FEDERAL OIL AND GAS VALUATION

PUBLIC WORKSHOP

October 4, 2011

The above-entitled matter came on for hearing on October 4, 2011, at 8:30 AM, at the Offices of Natural Resources Revenue, Denver Federal Center, 6th Avenue and Kipling Street, Building 85, Auditorium A, Denver, Colorado, before Martha Loomis, Certified Shorthand reporter and Colorado Notary Public.

OFFICE OF NATURAL RESOURCES PANEL PRESENT:

RICHARD ADAMSKI
PETER CHRISTNACHT
LARRY COBB
GREG GOULD
JOHN KUNZ
JIM STEWARD
DEBBIE GIBBS-TSCHUDY

INDEX: PAGE:

P R O C E E D I N G S

MR. GOULD: I'm Greg Gould, the Acting Deputy Assistant Secretary for Natural Resources Revenue, and also the Director of the Office of the Natural Resources Revenue.

I'm in DC, but I spend most of my time here lately. I think they're probably tired of hearing me in the building.

MS. GIBBS-TSCHUDY: I'm Debbie Tschudy, the Deputy Director of the Office of Natural Resources Revenue.

MR. STEWARD: Good morning. I'm Jim Steward, the Program Director for Financial and Program Management.

MR. CHRISTNACHT: Hi. I'm Peter Christnacht. I'm in the Valuation Division of ONRR.

MR. ADAMSKI: Good morning. I'm Richard Adamski. I'm the Program Manager for Asset Valuation.

MR. COBB: Good morning. I'm Larry Cobb. I'm the Manager of the Royalty Valuation Office here in Denver.

MR. KUNZ: Hello. I'm John Kunz with the Regional Solicitors Office here in Denver.

MR. GOULD: All right. With that we will get started with the prepared statement that we have here.

Good morning, and welcome to the third of our public workshops to discuss revisions to the Federal oil and gas valuation regulation.

The purpose of the Federal oil and gas valuation regulations are to ensure that the American public receives every dollar due on federal resources.

Through these public workshops and the Advanced Notice of Proposed Rulemaking the Office of Natural Resources Revenue is requesting comments and suggestions from affected parties and the interested public before proposing changes to the existing regulations governing the valuation of oil and gas produced from federal onshore and offshore oil and gas leases.

In proposing changes to the current regulations, ONRR has three goals in mind: Provide clear regulations that are easy to understand and that are consistent with fulfilling the Secretary's responsibility to ensure fair value for the public's resources, provide methodologies that are as efficient as possible for lessees to use, and 3, provide certainty that correct payment has been made.

"Early certainty."

The potential benefits from our discussions today include simplifying and clarifying aspects of the rules, decreasing industry's cost of compliance and government's cost of enforcement, streamlining audits by providing more certainty and reducing potential litigation.

We feel it's important to obtain stakeholder input to see if further clarification of our rules is in fact worth pursuing.

The issues we'll be talking about today will include use of index prices to value oil and gas, examining possible alternatives to the requirement to track actual costs for determining transportation allowances, and examining possible alternate methods for valuing wellhead gas volumes by eliminating the requirement to trace the value of liquids removed from processed gas.

We have an official court reporter today. So before you speak please identify yourself by stating your name and your affiliation.

Finally, based on our feedback, based on feedback we received today and from the other workshops, clarification to the Federal oil and gas rules may be in order; if so, ONRR will take the next step to issue a proposed rule, followed by a written comment period.

Any questions before we begin today? With that, I'll turn it over to Jim.

MR. STEWARD: Okay. Just a few more general comments before we get into the first set of questions for oil.

ONRR has over 23 years experience valuing gas under the current federal gas valuation regulations. It has over ten years of experience valuing oil under the current federal oil valuation regulations, which were updated in 2000. Additionally, we have over ten years experience valuing gas under the Indian gas valuation regulations.

Indian gas valuation regulations provide early certainty, and greatly simplify compliance. The lessons learned

from this experience suggest that the current federal gas valuation regulations could be improved to provide greater certainty that royalties have been paid correctly, and to reduce the burden to both industry and government.

We are interested in determining ways to simplify, clarify, and provide consistency in product valuation. We have examined the written comments submitted for the Advance Notice of Proposed Rulemaking, which closed on July 26, for Federal oil and gas valuation, and are interested in further input regarding the need to modify current oil and gas valuation regulations to meet the above-stated objectives.

We received comments from 19 parties representing a good cross section of stakeholders. So let's have questions on Federal oil.

Generally, commenters agreed that the current use of spot prices and NYMEX prices for non arm's-length sales of oil is working.

Should the use of index pricing be expanded or altered?

Anyone like to comment on the first question?

MR. ROMIG: I guess I'll comment. I have to say as a -- David Romig. I'm with Plains Exploration Production, so I guess industry is my affiliation.

I am concerned about the indexing for small and midsized companies with which I've been affiliated through most of my career, especially with the market conditions we're seeing right now, when you look at what happened with NYMEX versus posting in several different regions.

We have a lot of our contracts structured under one basis, and we see a disconnect with what's going on right now between NYMEX and posting in Louisiana. If you look at posting in California you see similar disconnects.

So the market risk that we take on as producers related to price is enormous. And then to put a burden on there to say, This is the way we've got to pay our royalties under an arm's-length marketing arrangement for independent producers, is just adding additional risk as far as I'm concerned.

So if it's an option you want to put in place then, you know, that's fine.

The thing that I'm going to jump on a little bit is the comment that was made about the Indian Rule. When I looked at economics for my company on acquisition and Indian properties are involved with Federal Indian royalties, we discount those properties in value so that a producer who owns those that are trying to sell them lose value for the assets because the risk and concern about the valuation of royalty associated with it.

Yes, it creates simplification in determining certainty on the front end. But the price risk that's created and the costs, when you look at a lease you look at what it costs you on the bonus, you look at what it costs you on the royalties, and what your expected market value is for other oil or gas that's in the ground. And that all goes into play.

When you put that on the value of how much I'm going to be out of pocket potentially for the royalty, that discounts the net value that I can realize as a producer.

We see this as a partnership. And so as a royalty owner we have tens of thousands of acres. We try to work with producers that get into situations where they have got to get into secondary recovery or enhanced recoveries. And we try to work with them about those costs and what our royalties are.

I know in the regulatory environment you-all aren't able to adjust the rules. But any time you're going to get into something like this where you're stepping out in a new way you're going to have to create a mechanism to modify, because the idea that you want to maximum the value for your royalty is the same thing that we have.

We want to maximum the value for our production; we want to pay every royalty owner everything they're entitled. But we also want to make money because that's what we're in business to do.

So that's why I would suggest if you do that on arm's-length contracts you make it optional, but allow us to makes an election.

MR. STEWARD: Thank you for those comments.

Would anyone else like to comment on that

question?

Okay. Staying with that theme, the next question is, Should ONRR consider any other methods to value oil that is not sold at arm's length?

Okay. Now, let's consider the transportation of oil. ONRR's examining possible alternatives to the requirement to track actual costs for determining transportation allowances for oil.

What methods should be considered that would adjust for location differentials between the lease unit and the index pricing and publication point?

Any comment on transportation deductions?

MR. RIEMER: Dan Riemer, Marathon Oil Company.

It would be helpful to the industry if ONRR would consider utilizing commercial rates, actual published tariffs, or contract rates even when a lessee owns a portion of the transportation system.

The way the rule is written now the lessee is forced to calculate their actual reasonable costs using operational, operations data and maintenance, and original investment and return on undiscounted capital. And it's an undervalued calculation as far as what the actual cost is; it really doesn't return a fair, reasonable rate.

