STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED
BY THE OIL CONSERVATION COMMISSION FOR
THE PURPOSE OF CONSIDERING:

CASE NOS -21528

APPLICATION OF OIL CONSERVATION DIVISION
TO ADOPT 19.15.27 NMAC AND 19.15.28 NMAC, AND
TO AMEND 19.15.7 NMAC, 19.15.18 NMAC, AND
19.15.19 NMAC; STATEWIDE.

REPORTER'S TRANSCRIPT OF VIRTUAL PROCEEDINGS

RULEMAKING HEARING - DAY 7
JANUARY 12, 2021
Via Webex Platform
Santa Fe, New Mexico

BEFORE: ADRIENNE SANDOVAL, CHAIRWOMAN
JORDAN KESSLER, COMMISSIONER
DR. THOMAS ENGLER, COMMISSIONER
FELICIA ORTH: HEARING EXAMINER
CHRIS MOANDER, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on January 12, 2021, via Webex Virtual Platform, hosted by New Mexico Energy, Minerals, and Natural Resources Department.

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HEARING EXAMINER ORTH: Good morning, everyone.

MR. AMES: Good morning, Madam Hearing Officer.

HEARING EXAMINER ORTH: I believe we have everyone on who I am expecting. I see all counsel. I see the technical host, Baylen Lamkin. I see Irene Delgado, our court reporter. I see Florene Davidson. Would counsel like to do a sound check by any chance?

MR. AMES: Madam Chair, Eric Ames for OCD.

HEARING EXAMINER ORTH: Thank you. Mr. Feldewert?

MR. FELDEWERT: Madam Hearing Officer, can you hear me okay?

HEARING EXAMINER ORTH: Yes, thank you. Let's see. I don't see Mr. Biernoff, actually. I see Ms. Fox. Oh, to give Ms. Fox -- thank you. It says to give Ms. Fox a minute.

MS. PARANHOS: Good morning, Madam Hearing Officer, this is Elizabeth Paranhos.

HEARING EXAMINER ORTH: Terrific. Thank you. Mr. Baake?

MR. BAAKE: Good morning, Madam Hearing Examiner and counsel.

HEARING EXAMINER ORTH: Great, and I see Commissioner Engler. And I feel like that teacher from that children's show about 60 years ago, came through her

mirror -- so, Ms. Fox?
MS. FOX: I can hear now. Thank you.
HEARING EXAMINER ORTH: Great. I see Commissioner Engler, and now I see Mr. Biernoff.
Mr. Biernoff, can you hear me?
MR. BIERNOFF: I can, Madam Hearing Officer. Good morning.
HEARING EXAMINER ORTH: Good morning. I can hear you clearly. And I see Commission Kessler. Commissioner Kessler, any audio issues?
COMMISSIONER KESSLER: (Inaudible.)
HEARING EXAMINER ORTH: You are very faint.
COMMISSIONER KESSLER: Is that any better?
HEARING EXAMINER ORTH: That's much better.
Thank you all very much. I thought we were going to have to lip read yesterday, frankly. So let's begin.
My name is Felicia Orth. We are on day seven of the presentation for the Commission Case 21528. When we broke yesterday, we had completed several of NMOGA's witnesses, the last one being Mr. Craft. This morning the Chair will be joining us a little bit late, but has committed to reading the transcript for what she misses here at the beginning.
We have no folks signing up to offer public comment at 8:30 this morning. We have do have two folks who

signed up to offer public comment at 4:30, so just keep that in mind.

We do need to have a scheduling discussion sometime soon in the event extra days are needed, but I don't want to do that without the Chair. So is there any reason not to revisit to NMOGA's next witness?

MR. FELDEWERT: Madam Hearing Officer, just for everyone's understanding, I intend to call -- we intend to call Joseph Leonard this morning and then Brian Davis and then David Greaves. So I don't know who is operating our system here, but all three of those will eventually need to be panelists, but we intend to call them in that order.

HEARING EXAMINER ORTH: Thank you very much. Mr. Baylen Lamkin is our technical host this morning.

MR. FELDEWERT: (Inaudible.)

HEARING EXAMINER ORTH: All right. Thank you. So do you have Mr. Leonard queued up here?

MR. LAMKIN: He has sound. He should be able to get sound.

HEARING EXAMINER ORTH: There you are, Mr. Leonard, hello.

THE WITNESS: So you can see me?

HEARING EXAMINER ORTH: I can see you, and I can hear you.

MR. LEONARD: Perfect. If you would please raise your right hand. Do you swear or affirm that the testimony you are about to give will be the truth, the whole truth, and nothing but the truth?

THE WITNESS: Yes, I do.

HEARING EXAMINER ORTH: Thank you. And your last name spelled?

THE WITNESS: Leonard, L-e-o-n-a-r-d.

HEARING EXAMINER ORTH: Thank you very much. Mr. Feldewert, whenever you are ready.

MR. FELDEWERT: Baylen, if you would be so kind to allow me to share content.

JOE LEONARD

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Leonard, would you please state your name, identify by whom you are employed and in what capacity?

A. Joe Leonard. My name is Joe Leonard. I am employed by Devon Energy as a facilities engineer.

Q. Okay. You may need to speak up a little bit, Mr. Leonard.

A. My apologies. I will speak louder.

Q. Okay. How long have you been a facilities engineer with Devon Energy?

A. I have been a facilities engineer with Devon

Energy for the past seven-ish years.

Q. Can you please describe your job responsibilities during that time frame?

A. It has been predominantly for design of production facilities, upstream facilities. In my recent capacity it has been for design and execution of production facilities in the Delaware Basin in the Southeast New Mexico area.

Q. As a result of your job responsibilities, Mr. Leonard, are you familiar with the equipment necessary to produce oil and gas?

A. Intimately.

Q. And are you familiar with the troubleshooting that occurs to address various operational issues?

A. Yes, sir. I'm very involved in our troubleshooting efforts.

Q. And are you familiar with the maintenance requirements and other issues associated with the life of that equipment?

A. Yes, I do get involved in maintenance requirements for equipment.

Q. If I turn to what's been marked as NMOGA Exhibit G, as in Gary, 1, does that accurately reflect your educational background and your work experience?

A. Yes, sir.

Q. It shows, Mr. Leonard, that you have a degree in chemical engineering. Is that correct?
A. Yes, sir.
Q. Are you a licensed -- are you a licensed chemical engineer?
A. I have a professional engineering license in the State of Oklahoma.
Q. Okay. I want to talk, Mr. Leonard, briefly about the emergency definition, and I want your perspective on those definitions as a facilities engineer for these upstream facilities or upstream operations, okay?
A. Yes, sir.
Q. So I'm going to look at -- give me one minute. I put up on the screen NMOGA Exhibit A, which is a small white binder, Mr. Leonard. I'm going to go to Subpart 28 -- or, sorry -- the definition of emergency, which is in Subpart G, and I want to address briefly the changes that NMOGA seeks in Subparts G.5 and G.6.
A. Yes, sir.
Q. Sorry about that. Would you give us your perspective on, first off, Mr. Leonard, do you agree it's appropriate to exclude in D.5 recurring equipment failure?
A. I am supportive of excluding the language including a recurring equipment failure.
Q. And would you please explain why?

A. Recurring equipment failure is an important diagnostic tool, and one of the most common times, to build on what was said yesterday, one of the most common times that we will witness recurring equipment failure is when an operator is trying something new.

An example I want to give is when we move from mechanical dumps on our separator to pneumatic dumps that use instrument air. We installed many compressors in the field, and there is a learning curve associated with that -- with new equipment in those air compressors, and when winter came around we had a lot of issues in keeping them running.

And so there was a learning curve and a learning effort within those equipment failures, and eventually over time when we arrived at the (unclear) to employ instrument air within our processes.

Q. And Mr. Leonard, were you present for the testimony about the troubleshooting that's sometimes required for this type of equipment?

A. Yes, sir. Yes.

Q. Okay. And does, in your experience, does -- does that troubleshooting take time?

A. That troubleshooting does take time. You, you witness a failure or you see a failure, and you try to employ a fix, and you hope it works. And if it doesn't you try another fix. And if it does, that's great. So recurring equipment failure is part of the troubleshooting process.

Q. And in your opinion does recurring equipment failure always mean an operator is negligent?

A. No, it does not.

Q. Okay. And I want to talk about Subpart G.6 where NMOGA seeks to add at one site for similar causes.

A. Yes, sir.

Q. Can you explain what you have seen that supports the idea of adding at one site to this definition or to this exclusion as currently drafted?

A. Yes, I do want to talk about that. And I want to back up and talk about the definition of emergency and reflect on what causes an emergency, from a technical perspective, what causes an emergency is a deviation from normal operating conditions.

And if we can turn to Exhibit G3, so for anyone interested in learning about deviations in production facilities, or any processing facility for that matter, and how to design around those, I would ask that you refer to API 14 C.

And that is the recommended practice for analysis, design, installation and testing of basic surface safety systems for offshore production platforms. Granted that says offshore, but a lot of those practices translate into the onshore, upstream and even midstream, really anywhere that you have processing.

And so what you will find in 14 C is that a production facility is comprised of multiple processes, and in each one of these processes you could have a deviation from normal operating conditions that could or could not constitute an emergency.

You could have deviation in temperature, pressure, rate, level, composition, et cetera. And so what Exhibit G3 illustrates is that you have a pressure vessel, and in this pressure vessel you could have deviations in any of those aspects of it.

So then I want to go back to Exhibit G2 that is a process flow diagram that represents a normal production facility. This is not specific to Devon or any company, but this is just maybe typical production equipment that you might see out there.

And as -- the way you look at it is it reads left to right, you got your wellhead, separators, heater treaters, vapor recovery towers, free water knockouts, tanks, et cetera. What this is supposed to illustrate is that a production facility is comprised of multiple processes.

Each one of those processes can have those deviations that I talked about. And so what I'm trying to get at is that a production facility can be very complex, and that's why I'm supportive of including the language at one site for similar cause.

Q. So Mr. Leonard, let me ask you this, you mentioned that there are various colored scenarios down at the bottom, red, blue and green?

A. Yes, sir.

Q. Does looking at the phrase, "at one site," does the scenario colored in blue, does that address that aspect of the language?

A. So if you were to include that at one site for similar cause, I think that -- consider you have three production facilities. Each one of those production facilities has an air compressor. Some event, whether it be be power or weather or whatever comes and knocks those three air compressors down at those three independently operating production facilities, the way the rule is written right now is that would be -- that would not -- that would not be defined as an emergency. That's why we would be supportive of this including at one site.

The scenario being multiple sites, it's the same process and the same cause.

Q. Which scenario is that?

A. That's scenario two. Sorry.

Q. Okay.

A. My apologies, the air compressor one.

Q. Okay. Let's look at the red scenario. Can you explain what's involved in the red scenario and why that's important to the additional language that NMOGA seeks to add here?

A. So the red scenario plays to at one site for similar cause. The red scenario is one site. It is different processes within that site, and it is different causes.

So here I have written, let's say you have a high sales line pressure, that can constitute an emergency. You have a VRU fault that can constitute an emergency. And you can have a clogged erector, a high differential pressure across your (unclear) on the low pressure side of your flare, that can constitute an emergency.

Q. How have you identified each of those circumstances on the diagram, Mr. Leonard?

A. Sorry, I have bubbled them. And so -- it's hard to see at the resolution that I have printed them off at, but the high sales line pressure would be --

Q. Is that the upper right-hand corner of the diagram?

A. Yes, sir. That is the upper right-hand corner. The VRU fault is XA301, kind of in the middle top-ish area, and the arrester is in the middle right, in the bubble around the flare.

Q. And then -- what are you illustrating there? What have you seen?

A. What I'm trying to illustrate is that at one site you can have three emergencies for different causes. And the way the -- the way the rule is written right now is that, if that scenario happened, that that would not be defined as an emergency the way the rule is currently written.

Q. So Mr. Leonard, in your experience, do three or more emergencies experienced by an operator in a 60-day period always mean that the operator is negligent or has poor maintenance?

A. No, sir, it does not.

Q. So, in your opinion, should a third emergency in a period of 60 days automatically be excluded as an emergency?

A. Can you repeat that? I'm sorry.

Q. Should a third emergency, should a third emergency in a period of 60 days always be excluded as an emergency?

A. No, I don't believe so.

Q. Now, there was a question about, if I go down to Part 28 -- 27.8.E.3 in Exhibit A, I'm going to go --

A. Okay. Okay.

Q. And E.3, E is the performance standards for separation, storage tank and flare equipment. And E.3 addresses the language associated with retrofitting flare stack pilots. Are you familiar with that?

A. Yes, sir.

Q. And the Division, and even with NMOGA's proposed changes, has some time frames to address this retrofitting. What's been your experience with respect to the lead time that is needed to retrofit these flare stack pilots?

A. So in my experience there is about, there is a longer time than many think that is required to define the scope of a retrofit project. In my experience I was part of a retrofit project in South Texas. It took approximately one year, and it was in the first four months that all the scope was being defined and we didn't really start executing until after that.

Q. Now, when you say it took year, it took a year for what part of the process?

A. That was from acquiring a company, a new asset in South Texas, to the due diligence process of looking at their facility to defining the scope of what retrofit facilities might be to executing on those retrofits.

Q. Okay. And in, in terms of that entire time frame, how much was associated with the planning, the

pre-planning, before you actually commenced conducting the work?

A. Approximately four months. And then throughout the life of the retrofit, as we learned more about the asset, scopes changed. And so even as the retrofit project was ongoing, we continued to amend the scope of the project.

Q. Have you -- there was a question about the cost to retrofit pilots on flare stacks. Have you had an opportunity to look at that?

A. Yes, sir, I have.

Q. And what did you find out?

MR. AMES: Objection. This is Eric from OCD. I'm not seeing anything in the description of Mr. Leonard's testimony that deals with flared stacks and retrofitting.

HEARING EXAMINER ORTH: Mr. Feldewert, I'm trying to follow myself, here.

MR. FELDEWERT: Mr. Ames, are you talking about the description of his testimony?

MR. AMES: That's right.

HEARING EXAMINER ORTH: The prehearing statement.

MR. FELDEWERT: I believe that Ms. Sandoval asked the question, and we indicated to her that we would have a witness to address the question. If you don't want us to, that's fine, but she asked and we told her Mr. Leonard would be able to answer the question.

HEARING EXAMINER ORTH: All right.

MR. AMES: Ms. Hearing Officer, I'm a little -- if Mr. Feldewert could orient us, what was the question that Ms. Sandoval asked that Mr. Leonard is going to address?

MR. FELDEWERT: She was inquiring about the cost to retrofit the flare stack pipes.

HEARING EXAMINER ORTH: Yeah.

MR. AMES: The cost; is that correct?

MR. FELDEWERT: Mr. Ames, you ought to look at the record. That's my recollection.

MR. AMES: The cost to process. I'm just trying to be sure the testimony doesn't stray too far from what you are suggesting he is responding to. Madam Hearing Officer, it's your decision. Thank you.

HEARING EXAMINER ORTH: I remember the exchange. Go ahead.

MR. FELDEWERT: Thank you.

Q. Mr. Leonard, did you have a chance to look at the costs that are associated with retrofitting flare stack pilots?

A. Yes, I did.

Q. And what did you find, what did you find out?

A. What I found out was that -- and I want to comment that for a grand retrofit effort, there is still the scope development and the engineering process behind that.

But if we, Devon, were to replace the pilot assembly which is probably representative of most pilot assemblies, if we were to replace the pilot assembly on our current flare design, that would cost around 3- to $5,000 in equipment, and then another 3- to $5,000 in labor.

Q. And what was the total cost that you determined?

A. So all in, I would estimate 6- to $10,000.

Q. Per flare.

A. Per flare.

Q. Okay. All right. I'm able to skip a little bit here.

Okay, Mr. Leonard, I want to now discuss Subpart G.2 and reporting categories that are involved there and NMOGA's changes to those proposed reporting categories, okay?

A. Okay.

Q. And it's -- it's on Page 19 of NMOGA Exhibit A Subpart G.2.

A. Yes, sir. Did you lose your ability -- did you lose your screen share?

Q. I did, but I'm trying to get back on.

A. Okay.

Q. Can you see it now?

A. Yes, I can.

Q. So we are in Subpart G.2 on Page 19 of NMOGA

Exhibit A, and in these proposed changes NMOGA is seeking to remove five of the reporting categories.

A. Yes, sir.

Q. I think we have already talked, had a witness talk about Subpart D. Mr. Davis is going to talk about Subpart E, manual liquids unloading. I would like you to apply your expertise to NMOGA's proposal to exclude as a reporting category for what the Division calls vented and flared natural gas. I want to apply your expertise to uncontrolled storage tanks, okay?

A. Okay.

Q. Would you explain what the Division apparently means when they reference uncontrolled storage tanks and what's involved with respect to the releases, low pressure releases from those tanks?

A. Sure. So a storage tank is the end of the line of a production. It is where the produced water, the produced oil waste to be transferred to third party, whether it be a truck or pipeline typically.

And it is at the storage tank where you can either be controlled or uncontrolled. A controlled tank can have its any vapors generated from it either combusted or covered. An uncontrolled tank is vented to the atmosphere.

Q. At what part of the process do you find uncontrolled tanks?

A. At what point in the process? Can you --

Q. Yes. In other words, when you look at the movement of the gas in the wellhead to the sales line, at what point in that process do we have uncontrolled tanks?

A. That would be at the very end. So the vapor that you will find in the uncontrolled storage tanks is the flashing vapor that is from pressure and temperature change from the upstream process, which could be heater treater, three phase separator, two phase separator, vapor recovery tower. Vapor can also be generated in small quantities from working and breathing losses.

Q. At that point in the process, has the recoverable gas been taken out of the stream?

A. If a tank is uncontrolled, then the operator has deemed that gas not recoverable, either for their emissions calculations, how they have sized equipment, they could combust or recover that gas, but if a tank is uncontrolled it's because the operator has deemed it infeasible to control it.

Q. Are we at a point in the process where those vapors can be recovered for sale?

A. Not easily, no.

Q. Is there any concern about trying to recover these vapors for sale at the end of this process?

A. Yes. Yes. Given the operating pressure that the tanks operate at, recovering those vapors for compression has a high risk of oxygen ingress. And whether a company chooses to do that or not is a risk-based decision for that particular company.

Q. And why is it a risk-based decision? What's the risk concerned?

A. Oxygen ingress is a severe risk from a technical standpoint. If you get it in your process, it's very corrosive and it also makes a combustible mixture, which is very dangerous.

Q. Okay. Now, you mentioned this as vapors coming off of these tanks?

A. Yes, sir.

Q. Those types of vapors, is that venting as normally understood by engineers?

A. If you don't have a control on your tank, the vapor has nowhere else to go but to vent. So, yes, from a technical standpoint, on an uncontrolled tank, it's only choice is to vent.

Q. And in your opinion, does it make sense to have vapors from an uncontrolled storage tank as a reporting category for monthly production volume accounting?

A. My opinion is that it is very difficult to measure with any certainty, and it is very difficult to evaluate with any certainty.

Q. Now, the next category is Subpart -- subsection dealing with venting as a result of normal operation of pneumatic controllers and pumps. Do you see that?

A. Yes, sir.

Q. Okay. Do you have an exhibit that relates to this, Mr. Leonard?

A. I do. My Exhibit G5 just shows kind of different styles and some pictures of pneumatic controllers that I am familiar with.

Q. Can you briefly explain to us what each of these pictures show?

A. Right. So the first one is a switch style pneumatic controller, and you will see that in liquid a lot pretty exclusively. The next is a displacer style or level controller, pneumatic controller, this is typically used in a liquid gas interface or even a liquid liquid interface. The next is pilot style which you will typically see on back pressure or back pressure reducing valves that are using gas surface.

Q. How are these devices utilized in the field? What purposes do they serve?

A. So these devices communicate with a valve, and what they do is they act as the gatekeeper between a pressure source, whether that be instrument gas or instrument air or any pressure source and the valve it is trying to control.

So when each of these devices receives a signal, whether that be an adjusted change in the liquid level or a change in the set pressure, when it receives that signal, it opens up and allows a pneumatic signal to travel through the valve that it is communicating with.

The valve will do whatever it's been set to do, whether that be open or close, and then when the set point has been reached, it will discontinue that signal to the valve, and now it has to do something with the gas that is trapped within the tubing and within the body of the controller itself. Traditionally what that does is it vents to the atmosphere.

Q. Are operators able to capture that -- those releases and send it to a sales line?

A. It would be very, very difficult, and that is because, especially on those liquid level styles, switch and the displacer style, the valve that those devices communicate with, that valve is held in the position by a spring, and so it's using that pneumatic pressure to combat the force of the spring.

And so if you were to put that back into a system somewhere, any pressure that, that would remain on that valve could interfere with that valve's ability to function properly. I misspoke -- that also includes the pilot style that would be used on a spring operated back pressure or pressure-reducing valve and gas surface.

Q. So that would interfere with the working aspect of this?

A. It does have the potential to interfere with the, with the valve's ability to function properly.

Q. Given the nature of these operations, are operators able to estimate for production volumes, monthly production volume accounting these types of releases?

A. You are risking a lot of variability, and it would be very -- the calculations from that would be very uncertain. What causes a pneumatic control release is how often it actuates. And how often it actuates is a function of its supply pressure, the length and size of the tubing, the weather conditions, the weight of which the valve is communicating with these to actuate. So it's very difficult to evaluate that with any certainty.

So to want that as a reporting category, there is a significant risk of that being an inaccurate number with a lot of variability.

Q. And then I don't know if we've touched this, what type of releases are we talking about here? Are these high pressure, low pressure? What type of releases?

A. Those, those displacer, they typically request a supply pressure of about 30 pounds. And the pilot style, that uses a supply pressure that the process is controlling, so whatever that may be.

But, again, the volume that these would vent is, is the gas that could be trapped within the body of the controller as well as the gas that would be trapped within the tubing from the controller to the valve.

Q. In your opinion, Mr. Leonard, does it serve any purpose to have pneumatic controllers and pumps as a reporting category for monthly production value accounting?

A. I can't speak to whether risking an accurate and unreliable data is worth it. I think that's what you are getting at.

Q. Okay. The next category that NMOGA seeks to exclude is improperly closed and maintained thief hatches that are routed to a flare or control device. Do you see that?

A. Yes, sir.

Q. What are we talking about here? What kind of a device?

A. So in a properly closed or maintained thief hatch that is routed to a flare or control device, one clarification I want to make is that a flare is a control device from a technical standpoint, so a control device can either be a method of recovery or a method of destruction or combustion.

And so what, what this reads to me is that they are wanting to evaluate any leaks from improperly closed or maintained thief hatch that is routed to a control device. So that's the first point I want to make.

Mr. Feldewert, can you help me? Can you repeat your question and say what you were getting at?

Q. Sure. In other words, what are we talking about here when we talk about thief hatches? It says, that are routed to a flare or control device. I think the Division had language now that says thief hatches on the tank that are routed to a flare or control device.

A. I apologize. Thief hatched are inherent to tanks. I think that was covered extensively in previous testimony. One thing I will stack on is that they should be sized in accordance with API 2000.

And so you have the tank, and then it's routed to a control device and then calls on that tank is a thief hatch that is used for maintenance and vacuum and overpressure protection.

Q. Now, when you look at an improperly closed or maintained thief hatch, are there going to be releases from that?

A. An improperly closed or maintained thief hatch would be, any release that you see from that would manifest itself in a leak state. That would be very difficult to detect with anything but, I think, an optical gas imaging camera. If it's a significant leak, I spoke AVO could catch that.

Q. If you were in a leak state, what kind of pressures are you dealing with from these types of tanks?

A. So if it's an ATEX (unclear) tank, which is 99 percent of tanks you are going to see out there, I didn't do the math, that's just to illustrate my point that I would be very surprised to see any different kind of tank from an upstream operator. So an ATEX 12 S tank can be rated up to 16 ounces or one pound of pressure.

Q. So when you say one pound of pressure, that's the pressure you would see if it was in a leak state?

A. That is the pressure that the tank is maximally rated to. If a tank was in a leak state in normal operating conditions, I think you would more likely see that it's operating in ounces, much less than that, probably between -- in my experience I have seen tanks operate in normal operating between zero and two to four ounces.

Q. So any emissions from an improperly closed thief hatch would fall in that range?

A. Yes, sir.

Q. Which, let's see, when I use a tire gauge, Mr. Leonard, to check my tires, would that kind of release even move my tire gauge?

A. You know, I don't believe so. I think you would have a hard time determining your tire pressure if there was only 16 ounces of pressure in your tire.

Q. Is there a way -- are you able to accurately measure or even estimate this type of release if we had an improperly closed or maintained thief hatch?

A. To estimate a thief hatch in a leak state would be incredibly difficult. You would be risking high variability, and I would -- I would argue that it would be very -- relatively inaccurate.

Q. Okay.

A. Both from the measurement and a mathematical calculation standpoint.

Q. Now, I believe that climate advocates has proposed to add as a reporting category under G.2 what they call controlled tanks.

A. Yes, sir.

Q. Okay. Which means that you would be asked to track what is vented, what is released from those types of tanks on a regular monthly volume accounting. Okay?

A. Yes, sir.

Q. Can you explain why that would be -- do you agree that that would be appropriate to try to calculate those releases from a controlled tank for a monthly production volume accounting section like this?

A. Okay. So to unpack that, again, a controlled tank from a technical standpoint means it is either combusted, destroyed or recovered. And so for that to be a reporting category, as I have said on several of these other low pressure resources, you are risking a high degree of variability, and the numbers will probably be inaccurate. It is difficult to measure, and it is difficult to calculate with any degree of certainty.

Q. Did you undertake an effort to, at some point, to try to estimate or measure the types of releases that would be -- that came off of these controlled tanks?

A. Yes, sir. I have tried to employee designs where we have used thermal mass measurement to evaluate these rates, and we have used just pressure measurement to try and correlate, you know, a pressure to a rate.

What we found is that the data, the measurements were not accurate. They were very good for relative measurement. That is to say, are we in a state of more or a state of less than the previous measurement. But for it to yield an absolute measurement that we had confidence in, we determined that that technology was not suited for that.

Q. In your opinion, will operators be able to report with any accuracy the monthly volumes of emissions released from these, from controlled storage tanks?

A. No, sir.

Q. Okay. Mr. Leonard, were Exhibits G1 through G5 prepared by you or compiled under your direction and supervision?

A. Yes, sir.

MR. FELDEWERT: Madam Hearing Officer, I move into evidence NMOGA G1 through G5.

HEARING EXAMINER ORTH: Pause for a moment in the event there are any objections to the NMOGA's Exhibit G1 through G5.

(No audible response.)

HEARING EXAMINER ORTH: G1 through G5 are admitted. Thank you.

(Exhibits G1 through G5 admitted.)

MR. FELDEWERT: Then I will pass the witness.

HEARING EXAMINER ORTH: We have Commissioner Kessler who would like to ask some questions before she has to depart briefly. Commissioner Kessler.

COMMISSIONER KESSLER: Thank you, Madam Hearing Officer. Good morning. I just want to have a few questions, and I would like to begin with your testimony related to changing the language that the Division has proposed for emergencies.

Do you understand the intent of the Division's rule just trying to prevent regular flaring for nonemergencies.

THE WITNESS: I believe so.

COMMISSIONER KESSLER: And have you been listening to testimony the past couple of days?

THE WITNESS: I have.

COMMISSIONER KESSLER: We have kind of a recurring theme here of avoiding mischief, but that's what I would characterize as companies using given exceptions in a way that those exceptions are not intended for. Do you understand what I mean when I say that?

THE WITNESS: Yes. I do.

COMMISSIONER KESSLER: So how would you, how would you propose the Division address a situation where a relatively innocuous category is created, such as expanding this definition of emergency and operators routinely using that, that category in a way that the Division did not intend?

THE WITNESS: Okay. So we're -- we are talking about the operators' negligence including recurring equipment failure.

COMMISSIONER KESSLER: Correct.

THE WITNESS: And it's my understanding that the intent of including recurring equipment failure is so that the operator can't use that as an excuse for mischief, well, this thing doesn't work, so we have to vent or flare.

COMMISSIONER KESSLER: Precisely. It hasn't worked five times so we flared five times a month.

THE WITNESS: So you guys are the ultimate authority on language with all of these, but, you know, I don't think that -- I think it could be at your discretion that if it is equipment failure that that is operator negligence.

What I don't want is, from an engineering standpoint, for recurring equipment failure to always mean an operator is negligent.

COMMISSIONER KESSLER: But the rule is not written that way. Currently there is an exception that the Division is allowed to grant a request to the operator.

THE WITNESS: Okay.

COMMISSIONER KESSLER: So would you agree that that allows the operator flexibility to be able to -- I see that Mr. Feldewert is hopefully pulling that up -- unintentionally shift the screen one way or another.

MR. FELDEWERT: No, I need to, Commissioner Kessler, only because I want to make sure we have the language in front of you. Right now you are talking about Subpart 5, which I don't believe includes the language you were referencing.

COMMISSIONER KESSLER: I believe I was looking at 6, which was, three or more emergencies experienced by the operator within the preceding 60 days unless the Division determines the operator could not have reasonably anticipated the current event. So that is the language that I was referring to that exists in the emergency portion.

Mr. Leonard, do you agree that that, as related to emergencies, affords the operator flexibility to, to rectify situations that -- through the Division that, that would otherwise be prevented.

THE WITNESS: So I'm very sorry, but that was a very long question.

COMMISSIONER KESSLER: I know. Let me try again.

THE WITNESS: Okay, sorry.

COMMISSIONER KESSLER: What we have discussed has been -- what you discussed in your initial testimony was the need for flexibility, both as I understand it through either routine maintenance and -- and with emergencies; is that correct?

THE WITNESS: Right. I am familiar with emergency planning and design and routine maintenance and troubleshooting.

COMMISSIONER KESSLER: So if the Division were to add a similar clause into the routine flaring provision in 5 that it currently exists in 6 where the Division is authorized to, to review circumstances and grant an exception for routine flaring, would that satisfy your concern related to routine flaring?

THE WITNESS: I think such a process would provide some relief and comfort. I don't know if -- so, yes, I guess that would provide some comfort. Really all I'm trying to get at is that, I'm very supportive of operator negligence does not constitute emergencies.

And I am also very supportive of equipment failure does not necessarily mean negligent operator. And I'm probably repeating myself, but those are just my two concerns as a technical facilities designer. So if you guys are proposing language to, I guess, help alleviate that concern, then I would be supportive of that.

COMMISSIONER KESSLER: Okay. My next set of questions, you preemptively addressed or responded, I suppose, to Director Sandoval's questions yesterday related to the cost of flare stacks.

THE WITNESS: Yes.

COMMISSIONER KESSLER: How many flare stacks does Devon have to replace?

THE WITNESS: As part of this rule?

COMMISSIONER KESSLER: Yes.

THE WITNESS: I have not done that evaluation.

COMMISSIONER KESSLER: Can you give us a ballpark?

THE WITNESS: This would be flare stacks that are not equipped with a pilot ignition system as described within the documentation.

COMMISSIONER KESSLER: That's correct.

THE WITNESS: I would be -- I don't think there are many.

COMMISSIONER KESSLER: Okay.

THE WITNESS: I am -- I am mostly -- I'm very unfamiliar with facilities constructed prior to 2018, 2017.

COMMISSIONER KESSLER: You had mentioned a 6- to $10,000 per flare figure, so I'm trying to determine, you know, what the roll up of that would be, what's the number that Devon would have to replace?

THE WITNESS: My general concern for it would be little. I would not be very concerned for Devon as an operator to undergo that effort.

COMMISSIONER KESSLER: Okay.

THE WITNESS: From a cost impact point, I would not be very concerned.

COMMISSIONER KESSLER: Okay. And now that Director Sandoval has joined us, I will generally leave this line of questioning for her, but can you tell me whether Devon uses modeling to determine or estimate emissions?

THE WITNESS: We do use process modeling to evaluate permit calculations. We also use it to evaluate, to get a good understanding of how our production facility will operate.

COMMISSIONER KESSLER: Why couldn't Devon use process modeling to determine some of the emissions for categories that you have mentioned would be difficult to calculate otherwise?

THE WITNESS: So process models can certainly be used to evaluate stuff like that. And I want to just go back and talk about what a process modeling software is. And it really all it is, is a high powered, it's a high force powered chemistry calculator.

And so a process model is only as good as it's input and the understanding of the system that the modeler has, and you can make them very simple, you can make them very complex, and depending on the range of assumptions you make for a process, it can spit out anything you want it to. As modelers say, trash in, trash out.

And so when I -- if I said it was -- I never mentioned today, and I don't think it was impossible, I think the point I was trying to make is, there's a high degree of risk and uncertainty with those numbers.

Another, point I want to make with evaluating, using process models to evaluate rates of flow pressure sources is that -- and I want to compare it to a high pressure source.

So let's say you have gas at 200 pounds, and let's say that that gas is associated gas from a wellhead.

Well, if you model it 200 pounds it says one thing, if you model it 199 pounds you don't get much different results. And a lot of that has to do with you're not deviating from the -- the actual (unclear) assumptions you can make. And also that associated gas wants to be a gas. By changing a 200 pound gas stream by one pound is not going to impact that calculation really at all.

What makes tanks difficult is that it's a low pressure source in that the gas from the tank is having an identity crisis in that it's unsure if it wants to be a gas or liquid. Slight changes in temperature or pressure could shift that composition in one phase or another.

So if your methodology is off by several simple assumptions, you could get pretty different numbers and a different set of assumptions. So when I say it's difficult to evaluate, I mean there is just a high degree of variability that you're risking.

Process models are great for permit calculations because the way we use them for permit calculations, we are building a box we are saying we will operate in using the most reasonably conservative assumptions we can.

