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:

APPLICATION OF MATADOR PRODUCTION COMPANY FOR A NONSTANDARD OIL SPACING AND PRORATION UNIT AND COMPULSORY POOLING, LEA COUNTY, NEW MEXICO.

CASE NO. 15363
(De Novo)

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

September 6, 2016

Santa Fe, New Mexico

BEFORE: DAVID R. CATANACH, CHAIRMAN
PATRICK PADILLA, COMMISSIONER
DR. ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.
CHERYL BADA, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Tuesday, September 6, 2016, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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EXHIBITS OFFERED AND ADMITTED

(10:03 a.m.)

CHAIRMAN CATANACH: All right. At this time I will call Case Number 15363, application of Matador Production Company for a standard proration unit and compulsory pooling, Lea County, New Mexico.

Call for appearances in this case.

MR. BRUCE: Mr. Chairman, Jim Bruce of Santa Fe representing the Applicant, in association with --

MS. ARNOLD: Dana Arnold of Dallas, Texas representing Matador.

MR. GALLEGOS: Chairman, Members of the Commission, I'm Gene Gallegos of Santa Fe, New Mexico, appearing for the Intervenor, Jalapeno Corporation.

MR. BROOKS: Mr. Chairman, David Brooks, Oil Conservation -- I'm appearing for the Oil Conservation Division as intervenor.

MR. FELDEWERT: Mr. Chairman, Members of the Commission, Michael Feldewert of the Santa Fe office of Holland & Hart, appearing on behalf of the New Mexico Oil & Gas Association as an intervenor.

CHAIRMAN CATANACH: Do I have any additional appearances?

Gentlemen, I believe before we start, we have a motion on the -- in this case filed by Jalapeno

Corporation that I think we need to dispense with, first of all, this morning. I would hope that we could take care of this very briefly and very quickly, so we can move on to the merits of the case. I will go ahead and allow statements by the parties, arguments at this time.

MR. GALLEGOS: Mr. Chairman, yes, we move to strike this intervention by the Oil Conservation Division and NMOGA. Their professed interest has to do with the agency's formation of project areas for horizontal wells and the question concerning the authority of the Division and the Commission in their nonstandard spacing authority to form those units.

Two good reasons why we should not prolong this hearing with these interventions: One is the matter is a legal issue, which was thoroughly presented at length to the Commission on August the 25th and indeed you heard from Mr. Brooks with the Division for quite a spell on that -- on that issue, and the Commission has issued a decision. We have an order from the end of that hearing on the 25th. Our motions were denied, so that's over with. That's done.

In addition, you have the standing issue. And if I might approach, I'd like to remind the Commission of its own order regarding standing to be in a de novo proceeding. Counsel for the Commission very thoroughly, competently analyzed the issue in the Matador case in which Amtex filed an entry of appearance after the Division hearing and then sought to participate in the Commission de novo proceeding. Amtex is truly a mineral owner with an actual stake, going almost 50 percent of the 320 acres that was subject of that proceeding. And you will recall that it was ruled that Amtex could not participate in a de novo proceeding.

And I just read from your order, which is -- which is issued in that case, which was 15366, Order R-14097-A. And your counsel referred to court authority, New Energy Economy versus Lanzia [phonetic], a New Mexico Supreme Court case, on the question of standing, and pointed out that for a party to have standing, they have to have a significantly legal interest in the particular matter at hand. And right here, the matter at hand is forced pooling the Airstrip well in Section 31, 18 South, 35 East. That's what this is about. This is not about your authority to form the standard units. That has been heard.

And there in that order, 14097-A, you wrote: "The Commission finds that Amtex did not take the necessary action to become a," quote, "'party of record,'" end quote, "in Division proceedings, and, therefore, have the right to a de novo Commission proceeding." Amtex did not take any action to become part of the record in the proceedings either by submitting any evidence or argument in writing or at the hearing or by filing an entry of appearance prior to or at the hearing or by appearing in the hearing.

Now, obviously, the two intervenors here were not parties. They were not part of the presentation before the Division on this application, and they cannot come forward at this time, based on your own interpretation of the rules. They have no standing. We shouldn't elongate this hearing with trying to argue something that has already been argued, in fact hours of argument on the 25th on this issue. So that's been heard and been decided.

I would also add the very strange position in which this places Chairman Catanach, because we're talking about the Division -- his division being a party to this proceeding and the Chair having to hear the evidence and make a decision on this. It's absolutely improper, totally inappropriate, and these interventions should not be allowed.

CHAIRMAN CATANACH: Thank you, Mr. Gallegos.

MR. BROOKS: Mr. Chairman, I'm going to

rest on my filed response.

CHAIRMAN CATANACH: Mr. Bruce, do you have any statement.

MR. BRUCE: I have nothing to say on this issue. I support what Mr. Brooks said.

CHAIRMAN CATANACH: Mr. Feldewert.

MR. FELDEWERT: If it's okay, I'll sit in the witness chair. I've never gotten to do that. Actually, I sat here one time when --

COMMISSIONER BALCH: You're now subject to cross-examination.

(Laughter.)

MR. FELDEWERT: Mr. Chairman, Members of the Commission, when I read through Jalapeno's motion, I didn't see any citation to the Amtex decision. And really when you look at their motion, there was nothing specific directed at NMOGA. It seemed like we were thrown in at the last minute, and there was some vague suggestion that NMOGA lacks standing on the grounds that we didn't have a sufficient stake in these proceedings, which is the issue, these proceedings.

They don't reference the governing statute here, which you-all know as Section 70-2-23, which requires reasonable notice to the public. And then it says and I quote, "Any person having an interest in the subject matter of the hearing shall be entitled to be heard." NMOGA and its members meet both of these standards, whether it's a stake in these proceedings or an interest in the subject matter of the proceedings because they filed a motion to declare the rights and obligations of the proceedings in a pooling application. That's what they said.

We filed a motion declaring rights and obligations of parties in a pooling application. They challenge rules that NMOGA and its members supported before this Commission first in 2003 and then in 2011. And their application is not limited to the specific pooling issues or the unique facts involving this particular hearing. Their whole proceeding, as part of it, involves a challenge to rules that NMOGA and its members advocated for the Commission back in 2011. And they're challenging now pooling practices for horizontal wells that NMOGA supports precisely because they promote effective horizontal well drilling.

So we have experience, NMOGA does, with the rules and the practices that they're challenging. We clearly have an interest in this proceeding to justify intervention because we have appeared before this Commission and supported these rules. And there has been no order yet entered by the Commission. This is not like the Amtex case, where they came in at the very last minute at the end of the proceeding and tried to appear. We're here before there has been any order entered by the Commission on these particular issues. So our intervention is timely and it's proper, and we ask that you deny their motion to strike our intervention.

MR. GALLEGOS: May I respond briefly?

CHAIRMAN CATANACH: Yes.

MR. GALLEGOS: The problem with what has just been presented by counsel, the reference he makes are to rulemaking proceedings, the 2003, the 2012 rulemaking proceedings in which the industry at large can participate and has that kind of a broad interest in standing.

This is an adjudicatory proceeding. The question here is simply whether Matador should be allowed to force pool the mineral interests in this particular acreage to drill this well. NMOGA has no interest in the minerals in this Section 31. It's not a party who has been given notice on that basis. We're trying to turn this case into something it's not, and the appropriate place for argument to be made about, you know, the Horizontal Well Rules was in the motion proceeding that we've already had and heard. They're more than a day late in regard to the legal issue. And in regard to the merits issue, NMOGA simply has no interest or standing, and their interference should be stricken.

MR. BRUCE: Mr. Chairman, Mr. Gallegos has spelled out that Jalapeno has an issue with the risk charge. That's also at issue. That's a stake to this hearing, and we think -- Matador thinks that certainly NMOGA, its member companies, operators, working interest owners, have a substantial interest in what happens here today because you've seen what we've already gone through in this hearing -- and I'm talking both parties -- and there is a lot at stake today. And certainly for member -- the members of NMOGA, they're not just mere bystanders. They have a substantial interest at stake in the results of this hearing.

MR. FELDEWERT: Well, the only thing I would point out is if this was just a straightforward pooling case, NMOGA wouldn't be here. But they filed a motion and they made it very clear that they're challenging the rules and the proceedings that NMOGA has supported before this Commission. And they made that very clear at the last hearing that you-all were here and had in this case. So now that that's clear and that's what they intend to do and because we have been a participant in the development of those rules and we have been an advocate in support of those rules, we have standing to now proceed in this case and protect those rules.

MR. GALLEGOS: Mr. Chairman, the question of the rule, the shorthand Rule 35 about the risk penalty, that was the subject of a legal challenge. It was briefed. It was argued at length. The question here today is not the rule. The question is what does the evidence show here for this particular well, in this particular acreage as to what is an appropriate risk penalty, among other things? That's the evidence. NMOGA has no interest in what the geology is underlying this Section 31 or the nature of the reservoir. Those are the issues here.

NMOGA could have been in this matter previously, had their oar in there and been heard on the 25th. That would have been the proper time to do it, not to try and get into the specifics of this particular merits proceedings, which only decides this case, this application.

CHAIRMAN CATANACH: Mr. Gallegos, your case today is not going to focus at all on the authority of the Division to pool these units.

MR. GALLEGOS: No, it does not. We heard

that out, and you ruled against us.

CHAIRMAN CATANACH: You believe that that issue has been settled already.

MR. GALLEGOS: That issue has been decided by the Commission on the 25th. We weren't particularly pleased, but a decision is a decision.

Well, let me ask Mr. Brooks.

Your proposed presentation today, Mr. Brooks, and your witness, is that going to be the focus of your witness today?

MR. BROOKS: It will be relevant to that issue, Mr. Chairman. If indeed I do present a witness, I'm going to present a witness if I feel it's necessary given the testimony that is elicited by the Applicant. But the purpose of it would be to show that you have to have a larger unit than 40 acres to have an efficient horizontal well, and that would be -- my witness is not prepared to address the specific geology of this area. If Mr. Bruce covers that adequately in his presentation, I see no reason to present any evidence.

However, I would point out, Mr. Chairman, whatever you rule on mine or Mr. Feldewert's participation in today's hearing should not result in the granting of a motion to strike the Interventions because the Interventions are in the case, not in the subject matter of any particular hearing.

Thank you.

CHAIRMAN CATANACH: Commissioners, do I have a motion to go into executive section at this time to decide the issue?

COMMISSIONER BALCH: So moved.

COMMISSIONER PADILLA: Seconded.

CHAIRMAN CATANACH: All in favor?

(Ayes are unanimous.)

(Recess, Executive Session, 10:20 a.m.)

(10:42 a.m., Open Session.)

CHAIRMAN CATANACH: Do I have a motion to go back into open session?

COMMISSIONER PADILLA: So moved.

COMMISSIONER BALCH: And seconded.

CHAIRMAN CATANACH: All in favor?

(Ayes are unanimous.)

CHAIRMAN CATANACH: In executive session, the only thing that was discussed was the motion that was pending in this case, and I will turn it over to Mr. Brancard.

MR. BRANCARD: All right. Let me just try to address a few of the issues that the parties have raised.

The statute that governs this is correct.

It's 70-2-23. However, that statute, dating back to the 1935 Act, conflates rulemaking and adjudication into one standard and reflects the issue of what is an interest in the subject matter is more properly defined by the Commission's regulations which separately deal with rulemaking and adjudication proceedings and who has the right to participate in those proceedings. There are standards for participation in adjudicatory proceedings because they do relate to the rights of individual parties that do participate in those proceedings.

There are two issues here -- actually three to discuss. First is the role of the Division in this proceeding. The Division filed a motion to intervene two weeks ago. The Commission, at the last hearing, did, in fact, rule on that motion and allowed the Division to participate as an intervenor in this proceeding. That is a legally defensible position because the Division is under the adjudicatory rules, one of the category of parties that can actually file an application in an adjudicatory proceeding. Therefore, since they have the right to file an application for an adjudicatory proceeding, they have a right to intervene in an adjudicatory proceeding.

The second issue related to the Division was what is its ability to participate in this proceeding. My understanding, Mr. Chairman, what the Commission prefers to do is to simply, if the Division wishes to participate in this proceeding at any time, to decide whether that witness or testimony is, in fact, relevant to the proceeding that is going on today. And so we'll rule on it at that time if the Division wishes to present any evidence, and the relevance will be the crucial issue at that time.

Then the next issue is the motion to intervene by the New Mexico Oil & Gas Association. As pointed out by counsel today, the Commission, in the last few months, has had a similar case dealing with the standing issue, and in that case -- it was not quoted by a party, but one of the findings of the Commission, the holdings, was that the Commission did not think that the term "party" should be given an overly broad meaning under the adjudicatory rules. And In that case, there were issues not necessarily of the standing of the party but of the timing of the participation.

The Commission has concerns with NMOGA's motion both from a standing and a timing participation. Had NMOGA asked to participate in the motion proceeding, I think the Commission would be looking at this as a different question and looking for a way possibly to give NMOGA a chance to file a brief for participating in that argument. But today we are at the hearing on the merits of the case, and the Commission finds that NMOGA does not have standing in relation to the merits of this case. And, therefore, the motion to strike NMOGA's intervention motion is granted.

The motion to adopt all of that long --

CHAIRMAN CATANACH: Do we rule or vote on it?

MR. BRANCARD: Yes, vote on it.

CHAIRMAN CATANACH: Commissioner, do I have a motion to adopt all of that eloquently stated position?

COMMISSIONER BALCH: So moved.

COMMISSIONER PADILLA: And seconded.

CHAIRMAN CATANACH: All in favor?

(Ayes are unanimous.)

CHAIRMAN CATANACH: With that, we will proceed to the case itself.

Any opening statements at this time?

MR. BRUCE: I have a brief one.

OPENING STATEMENT

MR. BRUCE: Mr. Chairman, Commissioners, last week the Commission decided it has the authority to create nonstandard spacing and proration units and to force pool interest owners into such units if the operator can't reach voluntary agreement with them. That leaves the following issues to decide today.

First, Matador will show that it negotiated in good faith to reach voluntary joinder with interest owners in the proposed well unit, and when it was unable to reach voluntary agreement with all interest owners, it followed the statute and applied for compulsory pooling.

Again, I note that 70-2-17C requires forced pooling for parties who have not reached voluntary agreement.

Second, Matador will show that the proposed nonstandard oil spacing and proration unit is in the interest of conservation and the prevention of waste and will protect the correlative rights involving all interest owners in the well unit.

Third, Jalapeno must show that there is a specific reason that the standard risk charge of 200 percent should not be applied and that this well is unlike the vast majority to which 200 percent is appropriate.

But regardless of that position, Matador will present evidence that if there ever was a case for the maximum risk charge, this is it. In its presentation, Matador will show how to assess the three items specified in the pooling order -- the original pooling order in this case, the geologic reservoir and operational risks, and it will discuss how there is overlap among those and will discuss what risk charge it thinks is appropriate.

And finally, Matador will discuss why the risk charge should apply to surface equipment, especially on wells testing unconventional reservoirs.