And so I think it would ease the administrative burden if the lessee were able to use commercial rates, and that the --

does track with one of the recent decisions regarding arm's-length transportation.

And currently in the oil rule there's a two-prong test. There's control, and then there's opposing economic interest. And control you addressed in the last rule. And there's five different steps that you walk through to determine whether there's presumption of control.

But opposing economic interest is one that, given the at least the criteria that ONRR has used in the past to determine, it's a very difficult hurdle to overcome.

MR. STEWARD: Thank you.

Any other comments on transportation? All right. Last question for oil.

Are there any other suggestions to improve the current oil valuation regulations?

All right. I'll turn it over to Rich Adamski to begin the gas portion.

MR. ADAMSKI: Good morning again.

Gas is a little broader topic than oil just because of the way it's marketed and sold in, you know, a lot of different ways and areas.

In the oil arena we did have some major changes to the valuation methodology of oil starting in 2000, and then again in 2004.

On the Federal gas side, however, it's a little bit different. The valuation portion of the Federal gas regulations has remained pretty much unchanged since 1988.

We've attempted several times to try to come up with some amendments, and we're here trying again today to see if there's any new ideas for going forward.

So gas, we're breaking down, and the first we're going to start looking at index prices specifically. Then we'll move into transportation and processing.

Comments on the use of index pricing in valuing Federal gas for royalty purposes were varied. Some commenters stated that they would support an index pricing methodology if it could be used as an option and not subject to any later true-up calculations.

Some commenters raised concerns that basing value on index prices may yield values that could be higher than they're getting under their gross proceeds sale contracts.

Still other commenters were opposed to the use of index pricing because of concerns of potential manipulation, and values may be less than gross proceeds received from royalty payments.

ONRR invites more specific comments as to whether index pricing could possibly replace gross proceeds in valuing Federal gas production. We want to hear from those that support index pricing as a option and how that would meet the intent of any changes to the regulations to add simplicity and clarity.

How would that option be applied?

Basically, any comments in general for those that support possibly using an index pricing methodology, either for not-arms-length sales or arm's-length sales? How would that work?

MR. WILKINSON: Okay. My name's Bob Wilkinson. I'm with ConocoPhillips.

I'm not sure it's going to be any more specific than the comments included in the written comments there, but obviously going to index pricing as an option would provide simplicity as well as certainty to the valuation process and then, you know, result in the elimination of a lot of pricing adjustments and prior period adjustments as well as audits and compliance reviews and stuff like that.

And it would just probably just leave the focus on the volumetric reporting so there's simplicity, there's certainty that would be provided by index pricing.

But index pricing does give market value but it is at an index point. And so it really does need to be optional because not all producers are getting, are able -- they may not sell their gas at that index point; they may be selling it back at the wellhead and not able to get that particular index price as well as there's a lot of producers out there that may not have systems that can handle the complexity that would be resulting from index pricing where they have to use a system that has to be able to use an index price for valuation of federal royalties and then use gross proceeds for valuation of their other fee and state royalties as well as their working owner interest settlements.

So because of that, not everybody would be able to go to index pricing for those reasons so it does need to be optional.

MS. GIBBS-TSCHUDY: Bob, can you help us understand how the option would work? Are you thinking it would be like federal oil where you opt in for two years to either pay an index, or more frequent? Or what are your thoughts on an option?

MR. WILKINSON: I would think obviously there would be a need for some kind of commitment for a certain period of time.

MR. ADAMSKI: Thank you, Bob. We appreciate the comments and explanations.

Does anyone else have a comment or perspective in this area?

MS. MUSTOE: Hi. My name is Laura Mustoe. I'm with Petroleum Management. And we represent a lot of very small producers.

I guess I would have some questions too. I like the index pricing because it does assure simplicity and fairness as far as gross proceeds exceeding indicis, well, like the Indian Rule, there was a safety method that I think could be implemented.

I'm not certain as to how you would do the option; I mean, what you can or could do. But I think a lot of producers are not considering the finality of using indicies. You're not subject to audit, not subject to contracts.

And that's it.

MR. ROMIG: David Romig again.

We've dreamed about this concept since the RegNeg Committee in the '90s, having indicis. And, you know, it's something --

(Discussion off the record.)

MR. ROMIG: We'd love to move toward it.

I can tell you, I worked for a small producer then, and was looking at how we could make it work.

One of the industry standards that we kind of looked to and is written in most fee lease agreements is like quantity and quality when you're doing price comparison. So royalty owners want to see that they're getting the same price that other people are getting in the area.

Well, that market presence between large producers and small producers does make a difference as to how they're able to obtain that index price or whether it's index minus.

So one of the things that would be an issue going into this is what is your market presence in an area so that you can determine whether you can get a fixed index. It's like Bob was

saying, is your point of sale really there at the index point?

Gulf of Mexico, a small producer, were able to get, you know, cooling agreements and able to get gas to a point. When you get on shore it's a little harder.

One of the problems that you get into is that, especially that first of the month index, is you need to have firm production commitments.

And production fluctuations are not easy for smaller or midsize companies, and so then you end up with daily pricing as opposed to first of the month or a blended price. That's where you create part of the challenge, the production fluctuation.

You also see those production fluctuations because the first of the month versus daily get more exaggerated when you have seasonal issues. That differentiation between a first and the daily can really get out of whack.

When you look at it overall on an extended period of time they look really close. But when you look at the exceptions on those months where you get those seasonal issues you get a real divergent price, so that market presence and the production commitment are probably the two biggest concerns for mid to small sized companies to overcome so that they can get consideration for looking at that.

You have to love the concept when you look at the big picture. Like I said, it's been something that I've hoped for

but haven't figured out how I can make it work.

One of the things that small publicly-traded companies are getting into more and more is the SEC oversight. One of the things the SEC wants to accomplish is transparency.

So how do you disclose these risk factors? All these costs have to be accounted for in the financial statements. And I'll save some of this or I'll repeat myself again when we get to the transportation processing I guess. But all these costs have to be accounted for in some way, shape, or form in the financial statements, and the scrutiny that we're getting.

So if it's not applicable to your royalty on the Federal royalty side then where does that cost go? It's a cost incurred. We can't just make money off of process. We're not in the business to process; we're not in the business to transport; we're in the business to produce oil and gas and sell it. So those are all expenses.

MR. ADAMSKI: Thank you for that perspective.

Anyone else while we're still on the topic of using index prices?

MR. SEVERSON: Moving to the left side?

MR. ADAMSKI: That was my next question. Let me ask the questions so you can respond to it.

We would also like to hear from those opposed to the use of index pricing and your concerns. It's a perfect segue.

MR. SEVERSON: I don't know if I'm opposed to it or in favor of it. I'm from the State of New Mexico, but I won't say that I represent the State of New Mexico and the position they may take. I don't answer; the governor is the one who makes the final decision. But I think I do come with experience of over 20 some years as associated to gas valuation and Federal royalties.

The gentleman talked about a dream. I consider it a nightmare. I did directly participate in the RegNeg Committee.

I would think that that report should still be considered because I don't think the overall conceptual framework that we dealt with in the RegNeg Committee has changed in the 10 or 15 years that we, you know, have passed by from the gas valuation perspective.

The thing that you will have to decide today are the same things that we talked about from a committee perspective 10 or 15 -- I don't know how long ago it was; 20 years ago. And it's not an easy matter. It's very complex. It's by location. It's driven by state. I think offshore is different than onshore.

One of the things that I struggle with personally is what is the Federal Government's ultimate responsibility. I hear bare value; I hear what, every dollar that's due collect; I hear simplicity; I hear certainty; I hear cost; I hear revenue neutrality; I hear clarity; I hear index equals market value with exceptions.

