NWX-DEPT OF INTERIOR-GEO-1

Moderator: Bev Winton
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Coordinator: Welcome and thank you for standing by. At this time all participants are in a listen-only mode until the question and answer session of today's conference. At that time to ask a question over the phone lines please press star 1 and record your name at the prompt.

This call is being recorded. If you have any objections please disconnect at this time. I will now turn over the call to your host, Don Judice. You may begin.

Don Judice: Thank you (Victor). Well let's get started. Welcome everybody to the meeting to discuss the new proposed onshore orders.

We have participants on the call today, so I will have a mic so when there are questions they will be fielded and a couple of individuals will walk by with the microphone.

We also have a stenographer that's working here, so please state your name and who you represent. Unfortunately as each and every time, if you ask 6 or 12 questions, we just don't remember - she won't remember your name. If you just continue, as you do have a question, to repeat your name and who you are affiliated with. That will help us get information into the record.

Again, thank you. My name is Don Judice. I am the Deputy State Director for Energy, Minerals and Realty at the Montana-Dakota State Office in Billings. And we have a lot of people here with us today. I will turn it over to Jamie Connell, our State Director for some opening remarks.

Jamie Connell: I'll try not to trip on anything up here. You know up here, I get blinded. Can you guys hear me in the back?

Welcome. Thanks for such a great turn out today. On behalf of all of my colleagues here from BLM here in Montana-Dakota, as well as our representatives from our national office, we want to thank you.

I know there are a million things you could be doing today. And for you to take the time to come over and spend your afternoon with us, we really, really appreciate it.

There are a lot of different things that we're going to be talking about today. Some of it can be extremely technical and some of it bureaucratic. But I appreciate the fact that you know how important this is to both your organizations, as well as ours.

You know we have a long history here in Montana-Dakota BLM of working closely with our partners. And the partnerships that we have with the oil and gas industry here in the Bakken has been extremely - a good one, at least for the five years that I've been here as State Director.

The work that we do with the North Dakota Petroleum Association and the North Dakota Petroleum Council. Did I get that right? Montana Petroleum Association.

We work very closely with you guys. You recognize the challenges that we face. We recognize the challenges that you face. And the more that we can address these things together, we really appreciate it.

The job that's been put forth for these (unintelligible) to take a look at regulations that are many, many years old is something that we know we can't do in a vacuum. We have - the input that you're going to provide will be extremely helpful.

So I'll let these guys talk to you about how they're going to facilitate the meeting today. But we really, really would like to hear back from you.

There are several people in the audience here that have experience with both the BLM and private industry. And so you know things from both angles, I'm sure that your input will be very, very helpful.

So thanks to all of you for being here. We're not going to take the time to go around the room and introduce everyone because I think it's more important to spend the time on getting the presentation from these gentlemen and getting your feedback.

There are a few people I would like to have introduce themselves that are just sitting in the audience. Because if we take a break you might want to know that they're here in the room. Dylan, why don't you just go up and introduce yourselves, you guys?

Dylan Fuge: My name is Dylan Fuge. I'm a senior Advisor in the Director's Office with primary responsible for fluid and solid minerals and am the primary point person in the Director's Office on the onshore orders.

Will Lambert: Hi, my name is Will Lambert. I'm a Petroleum Engineer with the Washington office BLM, but I was remotely located in Billings so I do a lot with issues in the local area.

Gary Torres: Good afternoon. My name is Gary Torres. I'm the Deputy Division Chief for Fluid Minerals in Washington. I only deal with fluid minerals.

Chris Ryan: Chris Ryan. I'm with the Department of the Interior Solicitor's Office, the Division of Mineral Resources.

Don Judice: Thank you. And we do have Senator Heitkamp representative, Shirley Meyer in the back. And again, thank you - again, another good relationship we have with (unintelligible) here.

Jamie Connell: Yes, so now I'm just going to turn it over to Amanda Leiter. She's our Deputy Assistant Secretary for Lands and Minerals for the BLM and a very busy gal. And we really appreciate her taking the time to come out here.

She also spent her whole day yesterday out touring around in the field with many of our local field office employees. So thanks for being here Amanda.

Amanda Leiter: Thanks so much. I'm very glad to be here and I appreciate all of you all taking the time to come out and give us your thoughts on this work.

I am going to go off what I've got written down, just to make sure that I don't forget anything.

As Jamie said, I'm the Deputy Assistant Secretary for Land and Minerals. My portfolio is mostly lands and minerals, so it's onshore and offshore - sorry, mostly the minerals side, both onshore and offshore.

So as you're going to hear, over the last four years or so, the BLM has been working hard to rewrite the regulations that deal with the measurement of production on federal and Indian leases. The regulations date from 1989, and you're going to hear they haven't been updated since. So this is principally just an effort to update the regulations that confirm to the technology which has obviously advanced quite a lot in the intervening decade.

We initiated the public dialogue on these onshore orders with a series of public meetings in 2013. Some of the feedback that we received then, you should probably recognize as incorporated in the current version of the proposal.

We're proposing these revisions as I said, to ensure accurate measurement of the oil and gas produced from federal and Indian leases, and a fair return of the royalty revenue for the tribes and for the American taxpayer.

The BLM oversees more than 100,000 federal onshore oil and gas wells that account for 10% of the nation's natural gas production and almost 5% of its oil production.

And the BLM is charged with balancing the administration of those minerals with conservation, enhancing energy security, and in the process of course, we're bidding jobs improving protection of the environment.

To give you some numbers, I think we're going to run through these later, but the production from tribal and allottee leases in fiscal year 2014 was quite significant.

Leases on tribal and Indian lands produced 56 million barrels of oil, 240 billion cubic feet of natural gas, 182 million gallons of natural gas liquids, and general royalties in that year of over $1 billion.

The royalty from production on Indian leases of course, goes directly to the tribes or to the Indian allottee owners. States with federal leases benefit from about 50% of the leases royalty revenue.

So there's a lot at stake here, and it's important that we treat all the lease holders consistently and fairly. And that's what this is really an effort to do.

As I said, these onshore orders were promulgated in 1989. A lot has changed in the industry since then. We have also heard from some of the agencies that oversee our work, including the Government Accountability Office, the Department of the Interior's Office of the Inspector General, and the Department Subcommittee on Royalty Management, that some updates to these orders are really due.

So the GAO in particular, the Government Accountability Office, made several recommendations of how we could be better at measuring oil and gas production. And these draft onshore orders incorporate a lot of the recommendations that we've heard from the GAO.

The proposed regulations as you know, were published this summer. They're meant to address these recommendations. They remain open for public comment. Some of them the public commentary was closed recently, but it's been reopened and they will all be open until December 14. So we look forward to hearing from you all in the next few days, until before the comment period closes.

Once the comment period closes the process is that we review quite closely all the comments that we receive and analyze them and determine how and whether they will be addressed in the final rule.

So now I'll turn this over to Rich Estabrook to walk us through the details. Thanks very much again for being here.

Rich Estabrook: Great, thank you. Can you hear me okay? Okay, my name is Rich Estabrook. I work for the Washington Office. I'm actually remotely located in the North Coast of California.

For the agenda, this is what we're proposing for our agenda. Briefly I'm going to go over why these regulations are important, and then why we are revising these orders.

I'm then going to cover changes that are going to be common to all three proposed orders, and then get into this new Part 3170 of the regulations.

After that I am going to turn it over to Mike Wade, and he is going to talk about our proposed Subpart 3173 that would replace Onshore Order 3, dealing with site security and other things.

(Mike McClarin) will then talk about proposed Subpart 3174 that would replace Onshore Order 4, dealing specifically with the nuts and bolts of (unintelligible).

I'll wrap it up, discussing proposed Subpart 3175 which would replace Onshore Order 5, dealing with the specific technical issues of gas measurement.

I think at this point we will take a break because you'll be saturated by that time. And then after the break we'll reconvene and then the rest of the day is yours to ask questions, make comments; however you want to use the time, the rest of the day will be yours.

So, why are these regulations important? They're important because they deal with money, specifically royalty revenue to both the federal government and to Indian tribes.

I thought I would go briefly into how royalties - federal and Indian royalties are calculated.

For oil, the royalty paid on oil equals the royalty rate on your lease, usually a fixed amount -- 12-1/2% for federal is common -- times the volume of oil in barrels, removed from your federal or tribal lease in a given month, times the value -- the dollar value -- of that oil.

We also care, not only about oil volume but oil quality. API gravity of the oil goes into the determination of value. Not a direct multiplier in the royalty equation but it does affect value which is a direct multiplier.

The royalty rate as I mentioned, is in your lease terms. Whether it's a federal lease or an Indian lease, there should be a number in that lease of what your royalty rate is. As I say, for federal it's normally 12-1/2% in this case.

The onshore orders or the revisions to the onshore orders we're proposing have nothing to do with royalty rates.

The dollar value of the oil is actually determined by a different agency. It's determined by the Department of Interior Office of Natural Resources Revenue. It's not BLM's function to assess dollar value.

The volume however, is BLM's responsibility. One of our primary responsibilities is to ensure volume of oil removed from federal and tribal leases is accurately measured and properly reported.

And Onshore Order 4 is specific, and to some degree Onshore Order 3, have a direct bearing on the accuracy of measurement and of proper reporting.

Onshore Order 4 also gets into the determination of oil quality or API gravity. Provisions of Onshore Order 4 are designed to ensure the gravity is properly determined and properly reported.

So the proposed revisions to Onshore Order 4 and Onshore Order 3 will directly affect how accurately oil and gravity are measured and how they are recorded.

For gas the equation is quite similar. The royalty on gas is the royalty rate on release times the volume in thousands of standard cubic feet or Mcf of gas removed from a release times the heating value of that gas or the Btu content, as people often call it, times the dollar value.

As with oil the royalty rate is fixed in the lease terms. Normally the oil and gas royalty gas rates are the same.

The value - the dollar value of that gas is determined by the Office of Natural Resources Revenue. Neither of these two things are covered I the proposed regulations that we're talking about today.

Onshore Order 5 and to a lesser degree, Onshore Order 3, directly affect gas volume determinations. And as with oil the purpose is to ensure accurate measurement and proper reporting of gas volumes.

Onshore Order 5 also talks about heating value. That's another one of our key responsibilities is to make sure the heating value of that gas is accurately measured and properly recorded.

And one of the things I want to point out is that the volume and the heating value both have an equal effect on the ultimate amount of royalty paid to the federal government or the tribes.

So for example, if volume for some reason was reported 10% in error, the royalty will be 10% in error for that month for that lease.

If heating value somehow is reported 10% in error, the royalty will also be 10% in error. Volume and heating value are equally important to the determination of gas royalties.

Now we'll talk about why that's significant in (unintelligible). So why are we revising these regulations? First of all before I get into the answer of that specific question, I want to talk a little bit about what exactly we are proposing.

So right now we have things called onshore orders. How many in here are familiar with the BLM Onshore Orders? So onshore orders I think are a very unique thing in the federal government. I'm not aware of any other federal agency that has something analogous to an onshore order.

