LUCAS LUCERO: Hello, and welcome to the BLM's third and final public outreach meeting for the proposed revisions to the oil and gas regulations. I'm Lucas Lucero, senior policy analyst with the BLM headquarters and I'm stationed in Phoenix, Arizona. I'm serving as the moderator and on behalf of the BLM I want to thank you for joining us today. I'd like to start by having our presenters introduce themselves, starting with Beth.

BETH POINDEXTER: Hello, I'm Beth Poindexter and I'm an engineer on the production measurement team located in Santa Fe and I'll hand this over to crystal ball to introduce himself

CHRIS DEVAULT: Hi, I'm Chris DeVault. I'm a senior oil and gas compliance specialist on the PMT and I'm located in Billings, Montana.

BETH POINDEXTER: Thanks, Chris. Stormy Phillips.

STORMY PHILLIPS: Yes, my name is Stormy Phillips, and I'm an engineer with the PMT, stationed in Tulsa, Oklahoma.

BETH POINDEXTER: Thanks, Stormy. Amanda Eagle.

AMANDA EAGLE: I'm Amanda Eagle. I'm an engineer on the PMT, and I am stationed in Anchorage, Alaska.

BETH POINDEXTER: Thanks, Amanda. And last but not least, Casey Hodges.

CASEY HODGES: Casey Hodges. I'm an engineer on the Production Measurement Team stationed in Granby, Colorado.

BETH POINDEXTER: Thanks, Casey.

LUCAS LUCERO: OK, next I'd like to introduce Mr. Troy Frost, deputy assistant director for Minerals and Realty Management, who's going to provide some opening remarks. Troy?

TROY FROST: Thank you so much Lucas, I really appreciate it. Yeah, and a thank you to everyone who's participated today, and especially the team that's been in development here. This is a great effort and it's-- we're about at the 90-- we're about at the five yard line, and this is going to be really good to get it across the goal line, but these last five yards are important. When we get input from the public and we make sure that what we think is a common sense rule that should make any adjustments based on any input we get, so this is really a good thing.

So I'm talking to you today from our new headquarters, the new BLM headquarters in Grand Junction, Colorado. And again, we're really excited to get the input from you. I think we've had over 300 participants over the last three days and got some valuable feedback so far and we're really looking forward to your feedback today. So on behalf of the Bureau of Land Management, thank you so much for participating, and we're really excited to get your feedback today and get this rule out there and make our organizations, all our organizations better. So thank you so much, Lucas and I'm going to turn it back to you.

LUCAS LUCERO: OK, thank you very much, Troy I appreciate that. You can go to the next slide, please. I'll start with our standard disclaimer. This presentation is not an official statement of policy of the BLM. The summary presentation was prepared for inspirational purposes only, and does not in any way limit or modifying the regulations described herein. Interested parties should not rely on the contents of this presentation, and should take care to review the full official text of the regulations at 43 CFR parts 3170, 3173, 3174, and 3175.

Next slide, please. As we get started here we ask our attendees to please be respectful. Any inappropriate questions or comments will not be tolerated. We're here to address as many clarifying questions as possible in the time allotted. You can ask questions verbally or using the Q&A function and write in your question. Keep in mind, all new questions that you submit today, we will address at the end, but you are welcome to add your questions at any time during the presentation using the Q&A box.

The attendee video is going to be turned off throughout the meeting, and we'll turn audio on when we call on individuals who have their hands raised. Any remarks or questions-- can we go back to that slide? Thank you. Any remarks or questions from the audience regarding the presentation do not constitute as comments for the purposes of proposed rule. And also keep in mind, if you want to submit comments, you can do so by submitting those by mail, personal delivery, or online.

Next slide, please. And for those that may want to understand how to submit comments, at the bottom of your screen highlighted in red is the Q&A button. You can click on that and type in your question, or you can click on the Raise Hand, and please keep your hand raised, and we will unmute you and you will be able to speak with us and ask us your question. And the Mute button is in the bottom left corner of your screen there.

Next slide, please. OK, our timeline for the proposed rule. The proposed rule was published on September 10th in the Federal Register. The 60-day public comment period closes on November 9th. The BLM also published a media release on September 10th. We are preparing transcripts of these public meetings, and we will post them on BLM's web page for our Oil and Gas Production Management team.

And lastly, a little on the history of the regulations. BLM's guidance was previously contained in Onshore Orders 3, 4, and 5, which were effective starting in 1989. In 2016, BLM published final rules, which established 43 CFR 3170 through 3175. Those final rules became effective in January of 2017. Following that in 2018, stakeholders and BLM personnel did identify some challenges with implementation of some of the 2016 provisions. At that time, BLM began drafting proposed changes to the regulations.

Next slide. Regarding who can comment, anyone can comment on the rule. And again, the comment period closes on November 9th. Comments are accepted by mail, personal delivery, or online. We remind you that comments should be as specific as possible and reference the specific section or paragraph of the proposed rule. Please confine comments to the issues pertinent to the proposed rule. Also, please explain the reason for any recommended changes and include your supporting documentation. And also, we remind you that strong comments are supported with data, so we encourage you to include data with your comments where possible. And lastly, caveat, BLM is not obligated to consider or include in our administrative record any comments that come in after the close of the comment period, or comments that are delivered to an address other than those listed in the proposed rule.

Next slide. And the addresses that are identified in the proposed rule are listed here for where to send your comments either by mail, personal delivery, or online. If you do plan to submit comments online at regulations.gov, we do remind you to please input in the search box the correct regulatory identification number listed here, which is 1004-AE59. And lastly a caveat, before including your address, phone number, or any other personal identifying information in your comment, be advised that your entire comment, including your personal information, may be made publicly available at any time. You can ask the BLM in your comment to withhold your personal information from public review. The BLM cannot guarantee that we'll be able to do so.

Next slide. OK, so now I will hand it off to Beth, who will cover the proposed changes to 3170.

BETH POINDEXTER: Hi, everyone and welcome. We're going to start with 3170, the Onshore Order production, and this section starts with definitions and general information for the rest of the subparts. And you'll notice in this rule that we have a lot more specific requests for comments that are included in this rule than were in the 2016 rule. So the first, we start off with a very specific request for comment put in here by the assistant secretary for Land and Minerals. Should the BLM establish a federal interest threshold for applying its site security and oil or gas measurement regulations.? What are the costs and benefits of setting a federal interest threshold? What would be an appropriate threshold? Would such a threshold jeopardize the federal royalty interest and fail to satisfy the BLM's obligation under Federal Oil and Gas Royalty Management Act, FOGRMA, and to what extent? Could a similar threshold be adopted by applying the regulations to units and communitization agreements, CAs, producing trust minerals? BLM specifically requests comment from state governments with federal and trust mineral oil and gas production that may be impacted by BLM regulation of mixed ownership units and CAs.

Next slide. 3170.30 is a new section on alternative measurement equipment and procedures, and it discusses the process for operators or manufacturers to follow for the BLM approval for using alternative oil or gas measurement equipment or methods. Alternative measurement equipment and procedures must meet or exceed measurement performance requirements, audit trail and verification requirements, and site security requirements. This is the exact same requirement in a variance request, however clarifying that 3170.30(c), requesting and granting a variance under 3170.40 does not constitute an approval of an alternative measurement technology method or equipment. In other words, variances are still separate from alternative measurement equipment and procedure approvals.

Next slide, please. 3170.40 is on variances, and we have a specific request for comment there. Should the BLM include a state and tribal variance provision that would allow states and tribes to request that BLM apply analogous state or tribal rules or regulations in place of the BLM requirements? This is analogous to the 2018 3179 methane waste prevention rule, where the BLM deferred to state regulation. What would be the appropriate standard for granting a state or tribal variance? What would be the scope of a state or tribal variance? What would be the appropriate process for obtaining a state or tribal variance? And how would the BLM address changes to state or tribal rules or regulations on which a variance is based?

Next slide, please. Now we enter into 3173, sites security and production handling. Next slide, please 3173.20 and 21 deal with seals. 3173.20(c)(2) clarifies that seals are not required on valves on water tanks unless the valve could provide access to sales or storage tanks, in other words, inventory, with common piping between the water tank and oil tank. We propose to eliminate the following seal requirements at LACTs and CMS. Sample probes, LACT meters or CMS, manual sampling valves if equipped, valves or divert lines less than one inch in nominal diameter, prover connections. We propose to modify the following seal requirements. Meter assembly on mechanical meters only, as well as the totalizer on mechanical meters only temperature averager, and that's standalone temperature averagers only, back-pressure valves that are fixed, meaning non-automatic adjusting back-pressure valves that are located downstream of the meter.

Next slide, please 3173.21, oil measurement system components, seals. We have a specific request for comment here. Are the assumptions presented for the rationale underlying the proposed removal of six seal requirements on LACTs and CMS appropriate an accurate? You might want to take a look at 3173.21(a) for reference, and the rationale is located in the preamble under this section. 3173.31 is water draining operations. We eliminate record requirements A through H and defer to the seal record requirements. We felt that the record requirements for water draining operations were duplicative of the seal record requirements, so we eliminated them. And there is a note here that the proposed change in documentation requirements does not negate an operator's obligation to report produced water on the OGOR-A. That's still a requirement.

Next slide, please 3173.50, site facility diagrams. We're replacing the API number with the US well number. In 2010, API sold the rights to the to the API number to PPBM, and PPBM renamed the number as a US well number. The number is exactly the same number as the API number is, and the way of assigning the number is exactly the same. It's generally done by state regulatory authorities at the time of the APD approval. That all remains the same, however, the label of the number has changed from API number to US well number.

This also identifies co-located facilities with a box, this is our new proposed change, and it removes the requirement for a skeletal diagram of the other operators co-located facility. We maintain the requirement for one diagram in the case of storage facilities common to co-located facilities and operated by one operator. We propose to eliminate the requirement to wait to receive a facility measurement point number prior to submitting new or amended diagrams. And we propose to revise the timeframe to submit a new permanent facility diagram from 30 to 60 days after the facility is operational or the facility is modified.