I also hear what is the definition of a royalty? It's 12 and a half percent of value, 12 and a half percent of market value or 16 and two-thirds. It's not a tax, it's a royalty. It's only 12 and a half percent, it's not 100 percent.

So when you hear the right side of the room talk about costs, you're only talking about 12 and a half percent of the revenue stream. You're not talking about 100 percent of the revenue stream.

Fair value, I don't think anybody knows what fair value is in the natural gas market. You hear some people get index, you hear some people get below index, you hear some get above index. What is fair value? I don't think it can be identified.

Simplicity, I guess that's in the eyes of the beholder. What is simplicity? The natural gas market is a very very complex market. A lot of it is driven by industry; a lot of it is driven by the needs for natural gas.

In New Mexico we can move -- our gas moves west, our gas moves east. So for you to pick an index out of the San Juan Basin you have to consider where that gas flows.

Again, it gets back to the RegNeg Committee that I was sold on is that you're going to have to possibly look at alternative flow availabilities when you're talking index if you go to an index.

Index point in the Permian Basin for El Paso has

historically been higher than the index point in the San Juan Basin. Yes, there's a location differential but I don't think that location differential is only associated with transporting.

I think a lot of it is location of the markets and historically the ability to move it to the midwest, to the Gulf Coast, to wherever those markets and the main pipelines can move gas.

The San Juan Basin is a very closed market. You know, again you move west it only goes to three or four different states. You don't have the opportunity to move it to 25 or 30 states based on pipeline availability.

Again, this is a revenue; it's a lease. When a person takes out a lease that company knows that there comes responsibilities with it. And I think at times the Federal Government misses that point from a philosophical perspective.

If I were to take a lease, I would hope that I would know what the federal regulations state; I would know what my risk factors are if I take that lease; I'd want to know what my overall reporting responsibilities are.

I think we've lost sight of that at times, and how the Federal Government may deal with the lessee.

Revenue neutrality, again the key word is "revenue." The State of New Mexico receives a revenue stream from this production in New Mexico. The Federal Government receives a revenue stream. That is our 50 percent or 48 percent of the 12 and a half percent.

I don't consider revenue neutrality to be -- I guess I would not want ONRR and the Federal Government to recognize revenue neutrality from an industry perspective because their revenue is being driven by the 87 and a half percent and our revenue is from the 12 and a half percent.

Clarity, I don't know. Good luck. It's easy to say "index," but is it index at the mainline? Does it try to track the flow of the index?

Again, I recommend that you look at the RegNeg report to see all the complexities that were developed in that in an onshore and offshore perspective. Are you allowing options? Are you simplifying the rules? Are you adding clarity?

Again, index on a POP contract, I don't know what that means. You say index on a percent of an index contract, I don't know what that means. Is it, again, at the mainline? Is it at the lease? Is it at the inlet of a plant? Again, good luck on clarity.

Index equals market value. Again, I've heard -- and

I'm repeating myself here, but I don't know if index equals market value. You know, because if you get gross proceeds you're saying's gross proceeds equals market value. We know that gross proceeds at times will be index minus something.

What does that minus represent? It's unclear when you look at the contracts what it represents. It could be the risk that that marketer is saying I'm going to take for accepting your nominations, for accepting your initial responsibilities as being, in a theoretical perspective, a shipper. I'm taking the risk; you're going to have to pay me for those costs.

Is that cost the Federal Government should be accepting through a gross proceeds type concept? A lot of the major marketing, the BP Energy, the ConocoPhillips, the Chevron Energy, I think get above index.

So, yes, they assume some risks by being a marketer. But is that market value, from their perspective, when they get above index? And should the Federal Government be allowed or be able to share in that on that 12 and a half percent or 16 and two-thirds royalty?

Again, I think you need to consider or look more broadly how you might define market value. And I think "market value" is in itself a very broad term.

I've also heard maximize value of royalties. If you want to maximize value of royalties then you'd want to, I would assume, go with the highest price that's available out there. And that might be an index; that might be something less than an index from a gross proceeds perspective, or it might be higher than an index if they're receiving higher than an index that are affiliated transactions.

That's my general comment.

MR. ADAMSKI: Thank you.

MR. MATTHEWS: Mike Matthews with the State of Wyoming.

I was just going to make the comment that when you're dealing with actual costs we have the ability to go out and satisfy ourselves in terms of an audit. We can go into the company and we have some control over what we go in and look at.

But when you're dealing with an index we can't audit that. I mean, we can audit whether they applied the index, but we're not in there looking to how that index was put together, what all it made up. Because in an index, what's getting reported is what's being chosen to be reported. Not everything's getting reported.

And, you know, as you pointed out, there were some commenters that were concerned about the possibility of increased gaming or manipulation of the index pricing. And we were one of those commenters.

And one only has to look at all of the marketers recently or, shoot, since 2002 that have gone to prison over manipulating those index prices.

But the point I wanted to make was that moves the ability to go in and look at that from under our purview, under, you know, our capabilities, to somebody else's, whether it be the SEC or whoever goes in and looks at those index prices. Maybe it's just through the prosecution of the marketers whenever, you know, it becomes apparent those prices were being gamed or manipulated.

So one of the reasons why we would like to see a continued use of actual costs is because we have the ability to go in and satisfy ourselves through an audit process that everything is above board and transparent, which in the vast majority of the cases it is. But it's nice to retain that ability to assure yourself that's the case.

MS. HECHT: Hi. I'm Vanya Hecht with the Bill Barrett

Corporation. We're a company that just specializes in the Rocky Mountains, so just onshore.

So my comments are kind of all over the place, but they ditto a lot of also what you touched on.

One of the things to take into account, with us being a Rocky Mountain company, we do also have Indians. So we are very familiar with Indian index pricing that are used to report Indians.

I can tell you that 100 percent of the time -- not 50 percent, not 80 percent of the time, the index price is higher than the price we actually realize in the markets.

And so just as a small example for you, in one of our smaller areas in Utah we process the gas through a plant. Our average revenue stream with residue and liquids is only about $40,000 dollars in this area.

The index price is coming out every month $15,000 higher than ours. And when you're talking about $40,000, you know, that's an exceptional increase for an index price.

And so some of the points he was making about the transportation markets, you know, some smaller producers and probably midsize producers, you know, we go out and we lock in the firm transportation agreements so we're locked into about a 10- or 20-year commitment for transportation when we're going to sell our product that, in our case, has ended up being less than what these posted index prices are.

So we realize a huge loss on such a material area as this, so we realize a monthly huge loss in this area.

And when we do dual accounting, for lack of a better term, for index pricing, because you still have the obligation to pay your fee owners that however the lease terms of their contracts are, and you end up with two different types of accounting.

So you're also talking about companies increasing their head counts. So not only do we have a loss with index pricing, but now we need to worry about doing our accounting twice in order to pay our fee owners the way they should be paid, pay the State the way they should be paid, pay the MMS the way they should be paid.

So revenue neutral? In our case we are miles away from being revenue neutral.

And the biggest point I wanted to make kind of really dittos the Plains Oil gentleman's comments is that, you know, we're all in this business to make money. We want to pay all of our fee owners and our working partners the best price for the

product. We're not trying to hose anybody, and us take the best price.

So I think that we need to look at this more as a partnership and not as trying to dictate a price for a company our size which is continuing to lose money.

MR. ADAMSKI: Thank you. We appreciate those comments.

Actually, I'd just throw in, I was just going to say this is wonderful. And, you know, we're getting all sides of the issue, which is a very complex issue. And the discussion that we've had here this morning is the best discussion we've had in any of our workshops so far.

