can work -- I found somebody.

MR. STORMY PHILLIPS: So I see how it works now. Anything that keeps me off the mike, Bob.

MR. ROBERT FRITZ: Exactly. Right. You

normally talk so much.

I have got just a couple of questions in general.

THE COURT REPORTER: Your name, please.

MS. LIZ O'BRIEN: Your name?

MR. ROBERT FRITZ: Robert Fritz with Enable Midstream. For the distinction between transporters and operators, from what I am seeing from the Onshore Orders, you're not making any distinctions at all and I'm not sure exactly where we fall in that. In other words, if we're picking up gas from a BLM, from a meter at a BLM site, are we, as transporters are we, responsible for the same level of paperwork and everything with regard to that meter, and volumes and all that as is the operator?

MR. RICH ESTABROOK: First let me ask, is it your meter?

MR. ROBERT FRITZ: Yes.

MR. RICH ESTABROOK: Okay. Then the answer would be that you would be responsible for all the recordkeeping, the record retention requirements as the operator would be.

MR. ROBERT FRITZ: The same thing as he would be.

MR. RICH ESTABROOK: Yes, sir.

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MR. ROBERT FRITZ: Who would answer to you? I mean, are you going to go to him first and then come to us? And also on all that, we can't go back to like Flow-Cal or B Gas or whatever, or our homemade system, and pull it, pull the data, when you come to us on that?

MR. RICH ESTABROOK: The proposal is that we want raw, unedited, unmanipulated, whatever, data from that meter. So it would have to come directly from the flow computer or, if we could get assurance from third-party software companies that we are, indeed, getting raw, unedited, unmanipulated data, we would be willing to accept that.

MR. ROBERT FRITZ: For how far back?

MR. RICH ESTABROOK: Well, the law, this is in a law, not even a regulation, is seven years for Federal, six years for Indian.

Now there is some -- some additional requirements for recordkeeping if there is a judicial action going on. But the basic standard, seven years Federal, six years Indian.

MR. ROBERT FRITZ: For raw, unedited data for hourly data?

MR. RICH ESTABROOK: Well, yeah. Whatever is out there. We normally require -- we normally

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require daily, daily records.

MR. ROBERT FRITZ: Okay. Even daily records --

MR. RICH ESTABROOK: And again, that -- the record retention requirements of seven years and six years is statutory. That's Federal. Federal Oil and Gas Royalty Management Act established the six year retention for everybody. The Royalty Simplification and Fairness Act in 1996 came back and said for Federal we're going to change from six years to seven years. So we have no flexibility on that whatsoever.

MR. ROBERT FRITZ: Okay. The next thing is move that back, probably more on the liquid side, if the operator is either tank gauging or has his own meter for the wells, he's collecting from the BLM land, and then downstream of that we have a LACT metering skid where he is selling it to us and we're putting it in a pipeline, are we then still required that, the same recordkeeping and the same BLM requirements, as he is with his meters?

MR. RICH ESTABROOK: My question would be, which set of meters is royalty being paid on?

MR. ROBERT FRITZ: I would assume it's his.

MR. RICH ESTABROOK: Then that's where the

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obligation stops.

MR. ROBERT FRITZ: Okay. And then my final quick question, if I might --

MS. LIZ O'BRIEN: You sure can.

MR. ROBERT FRITZ: I can talk as much as Dean can.

MR. DEAN GRAVES: No, you can't.

MR. ROBERT FRITZ: Almost as much as Dean.

MS. LIZ O'BRIEN: He's got a reputation, it sounds like.

MR. ROBERT FRITZ: Not the great Dean Graves.

Anyway, seriously, on the implementation of API standards, we were talking about this earlier, with like tank gauging, an Automatic Tank Gauger, that's an excellent example, or with API 14.1, you were talking about that with gas sampling, is not the data and the research that's available from API that they based their international standards on acceptable?

And you're looking at me strange, Rich. We --

MR. RICH ESTABROOK: I'm going to --

MR. ROBERT FRITZ: Ask it to the rest of --

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MR. MIKE McLAREN: I'll speak to the automatic tank gauging.