And onshore order is a regulation. It has the full weight and effect of a regulation, but it's not published anywhere. It seems strange.

In other words if you pick up a 43CFR Regulation Book, Onshore Orders 3, 4, and 5 or none of the onshore orders are there anywhere. They're not there.

You can get them on our Web sites. A lot of us have old copies buried in our desks somewhere, but they're unpublished regulations which is very strange.

So what we are proposing is to create a new regulatory subpart - or part; I'm sorry, Part 3170. And Part 3170 would be brand new and it would contain all things dealing with production and measurement.

In Part 3170 we would include things that would be common to everything dealing with production measurement such as common definitions, recordkeeping, prohibitions on bypass and tampering, variances, appeals, and enforcement. So all this stuff would be under the part 3170.

Within Part 3170 we would also - we're also proposing to create a Subpart 3173, and it would replace Onshore Order 3. And it would deal with site security which currently Onshore Order 3 does. It would also include a new concept called a facility measurement plan, which Mike Wade will go into all this. And it will have requirements for comingling and off-lease measurements.

It would also propose - we are also proposing to create a Subpart 3174 within Part 3170. It would replace Onshore Order 4, and it would specifically deal with the technical issues of oil measurement.

We are also proposing a Subpart 3175. It would replace Onshore Order 5 dealing with gas measurement, and it would also replace the statewide notices to lessees that each BLM state office has issued relating to the electronic and gas measurements.

For example in Montana, Montana has a Notice to Lessee 2007-01 which talks about requirements for electronic gas measurements. That would be replaced by Subpart 3175.

So, why are we revising these orders? As Amanda said, these were last revised in 1989 which was actually not quite correct. Onshore Orders 3, 4, and 5 were published in 1989 for the first time, and they've never been revised. So these have never been revised in 26 years.

The current orders do not address new technology or incorporate the latest industry standards and practices. For example, how many in here deal with Coriolis meters? Okay, a fair number.

Onshore Order 4, being written in 1989 does talk about Coriolis meters which is becoming I think, kind of the new industry standard for oil specialists.

There are gaps in existing orders that need to be addressed. One example I'll do on the gas side, in the gas measurement, heating value and volume have the exact same weight - the exact same effect on royalty value.

The existing Onshore Order 5 has I think, 26 separate requirements for gas measurement. One of those requirements and only one of those requirements has anything to do with heating value.

So we have 25 requirements dealing with volume and one requirement dealing with heating value. That requirement is simply that we have to determine the heating value once per year. That's a huge gap in our regulation of our being able to ensure the heating value is properly measured or accurately measured and properly recorded.

Amanda mentioned a number of internal reports. I'll start with the middle one there, the GAO. That's the Government Accountability Office. They are an agency I guess you would call them, that oversees us and makes sure we're doing our job properly.

And they did a report in 2010 that came up with 19 recommendations about things that we need to do better to do our job better. And many of those recommendations still specifically with the need to update our measurement regulations.

The bottom one, OIG, is the Office of Inspector General. They are another agency within the Department of Interior that makes sure the agencies within the department are doing their jobs properly. They've done numerous audits and consistently find that we need to do a better job. And to do a better job we need modern regulations that we can enforce.

The top one there, the RPC, that's the Royalty Policy Committee. That's a subcommittee under the old Minerals Management Service. In 2007 they did an exhaustive study on the Department of Interior's Oil and Gas Program, including both onshore and offshore. And they came up with 110 recommendations of things the department needs to do better to ensure accurate measurement and proper reporting, which is one of our primary responsibilities.

Of those 110 recommendations, 12 of them I believe had directly to do with (unintelligible) and quality measurements, and the need for new modern regulations which were enforced.

The bottom line is, we need to revise these orders so we can improve measurement accuracy, recording, and production accountability.

So now I’m going to get into some general things that are common to all three subparts that we’re going to talk about today.

First of all, all the onshore orders, if you are familiar with them, they all have a bunch of provisions in them. This is how you have to do it. And then after each provision there’s an enforcement action.

So if we find a violation on one of them -- let’s say it’s a tank seal-- if we find a violation on a tank seal, each provision says this is either a major or a minor violation. It states a corrective action and a timeframe for that corrective action.

Now the problem with this is that these enforcement actions were never intended to be concrete, absolute things. The definition of major violation, it has to meet three criteria. The violation has to be substantial, it has to be immediate, and it has to be adverse.

So let’s say you’re - an inspector is witnessing a tank and there’s a seal missing on a failed line valve. Now if that’s a big tank, clearly that’s probably a major violation because there's an immediate threat of that oil being removed within being recorded. There's a lot of oil at stake so, it's substantial. It's adverse because we could get - that could be unaccounted for.

So let's say the inspector is now looking at some old tank that's been out there for years. There's two feet of oil in it. The well may not even be producing or hasn't produced for a month or two, that's still raised to the level of a major violation.

Well it's immediate but it's substantial. It's a really lot of oil at stake there. Maybe not. So the idea here was that we wanted flexibility in how we take enforcement actions.

And BLM and industry has always been confused that these actions in the onshore orders are absolute. What we're proposing to do is remove all enforcement actions from the proposed regulations.

Instead of being in the regulations, the enforcement actions will be placed into an Inspection and Enforcement Handbook. This handbook then could go into great detail about all the extenuating circumstances that the inspector needs to consider before signing a major or minor violation or signing a corrective action or signing a timeframe for correction.

The current orders have one and only one immediate assessment, and that's currently in Onshore Order 3. If you break a federal seal, that's an immediate assessment.

The proposed onshore orders would increase the number of immediate assessments that we can immediately - when we find a violation.

The immediate assessments will all be $1000, the assessed value per violation. And the intent of the immediate assessment is not to be punitive, it's to compensate BLM for what's known as liquidated damages. And I don't really know what that means, but if you have a lawyer, you can ask them what that means and they'll be able to tell you.

The current onshore orders, if you want to use an alternate device, let's say a Coriolis meter which is considered an alternate device right now, you have to apply to a local field office for a variance request.

Now this has caused problems for the industry. Like I hear about it at a national level. And it's a huge inconsistency about how we - individual field offices approve these variance requests for alternate meters or alternate (unintelligible).

The example I've been using for these talks is, on the gas side there's an alternate meter from an orifice placed called a Wafer V-Cone. And it's a decent meter.

It was proposed to one field office in Wyoming and they said, yes it seems like a good idea. We'll go ahead and (unintelligible) that.

The same exact meter was done - proposed at another field office in Wyoming and they said yes, the meter is okay but here's the list of conditions that you need to apply to - or comply with.

And third field office, again the exact same meter, the third field office said, there's no way are you doing this in our field office. So the same meter had three different outcomes for three different field offices. And this (unintelligible) amount of inconsistency in what we do.

What we're proposing is we would establish a new Production and Measurement Team at the national level. And all requests for new technology, new procedures; new equipment would go through one central review process at a national level.

The Production and Measurement Team would consist of measurement experts that would devote their time to looking at that device and making sure that it is suitable for use at federal and tribal regulatory.

And how we envision this working - we're proposing this to work is that a manufacturer or an operator -- we don't care who -- will submit this request to use some new, Meter X we'll call it. They would have to go through some kind of testing. Meter X would have to be tested to some kind of standard.

For gas the standard would be API 2222. For liquids we don't really have a standard, but it would require some level of testing.

The test results would be submitted to this Production Measurement Team. And the Production Measurement Team would look at those test results and figure out, is this meter suitable for use at federal Indian points.

And if it is, are there side boards you need to place on it to make it - so it operates under certain conditions.

This approved device then would go up on a BLM Web site. So you could go to a BLM Web site and pick a - hit a pick list for approved equipment. And you could scroll down and find Meter X right there, once it's approved.

It would only have to be - it would only be approved once. So any manufacturer or any operator submitting this meter, anybody in the country could then go to that pick list and decide to use that piece of equipment.

One of the things besides consistency -- we're going to hold questions to the end. Can you just remember it? One of the things, besides consistency would be longevity. The longevity of regulations.

Right now we are dealing with regulations that are 26 years old. It's not inconceivable to think that once these proposed regulations go into effect, 26 years from now we will still be dealing with them. And who knows what the technology will be 26 years from now.

This Production Measurement Team will be able to approve equipment or new technology if it comes up, and maintain a list of that approved technology. So this basically builds in a tremendous amount of longevity of these regulations and provides a method by which we could keep up with technology without having to go through this whole four year process just to improve new equipment.

Orders 4 and 5 are a cookbook approach. In other words both Orders 4 and 5 lists the things you have to do. Here are the things you have to do for oil measurement, and there's a bunch of stuff. Here are the things you have to do for gas measurement and this is the list.

One of the problems with the cook - the cookbook approaches aren't bad, because I think some operators are, just tell me what I have to do. But the problem - one of the problems with a cookbook approach is that a cookbook approach by necessity is tied to one specific technology.

So in Order 5, the gas measurement one, there's a cookbook approach on how to deal with mechanical recorders - chart recorders. This is great. It's simple. The problem is we don't mechanical recorders any more. Not many of them.

And so now you go to electronic flow computers ad these cookbook approaches (unintelligible) or meaningless and obsolete. Electronic flow computers don't have pens.

Also in Orders 4 and 5, there's no stated performance goals. What is it that we're trying to achieve? What are the goals? What kind of accuracy are we trying to get to? What are all these cookbook approaches trying to get to?

What we're proposing is that Orders 4 and 5 would establish explicit performance goals in addition to the cookbook approach. We would have the cookbook approach for those operators that just want to know what to do.

In addition, we would have explicit performance goals for the accuracy levels we're trying to achieve, for example. It would be stated so that an operator would have the flexibility to come up with alternate ways of achieving that same performance goal.

When an operator comes up and says hey, we can achieve - we think we can achieve X percent uncertainty by doing this method which is not in your cookbook. They would then send this proposal to their Production Measurement Team who would look at it. And if they agree with it, your proposal was accepted and that would be put on a pick list so, anyone else could use it as well.

These performance goals, the accuracy for example, were designed -- and we're looking for comments on this -- were designed to balance accurate and verifiable measurements with economic realities. We know we can't expect a Cadillac meter on every well because it's just too expensive.

On low volume wells we realize we need to make some concessions and just accept the fact that we're going to get lower accuracy. And that's our attempt here. And we'll go through what these performance goals are.

Order 3170 contains regulatory language that is common to all three subparts. The orders, if you look at the onshore orders, they all refer to the operator.

Now here's one problem with that. Let's say the BLM is doing a production audit and they want a bunch of gas meter information for their audit. They want volume space and calibration records and data analyses and configuration logs.

Well they send out regular orders to the operator requesting all this information for X number of meters and for a certain timeframe. The operator looks at this request and says, this is not my meter. This is a pipeline meter.

So the operator then has to go to the pipeline company and say, BLM is doing an audit and they want all this information. Can you send us this information? And in some cases the pipeline company will refuse to do that for whatever reason.