So again, we really appreciate that and hope it continues. Thank you.

MR. RIEMER: Dan Riemer, Marathon Oil Company. I'm not from the right side of the room, but I just want to --

THE FLOOR: Then sit down.

MR. RIEMER: Point, counterpoint.

I just want to make a comment. I heard the "M" word, manipulation. I was encouraged that I only saw it in the public comments that were submitted by one of the states, and then referenced again today by one of the states.

Market manipulation is a concern, and has been a concern and was a concern. And then FERC stepped in, through their oversight and through their requirements for reporting

prices and the standards that they established and the requirements as well as the tape recordings that a lot of companies are using.

Yeah, there were some bad actors in the '90s and the early 2000s, but it was a handful or less. Suggesting that a lot of people have gone to prison, and that's even a current event, I think is a mischaracterization because the market has changed.

FERC has done a great job to provide confidence in the market and the indices, and eliminate the ability for any one person or company or even a group of people to manipulate index prices.

MR. SEVERSON: I have a couple of followups from New Mexico's perspective.

Again, as I stated, onshore and offshore is different. Even within New Mexico you're going to have to recognize from a valuation perspective we have the San Juan Basin that possibly could go to index; we have the Permian Basin that possibly could go to index.

We also have one royalty bearer from the Raton area and Vermejo Ranch that has gas. East I think on CNG's pipeline that potentially would have to be indexed or recognized as being in the market. Then we have carbon dioxide in eastern New Mexico that is not indexed off anything.

So again, from a simplicity perspective, you're not going to get total simplicity; you're going to have to look at it from state to state. When you start looking at it from state to state that adds complexity to the overall valuation of a product that you're responsible for obtaining fair value for.

The second thing that I think that I've got some concerns about is what is the overall production that is reported to these index publications? For example, using the San Juan Basin or even the Permian Basin, has any analysis been done? You don't need to answer this. Maybe you have done it.

But analysis needs to be done some on how much production from a pricing perspective is being reported at that index point on a monthly basis and a daily basis. And does that represent a fair number of elements' entries into that index point that you, if you decide to go to the index, does it represent fair market value?

MR. ADAMSKI: Okay. Great discussion.

Actually, the next two questions are pretty much followups and a little more probing.

You know, one of the central themes that is running through all of this is revenue neutrality. And, you know, as everyone recognizes, that's not a simple concept. And everyone has addressed that in one way or another in their discussion so far.

But let me throw this out there. Is there anyone who would support going to an index pricing methodology that would replace the gross proceeds calculation if it were not revenue neutral for every transaction? Would the economic benefits of simplicity, certainty, and consistency offset any potential increase in royalty revenues paid?

So again we can look at revenue neutrality in a lot of different, you know, aspects and broad, you know, conceptual terms. It can be revenue neutral for a given transaction in a given set of months in a given set of years. So let's not limit our thinking and scope for that concept.

Does anybody have any comments on that?

MR. MATTHEWS: Mike Matthews, Wyoming.

In our state there's been a number of transactions that we have been involved with that don't even represent the total volume of gas in the state. But just through, for instance, on single negotiations with certain companies the difference of a penny can be $100,000 for the state. Of course that may not seem like a lot of money to the Federal Government but it's a lot of money to the state.

And when you look at the overall volumes of gas in the state, the difference of pennies comes out to be millions of dollars, and so have significant impacts on state budgets.

And so given the choice between simplicity and loss of revenue, I think we'd go with the revenue. We don't mind doing the extra work to go in and take a thorough look at it through an audit process.

MS. SANCHEZ: I just wanted to point out -- I'm sorry. Sarah Sanchez with Ultra Resources.

I just want to point out that, you know, in the case where not every transaction is revenue neutral there are a lot of companies who have very focused production.

And so if you only produce out of one basin it's likely that, if that isn't one of the revenue neutral areas, you're going to get hit with that month after month.

Some of these bigger companies that are more diverse might not care that much. But smaller companies do.

MR. ADAMSKI: Thank you. Appreciate that thought and perspective.

Obviously yes, it is complex because it involves, you know, major companies, independents, states. So there's a wide variety of viewpoints in this issue.

MR. WILKINSON: Just to make sure we cover all the bases, you know, obviously if going to index pricing does provide certainty, consistency, simplicity, and overall neutrality, okay. We probably -- Bob Wilkinson, ConocoPhillips.

We'd be willing to recognize that we maybe will end up having to pay more royalties in one area for this property, and less royalties for another property. But it does have the same issues that have been identified, like in Wyoming. I mean, you need to make sure it's revenue neutral in the states.

And it would also impact companies whether they choose to go to index pricing. If they're focused in one particular area and that's going to result in paying more royalties, obviously they're not going to choose going to index pricing.

MR. ADAMSKI: Okay. Finally, our last question to kind of close out just the general area of index pricing, you know, we recognize that if we did go to some sort of index pricing methodology that there would certainly be some areas where either the spot market activity is limited or doesn't exist and, you know, we really couldn't apply an index.

So are there any thoughts on what valuation methodology we could use for those particular areas?

Okay. Let's move into transportation allowances.

Again, you know, all this is kind of intertwined, valuation, transportation, processing, because it's all part of the royalty formula. And again, a lot of these have already been commented on or touched on, but maybe we can get a little more specific now.

For transportation allowances we would like to examine possible alternatives to the requirement to track actual costs for determining gas transportation. So that's the crux of it here.

Comments during the Advance Notice of Proposed Rulemaking were divided with some commenters generally supporting retaining the use of actual costs, and other commenters supporting a location differential with an escalation factor and a separate component for fuel.

There was general consensus that a flat percentage for index would likely not provide revenue neutrality and is not preferred.

In the interest of simplifying the determination and verification of location adjustments I request any alternative methods to calculating actual transportation costs that would adjust for location differences between the leaser unit and the index pricing point and publication point.

Typically, to calculate a transportation allowance, if you have an arm's length agreement it's the contract price. But even at that there could be components of that, you know, contract price that are not allowable deductions for royalty, say, for marketable conditions, things like that.

On the other side, if you do have an interest in the pipeline or whatever then you have to come up with all the actual costs, which are numerous.

So to try to get way from all of those calculations and tracking those things, is there a way to come up with a higher level location differential that we could use for transportation allowance slash deduction?

MR. SEVERSON: I'll be first, then we'll go to the right side of the room.

One the reasons New Mexico, at least our group, didn't respond was we struggled with the question you were asking, what

types of ideas we could provide you. We just didn't come up with any.

We struggle with it because we're directly involved in the unbundling; we know what issues are being identified out there, the amount of working that it takes.

And, you know, I don't know if that's the right way to go down the road but I just don't, I can't come up with any type of location differential that could be used in New Mexico for, you know, the two or the three basins that we have.

Actual costs, that's, you know, actual costs are in the eyes of the beholder on what costs should be allowed and what costs shouldn't be allowed. Coming up with a location differential, I guess you guys could come up with saying 75 percent of a rate under an arm's-length contract or

50 percent of the rate. But I don't know what basis that you have for using the 50 percent other than you're the Federal Government.

I think you probably have that opportunity because the Secretary has the authorization to establish value so you could go 25 percent if you wanted or you could go 5 percent.

I don't know what that percentage rate is. And it's probably different from basin to basin and location to location. And it's probably different from arm's length to non arm's length. Because I think from a non-arm's-length perspective, at least in my opinion, that you should stay with actual costs.

Actual cost is actual cost.

So when they move gas over their own transportation facility they need to calculate actual costs. They do it for severance taxes, they do it for state royalties, why not do it for federal royalties?

You're not simplifying the process because they still have to do it. They're still burdened with it from other entities that they receive a tax from or a royalty revenue from.