The issues require the Commission to consider not only this case but the implications that it will set. The Commission should grant the entirety of Matador's application not only because it will meet all the requisite showings, but to deny the application would deprive all the interest owners, including royalty and overriding royalty owners, of their correlative rights. It will cause waste, and it will thwart horizontal well development in New Mexico, which I don't know an exact percentage, but I would guess in the high 90 percent these days of all wells drilled in the state. We'd be pretty -- we'd be pretty -- well, basically I'd be out of work if it wasn't for horizontal drilling.

And I would like to mention the natural conclusions of granting less than a 200 percent risk charge. To give less than a 200 percent risk charge would discourage voluntary agreement, and the supporting working interest owners wouldn't have to negotiate. They'd rather be pooled, pay no well costs, let the operator take all the risk and essentially get a carried interest.

Operators like Matador who invest substantial money and take substantial risks for the benefit of all interest owners and take the effort to explore and develop New Mexico's oil and gas resources would be discouraged from taking on riskier projects. And, again, we will show that there is substantial risk in drilling this well.

And finally, we believe the Commission should not give any encouragement to interest owners who want to halt horizontal development and discourage exploration drilling activity in New Mexico.

Thank you.

CHAIRMAN CATANACH: Do you have anything, Mr. Gallegos.

OPENING STATEMENT

MR. GALLEGOS: I don't have an opening prepared, but let me just say the question here is risk associated, if any -- if any, with the drilling of the proposed well.

Another issue is what I would call almost the duplicity of presentation by the Applicant who presents one set of science and justification to the Division and has prepared, I see from exhibits, to a 180-degree different presentation about the nature of the geology, reservoir and operational risk here.

The witness and the exhibits that we anticipate will suggest and raise the question whether the application should be granted to even be relative of this sort or whether doing so threatens waste and really invades the correlative rights of the parties just because of the nature of the well being such a very high-risk wildcat-type well, according to the exhibits.

Finally, we will show that the 100/300 percent penalty, called the 200 percent risk penalty, deprives the nonconsenting pooled owners of their property, that under any circumstance, with recoveries of those projected for this well or greater or lesser, the interest owners such as in this case, Jalapeno and others, can lose their property. Their property's taken, and they will never receive any revenue, return on their mineral interests.

That's basically the outline of what our case would be, and we'll be presenting witnesses on the -- on all of those issues.

CHAIRMAN CATANACH: Okay.

Mr. Bruce?

MR. BRUCE: I have four witnesses, Mr. Examiner.

CHAIRMAN CATANACH: And, Mr. Gallegos?

MR. GALLEGOS: I have three witnesses.

CHAIRMAN CATANACH: Can I get all the witnesses to stand and be sworn in at this time?

(Witnesses sworn.)

MR. BROOKS: For clarification -- if you please, Mr. Chairman, a point of clarification on the Commission's ruling, will counsel for the intervenors be permitted to question witnesses being called by the parties?

Mr. Feldewert has left so I gather he does not choose to do so, and I probably won't, but I just wanted to clarify that. Or do you wish for me to rise and ask for permission?

CHAIRMAN CATANACH: Let's deal with that at the time.

MR. BROOKS: Very good. Thank you, sir.

VAN H. SINGLETON II,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of residence for the record?

A. Van Singleton. I live in Frisco, Texas.

Q. Who do you work for and in what capacity?

A. I work for Matador Resources Company as executive vice president of land.

Q. And what are your responsibilities for Matador?

A. I supervise a team of land professionals who work on getting wells ready to be drilled, on acquiring new properties, trading existing properties, working with surface owners to reach agreement on how we can access those properties, pretty much every aspect of land work in oil and gas.

Q. Have you previously testified before the Commission?

A. No.

Q. Would you please describe your education and employment background?

A. I have a BA in criminal justice from the University of Mississippi. I have been a landman since 1996 so about 20 years. I've been with Matador for nine years, going on ten. And at Matador, I started as a landman, and I've held the positions of landman, senior landman, general land manager, vice president of land and executive vice president of land now.

Q. And do you oversee Matador's land work in all of its particular areas of interest?

A. Yes.

Q. Inside and outside of New Mexico?

A. That's correct.

Q. Are you a member of any professional organizations?

A. Yes, the AAPL, and the local Dallas association of landmen, the Permian Basin Association of Landmen, the New Mexico Association of Landmen, NMOGA. I think that covers them.

Q. And are you familiar with the application filed by Matador in this case?

A. Yes.

Q. And are you familiar with the status of the lands which are subject -- the subject of this application?

A. Yes.

MR. BRUCE: Mr. Chairman, I'd tender Mr. Singleton as an expert in petroleum land matters.

MR. GALLEGOS: No objection.

CHAIRMAN CATANACH: Mr. Singleton is so qualified.

Q. (BY MR. BRUCE) Can you please identify Exhibit 1 for the Commissioners and explain basically what Matador seeks in this application?

A. So Exhibit 1 is the Form C-102. What we're seeking is to drill a Wolfcamp well in the Airstrip; Wolfcamp Pool. That code is 970. The wells proposed would have a surface location that is 150 feet from the south line and 660 feet from the west line of Section 31, Township 18 South, Range 35 East.

The well would then be drilled laterally. The first set of perforations would be at a point of approximately 330 feet from the south line, 710 feet from the west line. And then the final perfs at the end of the well being 330 feet from the north line and 710 feet from the west line, effectively giving -- our unit being the west half-west half of Section 31. That section is not a standard 640, so it's not exactly 160 acres. It's about 154.

Q. And this will be an upper Wolfcamp test, correct?

A. Yes. I believe that's correct.

Q. Referring to Exhibit 2, could you briefly discuss the working interest ownership in the well unit and identify who Matador seeks to pool in this case?

A. As it stands right now, Matador has, through its original interest acquired from HEYCO, along with other interests that have been acquired, we've got about 93-and-a-quarter percent. We have gotten voluntary joinder from another 3.9 percent, and there is 2.8 percent, more or less, that we're seeking to pool that we've not been able to get voluntary joinder, although we still want to try.

Q. And one of the parties being pooled is Jalapeno Corporation, correct?

A. That's correct.

Q. And the others are various --

A. There are two trusts. In those trusts, we have tried to contact them on a number of occasions. We have gotten through to various family members who are beneficiaries for the trust or associated with the trust. Up to this point, we've had a very difficult time actually getting decision-makers on the phone or in person. We have sent offer letters. We've sent proposals. But for the most part, it's been no response.

Q. And since the original hearing before the Oil Conservation Division, has Matador acquired voluntary joinder from certain interests?

A. Yes. I believe we've gotten about seven other interests that we have reached voluntary joinder on.

Q. Can you refer to Exhibit 2? Could you identify that and identify the types of land we're dealing with in this proposed well unit? Exhibit 3.

A. I'm sorry. Yeah, I was going to say Exhibit 3.
Q. 3A, first of all.
A. So what we have in the -- in the unit as it's proposed, being the west half of the west half, is actually two state leases, one covering the west half of the northwest quarter and a separate lease covering the west half of the southwest quarter, which you'll see in red, the crosshatch on the map.
The rest of the section -- well, the one state lease that covers the west half of the northwest quarter also covers the north half of the north half. The state lease that covers the west half of the southwest quarter also covers the southeast quarter of the southwest quarter and the southwest quarter of the southeast quarter.
Q. And is that reflected on Exhibit 3B?
A. It should be, yes.
So you'll see one state lease being Tract 3, at the top, the other state lease being Tract 2, at the bottom. And Tract 1 is made up of various fee leases.
Q. And are there -- on those fee leases, those have -- are those HBP, or are you going to have to develop them?
A. Depending on what happens, there are

partially -- some of the interests are held by production from an existing Morrow well that's there. If that well were recompleted in a different zone, that would change its unit size, which would put some of those leases in upper exposure to expiration and continuous development. And so there are -- the effort to get this well drilled does have an impact on those continuous development clauses, and we're trying to do the best we can do to get our wells in and produce them.

Q. And are there any term assignments in the north half that --

A. Yes, which also have expiration issues and continuous development dates that have to be met.

Q. What is Exhibit 4?

A. Exhibit 4 is a proposal letter that was sent to Billie Kirby. It was the -- I believe the same proposal letter that was sent out to everyone. In the past few months, we've actually reached a voluntary joinder with this interest. And with the other working interest owners, I think it was seven in total.

Q. I think attached to that are green cards that show the parties to whom this letter was sent?

A. That's right.

Q. And so there was a trust and Jalapeno Corporation that did receive the notice, according to

these green cards?
A. Yes, that's correct.
Q. Other than the initial well proposal, has Matador had other contact with Jalapeno Corporation?
A. Yes. On a number of occasions, we had had phone conversations. We have sent various letters back and forth and met in person.
Q. Is Exhibit 5 a summary of communications between Matador and Jalapeno?
A. Yes. And also in there, Exhibit 5, is A, B, C, D and E, a number of written communications.
Q. So why don't we -- and in addition to the various communications, email, phone or letters, was a meeting held at Matador's offices with representatives of Jalapeno and, I think, Yates Energy to discuss proposals on this well?
A. That's right. I believe it was June 3rd of 2015. We did invite and they came to meet with us in person. There was Harvey Yates representing Jalapeno, and also Fred Yates and his daughter Becky Pemberton were representing Yates Energy. And from Matador, we had myself, Joe Foran [phonetic], our CEO, most of executive management group and members of our technical team and land team also.
Q. And the technical team and the land team were

there to answer any questions?

A. Help answer questions and -- and really what we all wanted to have was just an open discussion of what are the options to try to get to some kind of deal so we can get a well drilled.

Q. Have you selected some of the correspondence between the parties to illustrate -- and by between the parties, I'm talking about Jalapeno and Matador and what they have discussed?

A. Yes.

Q. And are those marked as Exhibit 5, 5A, et cetera?

A. Right, 5A through 5E, I believe.

Q. Could you walk us through those letters briefly?

A. Yes.

5A is the original proposal that was sent out by HEYCO, Harvey E. Yates Company, proposing a Bone Spring well in this section.

Now, just one important point, on the 5A, it did include the AFE also, which you'll see later was -- reference was made to a difference in charges for 1A Fee to the next. And just to preface that, it's because the well was changed from a Bone Spring well to a Wolfcamp well and it had different costs.

Q. Then Exhibit 5B, is that a response or -- excuse me. 5B discusses that. Now, is it followed by a response from Jalapeno?

A. Yes. 5B is the revised proposal revising the well from the Bone Spring to the Wolfcamp.

5C is the response letter from Jalapeno, and the gist of it is, for reasons enumerated in the letter, they might participate in the drilling of the well but really refusing to sign the JOA if it had a 100/300 percent nonconsent charge, and the fact that the JOA that was proposed was for a full-section development and not just a 160.

Q. And what is Exhibit 5E?

A. 5E is a response letter from Jalapeno giving a number of reasons why they did not want to participate with the JOA as we proposed it.

Q. Now, what options did Matador discuss with Jalapeno regarding their participation in the well?

A. Well, really, it was the option to participate on a heads-up basis, which is what we really welcomed. And alternative to that would be an assignment of their interest rate, $200 -- it would bring a 75 percent net revenue interest, which they would be retaining an overriding royalty interest up to 25 percent, or to just have a straight-out purchase and sale agreement and buy their interest out altogether.

Q. Did Matador describe the time frame Matador was looking at to get the well drilled?

A. Yes. I believe we stated we wanted to drill the well in July of 2015.

Q. Has the well been drilled?

A. No.

Q. At this point you still don't have voluntary agreement from all of the working interest owners?

A. Correct.

Q. What happened next?

A. We received a counterproposal from Jalapeno that essentially proposed that Matador pay $5,000 per that acre for only the Wolfcamp rights and that Jalapeno would retain an overriding royalty interest up to 25 percent. And, frankly, it just wasn't representative of the market in that area for this type of deal.

Q. You've already stated that you're looking at full development of this section?

A. Uh-huh.

Q. And for the court reporter, say yes or no.

A. Yes. Sorry.

Q. You have acquired other -- purchased other interests out here for more than 800 bucks an acre?

A. Yes, we have.

Q. But was that a full -- were they granting you the full Wolfcamp rights in the full section?

A. It was a different kind of deal. It was an all-rights title and interest, so not just Wolfcamp rights. It was throughout the section. Some override rights were retained, some were not, so it's not an apples-to-apples comparison.

Q. Now, did Jalapeno inform you that they would not execute the proposed JOA?

A. Yes.

Q. And what is the primary reason for that?

A. Because of the 100 percent-300 percent nonconsent charge and also having the full section inclusion.

Q. So they did not agree to the, under the pooling statutes, cost plus 200 percent risk charge?

A. Correct.

Q. Normally referred to as 300 percent under the JOA?

A. Right.

Q. Would you want the JOA as to a whole section so that you could steadily develop the whole section?

A. Steadily develop. And in most cases, when you can get a whole section -- or the more wells you can fit into a unit, the better, because you're going to get cost efficiencies with surface facilities. You know, you don't need multiple tank batteries. You can go into one tank battery. It saves everyone money. You can have one of many things versus many of many things. So it just saves time. It saves money. It helps to more fully develop the section and make sure that everyone's correlative rights are protected.

Q. And it does take time with this well -- even if there wasn't a forced pooling procedure, it still takes time from inception getting the leases, doing the land work --

A. Absolutely.

Q. -- getting the drilling rig to develop just one well?

A. Just one well. And when you have to do that multiple times, it might take a year or two years to get a location to drill.

Q. So what you're saying is that -- our provisions of 300 percent nonconsent charge or having a JOA cover more than one well unit, are those unusual?

A. Not at all. I mean, I have worked on, you know, JOAs, operating agreements as an operator, as a nonoperator. Matador has operating agreements covering hundreds of wells. It's something that we see very frequently. And, in fact, in the past few years, we have seen proposals that are higher, that can be 300 percent and 500 percent. So we are participating in many JOAs that have that exact provision, the 100/300.

Q. As an operator and as a nonoperator?

A. Correct, and everything from very small working interest owners being -- company sizes being small up to Chevron, Shell and everything in between. So it's not as though it's specific or that things change as you go from one type of working interest owner to another. I think everyone across the industry has adopted the 100/300 to be the standard.

Q. If Matador was a nonoperator in this well and Company X proposed the drilling of it, would it be amenable to signing a JOA with a 300 percent nonconsent penalty?

A. Yes.

Q. Did Jalapeno also raise the AFE, the cost of the -- or the -- yeah, the cost set forth in the AFE?

A. Yes.

I mean, what I recall is that the comparison of the costs were comparing a Wolfcamp well to a Bone Spring well, which are clearly going to have different costs just given the different depths and completions. And they're just not apples-to-apples comparisons.

Q. Now, when this well was first proposed, it had an AFE -- and another witness will discuss this, but has the cost come down substantially since the proposal?

A. Yes. Service costs have come down, which have allowed us to reduce our costs to drilling.

Q. Substantially?

A. Yes, I believe so. We'll let them tell us exactly, but --

Q. In your opinion, has Matador made a good-faith effort to obtain the voluntary joinder of the interest owners in this well?

A. Yes.

MR. BRUCE: Mr. Chairman, the next exhibits, Exhibits 6A through D, are simply the notice given to the offsets and the notice given to the parties being pooled in this case.

MR. GALLEGOS: We have no objection to admitting those.