Our only choice is to take - to do a violation against the operator for not complying with our written order, even though it's not their meter. And they really don't have any control over the situation, which doesn't really seem that fair.

What we're proposing is that requirements for recordkeeping only would apply to purchasers and transporters, as well as operators. To the point - to the royalty settlement point which is essentially the same thing as the FMP -- the facility measurement point -- or the point of first sale; whichever comes first.

So now when we do a written order for a meter that is owned by a purchaser or transporter or a pipeline, we could send that request directly to that purchaser, transporter, or pipeline requesting the audit information for that meter.

If the pipeline - or the purchaser, transporter or pipeline company refused to give it to us, you could take enforcement action directly against them and not involve the operator.

The order is just a little bit trivial I guess, but the orders - each onshore order currently has a variance section. What we're proposing is that all that variance language will be put up front in Part 3170. And it would increase the guidance on how a variance would be viewed, and how we would process it and the requirements for submitting a variance request.

And with that I will turn it over to Mike Wade to talk specifically about Subpart 3173.

Mike Wade: Thank you. My name is Mike Wade. I work for Washington Office but I physically sit in Denver, Colorado. So, that's a little of my background.

3173 addresses some new issues as site security, (unintelligible) key measurement, and (unintelligible) and issues involving comingling and off-lease measurement.

Currently Order 3 has absolutely no guidance for comingling or off-lease measurement. There's nothing out there. We're proposing some new procedures and requirements for off-lease measurement and comingling in the proposal, and to address some other issues as well.

Currently BLM has nothing in the way of formal written guidance except an IM that was prepared for internal use a few years ago.

What we are proposing would be approval of comingling if there's no royalty impact. Both would be relatively straightforward and simple, i.e., all the cases involved have the same royalty. All federal or all Indian, and therefore a percentage of allocation back have no impact on the royalty.

Another area would be on the low volume wells, there would be guide (unintelligible) and procedures for applying for comingling on low volume wells that we could work with. And then of course, extenuating circumstances.

We realize that there's no such thing as everything falls under the same set of rules, so there would be an opportunity for the operators to present unique measurements, problems, issues and give us the ability to look at those from that perspective for extenuating circumstances.

BLM is proposing to also review existing comingling approvals at the point in time when the operator would submit their requests for a facility measurement point.

If they were unable - if the old comingling approval did not meet current standards, we'd be working with the operators to bring them into compliance.

The first thing is to work with everybody and try to get the existing stuff. But it works without having to spend excessive amounts of new money.

Now Order 3 currently applies to sales in Order 3 and allocation meters equally. And what we are proposing to do, instead of (unintelligible) and also nothing related to royalty payment is not considered or defined.

It would be applied to measurement affecting only the royalty bearing meters. The meters that would be impacting the royalty computation. And then of course the BLM tracking and approval facility measurement point.

Order 3 currently has the only requirement for oil measurement and run tickets by base gauge. And then we have some minimal requirements for such things as water draining on other seal requirements, recording data on and date off, (unintelligible) basics, and drain water. That’s all that’s required.

We are proposing to modify that for the water, hot oil; etcetera, to require some additional information at opening gauge. How much fluid was in that tank before you broke that seal to drain that water off the bottom of the oil tank?

How much fluid was in the tank when you finished draining the water off? So we’ve got some numbers and a few other minor pieces of information for site safety to seal numbers at time. Who did it? And then of course obviously, why?

Run tickets are coming completely out of 3170 out of Order 3 will be addressed in 3174.

Then the other item is, end of month inventories. Currently there's no requirement in the Order 3 for end of month inventories or beginning of month inventories. We're proposing that the operator be required to maintain an end of month inventory.

No information in the order for royalty free use, sometimes called beneficial use; use on lease, all equal. We're proposing to make some information available to the BLM from the operators with respect to (unintelligible) diagrams involving equipment that's going to - that they're planning on using for beneficial use.

And giving it some information from the manufacturer or however they're going to determine that volume so that we can see how it's done and how you're doing it and make sure it's a valid methodology. Usually using operators or manufacturers specs. Or the operator may choose at their own discretion to put a meter out there. That would be their discretion, not our requirement.

So currently there's a requirement for a self-inspection plan and the site security plan, two separate types of documents.

We're proposing to remove those completely. And the added information that you would be providing with opening gauges, closing gauges on the seal valves or drain valves, for example. That would accomplish all the same requirements of a site security plan or a site security self-inspection program.

We are asking for some very specific information from industry in the order. Currently we have a number in there that says 10% rate of return on comingling. Is that a good number? Is it a bad number? Is it too high; too low? (Unintelligible) specifically involving that.

This is would be for example, you have to place a new tank out there in order to measure independently because comingling (unintelligible) the problem.

Now with the 10% rate of return on that piece of equipment, is that too high or is it too low. We're asking for specific information.

We also asking about the timeframe that we've currently proposed for parts on the onshore order or the site security. Right now we're proposing a nine month increment for high producing volumes. We're requesting their first FMP number on existing facilities with medium or mid-level or following nine months. And then low volume wells nine months after that for a due date for applying for a FMP number.

So that would be 27 months in total to get from high production to low production FMP number, based on volume and time. Is this good? Is this too high, is it too low? We're specifically asking for comments and input back from industry on those particular items in 3173.

Okay, I'm going to turn this over to (Mike McLarin), and he will take care of the oil measurement.

(Mike McLarin): I'm (Mike McLarin). I'll talk about what we proposed in 3174 for oil measurement. So hopefully everyone has had a chance to read it and working on it. If you haven't submitted comments, we're looking for comments.

So I'll go over basically what - what's in the current Order 4 and then what we're proposing.

Again the - as Rich stated, the current rules, they have no stated performance objectives. You know, its cookbook. So we're proposing a performance standard for the rule - an uncertainty standard. We proposed three standards in Order 4, based on volume thresholds of measurement.

So we're looking for comments on this. Hopefully you guys will do your (unintelligible), compare with what we've got. If you have different volume thresholds that you'd like to see, submit those comments.

We proposed for meters measuring more than 10,000 barrels a month, an uncertainty plus or minus .35%. That plus or minus .35% was based on an uncertainty calculation that we did on a LACT system with a positive displacement meter operating under the current Onshore Order 4 requirements.

The second tier, if you're greater than 100 barrels a month and less than 10,000 barrels a month, we propose a plus or minus 1% uncertainty. The 1% uncertainty was calculated from manual tank gauging on a 400 barrel tank, removing approximately 200 barrels out of that 400 barrel tank.

And then based on some comments from the 2013 public forum that Rich held, we included a third tier that if you're less than 100 barrels a month we proposed a plus or minus 2.5%. And the 2.5% again, was sort of uncertainty calculation on a 400 barrel tank where we moved about 40 barrels from that tank.

The current Onshore Order 4 references industry standards dating back to 1989. We've updated industry standards. We proposed to incorporate 21 API standards and two ASDM standards.

The current Order 4 for the oil tanks requires a pressure (unintelligible) valve. What we've proposed in the Order 4 is pressure vacuum fee patch and a pressure vacuum relief valve (unintelligible) pressure greater than a fee patch setting. Of course if you have a vapor recovery unit you wouldn't need that.

We've also explicitly stated in the rule, the condition we want to (unintelligible). We wanted to maintain and pressure vacuum integrity. So we've stated the equipment and we've clearly stating the condition we want that tank maintained in.

The current Order 4 for manual tank gauging, it has the requirements for gauging. They're in random order. There's no real order. We have requirements but it doesn't really say how you do it.

Initially we had a request to specify the proper sequence of tank gauging. So we wrote in the proposal, based in API 18.1 standard, a sequence for manual tank gauging, as well we the specific requirement for each one of those processes.

Current Order 4 requires two consecutive gauges within (unintelligible), 2013 API Chapter 3.1 A updated their standard. They required an API 3.1A. Two consecutive identical gauges or three gauges within one-eighth inch.

Current Order 4 requires tank calibration (unintelligible). No increments were specified. So we changed the gauging from a fourth inch to an eighth inch. So we specified strapping tables should be in eighth inch increments.

Currently Order 4 LACT system, it requires an automatic temperature compensator or an automatic temperature gravity compensator. It only allows the use of positive displacement meter.

We propose to prohibit the automatic temperature compensator and automatic temperature gravity compensators that require electronic temperature averaging device instead.

The reasoning behind that is the automatic temperature compensators, they adjust the totalizer reading automatically. There's no raw data. There's no uncorrected data for us to verify that totalizer reading.

So we're proposing to eliminate that and have the temperature average and have that totalizer reading be the raw data. We also propose to allow the Coriolis meter to be run in a (unintelligible) PD meter.

The current Order 4 has two methods of measurement. Manual tank gauge or measurement through the leased automatic custom transfer system utilizing PD meter. So we're proposing to, still allow the manual tank gauging. We're still allowing the LACT. And we also proposed a separate section for a standalone Coriolis measurement system.

We specified a few requirements for this standalone Coriolis measurement system. We proposed to retain the same 8400 pumps per barrel resolution that the current LACT system has.

We've included some specifications for the Coriolis meter, including some reference accuracy requirements, influence affects, ability and pressure drops. We still want an (unintelligible) totalizer.

During the proving of the Coriolis meter we proposed to require the meter zero verification prior to proving the meter. That's one of the manufacturer's recommendations. If you zero the meter at any point, you need to reprove it.

We proposed a Coriolis meter determine that standard volume. So we've got a couple of proposals for the (unintelligible) gravity. It can either be determined from a composite sampling system or from an average density reading of the Coriolis would be (unintelligible) tickets. The same for the temp pressure and temperature determinations.

We have some onsite display requirements for the Coriolis proposed. And we of course have our audit trail of that quantity transaction record, configuration log, even log, a line log.

Current Order 4 for improving the LACT meter, if you're greater than - or if you're less than or equal to 100,000 barrels a month, it's quarterly proving. If you're greater than 100,000 barrels a month, it's monthly proving.

What we proposed is for the LACT systems and the Coriolis measurement systems to prove, every 50,000 barrels on the totalizer or quarterly, whichever comes first.

We came up with 50,000 barrels for threshold on that by doing a statistical analysis of wet volume of going through the Coriolis meter with equal the potential royalty risk of overpayment or underpayment that would equal the proving cost of the meter, based on meter factor changes.

The current Order 4 has no standards for prover sizing. Those standards were proving conditions. No standard for false output on approving run.

What we proposed is minimum/maximum includes velocity rates for the prover sizing. We proposed that proving should be done at normal conditions; normal flow rates, normal pressures, a normal gravity.

And small volume provers are getting popular. But small volume provers generate a couple of thousand - 2500 pulses on a run. So if you're generating less than 10,000 pulses, we want to see pulse interpretation.

Currently there is no measurement ticket requirements for LACT systems. So we proposed to generate a measure ticket for a LACT system and the Coriolis measurement system immediately after proving, and monthly.

And in the preamble discussion, we were specifically asking for data and comments on many items. So here the volume - the uncertainty levels that we proposed, I talked about earlier, we're hoping you guys will take a look at your operation and maybe do your own uncertainty calculations.