And so that's kind of the differing calculation methodology in between saying we will -- saying we will operate in this area versus what's actually happening, especially from low pressure sources.

COMMISSIONER KESSLER: Thank you for that explanation. Again, I will let Director Sandoval follow up on that. Thank you. Those are all my questions.

THE WITNESS: Thank you.

HEARING EXAMINER ORTH: Thank you, Commissioner Kessler. Mr. Ames, do you have questions of Mr. Leonard?

MR. AMES: Yes, I do have a couple of questions for him. May I proceed?

THE WITNESS: Good morning.

MR. AMES: Good morning. May I proceed? Thank you.

CROSS-EXAMINATION

BY MR. AMES:

Q. Good morning, Mr. Leonard. Just a couple of questions. First I want to say I did appreciate your testimony regarding the cost to retrofit flares. I think you said it was 6- to 10,000 per flare; is that right?

A. That would be the cost to replace one of our current pilot assemblies.

Q. Is that cost of material and labor?

A. Yes, sir.

Q. So I think you said all in, I just wanted to confirm that.

A. Yes.

Q. Okay, what -- do you have an idea what it would

cost to actually, I suppose to -- when you said retrofit, you meant to replace it with a different kind of flare tip?

A. So retrofit could apply to either replacement or addition.

Q. Okay. So to bring a current flare up to an automatic igniter, for instance, if it's not already an automatic igniter, that's what you mean by retrofit? It's a replacement, in essence?

A. That could be within the scope of a retrofit project, yes.

Q. Okay, all right. I wasn't sure if there was a difference between retrofitting and replacing in your --

A. When I say retrofit, I mean going back to its existing location and making modifications based off of --

Q. Okay. Thank you. So you were asked whether, I think, whether emissions from tanks could be captured. Do you remember that question?

A. Yes, sir.

Q. And I think your answer was not easily. Do you remember that?

A. Yes, sir.

Q. So you're not suggesting that the standard for whether operators should control waste should be whether or not it's easy or not to capture, are you?

MR. FELDEWERT: I'm going to object to the form of the question. He didn't testify on a standard for waste.

HEARING EXAMINER ORTH: Mr. Ames, would you rephrase.

Q. Sure. Mr. Leonard, what were you testifying about when you said -- when you answered the question not easily, was it capturing or measuring emissions from tanks?

A. Both.

Q. It was both. So you're not suggesting that the standard for either measuring or capturing emissions from tanks should be weather it's easy or not, are you?

MR. FELDEWERT: Form of question.

MR. AMES: My question was perfectly fine.

HEARING EXAMINER ORTH: Sorry, what was your objection to the form of the question?

MR. FELDEWERT: He is asking him what he thinks the standard is for capturing waste.

MR. AMES: I'm asking him what he thinks should be the standard for whether or not emissions from a tank should be measured or captured.

HEARING EXAMINER ORTH: Right.

MR. AMES: He had answered the original question that it wasn't easy. I'm asking him what he thinks the standard should be.

MR. FELDEWERT: So the original question was whether capturing to a sales line. That was the question.

MR. AMES: He can answer that with one then.

A. So I think captures vapors from an atmospheric storage tank introduces new risk that you would not see from capturing vapors from a pressurized vessel, and I am likening increased risk to the ease or difficulty of doing such.

Q. But you are not suggesting to this Commission that it should make its decision whether it should require such gas to be measured or captured based on whether it's easy or not?

MR. FELDEWERT: He never said that, Mr. Ames. Object to the question.

MR. AMES: To the Hearing Officer, the question has been posed. There is no objection.

HEARING EXAMINER ORTH: Right. Mr. Feldewert, I think his questions are legitimate based on the testimony we heard earlier.

A. Mr. Ames, could you repeat it? And I want to understand it. So -- so I'm not suggesting that the Commission make regulations based off of ease.

Q. Thank you.

A. Okay.

Q. Thank you. With respect to pneumatics, I just have a couple questions for you on this. If I understand correctly, you're suggesting or arguing that operators

should not have to report data regarding lost gas from pneumatics because the data is unreliable. Is that correct?

A. My argument is that it is unreliable and inaccurate. I cannot speak for the Commission whether they are okay with data that could be reliable or accurate.

Q. You are aware that this is only reporting requirement; right? OCD is not proposing that emissions from pneumatics constitutes waste; right?

A. Yes.

Q. Okay. And Devon and other operators report emissions from pneumatics pursuant to EPA regulations; isn't that correct?

A. Yes.

Q. And you do that annually under Subpart W; is that right?

A. That's my understanding of Subpart W and how Devon complies with it.

MR. AMES: Thank you. No further questions. Thank you, Mr. Leonard.

THE WITNESS: Thank you.

HEARING EXAMINER ORTH: Thank you, Mr. Ames. Mr. Biernoff, do you have questions of Mr. Leonard?

MR. BIERNOFF: Madam Hearing Officer, I do not have any questions for Mr. Leonard.

HEARING EXAMINER ORTH: All right, thank you.

Ms. Fox or Mr. Baake, questions of Mr. Leonard?

CROSS-EXAMINATION

BY MR. BAAKE:

Q. Good morning, Mr. Leonard. I remember you from the map presentation, and to be honest your presentation was so rich here that I was still working on, working on some questions, but I'm up, so I will do the best I can. Thank you.

So Mr. Leonard, we spoke a little bit about the cost of retrofitting flares and talked about flaring and venting and so forth.

I want to start with a pretty basic question. When gas comes up from the well and it's in an operator's system, there is three basic outcomes for the gas, right, you either capture it, flare it or vent it. Would you agree with that?

A. Yes.

Q. And in general, there's going to be a variety of factors that an operator is going to take into account in deciding what to do with the gas between those three outcomes. Would you agree?

A. Yes.

Q. Is cost usually an outcome the operators can consider?

A. Cost is always considered. We try to find the most cost-effective solution to complete a goal or a scope.

Q. But the social cost would not necessarily, absent a regulation, that tells you you have to consider the social cost that would not necessarily be a consideration; right?

A. I would disagree with that. I think we would make decisions differently based off of the location from a design stand point.

Q. Okay. But like -- okay. Now, as between flaring and venting, would you agree that in the vast majority of circumstances, flaring is going to be the preferable option from a safety perspective?

A. I agree.

Q. And if you have venting going on, you could have risk to personnel safety, toxicity problems, would you agree?

A. Yes.

Q. Even asphyxiation, people can get asphyxiated if there is gas in the air?

A. That is a risk of personnel exposure. I would say asphyxiation is lower on the totem pole of risks that concern me, but it is a possibility.

Q. So a prudent operator is almost always going to be flaring rather than venting except for maybe when it's not, you know, a real emergency, you can actually get a flare up and running. Would you agree with that?

A. From a design stand point it is always my goal to minimize venting, yes, that is my goal from a design standpoint.

Q. Okay. I appreciate that. Now, I would like to pull of up your presentation to the map, if I could. Could I get sharing authority here? And I actually don't know if this is in evidence or not, but we would be willing to introduce it. It's on the NMED website, and (unclear) I'm sure you are intimately familiar with it.

CHAIRWOMAN SANDOVAL: Mr. Baake, I think it's an exhibit through the Division. I don't remember what number.

MR. BAAKE: Fantastic. I'm still not having sharing. I can move forward without it if I don't have it, but I would -- it might be a little helpful.

Baylen, are you able to give me sharing capacity.

MR. LAMKIN: (Inaudible.)

Q. Oh, perfect. Okay. Is this -- okay. Can you all see this?

A. Yes.

Q. Okay. So, so -- yes, so this is your presentation you gave --

A. Uh-huh.

Q. -- October 24, 2019, in person back when that was, you know, people were safe. And I was there, I enjoyed it. So we are here on Slide 8, I guess.

A. Okay.

Q. Let me put the title there. So what causes emissions? And just for the record, I will read them even though we can all see them. So unforeseen operating conditions, improper design, improper construction, improper operation, improper maintenance and malfunction.

So Mr. Leonard, we talked a lot about the definition of recurring equipment failure, and I think you made the point that it's not always due to operator negligence; is that correct?

A. That is correct.

Q. So I want to kind of put aside the question of negligence because that's kind of a legal term, and I'd rather just kind of focus on these categories that you listed and kind of see what we can kind of, maybe use these terms to figure out what might cause recurring equipment failure.

So is improper design a potential cause of recurring equipment failure?

A. Yes.

Q. And that might even include, I think you talked in (unclear) not being properly sized for the job, would you agree with that.

A. I think an improperly designed piece of equipment would fall into an improperly designed piece of equipment.

Q. In know, but my follow-up is like if you have a tank maybe too small for the -- maybe you answered the question and I misunderstood. If it's the wrong size that would be one sample, if a tank or some other device is not large enough for the job or too large?

A. That would meet improperly designed piece of equipment.

Q. Okay, thanks. Sorry. You answered that question but -- the same question with improper construction, that also falls under recurring equipment failure; correct?

A. Yes.

Q. And same for improper operation?

A. Right.

Q. Improper maintenance?

A. Yes.

Q. So really the only one here that I can see that would be really beyond the operator's control is unforeseen operating conditions.

A. Unforeseen operating conditions are beyond the operator's control.

Q. But they're -- okay. But there are a variety of reasons why equipment, you might have recurring failures, and it might be something the operator can control either by maintaining the equipment better, changing how it operates, even reconsidering the design of the facility. You would

agree with that?

A. Yes.

Q. Great. I want to actually switch over to a very technical question that we're going to present a little direct testimony on, but you spoke on as well, so it's fair game. And I even don't know if I understand it well enough to ask the question, but I'm going to try.

MR. BAAKE: Madam Chair, do we know if this is an exhibit? This is the presentation that was given a day after Mr. Leonard testified by Peter Mueller.

CHAIRWOMAN SANDOVAL: Actually, I'm not sure if those presentations are. Maybe Mr. Ames can clarify. I know the Map report is an exhibit. I'm not sure if the individual presentation, so that might be a clarification.

BY MR. BAAKE:

Q. I actually don't need to look at this, I just wanted to orient people that this, this presentation was given, I think it was the day after yours, Mr. Leonard. I don't know, do you remember it? Were you there by any chance?

A. That's correct. I was there. Just the next presentation, I don't know if it was the day after, but I see your point.

MR. BAAKE: And so just for the record, what I briefly had pulled up on the screen was the enhanced vapor recovery presentation by Peter Mueller cofounder of EcoVapor Recovery Systems, and this is on the NMED Methane Advisory Panel website. We are happy to introduce it into evidence if need it be.

Q. So you testified -- Mr. Ames already asked you about this, but vapors cannot be recovered from tanks very easily; correct?

A. I did say that.

Q. And I think one of the specific issues you spoke about is that this is really low pressure gas, and so to put it into a sales line you have to compress it; right?

A. Right.

Q. And so compression could introduce oxygen; correct?

A. That is correct.

Q. And oxygen can -- you heard testimony earlier that oxygen is something you definitely do not want in your pipeline because it's explosive. Is that --

A. The main risk of having oxygen in your pipeline is its corrosiveness.

Q. Corrosiveness, okay. That's why I like doing cross. Go ahead.

A. As I said before, midstream operators and downstream operators will quickly close that valve that that oxygen source is coming from because they have their own risks with oxygen in their system, but from an upstream standpoint, it is corrosive in our lines after the sales point. There are other risks upstream of that.

Q. And this is why I like doing cross-examination in these technical cases. I legitimately was not thinking that, but I appreciate that. I learn something every time I dig into this.

So corrosiveness, but anyway, we all agree oxygen causes problems in the system. So the EcoVapor presentation which you saw, this is technology that has been developed to remove oxygen from these low -- from low pressure gas. Would you agree with that characterization?

A. A more apt description of technology that EcoVapor is selling, at least from what I gathered from their presentation, is that they will remove oxygen downstream of the vapor recovery unit.

What that does not account for is oxygen ingressed within your tank, within your flare line if you have one, or really anything upstream of the compressor. So that would be additional design consideration that someone would have to make.

Q. Okay. But I think, if I understand the technology correctly, and I probably don't, you basically are using a catalyst to, to drive a reaction, a combustion reaction in this stream, and then you end up with the CO2 in

the stream which is not a problem rather than oxygen. Is that your understanding?

A. I would be speculating. I would have to rely on EcoVapor to explain their technology.

Q. That's a totally fair response. But anyway, you're aware there's technologies out there and that there are technologies that can be put into place to -- or at least people are marketing as having the ability to remove this oxygen and deal with this problem of recovering vapors from tanks?

MR. FELDEWERT: Mr. Baake, I'm going to have to object to the compound question. You want to break that down, please, for the witness.

MR. BAAKE: That's fair.

Q. But you agree there are technologies out there that could potentially deal with this problem of oxygen being introduced in the process of capturing tank vapors?

A. There is technologies that advertises the mitigating risk of oxygen in your system.

MR. BAAKE: Okay. I think that's all the questions that I have. I really appreciate the discussion, and I will pass the witness. And Mr. Feldewert, do you want me to introduce this into evidence? Like I said, it's on the Methane Advisory Panel website, either or both if you would like.

MR. FELDEWERT: I don't see any need to introduce it, no.

MR. BAAKE: Okay, thank you.

HEARING EXAMINER ORTH: Thank you, Mr. Baake. Ms. Paranhos?

MS.PARANHOS: I have no questions for this witness.

HEARING EXAMINER ORTH: Thank you. Commissioner Engler?

COMMISSIONER ENGLER: Thank you. Good morning, Mr. Leonard. Can you hear me.

THE WITNESS: Good morning. Yes, I can.

COMMISSIONER ENGLER: I guess my first comment is congratulations on being a professional engineer.

THE WITNESS: Thank you.

COMMISSIONER ENGLER: Despite you went to OSU, you made it.

THE WITNESS: Maybe just a little more work.

COMMISSIONER ENGLER: No. A couple of questions, clarifications, if you will. Going back to the cost that you provided for the flaring, you gave both and equipment labor cost, an approximation. Is that equipment cost for -- there is multiple emission systems. Is that cost you gave for any particular one of those types of emission or just in general for all the same.

THE WITNESS: So the cost I gave is for our pilot assembly. Our pilot assembly is continuous pilot, but I would not expect -- I would expect the same order of magnitude for any other pilot ignition system. But, again you know, I'm speculating, but I'm having a hard time fathoming it being much different.

COMMISSIONER ENGLER: I guess my other question, I guess Devon is going with the continuous pilot as their preferred ignition system?

THE WITNESS: That's what we use. That's what we have experience in. You know, I don't -- I don't want to speak that it's more reliable than the other ones, that might have just been the one we picked and we are happy with it.

COMMISSIONER ENGLER: Okay. You have provided, I think you had an example in South Texas that you used.

THE WITNESS: Yes, sir.

COMMISSIONER ENGLER: That seems like -- and I think you were talking about, mostly about timing there, and that seemed like a fairly worst-case scenario. I would like to know more of a, you know, between scope design, scoping and completing, what would be more of a typical installation, or retrofit, I guess?

THE WITNESS: It's hard to say that without being able to identify the scope of the retrofit. Mine was introducing upgrades to flares, installing new flares, upgrading other vapor recovery technology and other small aspects like replacing PSDs and stuff like that. So it's really difficult to speculate the scope of a project and the amount of the facilities that that scope might encompass.

COMMISSIONER ENGLER: So, yeah, I would say -- so you would agree -- yeah, I would just say, but it's very dependent upon the facilities out there now and then the scoping to get it up to a -- a particular level?

THE WITNESS: Very dependent. Yes.

COMMISSIONER ENGLER: Do you know -- I think your example, again, in South Texas, if I remember right, you said it was -- there was another operator and you purchased that facility, I believe, or something like that. Is that correct?

THE WITNESS: It was a collection of facilities, multiple facilities. We acquired them from another operator.

COMMISSIONER ENGLER: So just -- I'm sorry, go ahead.

THE WITNESS: We purchased them. I'm sorry, I just wanted to be clear how it shook out.

COMMISSIONER ENGLER: So for facilities that are Devon owned and operated now, do you have a feel, you know, how much, again, that scope or how much you would need to do to bring them to compliance?

THE WITNESS: So when we say the scope of compliance, are we talking about this rule, the OCD rule?

COMMISSIONER ENGLER: Yes.

THE WITNESS: From an equipment installation standpoint, I think the impact would be not very significant. Again, a lot of works goes into the scope, but I would not be too concerned about the scope of any retrofitting or fit. I think for this, the way this mostly concerns me is the reporting requirements. But the scope retrofit I'm not too concerned about.

COMMISSIONER ENGLER: So let me switch over, you know, there is this un -- what do you call it -- uncontrolled tanks, I guess is that they call it.

THE WITNESS: Yes.

COMMISSIONER ENGLER: I've never heard that term, but that's okay. What's the parameters on your design between an uncontrolled tank and then in situations where you do put a VRU and have a controlled tank situation?

THE WITNESS: So for me I would look at the rules given by the air permit. That's what would determine whether I have controlled or uncontrolled tanks. I will say that we don't have a -- I don't -- on new construction, which is what, most of what I do these days, we don't put in uncontrolled tanks. We, we combust, so I'm very unfamiliar with installing uncontrolled tanks.

COMMISSIONER ENGLER: So in your figure, if I refer to your Figure G2, that's your process diagram.

THE WITNESS: Yes.

COMMISSIONER ENGLER: So in that diagram you've got tanks, and it looks to me like you've got it going to flare stacks. So this would be kind of a design that I would see or Devon would do in terms of controlling -- uncontrolled tanks; is that correct?

THE WITNESS: Yeah, and I made this purposely not representative of Devon or really anyone. It's something that if you drove around, you might see something similar to that. But yes, that would not be a control strategy that I would consider wild.

COMMISSIONER ENGLER: I appreciate that. Thank you. No more questions.

HEARING EXAMINER ORTH: Thank you, Commissioner Engler. Madam Chair lost her connection briefly, but I believe we have her back on. Madam Chair, can you hear me?

(No audible response.)

HEARING EXAMINER ORTH: Madam Chair?

(No audible response.)

HEARING EXAMINER ORTH: Well, it did seem like she was back on, and I do see a box here that says --

CHAIRWOMAN SANDOVAL: Can you guys hear me?

HEARING EXAMINER ORTH: Ah, now we can, sure.

CHAIRWOMAN SANDOVAL: Okay. Let's see.

HEARING EXAMINER ORTH: There you are.

(No audio.)

HEARING EXAMINER ORTH: Sorry, now you're gone. Madam Chair, perhaps leave your camera off and just ask your questions through audio.

CHAIRWOMAN SANDOVAL: Can you hear me?

HEARING EXAMINER ORTH: Yes, quite clearly.

CHAIRWOMAN SANDOVAL: Okay. Maybe I will just try to keep my video off, but it keeps going in and out for me. There is literally an Xfinity truck outside my house, which basically means anything, I think, in this day and age.

All right. Sorry, Mr. Leonard, I know I -- I think I missed -- well, I just missed part of what Dr. Engler was asking, so I apologize if I repeat anything at all.

THE WITNESS: No worries.

CHAIRWOMAN SANDOVAL: And if you said this earlier during your testimony, again I apologize for that.

So you talked about, I think, 6- to 10,000 all in for retrofitting of flares. And you said that you did not have a count of how many flares Devon would need to retrofit; correct?

THE WITNESS: So the 6- to 10,000 is a little incorrect. The 6- to 10,000 cost on our current flare was that would cost to replace a pilot assembly on our current existing flare design. And if we were to do a retrofit project, that cost would be, you know, I would expect it to be that order of magnitude.

CHAIRWOMAN SANDOVAL: Okay. And just confirming what Ms. Iannuzzi said yesterday, there is not a count across New Mexico as to how many of these need to be retrofitted.

THE WITNESS: Not to my knowledge.

CHAIRWOMAN SANDOVAL: Okay. But NMOGA still believes that 24 months is the adequate time frame to retrofit flares?

THE WITNESS: That is my understanding that that's NMOGA's stance.

CHAIRWOMAN SANDOVAL: Okay. Are you familiar at all with (unclear) like how capital appropriations are done? Do you have any decisional insight from what Ms. Iannuzzi said?

THE WITNESS: Capital appropriations, can you help me -- what do you mean?

CHAIRWOMAN SANDOVAL: Like how capital planning -- so if it's going to cost 6- to 10,000 and say a company has five they need to retrofit, what Ms. Emkay (phonetic) talked about yesterday was, well, basically it's going to be at least a year before you can get that money.

THE WITNESS: I understand. So I have the luxury in my role of not being very involved in well economics. I propose solutions to challenges with that associated cost, and I get feedback from folks who do that.

CHAIRWOMAN SANDOVAL: Okay. So you talked about process modeling. I think you said trash in trash out, that's the nicer version of what I have heard or the whole group have heard. You said, you know, it's a good box to operate in for environmental permits. If a process model is good enough to be a permit for either EPA, NMED, some other state agency, why is that data not good enough for us?

THE WITNESS: So I think that, again, I will just state that the process model is very different from the calculations because they use conservative assumptions to build the box that you are guaranteeing you will operate in.

And as far as what's actually happening, that could require a lot more detail and have a variability depending on the assumptions you make. I don't want to speak to whether that's good enough or not for the Commission, I'm just saying that there is a high risk of variability and inaccuracy.

CHAIRWOMAN SANDOVAL: Right. So the model is going to predict even flow throughout the 365 days per year.

It's going to look almost the same every day, understanding that operations are not even each and every day, your flow is not even each and every day, but that it balances out and averages out over the year, do you not think that a process model would be a good average throughout the year which is essentially what I think, you know, OCD's reporting is looking for?

MR. FELDEWERT: Madam Chair, I would only interject here because I think we are talking about G.2, which is monthly reporting.

CHAIRWOMAN SANDOVAL: Okay. Let me rephrase that. For example, Colorado regulations on some situations require monthly reporting of tank emissions in that situation. That model is rerun on a monthly basis. So would something similar to that work in this scenario?

THE WITNESS: You would definitely get a number. The degree of accuracy of that number and whether that is good enough, that's a matter of opinion.

CHAIRWOMAN SANDOVAL: Other than for environmental agencies, be it federal or state; correct?

THE WITNESS: Good enough for -- representative for what's actually happening.

CHAIRWOMAN SANDOVAL: Okay, thank you. I missed this part of your conversation, but you have a slide, let's see, G5, I'm guessing you talked about pneumatic controllers since there is a picture of pneumatic controllers here.

I guess I'm just curious, did you discuss in that, in your testimony about the different types of calculations that are available to estimate the gas volumes off of that due to normal operations?

THE WITNESS: I didn't talk explicitly on that. It's my understanding, and I haven't looked in years, but it's my understanding that there are emissions factors used to evaluate the rates of those.

CHAIRWOMAN SANDOVAL: Is there -- I can't recall. I have it written down somewhere -- were you the one who I was sent to ask pneumatic questions to, or was that somebody else?

THE WITNESS: I'm probably one of people at least. I have a pretty good understanding of pneumatic devices, and I will answer anything to the best of my ability.

MR. FELDEWERT: Madam Chair, I did mention I think when you asked the question that we had David Greaves, a measurement expert.

CHAIRWOMAN SANDOVAL: Okay. All right. He is appropriate to ask them to. I will ask, and if you can't answer, that's fine. So do have you any -- I guess, do you have any expertise in what the factors are that are out there for Subpart W or any other, say, manufacturer specs or anything like that that might be associated with pneumatic devices to show how much gas is used in the actuation?

THE WITNESS: I have looked at manufacturer specifications. Some advertise a leak rate and some do not.

CHAIRWOMAN SANDOVAL: So would that leak rate be a -- would it be accurate, I guess, to use that manufacturer advertised leak rate to use in your reporting of the normal operations of a (unclear).

THE WITNESS: I think in the absence of any other numbers, I think that would be probably the one you use. But I want to comment that the actual leak rate of a pneumatic device is again a function of how often it actuates which is a function of operating conditions, and there is a degree of variability.

CHAIRWOMAN SANDOVAL: Understood, okay. I think that's all -- oh, I forgot my first normal questions here.

Do you support this rule?

THE WITNESS: Yes.

CHAIRWOMAN SANDOVAL: Do you, from your experience in this rulemaking, or previous, feel like it was a collaborative process?

THE WITNESS: I do. This is the most collaborative I have ever felt through a rulemaking, so that's my experience.

CHAIRWOMAN SANDOVAL: All right. Thank you, Mr.

Leonard.

THE WITNESS: Thank you, Madam Chair.

HEARING EXAMINER ORTH: Thank you, Madam Chair. Mr. Feldewert, do you have any follow-up with Mr. Leonard?

MR. FELDEWERT: I'm checking, Madam Hearing Officer. I do not. Thank you.

HEARING EXAMINER ORTH: All right. Thank you very much. Thank you, Mr. Leonard.

THE WITNESS: Thank you, Madam Hearing Officer.

HEARING EXAMINER ORTH: There is no reason not to excuse you, so thank you, you are excused. I see Mr. Davis on the screen. I'm wondering, Mr. Feldewert, if we can fit a break in between Mr. Leonard and Mr. Davis?

MR. FELDEWERT: I think that's a great idea.

HEARING EXAMINER ORTH: All right. Let's come back at 10. Thank you all.

(Recess taken.)

HEARING EXAMINER ORTH: Let's come back from the break, please. Mr. Feldewert, do we have you on?

MR. FELDEWERT: Yes, my colleague, Mr. Rankin, will be presenting our next witness.

HEARING EXAMINER ORTH: Thank you. Mr. Rankin, do we have you on?

MR. RANKIN: Good morning, Madam Hearing Officer. Our next witness will be Mr. Davis.

HEARING EXAMINER ORTH: All right. Would you raise your right hand, please, Mr. Davis. Do you swear or affirm that the testimony you are about to give will be the truth, the whole truth and nothing but the truth?

THE WITNESS: I do.

HEARING EXAMINER ORTH: Thank you. Go ahead Mr. Rankin.

MR. RANKIN: Thank you Madam Hearing Officer. In order to orient the Commission and Hearing Officer I will just review quickly what we are going to be addressing so you have the materials handy in front of you.

We will be referring to the NMOGA exhibit notebook Exhibits C through L, in particular, the exhibits behind tab H, so Exhibits H1 through H10. In addition, I will be putting up on the screen, if you want to have handy, NMOGA's Exhibit 2A, which are the updated modifications to Part 27.

We will also be referring to NMOGA Exhibit 2 -- rather Exhibit A, which is the NMOGA's modifications proposed to the Division's Part 27 rule. And also in order to save time, and in the interest of efficiency, we will be addressing EDF's and Climate Advocate's proposed modifications as well, so we will be referring to EDF Exhibit 4 and Climate Advocate's Exhibit 1. So I appreciate that.

JEFFREY RYAN DAVIS
(Sworn, testified as follows:)
DIRECT EXAMINATION
BY MR. RANKIN:
Q. Mr. Davis, will you please state your name for the record?
A. Yes, it's Jeffrey Ryan Davis. Last name D-a-v-i-s.
Q. By whom are you employed and in what capacity?
A. I work for Merrion Oil and Gas currently as their operations manager.
Q. And where do you reside?
A. Farmington, New Mexico.
Q. Looking at what's been marked as Exhibit H1 and H2 in the NMOGA exhibit packet, is that a complete copy of your updated resume?
A. Yes, sir, it is.
Q. Does it accurately summarize your educational background and work experience in the oil and gas industry?
A. Yes, sir.
Q. Mr. Davis, will you just briefly review for the Examiners your experience in the oil and gas industry as it pertains to production engineering, managing and overseeing liquids unloading.
A. Yes, sir. I guess I would start off, I received

my bachelor's of science in mechanical engineering from New Mexico Institute of Mining and Technology or New Mexico Tech. I spent the last 12 years working for Marrion Oil and Gas, a third generation family owned and operated oil and gas company here in Farmington.

I spent the first four years with the company as the production engineer, primarily -- primary objective there was well optimization which included artificial lift selection, lease operating expense optimization, well workover analysis, and I also supervise the field work associated with that.

Q. And are you a member of any professional groups or engineering affiliations or other types of organizations that you are a member of?

A. Yes, sir. I'm member of Society of Petroleum Engineers, American Society of Mechanical Engineers. I am also the current board president for the Independent Petroleum Association of New Mexico, or IPANM.

Q. Regarding IPANM, will you clarify for the record so it's clear, since you are the current board president, IPANM'S involvement here in terms of modifications that are being proposed by NMOGA?

A. Yes, sir. As the board president, and having other members, we have participated with NMOGA in drafting the proposed changes that are being put forward by NMOGA.

Q. So the idea was to consolidate those modifications into one set for the hearing; is that right?

A. Yes, sir.

Q. Now, Mr. Davis, your testimony will address the process known as liquids unloading at gas wells; is that correct?

A. Yes, sir, the manual liquids unloading from gas wells.

Q. And NMOGA and IPANM's proposed modifications addressing those issues?

A. Yes, sir.

Q. Now, specifically, I'm going to go ahead and just lead you to this, and then I want you to go ahead and get into the details, but you are going to be addressing NMOGA's proposed modifications, in particular at -- in Part 27, section D, Subpart -- which part is it? -- Subpart 3 which relates to requiring an operator to be present on site; is that correct?

A. That's correct.

Q. And in addition, your testimony is going to support NMOGA's and IPANM's request to delete liquid unloading from Part 27, Section 8, Paragraph G.2.E; is that correct?

A. That is correct.

Q. So Mr. Davis, in preparation for today's

testimony and in support of those proposed modifications changes, have you prepared a series of slides for our presentation today?

A. Yes, sir, I have. And they can be found in NMOGA Exhibit H.

Q. Thank you very much. Now, will you, in discussing liquids loading, Mr. Smitherman has briefly touched on it initially, but I think it's important to understand a little better the physics and the engineering behind it.

Will you please review, referring to Exhibit H4, for the Commission exactly what we are talking about here when talk about liquids loading, what the process is, what the physics are behind it and how it occurs?

A. Yes, sir. So liquids loading is a phenomenon in gas wells which is the accumulation of liquids in the wellbore. The liquid accumulation is due to the well flowing below the critical rate.

The critical rate is the gas velocity required to suspend a droplet of fluid in the flow. Gas velocity is dependent on the flow rate of the well, the flow and pressure of the well and tubing size. The gas flow rate is dependent upon the differential pressure from the reservoir to the flowing surface pressure. And one thing to note is, you know, the gas flow rate from a well decreases over time.

So real quick to illustrate the points I just mentioned, if we can move on to H4, illustrates a droplet of liquid shown with the forces that are acted upon it. The gas velocity exerts a drag force on the water droplet, the weight of that water droplet having an opposite force acting upon that droplet.

The critical rate is that point in which the droplet is suspended in the flow. Any flow below that, that point, the water or the liquid droplet is going to fall back into the reservoir.

So the key point I think from this is the gas flow rate is -- the critical velocity is dependent on the gas flow rate, and the gas flow rate is dependent upon the differential pressure from the reservoir to the flowing surface pressure.

Mr. Rankin, I believe you are muted.

Q. I was trying to take care for background noise.

Mr. Davis, if you would just review on the same slide why there are liquids in the wellbore. Explain that process here.

A. All gas wells are going to make some liquids. It could be produced water. In some cases there may be condensate for oil that is produced with the gas.

Q. And to be clear, this phenomenon, this process of liquid loading occurs just in gas wells?

A. That is correct.

Q. Now, what factors, if you would reviewing your next slide as you talk through it, would you review what are the factors that cause liquid loading to occur. You briefly touched on pressure differential issues and the fact there are liquids in the reservoir, but explain what causes over the life cycle of a well liquids loading to occur.

A. Yes, sir. So if we move to H5, this discusses the impacts of liquids loading, and figure two illustrates kind of the natural decline of a well. The red line there is showing the gas flow rate declining over time.

As we progress from the left to the right, you will see the different flow regimes that a gas flow will exhibit as that gas flow rate decreases over time.

We start off with a very steady state angular flow, and as we move to the right there, you will see that we begin to see the liquid loading phenomenon occurring where you move into more of a churn flow, slug flow, and the flow of that well becomes relatively unstable.

This makes the well difficult to operate as the gas production and fluid production are sporadic, and this makes the well more difficult to operate and requires more manual intervention.

Overall, the biggest impacts from liquid loading is it creates additional back pressure on the well and ultimately reduces the well's production performance. If liquid loading is not addressed, eventually you get all the way to the right where the hydrostatic pressure exerted from the fluid that is accumulated in the wellbore reaches equilibrium with the reservoir pressure and at that point the well is unable to flow at all.

Mr. Rankin, I think you are muted again.

Q. I'm taking too much care, I apologize. Now, to address that situation, to address the phenomenon of liquids loading in wells, what tools do operators have to, to manage the efficient production of their wells and to address the circumstance where liquids loading will essentially, as you described, prevent production from the well?

A. So we --

Q. I will ask you to refer -- well, go ahead and explain and then we can go to the next exhibit.

A. Okay. So we employ various, various artificial lift methods. Just to touch on a few that are common for gas well applications, the operator can use a surfactant or a foamer to try to lighten the density of the fluid and be able to still free flow the well and get those liquids out of the wellbore.

The operator can move to the installation of a velocity string which would be a smaller size tubing to increase that gas velocity. The operator can move into an intermittent flow configuration where the well is shut in for a period of time for the well to build pressure, and then flows at a higher production rate to ensure that that critical rate is exceeded and ensuring that liquids are removed from the wellbore.

Compression can be used for artificial lift. This would be a place where you are artificially lowering the flowing pressure of the well which would assist in increasing the gas velocity to remove liquids. And then plunger lift is probably one of the most common applications for deliquidization of gas wells.