So, you know, I wish I could give you some ideas. I just don't have any. And I don't think there's a right answer for the question that you are proposing.

MS. GIBBS-TSCHUDY: Can I ask a question?

One of the comments at the Houston and DC workshop was that industry gets their gas plant statements, they get their invoices, they know what their costs are. They're just not clear on what's deductible and what's not.

So there was an idea thrown out about do we add some clarity to the definition? Do we draw some bright lines? Of course, you'd have the challenge of revenue neutrality.

Do you recall one of the things we did in the RegNeg is we drew a bright line on compression. Anything upstream of the FMP is not allowed, and anything downstream is allowed.

Again, if we'd work out the issues of revenue neutrality what are the thoughts on at least adding some clarity around definition? Still be actual costs, but as we all know, with compression, compressors perform several functions, some of which are allowable, some of which are not.

Could we draw a bright line for compression and other types of transportation, or marketing or marketable condition costs?

MR. SEVERSON: I'll go ahead and comment. Valdean from New Mexico.

I think I offered that recommendation to ONRR before is to update your regulations and be more clear and concise on what's allowed and what's not allowed. I agree with Debbie that

I think that would benefit everybody to understand what is allowed and disallowed.

The only problem that you're going to have is you're not solving the whole problem because you're talking about actual costs. Not everybody calculates actual costs.

Their calculations are different because some of them are actual costs from a contract perspective that you still have the unbundling issue of compression that is part of the bundled rate that somebody is incurring for transportation, or the bundled rate that's associated to, you know, the processing of natural gas where you have compression at the inlet, you have compression at the outlet, and you might have dehydrators both at the inlet and at the other plant facility.

So again, it's not solving that problem from an arm's-length contract perspective; that would have to be worked out.

Again, maybe you just come up with a percentage then.

MS. HECHT: You know, I'm just all for the actual cost. Again, it's kind of my point earlier that when companies lock into firm transportation agreements they can extend out to 20 years.

It's like going in with a partner and deciding to buy a commercial piece of real estate. You each go in 50 percent. If you made a sound business decision you could realize 50 percent of those costs are going into the property, right?

So it's kind of like you lock into these contracts. When a sound business decision is made to use a particular transportation to get you to a particular pricing market, you make that on how much of this cost -- you know, maybe I'm paying a little more transportation to get a little bit further across the state to get to a higher price than we can in this part of the Rockies.

But you made a sound business decision that of my total costs I know I can count on 12 and a half percent of that being shared with the Federal Government. I understand the 50 percent cap, but generally speaking.

So it's hard to say now -- you know, the ideas are good; I think the ideas are good to try to have revenue neutrality and -- you know, they're all good ideas.

How do you get there? How do you after the fact say, We know you locked into all these deals. I know I said I'd buy this property with you but now I'm going to yank my contract back.

It's kind of a dicy situation that I'm not sure you can -- I don't have any ideas. I just really support continuing down the actual costs.

And definitions is always good. The more definition you can add in the reg, you know, are always going to help.

MR. RIEMER: Dan Riemer, Marathon Oil Company.

I just want to ask a point of clarification, Debbie, because you said "compression" when you talked about bright line definitions and you said upstream of the FMP versus downstream. Did you mean gathering as opposed to compression?

MS. GIBBS-TSCHUDY: Well, no.

MR. RIEMER: Because there's a certain amount of compression that's being disallowed downstream of the FMP.

MS. GIBBS-TSCHUDY: I agree with you.

MR. RIEMER: Both transportation compression and compression, recompression after gas has been processed.

MS. GIBBS-TSCHUDY: I really did mean compression. I don't know where -- you could draw the line at the inlet of a plant and say, Any compression that occurs -- and it's really in the context of the unbundling to try to address that issue.

You could draw the line at several places; maybe at the inlet of the plant. Any compression that occurs upstream of the inlet of the plant is not allowing. Any compression downstream is allowable, or you draw it at the FMP.

It's just an example of where could you make things clearer, still staying in the context of actual costs, but making it real clear so we get past some of this litigation around marketable conditions and that type of thing.

But again, there's issues of revenue neutrality doing that that I'm not sure we can get around it. But David has the answer.

MR. ROMIG: No, I don't. But I feel a lot more comfortable with the bright line at the inlet to the plant.

You know, previously I would have said FMP is a good thing. We have some unique properties that we acquired a number of years ago in California. And we're seeing the wind-down of those properties.

The FMPs were established onshore, and so we have a situation where we have offshore platforms. There were or are still FERC pipelines.

And so to comment on what Dan said earlier about FERC rates, it's kind of interesting on the oil transportation -- to digress a little bit -- the FERC tariff was set at $1.55 when the majors collected the tariff and went in, and the actual cost was running about 90 cents to a dollar. Well, you know, MMS wanted the actual cost, not the FERC tariff.

Well, now that actual cost, because of declining production, fixed cost, and depreciation, is running about

$8.50 a barrel. So overall, the government would come out ahead going with the FERC tariff than going with the actual cost. We have seen a real nice benefit of being able to share our actual costs in operating the pipelines.

Getting back to your point about the bright lines, the bright lines are another good generalization. But where those FMPs have been established creates an issue.

You know, we ran into an issue in Piceance where we have some assets, of the contradiction in the regulations about trying to create conservation of the gas and environmental impact and the terrain and so forth. So in order to address these concerns our predecessor in interest and ourselves, we had to go to central delivery points for compression.

Well, you know, onshore you may have to directionally drill into this or you're off the lease so here you're measuring at the wellhead, you're compressing down. Where is that FMP? It's at the wellhead. Is that really going to be acceptable to everybody?

You know, plants are a good situation where, you know, the operation of these plants, compression is part of that extraction of the liquids. It's not really a putting it back into marketable condition kind of thing. But it's disallowed because of the way it's treated.

So I think some of our understanding of operations from cryogenic plants have to evolve in the application of some

of the things. So there may be a different definition to different situations. Instead of one rule you may have to have a couple. Like New Mexico suggested, you may have to have indexes by basin for a situation. There are complexities that need to be looked at in every situation, and how do you address those complexities.

So transportation also gets back to what I talked about in pricing, market pricing. You know, what quantity do you have to negotiate? Sometimes having more volume actually hurts you because of the limitations of pipeline capacity so you do have to negotiate the capacity ahead of time. But generally that market presence can help you. So it helps with the rates you can get.

MR. WILKINSON: Bob Wilkinson, ConocoPhillips.

One more comment. And I'm not going to offer any comment specific to how to go about coming up with a transportation factor; I think it's all well documented in the comments from the various associations and other commenters and stuff like that. I don't have anything new there.

But, you know, in the pursuit of simplicity, certainty, ease of administration and reporting and stuff like that, to just go to using the index for just coming up with the price and not also doing something with transportation, location differential, and/or the processing bump and stuff like that, would not really offer enough simplicity and certainty to really

-- I don't think you're going to get many companies willing to go to index pricing if it doesn't address the location differential and the processing also, because that's where most of the complexity and simplicity would come from.

MR. ADAMSKI: Okay, great discussion and comments. Again, appreciate that.

Moving on to processed gas and processing allowances, again pretty much the same general theme. And it's been mentioned, you know, over and over again here that any changes that we're seeking to make to the regulations are in light of making them clearer and providing more certainty and clarity.

So ONRR is considering accounting for the value of liquid hydrocarbons contained in the gas stream by applying an adjustment or a bump to the index price applicable to residue gas when gas is processed in lieu of valuing residue gas and extracting liquid product separately, calculating the actual process cost and deducting those costs from the value of the extracted liquids.