We propose to eliminate the requirement to submit a modified facility diagram with a change of operator, and the only change to the diagram would be the new operator's name. However, if a new operator takes over and modifies the facility, then as always, a new modified facility diagram is required.

Next slide, please 3173.60, applying for a facility measurement point number. The concept is to apply for a facility-- an FMP number as opposed to an FMP. In the current rule, operators apply for an FMP and are assigned a number. In this case, we're just applying for an FMP number because the FMP already exists. And you might be saying, well, what is the FMP? It's the meter or location on which you are reporting your OGORs. And we also propose that gas storage agreements would have FMP requirements when royalties are due.

We revise the FMP number application deadline tiers that we created for the 2016 rule. In that rule we based them on 2010 production, in the current proposed rule, we base these tiers on 2017 production per agreement. So in the current rule, the application deadline of one year applies to agreements that are greater than 10,000 MCF per month or greater than 100 barrels per month. In the proposed rule, the deadline changes to agreements that are producing greater than 4,500 MCF per month per agreement or greater than 500 barrels per month per agreement, whichever is less.

For a two your application deadline, we had in the current rule, greater than 1,500 MCF per month and less than 10,000 MCF per month, or greater than 10 barrels and less than 100 barrels per month per agreement. We've changed that to greater than 1,000 MCF to less than 4,500 MCF per month, or greater than 50 to less than 500 barrels per month per agreement. That would have a two year application deadline for an FMP.

The three year deadline in the current rule is less than 1,500 MCF per month per agreement, or less than 10 barrels per month per agreement. The new proposed rule has the thresholds at less than 1,000 MCF per month, or less than 50 barrels per month per agreement.

Next slide. Conditions for commingling and allocation approval, surface and downhole. The BLM objective was to expand ability to approve commingling of production while preserving measurement performance. We've removed the requirement for the same revenue distribution on commingled agreements. Honestly, this requirement was very difficult for the BLM to comply with because it basically mandated that BLM understand on a lease where the distribution of the royalty revenue would go within the federal government. If it's hard for the BLM to determine that, we imagine it's even harder for an operator to determine that.

So we've also removed the requirement for allocation method for produced water, but operators are still responsible in upset conditions for oil production on commingled approval-- commingled locations. We've allowed for proposed CAA to include lease unit participating areas, PAs, or communitization areas, CAs, to be included as long as there is an approved APD at the time of the application. So this provision allows operators to apply for commingling prior to drilling wells.

Next slide, please. We also included a new condition for approving commingling. This condition is for the operator to provide an overall allocation uncertainty analysis, calculated by using the propagation of uncertainty method. In addition to that, we have four criteria. The first is overall allocation uncertainty analysis must meet the performance goals stated in 3174 for oil and 3175 for gas. The analysis must show no allocation bias as a result of commingling allocation, and the analysis must state the assumed underlying distribution of the volumes generated in the analysis and support the use of the distribution assumption.

And lastly, the analysis is limited to four agreements for commingling approval. And please note that that last criteria there-- criterium only applies to this new condition. There are four other conditions under which an operator can apply for commingling, and they are not limited to four agreements.

Next slide, please. Here we have another specific request for comment regarding new commingling approval condition. Would the operator be able to perform the required analysis, would an applicant use this condition to apply for coal mingling and allocation approval, and is there a better condition or method for ensuring no risk to measurement of federal or Indian trust mineral interest and approving coal mingling and allocation? And we would really like comments on that. If you've got a better way to do this, we'd really like to hear it, and please provide data to support that position.

Next slide, please. So when you apply for coming and an allocation approval, the application has removed the requirement for the surface use of plan of operations. In this case, you can replace-- we're replacing that with an applicant-certified statement that the surface disturbance-- the proposed surface disturbance is in compliance with current regulation. And a certified statement is a sworn statement that the SUPO has prepared pursuant to regulation. We remove the requirement for submission of a right-of-way grant, and again we replace that with a certified statement, applicant-certified statement.

We allow for agreements that are not yet producing to be included in a CAA application. We require an approved APD, offset well decline curve data offset well oil gravity, and/or gas BTU to support the projected production estimates in the application. And this is the big piece. There's no need to wait for a paying well determination prior to applying for commingling approval. So if you have a PA and you drill a well outside the PA, you can apply for commingling, receive the approval, and then later get the paying well determination and have the well come into the PA, in which case the commingling approval goes away.

Next slide. On existing commingling and allocation approvals, we've increased the thresholds for grandfathering on surface commingling to less than 6,000 MCF per month, or less than 1,000 barrels a month, and we've clarified that grandfathering of existing downhole commingling approval does not constitute new surface commingling approval. There seemed to be a lot of confusion on that point in the 2016 rule and we tried to clarify it in this proposed rule.

And then last but not least, our immediate assessments. We've changed the language on the first violation to read as follows. An appropriate valve on an oil storage tank was not effectively sealed as required by 3173.20 in the proposed rule, and we eliminate the immediate assessment for failure to seal an appropriate valve or component on an oil metering system as required in 3173.3 in the current rule, which includes LACT and CMS components requiring seals.

Next slide, please. And now we're going to move to some pre-submitted questions, the questions that were submitted when you registered. And we'll have Casey Hodges help us out here with reading the questions that were submitted and I'll give you the answers.

CASEY HODGES: All right, Beth. Actually, the first question is going to be for Lucas. Will the proceedings be recorded digitally for later distribution for those who cannot attend?

LUCAS LUCERO: Yes. The PowerPoint and the transcript of the meetings will be published on the BLM website in the same location where the previous PMT presentations have been posted.

CASEY HODGES: Thank you, Lucas. The rest of these questions will be for Beth. Will there be a time for API numbers to be used with or instead of the US well numbers? Some companies will need to add the US well number to the accounting process and reports.

BETH POINDEXTER: Right, the API number and the US well number are the same number. The process for assigning the US well number is the same as it was with an API number. State regulatory authorities continue to assign the numbers in the process of drilling approval. The explanation of this change is found in the preamble on page 55,495

CASEY HODGES: Will corrected site security diagrams need to be submitted to address the API to US well number change?

BETH POINDEXTER: The site facility diagram does not need to be updated to only change the label of the API number to the label of US well number.

CASEY HODGES: Is there a proposed window of time for Atmos 2 to be up and able to accept FMP number applications?

BETH POINDEXTER: The Atmos 2 development team tells us that they're working to be able to accept the FMP number applications when this rule becomes effective.

CASEY HODGES: Clarify the MDS, Management Data System is onsite and does not grant BLM access to any company accounting process.

BETH POINDEXTER: If the operator elects to use an MDS as part of the process of OGOR reporting, it must be approved by the BLM. The only requirement is the use of an approved software. The definition of MDS is found in 3170.10. Measurement data system, MDS, means a system that captures and stores source records from the flow computer at an FMP. The MDS is used by operators to validate, balance, and report volume and quality. An MDS does not include supervisory control and data acquisition, SCADA systems.

CASEY HODGES: Does BLM realize the PMT tiers for applying for FMP means nearly all filings will be in the first year, greater than 150 MCF per day and 16.5 barrels of oil per day?

BETH POINDEXTER: The BLM used 2017 production data based on federal or Indian agreements from OGOR reporting, and divided the production evenly into thirds based on agreement. Based on this, 1/3 of the FMPs will have an application deadline in one year, 1/3 a deadline in two years, and 1/3 a deadline in three years. The same method was used in the 2016 rule using 2010 production data.

CASEY Does BLM think it is fair to invalidate all existing off-lease measurement and

HODGES: commingling approval and use limited resources to review all such approvals in the local BLM offices?

BETH POINDEXTER: At the time of the FMP application, the BLM will review existing off-lease measurement and commingling approvals.

CASEY HODGES: If the BLM is to determine whether a facility is a gas storage agreement measurement point or a facility measurement point based on native gas production, is it possible that the GSAMP can become an FMP, and then when storage gas exceeds the base gas or native gas, it will revert to a GSAMP?

BETH POINDEXTER: Yes. If royalties are due on native gas, the meters must meet the requirements of an FMP, and a GSAMP can become an FMP.

CASEY HODGES: If only certain wells within a storage area are on federal or Indian lands, would the GSAMP injection slash withdrawal meters be considered GSAMP, and the specific wells would become FMP when withdrawing base gas or native gas?

BETH POINDEXTER: Gas storage agreements are established with contracts written by BLM state offices. There are currently 35 gas storage agreements regulated by the BLM. This part of the rule only applies to these federal locations. At gas storage agreements, FMPs are only required when royalties are due on native gas.

CASEY HODGES: And this is the last question for the 3170-3173 section. What is the expected timeline for the PMT to start accepting equipment, hardware, and software for approval?

BETH POINDEXTER: The BLM can accept applications for approval under the current regulations at this time. BLM will be able to accept applications for approval under the revised regulations once they become final. BLM plans to provide non-binding guidance, for example, testing protocols, that will help to ensure that applications contain the information the PMT needs to process applications expeditiously. We note that this guidance may be considered, quote, "guidance documents" end quote, subject to the requirements of Executive Order 13819, Promoting the Rule of Law Through Improved Agency Guidance Documents, published on October 9th, 2019. The Executive Order 13891 review process may delay issuance of the guidance.

Thank you and I'll hand off now to Chris DeVault, who will work on 3174, the measurement of oil.

CHRIS DEVAULT: Yeah and before we get started, just as a reminder, you can continue asking the questions through the Q&A at any time. They will be read and answered at the end. For sections 3174.30 incorporated by reference, it updates and reaffirms 16 IBRs API standards to reflect the most current versions. The new standards incorporated are API MPMS, chapters 7.1, 7.2, 7.4, and 12.1.1. The IBR standards that have been removed are chapters API MPMS chapter 6, section 1, chapter 7, 7.3, chapter 12, section 2, part 1, chapter 3, section 1, and chapter 18, section 2.