Q. (BY MR. BRUCE) Now, do you have any estimate of how many JOAs you've read or negotiated?

A. Hundreds, many hundreds.

Q. They get kind of repetitive?

A. They are very repetitive.

Q. And are those JOAs for horizontal development or vertical development?

A. There are a few vertical developments, but it's by and large horizontal development.

Q. And have those JOAs been in areas where there was existing production?

A. Yes. Absolutely.

Q. And, again, you were negotiating both as an operator and nonoperator?

A. That is correct.

Q. Do you recall any JOA that had less than a 300 percent risk charge?

A. No, I do not.

Q. Now, you mentioned 100/300. What does the 100 and 300 apply to?

A. So the 100 is typically equipment, say, your surface equipment that you really just get back your cost of putting it in there. You had to buy it. You had to install it. There's really no risk with buying that equipment and installing it, so it's really just recouping loss.

The 300 applies to the cost to drill, complete and produce the well. You may have to do some clean-outs, workovers. Those are the risky operations. And I think that's why the percentage over 100 is applied, because the working interest owners that do participate are accepting that risk. They're putting their dollars out there, and they may or may not get them back.

Q. And looking at Exhibit 7, what is this, Mr. Singleton?

A. Okay. Exhibit 7 is a 1981 operating agreement form that is applicable to a vertical well in the section. It's not an overlapping unit for this. But, you know, some key points to Exhibit 7 is that it does include the 100/300 risk charge. In fact, it also includes the equipment.

Now, Jalapeno did not -- was not an original signatory to this original operating agreement. I believe it was acquired through some other term assignment or something to that effect.

Q. So this -- this -- this JOA wasn't in place, but Jalapeno bought an interest under the JOA?

A. Correct, and is, in fact, participating under this agreement.

Q. Now, you mentioned the equipment. If you look at the bottom of page 5 or -- yeah, page 5 and the very top of page 6 of the JOA, the 300 percent -- top of page 6 -- does apply to certain equipment; does it not?

A. That's correct.

Q. So there is a basis for --

MR. GALLEGOS: Excuse me. What are you

referring to?
MR. BRUCE: Exhibit 7.
MR. GALLEGOS: Yes, I know Exhibit 7, but what language? You're talking about the top of page 6?
MR. BRUCE: Very top of page 6, Mr. Gallegos. It's kind of shaded on yours.
Q. (BY MR. BRUCE) So there is a basis for assessing a higher risk charge on certain equipment?
A. Yes.
Q. And will a later witness discuss that also?
A. Yes. Yes.
Q. Does Matador request, in this case, the cost plus 200 percent risk charge of any working interest owner that goes nonconsent in the well?
A. Yes.
Q. And who should be the appointed operator of the well?
A. Matador Production Company.
Q. Do you have a recommendation of the amounts which should be paid to Matador for supervision and administrative expenses?
A. Yes. $7,000 per month on a drilling well and $700 per month on a producing well.
Q. And are those amounts equivalent to those normally charged by Matador and other operators in this

area for horizontal wells of this depth?

A. Yes.

Q. Is this also in the JOA with the parties who are going along in the drilling with Matador on this well?

A. Yes.

Q. And this will be discussed by the next witness, but is this the northernmost Wolfcamp well drilled in the Delaware Basin?

A. In the Basin, yes. To my knowledge, this would be the northernmost horizontal Wolfcamp well drilled.

Q. So you haven't received any similar well proposals from other operators to test the Wolfcamp in this area?

A. No.

Q. And as to the overhead rates, do you request those be adjusted periodically as provided by the COPAS accounting procedure?

A. Yes.

Q. And were Exhibits 1 through 7 prepared by you or under your supervision or compiled from company business records?

A. Yes.

Q. In your opinion, is the granting of this application in the interest of conservation and the prevention of waste?

A. Yes. Absolutely.

MR. BRUCE: Mr. Chairman, I move the admission of Exhibits 1 through 7.

CHAIRMAN CATANACH: Any objection?

MR. GALLEGOS: No objection.

CHAIRMAN CATANACH: Exhibits 1 through 7 will be admitted.

(Matador Exhibit Numbers 1 through 7 are offered and admitted into evidence.)

MR. BRUCE: Pass the witness.

CHAIRMAN CATANACH: Mr. Gallegos.

MR. GALLEGOS: Thank you, Mr. Chair.

CROSS-EXAMINATION

BY MR. GALLEGOS:

Q. Mr. Singleton, let's focus on what I call the full-section inclusion issue. Would you explain what was that subject? What was involved?

A. Making the contract area for the operating agreement to be the entire Section 31.

Q. So in Section 31, the proposed well would just be the first -- it's a north-south, west half-west half?

A. Correct.

Q. And the expectation of Matador would be that there would then be an east half-west half well?

A. I think I'm probably not the right witness to testify to that point. I think our technical team and team leaders would be the ones to make those decisions as to how the development would be done and in what order.
Q. Well, let's just assume that Matador would drill four horizontal north-south wells in Section 31. All right?
A. Okay.
Q. And what you are requiring is that the JOA would include this nonconsent penalty of 100/300 for each of those wells in that section, correct?
A. Yes.
Q. Although the fact is, as you've testified, after the first well, you have an education on the area. You have cost efficiencies. You're not having to duplicate certain facilities, but yet you'd still want that nonconsent penalty on the next three wells?
A. I think, if you look back at what I said, I didn't see you'd have an education, because the fact of the matter is you have risk on every well, not only geologic but mechanical and especially on horizontal wells. The mechanical risk is just higher.
Q. Okay.
A. So I don't think I said that. But you do gain

operational efficiencies, which is why we try to do that whenever we can.

Q. All right. So, Mr. Singleton, let's just take it a step at a time then. You drilled the well. You have a successful well. So the geology is established. That's no longer a risk issue, is it?

A. Well, I think the engineers and geologists can testify to that point more than I could, but I would -- I would bet you a hamburger if you looked around the Basin, you would see some good wells with some bad wells right next to it.

Q. Well, the bad well might be -- we're talking -- my question is geology. And I realize you're not talking geology --

A. Right. I'm not a geologist.

Q. -- but I'm talking about the concepts so the Commission understands what you're requiring, that even though you're going to have an established well and three more are going to be drilled, your issue -- and I'm just talking about from the standpoint of agreement, not the science of it. But your requirement to Jalapeno was you've got to sign a JOA that is going to apply to all four wells?

A. Yes, everything in the contract. There could be more wells than that.

Q. In that Section 31?
A. Yeah. If you include everything in the section and all depths, then you could have Bone Spring wells. It could be different.
Q. You could have Wolfcamp wells -- four Wolfcamp wells and maybe four Bone Spring wells --
A. Sure.
Q. -- and maybe other intervals in those formations?
And with drilling already established, the position you presented to Jalapeno is you've got to accept a JOA with this 100/300 nonconsent penalty. It wasn't just as to the first well, was it?
A. I would tell you that the 100/300 percent nonconsent charge is -- I know Jalapeno believes it to be a very critical point in these negotiations, but it is a standard that has been accepted by the industry. In fact, in this section, seven other working interest owners have agreed to it. It was not the main focus point of the agreement. I think what the main focus point for us was how do we most effectively develop the minerals that are under this section and how do we do that at a reasonable cost to everyone involved? And so I would say it wasn't our focus.
Q. So it's not a question of science in terms of

risk? It's a question of what you say is the custom and practice in the industry?

A. It is the custom and practice of the industry because I think you will see, and later witnesses will testify to this, that the science and mechanical risks are there and that that's why the industry has used this as kind of a standard.

Q. If you go across the line into Loving County, Texas, Matador is developing wells on the same Bone Spring and Wolfcamp Formations; isn't that a fact?

A. I'll let the geologist testify whether or not it's the exact same, but in theory, yes, Wolfcamp wells and Bone Spring wells.

Q. Well, the state line doesn't determine -- doesn't change the formations?

A. No.

Q. But in Texas, since you're talking about custom in the industry, what is the risk penalty that's being allowed by the Texas Railroad Commission on your wells in Loving County, Texas?

A. Well, our wells in Texas are being developed under voluntary operating agreements that do have the 100/300.

Q. I'm asking about in instances where there has been an application so that you are to be awarded a risk penalty by the Railroad Commission.

MR. BRUCE: I'll object to that, Mr. Examiner [sic]. One of the reasons is there is no forced pooling like in New Mexico.

MR. GALLEGOS: No, but there are procedures which are -- which the Texas Railroad Commission -- if you're talking about the industry across the board, across the state line, if you have something different, I think it's important for this Commission to know that.

MR. BRUCE: And if there is something, then it's either by statute or regulation of the Railroad Commission, and it's not applicable here.

CHAIRMAN CATANACH: I'm not sure it's applicable, Mr. Gallegos.

Q. (BY MR. GALLEGOS) What is the area of acreage that Matador has besides Section 31 in this vicinity, in, let's say, 18 South, 34 East, 18 South, 35 East?

A. I would have to look back at a list to know absolutely for sure. But we have acreage from 18 South, 34 East. We do have acreage in other sections there and going all the way down to the state line and into Texas, and from 19 East or so to 35 East. You know, it's across the Basin and even some of the shelf -- on the northwest shelf.

Q. So would you say this well is to begin

Matador's development of acreage in those townships in which this well is centered?

A. We have drilled other wells in the Basin. This well would be the first horizontal Wolfcamp well, I believe, in that township, and so we would -- I mean, if you want to call that the starting of development in the area, I guess that's a fair statement.

Q. And so about -- just roughly, what I would call the area of interest, if we could use that term, how much acreage does Matador have?

A. Around 90,000 acres in the Basin, and then we have acreage in Louisiana and south Texas and other places.

Q. But I was talking specifically in this --

A. About 90,000 acres in the Delaware Basin.

Q. So the -- the full-section inclusion was one issue in which you could not agree -- obtain agreement with Jalapeno. The other was quantum of the risk penalty; was it not?

A. Yes, I believe so.

Q. And if we go to the letters -- let's take a look at Exhibit 5D.

A. B, as in boy, or --

Q. D.

I direct your attention to the last

paragraph on page 1. Does that basically express the rejection of Matador to the complaint of Jalapeno regarding the 100/300 percent penalty?

A. I think that's what he's trying to say.

Q. And on the final page of page 3, did Mr. Yates offer a compromise that was -- and I quote, "It can" -- this is referring to Matador, and I quote, "It can simply change the terms of the non-consent provisions in its proposed JOA to 100/150. Jalapeno will non-consent as to the drilling of the Airstrip Wolfcamp well, but may well later consent to Bone Spring horizontal wells or even later Wolfcamp wells within acreage covered by the JOA depending, of course, on the then price of oil."

So there was an effort on Jalapeno's part to reach agreement, in which case we wouldn't be here. Isn't that reflected by this letter?

A. Yes. But are you trying to say there wasn't an effort on Matador's part to reach an agreement? It sounds like that's what you're trying to say.

Q. Isn't it true that Matador's position was simply: We require the 100/300, and we won't give 1 percent off of that position?

A. Matador tried on numerous occasions to reach an agreement. This -- of the number of things that could be agreed on, this was one thing that couldn't.

Q. Your answer was this one thing that couldn't?
A. We have not reached agreement on this one point. And you're correct; that's why we're here today.
Q. Yes, sir.
And Matador wouldn't reduce the risk penalty by 1 percent, would it?
A. I don't know. We wouldn't agree to the proposed change.
Q. Well, did you offer anything at any time other than to say 100/300 or you're forced pooled?
A. That's not what we said at all. We said, We want you to participate. 100/300 is the standard. Other working interest owners in this section and across the Basin -- one, other working interest owners in this section had agreed to it, for this operating agreement, but other working interest owners across the Basin agreed to this. So although we want them to participate --
Q. So --
A. -- do you want my answer, or do you want to talk over me?
Q. Well, your answer is not an answer. Now you're volunteering --
MR. BRUCE: I object to arguing with the witness, Mr. Examiner [sic]. He asked the question and

he answered it.

THE WITNESS: So, in fact, we do want them to participate and on terms that everyone else involved, except for the few that we haven't been able to get in touch with, have agreed to.

Q. (BY MR. GALLEGOS) In this well, Mr. Singleton, you've done dozens of wells, in forced pooling nonconsenting owners literally in every application that you've brought before this -- or before the Division; isn't that true?

A. I believe so.

Q. And in not one instance have you ever tried to reach agreement with any of those nonconsent parties on the basis of saying we'll accept something other than the top limit risk penalty that we've obtained?

A. I'm not sure I understand your question.

Q. My question is: In talking to any -- any nonconsent owners or hopefully consent owners in your negotiations, in your wells in southeast New Mexico, there is not one instance in which you've offered to achieve agreement by giving ground at all on this 100/300 percent penalty?

A. We believe and so do most of the working interest owners in the region that 100 percent/300 percent is a fair provision.

Q. Would you answer the question? The question is: There is no instance in trying to get voluntary --
A. I don't know if it's correct.
Q. May I finish my question?
A. Yes.
Q. Since I didn't get an answer from you, I'm going to try it again.
In all of your forced pooling applications, there is not one instance in which Matador -- Matador has reached out to try to get voluntary agreement in which it says, We'll give on something; we don't have to have the top limit of 100/300 percent penalty?
A. I don't know that we have or haven't.
Q. Well, do you know of anywhere you have?
A. No. That's what I'm saying. I do not recall anytime we have done that.
Q. When this letter that we're referring to, 5D, to you, Mr. Singleton --
A. Uh-huh.
Q. -- was written on August 17th, 2015, the fact is Matador had already filed an application to force pool Jalapeno; had it not?
A. That's correct.
Q. What was the AFE that was proposed back in -- at this time period, August 2015? What was the amount

of that AFE?

A. I don't recall offhand. It should be in our proposal. The March 24th proposal? Is that the one you're referring to?

Q. I think that would be it. I think it was with the proposal letters.

A. Right. That was about $9 million. 5.3 million dry-hole costs, with completed cost of 9 million.

Q. All right. And in the negotiations and as reflected in these various letters, Jalapeno argued that the economics in the area had changed and that expenses were less or reduced and that the 9 million was no longer justified. Isn't that a fact?

A. I believe that argument was made. I'm probably not the right witness to testify as to what the costs were, had they changed.

Q. So you're not aware of whether there was a change, and, if so, the amount?

A. I'm sure there were changes. I just don't remember what they were. That's not something I work on.

Q. Okay. Have you been informed that there is a revised AFE on this well?

A. There may be. There probably is. I don't know for sure.

Q. So you don't know?
A. No. But I think we have other people here today that will testify to those points. If I knew, I'd tell you gladly.
Q. Understood.
Exhibit 2 -- your Exhibit 2 provides information on Matador's working interest; is that correct?
A. Yes, sir.
Q. Okay. And then with voluntary joinder, there is this additional interest of approximately 4 percent?
A. Correct.
Q. Now, given your 93 percent working interest, could you tell us what your NRI is?
A. Net to our 93 percent?
Q. Yes, sir.
A. I actually don't know that offhand. It's something I think we could find out, but I don't know what it is.
Q. These are state leases, correct?
A. Yes.
Q. This acreage is under state lease?
A. That's correct.
Q. And by the way, are those leases already held by production, or are you in a primary term?