Q. On that topic of plunger lift, let's look at your Exhibit H6, Mr. Davis. Just review briefly the elements of a plunger lift system, how it works and how they function to address liquids flowing within the well.

A. Yes, sir. If we move to H6, got a slide here kind of identifying the general components of a plunger lift system and then we'll walk through the cycle that takes place for plunger lift.

But we really want to start off, you know, all the artificial lift methods that I mentioned earlier as well as plunger lift are an engineered solution that are applied to wells on a case-by-case basis, based on the parameters of that well and the wellsite and production facility.

So for plunger lift, if we look at Figure 3 on

H6, you will see a cross section of a well to illustrate the components of a plunger lift. We have the wellbore, which is the biggest cylindrical piece in the cross section there. And there is tubing that is run down into the well.

At the bottom of the tubing you will see the bumper spring. Its purpose is to cushion the plunger during its dissent into the -- or to the bottom of the tubing.

As we move up you see the plunger. This is mechanical device that assists in lifting the liquids out the wellbore. On top of the plunger you will see liquid. This is commonly referred to as the liquid load.

And as we move back up to the surface you will see the wellhead. At the top of the wellhead is the lubricator. The lubricator has a spring in it that cushions the plunger upon arrival. As we move towards the right of the lubricator, you will see a pneumatic control valve. This can be installed at the wellhead or at the production facilities.

The purpose of the pneumatic control valve is to stop and start the flow of the well which controls the cycle of the plunger. The other key takeaways from that figure are the tubing and casing pressure. The lease operator can use the tubing and casing pressure to get an idea of how the well is doing and uses that information to optimize the cycle times that are set in the plunger lift controller.

The pneumatic control valve there is controlled by some sort of timer. My experience has been that most of those are based on time. So the lease operator will input times for the plunger to arrive, the time it takes for the plunger to descend the depth of the well and then also put in a time there for afterflow. This is the period that occurs after the plunger has arrived at the surface.

So touching on that, I think it's worth going through the cycles of a plunger. So Figure 4 shows the different plunger cycles. If we start in number one, the well is flowing, but the pneumatic control valve is open to the sales line, and the well is flowing with the lubricator or plunger held in a lubricator by the flow.

As the well is flowed, the liquids accumulate in the tubing that can be seen in two of Figure 4 where there is liquid accumulation at the bottom of the tubing. The lubricator is still -- or the plunger is still in the lubricator.

At this point after that predetermined amount of time has expired like -- or for the afterflow there, the controller would send a signal to the pneumatic control valve closing the well to sales and the plunger would begin its descent to the bottom of the tubing.

So 3 shows the plunger descending the length of the tubing. And then as we move into 4, you see that the plunger has made it to the bottom of the well, has fallen through the fluid that has accumulated at the bottom of the tubing and is awaiting the well to come back on line to bring that flow to the surface.

So on 5 we see, at this point the controller would have sent the signal to the pneumatic control valve, opening the valve, and the well is flowing to sales, and the plunger is bringing the fluid load to the surface.

The pieces that I wanted to touch on here indicated that the tubing and casing pressure are useful for the lease operator to understand how the well is performing and make adjustments.

The other key factor with plunger lift is the sales line pressure. We use a term called the load factor, which is the casing pressure minus tubing pressure, which is your fluid load, divided by casing minus the line pressure. And if this is less than .5, the plunger is going to make it to surface.

The casing minus line is really the energy available from the, from the well relative to the resistance of flow, which is the sales line pressure. So with plunger lift there is still a need to have differential pressure for the plunger to be able to lift liquids out of the well.

Q. And are there circumstances, Mr. Davis, even where operators have the plunger lift system in place that

the fluid will exceed the ability of the plunger to rise and unload those liquids?

A. So there are circumstances that impact it really on both sides of the equation there. You can have an increase in the sales line pressure, and that would keep the plunger from surfacing. And as a plunger lift system makes multiple attempts, in their failed attempts to surface that liquid accumulation compounds. So the well may not be able to lift that fluid load to the surface against the sales line pressure, and this would require intervention by the lease operator in the form of manual liquid unloading.

There is also the side of the equation where the fluid load could increase over time. Maybe the plunger is not cycling optimally and the fluid level or the fluid load is increasing over time.

As I mentioned before, the lease operator would be monitoring the production rates and case and tubing pressures should be able to identify this and proactively prevent the need for intervention. But when we look at the sales line pressure increase, a lot of times this is outside of the control of the operator and may not be something that the lease operator can circumvent ahead of time.

Q. (Inaudible.)

HEARING EXAMINER ORTH: Mr. Rankin, it's hard to hear you when you are not facing the camera.

Q. Mr. Davis, what are some of the circumstances then when those events or circumstances outside the operator's control might impact the ability of the plunger lift to unload the liquids?

A. So the increase in sales line pressure could be due to a midstream upset. There is some natural variability in the sales line pressure, but, you know, if there was an outage on the midstream side, our sales line pressure could increase. It could be a freeze in the winter that would increase that sales line pressure.

There are also, at least in my experience, situations where we have central compression, so we aggregate or surface commingle production for multiple wells and utilize a central compressor to lower the gathering pressure for those wells.

The compressor is a mechanical device and can go down for various reasons. So with that, you know, if the central compressor goes down, that could negatively impact the wells that are behind that central compressor.

Q. You used the term manual liquid unloading. Would you review briefly what that is, and then we will move into your next set of exhibits, H7, but I want to establish a basic overview of what manual liquid unloading is.

A. So manual liquids unloading is a manual intervention that an operator takes to purge the liquids that have accumulated out of a gas well, and this is done by maximizing the differential pressure.

I mentioned earlier that the gas flow rate is dependent upon the differential pressure. Manual liquids unloading is an effort to maximize the differential pressure, so the well is open to an atmospheric storage tank to maximize the differential pressure.

Q. Looking at Exhibit H7 next on your series here, explain the process in more details referring to your exhibit how that works and exactly what this (unclear)?

A. Yes, sir. So Figure 5 on H7 is a depiction of a well in normal production operation. So we see the wellbore and the wellhead there. Number 1 is the flowline from the wellhead to the production facilities. At this point we have multiphase flow, gas, water, possibly oil.

That production is sent to the production facilities where separation occurs. At this point the fluid, the water and oil are separated from the, from the gas. The oil and water go to their respective storage tanks, and the gas is metered and sent to the gas sales line.

Q. All right. Let's look at your next slide, Exhibit H8, and explain this scenario here.

A. So during the normal production operations there could be, as we have mentioned, the situations where the well accumulated liquids, the well was flowing below its critical rate or an upset condition on the midstream side and we had increase in sales line pressure.

So the lease operator is keeping an eye on the well again based on production and pressures they are seeing at the well. Once, once the lease operator is seeing that there is indications of liquids loading has occurred on that well, the lease operator will take reasonable measures to try to address that. That could include making cycle time changes on the plunger lift controller or the intermittent flow controller, could increase the surfactant amount being pumped in that well to assist with the liquid removal.

But at the point that we get to where the lease operator is unable to unload that well against the sales line pressure, we move into what we refer to as manual liquids unloading.

At this point, the lease operator -- this is really somewhat of a last resort to take, but the lease operator would open a bypass valve, and with this you can see in Figure 6 on H8 that we would be taking the production from the well -- again, Number 1 there shows this is multiphased flow, so you have gas, water and possibly oil.

That is bypassed to the atmospheric storage tank on the location, and your bypassing separation multiphase flow sent to the tank, then your tank becomes the point at which you have separation. Your liquids fall out in the tank and the gas is released to atmosphere.

And the purpose of this, as I mentioned before, is to maximize the differential pressure to assist in purging the liquids out of the wellbore.

The points I wanted to make here, I think, related to the reporting requirements are measurement is very difficult during manual liquids unloading.

You have multiphased flow. If you attempt to measure the production prior to the storage tank that would -- there are challenges with multiphase flow measurement.

I have had a little bit of experience with that, but we have someone coming up later that I think can get into more details on the challenges of multiphase flow measurement.

And then once the gas, once the production has reached the storage tank, this is a low pressure point of release and measurement is difficult there.

Q. Mr. Davis, I want to go back to touch on a couple points in your testimony here. Number one, you testified that this phenomenon of liquids loading and then is related to -- only occurs in gas wells; correct?

A. Correct.

Q. So what is the -- what is the primary, you know,

commodity that's being sold from those wells?
A. Natural gas.
Q. So is there any benefit to, to operators to, to release more volumes of gas than is necessary to manage the efficient operations from a well?
A. No, sir. As you mentioned, that is the commodity that we are selling, so it is our, it is an incentive by the operator to maximize the amount of sales. So minimizing the amount that is utilized for this necessary and beneficial use is definitely something that we take into account.
Q. Is that why you testified it's a last resort? Is that why it's a last resort?
A. Absolutely.
Q. Okay. Now, so I understand, your exhibits here went through a couple of different types of wells. Is manual liquids unloading necessary at times whether a well is equipped with a plunger lift system or not?
A. Yes, sir. As I mentioned before, when we look at the load factor when operating a plunger lift, the sales line pressure is a factor there on whether that plunger can surface, and so there are instances where a plunger is unable to run against the sales line pressure and there is a need to manually unload that well.
Q. So you used, in your testimony you used two terms I want to dig down deeper on. Number one, you said that the

process of manual liquids unloading is necessary at times. Will you just explain a little bit more about why it's necessary at times to employ this process.

A. Yes, I think I touched on this with H5 as we look at the flow regimes that a gas well will go through. And as I mentioned there, if liquids loading is not addressed, you will eventually get to a point where that well will cease to flow and become unproductive. So this is necessary to ensure that we can get wells back flowing to sales in a quick and efficient manner.

Q. Are there are other methods that an operator can employ to unload those liquids?

A. There are some proactive approaches as I mentioned before in terms of optimizing that well ahead of time. Once we get to a point that we are considering manual liquids unloading, as I mentioned, this is somewhat of a last resort, there are -- if the liquids loading has gotten to a point where we are unable to unloaded the well via manual liquids unloading, we do have the ability to move in a swab rig and go in -- John Smitherman covered this in his testimony, but this would be another way to mechanically remove the liquids, so we would swab the liquids from the well.

At this point the well would need to be open to the storage tank. The volumes of gas would be similar, if not more than what a manual liquid unloading in that would release.

Q. The other term that you used, Mr. Davis, was, I think, you phrased was beneficial use. Will you explain what you mean by beneficial use that manual liquids unloading has beneficial use?

A. Yes, sir. So utilizing the gas to purge liquids, again by maximizing the differential pressure and utilizing the gas from the well to purge those liquids, this is of benefit to return this well to normal production operations.

Q. So then going back to Exhibit H8, when you refer to the different elements of this exhibit, will you explain, by referring to this exhibit, whether there is any way that it's possible in this process to capture the gas that would be lost to the atmosphere during the unloading process?

A. So I think some of this has been covered previously, but we are taking this, this flow to an atmospheric storage tank. Mr. Leonard testified earlier that our tanks are rated for maximum operating pressure of about 16 ounces, which is one psi, and that's maximum.

So being able to recover this would be difficult. The flow from a manual liquids unloading event are transient and sporadic, so we've got high rate, high pressure initially falling off over a very quick time. So capturing those volumes at the storage tank would be very difficult

Q. And aside from the challenges inherent in attempting to capture that gas, are there other considerations that would impact your decision to try to do so? In other words, there is a -- we talked about the need for achieving a maximum differential pressure, would there be some considerations in that process to being able to achieve that if you were trying to also capture that gas? How does that work?

A. Yes, sir. I think an attempt to capture that would create additional back pressure, and again the goal here is to maximize that differential pressure. That same principle applies in terms of measurement, you know, any attempt to try to measure back volume is going to increase the back pressure, and the goal is to maximize the differential pressure.

Q. So I think with that background, I think we can move into what we are proposing here, what NMOGA is proposing in the modifications. So I want to first ask you -- I'm going to ask -- I guess I can already do it.

I'm going to put up on my screen here NMOGA's proposed modifications. Mr. Davis, if you just confirm for me that you can see my screen.

A. I can.

Q. Great. This is Page 8 of NMOGA's Exhibit A, which addresses the Part 27, Section 8, Paragraph b -- b as

in boy. If you would just review the part of this modification that you are addressing here, which is in the the red, includes red language.

A. Okay. So there on D.3 little b, NMOGA is proposing to add or in close proximity. The little b, 3.b there reads, "For liquids unloading by manual purging the operator remains present on site."

NMOGA's edition is, "or in close proximity" until the end of the loading, takes.

We struck "all" in both cases there, reasonable action to achieve stabilized rate and pressure at the earliest practical time, and takes reasonable, and struck "all" in that instance there as well, to minimize venting to the maximum extent practical.

Q. So let's just break this down a little. You've asked -- NMOGA's proposal is to add "or in close proximity." What does that mean? We heard some testimony, some questions around this in terms of what -- you know, how do you measure that? And what does that really mean?

A. So for close proximity I guess I would start with the necessity for this change, and I prepared Exhibit H9 to illustrate the need for this flexibility. NMOGA believes that the proposed change that we made allows for flexibility that's necessary.

So if we go to H9 you will see I've got an illustration of a central delivery point. Again, I mentioned this earlier where this is primarily from my experience in the San Juan Basin where you would start to commingle the production from multiple wells and bring it to a central compressor.

The issues that we discussed earlier or the situations we discussed earlier related to upsets either on the midstream side or, in this case, where we have a central compressor, that could impact multiple wells behind it. And this is a primary concern in the winter where we have more instances of outside conditions due to the freezing weather. The lease operator when he goes out to the field, because there is an outside condition or has noticed his well is behind a central delivery point or CPD has dropped off, he is going to go out there and evaluate the situation.

And, you know, the the first step is going to be the compressor to see if it's running or not. It may have been knocked down due to the high sales line pressure or may have gone down for mechanical reasons on its own.

From there the lease operator would move into the field and assess the conditions of the wells that are behind it. In a lot of instances, depending on the duration of this upset, the lease operator could have multiple wells behind that central compressor that have loaded up with liquid.

So the lease operator would assess the situation, figure out the best course of action to bring all of the wells on line and the compressor. So the lease operator has a lot of responsibilities there to get everything stabilized in terms of the rate and pressure on that system.

So in the instance where a well may take multiple hours to unload, if that lease operator were to remain onsite that entire time, he would not be able to balance his other responsibilities.

The central compressor, there is a key point there to be made, that once the lease operator has that central compressor back up and running, he must maintain enough gas on the system to keep it running. So when I refer to balancing his responsibilities, that's what I'm referring to.

The lease operator would go to the wells, begin the unloading process, and the lease operator knows the wells very well, would know the approximate time that it takes for that well to unload, and then would move systematically back through the field ensuring there is plenty of gas on the system and addressing the other wells that are behind that central compressor.

So the proposed change there for close proximity really is, is necessary where we've got central compression and multiple wells behind that central compressor.

Q. And just to be clear, this example here is an illustration, not an illustration, but it's based on a real-world setup; is that right?

A. Yes, sir. This is a CPD that we have operated in the past and illustrates that somewhat difficult configuration that exists in the San Juan Basin.

Q. Now, I would like you, Mr. Davis, to run through using the same map or illustration, if you would, the scenario where the operator is not afforded that flexibility to remain in close proximity, but instead, under the Division's proposal must remain onsite.

Tell me a little bit more about how that would impact his ability to balance his obligations and responsibilities to maintain the central pressure facility as well as manage and efficiently operate the other wells in the same field.

A. Okay. I guess I would first off state that, you know, one of the things to consider in the proposal that we made is leaving that remains on, remains present onsite, I would say that that is the operator's desire is to remain onsite, especially if the unloading event would be in a short period of time.

Really the only reason that this change is necessary is where the time for that well to unload is, is, you know, hours versus, you know, 15 or 20 minutes.

So in an instance where the rule goes through as proposed by the Division, the lease operator can go out to this set of wells that are illustrated on H9, and instead of being able to return the -- all of the wells to normal operating conditions quickly and efficiently, the lease operator could ultimately end up spending most of his time on one or two wells just to perform those manual liquid unloading operations.

Q. One thing I want to touch on, I think you did a little bit, but I want to understand that when an operator responds to an event, an upset of some kind and trying to figure out what's happening and how best to manage and respond, walk through a little bit about what exactly some of the, in more detail, what the operator is looking at, looking for, to understand what some of the factors are or maybe needs a liquid unloading and understands how it's impacting it's wells and how long it would take for those wells to unload. Explain a little bit more what the factors are specifically that you might be looking for when he arrived onsite?

A. So as I mentioned before, the lease operator knows these wells as he is the one that's operating them and monitoring them on a regular basis.

So the lease operator is going to look at the current condition of the well in terms of the pressures, tubing versus casing, and that relative to the line pressure that exists. Compare that to his normal operating pressures and taking into account the well's normal production in terms of gas and liquid, and based on that and his past experience with that well is able to determine the amount of time that that well is going to take to unload with a manual liquids unloading operation.

Q. So some of the factors that lease operators may be variable in terms of how long the upset lasted and existed, or other, how deep the well is, so some of those factors might be variable; is that correct?

A. That is correct. Yes. The duration of the upset is probably one of the most important variables there. We, we'd like to respond as quickly as possible, but sometimes in the winter with winter conditions and the workload of the lease operators, we may not be able to get out there immediately. And so the duration that the upset condition occurred definitely is the biggest factor in how long the well is going to take to unload.

Q. So just, so in assessing those variables, explain then so I'm clear -- I think you touched on it a little bit, but so I'm clear, how does the lease operator weigh the variables to determine -- you talked about the lease operator knowing their well and knowing the production, and how does the operator take those variable factors to

determine the time frame?

A. So the lease operator is going to prioritize their time in the field, and I know we keep harping on winter, but winter we've got shorter days, but the lease operator is going to prioritize his time while he is out there and look at the wells looking at the factors that we just mentioned and developing a game plan to quickly and efficiently bring that entire set of wells back on line.

So that coupled with the responsibilities of restarting and keeping the central compressor running becomes a little bit of a balancing act to ensure that the lease operator is able to get all of that back on line before he returns from the field that day.

Q. So based on what you have testified to, Mr. Davis, is it your opinion that NMOGA's proposed modification would allow operators to get more wells back on line with more gas going back to sales more quickly and efficiently than OCD's proposal?

A. Yes, sir.

Q. Now I'm going to talk a little bit about some of the other parties' proposed modifications, bring them up on the screen here momentarily, but have you had a chance to review both EDF and the -- I'm going to call them Climate Advocates, that group's -- their proposed modifications in the rule pertaining to this portion of the Division's

proposed rule?

A. Yes, sir.

Q. Now, are those groups proposing, I'm going to say essentially, but I think they are identical modifications to the Division's rule?

A. I believe you are correct there.

Q. I'm going to go ahead and pull up EDF's proposed modifications to this portion of the rule. Let me know when you can see that on the screen.

A. I can see it.

Q. So just in summary, Mr. Davis, what is it -- it looks like there are essentially two significant changes. What are the two modifications that EDF and Climate Advocates are proposing to what the Division has offered?

A. So the first one under D.3 there is they moved what -- sorry, I'm going back on the -- so they have moved what used to be D, I believe --

Q. They deleted --

A. I'm sorry, I had to look at OCD's. So they moved "c" of the Division's proposal up into "a" and modified it to read, "The operator" -- so I guess backing up to D.3 there -- "to unload or clean-up liquid holdup in a well to atmospheric pressure, provided," and they moved "c," the Division's proposed "c" up into "a," and it reads, "the operator uses an automated control system such as plunger lift where technically feasible and optimizes the system to minimize venting of natural gas."

I believe the Division's intent when it was originally proposed as D.3 little c was to encourage operators to optimize their plunger lift systems prior to, or parallel to utilizing manual liquids unloading.

With this change here it seems to move that up and indicate that manual liquids unloading would only be an option if the operator utilizes an automated control system such as plunger lift.

The second change is regarding prior notification. So they have added D.3 little e, which is the notification to the Division, prior to conducting unloading of wells, it proposes 48 hours prior or as soon as possible.

We definitely had some concerns with this just in terms of the feasibility of doing this. Most of the time the lease operator is going out to the field and assessing the conditions does not necessarily know that a manual liquids unloading event is necessary until he gets out to the field.

So being able to provide prior notice could be very difficult especially in the areas where well locations are not in an area where there is cell phone service for that lease operator to relay the need to perform manual liquids unloading.

I also have concerns on how this would ultimately reduce the volumes released by notifying the Division.

Q. Okay. I'm going to step back and talk about each of those proposed changes and a little bit more about the concerns quickly.

As to the first or first category of changes (unclear) that EDF and Climate Advocates delete what the Division had proposed, is that right, on the plunger lift system?

A. Correct. Deleted it and moved some of it into what they are proposing as D.3 little a.

Q. Is it clear based on the language that the parties are proposing what is actually going to be required of an operator in order to perform manual unloading, in your view?

A. I thought this was definitely less clear than how the Division had proposed it. As I mentioned before, had some concerns that this could potentially indicate that we need to install plunger lift before we can perform manual liquids unloading on a well.

Q. In other words, it's not clear whether you can even proceed to manual liquids unloading prior to retrofit a well with a plunger lift system. Is that your understanding?

A. That's my understanding.

Q. So tell me -- I want to kind of dig into that a little bit more. What would be the problem with mandating or requiring an operator to install plunger lift in order to first perform manual liquids unloading. What are the problems with imposing that requirement?

A. So I guess, just in kind of simple terms, I would say one size doesn't fit all. Plunger lift is not the one-size-fits-all type artificial lift method. I mentioned earlier there are various other artificial list techniques that operators will take. So in this instance, I don't think that prescribing a specific artificial lift method is appropriate.

Q. So the operator should retain some ability to determine the best method of production in a given set of circumstances. Is that your opinion?

A. Yes, sir. As I mentioned before, artificial lift application is, is an engineered solution, and it is evaluated on a case-by-case basis based on individual well parameters.

Q. What happens to the wells that aren't good candidates are for plunger lift systems if this rule is adopted as proposed. Would they be not permitted to undergo manual liquids unloading?

A. I think that's definitely a concern. To speak directly to my experience, we have some slim hole completions in the San Juan Basin that we absolutely could not, and I know it does say that if it's technically feasible, but so that there are some wells that plunger lift would not be possible.

For some instances it may be technically possible, but the installation of plunger lift may not be the best solution to optimize the production for that well. So this could be a misapplication of this artificial lift method.

Q. Okay. Your understanding of the way the Division proposed this rule, it didn't impose any limitations or restrictions on operators requiring them to utilize a plunger lift system or an artificial lift system?

A. That's correct.

Q. And do you agree with the Division's decision to give the operators flexibility to determine the appropriate mechanism for the operators to develop their own wells?

A. That is correct. We support what Division proposed with the edition of the changes that we have put forth.

Q. Now, I want to talk about the next set of changes we talked about a little bit here, which is the requirement to give 48 hours. I think you covered that pretty well. Are there circumstance -- is it always going to be possible for operators to provide that 48 hours' notice in advance?

A. No. As I mentioned before, most times the lease operator is not going to know ahead of time that manual liquids unloading is necessary, specifically in an event where we had an upset condition that has occurred that led to those wells loading up.

So just from that standpoint the lease operator is not going to know until he arrives on that location. So giving prior, specifically the 48-hour notice, would be very challenging.

And in some instances, you know, the lease operator may be in an area where he does not have cell coverage and would have to leave that area of his run to be able to relay the need for performing manual liquids unloading and then return back to the field to perform that manual liquids unloading.

We touched on it a little bit, but without, without a -- without -- or I guess I don't see how the notification would lead to any reductions in the volume released. So it seems overly burdensome for our field operations without a lot of -- without any reductions in the volume released.

Q. And I think you mentioned that these operators, they have a, this is commodity that they are selling, are they incentivized in any way to limit the volumes that are being released?

A. Absolutely. They want to put as much gas in sales as possible.

Q. In your opinion, Mr. Davis, will NMOGA's proposed modifications reduce unnecessary and excessive burdens on operators -- what did I say? Let me rephrase that question because I'm not sure -- In your opinion, will NMOGA's proposed modifications reduce unnecessary or excessive surface waste without beneficial use?

A. Sorry, Mr. Rankin, can you repeat that again?

Q. Yeah, I think I mangled it twice in a row, so let me try it another way. In your opinion, Mr. Davis, do NMOGA's revisions are offers to achieve the goal of reducing surface waste without imposing undue or unnecessary burdens on the operations?

A. Yes, I do.

Q. In your opinion, do NMOGA's proposed modifications give operators necessary flexibility to operate their wells in an efficient and effective manner?

A. Absolutely.

Q. And you ask that the Division reject EDF and Climate Advocate's proposal as to this section of the proposed rule?

A. Yes.

Q. Mr. Davis, were Exhibits H1 through H10 prepared by you?

A. Yes, sir, they were.

MR. RANKIN: Madam Hearing Officer, I would move the admission of H1 through H10.

HEARING EXAMINER ORTH: Let me pause for a moment to see if there are any objections to the admission of NMOGA H1 through H10.

(No audible response.)

HEARING EXAMINER ORTH: Exhibits H1 through H10 are admitted.

(Exhibits H1 through H10 admitted.)

MR. RANKIN: Thank you. No further questions, and pass the witness for questions by others.

HEARING EXAMINER ORTH: Thank you. Mr. Ames, do you have questions of Mr. Davis?

MR. AMES: Yes, I do have a few questions for Mr. Davis.

CROSS-EXAMINATION

BY MR. AMES:

Q. Good morning, Mr. Davis.

A. Good morning, Mr. Ames.

Q. So you testified that manual liquids unloading is necessary at times; correct?

A. That is correct.

Q. And what we are talking about here is the prohibition of venting and flaring in 8.A, and Section

8.D.2(c) provides an exemption for venting and flaring during manual liquids unloading; correct?

A. That is correct.

Q. And the issue here is that 8.D.2(c) put some conditions on that exemption; is that right?

A. That is correct.

Q. So the question for the Commission, I ask you, is not whether the emissions during manual liquids unloading is necessary, but whether such emissions are necessary, whether such -- let me see. It's not whether manual liquids loading is necessary or not, it's whether the emissions during manual liquids unloading is necessary or excessive; correct?

A. Correct.

Q. Okay. So let's talk about close proximity. How far away from a wellsite during manual liquids unloading can the operator be?

A. That's -- that's a good question, Mr. Ames. You know, I would refer back to the example that I provided. The scale wasn't on there, but you can draw a mile-and-a-half radius from the central compressor and that encompasses all the wells that are behind that central compressor. And this is based on my experience, the lease operator would be within that mile-and-a-half radius which equates to the lease operator being within 30 minutes of the well at any given time.

Q. Could it be greater than a mile and a half?

A. It could be greater.

Q. Could it be greater than five miles?

A. I would be speculating there. I would say, based on my experience, we don't have anything greater than five miles, but it is possible that there are other operators that have, you know, larger central facilities.

Q. Greater than ten miles?

A. I would be speculating on that.

Q. Okay. But the bottom line is, close proximity doesn't really have any limitation on how far away an operator can be while the well is undergoing manual liquids unloading; is that right?

A. That is correct. I mean, in my mind I would, you know, define that as the lease operator is staying in the area of that well. I know there are no necessary bounds to that, but, you know, within that system of wells before he heads back in. He is not going to leave that area.

Q. Okay. Not going to leave that area. Okay. So you said that a well that's undergoing manual liquids unloading could take hours to unload based on your experience; is that right?

A. That is correct.

Q. And so it's your testimony or it's your opinion

that an operator is going to stay within a few miles of that well during the entire time that it takes to unload that well?

A. Yes. Referring back to the example I gave, you know, if the lease operator went to Well A, began the liquid unloading operation, he may run to the compressor station and check on the pressures on the system, run back to Well A, check on it, run over to Well B, but again the close proximity is that he is in that area and periodically checking back in on the status of that well, checking pressures and ensuring that he can redirect that well to normal production operations and the gas to sales as soon as possible.

Q. So you testified that an operator may not know that a well requires manual liquids unloading before the operator gets to the site -- you also referred to it as ahead of time -- so before they get to the site they are not going to know is your point; right?

A. In the instance where the lease operator is responding to an upset condition, he may have an idea that wells are going to require manual liquids unloading, but that is confirmed upon his arrival at the site.

Q. You said that sometimes the operator may not have cell service out there and then have to go back in range in order to call for help to get the job done; is that right?

A. That is correct.

Q. My question for you then is, if an operator or the personnel of the operator calls to do the unloading gets to the site say late in the afternoon, it's an upset, they have to respond, right, and they, they know from experience that unloading, based on their analysis of the situation, that the unloading is going to take hours, are they going to stick around that site for the entire time it takes to unload that well?

A. It definitely depends on the situation. You know, the lease operator may choose, and I mean this is something that the lease operator would evaluate in the field, but may choose to shut that well in overnight if he has enough gas on the system to run the compressor.

This is a situation in the winter where it's important to keep things moving, keep gas flowing. So it really depends on the situation. He could shut it in and return in the morning to ensure he has plenty of time to do that, but if that volume is necessary to keep the compressor running, he may stay there until that liquid unloading event has concluded.

Q. I really appreciate your answer on this one. If I understand correctly, in the winter, an operator may not want to shut in the well, may want to continue with the liquids unloading, but it's the winter, it's, it's after

dark. Nothing in your close proximity language says that the operator can't go back to town, does it?

A. No, but I believe that's implied with the close proximity that he's not -- I know it's been previously mentioned that you can be in close proximity depending on what you are considering relative, but the intent from, from our side was would not return to town. He would stay in that area until that event concluded.

Q. So I appreciate that it was your intent that close proximity means something within five to ten miles or whatever it might be, but there is actually nothing in that language that says what an operator has to do. The operator gets to decide what close proximity is; right?

A. Correct.

Q. So how do we -- you know, I have a question for you about how OCD is going to enforce this. I'm not asking you to speculate, you know, as an operator you had to deal with enforcement issues with the district office, I assume, at some level, right? You are familiar with enforcement in general. Is that fair to say?

A. In general.

Q. So let's say an inspector goes to a site as the well is unloading and there is nobody in sight. Can't see anyone for as far as he can see, which might be a couple of miles given the hills and so forth. And so he sticks around

for a while and nobody shows up. So OCD cites the operator, and the operator responds the operator was nearby, they were in close proximity. Close proximity is essentially a trump card, isn't it?

A. I see your point that you are making there. I mean, I think, from my experience, what we are asking for is some flexibility with the remains on site. But I do see your point.

Q. I appreciate that. So you're aware that the BLM and Colorado have both adopted rules requiring that operators have to be on site during manual liquids unloading; right?

A. I am.

Q. And so operators on federal land and operators in Colorado, also in the San Juan Basin, have to comply with an on site rule, too; right?

A. It's my understanding on Colorado that is correct. My understanding on BLM is the requirement to remain on site was in the venting and flaring rule that was vacated by a filing in district court.

Q. Good point, but it was in the BLM rule?

A. That is correct.

Q. Thank you, Mr. Ryan. Appreciate your time.

A. Yes, sir, thank you.

HEARING EXAMINER ORTH: Thank you, Mr. Ames. Mr.

Biernoff, do you questions of Mr. Davis?

MR. BIERNOFF: Madam Hearing Officer, I do not have any questions for Mr. Davis.

HEARING EXAMINER ORTH: Thank you. Mr. Baake or Ms. Fox, do you have questions of Mr. Davis?

MS. FOX: No, we do not, Madam Hearing Officer.

HEARING EXAMINER ORTH: Thank you, Ms. Fox. And Ms. Paranhos?

MS. PARANHOS: Thank you, I have no questions for this witness.

HEARING EXAMINER ORTH: Commissioner Engler, do you have questions of Mr. Davis?

COMMISSIONER ENGLER: Yes, I do. Good morning, Mr. Davis.

THE WITNESS: Good morning, Commissioner Engler.

COMMISSIONER ENGLER: Let me start off, I appreciate you have a little bit of theoretical diagrams in your H4. I will not ask you what the differential equations are for that. I will assume that you learned those in the past. All right. I really want to focus on your Figure H9.

THE WITNESS: Okay.

COMMISSIONER ENGLER: And of course the discussion in question is this term close proximity. And I believe I heard you say for your H9, it follows roughly, for your central delivery point, about a mile and a half radius from that would be what encompasses these wells; is that correct.

THE WITNESS: That is correct.

COMMISSIONER ENGLER: Which is roughly, probably several, several sections, I guess is really what's included in that; is that correct?

THE WITNESS: Yes.

COMMISSIONER ENGLER: I noticed that your diagram -- so we are talking about manual unloading and having an upset particularly in your central delivery point. In your example here, you have multiple lift systems. Can you describe how that impacts this, this concept of manual unloading and getting everything balanced?

THE WITNESS: Yes, sir. So on there we've got some wells that are on rod pump, there is at least one free flowing well on there, and then the others are plunger lift.

So balancing the gas on the system entails ensuring there is a steady flow of gas to the compressor station. Once the lease operator has restarted the central compressor, he needs to ensure that there is plenty of gas on the system to keep that compressor running.

So balancing the intermittent flow from the plunger lift wells, the free-flowing wells and the rod pump wells is what he is looking at there to ensure adequate gas on the system.

COMMISSIONER ENGLER: So would it be safe to say, it's a flowing gas well, I assume it would be a flowing well would be the first and primary responsibility and then work from there?

THE WITNESS: Yeah, that's probably the largest steady flow that he could resecure for the operation of the system. So, yeah, I would say you are correct.

COMMISSIONER ENGLER: In your experience -- well, just one example, but the question is, is this close proximity. Again, it's rather vague. And so I guess what I want to get to is, in your example it's about upset and central delivery point. Do you have, in your experience, an idea just for your central delivery points roughly, besides this example, what would be the proximity of all the wells that would go to a given central delivery point?