Next slide, please. 3174.31, the Specific Performance Requirements. First off, for all FMP categories, there is no bias allowed, and they all must have the ability to be independently verified. The volume thresholds are, for a very-high-volume, is greater than or equal to 15,000 barrels per month, and must meet an uncertainty requirement of plus or minus 0.5%. High-volume is greater than 1,500 barrels per month and less than 15,000 barrels per month, with an uncertainty requirement of plus or minus 1.5%. Low-volume is equal to or less than 1,500 barrels per month and there is no uncertainty requirement.

The BLM approved equipment deadline for very high volume is within one year of the effective date of the rule, and for both high-volume and low-volume, if it's in service prior to the effective date, it is exempt until equipment is replaced or production increases. If it's in service after the effective date, it must be in compliance within two years.

Next slide, please. And this is a specific request for comment on these performance requirements. BLM is particularly interested in the views of states and other non-Federal lease holders with significant oil and gas production, and who may have experience in implementing different thresholds based on their own assessment of risk tolerance and compliance costs. Are the proposed uncertainty levels of an FMP category combinations reasonable or not and why? What would be a better uncertainty level and FMP category recommendation to minimize risk of mismeasurement and compliance costs, and please explain why.

Next slide, please. 3174.41 is the Approval of Measurement Equipment. Please note the items in a red font would be the new items, the ones in black are existing from the 2016 rule. The measurement equipment requiring BLM approval is automatic tank gauge, LACT sampling systems, positive displacement meters, coriolis meters, coriolis transmitters, stand-alone temperature averaging devices, temperature transducers, pressure transducers, flow computer software versions, portable electronic thermometers, measurement data systems, and temporary measurement.

Next slide, please 3174.50 is Grandfathering, it's a new section. It allows exemption from the approved equipment requirement of 3174.41 for low- and high-volume FMPs in service before the effective date of the rule. This is based on the PMT experience with field-collected data and the limitations of testing not conducted in a controlled testing environment. However, the exempted requirement is still required to meet the performance requirements of 3174.31. If the location is modified after the effective date or the FMP moves into the very high volume category, grandfathering will be rescinded.

Regardless of the flow category, devices not covered by this subsection are portable electronic thermometers, measurement data systems, temporary measurement, and then devices unable to meet the requirements of the rule. For example, automatic temperature and gravity compensators would not be grandfathered because they do not conform to the proposed rule.

Next slide, please. And these are the specific requests for comments on this grandfathering section. What would be the overall impact for not allowing or allowing this grandfathering option? Are the thresholds for the proposed grandfathering set at appropriate levels? Is there a better option or method for ensuring no risk to measurement of Federal or Indian trust mineral interests while allowing for the continued use of the equipment currently in service? Finally, the BLM seeks comment on its assumption that not grandfathering automatic temperature compensators and gravity compensators will not result in significant costs to industry.

Next slide, please. Next section is 3174.60, Timeframes for Compliance. It makes the compliance timeline for oil locations independent of the application dates. A major issue with the current rule was the connection to the compliance timeline of oil locations in service before January 17, 2017 to The FMP application date. The allowance under grandfathering should make it easier for the operator to comply with the time frames. Since equipment put in service after January 17, 2017 should already be in compliance with the current rule, there will be no phase-in period.

Equipment in service before January 17, 2017 will have the following phase-in periods. Very-high-volume must comply within one year of the effective date, and then high-volume and low-volume both must comply within two years of the effective date, and the operator can voluntarily submit a sundry notice for early adoption of the rule, and equipment approvals will be required two years after the effective date.

Next slide, please. This is 3174.80 through 88, which is Oil Sales by Tank Gauging. The tank gauging was divided into these various paths to make the requirements easier to follow. 3174.86(a) clarifies that tanks under 5,000 barrel capacity only require a single, mid-point, temperature measurement. And this is to clarify numerous questions that have come up about whether or not you have to take three temperatures and average them. And so now this just clearly specifies that only one is required. Removes the reference API MPMS 18.2 and replaces it with specific language on the use of an ATG.

3174.88(a)(2) removes the specific requirement that the same tape and plumb bob be used for opening and closing gauges. .88(b) provides specific allowance for automatic tank gauging. And then .88(b)(4) adds specific language for on-site requirements, such as an ATG verification log.

Next slide, please. 3174.100 through 108, Oil Sales by LACT. .102 more clearly explains the sample system approval requirements. .104 explains the requirements for the non-resettable totalizer. .105, temperature averaging devices can be part of the electronic liquid measurement or ELM. .106, the transducer requirements are explained. .108 allows for dynamic and automatic adjusting back pressure valves for changing flow conditions. And lastly, it provides for other meters and devices approved by the BLM through the PMT.

And then on to 3174.110, Coriolis Meter Operating Requirements. It specifies that a non-resettable totalizer can be displayed on an ELM and the meter must generate the output. And it lists the on-site and display requirements for coriolis meters, whether they are used in a LACT or CMS.

Next slide, please. The specific request for comment for this coriolis meter operating requirements section are, how would a coriolis meter be tested without a transmitter? Does the performance of a coriolis meter change based on the type of transmitter installed? How would the BLM prevent the transmitter performance contributing to the meter uncertainty twice, first if a transmitter is required to test the coriolis meter, and secondly if a transmitter is tested separately? Finally, is there data to support the position that the transmitters contribution to meter uncertainty is insignificant, and therefore will not change coriolis meters uncertainty?

Next slide, please. 3174.120, Electronic Liquids Measurement, or ELM. It's a new section. BLM must approve the software associated with the calculation of volume. The proposed rule adds a new section modeled off the gas subsection, which will include these requirements specific on the use of an ELM. Display requirements, alarm logs, event log, configuration log, quality transaction action records, or QTR, and backup requirements.

3174.121 is the Measurement Data System, or MDS. This is another new section. It adopts the industry terminology of the Measurement Data System, or MDS. Then for both 3174 and 3175, the current term "accounting system" is changed to MDS.

Next slide, please 3174.130(h), Truck Mounted Coriolis, or TMC. It adds specific language to address truck mounted coriolis, or TMC, as a coriolis measurement system. Additional TMC requirements are, you must meet all the requirements of a very-high-volume FMP, the metor factor used during the transfer must match the operating conditions of the fluid being transferred, the display requirements apply only during the transfer, proving frequency is derived from the total oil-- total volume from flowing through the meter, BLM inspectors must have the ability to witness provings, all data must be accessible to the authorized officer upon request, all lines must be connected before the seal on the sales valve is removed, the TMC must comply with audit requirements of 3173, and finally, any deviation for the CMS requirements on a TMC must be treated as an alternative method and be approved by the BLM through the PMT.

Next slide, please. 3174.150 through 158, Meter Proving Requirements. Without a clear and unified industry practice for the determination of normal operating conditions, the BLM has proposed a prove-forward method. Creates a path for the acceptance of a linear meter factor if proper data is submitted to the BLM for PMT review. The requirement to prove a LACT at startup has been changed to allow for line fill. The prove must now be conducted in the first 15-day of first flow and then the meter factor be retroactively applied to all the previous flow. Allows for the use of all proving runs from API MPMS 4.8, table A1 rather than only allowing the five consecutive runs within tolerance of 0.0005. And it allows other proving methods to be submitted to the BLM for PMT review.

Next slide, please. Continuing on with the meter improving requirements, in 3174.152, the proving would require the normal operating range for the LACT or CMS for the next period. Would determine-- think I said that wrong, sorry about that. Would determine the normal operating range for the LACT or CMS for the next period. The limits around the flow rate, temperature pressure, and API gravity would define the range around which another meter factor or prove would be required. 3174.154 allows for the justification to be submitted for excessive meter factor deviation. And will allow justification to be sub-- it allows for future methods of proving that are not dependent on pulse counts to be submitted to the BLM for PMT review.

3174.158 includes specific language concerning that raw data must be preserved on proving reports related to the calculation of the meter factor. And the requirement that proving reports be submitted with 14 days has been replaced with a requirement under 3174.158(c) that they be available to the authorized officer upon request.

Next slide, please. 3174.151 is meter proving. And this specific request for comment, the BLM seeks comments on other proving technologies or procedures that are not presented in this proposed rule but that meets its requirements, and please submit and data to support your opinion on this on your comments. 3174.152, Meter-proving runs. Normal point is defined by conditions at the time of proving. Unit would have to maintain operation within 10% of that defined value for flow rate and pressure, 10 degrees Fahrenheit of the temperature, and 5 degrees of the API gravity. The BLM seeks comments on these ranges and any supporting data that may show that the range should, without affecting the meter factor, be wider or narrower.

Next slide, please. 3174.160 through 162, Measurement Tickets. These sections outline all required information on the uniquely numbered measurement ticket or volume statement. They can be in paper or electronic format and must be made available to the AO upon request. 3174.161 clarifies the information required on a tank-gauging measurement ticket at the time of transfer, which is before the truck leaves location, and those that can be completed at the office. Basically, all the information necessary to correctly net out a run ticket must be on the ticket in the field, but then you can go through the netting-out process in the office to complete the ticket. The specific reference to 3170.50(g) requirements for location information now require that location information on the return ticket. That appears to have been an oversight in the past, but that's necessary information.

The request for a LACT or CMS run ticket to include total net standard volume has been added in 3174.162(a)(11), and it now allows for a volume statement generated by an ELM or QTR to be submitted in lieu of the measurement ticket. The requirements for this option are added into 3174.162(b), and must be raw, unedited data.

I have one other item that's not really on a slide, but it's for 3174.190, Immediate Assessments. The immediate assessment associated with the requirement to notify the authorized officer within 72 hours of a LACT failure has now been removed. It clarifies the language associated with alternative methods of measurement in this section.

Next slide, please. And now we're going to go into, as they as they did for 3170 73, Casey will read and we'll try to answer the pre-submitted questions.

CASEY HODGES: All right, Chris first question is, what kind of delay can we expect before the PMT approved list is available?