A. I believe they're held by production or through other agreements.

Q. So we know at least that there's a 12-and-a-half percent from the 93 percent, as we're trying to calculate NRI. Would that be correct?

A. Yes.

Q. But as the landman on this project, you can't tell us what the extent of overrides are?

A. Yeah. I'm not the actual immediate landman on the project. I oversee the department that has the landman that has that answer. So I can certainly get that for you.

Q. Would you mind supplying that for us, if you have a chance at a break?

A. Sure.

Q. Let's take a look at the JOA that's Exhibit 7. And first of all, do we understand this is what was presented to Jalapeno in the communications that have been discussed?

A. I'm sorry. I don't know that I understand that question.

Q. Okay. Does Exhibit 7, this JOA --

A. Right.

Q. -- exemplify the JOA that was proposed to Mr. Yates for Jalapeno?

A. In the current proposal?
Q. In the negotiations --
A. This JOA existed back from 1981.
Q. But in the negotiations, are you basically saying this is the JOA that we would operate under, or was there something else?
A. I believe as far as the form, this is what was proposed, but there were, you know, minor changes that get negotiated into these.
Q. Well, why is this an exhibit if this is not the one that was the subject of negotiations?
A. From a negotiation standpoint, I think that's correct. It's the same.
Q. All right. So I want to turn to the subject matter that you were asked before on your direct at page 5. This is the portion, is it not, of Article 5, Section B, Subsection 2 and Subsection small A?
A. Article 6, but yes.
Q. So what I'm doing is I'm directing your attention to that Subsection A that appears near the bottom of page 5.
A. Okay.
Q. Now, this section involves reimbursement of only 100 percent on the operator from the revenue of the nonconsenting party, correct?

A. As it pertains to certain costs, yes.
Q. Yes.
And those costs are -- and I quote -- "newly acquired surface equipment beyond the wellhead connections, including but not limited to stock tanks, separators, treaters, pumping equipment and piping" and so forth. There is no risk associated with those surface facilities, is there, Mr. Singleton?
A. I can't say there is no risk, but there is very little risk. One could always come out and not work, but you could have that replaced.
Q. So you have no penalty?
A. Correct. Right.
Q. JOA provides no penalty?
A. Correct.
Q. And this is custom and practice in the industry?
A. Yes.
Q. Now, you referred to something else that carries over to page 6. And this is 300 percent, and it's referring to cost and expenses of drilling, reworking -- drilling, reworking, deepening or plugging back-testing and completing after deducting, blah-blah-blah. What does this refer to? What is D referring to?

A. D is referring to costs that are associated with operations within the wellbore, your subsurface operations.

Q. All right. And those costs -- and it actually does say -- the words on page 6 are "equipment," quote, "in the well," top of page 6, Mr. Singleton?

A. Yes, "newly acquired equipment in the well."

Q. So that's not surface equipment. That's equipment in the well?

A. Correct.

Q. And that equipment is subject to the 300 percent?

A. Yes.

Q. That's all my questions. Thank you.

A. I will add one thing just to clarify on that point because this does, in fact, say "wellhead connection," which would be surface equipment. So it's not specifically subsurface. It does state that.

Q. Okay. "Including the wellhead connection." So that's not the wellhead. What do you understand the wellhead connection to be?

A. Well, I would understand the wellhead connection to be everything associated with that connection, being the wellhead, you know, above and below.

Q. Okay. So you don't put any significance on the word "connection"? You're saying -- what you think it means, it means the whole wellhead?

A. Right. I would separate it from tank batteries, but the wellhead, yes.

Q. But there is a -- there is a connection between the casing annulus and the casing and the wellhead, correct?

A. Yes, and also the connection between the wellhead and the flow lines going to the other surface facilities. That's why I would include all of them.

Q. All right. Thank you.

A. Thank you.

MR. BRUCE: A few follow-up questions.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Singleton, one thing, this well is a proposed upper Wolfcamp test?

A. Correct.

Q. And the nearest upper Wolfcamp produce that Matador has is quite a distance away?

A. Yes. I don't know exactly how far it is, but it's not in the immediate area for sure.

Q. Does Matador consider this an exploratory well?

A. Yes.

Q. So it's not development?
A. Not at all.
Q. Now, getting back to this question of risk charges, 100 percent/300 percent, I believe you testified that many JOAs have greater percentages than 100 percent/300 percent?
A. Right.
Q. Has Matador -- when a JOA has been proposed at higher risk charges, has Matador ever agreed to reduce them down to a little bit lower?
A. Yes, but not lower than that.
Q. Not lower than 100/300?
A. Correct.
Q. And when you sign a JOA -- because initially -- if you sign a JOA, does it initially -- does a JOA usually require that a party participate in the initial well, in the JOA?
A. Yes.
Q. Now, talking about Mr. Yates -- Jalapeno and Mr. Yates wanted a 50 percent risk charge? That's what he proposed in his letter?
A. Yes.
Q. Did he ever offer to increase it above 50 percent?
A. Not that I remember, no.

Q. And getting at the -- and we'll get the number that Mr. Gallegos requested, but there are also overriding royalty owners in this property in this section?

A. That's correct. And that's why I didn't know what it is. And I have not been the one directly working on that piece of information, but we'll have it.

Q. Okay. And then finally, when you said you wanted Jalapeno to participate, by that did you mean that you wanted Jalapeno to join in the well and pay its proportionate share of well costs?

A. Yes. And I would still like that.

Q. And a farm-out or a term assignment would be another option to participate without risk?

A. Yes.

Q. Under those, you would have a term assignment of Jalapeno's interest, I believe, and there's usually a reserved overriding royalty and a back-in and payout?

A. Correct. And we discussed that. We were open to that possibility.

Q. And when I say payout, we're talking 100 percent payout, not 200 percent, not 300 percent?

A. That's correct.

Q. And so they would not have to pay anything up front --

A. Correct.
Q. -- to participate in that fashion?
A. That's right. And then they would come back into the well at a proportionately reduced working interest after payout.
Q. Okay.
MR. BRUCE: I think that's all I have, Mr. Chairman.
I would just get in -- when we're talking about some testimony, I might want to do a little redirect on Mr. Singleton, you know, about the net revenue interest, et cetera.
CHAIRMAN CATANACH: Okay.
MR. BRUCE: And pass the witness.
MR. GALLEGOS: Just a final question.

RECROSS EXAMINATION

BY MR. GALLEGOS:
Q. The desire or invitation for Jalapeno to complete included Jalapeno signing the section covering 100/300 percent JOA, correct?
A. Yes, that's correct.
CHAIRMAN CATANACH: I have a few questions.

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:
Q. Mr. Singleton, in what tract does Jalapeno own

its interest?

A. I have to go back to my map. I believe Jalapeno's interest -- they have contractual rights in the north half -- I'm sorry -- it's the south half. They weren't the initial lessees. Many of these interests in this section have been combined together through various agreements over the years.

Q. So you're saying in Tract 1 and Tract 2?

A. I believe it's just in Tract 2, and I can clarify if we need to.

Q. So as far as you know, they own no interest in the fee leases, Tract 1?

A. I believe that's correct. If I find out that I'm incorrect on that in a few minutes, I'll come back and make sure to correct it.

Q. So that being the case, if they were Tract 2, they would participate in at least three wells in that section possibly?

A. Possibly, yes.

Q. Do you know what the association is between Jalapeno and Harvey E. Yates Company? Do you know -- that's not the same company?

A. No. Harvey -- Harvey E. Yates Company, being HEYCO, merged with Matador last year. Jalapeno -- the only association I know is that Harvey and George are related, family.

Q. Okay. So within --

A. I say Harvey. Harvey of Jalapeno, not Harvey at Harvey E. Yates Company. That would be the father.

Q. You've had some -- within this tract that you're trying to pool, you've had some other Yates entities that have joined in?

A. Yes.

Q. And you're proposing to do the joint operating agreement for the whole section?

A. That was the initial proposal, yes.

Q. And all of your -- all the parties that have joined have executed that JOA?

A. Yes. I believe they're all on the same form. Well, whatever they're on, it's all the same. I don't remember.

Q. Does that JOA have a subsequent well election -- election to join -- to voluntarily join after -- if you went nonconsent under the first well, under the JOA, would you have an election for the second or subsequent wells?

A. Yes. Depending on various circumstances, you would be able to participate in the subsequent wells.

Q. By paying your share of well costs?

A. That's correct.

Q. Exhibit 7 that you presented, that was just for -- just as a standard, kind of, JOA that's out there right now or --

A. Yes. In fact, it's a JOA that's being used in the section.

Q. So this was Harvey E. Yates Company that was the operator?

A. Correct.

Q. Do you know if Jalapeno was a party to that?

A. They were not an original party to this, but by acquiring interest that was subject to this agreement, they are a party to it now.

Q. They didn't agree to it themselves at the time?

A. By taking it -- by taking the interest that this is subject to, yes, they have agreed to do it and have participated under this. I believe that's the case.

Q. As a follow-up to Mr. Gallegos' question, have you ever been approached to lower the risk penalties from 100/300, and has that ever been requested of you?

A. Other than with Jalapeno, not that I can recall. I would hate to say it's never happened. Maybe. But I do not recall that. The only time I know that we've lowered or agreed to lower -- negotiated about lowering was where -- the 100/300 has become kind of standard, but there have been proposals that were 300/500. So negotiations have taken place that lowered some of those, but nothing that I can recall ever went below 100/300.

Q. So I'm a little confused. On Exhibit 7, on your pages 5 and 6, it looks to me like surface equipment is not subject to a risk penalty under that JOA.

A. Under this particular JOA, that's -- that's right, except for what's specifically stated in Part B. I didn't negotiate this one in '81, so I'm not sure exactly what they were getting at there, but that's what I see.

Q. So what do the JOAs today look like in terms of the surface equipment?

A. Many of our agreement these days actually include the cost to drill, complete, equip and produce. And so with the unconventional wells, it's not -- I apologize if what I'm about to say is remedial. But with the unconventional wells, it's not that you drill a vertical hole and it starts to flow back on you. You really don't know what you have until you get your horizontal drilled, you bring in your equipment, stake out the well and flow it back to even see if you're going to have an economic well or not. And so in order to get to that point, you're going to have surface equipment that is necessary to figure out whether or not you're going to have an economic well.

That's slightly different than we drilled the vertical well, it starting flowing back, you know, hundreds of barrels a day -- which is great; this is going to be a great well -- now let's go get our surface equipment and bring it in so we can handle it.

The unconventional wells just -- they operate differently, so you have to go to that cost, thereby taking the risk, but maybe you buy some of that surface equipment and you end up with an uneconomic well. And that's why I think today surface equipment gets included more than it did in the past.

Q. So all of your JOAs don't have that standard language in it?

A. All the JOAs are not absolutely the same. In fact, different companies will propose different model forms. But I think after negotiations are done to get down to an agreeable contract, you kind of end up with similar things. I'm not going to say they're exactly the same because they're not, but they're all very similar from one to another.

CROSS-EXAMINATION

BY COMMISSIONER PADILLA:

Q. Just following up on that point, so Exhibit 7, the one that is 100/300, is that not what's being proposed in this case?

A. The 100/300 is what's being proposed, yes. Correct.

Q. So there is no risk penalty associated with the surface equipment for the JOA we're discussing today?

A. I believe that is correct. I will double check that and make sure. If so, I will correct it, but I believe that's correct.

Q. Do you know why the target formation was changed from the Bone Spring to the Wolfcamp?

A. The Bone Spring well was proposed prior to Matador's merger with HEYCO, and so that closed kind of end of February, early March. As we took over operations, we were looking at the wells that HEYCO had slated to drill in the area. We decided that it would be better if we were to drill the Wolfcamp well. Now, the details of why we decided that was better or not, I'm probably not the right guy to answer, but we do have people that can.

Q. Okay. Going to -- I just want to clarify that Exhibit 2 is strictly for the project area, your summary of interest?

A. Correct.

Q. This breakdown is for that 160 or 154, whatever it is?

A. It's about 154 and a quarter, yes.

Q. What is Matador's overall acreage in that section, Tracts 1, 2 and 3?

A. If I remember correctly, we're about -- it's the majority, but I think it's around 260 acres. I'll have to look back to be sure because we have been acquiring interests as well. So it's changed from where we started.

Q. Out of the 636 in total?

A. Oh, I'm sorry. You were saying for the full section?

Q. For the full section.

A. I believe we're over 500. And, again, we'll double check that for sure and give you an accurate number.

Q. Just out of curiosity, where are those 300 to 500 JOAs you're talking about?

A. New Mexico, West Texas, south Texas, Louisiana, East Texas.

Q. Is that --

A. Everywhere we operate, we have operating agreements.

Q. Is that for wildcat exploration, or what is the reason for that higher penalty?

A. I'm sorry. I need to correct. The operating agreements that we have are in all those areas. The 300 to 500, we have seen that in New Mexico, Louisiana and West Texas. I don't believe we've seen it in south Texas. They, for various reasons, had those provisions in there. Some were the wildcattier stuff, if that's word.

Q. Sure.

A. And some being that the -- even though it may not be a wildcat, it may be a definite type of well or completion technique that everyone thinks is worth taking the risk on, but may not be what people feel like is the comfortable norm at that point, trying to make better wells. That's what we're always trying to do, is make better wells for less money.

Q. Okay. Looking at 3B, Tract 2 and Tract 3, those are two state leases; is that correct?

A. Tract 3 and Tract 2 are state leases, yes.

Q. Do you know what the numbers of those leases are?

A. I do not, but I can --

Q. I know there was some discussion whether they were primary term or -- production.

A. I do not know.

MR. BRUCE: Mr. Commissioner, on 3A, you can see the state lease number, E50146. It's a fairly aged lease. I don't know the number of the --

COMMISSIONER PADILLA: It's primary --

THE WITNESS: The one to the south looks E4906. I can't tell if that's a date or a number, but they have some age.

Q. (BY COMMISSIONER PADILLA) With regard to the AFE cost changes, I realize you may not be the person to answer that, but was the increase in cost strictly related to change in target formation between the Harvey Yates AFE and the Matador AFE?

A. Right. I believe that's correct.

That change in the target formation, you know, changes a number of things that have to be done.

Q. Right.

So I guess if we can just confirm whether or not the 100/300, as represented -- and I realize the older JOA here is what you're currently asking for, and I realize that that stops at the wellhead. I think that's pretty clear, but if we could get clarification later on today.

A. Absolutely.

MR. BRUCE: We'll clear it up over lunch.

COMMISSIONER PADILLA: That's all I have.

COMMISSIONER BALCH: I'll save my questions for the geologist and engineer.

THE WITNESS: Okay.

CHAIRMAN CATANACH: Just for clarification, Mr. Bruce, I thought the risk penalty for surface equipment was at issue in this case.

MR. BRUCE: Well, it is at issue, Mr. Chairman, but because they haven't reached voluntary agreement, we're -- we're -- and Mr. Singleton touched on it. One of the reasons we are asking for it is because of the unconventional reservoir, and we will have engineers discussing that specifically.

CHAIRMAN CATANACH: So you are seeking a risk penalty to be applied to the surface equipment?