Again, there was not a consensus in the Advance Notice of Proposed Rulemaking comments. Some commenters prefer actual costs, as we've heard here today. Those who believe a proxy is workable suggested that adjustments should be plant specific and frequently updated to reflect changing market conditions, again recognizing the complexity of the situation.

ONRR is actively soliciting suggestions regarding other methodologies that would simplify the reporting associated with gas processing allowances, or if possible, eliminate the allowances by substituting a market-based proxy to reflect the value of liquid hydrocarbons contained in the gas stream.

So any thoughts about processed gas? We have some experience with the Indian Gas Rule where we have a bump based on BTU content and also whether you're an owner in the plant or not to derive a proxy value for the liquids part of the gas stream.

Is there anything we can do similarly, you know, for the Federal gas side?

MR. ROMIG: David Romig again.

Before I get into the issue about the bump, I'm concerned about the generalization that's being applied. I've seen a few presentations and discussions about this. My concern has to do with the difference I see from my company's perspective being heavily oil aligned.

Oil was the primary product that everybody was after, and gas was a nuisance. Traditionally it was even flared or vented, you know. Regulations forced us to start to process it or to capture it, and to try to create a market for it.

The processing situation I see from our oil fields is that, you know, the costs to handle the gas, to process it and put it to market, exceeds the value.

Now, the way the regulations exist, we have to

continually apply for processing allowance exceptions for the NGLs, and so we typically run 99 percent of the NGLs to apply the cost, and a one percent royalty on the one-sixth or the one-twelfth, you know, the one-eighth royalty.

So we see an exceptional amount of costs in the oil fields. So to characterize it as a bump from an oil field I think would be incorrect.

So here again, I think you're going to have to look at the nature and characteristics of the basin or field or whatever. When it comes to processing of gas from a gas field, you know, at one point in time there were regulations and actually a schedule published by the MMS that showed the higher the BTUs, the less the gas was worth as we used it in field operations off the lease.

I think I still have one of those negotiated rates where we're using gas where the higher the BTU, the lower the percentage of index price. Now, part of that has to do with the quantity of gas, part of it has to do with the quality of the gas and the location to index.

But we do see a value in processing. It has been inconsistent. If you look at the owners, we've created a midstream market now for processing. But processing has not always been profitable. And so it has existed very marginally, and they run very lean.

The thing that I'm concerned about with the unbundling, and this was expressed I think back in Tulsa, the producers don't have an opportunity to participate in the discussion of what's going on. The plants' owners are not looking out for the best interest of the producers. They're asking and answering questions.

As a previous operator of a plant for third-party gas I pursued litigation with the State of Louisiana over the way they were handling taxing, sales and use tax on plant fuel. And we prevailed. It's unconstitutional in Louisiana to put sales tax on gas uses, fuel, and plants.

Midstream producer -- midstream operators are paying those taxes right now because it's not in their economic interest to pursue the legal battle with the state; it's cheaper to pay the tax because it's passed on to the producer. So you don't see the midstream industry looking out for the benefit of the producer or the royalty owner.

So I have a serious concern about the way these costs are being treated in the unbundling process, and the participation or lack of participation by producers. I think there needs to be some conversation along those lines too.

The idea of a bump by plant might work. It would have to be evaluated and then adjusted. But here again, it's going to be a situation where actual cost is still going to be the basis that most people are going to feel comfortable with.

It's economics. It's easier to predict your economics. And so to take the risk is going to depend on the size of the company and how much risk you can already bear.

MR. ADAMSKI: This is a very astute audience. Again, I appreciate it. I almost think like I left my notes somewhere on a chair in the middle for everyone to see.

The final question in processing does deal with the issue of unbundling. And that's something we've seen more and more pervasive over the last five to seven years. And that's a situation where either in transportation or processing, a lessee or producer is charged one price, which from a royalty perspective may include charges or costs that are either allowable or not allowable deductions from the royalty value, whether they're for, you know, because they're charges such as compression, dehydration, sweetening.

Some of the those, the way they're applied, could be allowable deductions; others are not if they're costs to put the gas in a marketable condition or gathering, things like that. So the final question does delve a little further into the whole area of unbundling.

What other approaches can you suggest that would eliminate the burden of accounting for allowable costs to produce gas, and reduce or eliminate the potential for disputes over unbundling of gas plant charges without reduction in royalty value?

There's an administrative burden both on the

governmental side and also industry side dealing with this whole area. Just any thoughts again along those lines more than we've already heard?

MS. SANCHEZ: Sarah, Ultra Resources.

I just wanted to speak to how the ONRR has handled audits of our company in the past. I don't know if everyone would be in favor of this or not, but we do have a bundled rate in a plant who refused to break out the costs, and we had another agreement in a different area, a close area, where there were two different plants. One of the plants was allowable, and one of them was not.

And due to the lack of information from the first plant, the auditors let us supply a percentage of the bundled rate that would not be allowed that was equivalent to the one that was separated out.

MS. HECHT: Our company recently changed from about 80 percent natural gas to about 20 percent oil. We were about more like 96, 98 percent natural gas, so we process a lot of gas. Obviously with the gas prices right now, we try to get things where they're more oil or more liquid.

So it's a challenge to try to unbundle rates or come up with a factor because I'm thinking of like four or five different plants right now in different areas in the Rockies, and our costs are all over the place when it comes to processing.

Not one of them fall within like a certain percentage, you know, to say, Hey, if we take always 20 percent saying that's processing -- I mean, it's just depending on area -- and I know I'm focusing on the Rockies -- but depending on the area it's just you're going to vary so much with what the actual realized costs are.

So I don't know if you pool an area and try to do it that way and come up with a way to unbundle it, but even there it's somewhat subjective. So it will be a challenge.

MR. RIEMER: Dan Riemer, Marathon Oil.

I just want to reiterate on some comments you made previously about definitions, and Debbie, you brought it up.

You know, we, when we have our gas processed, we get a plant statement. And the plant statement has a lot of detail and information on that. And then we have contracts from processing which stipulate the services that are going to be provided, which are sometimes bundled.

Sometimes it may just be a catch-all phrase that was carried over from a contract, you know, that we get treating, dehydration, processing, compression.

That doesn't mean necessarily that all the services are being performed. And it's really easy sometimes just to look at the gas analysis at the inlet stream, and you can see very quickly that treating is not being performed because it doesn't need to be performed for the gas to be in marketable condition, or if it's an integral process, or if it's something the plant is doing that's, you know, above and beyond.

So I think rather than try to build a better mousetrap, because of the comments she made is well taken that a handful of plants, you're going to have a handful of factors, and it's going to be very time consuming to get down to that level of detail.

We've already got that in our actual costs. We just need to find a way through definitions to know with certainty what is allowed and what's not allowed, how things are going to be classified, what's going to be considered incidental to transportation or marketing, what's considered incidental to processing or integral of processing as opposed to transportation or marketing so then we can focus on the contracts and how they're structured as well as encouraged.

Processors are slow to change. They have got performance on these settlement statements and, you know, they're plugging in numbers and they mash the button and it comes out and it works.

When you start messing with the formulas there it's very complex when you're plugging all the analysis and trying to get everything back to the various leases and wells upstream in that plant.

So just I guess to summarize, definitions definitely. Focus on that. We, the industry, we need to look long and hard

at our agreements and conform where we can, try to meet the definitions, get the processors and the transporters with their statements and invoices to try to give us the level of detail that we need.

At the end of the day it will be nice when Valdean and the State of New Mexico shows up, or we get a phone call from Wyoming or the Federal Government, to be able to just send them a PDF file, a copy of the statement we got or the invoice along with the contract, and match it up and things would line up. It would be nice if we can get there.