Take a look at the volume thresholds. And if you have comments on that, if you can provide some data that maybe they should be tested; those aren't good volume thresholds, we want to see that data. We really want those comments.

We're looking for some comments and some data on some alternate measurement - alternate tank gauging and different ways to sample. Different ways to take temperatures, different ways to determine sediment in water, especially up in this area.

If we can get people off the tanks, that's what we want to do. We want to look at the data.

We've got some different proposals in there for the composite sampling system on Coriolis measurement. If we don't have the composite sampler, then what do we use to determine the density would be the average density reading of the Coriolis meter between the measurement tickets?

And also if you don't have the composite sampling system on a Coriolis meter, how do you determine sediment in water? Currently we proposed, if you don't have the composite sampling system, we wouldn't allow deduction for sediment in water.

Is there a different way to determine sediment in water besides a composite sampling system doing the conventional grind out, we would love to hear that.

We're looking for comments. If you have a meter and you do have some very fluctuating pressures - density flow rates, we're looking for comments on determining a meter factor that we can use there.

Would you prove that the fluctuating conditions and average a meter factor? Would you come up with a thick curve meter factor to where a computer could automatically adjust the meter factor for the dynamic (unintelligible) in determining the volume? We'd like your input on that. We'd like to see some data on that and proposals for that.

And that's pretty much what I've got for the proposal on the oil measurement. I'll turn it over to Rich.

Rich Estabrook: Okay, we're going to wrap this - our presentation up with 3175 and then I'll open it up to you guys for questions; comments.

Order 5 discusses only orifice plates and mechanical recorders. Again it was written in 1989 - in fact it was written before 1989. It was published in 1989.

Electronic flow computers were just kind of coming on the market at that point.

Electronic gas measurement systems is not addressed in Order 5, but it is addressed in the statewide notices to lessees which is supplementing Order 5.

Order 3175 would maintain orifice plates as the primary method of gas measurement. We like orifice plates for a couple of reasons. One thing is that they give a reasonable level of accuracy. The other thing that we really like about them is that they are completely and independently verifiable by the BLM or by anybody for that matter.

You can verify orifice measurements from end to end entirely, and get 100% independent number per volume.

You would continue to accept mechanical recorders with some restrictions that I'll talk about a little bit. We would accept approved EGM systems. EGM systems approved by the Production Measurement Team, and on a pick list.

And we would have specific guidance for alternate measurements and flow conditioners. As (Mike) said in Order 4, Order 5 also has no performance standards. It's a cookbook things are things you have to (unintelligible).

Order 5 does have three tiers of requirements. So I have a little graphic I'll show after - in my next slide.

Proposed 3175 would actually establish four tiers of requirements. And I have a slide that will show that. So this is the current Onshore Order 5. This is how it's sort of (unintelligible).

And average flow rate - average monthly flow rate is here on the Y axis. So in the current Onshore Order 5, if your meter is measuring more than 200 Mcf per day, then all the 26 or however many requirements in Onshore Order 5, all of them apply.

If your meter measures less than 200 Mcf per day, you no longer need a continuous temperature recorder. And under current Onshore Order 5, if you measure - if your meter measures less than 100 Mcf per day, you no longer have to operate the DP - the differential pressure pin in the other two-thirds of the chart. And you no longer have to comply with the orifice plate beta ratio (unintelligible) .15 to .17. So that's the current onshore order.

The proposed 3175 would take this tier approach to kind of expand on this a little bit. We would actually come up with four tiers of requirements and we would name these tiers.

For meters measuring more than...

((Crosstalk))

Rich Estabrook: Many people are. For meters measuring more than 1000 Mcf per day, we would call those very high volume FMPs. For meters measuring - FMPs measuring between 100 and 1000 Mcf per day, we would call those high volume FMP.

For meters measuring between 15 and 100 Mcf per day, we would call those low volume FMPs. And for meters measuring less than 15 Mcf per day, we would call those marginal volume FMPs.

Now the idea here is much likely the oil measurement, is to have very tight requirements for high volume meters because there’s a lot of risk. If you have a risk measurement on a high volume meter, there’s a lot of volume at stake. A lot of royalty at stake.

But that high quality of measurement has a price tag to it, but we realize that. And so the idea her is that as meters measure less and less, the economics just aren’t there to maintain a very high standard of measurement as you would on a high volume meter.

So as we drop down in category, the requirements of that category are reduced. Our performance standards include for both volume and feeding value. Bias. Bias is a major one that will always read high or always read low. We always read high or always read low for example. And this is verifiability. This is our ability to independently verify those volumes that are measured and reported by your meters.

So for very high volume FMPs, we are proposing a volume uncertainty of plus or minus 2% and a heating value uncertainty of plus or minus 1%. Now I should stress here that when I say heating value uncertainty, I'm talking about the uncertainty of average annual heating value as a different mean than you may be accustomed to.

For high volume FMPs, we are proposing a plus or minus 3% uncertainty level, which is exactly the same uncertainty level that is currently in our statewide notices to lessees. That requirement is already there for meters of more than 100 MCF per day. We would have an average annual average heating value uncertainty of plus or minus 2%.

Oh I guess I forgot to go over the bias. There would be no statistically significant bias allowed for either a high volume or very high volume meters. And high volume meters, the measurement would also have to be independently verifiable by us. For low volume meters, we would do away with the uncertainty requirement altogether.

We still would not allow any statistically significant bias in your measurement, and the measurement would still have to be verifiable. For marginal volume FMPs, the only thing we would require is that we would have some level of independent verification of the measured volumes.

Order 5 adopts one and only one industry standard, and that's AGA report number three, and that's specifically the 1985 version. So we currently only have the authority to enforce against a 1985 standard that would be 30 years old.

Now one problem of that for example is that if you place straightening veins or tube bundles in the location specified by the 1985 AGA report number three, in some cases you will bias your measurement by 1 or 2%. So we are currently enforcing a standard that has built-in problems.

Proposed 3175 would adopt the latest API and GPA -- GPA, Gas Processors Association -- standards covering the primary device, orifice plate, electronic gas measurement systems, flow rate volume and heating value calculations, gas sampling and analysis.

Current Order 5 has no inspection requirement from meter tubes. API 14.3.2 goes into great detail about requirements for meter tubes, such as the straight length of pipe upstream or downstream of the orifice plate. It has standards for roundness and where you have to measure and verify roundness as standards for surface roughness for example, headings, protrusions.

We believe that because clearly API and GPA that feel that meter tube condition is an important finding for gas - accurate gas measurement, that perhaps we should inspect those meter tubes from time to time to make sure that they are in compliance with the AGA standards.

So what we're proposing is a meter tube inspection frequency that would depend on the category of FMP, as shown here. For marginal volume FMPs, these are the ones less than 50 MCF per day, they're just barely hanging on, we would have no requirements at all for meter tube inspection.

For low volume FMPs, we would require a visual inspection once every five years. The visual inspection would probably be conducted with something like a borescope where you do not - it does not require removal and disassembly of the meter tube. You can go in there with a fiber optic device and look around through a viewfinder.

For high volume FMPs, we would - we are proposing a visual meter tube inspection once every two years, and a detailed inspection once every ten years. The detailed inspection would in fact require removal and disassembly of the meter tube so that you can do the (miking) of the inside diameter of that to make sure you're in compliance of all the roundness specifications of API. Very high volume FMPs we're proposing a once-per-year visual inspection and a once every five years a detailed inspection.

Currently Onshore Order 5 automatically approves mechanical recorders. That's all that's approved. Proposed 3175 would limit mechanical recorders to those FMPs measuring less than 100 MCF per day. The reason we're doing this is because we're finding in very high volume FMPs we have an uncertainty standard. We do not feel that the performance of mechanical recorders is adequately categorized to even do an uncertainty calculation. And therefore, they would not be allowed an uncertainty as a criteria, which would be for high and very high volume FMPs.

Order 5, I think I mentioned this already, has one and only one requirement that has anything to do with BTU determination, and that is that the BTU has to be determined once per year. We have no standards on where potential samples, how to analyze other resources.

The proposed 3175 would change the once per year sampling frequency as follows. For marginal volume FMPs, we would actually maintain that once-per-year sampling frequency. For low volume FMPs, we would propose to change that to once every six month, a fixed sampling frequency. For high volume FMPs, we would have an initial sampling frequency of once every three months.

So we're also proposing something kind of different. The goal of - with this type of volume the goal of heating value is to get some level accuracy. That's what we're trying to do. And assigning any sampling frequency we realize was completely arbitrary. Generally we sample more frequency for higher volume meters, but the frequency is arbitrary.

So we wanted to get away from arbitrary standards to focus on the uncertainty levels in our performance requirements. What we're proposing is that initially you would do a once every three months quarterly sampling for high volume FMPs. We would then look at the statistical variation of heating value of outsourced historical samples.

If you have an FMP and the heating value is just all over the board from sample to sample to sample, there's something going on there. Either there's a sampling issue or there really is that level of change in heating value. Either way, it doesn't matter. If we're to achieve a 2% uncertainty in average annual heating value, we have to take more frequent samples, but if your heating value is all over the place, we may require you to step up your sampling frequency to monthly or maybe even weekly.

If on the other hand, you're heating value from sample to sample to sample is nice and even, didn’t change much at all, we may actually say you don't need to do three months anymore.

Same idea for the very high volume FMPs, just a different uncertainty standard. We would have an initial sampling frequency of once per month. We would get a statistical background about FMPs called a variability (unintelligible), and then we could either step up or step down the frequency requirement, whatever it takes to achieve that 1% uncertainty.

If -- this is a continuation -- if the heating value is so variably fluctuating in your FMP, it even looks like (unintelligible) sampling won't achieve the level uncertainty we're looking for, then we would require you to install a composite sampling system or online gas chromatograph, and that would take care of it.

Also we're proposing a new BLM database called the Gas Analysis Reporting and Verification System, or GARVS. We would require you to submit all gas analyses that are used for royalty determination would have to be entered into this GARVS system.

What we're envisioning is a system where you can either key enter the gas analysis data or you can just download it from (Flowcal) or some other program you could import it.

Order 5 has no requirements for sample location or mechanism. It has no requirements for gas chromatographs. We're proposing a key finding to change this. This first bullet item is again a little bit out there, I'll admit that. It's a little radical, a little creative perhaps.

What we're proposing is the sample probe would have to be located one to two times dimension DL downstream of the primary device. Dimension DL is out of the table in API 14.3.2 about meter tube length. It's the minimum meter tube length required downstream of the orifice plate.

So for example, if dimension DL that you're taking your meter on happened to be 8 inches, what we would propose is that sample probe would have to be located between 8 inches and 16 inches downstream of the orifice plate. Now this is just a proposal that we're looking for data on, and I'll talk more about that at the end here.

And we also realize this is in direct conflict actually with API and GPA sampling standards, which say the sampling probe should be located five height diameters downstream of a major construction like an orifice plate. What we're trying to get at here is API and GPA sampling practices are designed for pure gas, no liquids present at all.