THE WITNESS: In terms of time, is that what you are referring to?

COMMISSIONER ENGLER: Well, the thing about close proximity it could be time and/or distance.

THE WITNESS: Correct.

COMMISSIONER ENGLER: I guess what I'm trying to get to is, is an idea of, of whether -- how, how vast are the number of wells in terms of a given central delivery point, on average?

THE WITNESS: So I would be speculating on that.

I mean, I can talk from my experience. One thing that I failed to mention here is one of the reasons that we selected close proximity is that is the language that was proposed in NMED's rule, so we thought it would be consistent with the language there.

But in terms of my experience, most of our wells are going to be within three miles of the central delivery point, specific to New Mexico, anyway.

COMMISSIONER ENGLER: Has NMOGA done any type of review or analysis to see -- well, let's just take in your area, San Juan Basin, you know, roughly this -- the distances in the number of wells to a central delivery point and then roughly an idea of time and distance.

THE WITNESS: I'm not aware of such analysis, so I couldn't speak to it anyways.

COMMISSIONER ENGLER: So but for your experience, again, you know, you are saying this mile-and-a-half radius and roughly 30 minutes is representative of what you're aware of in your experience; is that correct.

THE WITNESS: That is correct.

COMMISSIONER ENGLER: I have no other questions. Thank you.

THE WITNESS: Thank you, Mr. Engler.

HEARING EXAMINER ORTH: Thank you. Commissioner Kessler, do you have questions of Mr. Davis?

COMMISSIONER KESSLER: Thank you. Good morning, Mr. Davis. Thank you for your presentation, it was helpful testimony. I know that you mentioned in the field there are issues with cell phone accessibility, et cetera, but I'm wondering if it would be useful if the edition for close proximity would also be, and post immediate contact information for operator on site. Is that something that NMOGA would be open to?

THE WITNESS: I can speak from my experience and for my company, I don't think we would have an issue with that at all. In fact, I think it does address the issue that Mr. Ames brought up earlier about enforcement there. I think that could be helpful in allowing an inspector to contact that lease operator and ensure that he is in close proximity during that event.

COMMISSIONER KESSLER: (Inaudible.)

HEARING EXAMINER ORTH: We couldn't hear any of that.

CHAIRWOMAN SANDOVAL: I think when you turn your head, the mic doesn't pick it up very well.

COMMISSIONER KESSLER: That might be it. Is this any better?

THE WITNESS: Yes.

COMMISSIONER KESSLER: Mr. Ames' point was a really good one and I want to make sure this provision is enforceable to have the operator nearby. So I think that there needs to be some additional parameters on close proximity, but, you know, I think that's hard to nail down.

So potentially providing contact information on, like posted to the location would be a way around, a way to refine close proximity in this provision. Do you agree?

THE WITNESS: Commissioner Kessler, I do, I appreciate your, your question along those lines.

COMMISSIONER KESSLER: Okay. That's all I have. Thank you.

THE WITNESS: Thank you.

HEARING EXAMINER ORTH: Thank you. Madam Chair?

CHAIRWOMAN SANDOVAL: I just have a couple of questions. I don't want to keep beating this issue, but -- so Commissioner Kessler, had, I think, a potential proposed solution to the language for close proximity.

Are there any other potential solutions that NMOGA has come up with since proposing this language initially?

THE WITNESS: No, not that I'm aware of. I do appreciate Commissioner Kessler's proposed solution there. I do think that's one way to address at least the enforcement side of it. So I do appreciate that because I do think that's a way to address what we were trying to achieve.

CHAIRWOMAN SANDOVAL: But you, off the top of your head, or NMOGA hasn't come up with any other solution?

THE WITNESS: I would say we've kicked around ideas, but it's difficult to put, you know, any bounds on the close proximity in terms of time or distance as there is a lot of variability in the field.

But, yeah, I would say we don't have any solution at this point to try to address the bounding of close proximity.

CHAIRWOMAN SANDOVAL: Okay. I think also in this same section in 3 b, NMOGA's approaching to strike the words "all." It says all reasonable actions as currently written, and NMOGA's proposing to strike the word "all." Can you just elaborate a little bit more on why all, or I guess why NMOGA thinks that word should be stricken?

THE WITNESS: Yes. So I would say that all is pretty strong and that there were concerns that that could be interpreted to include nonroutine and possibly experimental actions that are beyond the intention of what I think the Division intended there.

CHAIRWOMAN SANDOVAL: Do you think that leaving it with reasonable actions would, I guess, cover enough? Does that make sense?

THE WITNESS: I do, at least from my perspective. And I touched a little bit on this in my testimony, but you know, the operator is incentivized to minimize the volume vented and maximize the volume sent to sales. So the lease operator is going to take the reasonable action necessary and is incentivized to do so.

CHAIRWOMAN SANDOVAL: Were you -- or were you around or did you review any of the questions I had for Mr. Smitherman around, I think -- or previous witnesses -- around prudent operators and how that is a little fuzzy?

THE WITNESS: Yes, I would say I was in and out, but I believe I caught enough of it to, to know where you are going with the prudent operator.

CHAIRWOMAN SANDOVAL: I mean, would you be surprised to hear that operators who operate gas wells have vented gas inappropriately even though that's what makes them money because it was more convenient for them?

THE WITNESS: I guess I would say I'm not necessarily surprised, but it is outside of my experience. You know, I would say that I work for a prudent company, and that's not the way that we operate.

CHAIRWOMAN SANDOVAL: But do you understand how there has to be some real balance of not over-regulating things to regulate and bound all the non-prudent operators and let the prudent -- there has to be some sort of balance of the regulation. Do you understand that?

THE WITNESS: I do, and I appreciate that to some degree. I definitely have concerns that you could create regulation that is overly burdensome trying to capture every instance of an operator not acting in a prudent manner.

So I do have concerns about that, but I do appreciate what you are stating there in terms of balancing that regulation.

CHAIRWOMAN SANDOVAL: On -- well, sort of moving off of close proximity and that specific question right there, out of curiosity, what's the cost of adding a plunger system? Is there an average?

THE WITNESS: I would be guesstimating. It definitely depends on the existing equipment on the well, the size of the tubing, et cetera. But I would say for, for Marrion Oil and Gas, an average cost would be 6- to $8,000 with equipment costs. There could be additional labor for slick line work to go in and evaluate the tubing condition, you know, set downhole equipment. So I would say, all in, 10 to $12,000.

CHAIRWOMAN SANDOVAL: Okay. So not an insignificant cost?

THE WITNESS: Correct.

CHAIRWOMAN SANDOVAL: What types of wells are these plungers or so usually put on? Are they typically the wells in this rule that are classified -- I guess we have been terming them as regular wells or stripper wells or both well types?

THE WITNESS: I would say both well types. You know, all wells eventually require, you know, some type of artificial lift as the gas rate declines over time. You know, newer gas wells, you are probably not going to see plunger lift installations, but as that well declines over time, you may see that.

So it really is well-dependent. It depends on the flowing pressure, the flowing rate of the well, but I think you would see them on both stripper and non-stripper wells.

CHAIRWOMAN SANDOVAL: For stripper wells, could that be pretty cost prohibitive, that 10- to 12,000?

THE WITNESS: It could be depending on the well's, you know, economics. I think this has been touched on a little bit. But our lease operating expenses depend on the disposal cost of water, how much water the well makes, whether we have compression, various things like that, but it could be cost prohibitive on stripper wells.

CHAIRWOMAN SANDOVAL: Thank you. On I think Climate Advocates proposed E, it said 48 hour notification, and I think you talked about this some. I guess, from your perspective, what, what is gained by that provision?

THE WITNESS: To be honest, I don't see what is gained there. I think it puts burden both on the operator and the Division, and I do not see how there would be any reduction associated in terms of volume released due to that prior notification.

CHAIRWOMAN SANDOVAL: So you don't see how that additional provision would prevent waste?

THE WITNESS: I do not.

CHAIRWOMAN SANDOVAL: Okay. I think that's -- oh, I have my two questions for you. Do you support this rule? Or proposed rule, sorry.

THE WITNESS: I support the proposed rule with the modifications that have been proposed by NMOGA and IPANM.

CHAIRWOMAN SANDOVAL: Do you, from your previous experience with this regulation believe it was a collaborative process?

THE WITNESS: I do, with a couple of caveats. I would say that I haven't been experienced with rulemaking much in the past, but I would say it was a collaborative effort based on a first-time experience. But I think I would be remiss in not mentioning some concerns I had in the methane advisory panel.

This was an assembly of technical experts from various stakeholders. There was concerns that not all stakeholders provided technical expertise during that process. But overall, there definitely was a lot of collaboration that occurred.

CHAIRWOMAN SANDOVAL: Okay. Thank you, Mr. Davis.

THE WITNESS: Thank you, Madam Chair.

HEARING EXAMINER ORTH: Thank you, Madam Chair. Mr. Rankin, do you have any follow-up with Mr. Davis?

MR. RANKIN: Madam Hearing Officer, I just have a couple because the issue was raised and I want to see if I can provide some clarity or assurances.

HEARING EXAMINER ORTH: Would you keep your voice up, please, it really is hard to hear you.

MR. RANKIN: I'm soft spoken. I will do my best to be forceful.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Davis, there was some concern raised around the idea of enforcement. Mr. Ames brought up a hypothetical where enforcement or compliance officer is in the field and identified that there is nobody on site during a manual liquids unloading event. Ultimately, and in the case that the language, or in close proximity, is adopted by the Commission, is it your understanding that ultimately it's within the Division's own discretion how to interpret and apply it's rules in an enforcement action or enforcement context?

A. I do.

Q. And it wouldn't be the operator's discretion how this that would be applied against them, would it?

A. I don't believe so. I mean, there could be arguments, I guess, on both sides, but both are going to have their arguments to make.

Q. And then in the scenario that Mr. Ames raised where the operator, lease operator leaves the site and goes into town, would you be interested in taking an enforcement action of that nature to hearing against Mr. Ames or the Division on whether or not he was in close proximity?

A. So to make sure I understand your question, it is, if a lease operator left the field and went back to town and there was an enforcement action taken against my company, would we take that to hearing to dispute it? Is that your question?

Q. Yes, if he leaves the field, goes all the way back to town and is charged with an enforcement action against him for not being in close proximity, is that the kind of case you would want to make against the Division?

A. No, we would not.

MR. RANKIN: No other questions, Madam Hearing Officer.

HEARING EXAMINER ORTH: Thank you, Mr. Rankin and Mr. Davis, if there is no reason not to excuse Mr. Davis --

MR. AMES: Ms. Orth, OCD has a recross on the scope of cross -- of redirect.

HEARING EXAMINER ORTH: All righty. Go ahead.

RECROSS-EXAMINATION

BY MR. AMES:

Q. Mr. Davis, Mr. Rankin asked you whether, whether -- how you would deal with an enforcement action if OCD brought one against your company where an operator went back to town during liquids manual unloading. Do you remember that line of questioning?

A. Yes, sir, I do.

Q. And he said, if your -- if the operator had gone back to town, would you dispute that action seriously, and I think you said no.

A. Correct.

Q. My question to you is, if the operator says, we had personnel in close proximity, how is OCD supposed to know that the operator actually went -- or the operator or personnel actually went back to town?

A. I think that would be difficult to determine.

Q. Thank you. That's fine, thank you. Nothing further.

HEARING EXAMINER ORTH: Thank you. Is there any reason not to excuse Mr. Davis at this time?

MR. RANKIN: No, Madam Hearing Officer.

HEARING EXAMINER ORTH: No? Okay, I think I heard Mr. Rankin say nothing further. Thank you very much, Mr. Davis. You are excused.

THE WITNESS: Thank you, Madam Hearing Officer.

HEARING EXAMINER ORTH: All right. So it's after 11:30. As I read the order of NMOGA witnesses, I see that we would like to hear from Mr. Greaves next. And that his testimony is estimated at an hour. So rather than leaping into an hour's worth of testimony at this time, I'm wondering, Madam Chair, if you want to have the discussion around potential extra days.

CHAIRWOMAN SANDOVAL: Now would be a good time.

HEARING EXAMINER ORTH: All right. Would you like to lead that discussion? Would you like me to start?

CHAIRWOMAN SANDOVAL: Sure.

HEARING EXAMINER ORTH: All right.

CHAIRWOMAN SANDOVAL: Yeah, I can lead and you can jump in as needed. So yesterday I think we asked parties to take a look at their original timing proposal in the prehearing statements. Knowing what we knew yesterday and how much I think extra time everything has taken and to reevaluate those proposals, that, that information will then be used to sort of plan out how many extra days are we talking to? Are we talking two, are we talking five, ten, who knows? And then try to set those dates aside and hard plan things now. Were the parties able to reconsider that timing? And I can start with, I guess, Mr. Ames.

MR. AMES: Madam Chair, OCD has already presented its witnesses. All we have left is cross and rebuttal, so I think it would be more -- I think I would like to reserve any comments until I have heard the parties with witnesses still to present.

CHAIRWOMAN SANDOVAL: Okay, just to clarify I think we did ask for rebuttal estimates as well.

MR. AMES: I'm sorry, I missed that. Perhaps I wasn't listening close enough.

CHAIRWOMAN SANDOVAL: But if you want us to circle back to you, we can do that.

MR. AMES: I will take that offer. Thank you.

CHAIRWOMAN SANDOVAL: Okay. Mr. Feldewert or Rankin?

MR. FELDEWERT: Madam Chair, do you want this on the record?

CHAIRWOMAN SANDOVAL: I will defer that to Ms. Orth. What do you think?

HEARING EXAMINER ORTH: I don't know that it's important to have it on the record. I think we can have this discussion, and then when we get back on the record, announce a decision has been made. So give Irene a break.

MR. FELDEWERT: I'm not trying to circumvent anything, I'm not sure we needed Irene going through the process.

CHAIRWOMAN SANDOVAL: Thank you for that.

(Discussion off the record.)

HEARING EXAMINER ORTH: Let's come back from the break, please.

So Mr. Greaves, if you would you please raise your right hand. Do you swear or affirm that the testimony you are about to give will be the truth, the whole truth, and nothing but the truth?

THE WITNESS: Yes.

HEARING EXAMINER ORTH: Thank you. And please spell your last name.

THE WITNESS: G-r-e-a-v, as in Victor, e-s.

HEARING EXAMINER ORTH: There is a lot of ambient noise. Is there a way to address that?

THE WITNESS: Yeah, let me -- let me see.

HEARING EXAMINER ORTH: Mr. Feldewert?

MR. FELDEWERT: Yes, thank you.

DAVID GREAVES

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your name, identify by whom you are employed and in what capacity?

A. My name is David Greaves. I'm a facilities engineering manager. I work the Delaware, which is in Southeast New Mexico and part of Texas as the engineering manager. I work for XTO Energy, which is a subsidiary of ExxonMobil.

Q. And how long have you been with ExxonMobil?

A. I have been with ExxonMobil for 13 years.

Q. And can you give us an idea of what your job responsibilities have involved, have included over the last number of years?

A. Yes. So I started as the public flow assurance engineer. I looked after pipeline modeling, so the thermodynamics and fluid hydraulics within pipeline both offshore and onshore and did global projects.

And then I did project work, work out of Australia, putting in large projects in Pupua New Guinea. And then I worked assurance as a supervisor leading the team of flow assurance engineers to again work on pipeline hydraulics. And then I transferred to XTO Energy where I worked as the facility engineer supporting the Bakken in North Dakota where I looked after facilities, their design, the construction of them, and any sort of operational surveillance issues that might come up.

And then I transferred to Midland where I worked as a facility engineer and then later the engineering manager doing very similar work that I did in North Dakota, looking after our facilities design, keeping up with the drilling rigs, building facilities, and then doing a lot of surveillance in terms how the batteries operate and how to make them run well.

Q. Mr. Greaves, do you then manage a group of engineers in these processes?

A. Yes, I manage a group of approximately 20 to 25 engineers at any time who are facility engineers. They look after tank batteries, pipelines. We have an extensive network of gas and oil pipelines in Southeast New Mexico. We look after approximately 15 large compressor stations. I have two engineers who work at a gas plant and look after a gas plant that we are running now, and then as well as the electrical infrastructure that supports these facilities.

I would say we have around 200 tank batteries on the wells with tank batteries that the engineer steward provides surveillance on.

Q. And does the area of responsibility include the Delaware Basin of New Mexico?

A. Yes. Yes, all the Delaware Basin.

Q. Now, I look at NMOGA Exhibit I1. Does that accurately reflect your educational background and work experience?

A. Yes.

Q. It indicates you have a master's in chemical engineering from the Colorado School of Mines?

A. That's correct.

Q. And it looks like you spent some time addressing oil and gas -- oil and gas projects for ExxonMobil overseas?

A. Yes.

Q. Mr. Greaves, as a result of your job responsibilities, are you familiar with the challenges that are associated with the installation of metering equipment?

A. Yes. One of my primary responsibilities of North Dakota, and then as a facilities in the Delaware, was to support our flare monitoring in terms of looking after our flare surveillance and then providing decisions on flare measurement technology, assessing all the different meter types that are available to us, versus where it's appropriate for that formation and providing, you know, justification on what makes sense and what's the right technology for our company. And then I also provided information on flare measurement as part of the BLM rulemaking in 2016.

Q. You are also familiar with the difficulty of accurately measuring or estimating low flow and low pressure gas emissions on various field operations equipment and devices?

A. Yes. That has been part of my responsibility, and I have done different technologies to try and see what is reasonable and if there is an accurate or appropriate technology available.

Q. Now, you mentioned something about the BLM rule. Have you assisted federal agencies on the technical aspects of rules addressing measurements of gas release?

A. Yes. I met with the BLM multiple times during the 2016 rulemaking and provided expertise on metering technology, on flaring in general and the facilities engineering, but particularly metering, yes.

Q. Did you also address estimation issues?

A. Yes. And some of the items that were addressed are reflected in the final language from the 2016 rulemaking, based upon the challenges that we were able to share off of measuring.

Q. Did you also serve as a technical expert for the New Mexico Methane Advisory Panel?

A. Yes. During that process I presented on reasons for flaring, on the differences on capabilities of measurement versus estimation among other technologies.

Q. Mr. Greaves, I know you're a company man, do you consider yourself an expert in these areas?

A. Yes.

Q. Okay. I want to first apply your expertise to the placement of flare meters. Okay?

A. Okay.

Q. And I'm going to try to share a screen here.

A. Great.

Q. And I believe I have up, on my screen, anyway, I hope it's on your screen, it's an exhibit or document entitled OCD's Changes Related to Stripper Wells. Do you see that?

A. Yes.

Q. I'm going to represent to you that this is the OCD Exhibit 4B as in boy. Okay? Now, I want you to go down here towards the bottom of this exhibit, and at the bottom there is a reference to 27.8.F.2.

A. Yes.

Q. And are you familiar with this provision?

A. Yes.

Q. You had an opportunity to review it?

A. Yes.

Q. Do you understand the purpose of the Division's changes here and agree with them?

A. Yeah. These changes reflect the recent revision which was considered (unclear) after May 31 to the -- lost part of the language, but the changes in red have made it very clear going back to the rule from December that flare measurement would be required on equipment -- well, they clarify here more -- before a well is -- especially with a well authorized by an APD issued after May 31.

So it's for wells coming after May 31 in terms of when they received it, and then for, specifically for wells or facilities to have average daily production rate of 60,000.

Q. Okay. Now, you had me highlight the language here in yellow. Do you see that?

A. Yes.

Q. Beginning with, the existing process and ends with associated with?

A. Yes.

Q. What do you recognize with respect to that particular phrase?

A. Yes. So we have recommended striking this phrase, that would be consistent with the submission from NMOGA that this phrase be removed, and I can explain the purposes for not needing that phrase is --

Q. Let me ask it this way, Mr. Greaves, is there some confusion or concern that arises out of this phrase?

A. Yeah. So an operator is required to install a flare meter. We are going to put the flare meter where it makes the most sense, and there is several, as I will explain why it goes where it goes.

It's not necessary to be able to, to have to delineate where it should go with same existing process piping overflow line because a facility engineer in following a documentation will understand where the flare meter should go.

But instead of putting words like flowline, flowline is a very confusing term as written here because a flowline, the common practice in the industry is that flowlines means multiphase flow, which means that it represents that it's fused to the piping that connects a well to a facility and has oil, water and gas.

And so you would not expect to put a flare meter, which for accuracy purposes needs to be where there's gas on phase, on a multiphase line as on a flowline. It's also well before separation equipment in terms of where flow exists. So it leads to a lot of confusion to have that phrase "flowline" there.

It also leads to confusion when it says here to or from equipment. You can imagine that you would be measuring the gas that moves from equipment to a flare, but the way the to or from works here, it makes you wonder if you are putting in flare meters between equipment, not between the equipment and what goes to the flare.

But it's to or from as the -- to the statement that is unnecessary, and I think that we can accomplish the same thing by having a clear rule by simply striking out the entire phrase.

Q. Okay. And so when you say strike out the entire phrase, you are looking at Exhibit 4B at the bottom which references F and Part 2, and your recommendation is to strike the phrase that begins "existing process," and strike it all the way to the point where it says "associated with"?

A. Yes. And if you put out the phrase, I won't read the whole thing, but it will say, "The operator shall install equipment to measure the volume of natural gas vented or flared from a well or facility."

Q. Gotcha. All right.

A. Remove all the specification about where you should install flaring.

Q. Now, you mentioned a need for operators and engineers like yourself to have the flexibility on where to properly put a flared meter. Will this language that you proposed accomplish that goal?

A. Yes.

Q. All right. And I want you to turn to what's been marked as NMOGA Exhibit I12 in the black binder. Can you explain why it's -- why operators require flexibility to locate meter equipment?

A. Yes, it -- sorry not.

Q. I2.

A. Yes. So looking at I2 in the binder, I2 is a simplified schematic that I prepared of a typical facility.

And if you start -- I will be talking from left to right on the diagram. And just to give you some (unclear) diagram, the red lines are gas lines and the orange lines are flare lines, the lines that have gas going to the flare, and the green lines are oil lines.

Mr. Feldewert, will you pull it up. It looks like it paused your screen here.

Q. I'm trying. Go ahead and work off your notebook.

A. I'm opening the notebook, that's what I'm looking at.

Q. Sorry about that.

REPORTER: I'm getting really, really bad sound here with a lot of feedback. Could we have the witness turn off his video and see if that helps.

THE WITNESS: Is that any better?

REPORTER: Let's try it and see.

BY MR. FELDEWERT:

Q. So, Mr. Greaves, I apologize, it took me a little while. And, Commissioner Kessler, I think I now have up on the screen the exhibit that Mr. Greaves is going to refer to.

A. Yes.

Q. Okay.

A. Okay. So as I was saying, I will talk from left to right in the diagram. And so if you start with the well, which I have just drawn as circles, in this example I have put three wells. They are connected to the facility by flowlines. Those could be all varying, different lengths, so it's just a schematic, but it's not the correct length.

But they travel to the battery, and this would be for typical oil battery, say, in the Delaware, and when it comes to the batteries there will be some sort of manifold, commonly. And a manifold is a valve that will allow you to choose where to send production.

And so when they -- the battery in the manifold, they will -- this is just a test separator and a volt separator. The volt separator is where you will send all your wells except for when you need to do a test, and a test separator (unclear) where you are performing a test to know the relative sequence of that individual well.

This would be important for doing annual production tests for the state. It's important for doing commingling, so you have commingling conditions of approval specified.

Also the test separator, there are test meters for the different phases. You will have hydraulic oil meter in green, just a box test meter, and then the red box is for the gas test meter.

Now, I want to clarify before I go any further in this diagram that I cut out a lot of what's happening at the facility so the diagram doesn't get overly messy. So you don't see the waterlines in here, you don't see the water tanks, you don't see any low pressure gas lines or low pressure flares if you have them. So just remember that as we go through this simplified so we can focus on this.

You can see first off why having the word flowline can be confusing because you are nowhere near the flare at this point. If you follow the oil, the oil goes to the heater treater. Companies will have some sort of secondary separation condensate to help break out any more gas.

As an example, I have drawn the heater treater oil that goes to VRT, which is vapor recovery tower, you can see some gas there, and then they go to the oil tanks. From the oil tanks the oil is either sold by a truck connection or by what's called a LACT, which is the automated custody transfer which is (unclear) a meter that allows you to transfer oil to a pipeline.

So in each of those subsequent stages of separation, at that first stage gas comes off. Gas is evolved from the stage. And typically the gas that leaves the first stage of separation, the volt separator, that gas is at a sufficiently high pressure that it can reach the sales and enter the sales line because there will be higher pressure in sales, and so I did not draw compression there.

But on the lower pressure vessel, particularly on the tank, if you are to stop the gas, then it would require some sort of compression that you might have had in recovery. And so those hexagons or trapezoids on the side, that's a common symbol for compressors, that's to show the the compression to each section.

Now, all of this said, the question was, where should we put a flare meter. Well, there's quite a few ways to, to build a battery. No one battery is the same, but there is trends and I've operated as a facility engineer batteries from multiple different companies or did purchases, acquisitions for ones that I have built, and they are all a little different. But generally you will have various -- either route to sales or to the flare, which is what is shown as the heater treater, the red line and orange line. Or sometimes you will have all the gas go into the sales scrubber. And a scrubber is a vessel that draws liquid out.

And then from there you will have a gas line for the sales scrubber that goes -- at the top of the page in orange -- you will have, if it can't fit into sales, there's a path for it to go to flare. So you will see there is lots of ways for the gas to reach the flare depending on pressure and how your battery is laid out.

And then commonly on a high pressure flare, you will have what's called a flare scrubber. And the flare scrubber is to remove any excess liquid in case there is an upset you (unclear) send a slug of liquids to your flare, so that flare scrubber captures that and then the line moves to flare stack.

Now, this is where it's most flare meters. And when you look at language that's out there in engineering (unclear) decision, you do that analysis, you are going to want your flare meter where the fluids strains are aggregated together, where there is a single pipe, basically, if you installed your batteries that way. I wouldn't want to put a flare meter on every one of these small individual and then not have sufficient flow to get good measurement, so you put it in one common place.

You would also want to put your flare meter after a flare scrubber because if you have a flare scrubber, the best way to get good measurement is to the drop all of the gas before it goes to the meter. Certain flare meters will not tolerate liquid.

If you look at the Delaware gas, it's probably the rich gas that (unclear) batteries in condensed water and impact the measurement accuracy. If you put it after the flare, if you put it where you have aggregates of the fluid, and you would also want to put it -- all measurements need some sort of straight run of pipe to get accurate feeds, so you want to put it all by the vessels and congested where you have complex piping arrangements, it's more convenient to get good measurement putting it on the flare.

So by changing the language, we are able to provide the facility engineers what they need in terms of flexibility, put the flare meter where it makes the most sense, and not try to add confusion with complex flowlines to and from or put it on a certain vessel, when really you want to, if you can, you want it on the aggregated (unclear).

Q. So, Mr. Greaves, I want to, with this slide in mind, I want to talk about a different related subject, and that is the difficulty of retrofitting all facilities with a flare meter.

A. Okay.

Q. If we first turn to --

CHAIRWOMAN SANDOVAL: Mr. Feldewert, sorry, can I interrupt you really quick?

MR. FELDEWERT: Yes.

CHAIRWOMAN SANDOVAL: So the sound never got better when he turned off the video, so can you turn your video back on?

THE WITNESS: Sure. I'm sorry about that, Madam Commissioner.

CHAIRWOMAN SANDOVAL: No problem. I mean, I can still understand you, there is just like a little feedback, fuzzy sound.

THE WITNESS: Okay. At next break if I am still talking, I can try a different computer.

BY MR. FELDEWERT:

Q. Okay. Then let's proceed with the challenges associated with the retrofitting all facilities with a flare meter. Okay, Mr. Greaves?

A. Okay.

Q. If we you turn, with this diagram in mind, if we turn now to the next exhibit which is I3, does this assist in explaining the challenges that are associated with retrofitting all facilities with a flare meter?

A. Yes.

Q. Okay. Why don't you explain those difficulties.

A. Okay. So these first is when you build a facility, the best time to install a meter is at the beginning; right? So we appreciate that the language in the rule is such that the new location or around your service or a new well, that's when you would install a flare meter rather than retrofitting later because that's the best time when you can design your piping layout to accommodate it.

Retrofitting afterwards can require significant changes. And so I have referenced, it's called API MPMS 1410, which is a document from (unclear). MPMS stands for the Manual of Petroleum Measurement Standards, and 1410 is specific to flare measurement. And it's now included later on in the reference.

So 1410 is really the go-to document for understanding flare measurement systems. So there is three primary concerns when you are evaluating the need to do a retrofit with a flare meter.

The first is safety. It says, there's a flow meter and associated instrumentation must be acceptable for verification and calibration. So you can imagine a flare stack has radiation when the flare is going, and as often flares are emergency flares, we do not control when the flare will go.

So if you think about that, you should be able to put the flare meter in a location that personnel can come and perform calibration on the meter or inspect the meter, have access to the pressure and temperature, (unclear) off the meter if you have those, and be within a safe distance of the flare.

And so that can drive you to need a new location for your flare in order to retrofit (unclear) related to making more surface disturbance to be able to locate the flare safely where the meter should be.

The next primary is concern is related to liquid. I mentioned this when talking about the diagram, so I won't read all of this, but it says the ideal flare meter arrangement consists of a single flare meter located downstream of the final vent system liquid removal equipment.

So it's that whole concept that if you have liquid in your flare stream, it will impact your flare measurement certainty. So you want to be able to get liquid out. So if you haven't designed a flare scrubber or you don't have a good place to put the meter after the flare scrubber, then that will impact your ability when you go to retrofit (unclear).

Lastly it says straight run of pipe. So it mentions a reference there that the typical standard for measurement is 20 pipe diameters upstream and 10 pipe diameters downstream. And what that means is, in order to achieve good measurement, you want to have what's called your flow profile well developed. And you don't want to take a number of 90 degrees tortuous turns on piping for entering a flare meter because flare meters require having your flow stabilized.

And the way you do that is you have straight pipe upstream. So in this case, let's say it's, for ease let's say it's a one foot diameter pipe, 20 pipe diameter would be 20 feet of straight pipe and 10 diameters downstream would be 10 feet of straight pipe. So you are looking for that straight section of pipe in order to place your meter to get good clean measurement.

Q. Mr. Greaves, given the challenges here associated with retrofitting facilities for a flare meter, is that something you recommend avoiding in most cases?

A. Yes.

Q. Okay. Are there ways to actually estimate flare volumes where you are not able to install or retrofit a facility for a meter?

A. Yes. The language in the rule currently allows for use of a gas oil ratio, or GOR calculation. And by using the GOR as your means to calculate flare, you can accurately determine the flare without needing a flare meter.

In fact, you can invest in accurate well test measurements, which is how you determine the gas oil ratio, where it's much easier to measure, and you already have those locations for measurement because you needed the well test, and therefore you can invest in that measurement and achieve good quality measurement and use, use math to determine how much has flared. There is good quality certainty approach to achieving flare determination without a meter.

Q. Now, in addition to the difficulty, is there a substantial cost component to retrofitting facilities for

flare meters in circumstances where it's (unclear)?

A. Yes. So I hope to answer Madam Chair's questions around flare measurement, specifically in retrofitting costs here. And I've referenced -- I pulled this material from -- as I'm not able to specifically say how much charge for a flare here, we don't (unclear) cost data. I can share what was published by API during the flare, the rulemaking of BLM Rule 3179 in 2016, which was the flare rule.

And at that point, federal costs were shared publicly, and one of which was that an Ultrasonic meter, which is a very common flare meter, and when you read through it's a very much a preferred flare meter. An ultrasonic meter, they publish that the cost is between 20,000 and $90,000 for a meter, and that's the meter cost.

There's a separate part of that document that then said, okay, a typical install cost, and I want to make sure I say this right, the typical install cost is 1.92 times the purchase meter cost.

So they took $20,000 as the low end of a meter, multiplied by 1.92 and said it would be $38,000 for an installed -- for the low end on the Ultrasonic meter. And I have seen flare meters range all over the board in terms of cost. Better meters cost more money. More accurate meters cost more money, but that 20,000 to 90,000 certainly covers it. You might be able to buy a cheaper meter that does not perform across the range of conditions you need.

That 1.92 as a total cost multiplier is reasonable. Oftentimes it's more like three times the meter cost to do an install because you may need to do piping modifications. You may need to install a pressure and temperature transmitter oftentimes, and you need a test to be able to do a gas sample analysis, and you need then a flow computer which takes the meter data and then does the integration and combines the pressure and temperature for your total gas.

There is a number of changes that have to happen. If you have to relocate your flare or change your flare header system, change all of that piping so that you have (unclear) vent that's not included in those numbers that were provided by API.

Q. And given the availability, Mr. Greaves, of a GOR test method that you just discussed, in your opinion, is the cost and expense associated with installing flare meters on existing facilities a necessary expense for operators to accomplish the goals of this rule?

A. No, I do not believe so. By setting clear standards on the GOR and the testing to determine an accurate GOR, you will achieve the same goal of reasonable accuracy of your flare determination --

Q. Okay.

A. -- (unclear) to retrofit.

Q. I want to switch subjects here, and I want to go to the Division's Exhibit 2A, and I'm going to go down to 27.8.G.1, okay?

A. Okay.

Q. And I'm focusing in on G. This is reporting of vented and flared natural gas. I'm focusing in on G.1, B as in boy, Subpart 4, Mr. Greaves. And this addresses the rule where the operator needs to provide and certify the accuracy of information on a C-129. Okay?

A. Yes.

Q. All right. The Division had proposed the word compositional analysis. I'm going to represent to you that NMOGA has proposed to also add a representative analysis or a representative compositional analysis, okay?