CHRIS DEVAULT: BLM anticipates the first approved equipment list will be available at the end of the timeframe listed in 3174.60 and 3175.60.

CASEY 3174.43(a), will a sundry notice need to be sent in for FMPs already complying with

HODGES: the order?

CHRIS DEVAULT: Now we assume the question refers to 3174.43(a)(1), requiring a sundry notice for voluntarily early compliance with 3174. Oil FMPs installed after January 17, 2017 shall already be in compliance and no sundry notice is required. For oil FMPs installed prior to January 17, 2017, a sunry notice will be required to early adopt.

CASEY HODGES: 3174.60(b)(2) implies that these FMPs must meet the order in two years after the effective date, and per 3174.50, grandfathering, the equipment will not need to be approved by the PMT. Which rule applies, grandfathering or on the list?

CHRIS DEVAULT: 3174.50 has an exception from the requirement to use approved equipment listed in 3174.41(a) through (i) at high- and low-volume FMPs. This exemption terminates in the event equipment is replaced or the FMP moves into a very-high-volume FMP. Portable electronic thermometers, measurement data systems, and temporary measurement are not exempt from the equipment requirement. 3174.60, Timeframes for Compliance always applied, except in the case where there is a 3174.50 exemption.

CASEY HODGES: In regards to handwritten tickets, when that data is entered into the measurement data system, is the manually entered data considered to be original flow data, or is a handwritten ticket considered to be the original data?

CHRIS DEVAULT: The source document is the original document. If the source document is a handwritten ticket, the handwritten ticket is the original document.

CASEY HODGES: Will the PMT have an approved list of measurement equipment and software, including all models, makes, and version posted on the date the rule is effective?

CHRIS DEVAULT: No, the enforcement of the approved equipment list will go into effect two years after the effective date of the final rule.

CASEY HODGES: 3174.156, verification of the pressure transducer for liquid measurement is relatively much less important than verification of the temperature transducer. Considering the low pressures most measurement systems operate under and the lower compressibility of liquids, BLM should consider adding an exemption to this rule for systems where the pressure is less than 100 PSI.

CHRIS DEVAULT: The BLM welcomes data to support this statement. Standing industry practice uses the pressure of the system to correct for flow volume. This has a direct impact on royalty due. In order to change the proposed rule, please submit data to support the position. If warranted, BLM will evaluate the role or the impact of such a change.

CASEY HODGES: Regarding 3174.152(a)(1) through (4), 3174.152(h)(1) through (2), and 3174.153(f), is it intended that the full range of normal operating conditions that the meter must remain within between proving cycles can be expanded by proving at different conditions and applying the methods described in 3174.152(h)(1) and/or (2) to define a wider range for normal operating conditions if needed and supported by the last proving results?

CHRIS DEVAULT: Yes, that's the intent.

CASEY HODGES: Regarding 3174.152(c), is the intention of the reference to API MPMS chapter 4.8, table A1 to allow the tolerances as stated in table A1, which correspond to different numbers of runs to be applied, instead of 0.0005 when the number of runs is more or less than five, as described in methods shown in chapter 4.8 annex A?

CHRIS DEVAULT: The BLM recognizes that API 4.8 standard provides a table for various runs and repeatability that meet a 0.027% uncertainty. Therefore, the proposed rule would incorporate that table into the regulation to allow for greater proving flexibility while keeping the same performance standard for the proving.

CASEY HODGES: Regarding 3174.60(e) and 3174.41, is it intended that there be an exception during the two year period described in 3174.60(e) that would allow the equivalent listed in 3174.41 to be used prior to BLM approval? The proposed 3174.41 mentions an exception related to grandfathering and 3174.50 but makes no mention of an exception for 3174.60(e).

CHRIS DEVAULT: Items covered under 3174.50 are exempt from the requirements for 3174.60(e), Timeframes for Compliance.

CASEY HODGES: Regarding 3174.50(b), would equipment allowed under the grandfathering provisions that is only partially replaced, i.e. Replacement of the internal mechanism of a PD meter, no longer be exempt from the approval requirement in

3174.41, or would the entire metering unit need to be replaced to lose the grandfathering exemption?

CHRIS DEVAULT: Any in kind repair is not considered a replacement.

CASEY HODGES: Regarding 3174.162(a)(4), are the opening and closing totalizer readings of the indicated volume that must appear on the measurement ticket intended to represent the values from the non-resettable totalizer in the meter?

CHRIS DEVAULT: Yes, that's the intent.

CASEY HODGES: Regarding 3174.104(a) and 3174.110(d), if the meter is a PD or a coriolis meter in a LACT or a CMS, can the non-resettable totalizer value be generated by the flow computer using the pulses from the meter? In 3174.110(d) it states quote, "a flow computer generated totalizer does not comply with the requirements of this subpart" end quote and it is not clear why this restriction would be necessary for a CMS but not for a LACT. The concern is that, in addition to receiving pulses, a flow computer in a CMS would also require digital communication to read the non-resettable inventory totalizer from a coriolis meter in order to display this value and included on the measurement ticket. This restriction would apply only for CMS and not for LACT systems.

CHRIS DEVAULT: The intent is that the requirement applies to both LACT and CMS. The preamble section for 3174.104 states the proposed rule would make it clear that the non-resettable totalizer display may reside in an electronic flow computer. The non-resettable totalizer could display through the flow computer, but the output must be from the meter. We can see the concern with the regulatory text and we'll amend the discrepancy to reflect the intent.

CASEY HODGES: Regarding 3174.83(b), is the requirement to only follow the operation sequence in API MPMS chapter 18.1 for tank gauging intended to prohibit the use of automatic engaging, ATG, which is described only in API MPMS chapter 18.2?

CHRIS DEVAULT: 3174.84 through 3174.88 gives provisions to allow for ATG.

CASEY HODGES: Regarding 3174.105, can a coriolis transmitter be approved to also function as an electronic temperature averaging device if it meets all the requirements of 3174.105?

CHRIS DEVAULT: Yes. This would require BLM equipment approval for this use.

CASEY HODGES: Regarding 3174.105, can a coriolis transmitter be approved to-- I apologize, reading the same question again. 3174.157, is it intended that the density meter factor, DMF, should be determined and applied as described in API MPMS chapter 9.4, annex H, in cases where the verification of the density accuracy requires remediation?

CHRIS DEVAULT: The BLM did not incorporate that standard by reference. Please submit comments if you feel this is a good approach and explain why.

CASEY HODGES: Regarding 3174.120, as long as it meets all the requirements stated for an ELM in 3174.120, does a coriolis meter transmitter have to meet all other requirements in API MPMS chapter 21.2 to meet the requirements for an ELM or all CMS stated in 3174.120?

CHRIS DEVAULT: Casey if you don't mind, can we go to the next question while I look up something real quick on that question?

CASEY HODGES: Yep. Regarding 3174.30(b)(30), why is API MPMS chapter 14.3 on natural gas orfice metering referenced at 3174.31(a), which appears to only be intended to address liquid volume measurement uncertainty?

CHRIS DEVAULT: In this section, API chapter 14.3 is used to reference the root sum squared method only. And you can now go back to that previous question if that's OK.

CASEY HODGES: Yes. Do you want me to repeat the question? I'll go ahead and repeat it.

CHRIS DEVAULT: I think it's a good idea.

CASEY Regarding 3174.120, as long as it meets all the requirements stated for an ELM in

HODGES: 3174.120, does a coriolis meter transmitter have to meet all of the requirements in API MPMS chapter 21.2 to meet the requirement for an ELM or all CMS stated in 3174.120?

CHRIS DEVAULT: For a coriolis transmitter to be approved as an ELM, it would only need to meet the requirements in 3174.120 and the performance requirements of 3174.31.

CASEY HODGES: Regarding 3174.31(a), is the methodology described in the newly-published API technical report 2579, Liquid Hydrocarbon Uncertainty Calculations, also acceptable for calculating overall uncertainty?

CHRIS DEVAULT: The BLM has not reviewed the recently published API TR 2579, Liquid Hydrocarbon Uncertainty Calculations.

CASEY HODGES: Regarding 3174.151(a), is the intended reference to API 4.5, subsection 6.5, meant to be Table 1 rather than Table 2?

CHRIS DEVAULT: Yeah, great catch. Yeah, this is an error and should reference Table 1. Thank you.

CASEY HODGES: Regarding 3174.165, what is the required required accuracy for a pressure transducer? And Chris, this is the final question for this section.

CHRIS DEVAULT: Individual components do not have an accuracy requirement. It's a measurement system performance requirement. Next slide, please. OK, we'll move on to Stormy with 3175, Measurement of Gas.

STORMY PHILLIPS: Thank you, Chris. All right, guys, I'm going to go over the 3175 section. There hasn't been quite as many changes as we've seen in the other sections in this subsection, but there are some fairly significant ones so I'm going to go over a few of those, starting with the specific performance requirements. In reviewing everything, we analyzed the fact that BTU and flow volume have an equivalent impact on royalty due. So it made sense to the rewrite team that we should increase the uncertainty threshold for very-high- and high-volume FMPs on heating value uncertainty to the same as those of flow rate uncertainty. So we've changed the very-high-volume from 1% to 2% and high-volume from 2% to 3%, so a pretty significant increase in the allowable uncertainty values. Now we are requesting specific comments on that proposed change. Does this make sense?

Next slide, please. For the approved equipment requirements, there hasn't been a whole lot of changes here, but I'll walk through some of the changes and why they've come up. Just like we saw in the 3174, those items in black are the same as they were in the previous reg and the ones in red are new. Now first, you'll notice that we took out the previous linear meter section and the reason is, when the PMT began to develop the testing procedures for all the different equipment that needed to receive equipment approval, they found that it was basically impossible to just write one test procedure that can be applied to all linear meters. There's too much variety there to get any kind of useful testing from that. So what the rewrite team elected to do was to focus on the two most requested linear meters, that being the coriolis meter in the ultrasonic meter, and all other linear meters would now fall into that category of alternative measurement methods and could be approved through that. So you'll see that there's specifically mentioned coriolis meter-- gas coriolis meters and gas ultrasonic meters.