But I think especially - maybe especially up here with the rich gas you guys have, we know that that's probably not always the case. Oftentimes there's going to be entrained liquids in that gas. The problem is the way sampling systems are set up right now, the little, tiny microscopic droplets of entrained liquids can go through our orifice meter, and the heating value of that is never accounted for.

So what we're proposing, and this was based actually on a conversation with no data, I hope there's data out there, it's based on a conversation I had an API meeting. And I can't remember, somebody had done some testing on - it wasn't an orifice plate meter, it was another type of meter, but they had - they were taking a sample well downstream of this meter. They were getting a certain BTU value.

Then they took a sample right downstream of the meter, the differential type of meter. The BTU value was hugely - much greater. And the theory is that as the gas flows through this primary device and accelerates and gets all turbulent and mix up, it's going to pick up little particles of liquids and aerosol them.

And so by putting the sample probe closer to the orifice plate, the question is will this account for the liquids that we know are traveling through that meter? And we're looking for data on that. We have none, so we're putting it out there.

We are proposing to accept four spot sampling methods, and those would be fill or empty, (unintelligible), floating piston, and portable gas chromatograph. We would incorporate requirements for gas chromatograph calibration and operations. And this last one is we would - we're proposing an extended analysis if the hexane plus from a standard analysis was greater than .25 mole percent. And we're looking for data on that one as well.

Order 5 has no requirements for BTU reported. Proposed 3175 would. Now BTUs, as I'm sure most of you know, can be reported as - from a single sample, BTUs can be reported as gross or net, real or ideal, dry, wet, or as delivered, and a dry or different pressure basis. I've never seen a different temperature base other than fixed.

So if you multiply those together, the reported heating value from a single sample could be one of 48 different values. You have two here, two here, three here, and four there. If you multiply that together, you can get 48 different BTU values from a single gas sample.

We're going to specify - we're proposing to specify which conditions the BTU would have to be reported under, and those would be gross, real -- before I show the next one I want to talk about it just a little bit because I know it's confusing -- dry, wet and as delivered. These have to do simply with the function of how much water vapor is contained in that gas.

We have to assume that because gas chromatographs don't see water vapor. We have to make some kind of assumption. Dry means you assume you have no water vapor, as delivered means that we're assuming the gas is saturated water vapor as meter pressure and temperature, and wet means something completely ridiculous. Wet means that we're assuming the gas is saturated with water vapor at 14.73 PSI at 50 degrees Fahrenheit.

If you're reporting wet BTUs, you're taking a heating value, oftentimes, most of the times, you're taking value deduction from water vapor that cannot physically exist at the meter. We don't think that's right and we would like to see wet go away altogether.

So we're going to say dry, we would consider as delivered; however we want data to indicate that gas truly is saturated with water vapor at meter conditions. The data I've seen so far shows that gas is not. Also we want 14.73 PSI and 60 degrees Fahrenheit.

Order 5, the statewide NTLs have no requirements for independent testing of transducers or flow computers and basically accept all of them. I'll explain this a little bit. If in the notice to lessees, we have a 3% uncertainty requirement already. We have a tool called the uncertainty calculator that our inspectors use that enforced that uncertainty requirement. It's only for meters flowing more than 100 MCF per day.

And transducers are probably the main cause of inaccuracy or uncertainty in a gas meter. When our calculators, our (unintelligible) they hit a little button and it calculates. Behind the scenes, the calculation uses manufacturer-stated performance specs for transducers.

The problem with that is the manufacturer-reported specs are down in house by the manufacturer often using proprietary methods. There's no transparency at all for what those actually mean, what those specs actually mean or how they were determined.

Because uncertainty is such a critical thing in this proposed rule, we are proposing that all transducers used at high and very high volume FMPs have to go through a testing - a transparent testing protocol to define what those specifications are.

The transducers would go through this testing protocol. The results would be sent to the production measurement team. Unless the production measurement team was satisfied with them, they would go up on the pick list of approved ultra-flow computes and transducers.

Woman: (Unintelligible) Thanks.

Rich Estabrook: Sure.

Coming down to the end here. Both (Mikes) -- excuse me -- both (Mikes) stated at the end of the presentation about specific data and comment requests. It's in the preamble. When you see a specific request for data in a preamble, it means that we really - we're seriously looking for input on that, and we're looking for input on anything.

Anything is open for comment. But this is the stuff that we're putting out there where we kind of like, "Eh, let's give a shot and see what happens." But we don’t have much data for it.

So the specific things in Order 5 are the cost to industry for this transducer testing. We don't have a good feel for that. The current 3175 requires five transducers to be tested. I know 51 just has one transducer, because the manufacturer can send you their best one, for example. Is five the right number? Is that statistically significant? I don't know.

Are the requirements for online gas chromatographs? We couldn't find them. Are there industry standards or some requirements for online chromatographs that we could be looking at? I talked about this one already. If industry wants to persuade us to use a hand-delivered heating value other dry, we want data showing that that's a reasonable assumption. That would be really nice to have.

The data from the sample probe placement, again we're - that's - we're just throwing it out there to see what you think. We haven't found anything in literature that talks about heating value as a function of where the central probe is located. We'd love to see some data on that.

Finally, the (decentricity) requirements, I'll go over that. Chart integration, I don't think there's too much of that around here, so I'll skip over that one. Data showing the difference between C6 plus and C9 plus analysis as a function of mole percent of C6 plus, again we're proposing that if your hexane plus analysis is greater than .25 mole percent that you need to do an extended analysis. But again, we don't know. If there's data out there that it really doesn't matter, we'd like to see that data.

The last one, which is not on here, is we also have a request for methods on which - that we could use or that you guys could use, we've actually put a seal on a clean gas sample cylinder so that when we go out to witness a gas sample being taken, our inspectors can see that this truly is a uncontaminated clean cylinder, and I don't know how to do that.

With that, my last slide, and then we'll take a break and then we'll come back and the rest of the afternoon is yours, here is some addresses for submitting comments. I would recommend the regulations.gov site. If you go to that regulations.gov site, you can do a search for any one of our three orders here. I do a search for 43 states, CFR space, and then 3173, 3174, or 3175.

So on this site not only can you comment there, you'll find the proposed rule and submit comments, you can look other people's comments that have come through this site. There's also an economic impact analysis for each rule. There's an environmental assessment. And for 3175 in particular, there's a study that we did a couple years ago about this heating value variability issue so you can see where we came up with our proposed sampling frequency and this goal of not having arbitrary sampling frequencies.

PowerPoints. All these PowerPoints will be available at this website. They're already loaded on that website. So with that, why don't we take a ten-minute break. Be back at 2:35. Is that okay, Don?

Don Judice: Yes absolutely.

Rich Estabrook: 2:35, and again the rest of the afternoon is yours.

Don Judice: Callers on the phone, we are taking a ten-minute break and we will return at that time. We'll take questions from those who have signed up to speak. We will take some from the audience, and then I will take calls and questions from those on the phone. Thank you and we'll be back in ten.

((Crosstalk))

Don Judice: Okay let's get started. If I could ask if you could take your seats. Okay thank you. What we'll do is the first thing I'll do is I'll go through, there were individuals who when signing up indicated they would like to speak. If your speaking opportunity was, you know, just for a question, that's great.

If you're speaking opportunity was to make a statement or so, if you could be so kind as to limit it to about three minutes so we can get through the rest of the questions that not only do we have here, but we have 62 who have called in on the landline. And there are likely going to be calls on the phone also. So I'll go ahead and I will apologize right now for slaughtering of names. It's all based on your penmanship and my linguistics here.

So the first person who identified as wanting to speak is (Dale Farming) with Whiting Oil and Gas. (Dale), are you in the audience? There's (Dale). There's a microphone right there.

(Dale Farming): I'd just like to ask how you are determining the volumes for meter tests? Let's say you have well that's about over 1,000 a day on gas. The next month it's doing an average of 800 and then it bumps up over to 1,000 again. How are you going to monitor that? Will it be a six-month volume that we're going to an average for and then apply that to the next six months, or is month by month?

Rich Estabrook: What's currently proposed in 3175 is that that category would be established by the previous 12 months production or the life of the meter, whichever is less. Okay?

Don Judice: Thank you. The next individual who asked to speak is (Chris Canski) from (One Oak) (Chris)?

(Chris Canski): I just have a couple questions. I'll keep them short. On the proposed new orders, you talked about putting...

Woman: Excuse me? Would you stand up because I can't see you? Oh, you're there. No wonder I can't see you. You're fine. (Unintelligible) It's getting late in the day, I know.

(Chris Canski): On the new proposed orders, you talk about putting some ownership back on the owners of the meters for gas measurement for a responsibility like for possible enforcement. If we are being - getting information from the lease owner or the operator of that wellbeing - or has been released (unintelligible), how are we going to be - how will we know that? Because right now we're struggling to get that information.

And I know it's not the BLM's requirement to report it to us. There's nothing in the (unintelligible) for anybody that's responsible for reporting this well has a federal lease. So how will we know without being fined for something we don't know about?

Rich Estabrook: I believe what we have proposed in the rule, and I can't remember if this is actually in the rule or discussed in the preamble, that when we're doing an audit, we would actually go to the operator first and request that information. The operator then could tell us that it's not their meter and tell us that we need to go to the purchaser. In that case we would do that. I'm not sure that answers your question.

(Chris Canski): No, it doesn't. With (One Oak) we own our meters for the most part. So if we install a new meter on a well location, we set it all up usually before the producer finishes the site, as an example. We get first gas sales on the meter. We just plug along and we, you know, block our requirements and - for frequency and calibration and sampling. But usually we don't know about it being a lease well until BLM comes around to do an inspection or the operator notifies that hey this is supposed to be BLM requirements, why aren't you calibrating per BLM's regulations.

Rich Estabrook: Okay. So the question is how would a purchaser or pipeline company know that they're dealing with BLM (unintelligible)?

Well I don't have a real good answer. I think that would just be up to you guys to figure out a way to do that. I mean we do have well signs out there that it's a federal meter and there's plenty of data available. I don't know if you guys have a different answer.

Man: First of all it would be - primarily be who the operators keep you notified. However, federal facilities and wells do require a well sign or facility sign out there with a federal case number on it. So those are required if there's federal minerals or Indian minerals going through a location. So that would be another place where you could tell relatively quickly if there is a federal case numbers by looking at the on location signage and seeing that federal number.

Rich Estabrook: Just one quick point of clarification, that requirements applies to both oil and gas meters, not just gas. So for oil it's the same thing. Transporters, trans-purchasers would be required to submit information of recordkeeping on request.

(Chris Canski): The last question I had was what is the timeline for approval on new equipment through the PMT? Would it be on a pick list if it's not on there now?

Rich Estabrook: Yes we don't have any timeline on the proposed rule, this is a brand new concept so it’s a little bit hard for us to say. I mean I can tell you right now from meter reviews that I’ve done personally for the gas site it takes years.