MR. BRUCE: Couldn't reach voluntary agreement with the lower one.

CHAIRMAN CATANACH: And that's -- I believe that's in the rule -- on the rule, that it applies to that, so --

MR. BRUCE: I mean, the pooling order is the JOA.

COMMISSIONER PADILLA: What exactly does the JOA ask for, then, as a percentage on surface?

MR. BRUCE: Well, we will find out for certain over lunch, but, you know, again, that's a voluntary agreement. It's whatever is negotiated between the parties. As they said, it's 300/500, 200/400, but that's voluntary agreement.

COMMISSIONER PADILLA: So I can assume Exhibit 7 should be disregarded for that purpose?

MR. BRUCE: Well, what we wanted to show was what -- what we're interested in showing is that Jalapeno is subject to a JOA that has greater risk charges than -- in the south half of this section than what they are proposing by their exhibits today, which is a 30 percent risk charge, versus the statutorily authorized 200 percent -- cost plus 200 percent risk charge.

COMMISSIONER PADILLA: But not necessarily relative to the Airstrip well?

MR. BRUCE: Correct.

CHAIRMAN CATANACH: Okay.

COMMISSIONER PADILLA: Okay. Thank you.

MR. GALLEGOS: Mr. Chairman, I have to comment on this subject because Mr. Chairman said something about well, it's in the rule; we're talking about the well-cost issue.

What's of significance -- and Commissioner

Padilla reminds you. We have a statute that covers what the risk penalty applies to, and it's drilling and completion. The statute does not allow the risk penalty on surface completion and surface facilities. By the way, it shows the industry recognizes that with a JOA on that subject.

May I -- based on the Chairman's questions of Mr. Singleton, may I have a question or two about the JOA?

CHAIRMAN CATANACH: Go ahead.

RECROSS EXAMINATION

BY MR. GALLEGOS:

Q. Exhibit 7 is a 1977 AALPL [sic] JOA form; is it not?

A. Yes, it is.

Q. You would agree, sir, that JOA was written in what we would call a vertical well environment?

A. Yes, that's true.

Q. And there is a later form, and I believe it's the 1988, is it not, after this '77?

A. To start adding horizontal language? I mean, there are other forms, too. There is an '82.

Q. No. No. I'm going to get to that.

But isn't the next vintage, if we will, of JOAs, the 1988?

A. Right.

Q. And that was written in what we would still consider to be a vertical well environment in the industry, correct?

A. I suppose. I don't know that I'm proper to comment on what the industry thought in 1988. I was not in it at that time.

Q. Well, all right. You don't know if there was -- if there were horizontal wells?

A. For the purposes of making your point, sure. Okay.

Q. Okay. All right. So the question was -- and you seem like you started to touch on it. Is the AAPL in the process of and have some studies directed toward horizontal well JOAs?

A. Yes. And -- and members -- you know, we, for some time, have been in the process, as we negotiate our operating agreements, adding more language that's specific to horizontal development.

Q. Yeah, but my question was: There is not a form that the AAPL has yet said this is it, and we'll make it available for the industry?

A. Correct. There have been several iterations. They have formed a committee to work towards that end.

Q. That was what I was trying to get at.

A. Yes.

Q. Thank you.

CHAIRMAN CATANACH: Mr. Brancard?

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. So to clarify, the form that -- the JOA that was offered here was not the 1977 form that's in Exhibit 7?

A. I believe that's correct. This was here for other purposes.

Q. And so the JOA applies to the whole section, or if -- if they participate, is their participation based on ownership within this west half-west half or their ownership within the whole section?

A. Ideal- -- if you could get voluntary joinder from everyone involved or a contract area covering the full section, then you could do what you're saying, which is basically work an interest in each well off their working interest throughout the section as a proportionate interest to everyone else.

Q. In Exhibit 5A, the offer that was originally made by Harvey E. Yates Company and the attached exhibit to that, isn't the work -- isn't the estimated cost then been based on interest in the whole section? Because here it shows about a 5.1 percent for Jalapeno, and you're saying they have about a 2.7 percent in the 154 acres?

A. I'd have -- I'd have to check that. I wasn't involved when this proposal was sent, and so I just have to look back at it and see what numbers they were using.

Q. Okay.

A. Sorry. I wish I knew the answer, but I wasn't involved at that time.

CHAIRMAN CATANACH: Anything further for this witness?

MR. BRUCE: No. We'll bring him back briefly to give the info that people requested.

CHAIRMAN CATANACH: Okay. This witness may be excused.

Pleasure of the Commission for a lunch break?

Okay. How long?

Break for lunch until 1:30.

(Recess 12:13 p.m. to 1:36 p.m.; Ms. Bada present in place of Mr. Brancard.)

CHAIRMAN CATANACH: At this time we'll call the Commission meeting back to order.

And I believe, Mr. Bruce --

MR. BRUCE: If I could recall Mr. Singleton to the stand just to address some of the questions raised by the Commissioners and counsel?

VAN H. SINGLETON II,

after having been previously sworn under oath, was recalled, questioned and testified as follows:

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Singleton, over lunch, did you check on these issues about the JOA and the --

A. Yes, we did.

Q. Okay. I think Exhibit 7, that the JOA is a 1977 form -- AAPL Form 610-1977. What is the vintage of the JOA that is proposed?

A. A 1982 form.

Q. 1982 form.

And did you check on the risk charges in that JOA?

A. Yes. It is 100-300, and it appears to be the same language in the proposed form and the form in Exhibit 7.

Q. Okay. Now, again, we are dealing with two state leases. We are the west half-northwest and the west half-southwest. Did you check on the dates, the vintages of those leases?

A. Yes. The Tract 2, which if we can go back to Exhibit 3, I believe it is --

Q. 3B.

A. -- Tract 2, the lease number on that is LG7137. That's October 1st, 1979. And it is in its secondary term, clearly.

Tract 3 is Lease Number E5014, and that is from February 10th of 1951.

Q. Were there any other features -- was the proposal made to Jalapeno and other working interest owners in this proposed well modified for horizontal drilling wells?

A. Yes. There were some modifications to the proposed form, for instance, removing the casing point election for horizontal wells, because it's just not applicable. Once you start drilling the well, like I said earlier, you've got to keep going, and you've got to get it completed before you're really going to know what you have. Whereas, with conventional vertical wells, the casing point election made sense because you would see something on the way down that would make you decide whether or not you would move on to complete.

Q. And then as to Jalapeno's interest, does that stem from the south half JOA?

A. That's correct.

Q. And Mr. Brancard was asking questions -- because it has a certain percentage interest -- I think it's somewhat over 5 percent in the south half -- its interest in this well unit would be cut to 2.7 percent, cut in half?

A. Correct. Correct.

Q. And then what is the net revenue interest of Matador?

A. So our effective net revenue is about 75 percent, but since we are 92 percent working interest, our net -- our net revenue interest is about 69 percent.

MR. BRUCE: Pass the witness.

RECROSS EXAMINATION

BY MR. GALLEGOS:

Q. What is the extent of the overrides?

A. That information, we didn't have, and I think it might be unsettled a little bit at this point based on some assignments that are still pending from previous agreements that we weren't involved in. But to give you -- I mean, for us, for Matador?

Q. Yes, for Matador. I'm trying to understand how you arrive at the 69 percent.

A. Because when we acquired our interest, overrides had been previously retained. And so we were delivered a 75 percent net revenue interest in those leases.

MR. BRUCE: Times 92 percent.

THE WITNESS: Times 92.

MR. BRUCE: Gets you to about 69.

MR. GALLEGOS: Okay.

THE WITNESS: If I may, there was one other question that I just wanted to clarify, which was our net acres. For the section, Matador's net acres are 583.

RECROSS EXAMINATION

BY CHAIRPERSON CATANACH:

Q. The working interest owners that you've reached a voluntary agreement with, was that on the same terms as the terms you offered Jalapeno Corporation?

A. Yes.

Q. That's all.

RECROSS EXAMINATION

BY COMMISSIONER PADILLA:

Q. With respect to the Airstrip well, for the sake of brevity, have you -- do you know if you've already submitted communitization paper to the State Land Office as part of the regulatory process?

A. I don't know for sure, but I do not think we have.

Q. So the royalty interests are going to come back when you start doing that as part of that process, if you're going to have any hurdles to jump there?

A. I don't think we've submitted those yet.
Q. Because you're essentially -- we do require the comm for it to be --
A. Right.
Q. -- for the comm for any ownership clarification.
A. Sure. Right.
Q. Okay.
CHAIRMAN CATANACH: Anything further?

REDIRECT EXAMINATION

BY MR. BRUCE:
Q. Just to be safe and in partial answer to Commissioner Padilla's question, Matador has had title opinions prepared on this acreage?
A. Yes.
Q. But it's complicated, and you're piecing it together?
A. It is. And it would be different for a whole section versus a 160. It would change depending on the circumstances.
MR. BRUCE: That's it.
CHAIRMAN CATANACH: Thank you. You may be excused.
THE WITNESS: Thank you.
MR. BRUCE: I'm going to call my geologist.

But, Mr. Chairman, Mr. Gallegos and I both discussed whether -- what the pleasure of the Commission may be or displeasure of the Commission may be if -- assuming this case goes beyond 5:00 tonight. And I don't know if you've discussed that with the other Commissioners, but it's partly so -- I think all parties, all witnesses would like to know insofar as transportation or delaying transportation.

CHAIRMAN CATANACH: Well, I'm available tomorrow. I'm not sure --

COMMISSIONER BALCH: I'm available until tomorrow 2:30.

CHAIRMAN CATANACH: Until 2:30?

COMMISSIONER BALCH: I could come back Thursday.

COMMISSIONER PADILLA: I'm available.

MR. BRUCE: Would that be fine for you?

MR. GALLEGOS: Yes. Yes.

CHAIRMAN CATANACH: We'll try to go to 5:00 -- or we will go until 5:00 and then break.

MR. BRUCE: Thank you.

EDMUND "NED" LOCKE FROST, Ph.D.,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name for the record?

A. Dr. Edmund Locke Frost.

Q. And where do you reside?

A. Dallas, Texas.

Q. Who do you work for and in what capacity?

A. Matador Resources, and I'm their chief geologist.

Q. What are your responsibilities as chief geologist for Matador?

A. I guide, direct and ensure the technical quality of all staff work. I undertake regional exploration projects, as well as many other specialized geochemical and petrographic studies. I work with external vendors, offset operators, investors, university professors, all sorts of people outside of Matador as well.

Q. And have you previously testified before the Division, having qualified as an expert in geologic matters?

A. Yes.

Q. Could you, for the Commissioners, describe your educational background and work experience?

A. Yes. I've got a bachelor's in geology from the University of Colorado in 1998. I worked as a land surveyor for several years in between and then went back for a doctorate in geology in 2002, which I received from the University of Texas in 2007.

Upon graduation, I joined ConocoPhillips in their subsurface technology group, and I worked as a senior geologist there, working in reservoir and exploration projects all around the world, also focus in the Delaware Basin.

And then after that, I returned to the University of Texas as a research associate at the Bureau of Economic Geology, which is also the state survey for the University of Texas, again largely focusing on the Delaware Basin at that point. And then I joined Matador in 2014 and quickly worked through the ranks, starting as a senior geologist and now ended up as the chief geoscientist there.

Q. Are you familiar with the application filed by Matador in this case?

A. I am.

Q. And have you conducted a geological study of the area, including the proposed spacing unit for the Airstrip well?

A. I have.

MR. BRUCE: Mr. Chairman, I'd tender Dr. Frost as an expert petroleum geologist.

MR. GALLEGOS: No objection.

CHAIRMAN CATANACH: Dr. Frost is so qualified.

Q. (BY MR. BRUCE) Would you please identify Exhibit 8 for the Commissioners and discuss the contents of this exhibit?

A. Yes, certainly. This is a subsea structure map constructed on the top of the Wolfcamp. The contour lines are shown as a dark gray lines. The well control here is either denoted -- well, it's denoted with an open purple circle, and these would be the well points that were used to construct the structure grid here.

And then you can see the proposed location of the Airstrip State 201H, shown with the blue line with the open square and the open circle representing the surface hole and bottom hole, respectively.

The full -- the full purple circles here, the closed purple circles, represent Wolfcamp producers, and these would be vertical producers here. And in this map area, there is approximately 140 -- or 134 Wolfcamp penetrations. Of these 134 penetrations, 34 of these -- or 43 of these are produced out of the -- out of the Wolfcamp. It's also worth noting that there are 12 wells here that drilled down to the Wolfcamp and never set pipe, which we would consider to be a plug and abandoned. So, you know, that's the gist of it.

You can see also below here, there is -- the green letters are the cumulative production, NMBOE, from these wells. Given the vintage of these wells, these -- these cums are probably relatively close to an EUR on many of these wells. And the two fields here where the wells are clustered would be the Airstrip Field and the Scarb Field.

Q. Again, these -- these purple circles with the purple are the vertical Wolfcamp producers?

A. That's correct.

Q. And generally, what do those vertical -- what section of the Wolfcamp do those vertical wells produce from?

A. For the most part, though, they'll produce from the upper 4- to 500 feet of the Wolfcamp. It's not a consistent interval. A lot of times, you know, wells will perforate whatever -- whatever looked like it would flow oil, so there is not always a consistent preferred target at the same structural depth here.

And then you'll see in a subsequent slide all the wells that totally penetrate the Wolfcamp, and it's a much smaller subset of wells that get through the

Wolfcamp section here.

Q. Do they generally produce from, say, the Wolfcamp carbonate zones?

A. They do. This was obviously a vertical conventional play, so what would have been targeted here would be the Airstrip and Scarb Fields. These are basically debris flows that are coming off the south vacuum high, the Wolfcamp shelf edge at that point. They have conventional porosity and permeability often much higher than we ever see in unconventional systems. So it's a very different play that you see here with the Airstrip and Scarb Fields.

And you can also begin to see in the green numbers the amount of variability in these wells even within the field outlines, that some of these wells produce quite well and others don't.

Q. Just looking at these numbers, it looks like six, seven of these wells were decent producers.

A. Yeah. There were some -- I think that's a good number. There are some very nice wells in here, but those very nice wells, I would say, are a minority among the penetrations here.

Q. None of the existing -- all of the existing wells are vertical wells?

A. That produce from the Wolfcamp, that's correct.

Q. That produce from the Wolfcamp.
A. Yup.
Q. And what zone is Matador as well going to test?
A. We will test an organic-rich interval in the upper Wolfcamp. To be clear, this will not be what has been tested in the vertical world. We'll be looking at more of the -- however you want to call it, the unconventional shale targets, and we'll show you that target in an upcoming figure.
Q. As to the wells that are on this plat, what are the limitations of the geologic information that you can obtain from these wells?
A. Yeah. Well, the two most obvious limitations are really the spatial distribution of wells and the depth of penetration. So if we wanted to map something in full detail, you would obviously want to have a well or two every section. You can see that there is a lot of clumps of data points in the two -- in the two fields, but as you get away from that, it's a little bit -- a little bit spread out.
And then depth of penetration, you don't know if you're getting a well here that got into the upper 100 feet of the Wolfcamp but didn't get much further down. So from a targeting standpoint, we have -- we have a pretty incomplete and sparse data set

here.