Next, just like we had discussed in the last slide, there is an equivalent impact on royalty for BTU value as there is on volumetric value. So as everyone knows, in 2016 there was a much greater focus on the reporting and testing of BTU value. And as we started looking into this, we noticed that there's a lot of home grown software around the calculation of BTU value. And in a lot of cases that have come up, the issues have been with those calculation methodologies are using outdated standard component values. So the BLM is proposing to review and approve software for the gas chromatograph. Again, this is just for the calculation software, this isn't for the gas chromatograph itself or any of the specifics, just the overall calculation of BTU value against a reference standard, just like we saw or like we see with the flow computers.

Next is water vapor measurement devices. Now in the 2016 rule, we said that you had to report gas as dry, but you could report a water vapor content if you specifically measured that, and we gave three methods for that, the chilled mirror, automated chilled mirror, and a laser detection device, and what happened when we put that into practice, began to find a lot of, or some operators using laser detection devices that were not intended for use in natural gas service. So it did detect vapor, but it wasn't meant for that service and it was giving erroneous readings. So since there's such a limited number of these, we thought the easiest solution to this is require approval of those water vapor detection devices to ensure that they are actually intended for that use. Measurement one thing that we've previously termed accounting systems, we've mainly made the change to more align with operator and industry common language, and that we wanted to make sure that operators understood that the BLM isn't intending to actually look into accounting practices or software or anything like that. This is about the calculation methodologies and the preservation of raw data.

Next slide, please. On grandfathering, now the 2016 rule for 3175 had a grandfathering section that related to old, older style orfice meter runs, and all of that language is still there. But we've added in the same section that we saw in 3174, now it's very important here and Chris hit on it, but I want to hit on again because it's very important, that everyone understands that this exemption for equipment that was in place before the effective date of this rule would be exempt from the approved equipment requirement. Now it's not exempt from any of the performance standards or any other part of the rule, it just would not have to appear on the approved equipment list. Therefore, it would be just kind of like the old orfice meter-- or, gas uncertainty calculator that the BLM used in the past, where it would take that manufacturer's specifications and use that to verify the performance. So not an exemption from everything, just the exemption from that device being required to be on the approved equipment list that will help alleviate a lot of the backlog of outdated or obsolete equipment.

Next slide, please. On Timeframes for Compliance, now unlike 3174, 3175, the compliance phase-in periods were not tied to FMP number application. So all of the phasing periods have now passed 3175, so all the equipment should be up to date with the 2016 standard at every FMP. Because there's nothing in this proposed rule that's more stringent than the 2016 rule, we didn't really see any need to have a phase-in period. So there's not a proposed phase in period with the exception of three items. One is GARVS. So to be completely honest, the development of GARVS hasn't even really started, and since we don't have a set timeframe, we are proposing to have a 60-day phase-in period that goes after the BLM releases the software. So once the software comes out, operators will have 60 days to figure out all the inputs and all of that stuff, and then begin reporting the gas sampling through that system. Next is approved equipment and approved software, and just like we saw in 3174, that's anticipated to be-- that would go into effect two years after the effective date of the rule.

Next slide, please. For orfice meter tubes probably the biggest part of the changes here relate to the meter tube inspections. This was a new concept for the 2016 rule and we learned a lot by the years of people going out and actually conducting those inspections. And one of the things that we learned is that gases with higher volumes tend to have higher velocity gas, and that high velocity gas resists a lot of buildup. So having very frequent inspections makes sense from a royalty threat standpoint, but from a reality standpoint, those are some of the least likely to have those kind of buildups. But there can be build up on an initial startup due to garbage and things like that that often come through the line once when something's setting up. So what we see is now there's two sections for the basic meter tube inspection. One is an initial inspection frequency, so if you had a very high [AUDIO OUT] a basic [AUDIO OUT] and then after that, it would go to every five years. And then you can see, so it's very-high-volume on the routine would be every five years, high-volume would be every five years, and low-volume would be every 10 years and very-low would continue to be exempt.

Another thing that we tried to do with the inspections was we tried to clean up some of the language that really got legally interpreted different than what the original intent was. So one of the things has to do with what's labeled as obstruction. So many times on a basic meter tube inspection, we might look down that tube and see that a bunch of filter paper got caught in the flow conditioner. So an operator can open that up, they can remove the filter paper, and in the letter of what is written in the 2016 rule, it would be required to have a detailed meter tube inspection. Well that doesn't make practical sense. If there wasn't anything done and it's obstruction that can be easily removed, it didn't really affect anything so there's no value in requiring the performance of that additional detailed meter tube inspection. So now, we've changed the language to say, if an obstruction could be removed and it hasn't damaged the tube, then there's no requirement for a detailed meter tube inspection. So that example, if filter paper's there and you can remove that, no problem. Now if a rock got lodged in there and it scraped up and tore up the whole inside of the tube as it was it was flopping around, well then that would require a detailed meter tube inspection, but those easily removed and non-damaging obstructions would not.

Another thing is that in the 2016 rule, it said that if pitting was identified at low-volume FMPs that you would be required to perform a cleaning. And we recognize that you cannot clean out pitting and in a pipe, so there's no value to that, so we cleaned up that language to make sure it was clear that that wasn't required. Another thing that became a little bit confusing to operators and inspectors was when a orfice meter run is started up or re-fractured, then you're required to check the orfice plate every two weeks until that plate passes inspection, and then you go on to the normal inspection frequency. Well, some people read that as that that would need to be witnessed by a BLM representative or during an inspection, and that was not the intent. So we cleared out the language to make sure it was understood that that was not the intent of the language, an operator can verify that and then move to the routine without requiring a BLM approval.

Another thing was the sampling section had a specific table that would identify the maximum time between events. So if something was listed as having to be done monthly, it specified that the actual maximum amount of time that you could go was 45 days. There was a lot of value in that, and people asked if that should be applied to other things in the rule, and we agreed that that made sense. So we moved that table down to the appendix, and now it's reference for things like or orifice plate inspections and verifications and things like that.

Next slide, please. For mechanical and electronic chart recorders, one of the biggest changes has to do with the verification schedule for high- and very-high-volume FMPs. After a lot of discussion with secondary equipment manufacturers, with flow computer manufacturers, and with operators, we got the impression that there's probably more uncertainty induced into a system by frequent human interaction than there would be from natural drift from the the secondary devices. So because of that, we're taking a stance of increasing the verification frequency out to every six months. Now of course this is the maximum frequency, so you can take it out there to every six months. So if we go to the next slide, you'll see that we're requesting specific comments on that. Does this make sense, this concept of transducer or measurement device drift versus human interaction make good sense, or should we revert back to that and make the schedule more in line with the other inspection schedules?

Next slide, please. For logs and records, it's another thing that has to do with the flow computers that raised a lot of issues. In the 2016 proposed rule, we stated that the BLM needs a certain amount of significant digits to be able to adequately perform their verifications. And the response that we got from that 2016 rule is, it's very difficult with a flow computer for it to shift its decimal places based on the other numbers to make sure you always have the correct significant digits. So the solution that was put into the final rule was, well we will just make it so many decimal places, five decimal places or three decimal places so we always can ensure that we have the correct number of significant digits. The unintended impact of that is that by going out that many decimal places, these flow computers are required to do double precision math. That is that even some very good flow computers cannot handle. And it's not necessary, it's not actually what we need to perform that, so we're proposing to go back to that significant digits, but we are requesting comments on that. Does that make sense, or is it just impossible to do it any other way than going with the decimal places?

Next slide, please. For gas sampling and analysis, there's a couple of things here that we want to touch on. One was that we've tried to clarify that if you're going to use a quote unquote "equivalent cleaning method" for your sample bottles, that that would need to be reviewed and approved by the BLM. And the reasoning for that's very simple. On a lot of the inspections and reviews, we're seeing people that are using methods that are in no way equivalent to what the GPA recommends, and so we need to make sure that those sample cleanings are carried out correctly according to that GPA standard.

Next is, we received a lot of data about when a C9+ analysis should be required and the effect that it would have on the BTU value versus the uncertainty levels. Now through all that analysis, we have decided that the bias doesn't really come into a strong effect till closer to one mole percent. It was previously a half a mole percent. So by making that change, at least in the data that we received, it would very significantly decrease the situations in which an operator would need to perform a C9+ analysis but [AUDIO OUT] specific comments on that. Does this make sense, please look at that [AUDIO OUT] are the preamble for this part of the reg, and you can see the analysis that we reviewed and the way that we came to these conclusions and we're interested in feedback on that.

Next is we removed the requirement to have a normalized mole percent for [AUDIO OUT] percent the BLM uses to do some verifications that we believe that the flow-- I'm sorry, the gas chromatograph is working correctly but we don't really have a need for a normalized percent of each component. So we think that that is an unnecessary burden, and we're proposing to remove that.

Next is the change in the sampling frequency and the biggest thing here is, if you have a high- or very-high-volume FMP that has a variable BTU value, the 2016 rule could require at a highly variable FMP, a very highly variable, very-high-volume FMP would require the installation of an on-line gas chromatograph. In reviewing that, we feel like that's maybe too much of an unnecessary burden, looking at the lead times and the cost associated with the installation of an on-line gas chromatograph. So we've changed that, or we're proposing to change that to being never more frequently than bi-weekly, so you could never be required to do it more frequently the bi-weekly.

Next slide, please. So again here, you can see in relation to on-line gas chromatographs, we are very interested if there's more industry standards or best practices for selection and installation and operation of on-line gas chromatographs. The BLM definitely is looking for more information relating to that. Next is about that C9+. Does this analysis that we've performed in the preamble makes sense, is this a good way to go for us? And another thing you might notice in 3175 is the removal of the specific testing procedures for temperature pressure and differential pressure measurement devices and flow computer software.