And part of the reason is because I do a bunch of other things and so I get a pile of data on my desk for a new meter and just finding the time to do that and going through it and oftentimes it is an iterative process for the manufacturer on the testing requirements.

So I mean I've had meters pending approval for 2 or 3 years personally. Now with the PMT proposal this team would be focused on that, that's all they would do.

So I would say - I'll just throw a number out, a year for new approval. I think that's probably doable.

(Chris Canski): In the meantime we do what if we don't meet requirements and we don't have approval?

Rich Estabrook: In the meantime we will make adjustments to make sure that that doesn't fall on you guys.

(Chris Canski): Thank you.

Don Judice: The next person who has asked to speak is (Josh) with ConocoPhillips.

(Josh Morrett): Good afternoon. My name is (Josh Morrett) I'm the stakeholder relations (provider) for ConocoPhillips lower 48 (Rocky) business unit. I'm (unintelligible).

I do have co-workers who are on the phone right now in Houston and they are here to offer more technical, support technical aspects to proposed rules. So if you guys have any questions about what I'm giving you today.

They were asking for clarification is it star 1 to...

Don Judice: The Operator will indicate that during their open period yes.

Woman: Move the mike over here now.

Don Judice: Sorry about that, better.

Woman: Yes.

(Josh Morrett): ConocoPhillips does appreciate the opportunity to provide constructive comments on these proposed BLM rules. While we recognize that some of the updates are beneficial some of our subject matter experts have met with BLM and provided detailed comments about how some of these proposed changes could have serious impacts to oil and gas production on federal and Indian lands.

ConocoPhillips has concerns with BLM releasing these three on shore orders separately instead of simultaneously for public comment. We request that BLM grant an extension to the comment period so that all the proposed changes can be thoroughly analyzed especially with how they interrelate.

Where it appears that BLM has attempted to understand economic impacts of these rules in isolation we would request the BLM go back and look at the cumulative economic impact of the proposed changes in some across the rules.

We feel that the changes to the rules as proposed are significant and will have major impact to investments in new and existing projects on federal and Indian lands with potential for job losses, premature well closures and significantly lower federal and tribal revenues.

Some of the key issues that we see that pertain to on shore Order Number 4, we request that BLM consider grandfathering existing facilities into the order.

We also feel that the requirements to re-strap tanks from a standard of a quarter of an inch to an eighth of an inch does not generate value.

Furthermore we support using updated technologies such as guided wave radar devices to safely measure tank volumes. Safety is the most important and we support updates that establish a better way to keep all workers out of harm.

Generating new tables within 180 days does not seem feasible. We also feel that 24 hour notice of LACT issue is not adequate. Introduction of pressure transmitters on existing LACT meters is not feasible given that it will only adjust accuracy readings by approximately 7/10 of a percent - 7/100 of a percent.

Our key issues with on shore Order 5 are again grandfathering existing facilities, problem or failed equipment will be replaced according to maintenance protocols.

The gain of plus or minus (5 or 10) percent accuracy does not justify spending more money on existing equipment. There will be no measurable benefit to either the company or to the Federal government.

We request that BLM leave the marginal well MCFD volume trigger at 100, the low at 100 to 500, the high at 500 to 1000 and very high at greater than 100 and MCFD.

We also request the BLM have grandfathering language to exempt existing transducers and meter tubes. And finally we reiterate our request in asking that BLM conduct a more thorough economic impact analysis for the changes that they proposed with wells across the country.

I want to thank you for the opportunity to submit comments today and we also will be submitting comments, written comments before the (unintelligible).

Don Judice: Thank you.

Woman: Would you give me a copy of that before you leave?

(Josh Morrett): Yes.

Woman: Thank you.

Don Judice: The next person that was asked to speak is (Bill Bowman), District 39.

(Bill Bowman): Do I need to stand up? Okay now do you see me?

Woman: Yes I do.

Bill Bowman: Well first of all I'm glad I came to this meeting because I represent a big part of the BLM land in Western North Dakota from (Fulton) clear out to the South Dakota border. So we might just have a lot of this land.

All I want to see is that we take everyone's ideas into consideration because the people that work in the industry know way more than I know about this. I have to trust somebody and I trust the people that bring that information forward because they know how it's going to affect what they do.

Now I also want to say that I also want to make sure that what we're doing is accurate, we're getting the right numbers. But if it comes (unintelligible) that the industry shuts down because of that then is it worth it and I hope we take that into consideration it's just common sense and a lot of times that has more value than a number. So with that thank you.

Don Judice: Thank you Bill. That concludes those that have signed up on the sign-up sheet to speak. So what I will do now is open it up to the floor for questions. Again in order that we can get some assistance for the core reporter if you could stand we will get a mike to you, state your name and to whom you represent.

So are there questions in the group? Okay we have one.

(Aswald Bordet): (Aswald Bordet) with (SMNGA). I just have one question at this point and can you give me a little more explanation about who is going to be involved in this production measurement team? Will the industry be involved or associations be involved and how will that whole process be handled?

Rich Estabrook: Well what we envision right now is it would be probably just existing staff that would be assigned to do this or pretty much full-time at least for the time being it would be again we don't have this in the rule itself but this team would be solely responsible for reviewing the data and coming up with the recommendations.

We don't have plans at this time to open it up to industry or trade associations.

Woman: I'm sorry I did not get your last name.

(Aswald Bordet): (Bordet)…

Don Judice: Let me go to the phone now. Operator, (Victor) we are ready for any questions for those callers.

Coordinator: Okay, we will now being a question and answer session. If you would like to ask a question over the phone line please press star 1, un-mute your phone and record your name at the prompt.

To withdraw your question press star 2. One moment please for incoming questions. Our first question comes from (Ron Gibson), your line is open.

(Ron Ritson): (Ritson), thank you guys for letting me ask a question or two. I've got a couple questions let me - unlike Oklahoma City where asked all at one time let me ask them one at a time.
I think some of them would be short answers. Rich if I understood you right when we was talking about new technologies it takes years for some of that testing to be evaluated I have two concerns.

One, touched on just briefly once the amount of volume that you're going to receive on existing equipment how quick do you have any expectations of how quick you think you'll have existing equipment currently in use today approved?

And I'm presuming that we won't be penalized until that approval list is out there.

The other question that I have is a little bit more germane from some of the manufacturers. Some of our existing equipment today may not be in current production or may not be supported by the manufacturers or the manufacturers may opt to as opposed to do the testing and trying to keep an older model in operation and production just decide to negate and go newer advanced technologies.

Will we be able to have waivers that we can use that existing equipment and not be penalized because the manufacturers have decided not to perform the dynamic testing and the static testing on the existing equipment and they've opted to only go with their newest lines of equipment?

Rich Estabrook: Does this work?

Don Judice: Yes.

Rich Estabrook: It's really hard to anticipate the timeframes. You know, I think you're right we're going to get a flood of new testing data right away. You know, we will adjust our regs so that you guys aren't penalized that would be silly if that happened.

So and the other one is about existing equipment that may not be manufactured anymore. I'm not - that's a good point (Ron) and I would encourage you to make that - well you did make that comment but we'll consider that.

(Ron Ritson): And assuming Rich I mean you're a man of your word but without the reg being there is that something that's going to be rather an addendum that's going to kind of come out as a plan of operations from the BLM because, you know, that's not in a reg and of course the worry would be as an assessment officer comes out and says hey I want to be a - I want to draw a strict line and I'm going to penalize you and then this assessment comes out and the other location says hey it's not your fault let it slide.

Rich Estabrook: Well it's not a reg yes so I just want to make that clear to everybody. We don't have a reg we have a proposed rule. It is totally and completely unenforceable at this time. It has no bearing whatsoever.

It has no bearing until it becomes a final rule and, you know, but the process between the proposed rule that people have seen and commented on and the final rule is long and intense.

The final rule may look nothing like the proposed rule we just don't know until we sit down and start to review the comments.

(Ron Ritson): My next two questions are going to change if I can. I was looking at your report online and there is not an indication as to where you guys took the samples for these.

Was it primarily after the first set of separation or was it prior to this first - I mean can you discuss where these samples were taken and will that impact what we see at the custody meter location which is typically downstream of meter separation, sometimes downstream of LACT units, heater treaters and the whatnot.

Rich Estabrook: No I can't discuss that because I really don't know I mean the samples - the analyses that we got are analyses that were used for royalty determination. So for us that is the royalty plan I could care less what happens downstream with the sales meter 10 miles away that has no bearing on royalty.

So our study that's on the regulations.gov Web site was only based on gas analyses that came from royalty points and that's all we care about.

(Ron Ritson): Okay my worry card would be is that we see a little bit more variability when we're downstream of this and we are the custody point, we're the royalty point, we're downstream of a heater treater of a producer who may or may not operate and it's seasonal.

When you was looking at the - when I'm looking at the study and I do see that you have some time between samples and dates in some of the formations and you did do some type of an evaluation or study of the amount of time.

Was that figured in the 1% and the 2% variability when you was looking at your standard deviations was the seasonal impact sampling i.e. if we're on a 6 month sampling frequency or a 1 year sampling frequency there could be a lot of time between - in that variability between units because of the time of year you're taking a sample or the time between sample periods.

Rich Estabrook: Yes in the study there was no consideration of the time between samples. I believe the variability was based on all the samples we've had for that particular meter historically whether it was 4 samples or 30.

One thing I would say on the temperature side of it - see and the thing with seasonal would do I'm guessing that you're getting to is temperature. We did - we do have I believe an analysis based on temperature I think a sample temperature versus variability.

And the one thing I would say about that is only about 30% of our samples even reported pressure or temperature. So we did what we could and we found no correlation (repeating) value variability based on temperature or pressure but the sample site was smaller because so few samples are now since we concluded that information.

(Ron Ritson): Thank you.

Don Judice: Okay great do we have another question on the line?

Coordinator: At this time there are no questions queued up but if anyone would like to ask a question please press star 1, record your name at the prompt.

Don Judice: Okay let me open it back up to the field here. Yes we have a question, again state your name.

(Ramel Olsen): My name is (Ramel Olsen) with (unintelligible) in (Fulton) and I have some questions specific to the security diagram the removal of (unintelligible) plan. And basically with respect to the removal of the (unintelligible) plan (unintelligible) site security diagrams on specific locations of the multi-page (unintelligible) originally the order placed in the field office et cetera.
I am wondering is that something that you were hoping for that they would want a specific (unintelligible) be a site specific plan (unintelligible)?

Man: In the draft we've included a Section 4 that shows some example site security diagrams. And basically there has not been a significant change on the diagrams themselves only on some of the information, additional information that we would be potentially asking for.

For example specifically would be some of the equipment that would be using beneficial gas or beneficial use and how those numbers are being determined from the manufacturer or through meters.

The reason with a site security plan that you're talking about that is in the current order is about two sentences long with absolutely, with almost no detail as to what is required in a site security plan.

But left it well open to a significant amount of interpretation and variability. The plans have been - that I have seen have been anywhere from one paragraph to 50 pages and many times they said nothing.