A. Okay.

Q. So do you still believe that adding the word representative in this section is necessary and appropriate?

A. Yes.

Q. Can you explain why?

A. Yeah. I think it helps to use the -- are you able to go back to Exhibit I2 and use the background again?

Q. Certainly. Give me a minute here. So I'm going to go back to Exhibit I2, which is the diagram. Is that what you want to go to?

A. Yes. So by totally understand -- I totally understand the phrase compositional there and not said we needed to add compositional because to me it was well understood that that must mean compositional, right, that was obvious it must mean compositional.

Now, the reason we recommended adding the word representative, though, is that there was concern by having compositional analysis -- and some of this has been explained previously, so I will keep it short -- but that you would be required to note the composition of the flare vented gas at the time of the event.

And for many events that's just not practicable. It's also not feasible or possible in some cases. So for instance, if you were to think of your volt separator, for instance, will have a pressure relief valve. And this may have been an example here, is that if you have a pressure relief valve, it is designed so that if the vessel experiences an overpressure event, it will relieve pressures quickly and protect personnel from the pressure.

And so you cannot put a meter on there or have a person there who could take a gas analysis from the air for instance. And it would be very hard to go snag a sample and have a place to do so during the actual event, but you do need to get gas samples as part of (unclear) as part of tuning the test meter and the sales meter. And so by having a representative sample, which you are required to get at some frequency, oftentimes sales meters samples monthly or at least quarterly or semiannually depending on the contract, and so you do have a sample of gas on some location, you can apply the appropriate analysis to that event, and while it's not the composition during the event, the exact composition, it will be represented to be very close to the in situ comp.

The same would happen on the flare, for instance. When I've had a flare meter, I don't go measure the flare composition during the event, that's hard to do, but I can use the gas composition from the sales meter because if I'm (unclear) selling, then the gas must have gone to the flare, so it's that same gas composition I can apply logic about what gas composition makes sense and determine a representative sample.

Q. And by adding the word representative, that would accomplish the, the goal that you seek here to give the flexibility you need to provide an accurate sample?

A. Yes.

Q. Okay. Then I want to go back to the Exhibit 2A, okay?

A. Okay.

Q. I'm going to go up to part F.2, and you previously talked about F.2, and I want to now go to discuss

F.3 in the same section, so 27.8.F.3. And you will see the Division has removed references to the specific technology and instead referenced API Chapter 1410. Are you familiar with that?

A. Yes.

Q. Okay. And do you believe that that's an appropriate exchange?

A. Yes. In API MPMS 1410 is the right mode to reference this for standards, and it is the most commonly used one for flare measurement.

Q. Is that a standard that, that facilities engineers such as yourself understand?

A. Yes.

Q. And that operators can implement?

A. Yes.

Q. Okay. Why should the Division, why was it appropriate for the Division not, for example, to say specific technology?

A. Yeah. That measurement is challenged. It's a very difficult process, and it's difficult because it doesn't meet the paradigm studies we are used to with normal gas sales measurement. Under normal gas sales measurement you have consistent flow, you have consistent composition, you have high pressure gas, all of the same help you get good quality measurement.

But with flare measurement you don't have all the luxuries you are used to with sales. You can have very low pressure. It's accurate after a vessel, you don't want to put back pressure on the system oftentimes because it's going to flare. It's your safety relief mechanism. You want to be able to have a clear path to the flare.

So you have low pressure. There's a high variability in the rate, which is called turndown. So the term is turndown which describes the max rate to the minimum rate, and when you have flare measurement, you have to design for the max rate your facility can do. You also have to design infinitely, an infinite turndown down to essentially zero because you have small events happening, you might also have purged gas in your line.

So you have such a big rate, and meters aren't the normal thing to handle a wide turndown. Many of you are familiar with orifice meters. They are used for sales measuring. Orifice meters, depending on which manufacturer you go to, will say they can handle a turndown of 5 to 1, up to, I've heard some say, 14 to 1. I have seen 14 to 1 published.

So if you have, okay, you know, 10 MCF up to 50 MCF, 5 to 1, 1 million to 5 million, but I can't do zero. So flare measurement is very hard, and 1410 recognizes the challenges of flare measurement, it recognizes the challenges of putting a meter into your system, and it described all the different meters out there, and how any one of those meters might be the right choice, but there is not a one-size-fits-all meter.

That's why it was so appropriate to not only reference 1410, but also to strike the section here which technology should be used because there are a lot of technologies out there, and at any given point in your design, there may be one of those technologies may be better than the other, but to say there is one that's right for all of them, this is not the case.

Q. And is the Division's approach, is that consistent with the API 1410 standard that you referenced, that was referenced in your exhibit?

A. Yeah, if you would go to my Exhibit I5.

Q. Certainly.

A. Some quotes from API 1410 that I think are -- that illustrate this point.

Q. Now, I4 discusses the API standards that the Division has referenced; right?

A. Yeah. So I4 is -- I have shared a quote from 1410 that is one of my favorites that talks about how flare measurement is distinctively different from custody transfer, and I can talk to some of that for you now.

Q. If I go to Exhibit I5, what do you want to point

out?

A. Yeah. It's key to note type of technologies for flaring. You need to be able to pick for your flowing conditions. And so I appreciate that the, that the NMOCD changed that and made that clear.

If you look at these, I wasn't cherry-picking, it's very clear when you read 1410, that 1410 can be agnostic to the type of measurement available.

It says it is the intent of this that no flare measurement technology be excluded. And no single type of flow meter is suitable in all flare gas measurement applications, and all gas flares have a finite range of use. So I have used probably three or four primary technologies, I've looked at other technologies and it really depends on my flow conditions that I expect based for the type of meter that I pick.

Q. Now, the Division's Exhibit 2A, which if you go down here to Subpart F.5, the Division has made a decision here about discussing when metering is not practicable. Do you see that?

A. Yes.

Q. Okay. Do, do you agree with this language change by the Division, in particular, the edition of low flow rate to the existing language of low pressure?

A. Yes, I do.

Q. Okay. And why is that appropriate?

A. As I was saying, flare measurements, it's very challenging, and the same with venting measurements, so there are times where it is appropriate to estimate the volume. And particularly when you think about metering technologies, they really struggle at low pressure and low flow.

And those two are two different things. You can have them simultaneously, but they are two different things. And so I think it's important to make it very clear that low flow rate is included there. When you have low flow rate, you don't have stable flow profile, as I was explaining earlier, and that the unstable profile makes it -- makes it difficult to get quality measurement and you are unable to achieve the quality measurement that you are paying for, so it's better to estimate.

Also there is many times when you experience, when have you a different scenario, like -- I'll take an example. Like a (unclear) blowdown. You may have low flow rate at a period of time, and there is a great way to estimate that, right, you don't need to have a meter for that situation. You can use estimation approaches that in that case are very accurate. You can take the diameter of the pipe and the pressure and temperature and the composition of the gas in that pipe and use that for the amount of gas that must have been blown down when you are doing the (unclear).

So there are times when there are appropriate estimation methodologies that are accurate, and particularly those are used when you have situations around low flow, low pressure.

Q. And I believe, Mr. Greaves, you have an exhibit that discusses this in more detail; is that right?

A. Yes, if you go to I6.

Q. Okay. Up here in NMOGA I6, this looks like a pretty extensive exhibit here.

A. This is for Commissioner Engler.

Q. So what's important here? Orient us to this exhibit, why it's important to discuss.

A. Okay. Yes, so the right-hand side of the exhibit are all quotes that I pulled from API 1410, and they talk all about the challenges of flare measurement. And I summarized them on the left of the board, but I will pull out a few things here.

Flare measurement provides unique challenges. Flare meters are expected to operate over a wide range of velocities. And then if you look at the underlined, it says the user is also cautioned that operation at these low velocities may also subject the meter flow instabilities.

You read the next section it says, in low velocities air can become significant. So I'm a facilities engineer who really likes meters, right, but I like meters that are accurate. I want to pay for a meter when it's appropriate to pay for a meter that can give me valuable data.

Other, other points there talk about specific meters. So, for instance, orifice meters are typically not suitable as flare meters. Doesn't mean they are always not suitable, it doesn't mean that they are always not suitable, but typically not. And that's because meters like orifice meters that you are familiar with put a restriction in the piping. That's how they measure is they perform a restriction. They introduce a pressure differential which then can be measured.

An octagon flare measure -- flare run, flare piping, you will not want to introduce a pressure differential or restriction because it introduces a safety concern. You don't want to clog your flare system because that's how you lose gas (unclear) safety event in an emergency.

And so those are quotes on the right. On the left I summarized the main issues, low pressure, low flow, turndown and safety, liquids and variable gas compositions. Certain meters can't handle the gas composition change. You need to have a consistent gas composition.

And when, when you face these challenges and when it means that an accurate measurement is really not possible, then, then you are looking for an estimation of such. And the table that I have included at the bottom is out of API 1410, and it was there to demonstrate to you that 1410 gives you an example of a meter and has a number of tables and documentation around what's -- what are the pros and cons of those meters.

Q. Okay. Now, back here in Subpart 27.8.F measurements vented and flared gas, we get down to the bottom here, and the Division has language in here referencing or adopting the GOR test.

A. Yes.

Q. Okay. And I believe you mentioned that you believe that that is appropriate, Mr. Greaves. Do you have an exhibit that demonstrates how that's done, when it's appropriate to use a GOR test as your method of estimation?

A. Yes, if you go to Exhibit I8.

Q. Okay.

A. So, yeah, I would like to use this to explain what GOR test is used and hopefully address some of the questions that have been raised about GOR.

So again, the sketch on the right, this is extremely simplified just to make a point, but when a well test is done, or any number of test -- any number of vessels -- sorry, let me go back. When you look at a facility, you have produced, which is your total gas that you make, and you may determine that by a meter, although it's more commonly done with a GOR. So I will address that in just a minute. That's your produced gas, that's the total amount of gas on location.

And then your meter has three dispositions on the -- or three outlets. It can go to sales, and there may be multiple sales meters, but let's treat it as one sales meter. It can go to flare, or it can be for beneficial use.

And so I have drawn these little boxes to represent meters, so you might measure produced gas or you might get a GOR. And then you are performing a balance on the system, the ins and the outs and the difference to determine the flare.

So if you look at the words on the left, what is GOR? Okay, the GOR is the gas oil ratio. So when you perform a well test, which that frequency is set by the Division, or set by the conditions of approval whether from the Division or perhaps from the BLM, and, at a minimum, it talks about from an angle of tests, you will go test the well and determine how much gas it makes to how much oil is produced. It's just by ratio.

And the language proposed by NMOCD is 24 hour well test, which is good. That's important to do a sufficiently long well test so that you can average out the fluctuation in flow and determine a good quality GOR.

Now you know how much gas is made for every barrel of oil. So you can do -- and to go back to that well test, you have a good quality meter at a location that's easier to meter, it's high pressure gas.

So now you are able to do the system balance. And the system balance of the flare gas must be equal to how much gas I make, which is GOR times oil, plus the other disposition, the other outlets of that gas.

So it's GOR times oil minus sales minus benefit. And therefore, you know, without having a flare meter, you do have a (unclear) you do accurately measure the GOR, and benefit to this gas you can accurately determine with manufacturing data, or you may have a meter, and so you have the right number of equations to unknown. You have now one equation and one unknown, which is flare, and you can solve for the flare volume.

Q. Now, Mr. Greaves, when we go back and look at some of the proposed changes to Subsection 27.8.F 6 and 7, we look at the Division's changes, these are -- you believe these are appropriate; correct?

A. Yes, with one caveat there.

Q. What's that?

A. Well, they have said to allow the Division to independently verify the volume, rate and heating value of the flared natural gas, I was not -- I did not understand why they needed to verify the heating rate or the heating values because that is not part of a GOR test. It does not really determine the heating value, because the heating value doesn't impact the volume determination in doing a flare calculation.

Q. So then your suggestion would be to modify this language, but just deleting the reference to heating value?

A. Yes.

Q. Okay. And do you see any reason to require an estimation of the heating value for the Division?

A. I was not -- I was not able to think of why that was included.

Q. Okay. All right. Now, I believe that Climate Advocates have proposed a change to this section. Have you reviewed that, Mr. Greaves?

A. Yes.

Q. Am I correct that they have proposed to eliminate the use of a GOR test and replace it with an EPA Subpart W method?

A. Yes, that's correct.

Q. Would you explain why that's -- why you think that's appropriate, and if not, why?

A. Well, I think it's appropriate to keep the language as written by the Division rather than mention Subpart W, because when you look at Subpart W and you read the section on associated gas flaring, which is what, what it talks about here in terms of using the GOR, the Subpart W recommends, if you don't have a flare meter, using the GOR.

Subpart W methodology is, take the GOR, multiply by the oil rate and subtract off the sales volume. So they are actually the same except for one difference, which is Subpart W does not mention the beneficial use. And so you still need the proper balance, and that's why beneficial use must be subtracted. So there is one issue there that Subpart W doesn't include the beneficial use.

But given that they are the same, they both use GOR times oil minus sales, to me, thinking about trying to make a rule that people can understand, you know, this is -- this industry standard is well understood what GOR test means, I'd prefer to see it written rather than bury it in Subpart W and have to do what I did, which is then go study that and realize it was the same thing as what I was saying with the exception of changing subtracting beneficial use.

Q. You mention Subpart W does not account for beneficial use?

A. Yes.

Q. Is that because it's an emissions reporting methodology?

A. I, I don't have the background to know why it doesn't account for that.

Q. Okay. Okay. And then I'm going to then move to, the next topic is NMOGA, and that is NMOGA's proposal to eliminate five reporting categories in G.2. Okay, Mr. Greaves?

A. Okay.

Q. And I want to apply your measurement expertise to that particular topic. I believe if we turn to what's been marked as NMOGA Exhibit I9, does this identify the reporting categories that currently exist in G.2 that NMOGA seeks to eliminate?

A. That's correct.

Q. Okay. Would you provide us a discussion based on your expertise as to why it's appropriate to remove these as as reporting categories in a section like G.2 that is designed for monthly production volume?

A. Yeah, at a general level, these five categories are difficult or impractical or impossible certainly to measure accurately over high certainty. They are also challenged from the standpoint of quality estimation, which means that the calculations that you could perform -- and I know Madam Chair will be very interested in my opinion about the calculations that we will talk about today -- that calculations have high uncertainty, and therefore, for purposes of production accounting where you really want to have high -- you want to have quality reporting values, especially because that then leads to your gas capture percentage which has some implications, you want to have a good number, these five categories are very difficult to have an accurate volume.

So they don't lend themselves to being recorded in the same way as the other categories because you would be adding highly uncertain volumes to highly certain volumes, which creates unreasonable or numbers that just don't lend themselves to credibility.

They're overall generally low flow, low pressure, very inconsistent flow rates which makes them difficult to measure as well, which is part of the reason for the removing them.

Q. Would you -- can you apply that specifically to some of these reporting categories?

A. Yes.

Q. I think we have had a lot of discussion about downhole operations, and we have had a lot discussion about liquids unloading. So would you focus on the latter three, uncontrolled storage tanks, pneumatic controllers and pumps and then improperly closed thief hatches?

A. That will be fine. I agree you probably heard enough on some of these categories. So I will spend most of my time talking about uncontrolled storage tanks if that's okay. And it's simply the concept of measuring tank vapors.

And so having listened to the witnesses and some of the cross-examination, people are (unclear) with some of the methodologies out there for estimating tank vapors, and NMOGA's proposal is that these five be removed from the categories to report monthly, as well as then subsequently remove the categories that would count against you say in the gas capture plan.

So tank vapors are very complex subjects. It's one of my favorite subjects because it's when a facility engineer who works at a small tank battery gets to do a lot of good engineering and really think about the dynamics of the system that is being evaluated.

And so one of the -- one of the -- I want to explain the, the sources of gas and the dynamic situations that makes accurate measurements difficult, but in the same process I will try and address some of the questions that have been raised by the Commissioners related to why we can't go just use HYSYS or Promax or API 2000.

So when you look at storage tanks, there are really three primary categories of, of gas, of -- of emissions, let's say.

So you have your flash gas. Flash gas is the gas that evolves from the oil that occurs in the tank over time.

So that's one component.

We have the breathing component that's related to what I will call it thermal effects which has to do with how the temperature, the ambient temperature and weather conditions, the meteorology impacts gases in the tank and causes it to either expand, at which point the uncontrolled storage might leave through a thief hatch or through a pressure vacuum valve, the valve in pressure tanks, or it might cause it to contract, which can cause (unclear) gas in tanks, because you have heard this week people talk about pressure vacuum relief valves, it's doing both things, both overpressure and underpressure against vacuum. And so you have breathing, the second component.

And then you have these working boxes. And I'm just giving this background, I'm know some of you will be very familiar with it, but I'm giving this as (unclear).

So working has to do with the relative changes in the volume of the liquid that's in it. So it has to do with, you are flowing fluid from separation equipment into the tank, and as it fills up the valve, the gas, the gas becomes compressed and the pressure will build and go somewhere.

At the same time you are pumping out of tanks. And so when you pump out, then you are changing the volume in the other direction. And so these, these three events are happening, and each of those three events has a number of complicated thermodynamic factors behind them that influence the ability to accurately, for production accounting purposes, report the volume or determine the volume.

There are, like I said, I will get into about how to do design conditions, which I thought Mr. Leonard did a good job explaining how -- I can't remember his exact words, but this gas is having an identity crisis about where it wants to be. There is factors that drive this identity crisis.

So when we look at these three situations, and as we talked this week I thought it was important to go through this. I'm looking down, I made a lot of notes, in my mind, how these are all important to share with people.

So you have oil entering the tanks. That oil has a certain amount of flash gas. While the flash gas can be determined through HYSYS, the flash gas is dependent upon the pressure and temperature that the oil comes from. So the oil is coming from a separator. Let's say that separator is the heater treater. The heater treater to accurately know the flash gas at any given time and then integrate that over a month, you would need to accurately know the pressure and temperature of that oil all throughout that time. It's not enough to use a HYSYS design condition, we need to know it throughout the whole process.

And any sort of change in the temperature and the pressure of that vessel upstream would change how much gas evolves in the tank downstream. So you have that effect.

Once it's in the tank there are mass transfer limitations that really become important as you start to model this in detail and heat transfer limitations, and kinetics, all three things happening related to whether the gas can evolve out of the oil phase.

And so you have seen, you will have to consider things like does the oil enter the top of the tank, or does it enter the bottom of the tank, and there is a whole lot of very interesting debate about whether you should go to the top or bottom to help break out the gas.

And then the more time that the oil sits there in the tank, there is more time for that gas to go down. So that's some of the limitations we are talking about and why it's not a simple calculation.

Then there is -- there is all the effects that happened from what's going on with that upstream vessel. So that upstream vessel might have a -- a large control valve on it that opens wide open, which will have a very different response to how much gas is happening in the tanks versus if it's operating where it tries to hold a steady level. That control valve or dump may become stuck, and you've heard about that, it may become stuck and you can have more gas come in, more oil at a higher rate than you designed for. That's the upstream side.

When we start to look at the other side of the tanks, you have your pumps that are, that are operating in terms of evacuating the fluid. Many operators will design their, their lacts, l-a-c-t, lacts to operate, say turn on at 8 feet and off at 6 feet. So it turns on and then it pumps down. So you have these changing volumes that you need account for as part of those working losses.

Some folks have installed what are called variable speed drives, or VSPs, variable frequency drives, on their pumps to try to maintain a constant liquid level. So that will impact that calculation.

And then there is -- this is one of my favorites. So I can't remember everyone who is a chemical engineer, but I know a few of you are, so this is my absolute favorite which is the gas hole. So I get pretty excited about nerdy things, so just bear with me.

We are talking about uncontrolled storage tanks, but I want to expand and talk about tanks in general, and that's because NMOGA has proposed excluding low pressure gas and tank vapors from the gas capture calculation.

It is very common for operators to put what is called a gas blanket on your tanks. And a gas blanket is produced gas that is put like in a defense system on top your tanks you will have that pumping, and you will put in a gas supply into the tanks.

And you put that gas supply to keep oxygen out. We talked a lot about oxygen this week, and you want to be able to keep oxygen out. You don't want oxygen in your tanks for corrosion. You don't want oxygen in your tanks because you don't want an explosive mixture, and you also don't want oxygen in your tanks because you want to be able to run that vapor recovery unit if you have one.

So if you have a vapor recovery unit, then you -- commonly it will have a gas blanket, not always, but commonly will because you are trying to keep oxygen out. So that gas blanket is very interesting because depending on the composition of the gas blanket, the gas blanket can dissolve into the oil phase or it can strip components out of the oil phase by equilibrium.

So I have sent, I have sent gas blankets into tanks that are mostly methane, depending on where I steal them from the process, and I help stripped some of the light end out of the oil. I have also sent very rich gas blanket into into my tanks and seen that the oil basically heats up the gas blanket, it dissolves into the oil tank.

So you are now looking at the composition of the gas blanket and the composition of the oil phase and then trying to determine the driving force for equilibrium of where the molecules go.

So you have -- the gas blanket has a whole lot of complication in terms of predicting behavior because it's not just flash gas that provides (unclear) gas, now you have this other gas that you introduced.

There's another -- there's actually, there's a lot. I know a long list. I know you don't want to hear me talk about it. But when you look at, you've got to account for RVP of the oil, which is the root vapor pressure as to how volatile is the oil. You also have to account for sources of oil that come in that aren't part of normal production.

So you might all be familiar with the fact that it's very common on tank batteries to have a recycle oil stream. So recycle oil stream takes oil from your tanks and sends it is back upstream to where that heater treater was. This is to get any water you may have accumulated over time, maybe break an emulsion or get it hotter to help get gas out.

Well, now you've increased the oil flow rate into the tanks even though you haven't changed the oil flow rate into the battery, and so you have to account for that. There is other ways to do that, too.

For instance, on your lact, it's all lacts, all the ones I've operated, have what's called a diver line. And the diver line says, "Hey, I have bad oil at this moment. I'm not meeting spec. I need to send that oil back," so it recycles it back to the tank and now you've added more oil volume. And it's not live oil, so it doesn't have the same flash factors as dead oil, but it does change that level in your tank.

It gets even more complicated.

Q. So, Mr. Greaves, I know you are passionate about this --

A. Sorry.

Q. -- I'm conscious of the time here.

A. That's okay.

Q. Okay. So let me ask you this, you just provided all of these circumstances, which is very helpful, is there any place to measure these kind of vapors that you see released from these storage tanks?

A. No. So it -- there is not a good place to measure. It's an uncontrolled storage tank. The place where the tank vapors will go, it's either out the thief hatch -- so the thief hatch is a mini pressure vacuum release valve -- or it will go out the main pressure vacuum release valve, and that vents to atmosphere. It's already low pressure.

So we are talking, you know, I think Bill said earlier, a few ounces. And an ounce is 1/16 of a pound; right? So many tanks out there are rated four ounces, eight ounces, 12 ounces, 16 ounces. So you have very -- which means most of the meters out there that you are used to like a differential pressure meter (unclear) technology won't be able to measure the gas flow. They won't see flow.

There is also just no place to put because you are trying to get all the vapors to one place and then have it go through a meter, but the point of a pressure vacuum release valve is to immediately (unclear) the tank to protect the tank, not then route it into another piece so you can measure it.

Q. Now, you also -- you spent some time giving us an understanding of the variations of these tanks and gas moving in and out, et cetera. Is that -- as a result, Mr. Greaves, are operators able to accurately estimate production accounting reporting these types of periodic low pressure emissions?

A. No. And I did want to explain that. So I'm familiar at a working level with a number of the methodologies out there. I personally use API 2000, which describes how to calculate working and breathing losses. And when you rate it at a full -- the math they have used in API 2000, because it's for design conditions, you are trying to design how big the (unclear) how big the valve needs to be if I'm going to flare.

So, for instance, this says, if you're a liquid versus a non-volatile liquid, multiply this number by two. That's the extent. So it's not accurate, right, but it does give you a good box to work within. If you look at Subpart W, Subpart W talks about flash and it's makes some big assumptions; right?

It says, take the oil and the methane, CO2 content of the oil from the separator as it leaves the upper separator and goes to the tank, and the CO2 that all is emitted and that's how much gas comes out, or multiply it by your, your flash factor, your basically a description of how much vapor comes off your (unclear).

So they don't have all the nuance, and the nuance here actually has up to a big percentage of the box. But it definitely times calculating the thermal effects.

What I love about the thermal effects described in API 2000 is it specifically references Southwest United States, where we are, there is a reference because you can have such big temperature swings on tanks where we are, which leads to these, so while it is possible to, to estimate the volumes, you would not want to estimate them for production accounting.

You know, I, I kind of think it this way, okay? I've got five kids, believe it or not, that's why I have hair loss. I have five kids. I'm totally crazy. And I know that I have five kids; right? Like I know with certainty I have five, trust me I know, I've been there. I know there are five.

Now, my wife tells me she wants three more kids. Okay? I just die right there, but she tells me that she wants three more kids. But she said she wants three, plus or minus two. So she might want one, she might want five. Okay? So I know what I have for certain. I don't like to add five to that, that's a terrible number. One I might live with, ten, I couldn't live with ten. Six would be crazy. That would be -- we'd be done.

So that's why, you know, I know that's a simplified approach. That's why I'm getting at, we don't like to add very certain things to very uncertain things. We like adding certainty.

Q. Now -- and with respect to vapors from uncontrolled storage tanks that is currently under reporting categories, that would be a component of the gas loss calculation; right, Mr. Greaves?

A. Yes. Yes, it would.

Q. And a component of the gas capture that would count against us?

A. Yes, uncontrolled tanks would count against you in the gas capture calculation.

Q. And in your opinion, are there any credible methods of estimating those releases for monthly production accounting reporting?

A. No.

Q. Okay. Now, when we get to pneumatic control of the pumps, as the rule is currently drafted, those emissions do not count -- would not count against the operator, do they?

A. Yes, that's correct, because, as we learned earlier this week, they are part of beneficial use.

Q. But do you have the same problem with trying to report them, those releases for a -- on a monthly production accounting scenario?

A. Yes. I won't be quite as animated talking about pneumatics, however, you do face the same similar challenges where there is good quality average data, right, that's Subpart W, but it's average data. Right? And it represents, you know, lots of different controllers, lots of different operating scenarios, not your actual operating conditions. Right?

To actually -- to accurately know the pneumatic controllers in terms of volumes, and we heard some of this today, you would need to know the pressure of the pneumatic gas, the valve pressure. You also need to know the frequency of which you actuate, and that, that assesses no leaking or anything, which I'm not an expert on pneumatics in terms of leaking or anything like that, but that assumes, okay, if I can actually know my actuations, then I would be able to use this manufacturing data.

But we don't have data on our number of actuations, so people use Subpart W which has average data which just is not appropriate, again, because it's got accuracy that you are trying to then use as part of the -- part of the calculation.

Q. Okay. And then you may have testified to some of this a little bit, but releases from improperly closed thief hatches, those would be the same that you just discussed with respect to storage tanks; right?

A. Yeah. Much of that's the same. See ideally on a tank, if your tank is the not controlled, that gas would be going to the pressure vacuum valve. But if the thief hatch is not properly closed, or there might be some dirt on the seal, then the gas may escape through there. Not all the gas, but it's very hard to calculate that because you are looking at all the dynamics of the tanks, and then trying to apply that to something much worse, which is trying to apply it to an unknown orifice size.

When we do gas calculations we usually talk about orifice, how much area, cross sectional area is there for the gas to escape from. On the thief hatches oftentimes we are talking very little.

Now, if the lid is open, okay, totally different, you know the orifice size, but you don't know the volume again because of the dynamics. So whether it's open or just barely cracked with some grease on there, it's not going lead to an accurate calculation.

And oftentimes what happens is you get those little -- the seal isn't setting right, the lid didn't come down perfectly, now, as I was saying, oxygen is coming in, just as likely as the gas is coming out based upon the temperature swings throughout the day and how the liquid volume is changing.

Q. Does this have the same type of breathing that you were talking about earlier based upon the circumstances at the time that the hatch is either closed or open?

A. Yes.

Q. So they have --

A. They have the same effects as uncontrolled storage tanks in terms of vapors in or out.

Q. Okay. Okay. And while you are at it, Mr. Greaves, in your -- in these reporting categories that NMOGA has proposed to eliminate constitute circumstances where operators could not measure the releases; is that correct?

A. That's correct.

Q. And in your opinion, with respect to these reporting categories, do they involve circumstances where operators can estimate releases with any consistency or accuracy for monthly production accounting?

A. No. Not with the accuracy that is expected for production accounting.

Q. Okay. You mentioned oxygen, okay? Are you familiar with how oxygen can get into a gas stream even for sales?

A. Yes.

Q. And you were here for Mr. Smitherman's testimony; correct?

A. Yes.

Q. Do you have another circumstance where oxygen gets into the gas streams for sale through no fault of the operator?

A. Yes. I thought we heard -- we've heard a lot about ways it can go downhole, which has been effective, think about that, it's been a productive conversation. We've heard a lot about commissioning, and I'm very familiar with that. But what we want to talk about here is in terms of the last way that you might have oxygen is through running a vapor recovery on the tanks.

And so all of those dynamics that I was talking about can lead to oxygen coming into the tanks. It's part of the protection for the tank. You don't want your tank to collapse. If you've seen a collapsed tank, you know you don't want that to happen.

So oxygen can come in, and you will do all you can to prevent that if you have a vapor recovery unit. Because what happens is, you get a little bit of oxygen that comes in, and then that vapor recovery unit collects that oxygen and then routes it over to the sales scrubber or to the sales line down the sales meter.

And what's happened is, you've gone and made this effort to collect the vapors off your tanks, and then you've ended up shutting in your entire facility or flaring everything because the, the oxygen spec is no longer met. And many of those contracts we have learned about have a dual oxygen cycle, right, and so zero is a hard number to get to, and so a little bit of oxygen can really impact your ability to sell.

And so it's kind of -- the first thing people ask when you have oxygen is, oh, your vapor recovery unit is on. Well, yeah, I'm trying to make them work, but you get that oxygen in. Now, there is ways to try to prevent oxygen, which is why people install a gas blanket, and so I -- if you had to ask where do you -- if you were a facility engineer and not the manager, where did you spend all your time? It was trying to help operators keep their gas blanket because I was trying to keep oxygen out of the tanks.

And so you can do a lot in terms of engineering, you want to make it -- you want to make the best gas blanket valve ever. Right? And I've tried a lot of different valves to achieve this. And then at no fault of your own, you design it right, you design it right, you pick the right orifice size for the control valve that allows gas to enter, you put it in a good place, you put a good pressure transmitter on to control it, and then you get a massive temperature swing like we have this week with snow, and suddenly your valve that's right for normal conditions isn't going to be right for these huge temperature swings that happen, and then you will get some oxygen.

And so, you know, it's one those, we are back to a situation where you have some oxygen, and even as a prudent operator, as we have used the term this week, you can have oxygen in your tanks that then goes to your vapor recovery unit and then shuts you out of the sale line.

Q. Mr. Greaves, I want to -- were you here for the testimony (unclear) the definition of venting? Have you seen that?

A. Yeah. Mike, I guess -- sorry, I want to go back to what I was saying.

Q. Sure.

A. I just have one more thought. I talk about VRUs; right? Here we talk about uncontrolled storage tanks. When you do go gauge a tank, which is an activity you will do on the tanks quite often, even if you have automatic tank gauges, you will go and you have to go clean them off or you have to go open it up and go calibrate the automatic tank gauge, that also introduces oxygen.

But just thinking, I tend to think about it from vapor recovery units it's hard to get oxygen out, but normal activities around your tank can also bring oxygen in.

Q. So then let me ask you this, Mr. Greaves, based on your experience, is it, in your opinion, is it appropriate for the Division to always penalize operators due to venting or -- I'm sorry -- flaring that is caused by the failure of the gas stream to meet pipeline status?

A. No, it is, it is not. I have, I've personally tried myself many times to keep the oxygen down, and I know it is not appropriate to always penalize for oxygen.

Q. And currently the way the rule is drafted, am I right, Mr. Greaves, that any flaring that would occur due to pipeline impurities would not count against operators unless it was caused by oxygen?

MR. AMES: Objection; leading.

HEARING EXAMINER ORTH: Mr. Feldewert, would you rephrase, please?

Q. Mr. Greaves, you reviewed the rule; correct?

A. Yes.

Q. And do you understand how flaring events are treated for failure of capacity pipeline specifications?

A. Yes. So the gas capture percentage calculation, the enumerator, the top of the equation of what is captured includes sales, beneficial use, emergencies. Let's see, where was -- emergency where it's flared due to N2, h2s or CO2 or vented or flared from a delineation with the Division approval. So none of those categories specifically include oxygen.

Q. And are you aware of that the Division, the way they drafted the rule, would penalize oxygen for -- it would penalize operators for volumes flared due to oxygen in the system?

A. Yes, that's correct. If you have oxygen in the system, it counts against you. It appears to look like a penalty.

Q. Now, I'm going to ask you about NMOGA's change to the definition of venting. You are familiar with that?

A. Yes.

Q. Now, NMOGA's change is (unclear) okay, Mr. Greaves, would the activities that you just described, related to --

(Audio difficulties.)

A. Sorry, I'm getting that -- okay, I'm back.

Q. If the -- if NMOGA's change to the definition of venting was adopted by the Commission, Mr. Greaves, okay, that would be consistent with the Colorado definition; correct?

MR. AMES: Objection, leading.

HEARING EXAMINER ORTH: Mr. Feldewert, would you watch that, please.