MR. WILKINSON: Bob Wilkinson, ConocoPhillips.

There definitely needs to be more clarity, more definitions to help, whether we continue with the current way of using actuals, or if we were to go to some sort of indexing and coming up with transportation factors and processing factors and/or both. Obviously unbundling could be addressed in those factors, okay, to offer the simplicity and certainty that you have there.

But before the analysis is done for with what those factors are and so on, there really needs to be further dialogue between the ONRR and the industry on the whole concept and understanding of unbundling, because based upon what's currently posted out on the ONRR website on the unbundled rates, those rates lack any kind of scientific, engineering, manufacturing analysis done to them.

This has resulted in what I believe to be valid transportation and processing costs being incorrectly being disallowed.

And I think there was a commenter there in Washington that kind of discussed about how this kind of puts it in perspective here is how the more modern, efficient cryogenic type plants, okay, are being, based upon the way that they're currently being unbundled, end up with a much lower percentage of their costs being allowed as processing cost, even though they result in additional liquids being extracted.

So if you were to take this whole indexing concept and come up with a liquid bump, those plants would end up having a much higher liquid bump than the older, less efficient types of plants, whether it be lean oil absorption or something like that.

So, you know, you can sit there and have a situation where that plant ends up with a higher bump, and therefore has to pay more royalties. Then they're also allowed a much smaller processing deduction, whereas another plant that's less efficient has a smaller bump, pays less in royalties, and gets a much larger percentage of a much larger processing deduction. Something is just missing in that application, okay?

Another example, based once again on what's posted out there on the ONRR website, is that you could have three wells and they could have the exact same quality, okay? Be produced at the same pressure base with the same water content, the same liquid content, the same level of impurities or CO_2, exactly the same. But because this one well is going to this one plant it may be only allowed a deduction of 10 percent of its processing costs.

The other well, exactly the same well going to another plant, may be allowed a 75 percent deduction of their processing cost. And one going to a third one, this one, once again, is one of the more efficient plants out there is only going to be allowed a deduction for about 30 percent.

So something is just lacking in the application of how these costs are being unbundled. There needs to be, it's processing of the gas. There's value being added. More liquids are being pulled, so their cost should be allowed as a processing deduction. That's not coming out in the way the cost is being unbundled today.

MR. ADAMSKI: I'm giving everybody a chance to take this all in. These are not simple issues. So we got to the point now where actually we can think about some simpler issues. We can all take a deep breath.

And, you know, we are seeking to simplify and clarify the regulations in some way. Even if we can't address huge issues there still may be some ways to make the regulations as they stand now a little more clear and easy to follow.

And so the last part of our discussion we kind of want to open up the discussion for that area. I'll turn back the microphone to Mr. Greg Gould.

MR. GOULD: Thanks, Richard, and thank you all. This has definitely been a very good discussion with a lot more information coming out in this meeting than we had in the first two meetings. So I thank everybody for coming out and providing these comments.

One thing that Richard did talk about in terms of looking at our regulations, we may not get to significant changes if we can't get there. But I'd like to continue to look at ways that we could.

But we do want to look across all of the regulations. You know, we have the four different sections, and our regulations is in the 1,200 range instead of the 200 regulations, for those of you that track the 30 CFRs. And within that, we want to look across them to see if there's a way to just make them easier to understand and easier to read.

One option, we talked a lot about looking at the definitions. Well, the definitions are actually sprinkled throughout the regulations, the four areas.

So one area that we're thinking about looking at is maybe having a section right up front that has all the regulations that are common throughout, the regulations throughout all four.

So that way, you know, right away you know what the definitions are. You don't have to apply them differently. Then if there is a need to apply it differently then you do that in that section with the original definition and this additional information.

Any feedback? Does that sounds like a good approach to move the definition? I'm seeing a lot of heads shaking up and down.

MR. ROMIG: It's a good news-bad news story. This is Dave Romig.

One of the things you get into, it helps you look and see and know where the definitions are. But sometimes these regulations are so lengthy that by the time you get into the depth of the regulation you've got to go back to the definition. Having the definition in the text of the regulation is helpful, and reminds you what's going on.

It does create some consistency issues so I understand that. I don't have an easy answer for you. But, you know, having the definitions up front is consistent with the way most documents are written or contracts are written.

We do see exceptions to those definitions. And having that in the text of the regulation is helpful.

MR. GOULD: And this is actually an effort that's going on across government right now. There is a review of all federal regulations to see if they can be simplified and clarified.

Again, we're not doing this on our own here; this is something that's happening across the government. So again, as we move through the process, comments like that are important to us.

Also, technical corrections, as you know, some of these regulations haven't been changed since the '80s. Some of them have been changed as recently as 2005, I believe. So we've got, you know, the whole gamut in terms of, you know, in terms of picking and choosing in places where we can make changes.

So again, now to smoothen out so we have something published all at the same time too if there's technical areas that need a look, if you have any comment on that. I know some people have already done that. As we go through the next steps, look to the technical corrections well.

I think it was David, you mentioned that we've been dreaming about clarifying and simplifying. I've heard that theme, you know, for a while now, for 20 plus years. Now, I've been dreaming about this for three years.

The people that sit next to me here at this table, as many of you know, they've been looking at this for 20 or 30 years as well. We do have that experience sitting at the table here, which is good news for all of us.

It is something, you know, when you come in and read it for the first time and you say -- I think Valdean and others pointed out -- this is complicated stuff that we're dealing with here. But if there's a way that we can make it easier that's the goal. That's the goal of this whole exercise.

Because when I read through it, it was tough; it was some tough reading. I bring my reg book with me on the airplane. Every time I do everybody at this table starts getting very nervous because I'm always finding a place, What does that mean right there?

Now, I think over the course of time people have figured it out. Obviously our lawyers have told me they are clear, clear enough that everybody can understand them. But I think they can actually be a little clearer in many areas. So again, as we go through this, let's think about that.

Any final thoughts in terms of just generally comments? How best we can go about this process of cleaning up and clarifying our rules?

Bob?

MR. WILKINSON: I'm just going to take this as an opportunity to just voice some general things about the current regulations and stuff like that, maybe not directly related to your question there.

But, I mean, there are, you know, if you are in the process of revising a gas valuation regulation there are some issues in there that probably do need to be looked at, okay, whether we stick with some sort of actuals as far as how we come

up with the processing and transportation costs, or whether we go to the option of having some kind of indexing factors and stuff like that.

You know, just this is something that COPAS has been talking about, had discussions with ONRR or the MMS at the time for years is, you know, the whole concept on when you calculate your non-arm's-length processing and transportation calculations you kind of have to use last year's rate for the current year.

Then you kind of have to go back and do prior period amendments for every single property that goes through that plant or that transportation system.

You know, for some of these plants that are out there, I mean, that's really large. And if you carry it out to also incorporate what's going on with the unbundling effort, which not only applies to non-arm's-length transactions and now arm's length, it basically means every single federal property that's out there is essentially going to have an obligation to go back and Prior Period Adjust that as it tries to true up on the splits between allowable and nonallowable deductions.

Some thinking needs to be going in there to look at if maybe using a prior year's rate would be acceptable for a more current time period without having the obligation of trying to do that true-up there.

The other area that needs to be looked at, once again this is something CoPAS has commented on many times in the past any time gas valuations regulations have been looked at, is the keep-whole reporting provision, okay?

That is once again is on Federal gas and, you know, it talks about where, you know, the gas as far as the producer it's really handled and revenue reported as if it's unprocessed gas.

What the producer has to now do is come up with a pseudo processing deduction and figure out some way how to get it into the system or off the royalty reports for all those properties that have a contract or a keep-whole agreement.