(Ramel Olsen): If the serial numbers of the equipment basically inventory information and it seems like that - would that information specifically meet the (unintelligible) on location?

Man: No.

(Ramel Olsen): Okay.

Man: That's information that is submitted as part of the site facility diagram to the BLM and the BLM maintains those diagrams and as equipment changes (unintelligible) out there the operator is required to submit amended diagrams even under current rulemaking in Order 3 that if you put a new piece of equipment out there or remove something operators are required now to submit an amended diagram when those changes occurred.

The same with the (unintelligible) for the future would be no change in that respect.

(Ramel Olsen): Okay then (unintelligible). What are the specific criteria to decide what's going to be (unintelligible) or not now? What we're wondering is there a specific diameter of valve that is the smallest diameter useful in the security of the product? Are you going to specify that for each of the pieces?

Man: That is covered in the proposed rulemaking as well as a detailed description definition as well as an exact detail for size of the valves. Without opening and having it in front of me right now there is a valve size where fields would not be required.

(Ramel Olsen): I think that's it for now thanks.

Man: Let me make - as long there aren't any further questions or people on the phone - is there one on the phone? Let's go to that first.

Don Judice: Yes we do have a question on the phone.

Coordinator: Yes we have a question from (Ron Gibson). Your line is open.

(Ron Ritson): Thank you again. Two questions at least this time. Rich part of the testing requirements you're asking for your testing equipment to be 1/4% or 1/4 of the percent of accuracy that stated the transducers.
My concern is in as many companies that I know that we've been in our committees most people typically get twice as good or 50% of the stated accuracy.

If we're not in with the fine equipment especially portable equipment that's going to want to meet the 25% of the span what do we - what's the recommendation, what do we do?

Rich Estabrook: Could you refresh my memory of what that 1/4%...

(Ron Ritson): Generally it comes from transducer testing in Section 131 and specifically is number 2D.

Rich Estabrook: Okay and I'm sorry I don't have it right here could you read what that says for me?

(Ron Ritson): Yes the input and output if the output is analog each transducer must be measured with equipment that is a published reference uncertainty less than or equal to 25% of the published reference uncertainty the transducer under test across the measurement range blah, blah, blah.

Rich Estabrook: Okay so this is under the testing protocol section then?

(Ron Ritson): Yes.

Rich Estabrook: Well again this is up for comment. If you have - obviously you do have comments about equipment not being able to meet that spec then, you know, submit that comment and we'll reanalyze it.

Most of those transducer testing protocol requirements in the proposed rule came from IEC standards and so a lot of those requirements are verbatim out of those standards.

So we need comments on whether or not those are reasonable.

(Ron Ritson): That testing requirement also goes for your field testing not just your type testing right because it's under the general testing requirements?

Rich Estabrook: No for field calibration I believe we took the API 211 recommendations where there is no requirement for the test equipment to be more accurate than the equipment being tested because we will take the calibration equipment into consideration when doing uncertainty calculations. I think that's the case.

(Ron Ritson): Okay, well my bad well thank you for clarifying that. One other question on the gas reporting. I know your (GARDS) system is not in operation. Spot sampling reporting within 5 days after the due date might be pretty tough because of the gymnastics and coordination if you're doing sample cylinders to get those picked up or shipped to a particular lab.

And then get the lab to analyze and report back to the company and report to billing within 5 days. Is there a consideration for that? Is there a reason why you need it 5 days if it's not being applied until the end of the month or the, you know, the beginning of the next following month?

Rich Estabrook: Well I said like everything in there we put that out as a proposal and we will take your comment into consideration in reviewing that.

(Ron Ritson): Thanks.

Don Judice: Are there further questions in the room? Yes (Travis) we have a gentleman.

(Chris Camp): (Chris Camp) (unintelligible). On this proposal there is a mention of a 72 hour notice for scheduling calibration for gas meters. With our company as large as it is and the land that we cover we have multiple areas and I know the BLM is limited on manpower.

Is that scheduling based off of 100% witnessing and if so is the BLM going to be staffed up to meet that demand? An example would be we have meters covering Watford City to (Rolleston) over to Utah and if we have three, four measurement techs that notify the BLM within 72 hours of witnessing but you have only two or three agents in that area. Can they be everywhere at once?

Man: No and that was definitely assuming anywhere near 100% witnessing. I think the 72 hour notice may have been a remnant from the existing on shore Order 5 actually.

So again if it's something that is not reasonable or has problems, you know, we need to hear that. Do you want to talk about the strategy issues related to...

(Mike): The inspectors will find out where you're going to be 72 hours in advance and based on their - what their inspection priority workload is and whether it's a case that they are specifically inspecting by getting that information they can be out there and pick and choose which ones they need to be to.

That is a big issue with the inspection side is being able to catch those. The only other option we would have in order to adequately inspect those would be to regularly send out what is called a written order saying you will be out here on such and such a date and time to calibrate this meter.
And that is not a reasonable expectation for anybody's part in light of the fact that you may have just calibrated that meter three days before you got the letter or three days before you're scheduled to go do it again.

So that's part of the reason for the 72 hours is so that we can make a determination of which ones we want to be out there for and what our availabilities are.

Don Judice: Thank you (Mike). Let me go back to the callers on the phone. Operator are there any further questions?

Coordinator: There are no questions at this time sir. I can give the message once more though. If anyone would like to ask any questions or make any comment over the phone lines please press star 1, un-mute your phone and record your name at the prompt.

Don Judice: Okay let's go back to the field care to the group. Are there further questions? We have one.

(Ramel Olsen): (Ramel Olsen). Can you please explain again the FMP online application process in terms there is like a year (unintelligible) they'll have 6 months to a year, please explain that again thanks.

Rich Estabrook: Okay what we've proposed would be for the high producing wells those over a selected volume that the first 9 months would be after the effective date everybody who had those high produce - and this is based on the previous 12 months production average would have 9 months to apply for their FMP number.

So that would take our high producing cases if you will and try to get those FMP numbers issued first. The middle third of those producing cases still based on the 12 month previous production averages would start being due on the end of the 9th month through the 18th month.

So they would have that second set of 9 months to submit. And then the low producing cases would be due at the end of basically final 27 months and that would be the lowest producing 1/3 of the cases.

(Ramel Olsen): So the applications just needs to be typed in basically because I think you gave yourselves a year or a year and a half to actually get that permit number to us but is that...

Rich Estabrook: We just don't have a firm idea yet as to how long it would take to process. There are several variables that we are working on resolving for those of you who have any idea at all of the rewrite of (AFMUS 2), they're currently coming out with a module for APD's.

We are hopefully going to have a module for electronic submissions of the FMP numbers as well so that we can do a better job processing those more timely.

Right now we just do not have a good handle on how long it would take to actually process the application, it's contingent and dependent very much so on some of the available technologies that we are trying to implement between now and then.

But we felt at the time that the 27 month to process was a reasonable expectation on our part to be able to have at least 99% of the FMP's issued. Now of course if you have new production first time it comes on after - those would be due immediately before production is sold.

So this would only impact those that are in existence prior to the effective date of whatever the rule is actually set up as.

(Ramel Olsen): Is that available online now to get a jump on that for our clients?

Rich Estabrook: No, these are still draft and proposals. We don't have a firm rule as to when everything is due. So without a firm rule no we do not have that and in fact the current requirements that we proposed in draft for information that would be selected that could change too based on the comments we receive from the public.

So the ability to get an early head start probably not there but at least the knowledge that we may have a requirement when these become final for requesting the FMP numbers that that would be useful information.

Don Judice: We have another call on the phone. Go ahead.

Coordinator: Our next question comes from Mary Indihar. Your line is open.

Mary Indihar: Hi, good afternoon. I have a question on your proposed 3 - 173 where it says documentation review required for water draining, hi oiling, clean up, et cetera. What kind of documentation? And is that documentation, is that or codes that we have to supply on the (OGAR) report?

Rich Estabrook: No it is not. Mostly it is a record-keeping process. We will request if we needed the specifics, same as we do now for a seal record. If we send out new production accountability, we would request you to provide us that information.

There is nothing in the requirement that would require regular submission of data. Data would be requested as needed so that - and the new information would be, like I was mentioning potentially opening gauges, closing gauges.

That would just be additional information that you would record at the same time that you record a change of seal number. So there would be really no change in what you're doing now for seal numbers except writing down a few extra numbers.

Mary Indihar: Okay. And another question on the FMPs. Are those - will those be retroactive or just as the date effective? (I have a) request one and it's effective December. And we send an amendment. Will we have to submit that FMP number on the (OGAR)?

Rich Estabrook: No. You would not. These would only be if you - if, for example, one was issued with an effective date of March 1, that would be the earliest that you would have to report on. It would probably be 30 days after that I'm guessing right now because we haven't got a final rule.

And it would not be retroactive. It would not impact any of your historic data prior to the date it was issued.

Mary Indihar: Okay. Thank you very much.

Don Judice: Please, for the court reporter, could you please state your name?

Mary Indihar: Mary Indihar.

Don Judice: Could you spell that last name?

Mary Indihar: I-N-D-I-H-A-R.

Woman: Thank you.

Don Judice: Thank you.

Mary Indihar: Thank you.

Coordinator: Our next question comes from (Ron Gibson). Your line is open.

(Ron Gibson): You know, as long as there is an open line...

((Crosstalk))

(Ron Gibson): Rich could you help me with how the determination of the FMP is - how the deal end would see that happening for a new well because I just heard someone talk about that on the new production that we would have to have a site determination or a site member for whether it be high or very high?

Often times we don't know what that well is going to produce until we get it going. And then, you know, if there's sharp decline, as mentioned in Oklahoma City, it's going to be 50% of what it's an issue flow within a few months.

And maybe literally within a few days of it's opening initial production. So how do we classify an FMP? How do we do that when it's on a moving target for that first six months and it's got a pretty good size exponential decline?

I mean do we have, every month we have a different, I mean we have a different classification because, you know, I know the reg says history or last 12 months or whatever history. But, you know, on the first day you got history of one day, second day you've got history of two days, if you understand what I'm trying to drive two.

Man: Yes. This historic record that we're talking about for high production and low production on a plain would only apply to those cases that are in existence prior to the effective date.

A new facility who's limit has just come on a day after the effective date, and if memory - we are proposing I believe a 30 day timeframe for you to request a new FMP number on that new production.

Like I said, and if it was in - if the facility and well was in existence prior to the effective date, it would fall under the standard category as the others based on high or low, based on the previous 12 months or less if that's all that was available average monthly production.

(Ron Gibson): So for the new one after the first 30 days we apply for a permit based on that first 30 days of production. It declines again, we can reapply after the next 30 days for a different classification? I mean how do you see that happening with gas wells not like oil wells that produce a little bit more solidly gas wells that have huge decline rates?

Rich Estabrook: So (Ron), this is Rich. I think I understand your question now. So your hypothetical would be you drill a new gas well that produces gas. And for the first couple of weeks it's just a screamer. It's doing 1000 MCF a day. And within four months it's down to 200 MCF a day.