Q. Mr. Greaves, would it be consistent with the Colorado definition?

A. Yes.

Q. And if that definition was adopted, would categories like uncontrolled storage tanks, pneumatic controllers and pumps, improperly closed thief hatches, would those low pressure emissions constitute venting as normally -- as defined by Colorado?

A. No, they would not.

Q. Okay. And you've had experience with the BLM rule?

A. That's correct.

Q. And did the BLM rule attempt to address these low pressure emissions that you see from uncontrolled storage tanks, pneumatic controllers and improperly closed thief hatches?

A. Yeah, I think -- hold on, I was going to go to the language, but I can summarize it.

I think it's important to note on the BLM rules, the 26 D rule, where there is a gas capture percentage imposed, and it was 98 percent. At the time it was set at 98 percent to be achieved by January 1, 2026, I believe, that the way the calculation is done for that gas capture percentage, it says, the term adjusted total volume of gas produced means the total volume of gas captured over the month, plus the total volume of gas flared over the month from high pressure flares. And then there is a credit, it subtracts a credit.

So what that means without reading the whole section is that the, the gas capture percentage applies only to volumes that are flared at a high pressure flare. And the rule purposely excludes tank vapors whether they are flared or vented. The focus is on high pressure flare to achieve that 98 percent.

Q. Do you have an understanding as to why the BLM approached it that way? Do you have any challenges associated with trying to estimate these types of low pressure volumes?

MR. AMES: Objection. Calls for speculation about what BLM was thinking.

HEARING EXAMINER ORTH: Mr. Feldewert, I have to agree with that.

Q. And, Mr. Greaves, you were -- you actually met with the BLM with respect to their rule?
A. Yes.
Q. And advised them on issues like you just advised the Commission?
A. Yes.
Q. And based on your understanding of the rule, BLM did not seek to include these types of low pressure circumstances in their accounting for gas capture?
A. Yes. We did have conversations about the challenges of low pressure measurement.
Q. Okay. Mr. Greaves, were NMOGA's I1 through I10 prepared by you or compiled under your direction or supervision?
A. Yes.
MR. FELDEWERT: Madam Hearing Officer, I move the admission into evidence of NMOGA Exhibits I1 through I10.
HEARING EXAMINER ORTH: Let me pause for a moment in the event there are objections to NMOGA Exhibits I1 through I10.
(No audible response.)
HEARING EXAMINER ORTH: Exhibits I1 through I10 are admitted.
(Exhibits I1 through I10 admitted.)
MR. FELDEWERT: Madam Hearing Officer, I pass the

witness.

HEARING EXAMINER ORTH: Thank you. Mr. Ames?

MR. AMES: Yes, thank you, Madam Hearing Officer. I just have a couple of questions for Mr. Greaves.

CROSS-EXAMINATION

BY MR. AMES:

Q. Good afternoon, Mr. Greaves.

A. Good afternoon.

(Audio difficulties.)

HEARING EXAMINER ORTH: I'm sorry, Mr. Ames, there is some really bad feedback. Mr. Feldewert, are you able to mute unless you actually have to object?

MR. FELDEWERT: I'm already muted.

HEARING EXAMINER ORTH: I'm not sure how -- let's give it a try. Irene, speak up if you can't hear.

REPORTER: There is a lot of background noise. Unless somebody else is on their device and not muted, I'm not sure where it's coming from.

MR. AMES: Perhaps, Mr. Greaves, you can mute yourself until you answer the question and maybe that would -- it would leave me only speaking, maybe that would help, and then I will do the same for you.

BY MR. AMES:

Q. Can you hear me, Mr. Greaves?

A. Yes.

Q. Mr. Greaves, you testified that about five reporting categories, downhole operations, liquids unloading, uncontrolled storage tanks, pneumatics and thief hatches. If I understood your testimony correctly, you were not comfortable reporting on these categories because the reliability of the data that would be collected; is that correct?

A. Based upon the challenge to measure and to be challenged to accurately calculate an estimate that is in the objective of production accounting, they were not appropriate to include.

Q. Right. So I think you said it was difficult to meter; is that right?

A. It would be very difficult to meter with any certainty.

Q. But you can estimate them; isn't that correct?

A. You can estimate them, but not with a high amount of accuracy, with the accuracy that you would have, say, anywhere near with a sales meter.

Q. And you can model them; right?

A. Yes.

Q. And you actually -- your company and other companies have to estimate or model the emissions from these categories for some permitting and even some federal requirements; isn't that right?

A. That's correct.

Q. So you testified that these five categories would be counted as lost gas for compliance with the 98 percent natural gas capture requirement; right?

MR. FELDEWERT: Object to the form of the question. That misstates his testimony.

HEARING EXAMINER ORTH: Mr. Greaves, do you remember that you gave that testimony?

THE WITNESS: I did not say that all of them except for the pneumatics would count against your gas cap.

Q. Thank you. That was my next question. I wanted to ask you if you knew pneumatics were excluded from the five categories reporting. So you were aware of that?

A. Right.

Q. So the other categories, the four other categories, you're aware that the capture requirement allows two percent free waste; right?

MR. FELDEWERT: Object to the question. I don't know what you mean by free waste.

MR. AMES: It's not a valid objection that counsel doesn't understand the words.

MR. FELDEWERT: Object to the form of the question.

HEARING EXAMINER ORTH: Would you rephrase.

MR. AMES: There is nothing wrong with the form of the question.

HEARING EXAMINER ORTH: Mr. Greaves, would you mute yourself when you are not speaking.

THE WITNESS: It's keeps auto unmuting. I'm trying.

HEARING EXAMINER ORTH: Mr. Ames, now I've lost track of the question myself. Would you please repeat that?

MR. AMES: Sure.

Q. Mr. Greaves, you're aware that the natural gas capture requirement is 98 percent; correct?

A. Yes, I am aware of that.

Q. And therefore it allows two percent lost gas without consequence. Isn't that right?

A. That is my understanding.

Q. And one might call that free waste; isn't that right?

A. I'm not an expert on waste, but I can see that's two percent, you are saying is you have a two percent margin or something.

Q. And that would cover the categories of venting and flaring, the five reporting categories that you have concern about with respect to (unclear); isn't that right?

A. Well, I do not think that the devouring the two percent that you may have, which you have called free waste, with five categories, or four, not five, that are highly uncertain is appropriate when there are other categories that are related to high pressure flaring and venting that are enumerated in your rule that it is appropriate to devour the two percent with categories that you cannot appropriately estimate or accurately estimate.

Q. Cannot accurately estimate, but what you consider to be fairly small relative to the high pressure venting; isn't that right?

A. Relative to high pressure venting may be large or small. It depends on the operator. The purpose of this rule, as I understand it, is to eliminate routine flaring. So as you get smaller and smaller, then it may or may not be a large contributing factor. Now a high uncertainty that, you know, that may be small may be a significant portion of your two percent.

Q. But you just said that it's almost impossible to monitor reliably, so you really don't have any data to back that up, do you?

A. I just would not want to include that in the two percent with something I cannot accurately estimate.

MR. AMES: Nothing further. Thank you.

HEARING EXAMINER ORTH: Thank you. Mr. Biernoff, do you have questions for Mr. Greaves?

MR. BIERNOFF: Thank you, Madam Hearing Officer. I have just a few questions for Mr. Greaves.

May I proceed?

HEARING EXAMINER ORTH: Yes, please.

CROSS-EXAMINATION

BY MR. BIERNOFF:

Q. Good afternoon, Mr. Greaves. Mr. Greaves, you testified during your direct, and this is -- well, let me orient you first. Mr. Feldewert was asking you some questions about OCD's proposed rule, Part 27.8.F.5, do you remember talking about that provision?

A. Yes. (unclear) of that, but yes.

Q. Okay. And you testified that for valves that were not required to be equipped with metering equipment, that you (unclear) operators can use a methodology that could be independently verified to estimate vented and flared volumes; right?

A. That's in terms of the GOR.

Q. Right. And are there any methodologies that the operator can use that you are familiar with that cannot be independently verified for this purpose?

A. Can you clarify? You are talking about the associated gas flaring, or what specifically are you speaking about?

Q. I'm speaking specifically about the language that you testified about earlier this afternoon, and the language -- I'll just read it. The provision that says, if

metering is not practicable in the circumstances such as low flow rate or low pressure venting and flaring, the operator may estimate the volume of natural flared natural gas using the methodology that you (unclear).

A. Okay. Can you restate your question now that I'm reoriented?

Q. Absolutely. I was asking you, were you aware of any methodologies that operators might use pertinent to the provision looked at that cannot be independently verified?

A. Let me think for just a minute there.

I think if you are able to develop an approach to estimate, that it therefore implies you would be able to share an approach.

Q. Are you aware of any methodology, reporting methodology, estimation methodology that cannot be independently verified?

A. I may struggle to give -- if say my estimate is based upon looking at scada data, it may be difficult to provide some of that scada data, but I could still be able to describe why I determined what estimation methodology I've used and why I would believe that makes sense as an appropriate methodology.

Q. I may not have understood your answer, and I apologize.

A. Yeah, I'm a little hesitant to say that I could give all of my data that, you know, the number of factors I might need to include. I just haven't thought about the, you know, the implications of providing all of that data. You know, for instance, if you have to estimate a PSV release, and you need to know all the pressures and temperatures and flow rates, I don't know how easy -- I don't know if I feel comfortable in speaking for everybody in providing that data, but I could certainly for that instance provide a methodology. I can describe -- I can provide a methodology that can be verified.

Q. Okay. But you're not, you're not here today thinking of a methodology again pertinent to this provision that cannot be independently verified?

A. No. I'm not thinking of such a thing.

Q. Okay, great. So you testified earlier this afternoon, I believe, that you had assisted the BLM with that agency's methane waste rule; is that right?

A. Yes. I mean, I provided expertise and met with them on multiple occasions about the challenges of flared measurement like we have talked about today.

Q. Okay. But you were not hired by the BLM as an expert or consultant; right?

A. No. That's why I wanted that to be clear. I met with them on multiple occasions, but not as a hired consultant.

Q. Okay. You met with them on behalf of XTO?

A. I met with them via XTO and through API.

Q. Okay. And who was paying for your time when you were meeting with the BLM regarding the methane waste rule?

A. XTO Energy.

Q. Okay. Were you part of the delegation that was led by the North Dakota's Petroleum Council that met with the Federal Office of Management and Budget to (unclear) about the BLM rule in the fall of 2016?

A. I believe so. I'm having a hard time remembering if that was one of the meetings that I participated in.

Q. And at the time in the fall of 2016 the North Dakota Petroleum Council said that the BLM methane waste rule posed a serious risk to the state, tribal and national economy, and that the federal government should instead be focused on approving permits for more pipelines.

Do you agree with that statement?

MR. FELDEWERT: I'm going to object to the form of the question. I don't know how that relates to this particular rule that is before the Commission, number one. And Mr. Greaves just indicated that he was -- he did not recall that he was part of that council. So his opinion on what the council said has absolutely nothing to do with the issue before this Commission.

MR. BIERNOFF: I totally disagree with that, Madam Hearing Officer. First of all the witness said he believes he was part of that meeting. And Mr. Feldewert has also presented the witness as someone who spoke to the BLM and managed their rulemaking, so I think it's appropriate to ask some follow-up questions about that.

HEARING EXAMINER ORTH: I agree. Please, Mr. Greaves, if you can, answer the question.

A. Okay. I, I don't remember if I was at that meeting, Mr. Biernoff. I would like to say yes or no, but I don't remember. But my expertise both there and here today have to do with measurement and estimation methodologies, and that is where I provided information before and currently.

Q. So I'm asking you again, do you agree that the BLM rule should have been set aside because it was harmful to the economy and that BLM should have been focused on approving more pipelines?

MR. FELDEWERT: I object to that question. It has nothing to do with the rule that's before this Commission.

MR. BIERNOFF: Mr. Feldewert, Madam Hearing Officer, has presented multiple times on the subject of the BLM rule, including through this witness, and has analogized to this rule, and has made statements about the shortcomings of that other rule, so I think it's appropriate to determine what this witness knows about the BLM rule.

MR. FELDEWERT: That's a different subject.

HEARING EXAMINER ORTH: Aren't we still on the same subject, Mr. Biernoff?

MR. BIERNOFF: We are on the same subject. I had a question that has not been answered by Mr. Greaves regarding his view of the organization that he went to Washington, D.C. with to lobby the BLM about.

MR. FELDEWERT: I object to that. There is absolutely no evidence in the record of that. Ask him whether he went before you ask that kind of question.

HEARING EXAMINER ORTH: Right. I'm not sure that I heard a foundation laid for that question. Perhaps I missed it, Mr. Biernoff.

MR. BIERNOFF: Madam Hearing Officer, I asked this gentleman if he was part of a delegation led by the North Dakota Petroleum Council that met with BLM. He said he believed he was. That organization made a statement, and I'm asking the witness if he agrees with the statement that his companions announced.

MR. FELDEWERT: That mischaracterizes his testimony, Mr. Biernoff.

MR. BIERNOFF: And his -- I'm sorry, Madam Hearing Officer.

HEARING EXAMINER ORTH: Go ahead.

MR. BIERNOFF: And at this point I'm simply looking for an answer, a straightforward answer one way or the other whether Mr. Greaves, who said he assisted the BLM in multiple meetings, agrees with what this other party said about their rule which has been compared by the New Mexico Oil & Gas Association to this rule.

HEARING EXAMINER ORTH: All right. So, Mr. Greaves, if you can answer the question, have an opinion of that, please answer the question.

A. Okay. And I apologize, Mr. Biernoff, that I don't remember if that was one of the meetings that I was in with them. I can remember certain meetings. I don't know if I remember that meeting.

Again, my expertise is around measurement. Do I believe that it's very important to be able to have gas pipeline takeaway capacity? Yes. And that the way to reduce flaring is through adequate sales line capacity, and that is just the nature of how this works, you want it to be able to go down a pipeline for sales. But I don't have the expertise to comment on the --

Q. Okay. And you did not tell, Mr. Greaves, you did not tell the Office of Management and Budget for the BLM that you believed or that XTO believed that the BLM Methane Waste Rule was dangerous to the economy?

A. My, my expertise was brought in to talk about measurement, as I said.

Q. So you did not make a statement to the --

A. About the rule?

Q. -- harming the economy.

A. I don't believe I have. I don't remember I said that. I don't remember saying that.

Q. Okay. Okay. Thank you, Mr. Greaves.

MR. BIERNOFF: Madam Hearing Officer, I don't have any other questions for this witness.

HEARING EXAMINER ORTH: Thank you, Mr. Biernoff. We have been going nearly two hours, and so what I would like to do is take a break before we continue Mr. Greaves questioning. Can we take 15 minutes, come back at 2:55. Thank you.

(Recess taken.)

HEARING EXAMINER ORTH: Let's come back from the break, please.

Ms. Fox or Mr. Baake, are you going to have questions of Mr. Greaves?

MR. BAAKE: Madam Examiner, this is David Baake, I have a few questions here. Let me see if I can get the light -- it doesn't really matter.

CROSS-EXAMINATION

BY MR. BAAKE:

Q. Hello, Mr. Greaves.

A. Hello.

Q. Good afternoon. So Mr. Greaves, are you aware that XTO and other operators are required to report their venting and flaring data to OCD on the C-115 form?

A. Yeah, I'm not an expert on the C-115, but I understand that.

Q. And do you have any idea how much venting and flaring XTO reports per year?

A. I don't have those numbers in front of me, no.

Q. Would it surprise that they reported venting and flaring 4.5 billion cubic feet in 2019?

A. I don't know the number to know if that's accurate or not.

Q. Okay. But that, we do have an exhibit on that, but it sounds like you are not familiar with it. The reason why I'm asking about this is because you testified about five sources for, sources and operations that are -- that NMOGA is proposing should be excluded from the rule; is that correct?

A. Yes. Five reporting categories.

Q. Downhole operations, liquid unloading, uncontrolled storage tanks, pneumatic devices, improperly closed thief hatches?

A. Yes.

Q. So it doesn't sound like, you wouldn't know how

much, on the C-115s, how much XTO venting and flaring that are reported came from those five categories?

A. No. I don't know the fraction of that volume is from those categories.

Q. Okay. Are you familiar with NMOGA's methane mitigation road map?

A. No, sorry, sir. I'm -- I'm not -- that's not my expertise. I'm not familiar with it.

Q. No, I understand, just wanted to ask because, you know, you spent -- you talked about these five categories, and I don't know -- so I don't know if would surprise you to learn -- let me ask a different question.

Would it surprise you to learn that NMOGA's road map stated that four of the most significant sources of venting were emissions, storage tanks, pneumatic controllers and well maintenance (unclear)?

A. Well, I'm not familiar with the data, so I would prefer if I knew the data to be able to answer that question better.

Q. Okay.

A. I --

Q. Understood, but I guess I'm a little confused because I did understand that you were testifying about those five categories and saying they shouldn't be part of the rule; right? They shouldn't be covered by the gas

capture requirement; is that correct?

A. Yeah, they should not be reported, which would then not -- which would then change their impact to the gas capture percentage.

Q. Okay. But I don't know -- I mean, NMOGA put out this report and did say that these four were the most common sources of emissions. So it sounds like NMOGA had an idea of how much gas was being vented as a result of those operations. That's a again -- it's not fair to ask you to explain why, why they said that.

But I do, I apologize for directing some questions that do not -- maybe, you know, are not exactly within your wheelhouse. I want to go to the BLM rule, all right?

So I think you testified that BLM exclusively focused on venting and flaring of high pressure associated gas as part the gas capture plan?

A. Yes. Within the rule their language is that the the gas flaring -- the gas capture requirement is focused on high pressure flare gas.

Q. But it adopts specific performance standards for pneumatic devices; correct?

A. Yes.

Q. Do they adopt regulations with downhole maintenance and liquid unloading?

A. Yes. Although I will admit that my expertise was brought in around measurement and estimation, and less about -- I'm not -- about air emissions or the categories liquid unloading, and what was the other one you said?

Q. Downhole maintenance and pneumatics?

A. Yeah.

Q. And BLM did adopt performance standards for storage vessels as well. Is that your understanding?

A. Yes.

Q. Okay. So I just want to be -- it was a helpful clarification that while I -- let me ask a different question. So BLM did consider venting from these sources to be waste in this regulation?

A. I'm not an expert on definition of waste. I just know what we focused on for measurement and estimation and the gas capture calculation.

Q. Okay. But would you agree that just because of it can't be measured with great precision doesn't mean it's not a significant source of waste?

A. Yeah, I'm not an expert on the definition of waste, but I can -- I can say that your approach is that they're independent, whether it's waste or not is different than whether it can be measured and accurately determined. I can understand you are trying to segregate those two activities.

Q. Right. And I appreciate you answering my question, which I -- I probably could have phrased it in a little more coherent way, but I think you got it.

So I think we are clear that there may be a source of waste -- of venting that's just hard to measure, but it may still be significant and may still warrant (unclear) you wouldn't disagree with that?

A. I'm not -- yeah, not necessarily. I have to think about the exact situation you are describing, but yeah.

Q. And I, I appreciate that. And I wanted to ask one technical question about GOR. How -- you know, one of the themes of your testimony seems to be accurate and something you can measure with reasonable consistency.

How accurate is GOR? How -- could the gas oil ratio -- well, how much does it vary within, you know, a single day. Does it vary every single day?

A. I think the easy way to talk about this is we can, without getting into a lot of complications about uncertainty and how to define uncertainty, which is a whole different realm of expertise, I can just kind of speak anecdotally if that's okay.

I have spent a lot of time looking at our well tests and our GOR, and when I use well tests -- I'll stage it with this: A typical uncertainty for flare meters of high pressure gas, when you have -- and I'm going to set the stage with flare meter, so hang with me a second -- a typical uncertainty may be five percent if you are greater than one foot per second.

So again trying to get to the rate, that's where the velocity comes in, and that's for high pressure gas. So where you can accurately measure, you can target say five percent is typical for higher rate.

When you're on a separator that's very similar conditions, where you have high pressure gas, you also have very consistent, you have a well test separator where you determine the GOR is more consistent than flare, and it can be easier to get even, even a greater certainty.

And so I have seen where I do 24-hour well tests, it's not unreasonable to have, you know, the same order of magnitude of certainty if not better on my GOR when I look at doing a gas balance. So if I, if I look at taking those well tests and then using that to do a gas balance against my sales, and if I did have a flare meter, then I can see that I can get very similar, if not better, uncertainty.

Q. So I, so you do 24 hours as an average, is the average period that you would do?

A. It's very typical. Me, personally, I have done -- always I do 24 hours because I want to smooth out any, any erroneous or, you know, behavior around slug or whatever. So, yes, 24 hours for the wells that I have looked at provides good, reliable data.

Q. Do you have any familiarity with the Canadian federal government's regulation in this area and how they recommend operators calculate GOR?

A. No, I don't.

Q. Okay. Would it surprise you that they recommend a 72-hour averaging period? Do you think that is consistent with --

MR. FELDEWERT: I'm going to object. It's based on facts that are not in evidence.

MR. BAAKE: I think if we can testify about GOR methodology and how reliable it is, I don't understand why it's problematic to ask how their regulators have proposed averaging. We can introduce this regulation as an exhibit, we are fine with that.

HEARING EXAMINER ORTH: Right. And I think as an expert that Mr. Baake can pose hypotheticals to Mr. Greaves. Go ahead and answer the question, if you can, Mr. Greaves.

A. Okay.

Q. I'm happy to restate it if you like me to.

A. Please.

Q. The question was, would it surprise you that the Canadian federal government or any regulator would say that 72 hours is the appropriate averaging time for GOR?

A. Well, I -- I don't know the Canadian government or their -- and Canada is not New Mexico. Sorry, Madam Chair, I thought you might laugh. So, but, it's very, you know, it's very dependent. For some reservoirs you can do much less than 24 hours and have consistent flow.

Perhaps their reservoirs are very different and need a longer time, so I don't know their reservoirs to know that. 24, I have looked at our data, and that provides very stable data where we operate in the Delaware.

I think it is interesting that you said Canadian because like I have read another document from Canada that I have near me. I did not -- I think you may have mentioned this as an exhibit, but it's from Canada, it's from Alberta, an engineering firm there, and they specifically say GOR values be developed based on at least a 24-hour test, and that these results be updated annually.

So there is people in Canada using 24 hours, not 72, so I'm not sure where the 72 comes from or why they are saying 72. It must not be any across-the-board Canadians believe in 72.

Q. For sure. Appreciate that, and just to pick up on that, and then I'm almost done. I appreciate this colloquy, it's been interesting to me. But you said, but that map reference that should be updated annually.

A. Yes.

Q. And that's because the well characteristics change or --

A. Yeah.

Q. Very interesting stuff. I really appreciate it.

MR. BAAKE: I will pass the witness.

HEARING EXAMINER ORTH: Thank you, Mr. Baake.

Ms. Paranhos, do you have questions of Mr. Greaves.

MS. PARANHOS: Thank you, Madam Hearing Examiner, I do not.

HEARING EXAMINER ORTH: Commissioner Engler, do you have questions of Mr. Greaves?

COMMISSIONER ENGLER: Yes, I do. Good afternoon, Mr. Greaves. Can you hear me?

THE WITNESS: Yes, I can here you well.

COMMISSIONER ENGLER: I have got a -- my first question is, how is your wife going to react when she hears this recording about having five more kids?

THE WITNESS: Well --

COMMISSIONER ENGLER: You don't have to answer that. I just that -- that was just a simple question, but that's all right. I do have some real questions.

THE WITNESS: I like that question better, but thank you.

COMMISSIONER ENGLER: We are going to send her the recording, by the way.

No, I do have some legitimate questions. I want to go to -- it's this discussion between. Let's see, the Division wants compositional analysis of vented and flared natural gas, and NMOGA wants to change compositional to representative. I do believe you know where I'm talking about.

THE WITNESS: Yeah, I should clarify. It's -- we keep the word compositional, but we put the representative or representative compositional.

COMMISSIONER ENGLER: So it does have compositional in it?

THE WITNESS: Yeah, we are not to trying remove the word compositional.

COMMISSIONER ENGLER: That's good. I was wondering about that. But I do have -- my suggestion here is, it would be nice to say not just the representative compositional, but also say analysis of vented or flared natural gas from that well or facility, because representative is just too undefined for me.

So would you, would you agree or that having that, that quantifier there from that well or facility be reasonable?

THE WITNESS: Yeah, that makes sense to me. I, when I say the word "representative," if you listen to my examples, right, the examples I gave were from that well or facility.

Because you have to -- I don't like to speak for all of NMOGA, right, but because you have to know -- you have to know your gas composition somewhere for your facility at sales, you are going to know a representative sample. You won't have it the first day, though, so I don't know if maybe we feel comfortable when you, you know, day one when you bring on a well a lot of times people use analogues because they know what formation it's in, they know the area, they have good samples, sometimes that's best. But eventually you have to get -- an operator will have to get a gas sample for the location where they are in order to tune the sales meter.

COMMISSIONER ENGLER: I appreciate your example. For me it's -- I want to get away from this overuse of analogues from somewhere else. Okay. I haven't -- I have a different question. It goes back to the GOR. And I want to ask questions and hopefully you can help walk through me on some of this.

And you answered, I guess where I was going to go with some of this. So if I, if I could have a facility that has a flare meter, and then if I also can then do a GOR check and do my balance equation, have you, have you done -- have you compared in a single facility between the two to see the variation or how close they match or don't match?

THE WITNESS: Yeah, I -- this is my own practice, right, so this is not all of NMOGA, but my personal practice, again trying to make sure it's very clear.

When I have all that data, I like to do system balances and have seen, you know, anywhere from 2 to less than 10 percent just to balance there because I want to know how good -- I like to use that to then know how good are my meters and if I tuned them right. So I have done that.

COMMISSIONER ENGLER: So you have a flare meter measurement, right, with probably with some accuracy?

THE WITNESS: Yeah.

COMMISSIONER ENGLER: And then you will have, in your equation you've got your, you know, your test -- so you are GOR times oil, minus your sales meter, minus your beneficial use, which you, you know, you list there a variety of beneficial use. So you have your calculated volume from, from this equation; right? And that's plus or minus as well; is that correct?

THE WITNESS: Well, yeah, and I thought you had asked if I also have a flare meter so that I could do a balance. If I don't have a flare meter, then I use the GOR calculation as you are saying.

COMMISSIONER ENGLER: (unclear) You are

absolutely correct. So I have both, so I don't have to worry about the balance because I have too many balances of the equation of the comparison between the calculated value and the flare meter value.

THE WITNESS: Okay, I see your question.

COMMISSIONER ENGLER: Have you ever done this?

THE WITNESS: No. No. And I guess the way that I describe the balance that I have done, and I was just looking at some of my recent ones to give you an idea, they are even better than I thought, so -- sorry about that. The reason I was describing it the way I did, even though I haven't said I'm going to compare what a GOR would give me versus what the flare meter would give me, I think that's what you are asking; is that correct?

COMMISSIONER ENGLER: Yes.

THE WITNESS: Okay. I have done it by balance which mathematically will lead to the same thing. I take all the gas that would be produced if I used based upon my well test, and then go subtract off the flare that I have measured, subtract off the beneficial use that I calculated, and subtract off the high pressure sales, or the sales and then look at that difference, and it's the same math, right, it's the same thing. And I have done that, and oftentimes it's within -- I am looking at ten batteries right now, and many of them are less than a percent, many are within five,

five percent, give or take.

So these two approaches being comparable, you know, given that any given -- given that a flare meter is typically five percent uncertainty, that's pretty good that my, you know, it's very good that my gas test meter is getting within the same uncertainty as the flare meter within the bounds.

COMMISSIONER ENGLER: Yeah, what you are doing is what I'm asking.

THE WITNESS: Yeah.

COMMISSIONER ENGLER: So.

THE WITNESS: That's why I try to say that I have confidence in the GOR approach. If it's --

COMMISSIONER ENGLER: Okay.

THE WITNESS: If it was giving me 50 percent, I would say I don't have confidence.

COMMISSIONER ENGLER: Yeah. Now I've got a follow-up on this, and this is where I would like to get your expertise on.

When you do -- when you do just the balance calculation, again you take GOR times the oil, minus sales, minus your beneficial use, what you have that you have what you are calling flare volume is really flare plus anything else. That could be losses in anything else. I'm not saying anything individually, just some of the facility.

THE WITNESS: Yeah.

COMMISSIONER ENGLER: And so, is it possible to take -- again, I'm trying to take that calculated volume, and when you compare it to a flare meter volume, is there sufficient accuracy there to say, "Oh, okay. I know how much went to flare. The rest of this that is not flare is coming from somewhere else through the whole facility." Is that a clear? Did I --

THE WITNESS: Yeah. I know what you are asking. That would be very hard from the standpoint of the, you know, when you look at -- I just just think about relative volumes. If I have a sudden flare event of gas, and I'm routing, say, all of my sales to flare suddenly because there was a midstream emergency, then that volume relative to, say, whatever we talked about today, a leaking flange would be very -- that's orders of magnitude smaller, right, so I wouldn't know that.

Now, if I -- that's the sample from the measurement certainty and how many significant figures there are in that flare measurement. If instead I have an event that say I knew the PSV, but say I have a facility where the PSV is routed to the flare, which some companies do, they route their PSV to the flare line, and I knew that the PSV lifted, let's say I have data on the pressure in that vessel, so I knew that the PSV vessel lifted because it overpressurized, then I could back out and know, well, a certain amount of this volume must have been attributed to that.

But without knowing the event I would not be able to back it out to a balance given the certainty of flare measurement. Or GOR, either way, I would not be able to get it.

COMMISSIONER ENGLER: That's sporadic, yeah, I was thinking more about uncertainty of plus or minus, but, yeah, the sporadic events will overshadow these minor -- what I call minor losses. That's interesting, I thought I had something like where we could learn something new here. Okay. I appreciate it. Thank you very much.

THE WITNESS: Thank you.

HEARING EXAMINER ORTH: Commissioner Kessler, do you have questions of Mr. Greaves?

COMMISSIONER KESSLER: Yes, thank you. Good afternoon, Mr. Greaves, I'm looking at your Exhibit I8 which has your calculation description measurements for -- that's the calculation for estimation based on GOR method.

THE WITNESS: Okay.

COMMISSIONER KESSLER: And we talked about the (unclear) capping out beneficial use, and the context of my question is in -- with respect to the Division's language in the proposed rule that says independently verifiable. So for audit purposes at the State Land Office, it's important to be able to go in and verify each different category of the calculation, right, so it's pretty easy for us to validate sales.

How, in your experience and based on your expertise, how do companies track beneficial use?

THE WITNESS: I will answer from my experience if that's okay. So personally we, we keep track of our equipment in terms of we know where we have equipment, right? And so I know where I have treaters, the heater treater is an easy example. It's, on traditional batteries, it's one of the most common uses of least used gas.

So heater treater, I will know how many heater treaters I have and I know where I have them. So X battery has three heater treaters. I then also keep track of the size of the heater treater. And so I know this is called a a 6 by 20, which means it's 6 feet in diameter, 20 feet tall, and it's 500 -- I get the unit wrong, 500,000 BTU, whatever the right unit is, right? And so I know how much the BTU value is, or the heater value for that heater treater, and then I also know the manufacturer.

So then I go to the manufacturer -- and this is if you are not measuring, this is when you are using data -- I go to the manufacturer and I get from them information for -- you know, we don't use a thousand manufacturer, we might use ten for heater treaters -- so I go to each of them and get their information.

Now, heater treater is pretty standard and there is a really nice API calculation you can use for heater treater, so I might use that, but let's say I use the manufacturing data, which is going to give you a very similar answer, and I use the manufacturing data and I say, okay, this brand uses this much. I put that into my accounting software and say, "Every month I need to know how much that heater treater ran."

So my operator says, "Hey, I had that heater treater on for three weeks."

Okay. I take three weeks -- and the software does this -- and it multiplies that time that it's on by the factor that you have put into the program that the manufacturer gave you. Like, I use this much MCF per day or this much per hour, and it multiplies the two.

And that's very easy to track and then be asked about, you know. I did not -- I was not responsible for that in New Mexico, but I was responsible in North Dakota for that, and I knew all of my equipment, and I knew the factor for each brand. And I have gone to each manufacturer and I have that information. Like this company says this is how much a pilot uses based upon if you follow their specifications, and we do, so I was able to provide that in a graph.

COMMISSIONER KESSLER: We'll just use your company (unclear) be able to estimate beneficial use for a given well?

THE WITNESS: Yes.

COMMISSIONER KESSLER: Do you know how long XTO keeps records of that?

THE WITNESS: No, as long as we keep our -- I can't tell you how long they would keep like the documents that went into the factor, but you know, many -- I'm not an expert on how long they keep things, but there is always a record how long you have to keep things, and that controls. I can go back several years myself and see how much we produced for every well, because we want to know what a well produced, and this is part of what it produced. I just don't know how many years the data is stored.

COMMISSIONER KESSLER: Does it make sense that the beneficial use is an estimate, then if you are just saying I used this piece of equipment for three weeks, then that necessarily -- that input wouldn't be something that, that when you get to that granular level would be auditable; right?

THE WITNESS: I'm not sure I understand your question.

COMMISSIONER KESSLER: Well, you said that when you were -- you used the example of the heater treater, and you would talk to your operations staff, and they would say we ran the heater treater for three weeks.

THE WITNESS: Oh. They would report every day how many hours they ran it.

COMMISSIONER KESSLER: Okay. That's based on actual also a record that's kept --

THE WITNESS: Yes. Yes. For XTO, knowing what I know, we have them do that. So that's, that's how we choose to calculate use. Our choice is we want operators to write the hours that a piece of equipment is on, and then the engineers have worked with manufacturers to determine the factor that gets multiplied by that time.