So in the 2016 rule, even though there's several items that would require BLM approval, the specific testing procedures for those two items was written into the rule. And what's happened since then is for temperature pressure and differential pressure measurement devices, the API has come out with a new testing standard, that testing standard makes sense, it would show compliance with the performance requirements of the BLM, but the BLM wouldn't be able to accept a test done per those procedures because it varies slightly from what's written into the regulation.

To avoid this in the future, the concept would be to require that the tests show that you've met the requirement, the performance requirements of the entirety of the 3170's regulation, and then the actual test procedures that would most commonly be only used by the equipment manufacturers would be located on the BLM website. So we are seeking comment on that, but that's the concept behind removing those specific testing procedures.

Next slide, please. Now, for the reporting of heating value and volume, we wanted to clarify that if you are not reporting dry, that you do have to include in the report the water vapor content. That way the independent analysis could be done to verify the calculation of the BTU value. I already touched on this, so I won't spend a lot of time on that, about the need to have water vapor detection equipment approved and why we've done that.

Another thing that was a little bit confusing about the 2016 rule is some operators and inspectors interpreted the rule to mean that if a C6 plus analysis was said to be done, in the 2016 rules, that an operator couldn't elect to do a C9 plus analysis. And that was definitely not the intent. So we tried to clarify that if an operator elected to do a C9 plus analysis, they're welcome to do that. They don't have to do a C6 plus analysis.

Another thing is a lot of operators came and said, hey, we have specific contracts that don't allow us to do a 60, 30, 10 split. And so by having it be very prescriptive about that breakdown, it could cause some issues. And we understand that. So what we are proposing to do is for C6 plus and C9 plus is just have a minimum BTU threshold rather than that prescriptive 60, 30, 10 split. Next slide, please.

I won't spend a lot of time on this next point, because it is very few locations, only about 28 locations in the country. But we've got some questions about federal gas storage agreements and whether the meters used at those locations should be considered FMPs and have to follow the 3175 rule or what regulation they should be required to do. So we've proposed to make this new section and define gas storage agreement measurement points and make slightly different allowances in the regulation for those, as compared to an FMP.

And there's a lot of discussion in that in the preamble. So if you have one of the very few operators that are affected by this, please look at that analysis and let us know if this makes sense to you.

And lastly, there's two immediate assessments that have been removed from the rule or being proposed to be removed from the rule. And both of those relate to mechanical chart recorders. And the reason for this is we feel that since mechanical chart recorders are only allowed to be used on low and very low volume FMPs, having an immediate assessment associated with improper use might be a little bit excessive. Now you can still absolutely be inked for those. It just wouldn't be included in that immediate assessment category.

And so that's the end of that. And I think we'll move over to some of the pre-submitted questions.

CASEY HODGES: All right. Stormy, so the first question is, equipment slash software PMT approvals, why require PMT approval if the equipment can meet or exceed the standards published in API, GPA, et cetera? As long as the equipment meets the BLM uncertainty in 3174.31(a), the PMT approval should not be needed.

STORMY PHILLIPS: Yeah. So it's very important to remember the performance requirements are BLM requirements, not API or GPA requirement. And the BLM equipment or software approval is a verification that that equipment meets those published specifications.

CASEY HODGES: Is there a proposed window of time for GARVS to be up and running? And is there any discussion about a common reporting format?

STORMY PHILLIPS: At this point the BLM does not have any estimated date for GARVS.

CASEY HODGES: In regards to 3175.92, the two Mcf per day and 2% requirement to trigger re-reporting, does this mean the adjustment is averaged out two Mcf per day, even if the adjustment only touches one day in that month? And likewise, the 2%, is that talking about a 2% adjustment for the entire month?

STORMY PHILLIPS: So these requirements are based on your OGOR monthly reporting, not those daily QTR values.

CASEY Is the tables time frame referring to sample dates or effective dates, if the dates are

HODGES: different?

STORMY PHILLIPS: I appreciate this question, and we hope that you submit a comment on that. We recognize that that point can be a little bit confusing, because the date of the sample and the date of the analysis are both referenced in that requirement. And the intent is that the time would be time between samples. But it's important to remember the effective date has no bearing on this.

CASEY HODGES: At times, we will have samples with analyses that are much different than historical. These samples will be rejected. If a sample is rejected, will that meter still need to be sampled within the 45 day period monthly sample?

STORMY PHILLIPS: OK, so if another sample could be taken and analyzed within that 45 day period, no additional action would be needed. But if there's a mis-sample period, the operator should contact the AO immediately and work with them to resolve that gap.

CASEY HODGES: 3175.112(c)(4) and 3175.113(d)(1), discussion of changes, talks about membrane tipped probes and samples separators. 3175.113(d)(1) lists some contaminants that can be found in the production gas, specifically hydrocarbon droplets and water. Much of the gas coming from the wells is at or below the hydrocarbon dew point, HDP. This would mean many of these wells have multi-phase flow streams.

I am gathering data to show the concentrations, HDP, and pressure at the sample point. The use of membrane tipped probes would increase the accuracy and repeatability of sampling a multi-phase stream by keeping liquid out of the sample bottles and GC. This could also be a safety issue if you get too much liquid in a sample bottle and then heat it. A manufacturer submitted data on the benefits of membrane tipped probes.

STORMY PHILLIPS: So the BLM welcomes comments with data on this issue. It's just very important that we receive significant data on that issue.

CASEY HODGES: Location of sample probe seems to conflict with location of temperature thermal well in 3174.105 versus 3175.112(b). API section 14.1 section 7.4.2, in API 14.2 part 2, section 6.5. Please confirm location and order of sample probe and thermal wells.

STORMY PHILLIPS: So I think that the question asker here has gotten a few things confused, because there's references here to both the oil and gas rule. But if the question was only referencing gas sample, the recommendations of 14.1 and 14.32 only state the minimum and maximum distance requirements. And the thermal well location ranges in the rule are within both of those limits. So we don't understand where the conflict is, but we welcome more information and comments on this concern.

CASEY HODGES: For FMPs measuring production from wells first coming into production or from existing wells that have been re-fractured, including FMPs already measuring production from one or more other wells, the operator must inspect the orifice plate upon installation and then every two weeks thereafter. In some instances, where the FMP is at the end of a large gathering system for a large unitized area and ongoing development is adding new wells or refracts virtually constantly, the two week period may create an unnecessary burden if it is interpreted that each new well or refract resets the clock. BLM should consider adding clarification to the rule regarding such situations.

STORMY PHILLIPS: So in situations that are specific to a particular location or operator, the operator should seek a variance under 3170.60. This option allows for operators to work with the local field office for field specific issues with the rule compliance.

CASEY HODGES: Thermometer wells must be located in such a way that they can sense the same flow and gas temperature that exists at the orifice plate. The operator may accomplish this by physically locating the thermometer well in the same ambient temperature conditions as the primary device, such as in a heated meter house, or by installing insulation and/or heat tracing along the entire meter run. When neither of these options is practical for various reasons, BLM should allow the installation to stand as is, as long as the possible error introduced is within the performance standards for the FMP.

STORMY PHILLIPS: So the rule requirements relating to thermal well placement come directly from industry standard practice that has been in place since the '70s. The BLM would need additional information and a lot of data to overturn such a longstanding industry practice.

CASEY HODGES: 3175.80(p)(1) requires horizontal meter tubes to have their sample probes located vertically at the top of a straight run of pipe, in accordance with API 14.1. 3175.80(o) lists several requirements for thermal wells, but does not require a similar vertical installation requirement. BLM should clarify that there are no industry standards that prohibit such an installation where the taps after the sample probe are offset by some degree relative to the sample probe, similar to API NPMS 14.3.2, not specifically prohibiting vertical meter tubes.

STORMY PHILLIPS: So the sample probe requirements come from API 14.1 recommendations. And there's no such recommendations for sample probe orientation. If you believe that the orientation of the temperature probe should be prescriptive in the regulation, you can provide data and request that change in a comment. Otherwise, there is no prescriptive requirement for thermal well orientation.

CASEY HODGES: 3175.80(a). The new rule language under this section may require operators to demonstrate compliance with the fluid condition requirements, under the proposed 3175.80(a), specifically, for single phase flow requirement. BLM should clarify how it expects operators to accomplish this.

STORMY PHILLIPS: So there's no change from the current rule in this requirement. The proposed rule just simply removed that requirement from the table in 3175.80 to the text. All relevant API standards are developed for the use of meters in single phase flow. The regulatory language reflects the API standard, and multi-phase flow is not covered in this rule or permitted in FMPs.

CASEY HODGES: 3175.80(o)(2) gives the operator to use installation or heat tracing to comply and requires the entire meter run be insulated or heat traced. This requirement to insulate or heat trace should only apply to the section between the orifice plate and 12 inches downstream of the subject thermal wells.

STORMY PHILLIPS: So for the purposes of the rule, the meter run, quote, unquote, "meter run" is defined by the measurement area as established an API NPMS 14.32. The area of piping that's downstream of this area is not affected by these requirements.

CASEY HODGES: 3175.92, verification and calibration of mechanical recorders, E1. For verifications performed after installation or following repair, the operator must notify the AO at least one business day before conducting the verifications. Is this intended to address the next scheduled verification, subsequent to initial installation or repair? Or the verification performed during the initial installation or repair?

STORMY PHILLIPS: So 3175.92(e)(1) of the rule applies to notification of the installation or following repair. The subsequent verifications, the operator must notify within 72 hours before the verification. The BLM understands that this is confusing and will work to make the intent of the section clearer.

CASEY HODGES: 3175.92, verification and calibration of mechanical recorders, f, volume correction. At the normal operating points tested result in a flow rate error greater than 2% and 2 Mcf per day, the volumes reported on the OGOR and on royalty submitted to ONRR must be corrected beginning with the date that the inaccuracy occurred. If the error does not meet both of these conditions, 2% and greater than 2 Mcf per day, is a volume correction still allowable?