Some of the other limitations are log vintage and really the curves that are available in any one log suite that you get. Vintage matters in the respect that in a conventional system, a standard triple combo or a porosity suite, a resistivity suite, a density suite, along with gamma ray would be enough to get you everything you need.

In the more unconventional plays, we're looking at some completely different scales of porosity here. We're looking at much different rock types and pore networks, so we -- typically, when we will come out and log a new well, we'll have a greatly enhanced log suite. Some of the magnetic resonance tools, some of the litho-scanner tools become very important. Obviously, we don't have any of that here.

The other information is -- a lot of times we do a lot of -- we do work with cuttings, where we'll take well cuttings from other wells, have them analyzed for thermal maturity. You can get total organic carbon from that. You can get many others things. We don't have any of that data at our disposal at this point.

Q. And you mentioned a couple of them, but what are the geologic parameters you would consider for screening an unconventional prospect?

A. Really, in the most basic sense, the things that we would look for are porosity, total organic carbon, thermal maturity and some proxy for brittleness, other Vclay or something a little bit more sophisticated to understand whether that rock will -- how it will behave with artificial stimulation.

Q. And of these parameters, what can you gain from the wells that are on this plat?

A. Honestly, I wouldn't say very little. It's a very sparse subset. There is very limited data.

Q. You might be able to get porosity?

A. Yeah. We have porosity. Absolutely. We get resistivity. In some cases, you have the logs you need to calculate, you know, a Vclay or something like that or a very crude way to get a TOC, but it really is -- I mean, this is, I would say, a data-limited area for us.

Q. Could you identify Exhibit 9?

A. Certainly. This -- this exhibit is really meant to show the horizontal development in the area, and what you see here are all the horizontal producers coming down from the Queen, 2nd Bone Spring, 1st Bone Spring -- sorry they're out of order -- 3rd Bone Spring. And I kind of want to reiterate this. It's in red, bold on the last one. There are no horizontal Wolfcamp producers in this area. All the wells that we're seeing are 2nd and 3rd Bone Spring, for the most part. And we'll talk about it with some of the other exhibits, but it's worth pointing out that the Bone Spring is a different play type than the Wolfcamp is, and we'll show that a little bit later. So it's our assertion that using the Bone Spring as an analog for production in the Wolfcamp is not realistic.

Q. Now, HEYCO originally proposed a Bone Spring well?

A. Yes.

Q. And a question came up with Mr. Singleton. Matador changed its mind?

A. We did.

Q. Are there issues with 3rd Bone Spring development?

A. Well, we -- we do feel that the 3rd Bone Spring could be prospective out here. Based on our screening criteria, which are different than HEYCO's, we felt that the Wolfcamp would be a better target, that we like to -- as we said on the previous screening criteria, we like to see a few boxes get checked here.

We often like to see, depending on who you talk to -- I'm more stringent than some of my staff, but we would like to see a pretty good thickness of porosity above 8 percent on a density porosity log. We did not see that in the 3rd Bone Spring. It does not mean that won't be a target, but the Wolfcamp did exhibit that, and that is why we felt the Wolfcamp would be a viable test here.

Q. You've already said this is the only horizontal well on this plat. But are there any horizontal upper Wolfcamp producers in the Northern Delaware Basin?

A. Not that we are aware of at this point. The closest upper Wolfcamp horizontal producers that we know of are some 29 to 35 miles away.

To be clear, there was a discussion about wells testing the Wolfcamp here. Matador has drilled a deeper Wolfcamp target called the Pickard 2H, and that is in the lowest part of the Wolfcamp. Some of the things are analogous. We don't feel that it's a perfect analog for this -- for this data set. And I think it's important to really kind of drive that home in the upper Wolfcamp. This is a pretty tremendous step out for Matador and for the industry.

Q. And how thick is the Wolfcamp out here overall?

A. That's probably better explained on a subsequent feature, but the upper Wolfcamp here is -- or a subsequent exhibit. The upper Wolfcamp here is in the ballpark of 4- to 500. The total Wolfcamp, on average, is about 1,300, and it thickens and thins across the interval.

Q. I see.

And did you prepare a cross section of wells in this area?

A. We did. We did. That's in Exhibit 10. So this is Matador's standard log presentation here. We have a gray scale, a gamma ray, and really the white-to-light gray is meant to represent the more carbonate-rich intervals, while the darker gray represents the more organic or unconventional targets, the things that the industry, for better or for worse, would call shale.

Then we have a resistivity track here that's shaded on ten ohmmeters or greater in green and a porosity track with an 8 percent cutoff. Really wherever that track goes above 8 percent, it starts to shade red. So you can begin to see there's some porosity development in the A well on the edge. That porosity in the 3rd Bone Spring really decreases, and by the time you're in the two type logs for the -- for the 3rd Bone Spring target and Airstrip, you're not really getting that first screening criteria that we like to see of a net porosity of greater than 8 percent across the reservoir.

You do see that in the Wolfcamp that that is the case. You have a pretty thick interval of what appears to be porous rock. And, again, porosity is only one of the screening criteria that we use, but that was really one of the reasons we decided to move the target down in the Wolfcamp so we would at least have a fighting chance to get the porosity we wanted to see.

Q. Do you consider the wells on this cross section to be representative of wells in the Wolfcamp Formation for the area near the proposed well?

A. Yes, I do.

There are, you know, a couple things to point out. The purple line and the yellow line are really -- the purple line shows the top of the Wolfcamp, which its cross section is datumed on. The yellow line shows the operational base of the Wolfcamp, which is the Strawn. And you can begin to see the Wolfcamp thinning to the east or to the right in this cross section, from A to A prime. The upper Wolfcamp target stays relatively consistent, but the one thing here that does vary is the relative proportion of carbonate rocks in here, which we would consider to be, you know, probably nonreservoir in our -- in our model here.

And then as we mentioned before, you can see the 3rd Bone Spring thinning pretty dramatically from about 350 feet in the well A on the left side to really down to about 200 feet in well A prime on the right side of the cross section. So it was really that thinning in the 3rd Bone Spring that gave us concern. When you look at the offset wells near here that sit in a similar thickness such as, I believe, the Albatross well and the Buttercup well, those are pretty low-productivity wells.

Q. And, again, your target interval is about 25 feet thick?

A. Yeah. We typically, when we design -- when we design a target, we have a pretty narrow target and steering interval. Mr. Byrd, who will be up later, can talk to some of that. But our target interval, we try and choose the best -- kind of the best of the best, and we try and place the well in that best 25 feet. And then, you know, beyond that, hydraulic fractures, we'll be able to link up some of that rock. But we've found that it's critical to be in the best target window of these wells, and even being off a little bit in targeting your laterals can have a pretty profound effect on well performance in the long run.

Q. Now, Matador has some upper Wolfcamp wells in Eddy County, correct?

A. We do.

Q. Is the zone that was targeted in those upper

Wolfcamp wells, does that exist here?

A. It does not. We target a sand that, rightly or wrongly, we call the x-y sand. It's two -- two sand bodies that look like little Bone Spring Sands -- they're about 25 feet thick -- that occur in the uppermost part of the Wolfcamp A. Much of the type curves you see on Matador's Wolfcamp wells on our investor presentations are wells that are landed in these x-y sands. That sand package is not present here, and we've really stepped out about, I would say, five miles north of the depositional limit of that sand package.

So, again, when comparing Matador's -- this well to Matador's other well results, I don't feel it's a very apt comparison because the target that we often choose to drill is not present here. We have drilled the more organic-rich upper Wolfcamp interval in other places. Those wells are as much as 50 miles away from here. So for us, for our institutional knowledge and our institutional database of rock properties, we're taking a pretty big leap.

Q. So you don't think that the upper Wolfcamp wells, the x-y wells you talked about are predictive of what will happen here?

A. We certainly hope they are, but I think -- I think we have to be honest with ourselves and say no, I don't feel they are predictive of what we'd expect to see here. If we were going to use a type curve, I would be more comfortable using some of our wells where we could at least target like rock.

Q. From the data you've seen, have you noticed any faults or any faulting that would cause problems during the drilling of the horizontal well?

A. Yeah. We have not. And that's -- it kind of loops back into one of the previous lines of questioning that you had about -- about what the limitations of the wells that we have. That's where the spatial distribution of wells comes in. We have a well at the heel and a well at the toe -- or a well at the heel and low at the toe of the proposed location, but we -- we can't say with certainty that there is no faulting there. In our analysis, we -- we do not believe that there is, but there's, again, always the possibility, when you get down to 11,000 feet in depth, that you find something you didn't expect.

Q. Could you walk us through Exhibit 11?

A. Yeah, certainly.

Exhibit 11 is an isopach or a thickness map of the total Wolfcamp. It's similar to a map that we presented, I believe, in the last round. And really what it shows is a thinning of the Wolfcamp section -- excuse me -- from -- from northwest down to southeast. Some of this thinning and thickening is controlled by where you sit on the shelf edge. That thickest 1,700-foot interval is back towards the Wolfcamp shelf, so you're kind of climbing uphill, and that section is thickening.

What it does show is that really across the Wolfcamp -- or across the Airstrip to a 1H target, the Wolfcamp is of really pretty constant thickness, and the Wolfcamp A in particular here, our target interval is still a pretty constant thickness across here.

It's worth -- we discussed it, but it's worth bringing this back up. The blue dots here are isopach points, and to make an isopach, you have to have a top and a base. So we would have to have a well that penetrated both the Wolfcamp and the Strawn to make this map. And you can see that they're actually relatively limited penetrations in the middle here. But isopachs often don't change too dramatically over short distances, so I think this -- despite the data limitations, this is still a reasonably accurate portrayal of what's happening out here.

And, again, to the screening criteria, I think it's also worth pointing out the thickness of an interval has very little bearing on its -- on its ultimate success as an unconventional target. That gross Wolfcamp thickness is not going to predict well performance here, and that's why we've sort of outlined these other screening criteria.

Q. And, again, in looking at this -- and I think you said this before once or twice, the Bone Spring data points have no bearing on the Wolfcamp?

A. No. No, they don't.

And I think on one of the previous maps, we've had all the horizontal Bone Spring producers laid over this, and that tends to cause a lot of confusion because people look at it and say, Oh, look at all the horizontal development up here. Well, it's -- it's Bone Spring horizontal development, and as we've said many times, I feel that that has very little bearing and is a poor predictor of the Wolfcamp development here.

Q. Referring to Exhibit 12, could you discuss how close the horizontal upper Wolfcamp wells are from the proposed well?

A. Yeah. So the two -- the two closest wells are 29 miles and 36 miles away from the Airstrip prospect. These are wells drilled by other operators. The one that's 29 miles away was drilled by Devon. The one that's 36 miles away was drilled by Endurance. There is data we can glean from these wells but very little. We obviously are not privy to other operators' data, so all we can really look at is a well log, if we're lucky, and production data here.

So when I think about delineating a play, we often talk about what we know. So the closest place where we actually have good data, our own data, would be the Scott Walker well, which is 45 miles away. And as we said earlier, the target that Scott Walker went after were these x-y sands, and those aren't even present in the Airstrip. So when we -- when we kind of look at it in that -- in that sense -- we wanted to make an apples-to-apples comparison -- our closest upper Wolfcamp A well would be in an asset that we call Jackson Trust, which sits in the -- in the northeast corner 11 county some 50 miles away. So that -- that for us -- I mean, our closest analog well would be over 50 miles away, and the closest one where we have really any data at all, not even a great analog, is 45 miles away.

Q. So geologically speaking, is that some distance away?

A. It's a huge distance, honestly.

You know, for context, if you were to look at the Eagle Ford System and you look at the oil window, the condensate window, the draw gas window, in parts of that play, you can go from the updip oil window to pretty marginal production there in the uphill [phonetic] oil window to the dry gas window in less than 30 miles. So a 30-mile distance here would be like the equivalent of missing the core of the Eagle Ford. That distance is huge.

Now, when we talk about 45 to 50 miles -- I'll put it back into the context of a little bit closer to home -- the Central Basin Platform is 40 miles wide in many places. So this would be the equivalent of using a Wolfcamp well from the Midland Basin to say it's going to be a good predictor of well performance in the Delaware Basin.

Q. Assuming Matador makes a well out of the Airstrip -- proposed Airstrip well, would that have an advantage not only to -- to Matador but to all working interest owners and royalty interest owners in this area?

A. Yeah. Absolutely.

I mean, I apologize. It sounds like we're -- you know, we're saying, Oh, there's -- there's -- you know, we're so far away from anything. And we're willing to take risks. Matador -- the Scott Walker well is the furthest north anybody's tested the

Wolfcamp A in Eddy County.

We were the first to drill these targets in Eddy County, and many of these wells are really -- they're quite nice wells. So I think if Matador can be successful in delineating the upper Wolfcamp here, it will have a significant benefit to all parties interested, that hopefully a good exploration test up here will help us de-risk the upper Wolfcamp in the northern part of Lea County and hopefully will lead to more development by us and by our competitors.

Q. Is the Wolfcamp Formation in this area heterogeneous?

A. It is. And I think the people who have produced this vertically, the Yates family, I give them -- I give them much credit for the wells that they've drilled out here. Both Jalapeno and HEYCO have done a great job of delineating the upper Wolfcamp, and I know that they would tell you there is quite a bit of the heterogeneity in these systems.

When I talked to George Yates, when Matador and HEYCO first joined forces, we talked about how this play really evolved. And George's assertion was that, you know, you -- you go for the deeper target, but you always want to have a bailout, that you want to come uphole and be able to try something else. And George basically said, you know, for HEYCO, that was sort of how they really became more comfortable with the Bone Spring. When the Wolfcamp wouldn't work, they'd come uphole and try to make a hole in the Bone Spring.

This figure here really kind of shows some of the differences in an unconventional play versus a conventional play. So on the left here, we have 100 feet of core. This is a Matador core relatively nearby in Lea County.

Q. Is that Exhibit 13?

A. Exhibit 13, yeah. Sorry, guys, if I didn't say that.

And this core is from the lower Wolfcamp. So it's not a perfect analog, but it sits in a similar position on the Wolfcamp shelf. And what you see is the blue intervals of these carbonate-rich intervals. The gray intervals are the more organic-rich and shaley intervals.

So at that 100 feet, you can see there's quite a bit of heterogeneity and rock types and reservoir types, and, again, we can kind of use the binary distinction of blue versus gray. We want gray. You know, in the vertical development, you want it blue. Our experience with these carbonates here is many that were tight and nonreservoir.

So the red box at the top here shows you this ten-foot core box. And I apologize that this didn't reproduce very well. It's looking like a lot of gray, but it kind of is. On the top, you can see these, you know, carbonate debris flows coming in with a rich class of, you know, Brett shelf-Moon shelf [phonetic] edge and all sorts of other organisms coming down. And then you go into these finely laminated organic-rich intervals.

The red box here at the base of this ten-foot core box shows you the photomicrograph of a thin section taken from one of these organic intervals. If you look at that, we typically color porosity in thin sections as a dark blue. It's a stain that we use in the epoxy that mounts across the thin section. You see no visible porosity in this rock. It's not until you actually get down and take an SEM image or a scanning electron microscope image of this that you can actually see the pore network here.