COMMISSIONER KESSLER: Yeah. And what I'm saying is whether or not each of those pieces of information can be independently verified. And it sounds like, based on recordkeeping, that XTO would be.

THE WITNESS: Yeah, I would be able to, if required sometime to give you, I would be able to print the hours on data for a piece of equipment, and you would be able to see that I multiplied the hours by this factor for the piece of equipment and get to the number that we got you.

COMMISSIONER KESSLER: Have you ever worked for a company besides XTO?

THE WITNESS: No.

COMMISSIONER KESSLER: So do you have knowledge about how other companies calculate their beneficial use?

THE WITNESS: I know -- I can tell you, you know, that the -- it's pretty standard. I don't know the details of how they do it, but I know that when I have talked to other people it's very common to, to work with a manufacturer and determine the right estimation methodology.

COMMISSIONER KESSLER: I'm wondering for smaller companies.

THE WITNESS: Oh, okay. I don't know how, I don't know that detail, no, sorry.

COMMISSIONER KESSLER: Okay, thanks. Those are all my questions.

HEARING EXAMINER ORTH: Thank you, Commissioner Kessler. Madam Chair, I don't know if you have more than 20 minutes of questions, but if you do we can take a break anyway.

CHAIRWOMAN SANDOVAL: I actually don't think I do. My first standard questions here, do you support the rulemaking?

THE WITNESS: Yes. Madam Chair, I'm -- you know, I've come here and made it clear that I'm a technical expert, really focused on measurement, and that's where my expertise is today. So within that role, I do support many of the provisions that the Division has developed in this process, you know, particularly some of the revisions that have happened December 30, and then, you know, in the last few weeks, right, Part 27 and 28 on measurement, I do support those changes.

And I believe that, you know, with just -- with some changes that I have discussed today, that it would provide some certainty related to the ability to implement this rule and be consistent. And so with those changes I think it could be better, and that's, that's just how I measure my support.

CHAIRWOMAN SANDOVAL: Okay. From your experience with this rulemaking or previous, do you feel like it's been a collaborative process?

THE WITNESS: Yes, I do.

CHAIRWOMAN SANDOVAL: Okay, thank you. You mentioned in your testimony, I believe, that Ultrasonic meters can be anywhere from 20 to $90,000. What is the variability -- or what causes that variability?

THE WITNESS: Yeah. And that's, that's the -- if I -- I just want to put on the record, right, that an Ultrasonic -- I don't want them coming after me. So that's the number that API published as part of the comments to the BLM rule based upon data that they had.

So with that caveat, with metering technology, you can pay for accuracy sometimes, right? And so you can pay for, there is multiple passes to Ultrasonic meter and you can have multiple probes that might impact the accuracy.

You can pay for like -- like if you think about an orifice meter, if you have seen an orifice meter, they have what are called finger fittings where you can pull out the orifice and still keep flowing, and that way you don't -- that way you don't interrupt flow. So there is that Ultrasonic.

And then there is also, some Ultrasonic meters are insertion-type where you put in your own fittings on the pipe and insert them. Others Ultrasonic meters are prefab and built with the diameter of the pipe and it's flanged up. So you can imagine on those if you have a bigger pipe to flare, you need a bigger meter.

And so there's kind of a whole variability. A lot of meters you are paying for pipe diameter. Like Coriolis, you are paying for pipe diameter. For Ultrasonic there is different ways to do it. So sometimes you are paying for pipe diameter and sometimes you are paying for accuracy and there is a balance there.

CHAIRWOMAN SANDOVAL: Okay. So talking in the measurement provisions I think in -- oh, gosh, like F -- one of the later numbers, one of the GORs, you said, setting clear standards on GOR measurement and basically saying that if there were clear standards for GOR measurement, then it's is very accurate and can be as accurate as a meter. Do you recall stating that.

THE WITNESS: That sounds like something I would said. It's been a long afternoon, but I'm sure I said that if you wrote it down.

CHAIRWOMAN SANDOVAL: Do you feel like the Divisions rule, proposed rule gives those clear standards on GOR measurement? Are there enough confines in it to make sure that the GOR calculations that would be utilized would make those numbers as accurate as a meter or on par?

THE WITNESS: Yeah, I was trying to pull up --

CHAIRWOMAN SANDOVAL: 6 and 7-ish on 27, so 27.8.F.6

THE WITNESS: Yeah, sorry.

CHAIRWOMAN SANDOVAL: The end talk about GOR.

THE WITNESS: Yeah, I was actually looking at the language within the New Mexico Rule 19.15.18, but.

MR. FELDEWERT: Madam Chair, I did try to bring it up on the screen.

THE WITNESS: Thank you.

CHAIRWOMAN SANDOVAL: We can't see it. Maybe --

MR. FELDEWERT: Hold on. How about now?

CHAIRWOMAN SANDOVAL: Yeah, there we go.

MR. FELDEWERT: Okay.

THE WITNESS: Yeah, you know, Madam Chair, I can say that annual is important. I, I think that an operator is likely going to do more when they need to because the Division already makes them do more when needed.

And so, annual is, you know, it sets the boundaries that works for a lot of wells that are on decline, and that's why, when they are on decline annual is plenty fine.

When, when they are declining, the Division a lot of times makes you do more tests. I know that's part of the commingling at least.

CHAIRWOMAN SANDOVAL: That was an issue as of late.

THE WITNESS: I have heard that. So I think, you know, it says, an annual well test, an operator is going to do what makes sense. They are not going to want to have, you know, if you have varying different circumstances, they would go get another test. It's part of wanting to accurately report your production and you, you actually want to know what your well is doing.

CHAIRWOMAN SANDOVAL: So that sort of maybe begs the question if it is -- I don't remember how you just stated it -- a well that was in decline, if it's a well. If it's a newer well and the Division is requiring potentially more well tests or commingling or something else of the sort, would it be more appropriate to require the usage of those?

THE WITNESS: It can be. Sometimes it's hard to program in -- I don't know how your software works all -- like GOR is changing a lot. Like say the -- I don't want to speak for everyone's software, but if the Division is requiring you to put in a different GOR every week -- I don't remember what, it's a long document that describes how to do the GOR, then I would not necessarily want commit to go do that because you do monthly reporting, right?

But I think people will want to, you know, use the GOR that's most appropriate. I know when I have done it, if my GOR has changed, I want to go put that new GOR in because then it lets me know my flare volumes more accurately.

But I also don't think that we want to burden this rule with a long complex explanation of how to do GORs and when it's necessary because even though a well might be on decline, that doesn't mean the GOR is changing; right?

Sometimes when you plot GOR, the oil and the gas are declining, right? And they are declining such that the GOR is fairly constant. That depends on your reservoir, but an operator is going to know that, versus saying I have to have a GOR with every step change in production. Well, that's -- that's not always how GOR works. It can be constant over a period of decline relatively.

CHAIRWOMAN SANDOVAL: Okay. I'm just trying to think about how to make this, as you said, I think, simple without burdening the rule with a very lengthy explanation and making it so cumbersome.

THE WITNESS: Yeah, I would like to think about that, too. I need some time to really consider that, Madam Chair.

CHAIRWOMAN SANDOVAL: But you feel like in general annual is adequate?

THE WITNESS: Yeah. For many of your wells, and the majority of your wells are on decline, annual is very good; right? Like, I mean I have watched them for years and said, wow, that GOR is not changing even year to year.

CHAIRWOMAN SANDOVAL: Okay. Going back. So it asks -- I think actually -- let's see. Could you scroll up a smidge, Mr. Feldewert, please, up into 2.

MR. FELDEWERT: Certainly. Give me a minute here.

CHAIRWOMAN SANDOVAL: Yeah, and I think this is.

MR. FELDEWERT: F.2?

CHAIRWOMAN SANDOVAL: Is this the outdated version. I don't think this has the most recent -- that's okay, this language I'm talking about is still the same.

MR. FELDEWERT: Okay. Otherwise I can bring down

Exhibit 4B which has the more recent language.

CHAIRWOMAN SANDOVAL: If you have that handy, that might be good.

MR. FELDEWERT: I may have spoken too soon.

CHAIRWOMAN SANDOVAL: That's okay. So if you look in F.2, and this language is still existing in the other, you know, in the second line to measure the volume of natural gas vented or flared from existing, and then it goes into the section I think you said should be removed about the process piping.

But I wanted to ask you about the word "vented." And I asked, I believe, Mr. Powell this question, as well -- I think it was Mr. Powell, or Mr. Bolander, I can't recall.

THE WITNESS: Yeah.

CHAIRWOMAN SANDOVAL: I'm concerned about I guess, in your experience, are there many situations where you can meter gas that's vented? I thinking like a PRV or some other things, do you have any experience in metering gas?

THE WITNESS: No, and I do remember your question because I felt the same way. When I looked at this, this language about metering vented or flared, I'm trying to think when I have had a meter on a vent, right, like -- I have never put a PSV -- I have never put a meter on a PSV. Okay? So that's the comment. I have never put a meter on a gasket that might be leaking, but I don't know how to meter that.

So I didn't, I didn't know what was really meant by having the word vented there, you know. And so I, I, when I thought about how I would live with this rule after it came out, then I thought, well, I guess maybe if I ever put a vent stack, which I can't imagine building, I've never built a vent stack, okay, but maybe there is something that would be permanent that I could maybe then put a meter on that, but I really struggle to know where to -- when you would measure gas that is vented.

CHAIRWOMAN SANDOVAL: Okay. I believe, I don't know if you heard it or recall the (unclear) which they were trying to be consistent throughout the language.

THE WITNESS: Yeah.

CHAIRWOMAN SANDOVAL: But do you feel like keeping the word vented in there may actually create more confusion than --

THE WITNESS: It's bothered me from day one.

CHAIRWOMAN SANDOVAL: Okay. Thank you. That's helpful. And I do think that -- or do you think that likely that if that word were removed, you know, venting would probably fall under Number 5 which talks about when metering is not practicable.

THE WITNESS: Exactly.

CHAIRWOMAN SANDOVAL: But it sounds like it would just be better and less confusing to remove that word entirely.

THE WITNESS: That would be great, Madam Chair, and very clear, because, in my mind, I just jumped to 5, anyway, because I didn't know how to do it.

CHAIRWOMAN SANDOVAL: Okay. Thank you. So actually just staying here -- and I didn't notice this until today, and I would like your thought on the interpretation. So here it appears that the operator shall install basically equipment to measure the volume of natural gas vented or flared as you would prefer it written from a well are or facility associated with the well authorized by an APD issued after May 31.

So the way you read that is that, that you only have to install new metering equipment on new facilities that have been permitted after May 31 of this year. Do you feel (unclear) you don't have to retrofit facilities, you only have to install meters on new facilities?

THE WITNESS: I -- I was confused. I think I know what you are saying. Is do you -- do you interpret. You can ask if I interpret it the same way.

CHAIRWOMAN SANDOVAL: Yeah, I'm not trying to be --

THE WITNESS: Okay.

CHAIRWOMAN SANDOVAL: Let me make sure that I'm reading this the same as you are. Basically I think the way it reads is -- I would like your confirmation on this -- is that only new facilities permitted after May 31 of 2021 require measurement equipment, so basically you don't have to go backwards to your previous existing facilities and retrofit. Is that how you read it?

THE WITNESS: I've read it both ways, okay? To be honest, I've read it that it meant the facility, but also the way it says facility associated with the well, so I wondered does mean if I drill a new well and bring it to an existing facility and my new well has a new APD, do I need to go and retrofit the facility.

CHAIRWOMAN SANDOVAL: Okay. So then maybe there's mutual confusion.

THE WITNESS: Yes.

CHAIRWOMAN SANDOVAL: Okay.

THE WITNESS: I have had my own internal debate about which was intended.

CHAIRWOMAN SANDOVAL: So then if I go, and this is not up here, and I don't think you spoke about this, but it's on the same line, and if it's outside of your realm, that's fine.

If you look in Part 28, so Part 28 (unclear) a different Section E, is the measurement of vented and flared gas as opposed to gas in Part 27. And the comparable language here is in 2 again, and it just very plainly says, "The operator shall install equipment to measure the volume of natural gas vented or flared from a natural gas gathering system."

So that -- so that one is much more simplistic; correct?

THE WITNESS: Yes. And I -- my understanding of that one, was it's everything. I mean, in terms of its midstream facilities, there is there is no -- you can still estimate for low pressure and low flow, but you are going to read that and believe that a high pressure flare would need a meter whether it's new or existing.

CHAIRWOMAN SANDOVAL: You would not -- so you -- okay. So we have, it seems, maybe some inconsistencies between 27 and 28 in terms of retrofit; correct?

THE WITNESS: Yes. Yes. There is -- retrofits are required as part of 28.

CHAIRWOMAN SANDOVAL: Okay. And I think your testimony was, and maybe it was in one of these exhibits, but it's quite difficult to retrofit or can be quite difficult to retrofit on existing systems; correct?

THE WITNESS: That's correct.

CHAIRWOMAN SANDOVAL: Do you expect that the cost would go up from the 20 to 90, and then you said, on average, it's 1.92 times the meter cost, would that be for a into new facility or would that be for retrofitting or both?

THE WITNESS: That was, that was for, that was for adding a meter where I -- you know, because, because you know, I kind of helped provide some of that information working with other operators, adding a meter without needing to go repipe that facility. So that assumes that I've got straight pipe and liquid scrubbers and can cut in new flanges and go install a meter.

CHAIRWOMAN SANDOVAL: So you would expect that that cost factor, 1.92, would go up if you are having to retrofit the facility?

THE WITNESS: Yes. And my insurance with Delaware is that there is a premium to do anything in the Carlsbad area. So, even that, yes, but it would go up with retrofitting.

CHAIRWOMAN SANDOVAL: Okay. That's helpful, thank you.

Actually you mentioned, you said that -- you just said, I think, there's a liquid knockout or a scrubber. Is it possible that some of these existing facilities you might have to add that in addition to the --

THE WITNESS: Most of the facilities -- I can best speak to facilities that I have inherited or, you know, and most of mine have flare scrubbers. It's occasional that

people didn't put it because it is a good practice, right?
So maybe, maybe we bought some really old facility that didn't follow all the best practices -- I don't know, I'm just trying to give an example, and then it wouldn't happen. But typically people would have wanted to install a gas scrubber, but there have been times where I have seen without a flare scrubber.
CHAIRWOMAN SANDOVAL: So there could be even more, not unintended, but unexpected costs than just the meter?
THE WITNESS: Yes, certainly.
CHAIRWOMAN SANDOVAL: Okay, thank you. Ms. Orth, I needed to take a couple of minute's break, but I -- let me just power through this real quick.
THE WITNESS: Yeah, then I get to be done, so that's --
CHAIRWOMAN SANDOVAL: You get to be done, yes.
On E -- okay, so if we go to E in Part 27, which is performance standards, and I don't recall if you were the one to talk about this, you briefly mentioned that auto gauging on tanks -- I think you talked about in the context of oxygen?
THE WITNESS: Yeah. I talked about it with oxygen.
CHAIRWOMAN SANDOVAL: Okay. So you may not be

the best person to answer some of the questions?

THE WITNESS: Probably not.

CHAIRWOMAN SANDOVAL: Okay. So you talked about thief hatches and how, you know, some of them can be designed to breathe. I can't remember what the words you used.

THE WITNESS: Yes.

CHAIRWOMAN SANDOVAL: And that's a part of normal operation. But are you familiar with circumstances where the thief hatch is left completely open?

THE WITNESS: Yes. I am familiar with that.

CHAIRWOMAN SANDOVAL: And since that is not part of normal operation, does that seem like an important piece of venting to be counted in, you know, in your gas capture calculation?

THE WITNESS: I guess, if you look at my testimony, while it may be a volume that you, that you want to capture or that you want to, to report, it's -- it's very difficult to know the amount of gas that's released.

And I can say that because I have tried, right? So I have looked at the thief hatch size, and I have looked at the -- you know, we don't want to find thief hatches open. The one or two times I have found them, I really -- the operators don't like me when I come to -- I chew them out very clearly, okay? How could this happen? And it wasn't always their fault, someone showed up and did it, maybe the truck hauler.

But the challenge where my expertise is here, the challenge is about calculating that volume. And so, you know, if I have -- I have tried to calculate it and I've had a VRU running, right? So I've had a VRU going, which really makes the challenge of how much gas must have gone out because I didn't just blow down all of the tanks.

You know, I didn't just see like (unclear) pressure was this and my reservoir size, basically the (unclear) and now it's zero, which would required me having the data map, and a lot of times you won't have that data but the VRU will have that data, and it doesn't just go to zero, right?

So all the known approaches that I like to use to calculate gas volumes, which is typically the CB, which is the size of the hole that you have, and the DP tends to not work in terms of the accuracy that I need.

CHAIRWOMAN SANDOVAL: But does it seem -- I mean, I can understand, I mean, the data quality concerns from your testimony, but does it seem like there would be more of a hole in just not reporting that than reporting a number that may have a degree of accuracy?

THE WITNESS: No. I just don't like adding bad numbers to good numbers.

CHAIRWOMAN SANDOVAL: I mean, let me restate that in another way. If New Mexico is trying to determine what the entire, basically the entirety of waste is within the state, wouldn't the number at the end of the day likely be more accurate if that information is included, understanding there is a degree of accuracy than if the number is completely excluded?

THE WITNESS: Okay. So it wouldn't necessarily be more accurate, but it will have, you know, what I -- what I don't like about -- I know you want me to say yes. I know what you want. But if I have a number that, you know, it's here, and it's margin of error is here, then, you know, the uncertainty puts you either plus or minus.

So I wish there was a, you know -- I just -- I just don't have a good way to do it. That's the problem. I just don't have a good way to give me a number that I can stand behind and say, yes, this is the right number to report.

You know when we find accidentally opened thief hatch, you know, we want to deal with it right away. And we do lots of training to make that happen, and we go through a lot of effort to really hold people accountable with that, and I just don't have to good way to tell you what the number should be.

CHAIRWOMAN SANDOVAL: Can you think it might help companies hold operators accountable internally if these accidents actually counted against them in their statewide gas capture than if it's just, did wrong, please do better? If there's a -- it's more tangible, would that be potentially help companies hold their operators more accountable.

THE WITNESS: Well, we do -- and I don't know all the details of why, all the rules related to (unclear)LDAR, right? But we do a lot of inspections on ourselves because we would rather inspect ourselves than have other people inspect us, right, better to catch it ourselves. So we already do a lot of that.

Yeah, I can, you know if it makes sense that what you are trying to say is you are trying to make it very clear that there is -- trying to give more impetus to operators is, I guess -- I can see that that's -- you know, for someone for -- for a prudent operator -- I don't like to use that term because I don't have the Miriam Webster dictionary in front of me -- but for a prudent operator we are trying to avoid that at all costs, right?

We are trying to make sure third parties don't do it, and the third parties don't get their hands slapped, right, like it's the operator, it's our responsibility to look after our battery. So it's not always your fault, per se, that they did it, so I don't like that respect.

I don't know, I think there is other ways that prudent operators come up with to motivate their employees do what's right, and we try to work really hard to hold our operators accountable. And if you set objectives, and this is one of them, like XTO's objective, I can speak for XTO, we take this very seriously, that's an objective we hold operators accountable for.

And I didn't mean to go tell you that it happened in that case, I don't know how the reporting works, I just know that, hey, we found this and we took it to that operator.

CHAIRWOMAN SANDOVAL: Okay. Well, that is all have I for you. Thank you.

THE WITNESS: You're welcome.

HEARING EXAMINER ORTH: Thank you, Madam Chair. Mr. Feldewert, do you have any follow up with Mr. Greaves?

MR. FELDEWERT: Can have I have five minutes to confer with my co-counsel?

HEARING EXAMINER ORTH: Well, let's take ten minutes then and come back at 4:10.

(Recess taken.)

HEARING EXAMINER ORTH: Let's come back from the break, please. Do we have Mr. Feldewert?

CHAIRWOMAN SANDOVAL: Ms. Orth, would it be possible before Mr. Feldewert to ask Mr. Greaves one more question?

MR. FELDEWERT: So your question to me, Madam Chair, is whether you can ask him one more question?

CHAIRWOMAN SANDOVAL: Yes.

MR. FELDEWERT: Well, as you can expect, my answer is going to be certainly.

CHAIRWOMAN SANDOVAL: Great. Do we have the Hearing Examiner -- not the Hearing Examiner -- the court reporter. I don't want to start before she is ready.

REPORTER: I'm here.

CHAIRWOMAN SANDOVAL: All right. Just one quick question. I think back -- I say it's a quick question -- back in Part 28, and again we are in E.2, which would the equivalent in Part 27. So it doesn't -- we talked about this -- it doesn't seem to have any sort of exemption for retrofitting. It's anything and everything.

I guess my question is sort of along that, in Part 27, and I don't -- maybe you are not the person to ask this, but maybe you are -- in Part 27 there is an exemption for retrofitting for stripper wells which is under 60 MCF, but there doesn't seem to be an equivalent for an exemption for retrofitting --

THE WITNESS: No, there is no exemption for retrofitting as written in Part 28.

CHAIRWOMAN SANDOVAL: Do you recommend there should be some sort of equivalent exemption for retrofitting if retrofitting is required for Part 28?

THE WITNESS: Yeah, I just wasn't sure where -- I don't have a good, off the top of my head, boundary, I guess I would say, as to where you want to have to retrofit.

CHAIRWOMAN SANDOVAL: Is there any sort of administrative equivalent to a stripper well? Or maybe, Mr. Feldewert, if you know of another witness who might have any insight on that?

MR. FELDEWERT: So I guess, Madam Chair, your question relates to 28.8.E.2?

CHAIRWOMAN SANDOVAL: Yeah. In 27, right, there is the exemption for retrofitting for stripper wells that appears, and may be some ambiguity in the language where it makes it unclear as to exactly is supposed to be done is what we talked about in the testimony.

And then in Part 28.E.2, there is a no ambiguity, it's pretty straightforward, but there is also not some sort of exemption. I understand that midstream doesn't have wells, but I guess my question is, should there be some sort of equivalent-type of exemption for midstream operators who are maybe -- is there a similar scenario where they are all on the economic margin in installing, I don't know, from what Mr. Greaves said, essentially hundreds of thousands of dollars worth of metering equipment would put them belly under -- belly up.

MR. FELDEWERT: I mean, the best I can do is suggest that at the end of the day I can do some inquiries and maybe have, you know, an answer for you tomorrow?

CHAIRWOMAN SANDOVAL: Okay, that would be fine. Thank you.

THE WITNESS: Thanks.

CHAIRWOMAN SANDOVAL: Sorry. That, maybe that wasn't exactly for you, Mr. Greaves.

THE WITNESS: That's fine.

HEARING EXAMINER ORTH: Mr. Feldewert, do you have follow-up for Mr. Greaves?

MR. FELDEWERT: Madam Hearing Officer, I do not. I think we are in a position where we can call our next witness at your convenience.

HEARING EXAMINER ORTH: All righty. Thank you very much, Mr. Greaves, you are excused.

Mr. Feldewert, if would you call your next witness. We do have to remember a stop around 4:30 for two public commenters. So perhaps we could get him sworn in, and you could get some of the introductory background out of the way before we accept public comment.

MR. FELDEWERT: Certainly. And then there is one small part we might be able to get out of the way, so let's see if we can get that done. We call Michael Smith.

HEARING EXAMINER ORTH: I see you, Mr. Smith.

THE WITNESS: Can you hear me okay?

(Audio difficulties.)

HEARING EXAMINER ORTH: It's not clear. It's that echo feedback we had before he put on the headphones.

THE WITNESS: Okay. I can try to speak closer. Does that help at all?

HEARING EXAMINER ORTH: That is definitely better. Thank you. Would you raise your right hand for me, please?

Do you swear or affirm that the testimony you are about to give will be the truth, the whole truth and nothing but the truth?

THE WITNESS: Yes, I do.

HEARING EXAMINER ORTH: Thank you. Mr. Feldewert, whenever you are ready.

MICHAEL SMITH

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your full name, identify by whom you are employed and in what capacity?

A. Yes. My name is my Michael Smith. I work for Devon Energy as an environmental professional.

Q. As an environmental professional, what are your

job responsibilities?

A. Currently I advise the company on environmental policy and regulatory matters. Previous to that I was the supervisor of our air permitting group.

Q. Does your experience and job requirements extend into New Mexico?

A. Yes, they do.

Q. And how long have you been involved in New Mexico on behalf of Devon Energy?

A. I have worked for Devon since March of 2015.

Q. Okay. If I turn to what's been marked as NMOGA Exhibit M2 --

A. Yes.

Q. -- does this accurately reflect your educational background and work experience? I think it carries over -- I'm sorry, I should say M1 through M2.

A. Yes, it does.

Q. Okay. It indicates that you worked for four years with the Oklahoma Department of Environmental Quality?

A. Yes, I did.

Q. Can you describe what you did for that state agency?

A. Yes. I assessed oil and gas facilities for compliance against air permits and regulations.

Q. And did you deal with enforcement issues?

A. I did.

Q. Okay. Since leaving that agency, have you been assisting oil and gas companies with their air permitting facilities and issues?

A. I have, I have worked as a consultant performing obtaining air permits and doing emission inventory and with Midstream and Chaparral Energy prior to Devon Energy, also working with air permitting and emission inventory.

Q. So, Mr. Smith, I guess you are familiar with both oil and gas production operations, and then oil and gas gathering, what some people call midstream operations?

A. I am, yes.

Q. Are you familiar with the federal and state regulatory applications and processes for air emissions from oil and gas operations?

A. Yes.

Q. Are you familiar with how those air emissions are tracked, measured and estimated for environmental reporting?

A. Yes.

Q. And are you generally familiar, Mr. Smith, with how volume production accounting takes place for the oil and gas upstream operators?

A. Generally, yes.

Q. Okay. I want to share the screen real quick and see if we can get through this topic before we have to take

a break. I have up in front of you, Mr. Smith, on the screen, NMOGA's Exhibit C14.

A. Yes, I see that.

Q. Okay. And are you familiar with NMOGA Exhibits C12 through C16 which dealt with NMOGA's proposed changes to the definitions in these rules?

A. Yes, I'm familiar with that.

Q. Are you familiar with the EPA Quad 0a, new source performance standards?

A. Yes.

Q. I hope I said that right.

A. Yes.

Q. And have you worked with those routinely?

A. I have, yes.

Q. How long have Quad Oa definitions been utilized for oil and gas?

A. These definitions have been in place since 2011 when Quad O was promulgated.

Q. Drawing upon your experience, do these definitions accurately convey, for example, when the completion phase ends and the production phase begins?

A. Yes, they do. These are definitions that are well understood within the industry.

Q. And do you agree that it is important, where possible, to maintain consistency in the meaning of terms

like you see in Exhibits C12 through C16?

MR. AMES: Objection, leading. Counsel is testifying.

HEARING EXAMINER ORTH: Mr. Feldewert, if you would please take care not to lead.

MR. FELDEWERT: I guess I'm at a loss as to what the problem is with the question.

MR. AMES: Madam Hearing Officer, there is no (audio interference) who, where, when, why and how. And these questions are essentially (audio interference) and if the answer is yes or no, or I agree or I don't, that's the definition of a leading question.

HEARING EXAMINER ORTH: Right. No, I understand, Mr. Ames. Mr. Feldewert, would you please rephrase the question?

MR. FELDEWERT: Sure.

MR. FELDEWERT:

Q. And, Mr. Smith, do you understand -- do you have an understanding about whether it's important to maintain consistency in the meaning of terms when possible?

A. Wherever possible it would be beneficial for there to be consistency, especially across different regulating bodies.

Q. And in your opinion, will adopting these changes to the definitions that NMOGA has proposed promote that

consistency?

A. Yes, I believe it will. It will ensure, you know, certainty that these definitions are consistent.

Q. And when you say consistent, would that be consistent with Quad Oa?

A. Consistent with EPA, with the Quad O definitions.

Q. Okay. And do you believe that it assists in avoiding confusion among operators as to when these phases end and when they begin?

A. Yes. It would avoid confusion, and again it would allow certainty when complying with the rules that there would be consistency across, across these different agencies.

MR. FELDEWERT: Okay. Madam Chair, we'll be moving to a different topic that's going to take a little more time.

HEARING EXAMINER ORTH: All right. Let me ask our technical host if we have the two public commenters yet. And let me give you their names, Mr. Lamkin. Glen Schiffbauer and Mara Matteson.

MR. LAMKIN: Mr. Schiffbauer is here. I don't see the other one.

HEARING EXAMINER ORTH: All right.

So, Mr. Feldewert, let me make a request of you. While we are taking public comment, if perhaps you could work with Mr. Smith to either practice muting and unmuting the way we had to do with Mr. Greaves, which helped some, or I don't know if Mr. Smith has the same headphones, for example, it really is hard to hear his testimony.

MR. FELDEWERT: Understand. So let's see what we can do.

HEARING EXAMINER ORTH: All right. Thank you very much. So let's switch now from the technical case to accept public comment. We have at least one of our commenters available all ready.

His name is Mr. Glen Schiffbauer.

Mr. Schiffbauer, I understand you are on a call, and if you would please keep your comments to just a few minutes.

MR. SCHIFFBAUER: Thank you very much. Is the volume okay?

HEARING EXAMINER ORTH: That volume is good, thank you.

MR. SCHIFFBAUER: Good afternoon. My name is Glen Schiffbauer. I'm a resident of Santa Fe, New Mexico. I'm speaking to you today on behalf of the Center for Methane Emissions Solution, or CMES, the national business coalition representing the views of companies in the methane mitigation industry across the United States and in New Mexico.

CMES appreciates the opportunity to participate in today's hearing, and my testimony today is intended to serve as a compliment to the written comments CMES sent in last week. Our members commend Governor Lujan Grisham and her administration for the thoughtful deliberative approach undertaken to address methane emissions from oil and gas sites in the State of New Mexico.

While we think the proposal today takes important steps, there are refinements that can be made to meet the critical goal this rules intends to meet.

Specifically, CMES respectfully suggests the following: The proposal requires both midstream and upstream operators to capture 98 percent of their natural gas by the end of 2026 while also requiring reporting for gas loss at each stage of operations.

We support this policy; however, the policy currently states that any operator that fails to meet required gas capture targets could be denied future drilling permits prohibited from starting drilling operations or face enforcement action such as fines.

Our view is that in order for the 98 percent capture goal to be met, a more stringent result should be considered, especially since viable options for compliance are readily available.

Further, in order to be certain that flares function at 98 percent or better, CMES encourages OCD to require the use of auto igniters, continuous pilot lights and regular site inspections.

Last, CMES strongly supports OCD's inclusion of emerging technologies as a means of compliance under the ALARM program. Such incentives create important market signals for innovative companies to continue to develop cutting edge technologies to address methane.

The methane mitigation industry in New Mexico stands prepared to provide solutions that will help address this serious issue while also supporting our oil and gas partners. We welcome the opportunity to be a resource to the department as this rule moves forward.

Thank you for your time.

HEARING EXAMINER ORTH: Thank you, Mr. Schiffbauer. I forgot to ask you if you would please spell your name, first and last.

MR. SCHIFFBAUER: Yes, it's been an issue since fourth grader, but G-l-e-n-n, the easy one, S-c-h-i-f-f-b-a-u-e-r.

HEARING EXAMINER ORTH: Thank you very much. Mr. Lamkin, do we have Ms. Matteson with us?

MR. LAMKIN: I don't see her name on the attendee list, but I unmuted the call-in users.

HEARING EXAMINER ORTH: Are any of the callers Mara Matteson?

(No audible response.)

HEARING EXAMINER ORTH: Mara Matteson?

(No audible response.)

HEARING EXAMINER ORTH: No? Let's just take a very, very short break. I feel like I can't move back to the technical case since it's just turning 4:30 right now. So let's take about three minutes.

(Recess taken.)

HEARING EXAMINER ORTH: Let's come back on the record.

Mr. Lamkin, do we have Ms. Matteson?

MR. LAMKIN: Nobody new joined the meeting.

HEARING EXAMINER ORTH: All right. Well then, please excuse the three-minute break. Let's get Mr. Feldewert and Mr. Smith back on the screen.

MR. FELDEWERT: I'm ready to proceed whenever you are, Madam Hearing Officer.

HEARING EXAMINER ORTH: Anytime, Mr. Feldewert.

BY MR. FELDEWERT:

Q. Mr. Smith, I put back up on the screen what was marked as NMOGA Exhibit I9. Do you see it -- woops -- do you see that in front of you?

Mr. Smith?

(No audible response.)

(Audio difficulties.)

MR. FELDEWERT: Can anyone else hear Mr. Smith?

HEARING EXAMINER ORTH: No. I can hear you clearly, but not Mr. Smith. Mr. Smith? We can't hear you.

(No audible response.)

HEARING EXAMINER ORTH: I think you fixed this too well, Mr. Feldewert.

MR. FELDEWERT: Well, I didn't do anything because I was not --

THE WITNESS: Can you hear me now?

HEARING EXAMINER ORTH: Yes. But now there's feedback.

THE WITNESS: I apologize. I'm trying to put ear buds in, but they weren't picking up the audio.

HEARING EXAMINER ORTH: All right. Let's do our best to start speaking loudly and slowly. Go ahead.

BY MR. FELDEWERT:

Q. So Mr. Smith, I have placed back up on the screen NMOGA Exhibit I9, which are the five reporting categories that NMOGA seeks to exclude from Subpart G.2.

A. Yes, I see those.

Q. And, Mr. Smith, with respect to the remaining categories that exist under Subpart G.2, can you please discuss them and characterize them in relationship to these types of categories?

A. Yes. The remaining categories are sources of high pressure venting and flaring, and that would include both, you know, both routine and nonroutine events.