MR. ROBERT FRITZ: Yes.

MR. MIKE McLAREN: Okay. The API has a standard out there.

MR. ROBERT FRITZ: Yes.

MR. MIKE McLAREN: There's a company who took the automatic tank gauging and they tested it. They tested it on private leases comparing it with the manual tank gauging. And they did find there were certain conditions, certain configurations that wasn't working for them. They were finding different mixers -- different results from different mixers, different results from different sample locations. And they were piecing them together so they could come up and meet the same accuracy they could with the manual tank gauging.

And then with that, they presented that data to the BLM Office in Colorado, in that area to use it. But that's the testing that we -- that we were talking about. And that's the data that we're asking for. And on that particular one they were using flow meters. They didn't use a --

There is a company in Montana right now doing the same testing. They are using a radar gauge, they are using a different mixing system, different sampling systems, different temperature determinations.

That's -- when I talked about requesting data, that's what I'm looking for. That's what we're asking for.

MR. ROBERT FRITZ: I would submit that all of those things that you just indicated would need to be -- the mixing for the temperature stratification is just as important in manual tank gauging as it is with automatic tank gauging.

MR. MIKE McLAREN: Right. And that's what they're comparing is the manual tank gauging results with their reference as a hybrid tank measurement system. Different methods to determine temperatures. Are we getting the same results as gotten when we gauge in the tank. The sampling, the mixing sampling, are we -- at what part of the flow through that line are we going to get a sample and get the same results as --

MR. ROBERT FRITZ: Okay. Well, that would be pricey if we're trying to get --

MR. MIKE McLAREN: Well, if that -- that method --

MR. ROBERT FRITZ: That's how I always --

MR. MIKE McLAREN: Well, we're starting to get down to the --

MR. ROBERT FRITZ: Okay.

MR. MIKE McLAREN: But if we implement that into the order, it's going to be the hybrid system. The whole process, you know, is what we would be looking at. And we'd be looking at it from an uncertainty-based standard. It's the overall that Automatic Tank Gauge, the sampling process, the temperature, is that all going to be the combined uncertainty.

And so, that's what these two companies, they are doing two different forms of hybrid-type systems, is what they're comparing against the current manual tank gauging. To receive the same results, the same temperature, the same API determination, the same write-up, that is what they are looking at. And that's what we're --

MR. ROBERT FRITZ: That really doesn't have anything to do with the gauging. The standard says you should -- we will not have automatic tank gauging. If you have everything else the same and you gauge the tank manually or you gauge the tank with an Automatic Tank Gauger --

MR. MIKE McLAREN: We could -- the intent of

why people want to go to the Automatic Tank Gauges is to get people off the tanks.

MR. ROBERT FRITZ: Okay.

MR. MIKE McLAREN: It's --

MR. ROBERT FRITZ: Where is the benefit if you use automatic tank gauging if you still have to go up on the tank to get the sample?

MR. MIKE McLAREN: No. No. No.

MR. ROBERT FRITZ: Well, that's not the way right now that we --

MR. MIKE McLAREN: Right. And so what people are testing out there and what we're hoping we get in the final rule is a hybrid-type tank measurement keeping people off the tanks. Keeping them off the tanks. And that's the data we're looking for.

MR. ROBERT FRITZ: Okay. I see where you're coming from. It's not just the gauging, it is the whole process.

MR. MIKE McLAREN: No, it's the whole process.

MR. ROBERT FRITZ: Okay. Richard, you said that initially that you were basing all of the Onshore Order 5 on all the latest international or API, AGA, GPA standards. But in your requiring for

C6+ a split of 60-30-10, and the GPA standard says you use 60-30-10 only if you don't have better data.

MR. RICH ESTABROOK: Well, I --

MR. ROBERT FRITZ: If we have better data, do we then say, no, we don't want to use 60-30-10?

MR. RICH ESTABROOK: That's a comment that we would consider.