All of this is done essentially just to check to see whether the processing rate exceeds the two-thirds cap. I definitely understand the need for the cap and stuff like that, but the requirement and maybe how it's handled, I guess it has to be reported as being processed, processed gas and is, you know, one of these examples how you go about doing it.

And those examples are real nice, but a lot of times that information is just not available, okay? So the producers are then placed in a position where they kind of have to come up with these factors and they don't have that information.

And the contact, we contacted ONRR, and they don't really have that information for all the plants involved with that.

For just trying to calculate, you know, and see whether it exceeds a cap there, it just seems like this is a reporting obligation that's difficult if not impossible at best, and needs to be looked at, and maybe even considered for being removed, stuff like that.

I really don't know that it ever really has resulted in the cap ever being exceeded. Again, I don't know all the applications in all the plants.

One other area is I was thinking about the PASO workshop that they had there, and Bob Prael saying, We don't like estimates.

Maybe there needs to be a different way how estimates are reporter and accounted for. Does it really have to be at a property level? Or can it be done at a prior level where, you know, you don't have to sit there and do it in a lease agreement type stuff that runs into all sorts of problems where they don't get changed timely and stuff like that by the producer report.

So there may be a simpler way to do that, which I think would be good for both industry and for ONRR.

MR. GOULD: Thanks, Bob.

Other comments before we wrap things up here?

MR. SEVERSON: Just a couple of things.

I read Wyoming's comments. And I guess you need to look, or I think you want comparability in most instances from oil valuation definitions to gas valuation definitions where they're common in nature.

Wyoming identified two key areas. The definition of lessee is different and I think the definition of affiliate is

different. From New Mexico's perspective or my perspective I don't see that there needs to be a difference between oil and natural gas.

Bob from ConocoPhillips brought up keep-whole. It would be easier just to keep whole because if you unbundle the keep-whole it just has complexities to it. Again, keep-whole agreements are recognized as being processed under your regulations so therefore we have to unbundle the costs.

So again, I agree with Bob. The keep whole, the whole keep-whole reporting and the theory behind why you took it upon yourselves to identify those as processing arrangements I think possibly could be looked at from a simplicity perspective and clarity perspective. But it does have a revenue issue if you look at it from an unbundling perspective on how you apply it today.

Opportunities, I think possibly there's an opportunity if you get an agreement with plant owners both on arm's length and non arm's length to support unbundling that might be available to you. I don't know, because it is considered confidential information from a plant perspective.

One of the concerns that I have that Bob brought up is, you know, it has to be -- I don't know what his words were, but engineering certified, things like that.

And when you start talking about certifications and using terms like that you're going to get into disagreements.

If ONRR thinks that they're going to have to justify every decision that they make, we'll be here ten years from now still talking about the same subject.

Again, these are hard decisions that are going to be made. Not all of them are going to be probably logical to everybody, or engineering driven to everybody. But if you get into that area we won't get anywhere.

The other thing I think that there is an opportunity for ONRR to look at is the possibility of a valuation agreements, a framework that you can develop four corners around where you can come up with valuation agreements associated to unbundling or compression or index versus non index, recognizing there would have to be limitations to it, recognizing that there may be many valuation agreements that are a little bit different from basin to basin, state to state, company to company. At least it gives you that opportunity to establish simplicity in the realm of that environment.

Those are areas I would hope you guys would look at, recognizing that, you know, maybe somebody has a valuation agreement that brings in a little bit more revenue than somebody else. But you are solving other issues associated with simplicity.

So those are my comments.

MR. GOULD: Thank you.

It's interesting during the whatever you want to call it, you hear a lot of the same things, you know. Just from that little different perspective, and it's that little different perspective that I'm constantly reading about in my appeals that I'm reviewing and having to decide on.

Again, that's what we're trying, if we can try and get that, you know, get everybody to feel we're not left and right anymore, and that we're all in this for the same reason. I honestly feel that we all are. I think we're close, but there's that little area.

Bob?

MR. WILKINSON: Bob Wilkinson.

I just wanted to clarify something in one of my earlier comments that was referenced by Valdean.

I'm definitely not advocating that there needs to be some engineering certification, okay? What I'm suggesting is that there needs to be some engineering and manufacturing analysis applied in determining whether the various pieces of equipment at that plant, the purposes, whether those purposes of those pieces of equipment are actually part of the processing, manufacturing process then.

And so when you have different plants that have different processes that are involved, there's going to be different pieces of equipment, so compression may be actually considered part of the processing that is done there to extract the liquids, okay?

There may be a need for some of that dehydration. It may have to be bone dry in order to protect the plant, processing plant they're processing in, okay? So those may need to be considered.

None of that has been taken into consideration in the rates that have been unbundled out there today.

MR. GOULD: Any final thoughts before we wrap up for today?

MR. ROMIG: David Romig.

One of the issues that we're running into is the processing exceptions. The scrutiny that's placed on processing exceptions has decreased recently. I'm not saying it's a bad thing. But we have properties that are audited on a regular basis.

And I think it would be in the best interest of both the government and industry if we put that level of effort in this process, that we either look at the historical nature of the property associated with those processing exceptions, or allow that time to be utilized so that the processing exception is extended rather than just annual periods so that we could get a processing exception for two years or three years.

They're always subject to audit. And that way it might free staff time. I know it would free my industry staff time from having to apply for these annually.

So if there's a historical track record, or if there's

going to be the need to go through that, you know, the State of California is very rigid on wanting to audit some of my properties regularly. That's why my processing exceptions, transportation exceptions are going to be reviewed in detail.

So I don't know that there's any recognition in the process, just one standard treatment as to how things are going.

The other thing has to do with the idea of the data mining that's going on. I like the idea that we can get these issues identified sooner rather than later.

The problem that I'm running into is that the timing of the field audits isn't occurring within three years. It used to be I'd get that audit on the third year. I would have notice of an audit pending. And I would get calls about the desk audits or data mining or whatever, wanting to look at issues.

Then I'd say, Hey, they have already scheduled an audit for this, you know. And they would say, Okay. We'll kind of squelch the desk audit and data mining issue and we'll send our issues to the auditors.

So the timing that's occurring right now, the audits are occurring in the fourth year and not the third year, so I'm getting all the data mining and audit questions hitting. Then the next year I'm getting a notice of audit.

So the question is, can we come to some understanding so that we can best utilize our resources? I want to create the certainty for ONRR to see that this stuff is paid correctly.

Whether that is through the desk audits or through data mining or field audits, that's fine with me. I'd just like to do it once and not twice.

I think that would be a better utilization of both of our staffs.

MR. GOULD: Other final thoughts?

I want to thank everybody for coming out. Obviously the next step now, this is our final of the three workshops that we're going to do. We have to gather all the information that we have received both in the comment period as well as the public workshops.

We will then decide on next steps in terms of whether or not we will go through a rulemaking. My feeling is we probably will be doing something to the rules.

So I would expect the next step would be a proposed rule, and at that point you'll have additional opportunity for comment as we move through that process. Again, hopefully you'll be hearing something pretty soon from us.

With that, thank you very much.

(Whereupon the within proceedings adjourned at 10:10 AM.)

C E R T I F I C A T I O N

I, Martha Loomis, Certified Shorthand Reporter, appointed to take the within proceedings hereby certify that the proceedings was taken by me, then reduced to typewritten form by means of computer-aided transcription; that the foregoing is a true transcript of the proceedings had subject to my ability to hear and understand, and that I have no interest in the proceedings.

IN WITNESS WHEREOF, I have hereunto set my hand.

____

Martha Loomis

Certified Shorthand Reporter

Proofread by D. Drake