The pore network that we target here is fundamentally different than the Bone Spring. Here we're trying to find pores inside the source rock. These are organic pores that develop by the maturation of kerogen. So prospecting for these rocks is very different than it is in the Bone Spring. And they're kind of hard to see in this lower SEM image, but they're these little orange call-outs that say OPM. Those are organic nano-pores. That's where the oil is stored in these unconventional rocks.

So this rock in the thin section looks like it's completely tight. If you were to, you know, take a well here, take some thin sections and come back in here say, Where do I want to drill, in the vertical world, you would probably never say you want to drill in this rock. It's really not -- through the understanding of the -- the -- the finer scale pore networks here that we understand what makes an nonconventional target. This rock, actually, surprisingly has over 90 percent porosity. So it's actually not a -- not a terrible -- not a terrible interval here.

But the reason we included this is really to show that there is quite a bit of heterogeneity in these rocks. And the reason that we kind of keep belaboring this point is in the vertical sense, you have the opportunity of a bailout. If your original target doesn't work, you can come up the hole and, in theory, perforate other targets and try and find something that does work.

In the vertical sense -- or I'm sorry. In the horizontal world, you have to do a very deliberate job of targeting your wells. And, again, we said it's a pretty important difference on if you get this right or not to whether you make a good well. So this is, I think, one of the underappreciated aspects of drilling horizontal wells.

People often think oh, well, you just drill it and you frac it and oil will come to you. Well, that's true to a degree, but well performance is ultimately predicated on how well you target your well in the first place. So understanding -- understanding your target, getting in the right target, getting all these parameters that we've outlined to line up properly is critical. And it's really worth noting that Matador has invested significantly in this part of New Mexico to help de-risk prospects like this through multiple cores and logs, through 3D seismic. There's a lot that we do to try and help de-risk the prospect.

Unfortunately, spending money doesn't completely alleviate risk. We understand it better. We do -- we do what we can to come out and put our best foot forward, but ultimately there is always intrinsic geologic risk here that I think is sometimes underappreciated in the horizontal world.

Q. So the risk is still significant even though the formation is there?

A. Absolutely.
Q. Is Exhibit 14 another example of the Wolfcamp characteristics in this area?
A. It is. And this is what happens when you let a geologist testify. They always want to show a photo of pores and outcrops. So I showed you pores, now we've got outcrops.
Basically what this is is an outcrop example from a body in the upper Wolfcamp called the Kriz Lens. It's been studied for some 30-odd years. I think P.B. King, even when he started in the '40s, recognized this feature.
But the reason we include this is this body represents a debris flow down in the Wolfcamp slope. Basically what happens is this setting here north of Van Horn, south of Victorio Peak, in an area called the Corn Ranch, sits in roughly a similar setting to the -- to the Airstrip prospect. It's about four miles from the shelf edge, so it sits in kind of this toe-of-slope setting that the Airstrip prospect sits in. The red arrow here on the lower image of the blue-and-white arrow is meant to denote 100 feet so this -- this Kriz Lens debris flow is about a 100 feet thick. And then above that, you have these two little ooid grainstone reservoirs.

And the reason this -- this outcrop became sort of famous is the fact that it pretty nicely captures some of the heterogeneity that you have and really the issues of exploring in vertical wells, that you have to find that reservoir, and it's not always present. So if you are really lucky, you might be able to find a place where you get these lower debris flow -- or fans up above.

Now, on the other side of the table, we look at this from a horizontal exploration standpoint. Here you have -- you know, you could basically take this narrow bed that's about 25 feet thick and hope it's continuous and hope that you can stay in it and you can steer across this. So the reason I like this image is, I feel like it shows the complexity of both the unconventional and the conventional phase.

And we, again, certainly appreciate the vertical wells that have been drilled here. I have a lot of respect for the exploration in the Northern Delaware Basin, but I think there's as much, if not more, risk associated with horizontal wells, for many of the reasons we outlined, and I feel this image actually brings that home to a degree.

Q. And what conclusions have you drawn from your geologic study of the area?

A. Yeah. Well, we said it several times. We do feel there is an element of risk that is intrinsic to this process. We're going to have to -- it'll take one or two wells in here before we feel like we fully understand it. Since it is a step out, there are some things that we can characterize with the data we have. There are other things we can't characterize until we drill the well and we have some rock data from that well.

You know, the other thing that I would conclude is, having said that there is risk, we don't feel that there is really any major faults in the prospect or anything that would limit the well across the section, and we feel that horizontal drilling here would give far be the most efficient way to exploit the resources in the upper Wolfcamp A.

Q. In your opinion, will each quarter-quarter section in the proposed well unit contribute to production?

A. Absolutely. That is our -- our opinion.

Q. So it's your recommendation, then, that the drilling of one horizontal well will be more productive or effective in developing this -- in exploring for and developing this acreage than four vertical wells, say, spaced in each quarter-quarter section?

A. Yeah. I mean, I think one of the things -- it is my recommendation that horizontals are the most efficient way. And if you look at the original -- sort of the vertical completions from the Wolfbone, those wells get down sub 20-acre spacing. It was taking them tens of wells to drain what one horizontal well could drain.

Q. Getting a lot more perforated section?

A. Exactly.

I guess the way to think of this one vertical well equivalent of the one perforation cluster in a horizontal well. So typical Matador well 16 clusters. I mean, if you're going to use that analogy, basically drill 16 vertical wells to compete with the production with one horizontal well.

Q. Does it make economic sense?

A. Not to us.

Q. Could you turn to Exhibit 15 and discuss how you define the geologic risk in this well?

A. Well, this is -- this is basically a qualitative risk profile here. We'll say that. The parameters that we're using -- when I say qualitative, we've ranked them as low, medium and high. This is still, I think, relatively robust in understanding about the things that we need to -- that we need to focus on to help de-risk a well, but this kind of goes back to our four most basic of criteria: Porosity over 8 percent; total organic carbon, 2 percent; maturity of vitrinite [sic], 1 percent; and brittleness.

So the thing we can characterize fairly well is porosity. So we put that as a low. TOC here -- we get at it from the existing historical logs here, but it's not a particularly reliable way.

Typically when Matador is working up a prospect, we'll take well cuttings and have them analyzed for a TOC, and that gives you a TOC up and down the hole. We don't have that here.

Thermal maturity is actually one that is very, very important. Thermal maturity governs basically what type of oil you get. When you're talking about organic pore networks, it's very important that you get a product that has molecules small enough to flow through those tiny, little organic pores. That typically happens at a maturity of greater than 1.0. So we've put that as a high risk because the offsetting data where we do have maturity, it's not getting across that threshold. It's close, but until we drill the well and actually see what it does and see what the oils come back to us, what they look like, we can't put that into any lower of a risk category.

And then the brittleness here, we don't have a good -- a good way to characterize it. The well log data offsetting is not suitable, so we kind of have to put this in the medium category.

Q. Is geologic risk as simple as presence or absence on the formation?

A. In my opinion, absolutely not. There's -- there's much more than -- there's much more that goes into it. And I would argue that's certainly the case in a well that's this big a step out. Maybe when there are 100 wells in the section -- in the -- in the surrounding area, it's a little bit more straightforward, but I think with first well, you know, and 30 miles away from the nearest producer, I don't think presence or absence on the formation is a good predictor of success.

Q. And I think you already stated that the same holds true of the overall thickness of the formation?

A. Absolutely. Absolutely.

Q. Can you tell us about the porosity and permeability in the upper Wolfcamp?

A. Well, we can tell you about porosity, like I mentioned, from the well logs, but we can't tell you anything about permeability. The well -- some well logs do an okay job of representing permeability. These are typically the advance suites that Schlumberger likes to charge you lots of money for. We don't have any of that. So we can tell you that this porosity -- we can only use offset analog data from the lower Wolfcamp to infer permeability. So we don't have a good way to get at permeability here. That's also a risk. And I believe that will come up in the reservoir engineering, with metrics, also.

Q. Are there any geologic risk components that overlap with operational and reservoir risks?

A. Yeah. One of the big ones is geosteering, and this is where the geologist and the drilling engineers work together to keep the well in your preferred target interval. And Matador does, I think, a very good job of steering its well, but there are many cases -- when you get down to 11,000 feet, there are things you can't account for. So if we get out of zone, potentially that can cause a risk.

The other risk that I would say is pressure. When we look at our type curves from Eddy County or Loving County, these are overpressured units, so they will flow hydrocarbons. We don't know that the Wolfcamp here is overpressured. By saying it's Wolfcamp doesn't guarantee that it's overpressured. And that to me I view as a risk. But, again, I realize I'm kind of speaking to the reservoir engineer's testimony here, too. So I'd say yeah, steering and pressure are the two big ones.

Q. So geologically speaking, this is a step out for Matador?

A. It is.

Q. And, as a result, it's risky?

A. It is. It's a big step out for us. It's a step out we're willing to take because we do think there is a lot potential in the Wolfcamp A, the upper Wolfcamp in northern Lea and Eddy Counties. And, you know, the -- the risk is one that hopefully, if this well works, will -- will benefit, again, really all interested parties and hopefully will spur development up here.

A lot of times people kind of wait and see who the first one is, this group of people called fast followers who sort of say, Oh, Matador drilled a well up here; we've got some acreage we can probably do that on. So we hope this is a good result. We hope that it encourages production up here, but there are no guaranties in that.

Q. And you hope the upside exceeds the risk?

A. Absolutely.

Q. And Matador does have substantial acreage in the general area that can be developed?

A. We do. Our exposure to, really, the lower Wolfcamp A and the lower Wolfcamp across northern Eddy and Lea Counties is substantial, so really making this well work up here and learning from this well will help us, in our mind, begin to exploit that acreage.

Q. Is the -- in your opinion, is the risk charge of cost plus 200 percent justified in this application?

A. I think it's absolutely justified. And, you know, frankly, I think it could probably be even a little bit higher for this case.

Q. And will subsequent witnesses also discuss risk?

A. They will.

Q. In your opinion, is the granting of Matador's application in the interest of conservation and the prevention of waste?

A. Yes.

Q. And were Exhibits 8 through 15 prepared by you or under your direction and control?

A. Yes.

MR. BRUCE: Mr. Chairman, I move the admission of Matador Exhibits 8 through 15.

MR. GALLEGOS: No objection.

CHAIRMAN CATANACH: Matador Exhibits 8 through 15 will be admitted.

(Matador Exhibit Numbers 8 through 15
are offered and admitted into evidence.)

MR. BRUCE: And I pass the witness.

CHAIRMAN CATANACH: Mr. Gallegos.

CROSS-EXAMINATION

BY MR. GALLEGOS:

Q. Dr. Frost, I'm interested in your screening criteria. And let's -- let's place ourselves, say, in late 2014. The first proposal in this well was in 2014, and then that was Bone Spring. And then the Wolfcamp was early 2015. So let's put ourselves in that time period, if you would, and then tell us what the elements are in your screening criteria.

A. Okay. So in the courses of screening criteria, which is what I have presented to you, you would have a net porosity of a certain thickness greater than 8 percent. You would have a net TOC of a certain --

Q. I'm going to take some notes.

A. Okay.

Q. So porosity of 8 percent or better --

A. Yes.

Q. -- is what you would be looking for?

Okay. And how do you normally, typically obtain the data so that you can deal with that screening criteria?

A. Yeah. So in -- in -- I'll present you two cases for that. One would be -- in the ideal case, you would drill a pilot hole. You would take rotary sidewalls. You would run advanced suite logs. We are not advocating for a pilot hole here. There are -- in other cases, porosity, you can really begin to get from normal well logs. The one thing that becomes important is the concept of total porosity, the concept of effective porosity. Total porosity is all the holes in the rock. Effective porosity is how many of those pores will begin to flow oil to you.

So well logs give you a reasonable approximation of total porosity once you've corrected them. And we've had a petrophysicist go through and do that.

Now, you need to start getting a sense of effective porosity by getting clay, and that's something that's a little trickier to do. So in the most coarse sense, we can give you a total porosity. And we understand that that gross porosity or that net porosity cutoff is a very blunt tool, and that's the one tool I think we have that we can all agree at least, you know, we're seeing that get above our screening criteria.

Q. When you say porosity of 8 percent or better, are you telling us that's gross porosity or net porosity?

A. Well, when you're giving it a cutoff, it's a net porosity, so you're saying porosity above.

Q. Okay. All right. The next screening criteria?

A. Total organic carbon. We like to see total organic carbon above 2 percent. If your pores are hosted in organic carbon, the more organic carbon you can have in a rock, the more likely you are to have a suitable porosity in that rock. So --

Q. And how do you obtain evidence of total organic carbon, speaking in general? We'll get to --

A. Yes. There are a couple of log-derived methods. Passey and Schmocker have introduced methods for this. Those methods typically require a pretty robust log suite. It requires a sonic log, which not all of these wells have.

Really, in our opinion, one of the best ways to do it is go grab a bunch of well cuttings, pick through them carefully, send them off to our preferred geochemical vendors in Houston and get a porosity log -- sorry -- a TOC log from that. Unfortunately, we don't have cuttings at our disposal to do that, so we're left with the less sophisticated and less reliable methods of the Passey and Schmocker evaluations.

Q. Is there a New Mexico library of cuttings that

New Mexico Tech or some other --

A. There is. Yes, there is. And we've -- we've looked in some of these. The Midland Sample Library also has this. HEYCO has a fair amount.

One thing that we find that's actually very critical in cuttings is that they're fresh. If you think about a summer in -- New Mexico Tech is -- forgive me. That's Socorro. I'm assuming that coreshed is not climate controlled, that the inside of that coreshed can get pretty close to reservoir temperatures. So cuttings that have sat around in coresheds for a long time are of less reliability in the respect that you tend to lose a lot of the evaporative hydrocarbons contained in those cuttings. So it is a place to start, but it's still a relatively unreliable place to hang your hat.

Q. All right. Criteria number three would be what?

A. Well, in this case it's thermal maturity. So this is one where -- to your point of pulling cuttings, thermal maturity is a relatively reliable parameter. Things we do, we do basin modeling to get at this. We invoke pretty much the state of the science on modeling thermal maturity.

We do have two wells from Lea County, not far away, the range of 12, the range of 33, that both give us maturity in the upper Wolfcamp, and we are using those analogs in calibrating those to this target. And that's where we feel that we don't have the, sort of, Goldilocks window we'd like to see of 1.0 or higher.

Q. Would electric logs give that you information?

A. No.

Q. Is there any type of log that will give you that information?

A. You know, that's kind of an ongoing debate where thermal maturity -- again, the guys at Schlumberger and the guys at Weatherford, I mean, this is something they work on at their research labs. You know, gas logs -- you know, as you drill across, if you look at wetness and balance and character of mud gas, there's a way to draw analogy there, but you're never quite certain about what -- what -- you know, mud gas is always a little bit tricky. So there is an indirect measurement there, but those are -- really, for thermal maturity, it's modeling and it's rock, are the two things that really are critical.

Q. Okay. And how do you approach the modeling?

A. So the basin modeling -- I feel like I've kind of rambled on too long. This is what happens when you let a geologist talk about the technical things they like. They'll tell you all about them.