MS. LIZ O'BRIEN: Okay. I'm going to have to -- I'm going to have to get a wrap.

MR. ROBERT FRITZ: Okay. She's telling me to shut up now. Okay. Yes, ma'am.

MS. LIZ O'BRIEN: I did not. Okay. We had a couple of other hands up here.

MR. STORMY PHILLIPS: I didn't realize we could ask so many questions all at the same time.

MR. ROBERT FRITZ: You don't talk as much as I do.

MR. STORMY PHILLIPS: I actually just have some more clarification questions. Stormy Phillips with WPX Energy.

One is, during the royalty determination slide that you showed at the very beginning, you showed that the volumetric and the heating value had equal standard or effect on the royalty rate.

Why is it that you decided to have a higher uncertainty level on the heating value, as opposed to the volumetric measurement?

MR. RICH ESTABROOK: Part of it was what we thought was reasonably achievable. The 3 percent is a number that we have been using for over 100 Mcf a day now for a number of years as the state NGL. And the proposal is 2 percent for over a thousand Mcf per day. We think that, because normally those high volume wells or high volume meters are flowing much more consistently and often measuring a more processed product, we thought we could do better than that. Again, we're open for comments on that.

The heating value, again, we're talking about average annual heating value uncertainty, which I equate with variability. And we could talk about that more, too.

That -- those uncertainty standards or uncertainty proposals we're actually based on where the cost of obtaining those uncertainty levels meets the risk of under or overpayment of royalty, if that makes any sense. That was the basis of a lot of the thresholds we used on Order 5 and, I think, on Order 4 as well.

MR. STORMY PHILLIPS: In an effort to reduce some of the strain on transmitter and equipment

manufacturers, would the BLM be willing to approve the release of existing data for review by the PMT, rather than reconducting the tests?

MR. RICH ESTABROOK: We -- I mean, sure. Yeah. We'd take a look at the existing data and see if that meets -- meets what we're looking for.

MR. STORMY PHILLIPS: And one last question involving the Performance Measurement Team.

It seemed to be, or even in what you stated, that a big purpose of that is to try to stay up-to-date with new equipment as it comes out. However, some of the areas of especially gas measurement that we've had the most technological growth in has been linear meters, which in the standard are only going to be accepted on a case-by-case basis, still requiring variance.

Since that's likely to be the area of the most technological growth, isn't that kind of counterproductive to the PMT idea?

MR. RICH ESTABROOK: Well, you know, that's the proposal in the rule. We still have issues with linear meters as far as verifiability. In the comments, if we were supplied enough data to satisfy our discomfort with the verifiability aspects of linear meters, we could certainly consider an

alternative.

And even with the proposal, there'd be a case-by-case approval of linear meters and then the BMT would be doing that as well, but only on a case-by-case basis application specific.

MR. STORMY PHILLIPS: And there's no consideration for documents like AGA Report Numbers 7, 9 and 11 that address those style or at least the three examples used in the document?

MR. RICH ESTABROOK: I mean, there certainly could be. Again, our main concern with the linear meters is the verifiability aspect of it. And I don't know -- I'm actually not that familiar with those documents. And if there's -- if our verifiability concerns could be addressed, then, yeah, it's possible we would consider them.

MS. LIZ O'BRIEN: Thank you. I had a hand up over here somewhere. I'll get around to you.

MR. FRED YOUNG: Fred Young with Enterprise Services.

So I think everybody here -- and I'll preface this with -- understands the, you know, we're-the-government, we're-here-to-help-you concept.

When I read these documents, and we've heard a number of references to API and GPA and AGA

Standards today from you all, there appears to be a cherry picking, or some other phrase, of those documents. And part of me wonders what is the basis for that. Because if -- and I don't -- this is going to really sound bad, so, please, bear with me. Okay?

It feels like you all are saying, or the BLM is saying, some of these documents are good and some of them the BLM knows better. And that kind of flies in the face of the bases of those documents, because there's been a lot of work on them.