STORMY PHILLIPS: OK, so the minimum requirement of the rule states that if an error of 2% and 2 Mcf per day on a monthly basis, the operator must edit the OGOR report. Any operator may elect to edit the OGOR based on lower thresholds, for example, less than 2% error or less than 2 Mcf a day. But the rule just establishes that minimum standard.

CASEY HODGES: 3175.100, electronic gas measurement, secondary and tertiary devices. Cable one changes the frequency of routine verification for high and very high volume FMPs to every six months. And BLM seeks comments on this change. Here's a comment. An operator intends to continue to verify transmitters at the same frequency as plate inspections.

STORMY PHILLIPS: So again, the rule establishes the minimum requirements. Operators may exceed the minimum requirements in their day to day operations without BLM taking exception.

CASEY HODGES: What is the purpose-- you've got two more questions here, Stormy. And I'm going to ask them both at once, because the answer is the same. What is the purpose of the volume statement and the quantity transaction record QTR? How did these statements contribute to ensuring accurate measurement of royalty quantities?

Normally, measurement tickets are the official documents of record for royalty quantities. Consequently, volume statements and QTRs are not currently used. It appears the added creation and retention of volume statements and QTRs is redundant and unnecessary.

STORMY PHILLIPS: Yeah, so the rule states that an operator can use measurement tickets or volume statements if they're used in an ELM or EGM. So this is an or statement and not an and statement. But I think the issue here is that there just might be a little bit of a language confusion. Measurement tickets, at least from what was communicated to us, most commonly refers to handwritten type tickets from, let's say, a truck call, whereas volume statements or QTRs are often referring to outputs from flow computers.

So that's the reason that we basically tried to clarify that. And you'll notice, if you look into the requirements of volume statements are basically exactly the same as what you see on a measurement ticket. So hopefully that clears that up.

CASEY HODGES: Thank you, Stormy. Those are the last of the questions that came in with the registration. Now we're going to move on to the questions that have come in during this session.

If at any time we're reading one of your questions and you want to clarify or add anything additional to the question, go ahead and raise your hand, and we will call on you. When you raise your hand, you will be called on. And then you have to unmute yourself from the bottom left hand corner.

Additionally, please feel free to continue to submit questions in the Q&A section. Once we get through these questions, then we'll be looking for people that want to verbally ask questions to raise their hand. We'll start back in the 3170 and 3173 questions.

First question comes from Justin Richardson. 3173.96(a) states, quote, "however, if the FMP is located off of the well pad, regardless of distance, measurement at the FMP constitutes off-lease measurement, and BLM approval is required under section 3173.90 through 3173.94." End quote. The rule seems unclear. Is 3175.70(b), off-lease measurement, defines off-lease measurement as, quote, "gas must be measured on the lease unit or CA unless approval of off-lease measurement is obtained under 43 CFR sub-part 3173." End quote.

There is a potential for confusion by both BLM and industry. Can the PMT please clarify this or illustrate using the purple boundary from previous outreach sessions? Beth, you want to go ahead and answer that?

BETH POINDEXTER: Sure. First of all, this section hasn't changed since from the current role. But 3175.70(b) states that gas must be measured on-lease unless off-lease measurement is approved under 3173. 3173.96, that section, the title of it is, instances not constituting off-lease measurement, for which no approval is required.

If the gas FMP is located on the pad of a directionally drilled or horizontal well pad, horizontal well, on that pad, no approval is required. So as long as the measurement equipment is on the same pad as the wellhead, there is no approval required. So basically, the well pad of a directionally drilled or horizontally drilled well is considered on-lease. So if you want to talk about the magic purple line, basically, the magic purple line extends to the well pad, when the measurement equipment is on the same pad as the wellhead.

Hope that helps. And, Justin, if that didn't answer your question, you can raise your hand and help me out if I've missed it. Thanks.

CASEY HODGES: All right. The next question is from Greg Harden. Why is the new commingling allocation limited to four agreements?

BETH POINDEXTER: Well, Greg, this is something we were hoping people would comment on. The BLM proposed to limit to four agreements due to assumed limitation of calculation methods that might be used to generate the models that we're requiring. If there's a better calculation method that would allow for more complex calculations, we welcome those comments. So please feel free to comment on it and make a suggestion.

CASEY HODGES: All right. Another Justin Richardson question. What is the BLM strategy in assuring that these rules are enforced similarly between all field offices? Example, an office in North Dakota applies the rules in the same fashion that an office in New Mexico will.

BETH POINDEXTER: Well, that's an ongoing struggle, but we're working on it. The BLM is going to have members of the regulatory drafting team and the PM to assist with internal outreach. Then we're going to have inspector training in conjunction with national training center.

And then the development of the enforcement handbook. The enforcement handbook for the current role never got published. And we're hoping to have the draft final by the time this rule goes final and hopefully publish shortly thereafter.

Those are some of the things we're doing now. Is that going to be perfect? Probably not, but we're trying.

CASEY HODGES: Another question from Greg Harden. Has the BLM considered that separating surface commingling and off-lease measurement may cause additional work, as the need for the off-lease may be contingent on commingling approval?

BETH POINDEXTER: Well, we decided to separate these decisions, because granting surface commingling is a separate decision from granting off-lease measurement. So if commingling and off-lease measurement were submitted on the same application, it's possible the BLM could grant off-lease measurement and deny commingling, or vice versa. And in this case, the sundry notice would be returned. And the operator would be asked to submit an application for off-lease measurement only or for commingling only. The separation of these two decisions also makes an appeal of a decision to a state director review easier to manage for both the operator and BLM.

CASEY HODGES: Thank you. Next question comes from Paula Watkins. Can applications for FMP numbers be submitted now? Or do they have to be submitted through the AFMSS system? If the latter, given that completion of the module for AFMSS for FMP submission has been continually postponed since the current rules went into effect in January of 2017, what is the BLM's plan for making this module available concurrent with the updating rules becoming effective?

BETH POINDEXTER: So the FMP number applications have to be submitted through AFMSS2. We completely understand your concern for BLM's AFMSS2 development credibility. We've delayed plenty of times. Because industry has put more emphasis on drilling than production, the BLM reallocated resources away from production to drilling in the AFMSS2 development.

However, the AFMSS2 development team assures us they will be ready to accept FMP number applications when this rule goes final. I believe the FMP number applications are in the current sprint that started at the end of August. So they have at least, I would guess, six months at minimum to develop that. And they are working on it now.

CASEY HODGES: And another question from Justin Richardson. When a piece of equipment or software is approved by the PMT and posted to their website, how will operators, users of the equipment, and BLM field staff be notified?

BETH POINDEXTER: So that's a great question. Internally, headquarters, the PMT will communicate to headquarters. Headquarters then communicates to deputy state directors of fluid minerals, who disseminate the information to field offices.

And I'd like to ask anybody on the call how they would like to be notified of an equipment approval? What would work best for them? We don't really have something developed yet. But if you have suggestions, we'd like to hear them.

CASEY HODGES: And those would be excellent comments to submit, on how you'd like to be notified via the comment submission methods that we've talked about. Beth, thank you. We're going to move on to 3174 questions.

So, Chris, it looks like you got the easy or the long straw so far. Only one question. This question comes from Paula Watkins. API NPMS chapter 18.2 references API NPMS chapter 3.1(a) for manual tank gauging, and chapter 3.1(b) for automatic tank gauging. Why, therefore, has BLM removed the reference to chapter 18.2 that included additional requirements for ATGs, when they are already covered under chapter 3.1(b), as referenced in chapter 18.2?

CHRIS DEVAULT: Yeah, the enforcement of API 18.2 proved to be difficult. And the BLM elected to be prescriptive in requirements. The BLM still allows use of automatic tank gauge and track mounted coriolis meters in the proposed rule.

CASEY HODGES: All right. Thank you, Chris. And now we're going to move on to Stormy, who I think drew the short straw and got hammered with questions in this session, which is great.

STORMY PHILLIPS: My favorite.

CASEY HODGES: We're going to start with a question from Dave Curtis. It is my understanding that the portion where the BLM could require an online GC or composite sampler. If that is the case, why does 3175.115 still have a 90 day requirement for installation? If that is at the operator's discretion, there should not be a timeline, correct?

STORMY PHILLIPS: Yeah, so this can be a little bit confusing. So the BLM could not require an operator to install an online gas chromatograph or use a composite sampling system. But the idea here is to make an allowance for a gap between that next required sample and the installation of this new setup. So if a location required monthly sampling, then if an operator was installing a composite sampler or an online gas chromatograph, they would have 90 days to do that installation while being exempt from that spot sampling frequency requirement. If that answers the question, Dave.

And again, for any of these questions, if you guys want to follow up on that, just hit that Hand Raise button, and we'll call on you, and you can tell me that I'm reading your question wrong. And I'll do my best.

CASEY HODGES: The next question comes from Justin Richardson. 3175.101(c)(13) requires the last meter tube inspection date to be on site. How would the PMT recommend industry follow this? Also, would the mike sheet/meter tube calibration sheet be feasible for the primary inspection documentation?

STORMY PHILLIPS: Yeah, OK, so this is a great question. So this should be done in the same method that you do for your posting of your routine verification requirement, because all that's required is an identification of that date. So I know a lot of companies use a sticker that's affixed the side of the flow computer, and they write those things in. Now, if any further documentation was required, they AO could request that. But you're not required to have that on location.

Now as far as the detailed meter tube inspection, a calibration report would be an ideal way to show compliance with that required pre-installation detailed meter tube inspection. But I will caution operators, you need to make sure that that calibration report contains all the required information. I have had an operator send me calibration reports from three different meter tube fabrication companies, and none of the three calibration sheets contained all the required information. So just a word of caution there.