Q. And when you say high pressure venting and flaring routine, venting or flaring or nonroutine venting and flaring, do those terms have meaning within the industry and within the EPA rule?

A. Yes, they do.

Q. Okay. Does it, in your opinion, is it appropriate, make sense for the Division to track these types of events for monthly production accounting purposes under Subpart G.2?

A. Yes, I believe it does, and as others have testified, those are volumes that can be accurately estimated.

Q. Okay. And, in your opinion, will that provide useful data to the -- the Division for the purpose of preventing unnecessary and excessive surface loss?

A. Yes, I believe it will. Those are the volumes that, you know, I think are, again, they can be accurately measured, estimated. It's going to provide the Division certainty that these volumes are reported, and it will allow them, as we have broken them down into the various categories and as they are listed out, will give the Division valuable information in, in regulating the sources.

Q. Now, by contrast, why were the categories in the

(unclear) seek to exclude not provide valuable information for purposes of addressing unnecessary and excessive surface loss?

Q. Well, as others have testified, the remaining sources, these would be low pressure or low flow, low volume sources, and you know, we -- we think it's been pointed out that these are normal operations. They are necessary operations. They are -- they are not accurately measured or estimated, and therefore, when I look at this rule and we are looking to get accurate data and essentially establish a meaningful baseline, these -- these remaining sources, again, as I think as Mr. Greaves said, they provide uncertainty, and you begin to add uncertain values to values that are certain.

MR. AMES: Madam Hearing Officer, I'm going to object to this line of questioning. It is repetitive. The witness himself has said others have already testified. He has know referenced Mr. Greaves' testimony on the same point. If Mr. Smith has something new to add, I would ask that counsel elicit the new information. But it does not help this process to have witnesses repeat testimony that has already been delivered.

HEARING EXAMINER ORTH: Mr. Feldewert, I was hoping that there would not be duplication of prior witnesses, particularly the one immediately prior.

MR. FELDEWERT: Madam Hearing Officer, first off, I'm setting up the additional discussion of Mr. Smith, so I assumed I would get some leeway to do that, number one.

Number two, if you look at what the Division did, they had three witnesses that talked about the same topics and utilized similar exhibits throughout this time, and we didn't object to that, it's their case.

We spent a lot of time dealing with the (unclear) behavior by Mr. Ames, and including, including Mr. Ames sits there and talks about how the civil procedures don't apply to these proceeding, but they can be efficient and effective and we can move things along, yet he continues to object to minor questions and issues and leading questions.

My effort has been here to try to move this thing along, to try to get these witnesses presented, and I think we have done a pretty good job doing that. And it's frustrating to have Mr. Ames continually inject himself with these types of objections. We just started with this witness.

HEARING EXAMINER ORTH: Right, no I understand. I think, though, he is not the only one, Mr. Ames, to want to avoid duplication. And so long as that is not the testimony that's going to be elicited from Mr. Smith, you can continue. I will just ask you, as you proceed, to avoid duplication.

MR. FELDEWERT: Certainly. Certainly.

Q. Now, Mr. Smith, do you remember where we were?

A. I believe so, yes.

Q. Okay. Now, when we look at these low pressure sources, are those low pressure sources already regulated by other states and federal agencies?

A. Yes, they are. Yeah, in all of these cases these are sources that either currently regulated or proposed to be regulated under NMED's precursor rule.

Q. And do you understand or have you seen literature posted by the Energy, Minerals and Natural Resources Department and the New Mexico Environment Department indicating that they were going to try to avoid redundant or conflicting requirements?

A. I do, and I served under the -- the executive order that these two rules would create regulatory framework and they would be complimentary and attempt to avoid duplication.

Q. Is that reflected in what's been marked as NMOGA Exhibit M, as in Mary, 3?

A. Yes, it is.

Q. Okay. Now, there's been a lot of talk about how these five categories, these activities or the emissions from there are already reported to the NMED or EPA. Do you recall that discussion?

A. Yes, I do.

Q. Okay. And there was questions about why the, you know -- I maybe inartful here, but I wrote down "process model," why the process -- there were questions about why the process model used estimated emissions from these sources for the NMED should not likewise be used for monthly production volume accounting under G.2. Do you recall those questions?

A. Yes, I do.

Q. Would you please bring your expertise from dealing with the NMED world to explain why that's not appropriate and why that does not work in accounting under Subpart G.2?

A. I guess the way that I would answer that is that when we -- we do utilize process modeling, there are multiple ways to estimate emissions. But we are establishing and emission limit within our air permit, so we are typically using worst-case-scenario operating parameters to determine the maximum emission limit that we will be operating under.

Q. And why is that not -- why should that not be utilized to come up with a monthly production volume for the accounting under G.2 and then for the lost gas and gas capture accounting?

A. Like I said, we are calculating these emissions using worst case parameters for the purpose of obtaining an air permit and establishing the limit that we will operate under. The purpose of those methodologies is not to take the volume for monthly production accounting report.

Q. Would the utilization of those methodologies come up with reliable data for gas loss accounting?

A. I don't repeat testimony, but I think the previous witness explained why, why those would not be accurate for production accounting.

Q. Okay. And is it your understanding from -- were you present for the Division's testimony?

A. Yes, I was.

Q. Okay. And was it your understanding -- what was your understanding with respect to the type of data that the Division wants based on their testimony?

A. I believe the Division stated multiple times that they were, they were seeking accurate data in order to establish a meaningful baseline, and that accurate data was critical to this effort.

HEARING EXAMINER ORTH: Mr. Feldewert, are you about to move to a different exhibit, perhaps a different topic?

MR. FELDEWERT: Hold on one second. I'm trying to find a certain exhibit.

HEARING EXAMINER ORTH: Okay. I'm asking because the second commenter from the 4:30 session has appeared.

MR. FELDEWERT: Oh, I see, yes, that's fine. I'm fumbling around trying to find the exhibit. We can pause.

HEARING EXAMINER ORTH: All right. Thank you very much. Ms. Matteson, Ms. Mara Matteson?

MS. MATTESON: Yes. Can you hear me?

HEARING EXAMINER ORTH: Yes, I can hear you. Have we have all the Commissioners here. If you would please spell your name and make your statement and try to keep it to just a few minutes.

MS. MATTESON: Yes, I will keep it short. My name is Mara, M-a-r-a, Matteson, M-a-t-t-e-s-o-n. I'm really grateful that you're allowing me to make a comment, and I'm grateful for this opportunity.

I'm a teacher. I taught for almost 20 years for the Bernalillo Public Schools, and now I'm teacher at the Children's Learning Center in Cochiti Pueblo where we are a language revitalization school. And we are very interested in children and their future and children in New Mexico and their health.

And so I'm eager to have the -- I'm eager to have the rules that you are proposing, negotiating, strengthened as much as they can so that we can protect children's health and protect the land and protect the future.

I am inspired by the idea that we have (unclear) methane rule. And as a teacher, you know, we're -- we are currently about using resources wisely. So it seems to me that if we were able to have rules that did not allow for waste, or that allowed for a lot less waste through flaring and through venting, we could recapture not just the resource itself, the methane, and use it, we would be creating a solution. And then we would also be able to, you know, sell it to make more revenue for schools.

The other thing is that, as a teacher, you know, we are about enforcement, so when there are rules and procedures, we support the following through on this. And so I would support and encourage you to create a situation that allows for the least waste and enforcement of companies that allow for checking and making sure that waste doesn't happen and waste isn't occurring and (unclear) isn't happening.

And I guess, with that, I would finish my comment. Thank you for hearing me.

HEARING EXAMINER ORTH: Thank you very much, Ms. Matteson.

Mr. Feldewert and Mr. Smith, can we have you back?

MR. FELDEWERT: I am here.

HEARING EXAMINER ORTH: Whenever you are ready.

BY MR. FELDEWERT:

Q. Mr. Smith, I put up on the screen what's been marked as NMOGA Exhibit M4. Do you see that?

A. Yes, I see that.

Q. And this is an introductory slide, as I understand it, to the subsequent slides dealing with this topic?

A. That's correct. These are the specific categories that NMOGA is proposing to remove from the reporting categories.

Q. And did you prepare this slide and the subsequent slide?

A. I did, yes.

Q. Okay. As I move to M5, can you explain how this slide is put together and what it conveys?

A. Yes. Again, this is a summary slide showing the various reasons why NMOGA feels these reporting source categories should not be included. I will point out that the top bullet points have already been discussed, so I will not discuss those again. But we did want to point out that these sources, even though we are proposing to remove them as reporting categories in this particular rule because they would not necessarily provide useful information as far as a monthly volume reporting, they are reported to, to both EPA and to NMED.

And so these, these categories are, in a sense, reported, but they are reported to other agencies as air emissions which would be more appropriate in this context. And then if you look down there at the bottom, the Environment Department is proposing to regulate these sources, so we do not mean to, to say that these, these sources would be otherwise unregulated. They will be regulated.

Q. This slide we're looking at addresses routine downhole maintenance?

A. Yes, it does.

Q. And then you see a similar slide under M6 for manual liquids unloading?

A. Yes.

Q. Does it have similar information?

A. Yes, it does.

Q. Then Slide M7, you put this together as well.

A. Yes, I did.

Q. This deals with the topic of controlled storage tanks?

A. Yes, that's correct.

Q. Would you please identify how this slide was put together and what additional information you have added for the Commission?

A. Yes. We've already pointed out that, I think, the concept of an uncontrolled storage tank was already explained, but what I wanted to point out here is that we are calculating the emissions from these sources. They are evaluated against the permitting thresholds of NMED, and you know, talk about estimating emissions from these sources, we do that as part our permit application process. And then we would also apply the emissions from sources again (unclear) in the emission inventory.

I did want to point out that, you know, others have pointed out that there are process simulation software packages that exist that can predict and estimate these emissions. There are others, and you can see there that, you know, in our NMED's permitting program, they do allow for operators to choose the most appropriate estimation method or calculation method for calculating these emissions.

And again, I'll state that when we are calculating emissions for permits, we are using worst case operating parameters and scenarios that will establish a cap for am emission limit, if you will.

Q. Mr. Smith, what is the significance of this bullet point I see down here? It's a sub bullet point under the third one. It says, "Multiple acceptable calculation methodologies exist to estimate the emissions from storage tanks that do not require emission control."

Why is that significant?

A. So I (unclear) really there are different methodologies that exist to calculate the emissions sources, and just to point out that there is variability. So when we take a look at the reporting categories, and again, we're -- we have volumes of these from the high pressure sources that are accurately estimated. When we get to these sources we start to pull in variability and recognizing that different methodologies exist and are acceptable, that each of those methodologies will produce a different emission calculation or total, and that then would start to introduce uncertainty or perhaps inconsistencies across how you could compare (unclear).

Q. So when you say variability and inconsistency, are you referring to operator reporting?

A. No, just that you have options in how you calculate these emissions.

Q. And so is it possible that one operator could use one methodology and another operator could use a second methodology if this was somehow utilized as a standard over 40?

A. Yes. That's correct. And so the data, you could have two operators using different methodologies that would produce different results.

Q. Does this same analysis in slide -- I see it's titled uncontrolled storage tanks. Does it also apply to

controlled storage tanks?

A. It does. The same, you know, the same logic applies there.

Q. Okay. Now, if I move down to the next slide, which is M8, this one deals with pneumatic controllers and pumps. Would you please explain how this slide is put together and what information you are able to offer the Commission on this topic?

A. Yes. Again, this is a summary slide. The previous -- the top two bullet points have already been discussed, but again, looking at the third bullet point, you know, pneumatic controllers, we do report those to EPA through the greenhouse gas reporting program, but the point is, you know, these are using factors, and, you know, when we are using these factors, the volumes are derived using those factors, it's not going to reflect the actual volume of gas released.

And again, I won't get into further detail that's already been explained, but again, we -- we look at the -- there is a reporting requirement that does capture information from sources and can show you the relative contribution sources, but again, it will not, it will not produce an actual volume for production accounting.

And then that last bullet point, we didn't want to forget to point out that these, these sources are not otherwise unregulated just because they are not reported here. They are regulated both federally through Subpart Quad Oa, and then will also be proposing additional standards for pneumatic devices.

Q. And, Mr. Smith, I see a sub bullet point here about halfway down that says studies have shown a wide range of emission factors.

A. Yes. That goes to -- if you go to the next slide.

Q. Okay.

A. I'm sorry.

Q. Okay.

A. Yes. What we are pointing out here is that, you know, we are relying on EPA's emission factors. My understanding is that those factors were based on a very small sample of devices in the mid '90s. There have been recent studies. I think you can see here that, you know, it shows quite a bit of variability that again leads to uncertainty into, you know, whether these methodologies, even if you, if you use them will reflect any, any actual volume that's being released.

Q. And I believe M10 addresses improperly closed and maintained thief hatches.

A. Yes, it does.

Q. And what do you -- what are you -- what are you

showing on this slide?

A. Yeah. Well, here again, I think we've already talked about the difficulties in trying to come up with a number when you have this current situation. But, you know, whether it's, you know, in this case this would be a controlled storage tank.

Again, these sources are regulated. They are regulated by NMED. And, you know, emissions from storage tanks, both controlled and uncontrolled, are reported to NMED. If we did have a leak from a thief hatch, that is something that would be identified and corrected through our leak detection repair program.

Q. Okay. Any more about these slides?

A. No, sir.

Q. Okay. I want to take a look at -- I'm gonna try here. Give me one minute. There. I want to direct your attention to what was Slide 16 under the Oil Conservation Division Exhibit 4A.

A. Yes, I see that.

Q. Okay. Now, focusing, Mr. Smith, on the five reporting categories as you look through these slides, I want to ask you a couple of questions, okay?

A. Okay.

Q. This slide from the Division, as I look at the second bullet point, states that accurate data is critical

to establish a meaningful baseline, enforceable goals to reduce natural gas waste. Do you see that?

A. Yes, I see that.

Q. In your opinion, will operator efforts to report under the categories that NMOGA seeks to exclude meet that goal?

A. No. Because you, again, you know, we've got, we've got data from the high pressure sources that is going to be accurate. I think it would be very meaningful to establish a data baseline and an enforceable goal. Again, we start to, with all these other sources, we start to introduce uncertainty into what would otherwise be a certain value. And therefore I think it would, it would, in a sense, make the overall dataset less meaningful because you are going to have the -- there is going to be a lot of variability and inconsistency. It's not going to give you a sense of what that baseline is.

Q. If I move to what was marked as Slide 19 in Oil Conservation Exhibit 4A, I see under reporting, now, we talk about the categories under G.2, we are talking about reporting categories; correct?

A. That's my understanding, yes.

Q. Okay. And it indicates in this bullet point that streamline forms set thresholds reduce categories for reporting while still ensuring meaningful data capture.

In your opinion, will attempts to report under the five reporting categories that NMOGA seeks to exclude ensure to provide meaningful data capture?
A. Not to a level of accuracy that I think would be expected for production accounting.
Q. Okay. And if I move to their Slide 25 on Exhibit 4A, it reflects an objective on the right-hand side. Do you see that, Mr. Smith?
A. I do, yes.
Q. And it says one of the objectives of the rules was to obtain complete and accurate measurements and reports of the volume of vented and flared natural gas. Will that be accomplished if operators are required to report under the five categories that NMOGA seeks to exclude?
A. Again, I don't believe that it would meet that objective to obtain the accurate measurements.
Q. If I move to Slide 49, this slide specifically deals with 27.8.G; right, Mr. Smith?
A. Yes.
Q. And it's counterpart in Part 28, which is 28.8.F?
A. Correct.
Q. And again, it shows as an objective, obtain reliable, accurate data on the volume of gas produced, volume of produced natural gas being vented or flared. Do you see that?

A. Yes, I see that.

Q. Same question. Will that objective be met if the reporting categories that NMOGA seeks to exclude remain within 28.8.G?

A. I'm sorry, could you state that again?

Q. Will this objective to obtain reliable, accurate data be met if the reporting categories that NMOGA is seeking to exclude remain within 28.8.G?

A. No, I do not believe it would.

Q. Okay. Now, I will move to a final slide, Mr. Smith, Slide 83 in the Division's Exhibit 4A. Now, this specifically relates to the subsection you were addressing, 27.8.G.2. Do you see that?

A. Yes, I do see that.

Q. And it notes, for example, that drilling operations was deleted and volumes are too small to measure and do not -- are not considered waste. Is that criteria equally applicable to the categories, the five remaining categories or the five categories that NMOGA seeks to exclude?

A. Yes, I think, as has been demonstrated, and not to go into too much detail, but it seems like the same criteria was used to delete -- that the Division used would apply to the remaining categories that NMOGA is proposing to delete.

Q. And would that -- those categories or this basis down here that we see for Bradenhead, the leak, because volume is too small to measure and not considered waste, that criteria, does that criteria likewise apply to the categories?

MR. AMES: Objection, leading. Outside his experience. I mean, are we going to go slide by slide where the Division has said that we need accurate data that he is going to offer the same opinion?

MS. FOX: Madam Hearing Officer, I have to object on the same grounds. I have been sitting here for 20 minutes now, and it is leading question after leading question. It is repetition after repetition. And a lot of this appears to be outside the scope of his expertise as a lawyer and compliance specialist.

HEARING EXAMINER ORTH: Mr. Feldewert, all three of those objections seem relevant here.

MR. FELDEWERT: I don't see how it's outside of his expertise. He is familiar with the reporting that is done through the NMED under these five categories and is qualified to discuss why that is not applicable to this production accounting reporting.

HEARING EXAMINER ORTH: All right. What about the fact that we have heard this testimony before though?

MR. FELDEWERT: Mr. Smith is offering his expertise on this same criteria. We heard this from the Division. We have not heard it from our witnesses.

MS. FOX: Virtually every questions that are being asked are yes-no questions that are leading.

HEARING EXAMINER ORTH: Right.

MS. FOX: I have refrained from objecting for a while here.

HEARING EXAMINER ORTH: Mr. Feldewert, how much longer do you think we will be hearing from Mr. Smith?

MR. FELDEWERT: Well, I think I was about ready to end up before these objections.

HEARING EXAMINER ORTH: All right. So if you would, please, wrap up, and do it in a way that is not leading, please.

BY MR. FELDEWERT:

Q. Mr. Smith, I want you to look at the rationale that was utilized in this exhibit for the deletion of venting in excess of design specifications for pneumatics. Do you see that?

A. Yes, I see that.

Q. Okay. And what's your understanding based on this slide as to why that category was deleted?

A. Well, if there is no credible method of estimation, it doesn't make sense to have it in here as a reporting category. And it's a very low accuracy to, to the information that you are going to get, and so I -- I would say, again, the categories that NMOGA is proposing to delete would fall into that same category, that there is not a credible method of estimation for the purposes of production accounting. The calculation methodologies that are going to be employed are for other purposes such as reporting the greenhouse gas reporting program or establishing the permit limits or calculating emission inventory.

Q. Thank you. And Mr. Smith, were NMOGA Exhibits M1 through M10 prepared by you or compiled under your direction and supervision?

A. They were.

MR. FELDEWERT: Madam Hearing Officer, I move the admission of NMOGA M1 through M10.

HEARING EXAMINER ORTH: Let me pause for a moment in the event there are objections to the admission of NMOGA Exhibit M1 through M10.

(No audible response.)

HEARING EXAMINER ORTH: M1 through M10 are admitted.

(Exhibits M1 through M10 admitted.)

MR. FELDEWERT: That concludes my examination of this witness.

HEARING EXAMINER ORTH: Thank you very much, Mr. Feldewert. Mr. Ames, do you have questions of Mr. Smith?

MR. AMES: (Inaudible) the other witness is on the same topics. Thank you.

HEARING EXAMINER ORTH: I'm sorry, we lost the first part of your sentence. Would you repeat that?

MR. AMES: Yes. I have no questions of Mr. Smith that I have not already asked the other witnesses on the same topics, so there is no need to put Mr. Smith through that again. Thank you.

HEARING EXAMINER ORTH: All right, thank you. Mr. Biernoff, do you have questions of Mr. Smith?

MR. BIERNOFF: Madam Hearing Officer, I don't have any questions for Mr. Smith.

HEARING EXAMINER ORTH: Okay. Ms. Fox?

MS. FOX: I do, Madam Hearing Officer.

Let's see. Mr. Feldewert, either you could share your Exhibit I9 or I can, too, if I have sharing capability, which I don't right now.

MR. FELDEWERT: Would you like me to?

MS. FOX: Great, either way.

MR. FELDEWERT: Let me see if I can get to it here. Okay.

I think we are there now. It's I9 in NMOGA's large, black binder, okay. Is that what you need, Ms. Fox?

MS. FOX: Thank you so much.

MR. FELDEWERT: You bet.

CROSS-EXAMINATION

BY MS. FOX:

Q. Good afternoon, Mr. Smith.

A. Good afternoon, Ms. Fox.

Q. Mr. Smith, you are familiar with OCD's proposed 27.8.D entitled Venting and Flaring During Production Operations, aren't you?

A. Yes, I am.

Q. And that provision generally prohibits venting and flaring except under specific enumerated circumstances; is that correct?

A. Yes, that's my understanding.

Q. And looking at NMOGA's Exhibit I1, I heard basically -- mute while I'm talking and vice versa, thanks -- and I heard you, your testimony that in looking at the sources under I9 that you object to OCD regulating those sources because those are sources that are subject to regulation by NMED and EPA; is that correct?

A. No. What we are proposing to do is delete these from the reported categories and have them uncertain values be -- establish a baseline and determine compliance with the gas capture percentage.

Q. Now, I heard you say many times that you objected to OCD regulating these sources. Did you mean only that you object to the reporting requirements for these sources?

A. Our objection is, as we have stated here, is we are proposing to delete these categories from the list of reported categories. We did want to point out that they are otherwise, they are otherwise regulated.

Q. And you can see that virtually all of the sources listed in 9, in I9 are exempted from the venting and flaring prohibition in OCD's proposed rule, and therefore OCD is not regulating them for that purpose.

A. But the volumes that would be, that would be estimated from these sources other than pneumatics would be counted against our gas capture percentage.

Q. Mr. Smith, that wasn't my question. My question was, you can see that those sources are exempted from the requirements of 27.8.D, the prohibition on venting and flaring?

A. They are allowed, yes.

MS. FOX: That's all I have, Madam Hearing Officer. Thank you, Mr. Smith.

THE WITNESS: Thank you.

HEARING EXAMINER ORTH: Thank you, Ms. Fox. Ms. Paranhos, do you have questions?

(Audio difficulties.)

MS. PARANHOS: Sorry. Hang on one second, one second. Sorry, hang on one second. One second. I have no sound.

HEARING EXAMINER ORTH: I can hear you. Can you hear me?

(No audible response.)

HEARING EXAMINER ORTH: Ms. Paranhos?

MS. PARANHOS: Hi, Madam Hearing Officer. Thank you. I was having audio problems there. I don't have any questions for this witness.

HEARING EXAMINER ORTH: Thank you. Commissioner Engler, do you have questions of Mr. Smith.

COMMISSIONER ENGLER: Thank you. I do not.

HEARING EXAMINER ORTH: All right. Commissioner Kessler just had to depart and said that she had no questions for Mr. Smith, so over to you Madam Chair.

CHAIRWOMAN SANDOVAL: Thanks. Mr. Smith, do you --

(Audio difficulties)

HEARING EXAMINER ORTH: Madam Chair, that didn't come through at all. I trust Mr. Smith is muted.

CHAIRWOMAN SANDOVAL: Can you hear me?

THE WITNESS: I can hear you now, yes.

CHAIRWOMAN SANDOVAL: Okay, do you support this rulemaking?

THE WITNESS: I do support the aspirations and the objectives of the rule. I do believe that it needs some some modifications proposed by NMOGA for me to fully support it.

CHAIRWOMAN SANDOVAL: Do you believe from your experience in the past, present, whatever, that it was a collaborative process?

THE WITNESS: Yes, I do believe it was a collaborative process and appreciate that and would hope that that collaboration would be, would be through the finalization and implementation of the rule.

CHAIRWOMAN SANDOVAL: Thank you. So I don't know if you were on the line earlier. Mr. Baake asked the last witness a couple of questions about the NMOGA methane mitigation rule. Are you familiar with that?

THE WITNESS: Yes, I am familiar with that.

CHAIRWOMAN SANDOVAL: And from I think some your testimony, it seems like you may be a witness in greenhouse gas reporting; is that correct, that you have a lot of experience in it?

THE WITNESS: Yes, I have a lot of experience with greenhouse gas reporting.

CHAIRWOMAN SANDOVAL: It appears that this report was predicated off of greenhouse gas reporting; correct?

THE WITNESS: Yes. That is correct.

CHAIRWOMAN SANDOVAL: And on Page 5 it talks about, I think, the sources or the main sources, and if you are looking at -- do you have this in front of you, by chance, or no?

THE WITNESS: I think I -- well, let's see.

CHAIRWOMAN SANDOVAL: I could share my screen, Baylen, if you let me.

THE WITNESS: I have it in front of me now.

CHAIRWOMAN SANDOVAL: All right. Thank you, Baylen.

On Page 5 at the bottom there are three little graphs. Do you see those?

THE WITNESS: Yes, I do see those.

CHAIRWOMAN SANDOVAL: Or charts, they are not graphs, sorry.

THE WITNESS: Yes.

CHAIRWOMAN SANDOVAL: And on the right-hand side -- oh, I'm sorry, on the left-hand side -- it's getting late -- this is all of New Mexico, correct, represents New Mexico?

THE WITNESS: Yes, that is correct.

CHAIRWOMAN SANDOVAL: And is it correct that it shows the largest sources were pneumatics, unloading equipment, liquids -- I'm not quite sure what that means -- and tanks, followed by (unclear); is that right?

THE WITNESS: Yes, I see that, yeah.

CHAIRWOMAN SANDOVAL: And there are striking similarities to those categories as there is listed on I9,

Exhibit I9 from NMOGA that is proposed to be stricken from the regulation; correct?

THE WITNESS: Yes.

CHAIRWOMAN SANDOVAL: Do you think that there could be a large gap in understanding the whole of New Mexico's waste if those categories were not reported?

THE WITNESS: I think I would point out that the greenhouse gas reporting program, it does not -- it can give you a sense of the, I guess, the sources that would be the, you know, the relative contribution of those source categories.

Where we struggle is that if we are using these methodologies to come up with a number, then that number is used to establish a baseline and enforceability around that, then that would be problematic. I think, again the greenhouse gas reporting program was never meant to establish a limit or a cap. So I think it's acceptable in that context for there to be some uncertainty because it does allow for large-scale analysis, and, you know, it does provide some consistency in how operators report.

It is a reporting framework that operators are, you know, are required to do, it's mandated, but what it doesn't do is, I think, is produce a volume that would necessarily be appropriate for determining compliance with the gas capture percentage.

CHAIRWOMAN SANDOVAL: So but do you agree that if those sources were potentially left out of the roll-up for the total, that there is no way of truly knowing what 98 percent is because you don't have the whole to divide by?

THE WITNESS: Well, I guess I would also look at that, though, if we did include -- if we did include data that is uncertain and doesn't reflect the actual volume released, that you might have information, but I don't know that it would, it would be accurate.

Again, we are adding uncertain values to those that are certain, and I think that it would still potentially lead to some inconsistency. I think the reporting program, again, it's looking at its purpose to understand the, you know, the relative contribution of these sources. I think it provides that data, but I don't know that it would give you a true sense of what is actually being released in the atmosphere. Whereas if we focused in on the high pressure venting and flaring, those would be very certain, and these values would be broken down into these, in the reporting categories that I think would give the Division a very good sense of why the high pressure venting and flaring is taking place.

CHAIRWOMAN SANDOVAL: So what you are saying is because there may be some uncertainty, it means it shouldn't happen at all. There should be none of that information because there is some sort of level of uncertainty that people are too uncomfortable with?

THE WITNESS: Well, again, you know, information, information is good, and information is empowering, but I don't know that it would again give us a true sense because, you know, we do have these high pressure sources that we can focus in on, and those sources can be very accurately measured or estimated.

If we start to add in these other source categories, I fail to see how we are establishing a meaningful baseline because we are using these values that, again, the program itself allows for some uncertainties, allows for operators to choose different methodologies, it has some factors that, you know, I think are suspect, but again, you know, can provide some, you know, useful analysis and insight, but does not necessarily for accounting purposes.

CHAIRWOMAN SANDOVAL: So there seems to have been a lot of talk, and you have mentioned that -- I think almost every witness has mentioned it so far -- it's not good enough for production accounting. What is good enough for production accounting here because it seems like a lot of the categories are not good enough, so I would love to understand, what is that bar.

THE WITNESS: Sorry, I was trying to get myself off mute. I think that, you know, if we have -- I think, Mr. Greaves, going back to his testimony, he provided a good, you know, a good explanation of that, that certainty, but, you know, if I start to add in, you know, all of the, you know, emission factors, like we talked about pneumatics, the emissions factors, that exhibit, we know they are not accurate, there is newer data, it seems to me that that would not -- it wouldn't give the Division the, you know, the certainty or the useful information that they are seeking here as far as what we can (unclear). In this we have two high pressure sources that we can accurately measure and estimate, and I believe those are the sources that, you know, if we agree that that information is appropriate for the Division to have, and even breaking it down into those categories to understand why those volumes are being vented or flared.

There is certainty there.

CHAIRWOMAN SANDOVAL: I still don't think, though, you answered the question. What is the bar to be production accounting certified, check box, it can go in production accounting, because every witness has testified in some form or fashion similar to that. So I want to understand what is that bar. Is there -- is there some API method that -- like what is that? Is it tangible?

THE WITNESS: I, I don't know that I have that particular answer. I do know we do have one more witness coming up that is talking about reporting and maybe could speak to that more clearly, but I know where we have known uncertainty, it does seem like that wouldn't meet that bar.

CHAIRWOMAN SANDOVAL: Okay. So are you familiar with -- I guess, have you -- I think maybe Mr. Feldewert pulled it up earlier -- in NMOGA's prehearing statement on Page 4 they list the definition here of surface waste. And they underline (unclear) the unnecessary or excessive surface loss or destruction without beneficial use.

And I think that some of what -- the prior -- pre -- prior witnesses have hinged upon is unnecessary or excessive loss of surface structure. In terms of maybe -- I think I heard you say this earlier, or it was on a slide -- do you -- does NMOGA think that an open thief hatch would not be waste?

THE WITNESS: Well, an open hatch, you know, if we're talking about a -- if we are talking about a typical tank battery, and I think, you know, we just talked about that being the end of the line, you know, when you have these -- when you have storage tanks you can, you do one of three things, you can capture it, you can vent it through or you can combust it. And in this case, if you capture what can be economically captured, then the other two options are to vent or flare.

But, you know, from, from my standpoint, you know, I think from the -- combustion would be preferable there. But the same logic would apply to an uncontrolled storage tank as well. You don't have that third option, but an open thief hatch at that point, you know, those are volumes that are otherwise not recoverable.

CHAIRWOMAN SANDOVAL: So you're saying it's all waste; correct?

THE WITNESS: In that context, no.

CHAIRWOMAN SANDOVAL: What about a midstream facility with a tank, is that the end of the line?

THE WITNESS: To the extent that you are dropping out the liquids in that particular context, it could be.

CHAIRWOMAN SANDOVAL: Okay, we can leave it there. I think that's all I have. Thank you.

THE WITNESS: Thank you, Madam Chair.

HEARING EXAMINER ORTH: Thank you, Madam Chair. Mr. Feldewert, do you have any follow-up with Mr. Smith?

MR. FELDEWERT: I do not, Madam Hearing Officer. Thank you.

HEARING EXAMINER ORTH: Thank you. In that case, Mr. Smith, you are excused.

THE WITNESS: Thank you, Madam Hearing Officer.

HEARING EXAMINER ORTH: Is there anything we need to talk about before we adjourn for the evening and plan to reconvene at 8 a.m. in the morning?

(No audible response.)

MR. BIERNOFF: Madam Hearing Officer, this is Ari Biernoff from the State Land Office. I would just ask Mr. Feldewert if he has any revisions to his time estimate for his witnesses' testimony tomorrow so I can make sure that my witness is ready at the right time.

HEARING EXAMINER ORTH: Mr. Feldewert?

MR. FELDEWERT: Sorry, I was on -- I was on mute. We do have one more witness, Ms. Perez. I anticipate maybe two hours. Okay? Hopefully it will be shorter than that, but I anticipate that.

MR. BIERNOFF: Thank you, sir.

HEARING EXAMINER ORTH: All right. And actually I have a question. Mr. Feldewert, do you intend to file a, for example, a brief written reply on your motion on the Climate Advocate's proposed, their emission equipment language?

MR. FELDEWERT: No.

HEARING EXAMINER ORTH: You don't. Do you think it would be important to set aside really truly about ten minutes, not very long at all, to make a verbal reply?

MR. FELDEWERT: Certainly.

HEARING EXAMINER ORTH: All right. So we can do that when you are done with your last witness. And let me just say, we've read the motion. We've read the two responses, and I really and truly would be just looking for a reply from you.

MR. FELDEWERT: Understand.

HEARING EXAMINER ORTH: All right. Thank you very much. We will adjourn, and we will see you at 8 o'clock tomorrow morning.

(Recessed.)

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

REPORTER'S CERTIFICATE

I, IRENE DELGADO, New Mexico Certified Court Reporter, CCR 253, do hereby certify that I reported the foregoing virtual proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings to the best of my ability.

I FURTHER CERTIFY that I am neither employed by nor related to any of the parties or attorneys in this case and that I have no interest in the final disposition of this case.

I FURTHER CERTIFY that the Virtual Proceeding was of poor to good quality.

Dated this 12th day of January 2021.

/s/ Irene Delgado
____
Irene Delgado, NMCCR 253
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