You know, and I can look specifically in Chapters 4 and 5 of the API and the BLM's where sections were specifically excluded. But it is through a number of chapters. And I'm just curious why, if you're going to use those documents, if you're going to refer to API and AGA and GPA, why aren't those reports accepted from stem to stern?

MR. RICH ESTABROOK: From the Order 5 standpoint, we actually carefully read through all the standards that we were accepting, either in whole or in part. On the gas measurement side, we excluded parts of some standards that were written in a way that we could not directly enforce or that were general statements that really were unenforceable and not standards at all. So we really wanted to focus on those, those sections of the API Standard, that we could implement and enforce specifically. So that was the case on a couple of the ones on the Order 4 and Order 5 side.

In some cases we -- we took standards and modified them a little bit to make them more enforceable. The one that comes to mind is the upstream and downstream LACT tables in API 14.3.2. This is kind of trivial, but those tables are a little confusing. They are a little hard to use, because, instead of giving Beta ratio ranges, like from .2 to .3 here is the requirements, from .3 to .4 here is the requirements, they give the -- they give the nodes, .3, .4, .5. So how do you use the table?

So we added something in there to make it clear how we use the table. I hope we did it right, but, if we didn't, I'm sure we'll hear about it. But that's the idea, because we were very deliberate in going through each one of those standards and making sure that we were only incorporating those parts of the standards that were relevant to our mission.

Like some of them had safety stuff in there. We're not a safety agency, so we excluded those. And that we could specifically enforce.

MS. LIZ O'BRIEN: Thank you. Operator, it seems that we have a caller on the phone.

CONFERENCE OPERATOR: Our first question today is from Ron Gibson. Sir, your line is open.

MR. RON GIBSON: Thank you, gentlemen, ladies. I appreciate you giving me the opportunity to speak. I have got several concerns. I want to try and minimize as many as I can and maybe touch on the areas that maybe have not been touched.

One of the discussion points, Rich, that you had mentioned was the sampling probe spot being -- even in your document and it even indicates that it's going to end up essentially being 2.8 to 9.0 pipe binders from the orifice meter. And this is in Section 3175.113.

My worry part is that, even as you kind of indicated in the regulation, it's different than API 14. And I'm not confident that even 80 percent is going to be enough to cover all the meter tubes that we're going to have to replace for some of our Beta ratios, because, obviously, you're going to -- you're going to try and go for the 2.8 size, which none of our tubes will go.

So can you give me some indication of what

the intent is? One of the things I heard you say was that the closer you are with the sample probe to the orifice plate your intent is to hopefully pick up heavier hydrocarbons that may be coming over in liquid phase and by the time you get to the sample probe it may be aerosol.

I have a fundamental problem with that, because we're not trying to measure two-phase liquids. And liquids, to specifically try to exclude, it feels like the transporter company, the transporter is being penalized possibly because of inefficient separation up there on the meter. So I have a little bit of heartburn on that.

I have a little bit of heartburn with the -- just the gymnastics of how you guys are going to approve all the different pieces of equipment that are going to come in to you in a timely fashion such that we, as operators, will know which pieces of equipment are going to be acceptable and which ones not. And in that time lag are we subject to minor or major violations and penalty assessments because you guys haven't got all the data resolved and on the board. And even the PMT is not functional yet.

Is it your expectation that the meter manufacturers and their -- the manufactured equipment

inspectors are supplied that data, or does that come from the operator to approve different manufacture -- different pieces of equipment, because we don't have any ability to do that. It would cost us a tremendous amount of money to do that. It should come from the manufacturers, but it is not brought out in that regulations.

And then finally my worry part is that the concern about water vapor corrections and assumptions. We have not been able to find some equipment that can accurately measure water vapor at pressures less than 100 pounds in any effective and economical fashion. And trying to understand why the assumption of fully saturated -- granted, there are times when it possibly could only be partially saturated, but the assumption of fully saturated, which has worked in the past for a very long time, you can -- I would just mention to you that, you know, our accuracy percentages aren't all new. They are very old on some of our data systems, and why that is no longer an acceptable method, because I don't think we're going to be able to monitor water sampling water and take water samples on all of our meters.