CASEY HODGES: All right. Thank you. Another question from Justin Richardson. 3175.102(b)(3), if an FMP is in non-flowing status at the time that a routine verification is due, a routine verification must be conducted within 15 days after flow is reinitiated. Would the BLM find it acceptable if the meter is tested at a previously known differential static in temperature for normal operating points and then tested the remaining points as prescribed in an API 21.1, and verify the orifice plate prior to flow being reinstated to maintain a calibration schedule?

STORMY PHILLIPS: Yeah. So if you have a non-flowing and then you're doing that 15 day, that would be considered another routine inspections for the purposes of the requirement. So you would use those required points under the routine verification, not the new installation verification.

But I just want to make clear, because this is one of the things that we tried to clarify in the rule, for something to be considered non-flowing, that doesn't include intermittent flow. So if you have a meter that just kind of flows for part of the day, and you go out there to do that inspection, and it's not going on, that's not considered non-flowing. Non-flowing is you've got it shut down for some kind of reason when the required comes. If you have an intermittent flow, you're still required to keep the schedule.

CASEY HODGES: Thank you. The next question comes from Dave Curtis. In the current rules, laser detectors were approved for moisture analysis. They're not an approved device in the proposed rules. Can you tell us why?

STORMY PHILLIPS: Yeah. So I tried to hit on that a little bit about why we're doing the laser detection, or why we're requiring equipment approval for those. But another part of that is laser devices would be included under the items covered in 3175.126(a)(1)(iii). It's listed as other equipment and methods approved by the BLM. As to why we specifically mentioned automated chilled mirrors and then included laser detection devices and all of the other deal, I'm not sure. It's just kind of how we ended up with the writing.

CASEY HODGES: All right. The next question comes from [INAUDIBLE]. Follow up question for Stormy from yesterday. 3175.80(p) requires the sample probe first disturbance to be at least five published inside pipe diameters of the orifice, downstream of the orifice plate. Similar requirement in API 14.3.2 is 4 and 1/2 diameters to the first disturbance. Another similar requirement exists in API 14.1 for the sample probe, and lists this minimum distance as 5 diameters, which is where the new requirement comes from.

But the difference in 14.1 is that for major disturbances like an orifice plate, the diameter of the orifice plate and not the pipe ID. Considering max beta of 0.75, the d would become 0.75 d, and the required 5d would become 5 times 0.75d, which is 3 and 1/2 diameters. This is less than the 4 and 1/2 diameters listed in 14.3.2, so I think if the new 3175.80(p) will define this distance, it should be defined as 4 and 1/2 d and not 5d.

STORMY PHILLIPS: Yeah, I think he might have just misread that a little bit. The specific section of API 14.1, it states for major disturbances that change the flow profile of the flowing stream, such as orifice plates, elbows, Ts, reduce port valves, flow conditions, filter, strainers, et cetera, the diameter of the disturbance shall be considered to be the inside pipe diameter at the disturbance. And the other thing that I want to remind everybody, because we get a lot of questions about this, is that the 4 and 1/2 d minimum distance for the first disturbance on the max beta ratio, all of 14.3.2 has to do with the measurement of that. So that minimum distance to the first disturbance is to preserve the measurement value and quality of that meter.

For sampling, 14.1 has those sampling standards. So these are kind of independent. And so that's why it's important that we reference both of those different requirements there. So hopefully that answers. I'm happy to expand on that more, if there's additional follow up questions on that.

CASEY HODGES: OK. Kyle Bates has the next question. I would like to confirm if the gas chromatograph software approval requirement, 3175.40(g), measurement equipment requiring BLM approval, is applicable to all GC software? Both portable and gas chromatograph where the sample is taken at the FMP and hydrocarbon gas laboratories that may analyze spot and composite samples from bottles taken at BLM FMPs. If so, will the BLM post both the hydrocarbon lab and its improved software version on BLM.gov, so that operators can determine which lab software have been approved?

STORMY PHILLIPS: So this is a good question. Because, yes, the approval requirements would apply to all GCs in use of the calculation of heating value, regardless of the location. As for the identification, this would depend on how the software was named and who submitted it. Because the way the system works is if somebody submits a software and we approve it, then that's approved for use across the country. So if a lab had a homegrown software and they submitted that, if somebody went on to that approval on BLM.gov, they could see who submitted that.

But if it was an off-the-shelf software that somebody could buy, once it's approved, anybody could use that. So it would just be a matter of checking that. So it wouldn't be necessarily specific to a device or a lab or an operator, if that answers the question, Kyle.

CASEY HODGES: The next question is from Dave Curtis. Following up on Kyle's question, which was the previous question, does the PMT have the expertise to understand resolution integration, valve timing, et cetera, to know what constitutes approval? If they are looking for quantification of heating value, that typically is not performed in the chromatograph software. It is usually done in the LIMS or the MDS.

STORMY PHILLIPS: So, granted-- and we welcome comments on this, Dave, and I know you're going to come up with some good ones-- but the concept here is to approve the software that's doing that BTU value calculation. And like I said, it's aimed at addressing the most common issues that we have seen in the BLM, which is people not performing the calculation correctly or using outdated component standard values.

And that very well might be an MDS system or what commonly is termed as an MDS system or something like that. So we welcome comments on that. But again, it would all be the calculation versus a reference standard. And just like in flow computers, there wouldn't be any necessarily uncertainty attached to this. It's just a pass or fail of that calculation method versus the reference standard within that tolerance.

CASEY HODGES: All right, Dave, we see that you've raised your hand. We'll go ahead and call on you. Please unmute yourself when you get called on. I know he's going to give me a hard time.

DAVE CURTIS: Howdy everyone. Can you hear me OK?

CASEY HODGES: Yeah, we can hear you good, Dave.

DAVE CURTIS: I appreciate it. And maybe I just didn't read it clear enough, and I apologize for that. But the recommendation I would make here is that you all clarify that that's what you're looking for.

Because I agree with you, Stormy, that makes 100% sense, because that is a common problem. But it is calculated in different ways. And a lot of times, yes, the GC software may calculate it.

But folks don't use it out of the GC software necessarily. It's done in their MDS or like in a big lab. And it goes through their lens or even a portable. It goes through a secondary software system other than the chromatographic software. So I would just recommend that you all clarify that whatever software is making that calculation, that's what you want to verify.

STORMY PHILLIPS: Yeah, and again, Dave, I think that's a great point. And I hope you do make a comment about that. Because that's the same reason why we've kind of tried to go away from the term flow computer software to this electronic gas measurement software language to clarify. It's just wherever that volumetric calculation is going on, not necessarily within that device. So, yeah, it's a good point.

DAVE CURTIS: Perfect. Thank you.

CASEY HODGES: Thank you, Dave. Next question comes from Justin Richardson. 3175.115(b)(4) states that sampling is no more frequent than once every two weeks, nor less frequent than once every six months. However, 3175.115(a) states that very low volume wells are annual. Can the PMT explain why there is no mention of annual frequencies in 3175.115(b)(4)?

STORMY PHILLIPS: Yeah, so the subsection 3175.115(b) only applies to high and very high volume FMPs. So very low and low volume FMPs are not subject to the variable sample frequency requirements of that part. So hopefully that answers it.

CASEY HODGES: All right, excellent. And, Dave, I see your hand is up still, I believe. Thank you very much. Want to make sure you didn't have another question.

The next question comes from Jason Rigg. I believe the proposed rule says 90 days to start using GARVS after it is available.

STORMY PHILLIPS: Yes. So that's a correct statement in accordance with 3175.60(b), timeframes for compliance. Did I say it wrong in the presentation?

CASEY HODGES: I'm not sure where that came from.

STORMY PHILLIPS: 90 days is correct. I might have said 60. I don't know. But 90 days is correct.

CASEY HODGES: OK. If that was what it was, good catch on that, Jason. All right. And then, Stormy, this is the last question that has been submitted so far. Another one from Dave Curtis. Slide 52 just stated that water vapor is to be in the volume calculation. Did I read that incorrectly? Isn't water vapor reflected in the heating value calculation?

STORMY PHILLIPS: Yes. That's correct. So the requirement here is that the actual water vapor content measure would be reported on the gas analysis, on that heating value calculation. Basically that's just so the BLM can perform an independent verification of that BTU calculation and make it very clear that there's not just the use of some standard value there.

CASEY HODGES: All right. Thank you, Stormy. That is all of the questions that have been submitted so far. We'll give some people a little more time to submit questions. If you are typing in a question, just go ahead and raise your hand. Or if you want to verbally ask a question, raise your hand. And we will get you called on, so that you can ask those questions. We'll give people a little bit of time here to go ahead and raise their hand or submit any questions.

STORMY PHILLIPS: And while we're waiting for those questions to come in, I'd like to, again, make a call and a plea for everyone to please make comments and look at this. I often say that you could get the smartest people in the world-- and I'm definitely not saying that we're the smartest people in the world-- but you get the smartest people in the world to write something, but they're still going to miss things. And we have looked at this document for so long and through so many iterations, that it's very easy that, maybe even if we didn't miss something, it's just not very clear.

And for us to make changes, we have to show a logical outgrowth. And the most common way to do that is by addressing your comments. If you state, hey, this is wrong. It should be this. Here's the reasons why it should be this. Here's what it should be. Here's all the data to back that up.

It's very easy for us to make that change and justify why that change is being made. And again, I'll state that those are the kind of comments that we're looking for. I know one comment we've received already is that every regulation that the Trump administration released should be rescinded. And although I appreciate that comment, it doesn't really help us work on drafting a quality final regulation for you guys.

CASEY HODGES: All right. Not seeing any other questions or hands popping up. So I think we'll go ahead and send it back to Lucas to wrap things up

LUCAS LUCERO: Yeah. Thank you. So again I'll just reiterate that the comment period closes November 9. So again we encourage you to submit comments. We will be working to get the transcripts posted as quickly as possible at the link that's provided on the bottom of this slide.

And then lastly, we just want to thank all our participants for your great questions and for joining us today. Thank you to the presenters, and also thank you to our technical support helping run this webinar. With that, we will go in and wrap up. Thank you, and have a great day.