And I think if I understand your question is how would you - what category would you put that in based on just a couple of months of data? Is that a fair paraphrase?

(Ron Gibson): Yes sir, very much. Very correct.

Rich Estabrook: So, you know, I can't remember if we have specific provisions right now or not, but it's a great question and something that if we don't have something in there now, which I don't think we do to address that situation, we will consider that. It's a great point.

(Ron Gibson): Yes. It's not anywhere in here that I can find. And as we were mentioning, you know, it's a difference of do I have to put composite samples on it or do I go with a portable gas or Mata graph or some type of spot (sensor)?

And do I put a composite sample on there that's going to be on there for by the time I get it ordered and installed, it's there for a week.

Rich Estabrook: Yes, not great point. Thank you.

Don Judice: We have a question here in the audience.

Man: (Unintelligible) (SM) Energy. I have a couple of questions. The first one, (on shore Number 3) talked about the fact that you will be requiring an approved APD on state and fee land. Is that correct or is that an error or oversight?

Don Judice: That is - (Dillon) will answer that one.

(Dillon): No. The - an approved APD is required to (unintelligible) federal minerals at any part of the well bore pierces through federal mineral.

If you are - if you have a nicked unit, which is, you know, federal, private, tribal - federal, state, private, tribal or something like that you'll be (unintelligible) type areas.

As we state under the current rules, those scenarios are subject to federal measure rules. They're federal component (CD unit) will (communitize) the area. But if well water just travels through state and private lands, we will not be requiring it.

Man: So that will be clarified in the final rule?

(Dillon): Yes.

Man: Second question here. You talk about the fact (unintelligible) approvals that they're going to have to be reapproved. And that you will only approve comingling when it's 100% federal or 100% tribal. Is that correct?

Man: No, that's not correct. That's one of the situations where we would approve comingling. If everything - everything was 100% federal, same royalty rate, same royalty distribution or 100% tribal, same tribe, same royalty distribution.

In other words if the allocation method has no impact on the ultimate amount of royalty that's received, that would be a case where we would approve co-mingling.

However, there are two other situations if that wasn't the case. There would be two other situations where we would consider approving comingling. One is if the production from cases or wells are proposed for comingling and qualifies under our low-volume definition. That's one.

And the other one - and I can discuss that if you want in a little more detail. And the other one would be if there are extenuating environmental circumstances or issues of maximum ultimate recovery, that would be another situation where we could approve comingling even if there were royalty impacts to allocation.

Man: Thank you.

Don Judice: Again, any further questions of the group here? Let me go back one more time to the phone. Are there any further questions?

Coordinator: There are no questions over the phone lines sir.

Don Judice: Thank you.

Rich Estabrook: We get the - we consistently get comments about these rules causing such economic hardship that wells and leases would have to be shut in. And I wanted to address that briefly.

Now the goal of these rules is to make sure we're getting the proper amount of royalty that we're due, that the federal government is due, that the American people are due or tried to do. That's the goal of these rules.

It would be really bureaucratic or silly or something for us to impose rules that instead of doing that resulted in less royalty. That would be - that's not what we want to do. That would be crazy for us to do that.

So, and I understand the concerns. And maybe the way the rule is written right now that could happen. So what I would say is if you submit a comment that says we're going to have to shut in our wells or leases because of these rules, obviously that's helpful, but that's difficult for us to deal with, a comment that's vague like that.

What would be much more helpful is if you submitted the same comment but said, here are the provisions, the specific provisions in your rule that we find costly and could result in this.

And if you wanted to make it a really useful comment you could say, and here's a less expensive way to achieve the same goal that you are trying to achieve. That would be really useful for us.

So I would encourage, instead of just submitting generic comments saying that we're going to have to shut in our wells because of these rules, be specific about spe - because, you know, we will consider changes. That's what this whole comment period is about. We will consider changes.

And if there are changes that legitimately would cause people to shut in meters or wells, that's the last thing in the world we want. So anyway, just some advice perhaps.

Don Judice: And I understand we have another call on the phone.

Coordinator: Yes, it will just be one moment while I get the person's name. For this next person we did not unfortunately get a recording of their name. But if you pressed Star 1 to ask a question, your line is currently open.

(Darren Steel): Yes can you hear me now?

((Crosstalk))

Coordinator: You have an open line now sir.

(Darren Steel): Okay this is (Darren Steel) with XTO Energy. I was hoping...

Don Judice: One moment. Could you say your name more slowly please?

(Darren Steel): It's (Darren Steel) with XTO Energy.

Don Judice: Okay your question.

(Darren Steel): Okay, Rich I was hoping you could speak a little bit to I believe it's Section 3175 under logs and records. It states that you would not allow any QDRs that are - that aren't unaltered, unprocessed or uninhibited.

And it specifically states that no third-party (soughter) would be allowed. Now is that specifically - means that - I mean exactly how are we supposed to meet that requirement?

Rich Estabrook: Well, I mean the requirement is as stated. When we request raw data for an audit, we expect to get raw data. We are not convinced that some of the data we get from third-party software packages represents raw data, in fact much of it does not.

And it, you know, we're looking to independently verify the volumes and qualities that you actually measure in the field. My goal would be to have third-party software companies that actually provide raw data.

And that currently we believe is not necessarily the case. So until we're assured that we're getting raw data from third-party software companies, we would basically require data to be recovered right from the electronic flow computer.

Don Judice: Okay thank you. We have some closing remarks from Amanda.

Amanda Leiter: So I don't want to cut anybody off. There are no further questions here? Okay. So I just wanted to talk a little bit about what the process is from here.

So with rule-making in general, the federal agency (blocks) is very careful (tightrope) because we are putting out a proposal that is what we think we want to do, but we're very open to comments from you all or from whoever the regulated entities are because you know your business better than us and better than we do.

And so we're putting out this proposal. And we want to hear back from you if there are things we are doing that don't make sense or that we're not doing in the most cost-effective way.

And then we take account of those comments and the rule can be modified somewhat, the proposed rule can be modified somewhat before we get to the final. So this really is an opportunity for you to help us shape a rule that makes sense for you.

Now that said, the final rule has to be, you know, the legal term is a logical outgrowth. The final rule has to look something like the proposal. It can't change too much during that process.

That's why you sometimes see federal agencies put out a proposal and then a revised proposal because they have some big change they want to make. But, you know, bigger than is fairly encompassed in that process.

So the final rule that you should expect to see in the next few months, and I can't give you an exact timeline on that, is going to look something like the proposals you've seen.

It's good to be an outgrowth of the proposal you've seen, taking account of the comments we get. And that's why the suggestion that the more specific you can be, the better for us. That's why we're giving you that suggestion because, you know, we're really promulgating a very detailed rule that sort of get that how you do these measurements.

If you know a more cost-effective or more reliable way to do the measurements, we want to hear about it. If you know that some method that we proposed isn't effective or isn't going to work, we want to hear about that.

The timing - I mean the rules have been open for public comment for quite a long time. So unfortunately for you, you're sitting in a public meeting at which I have to tell you that your comments are due next Monday.

That is the final date for getting in comments. We did hear from both - we heard it earlier in the room. We did hear from both that they wanted all three of these onshore oilers open at the same time. And that is why they're now open at the same time.

So this is your opportunity to look at how they all interrelate. Make sure you think they interrelate in a way that makes sense and get back to us with those requisitions.

So again, we are very open to your comments. The way this will now work is the comment period closes Monday, December 14. We then do a very thorough sort of evaluation of the comments that come back. And we think about which ones make sense.

Often, as you might expect, we're hearing conflicting things from folks. So, you know, we can't make everybody happy all the time. But we're doing our best to do something that makes sense and takes account of everything that we hear from all of you.

There's then a sort of process that we're (riding) the proposal to get to a final version. The final version goes through a couple rounds of vetting. There's a lot of folks involved.

So, you know, we can't give you an exact time frame for how long that will take. But the aim certainly is to turn it around in the next few months. So, you know, earlish in 2016, but I can't be any more specific than that.

So any questions about that process?

Man: Yes Amanda, one question. If for some reason, since Rich is asking for information on new approaches of technologies that are out there and the industry has now been given the opportunity to look at those and see whether or not we agree with those or not.

Will there be any possibility of those will reopen again to give us a chance if we got one last time before you make the final?

Amanda Leiter: So you mean if there are changes? If there are changes to the final rule?

Man: If there is changes to the final rule based on new data that was presented to Rich that he analyzed that industry has not had a chance to look at and comment, whether or not they would be given that opportunity?

Amanda Leiter: So likely not. I mean if we got some data that really sort of starkly changed our view, then we could do a re-proposal. That is not the aim for the process here. The aim for the process here is to go from the issue to a final rule. In which case there wouldn't be that opportunity.

Woman: Will the inspector's handbook - it sounded like there's going to be an inspector's handbook you're taking on. But is it part of the actual rule. Will that be released at the same time as the final? And will there - put the cabash on individual field offices having their own modified versions of those? Just pertaining to the first few years anyway.

Man: The intent is yes, to publish those so that industry can look at those recommendations and what the handbook is. Of course we can't even start writing the handbook until we have a final version ready to go to the press.

Once that goes to the press, we can start writing the final. I would hazard a guess, keep in mind this is a guess that it would become available approximately the same time as you have an effective date of the rule.

That would be the earliest we could possibly do that. If we are unable to do it at that time frame, then we would also look at having the implementation for example on the FMP number.

Okay, obviously you can't issue any solid low-volume FMPs until you have time to miss and apply for. That's 17 or 27 months down the road as it's currently proposed.

So there would be all of those issues to consider before and in the process of writing that. So as to give everybody an opportunity to look at them, see what they are and it would be based on implementation time frames.

I mean we wouldn't be enforcing something retroactive to the date that it was published except in those rare instances where it is obvious that that is necessary.

Don Judice: Do we have one in the back?

(Shirley Meiers): There was a request...

((Crosstalk))

Don Judice: That's (Shirley Meiers).

(Shirley Meiers): (Shirley Meiers) with (Center I Can). There was a request made earlier about the...

((Crosstalk))

Woman: Thank you.

(Shirley Meiers): There was a request made earlier about the comment period be extended because this is the first time having seeing this for some people. And what process would have to take place in order to extend the comment period? Or is it just next Monday it's a done deal? There's nothing that could happen that would extend these comments.

Amanda Leiter: So comment periods are sometimes extended in response to requests. My sense is these comment periods now have all been extended. And in fact two of the (actual) orders of comment period were reopened so as to make sure that they were all open at the same time, with this final deadline of December 14. My sense is that they're not likely to be reopened at this point.

Any other questions on the process or anything else? All right, well thanks again everybody for taking the time to come out. And really appreciate it. I enjoy learning about your industry, so thank you.

Don Judice: There are extra copies of these regulations on the table. Please take them.

((Crosstalk))

Coordinator: This concludes today's conference. Thank you all for your participation. You may now disconnect.

END