MS. LIZ O'BRIEN: Okay. That was a big,

long question, Ron. Let's give it to somebody to answer it -- or them.

MR. RICH ESTABROOK: Well first, Ron, why aren't you here? You live in Oklahoma City.

MR. RON GIBSON: Well, unfortunately, yes. I should be there. I just came back to work just the other day. I have been off some time.

MR. RICH ESTABROOK: The sample probe location, you know, as I mentioned, all the API -- for the API and GPA standard on sampling is based on the assumption that there's no liquids present. And I think we all know that's not really true much of the time, maybe most of the time, especially at lease level measurement. And our intent is with that proposal, is there a way that we can fairly account for those liquids, those little droplets of liquid, that are going through the orifice meter and not being accounted for by the traditional API 14.1 or GPA Gas Sampling Methods. That's the intent. If there's no way to do that, then there's no way to do that.

And part of this was our discussion at the Midwest Measurement Conference a couple of years ago. We had that panel discussion about wet gas sampling. And there's no -- there is nothing we found on the

books to even experiment with wet gas sampling and tube plate sampling.

So this was a simple attempt to try to address that. And again, that is all it is. And we are looking for data on it, we're looking for comments and input. But that is the intent.

If I wrote down the end of the second one correctly is, you know, we're going to have to internally figure out the implementation of how the Production Measurement Team works. And then, if not, I can't imagine there would be any penalties if you couldn't meet time frames because the Production Measurement Team wasn't in place or wasn't on the list to use yet. I can't imagine that would happen.

Who submits the data? I don't think we care. I'm assuming it makes more sense for the manufacturers to submit the data than the operators. But if an operator wanted to submit the data for a particular transducer, then we would accept that, just as we would from the manufacturer.

The water vapor correction, again, the dry assumption is one end point, that's the minimum amount of water vapor that can be there. The fully saturated, as-delivered, not the wet form, is the other end point. The truth is somewhere between, I'm

guessing. And we don't believe that we should take a royalty hit for an assumption of fully saturated when that is essentially, I believe, to be a high bias. You know, we're looking for data to see what the saturation actually is. And that's about it.

I will add this. Yeah. We certainly don't think that anyone -- anyone economically -- or maybe I should actually -- that might not be completely true. But the costs of chill meters or laser water vapor devices is very high, especially for lease level measurement. And that's why we're trying to achieve an across-the-board solution for how to deal with water vapor saturation.

MS. LIZ O'BRIEN: Thank you, Ron. I think we're going to end. Hello? Okay. One more. One more question.

MS. LESLIE GARVIS: Very quick, I promise.

MS. LIZ O'BRIEN: Very quick. Okay.

MS. LESLIE GARVIS: Hi, my name is Leslie Garvis. I'm with Burnett Oil. And I just want to make you aware of a situation that those of us in New Mexico could run into if it's not cost effective to comply with some of this and we have to start shutting some of our wells in because of that.

The State of New Mexico only allows us to

have so many wells down for a given period of time. For example, we're only allowed to have five down for 15 months. So what ends up happening during that time, if we're not able to comply and we have to shut those in, we're going to run into having to plug a lot of wells. And that's going to mean a lot of lost revenue for the BLM, as well as us as an operator.

So I just want you to be aware of situations like that. You may already know about it, but the state puts limitations on us, even on BLM land.

MS. LIZ O'BRIEN: Thank you. Thank you all for being here today. I would like to thank the panel here for their expertise. Thank you so much.

To our lovely court reporter who was fantastic.

And to the folks from DC who I think would like to say a little something. Thank you all so much. I appreciate it.

MS. KAREN MOURITSEN: Well, thank you. Thank you, Liz. And I thank you all for your expertise that you're adding to our experts. So just thank you again. Please, send your comments in. We look forward to seeing them. And thanks for coming. Have a good afternoon.

(The afternoon session ended.)

** C E R T I F I C A T E **

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