But the basin modeling is -- effectively what you do is you create a burial history of these rocks and plug in the thermal conductivity of these rocks, and you begin to model how kerogen matures and expels hydrocarbon. This is a widely accepted technique that is used in frontier exploration all the way down to in-basin exploration in basins like the Delaware.

So what you basically get out is a number of logs -- you would begin to get oil-in-place numbers. You get various parameters, but one of the things you get is a sense of thermal maturity based on your understanding of thermal and burial history. So when I say thermal and burial history and our understanding of that, there is always a little bit of uncertainty, too.

Q. All right. Is there a fourth criteria?

A. The fourth criteria is brittleness, and really what we're looking for is a rock that can be stimulated with a high-energy fracture treatment. The more clay or the less brittle of rock you have, the less -- the less efficient your fracture stimulations are going to be. So you kind of want to find that -- again, that zone of adequate brittleness where the rock will fracture, but it's not so brittle that you have to work overly hard to break it down.

Q. Would a sonic log give you that information?

A. You can get at it from a sonic log, but ideally, you would need a dipole sonic, which we certainly don't have up here. And then you are taking some pretty big leaps of faith on your ability to drive more elastic porosities from a 1980s-vintage sonic log.

Q. But modern log suites, what is your view in that regard, as far as being an adequate indicator of the brittleness?

A. They are. What they'll give you is a dynamic modulum, and you always want to calibrate those back to rock data. You know, again, this would be sort of one of the overlapping topics here, and in many ways, I would defer to Mr. Robinson later, who has -- has worked on many, many fracture projects in unconventional wells. But that one -- you know, from the log suites we have, where we're using indirect measurement like the clay, we're not really getting any -- any direct properties, any module properties from -- from the logs we have. So that's why --

Q. You're kind of circling back in this particular well?

A. To the brittleness, yeah.

Q. Okay. And we'll do that. But what I was trying to get at is, you know, broadly your criteria and how you satisfy yourself about those.

A. Yeah.
Q. So is there a fifth screening criteria?
A. You know, there are. There are some more advanced ones. I mean, we at Matador key in very heavily on a lot of the geochemical properties. We like to do oil extracts from source rocks to understand what the products are going to look like. Again, we don't have cuttings, so we can't do that. The cuttings also tell you the amount of distillable hydrocarbon in the rock. That's another thing you get from a technique called Rock Eval.
So I think -- for where we are in the initial screening process, I think we're -- we're at a pretty good spot to understand what we're up against. In a perfect world, we would always like to have more, but I'm assuming there are a few engineers in the room, you know, geologists who would like to have more data. But I feel the ones we've given you here are pretty much the bare-bones criteria for screening a play.
Q. And I take it you or a staff geologist at Matador would apply these screening criteria as a general -- general rule --
A. Yeah.
Q. -- if a well is to be proposed?
A. Absolutely.

Q. And one would assume -- and I ask you if it's correct -- sometime the screen criteria will fail at the proposed well, will it not? Doesn't pass?

A. Well, yes. Some will fail. Some will -- some will also, I guess by that token, produce false positives, ones where everything lines up and for some reason, the well didn't perform as expected. So these screening criteria are far from perfect, and there is very little certainty in this game. So, you know, the screening criteria are good first batch, but I feel like they're -- you know, it's still a pretty dull tool.

Q. All right. Let's now go to the time when either you or somebody working with you said, Here's the Airstrip well. Management wants to drill this upper Wolfcamp. Let's apply our screening criteria. And that's what happened, I take it?

A. It did. It did.

And I like I said earlier, the 3rd Bone Spring prospect barely passed the 8 percent porosity cutoff. When we look at offsetting 3rd Bone Spring wells, some of the worst wells in the area are failing these criteria. So when I looked at it, you know, and the team looked at it, we felt like there was a better chance in the -- in the Wolfcamp. We're not saying that the 3rd Bone Spring couldn't produce, but one of the beautiful things about drilling a deeper target is you get a look on the way by. So if we're uncomfortable with the Bone Spring, we can look at that as we go by, and now we have rock data. Now we have cuttings to analyze that and hopefully be proven wrong. So there is a strategy to drilling the deeper target from an exploration standpoint, that you do get a sense of what the uphole targets look like.

Q. Is Mr. Juett one of the staff geologist?

A. He is.

Q. Did you attend the September hearing in this case before the Division?

A. I did not.

Q. You are aware, though, of course, that Mr. Juett testified that the porosity was 8 to 12 percent and 14 percent in stringers in this?

A. I believe he was referring to the Wolfcamp Formation.

Q. Yes. And that's what I'm asking about.

A. Yes.

Q. I'm not asking about the Bone Spring.

A. Okay. I am aware of that, yes.

Q. All right. What -- what was the data or what was the information in your screening for porosity that you were able to make that assessment?

A. Well, like we said, it's a neutron porosity and density porosity log from the '80s vintage logs. So we have -- we have -- like we said, when it comes to porosities, it's the most straightforward one we're stringing from, probably the one we feel most comfortable with applying to.

Q. And those, I take it, the source was, as you say, '80s vintage logs for vertical wells?

A. Yeah. Could be '90s. I'm being a little bit glib. I'm not sure exactly of the date, but they're certainly pre-2000s.

Q. And there has been significant technical advance in logging since that time?

A. The service companies would like to tell you that's the case. In the logs suites that we're considering here, that you're questioning on, the density porosity, the neutron porosity, those logs -- those tools have really, you know, not changed very much in the last several decades. They were good in the '80s. There was a period, you know, depending on who you talk to, before the mid-'70s when the tools changed drastically. But, you know, really '80s and beyond, those tools are pretty acceptable for an initial porosity screening.

Q. So with that being the source of information,

did the Airstrip log -- use the word -- pass on criteria number one, porosity?
A. Yeah. In the Wolfcamp, it did.
Q. Okay. All right. Let's go to total organic carbon.
A. Yeah.
Q. And maybe I asked you about a sonic log and you said no, or --
A. Well, sonic logs -- sonic logs for total organic carbon help. And like I've mentioned, that's where you get back to the Passey and the Schmocker equations, where you're trying to relate some indirect measurement such as density or resistivity or sonic response to organic -- not -- yeah, total organic content. It's worth pointing out that some very big assumptions are being made in that -- in that arrangement.
So I'm not sure that these logs have the requisite suite to get that done. One of the assumptions with Passey's method, which is called Delta Log R, is you have to assume the thermal maturity. So if we're having a hard time assuming thermal maturity to the rocks -- you know, you're often left with many unknowns here, and, unfortunately, some of the unknowns are related to each other. So you're, at times, left

saying, Okay, well, if I had this piece of data, I could solve this problem, and if I had this piece of data, I could solve this problem. Unfortunately, you have neither.

Q. We're still on total organic carbon. And I may not appreciate your testimony, but it sounds like all you had for that were these logs from the older vertical wells?

A. Yeah, that's right, and some offsetting information as well.

Q. You would have liked to have some cuttings, but you didn't have that?

A. Exactly.

Q. So with that information, did the Airstrip pass?

A. That's why it's a medium-risk category, because we don't feel like we can de-risk that.

Q. Because of the lack of information, basically?

A. Because of the lack of information.

So we have some information from regional analogs, but we don't feel that's a full way to make that go from using our qualitative medium-risk category to a low-risk category.

Q. Thermal maturity, then, what -- what do you have as reliable evidence so you can draw conclusions --

A. Well, like I mentioned previously, we have vitrinite data from two offset cored wells -- not offset, but two cored wells where there were core plugs taken in the Wolfcamp A. They sit in a slightly different setting, so that's why I mentioned we weren't quite getting to that number we like to see of 1 percent RO. And that -- that's the best we have. So we would put that in the high-risk category.

Q. Okay. That's Exhibit 13 you're referring to?

A. No. It's Exhibit 15.

Q. 15. I thought you were talking about a core.

A. Well, yeah. That's a core from the lower Wolfcamp. When we often core wells, we'll take rotatory sidewall cores, working on a continuous bore uphole, but it gives you individual data points. So you're asking about thermal maturity for the Airstrip prospect, and I think the best place to look at that is Exhibit 15, where we still show that as a high-risk category.

Q. I wasn't talking about your conclusions yet. I was trying to get at what tools you had. I thought you were talking about core. Evidently core, but maybe -- maybe not.

A. Yeah. So I'll --

Q. What did you rely on for thermal maturity?

A. I'll explain it again. We relied on rotary sidewall cores from two other wells nearby and basin modeling.

Q. Same wells? When we're talking about these older wells, were they all the same --

A. No. These were wells that Matador drilled and cored in 2014 -- roughly 2014.

Q. And what was the proximity of those wells to this prospect?

A. I don't think one is closer than five miles, and they -- so I would say five to ten miles away.

Q. And they are Wolfcamp wells?

A. One is cored in the lower Wolfcamp, and then one is a series of rotary sidewall cores from the Avalon in the Bone Spring lime all the way down to the Strawn.

Q. No -- no upper Wolfcamp information?

A. No. We have -- sorry if I'm not articulating that. Yes. We have data points from the upper Wolfcamp in these wells that are five to ten miles away.

Q. For thermal -- and we're talking about thermal maturity?

A. Yup. Yup. Yup.

Q. Okay. So you have upper Wolfcamp information five to ten miles away?

A. Yes. And it's below -- five to ten miles away. It's below the cutoff we like to see. So there we can put it in the high-risk category because we aren't seeing the number we want to see, but we acknowledge that we're not fully going to put that issue to rest until we have hard data at the well itself.

Q. So on thermal maturity, then was it your conclusion, as you were going through the screening process, that this well did not pass?

A. Like I said, we have data. It's very close, but ultimately the data we have is offset. So we'll kind of, I think, have to reserve the right to see -- so technically, yes, it does not pass, but it's close. And we would like to see ultimately, you know, what that value is at the well, and that's where we have to have cuttings a little bit closer than we have them.

Q. Okay. And the other -- the final criteria that you gave us was brittleness?

A. Uh-huh.

Q. And I suggested modern sonic logs might give you that information, and what was your --

A. Yeah. That has occurred to us as well. Unfortunately, we don't have them.

Q. But you don't have them?

A. No.

Q. So you really just -- I don't know. In a case like that and that's one of your screening criteria, you don't have information, then doesn't the conclusion have to be this prospect doesn't pass that criteria?

A. Well, we have -- we have analog data. We participate in a number of consortia such as Core Labs, Delaware Basin Consortia. So we have ways to get at it. You know, we can do very simplistic brittleness logs. There are any myriad of brittleness logs that have been introduced over the last decade of looking at ways to get it from gamma and this, that and the other. So we feel like what we know from offset -- offset analog data, this is probably not a huge risk. We've seen wells of 50 percent Vclay, but those are not -- those are not the norm in this Basin.

So, you know, we -- I think one of the things that's hard here is you don't really have really the requisite data you need to either green-light or condemn these prospects, that ultimately you're going to have to step out, and you're going to have to drill the well to really figure it out. And that's why I say we can collect the most data we can, but ultimately there is going to be a certain amount of risk that you can't reduce away, and that's where, as a management staff, you have to decide does the upside of this well outweigh the downside of the perceived risk.

Q. You're aware -- and I guess it was a different and higher figure when you were doing your screening, but you're aware that this well is proposed to cost about $6.5 million?

A. I would have to refer to Mr. Byrd's testimony to give you an exact number on that.

Q. Well, I was going to say let me ask you to assume that, that that's the AFE on this well.

A. Uh-huh.

Q. That's a fairly significant financial investment; is it not?

A. It is.

Q. And as you say, there are times when prospects don't pass the screen criteria. If this well, after what you've seen and lacking the information you have, says to you -- let's say there is less than a 10 percent chance of making a well, then isn't your responsibility to tell management, Don't spend $6-and-a-half million on it?

A. Well, if we thought the outcome was that grim and we would learn nothing from this well, then yes. But, as we've been careful to try and outline, we feel that testing the Wolfcamp A here does have strategic value to a company like Matador. Given our exposure to the upper Wolfcamp in this part of the Basin, having a test that performs favorably has a huge bearing on

Matador's bottom line.

So we, as geoscientists and petroleum scientists, are always weighing the concept of the risk and reward. So we feel like we have enough data to know that this is probably not going to be a complete failure, but we can't say with certainty if it's going to be a full success by our criteria either. Even if the first well in the campaign is not, you still learn valuable -- you still learn valuable information from that, and hopefully that begins to help you de-risk some of these categories that -- that -- I mean, if I had cuttings across this well, I could very much understand, you know, what thermal maturity here was and begin to get some of the other properties out of that. So that's why we advocate to drill the well.

Again, we feel like this is a good prospect. There is inherent risk. We can't de-risk anything -- everything, but there is obviously quite a bit of upside to this proposal and, we feel, to other interest owners in this area as well.

Q. Where do you place it on a scale of 0 to 100 as far as likelihood of this successful well?

A. You know, I think the -- the number we've given here of 25 percent chance of success is fair. I think that's about what I would put it. I mean, we're not talking about drilling in ultra-deep water here, you know, 6 million -- you know, there's -- it's always a capital expenditure here, but when we talk about risk, we've certainly seen far riskier prospects than this.

Q. Dr. Frost, about how much would it cost to just drill the pilot hole?

A. I would have to defer that to Mr. Byrd.

Q. Okay. You know that the areas that lack information, do not have answers, all of that could be addressed by a pilot hole and running a suite of modern logs; isn't that true?

A. It is. We feel like we have enough confidence in this that that is an additional capital expenditure that in this time of low cost, it's hard to justify.

Q. I'm sorry? It's hard to justify --

A. Internally, Matador --

Q. -- getting the answers that you need to make an informed decision on a pilot hole and a suite of logs, but it's justified to spend $6.5 million without the information?

A. We feel like we have enough of a handle on the data here to justify spending the $6-and-a-half million. I think given -- given the push-back on AFEs, adding -- adding a pilot hole to this situation wouldn't really improve -- really wouldn't improve things. I feel, you know, pretty comfortable that we have a good shot at this well. I think 25 percent chance of success is a fair appraisal, and I think -- I'd love to have a pilot hole, but, honestly, that's not always the case. Out of all the wells that Matador drills, I can think of probably four or five pilot holes that we have drilled. Matador does a very good job of de-risking prospects without pilot holes.

Q. Did you not recommend drilling a pilot hole -- a suite of mud logs?

A. That is not -- to my knowledge, that has not been recommended on this prospect.

Q. So when you talk about the outlook then -- I wanted to call your attention to things that were in the Division order resulting from the hearing in September --

A. Uh-huh.

Q. -- and the testimony of Mr. Juett and Mr. Byrd, and see what your reaction is, because based on that testimony, the order says, "Applicant anticipated an estimated ultimate recovery of 350,000 to 400,000 barrels of oil for the proposed well with the Wolfcamp target." Do you concur with that?

A. That is our expectation, yes.

Q. And you've already testified that you believe all quarter sections in this -- I forget the acreage now. It's not 160. 158 -- that all quarter sections will be productive.

A. That is our assertion as well, yes.

Q. And the Division also found, based on the Applicant's expert who testified, quote, "that there are no geologic impediments to drilling a horizontal well in the unit." Do you concur?

A. Well, yes. As we define that, I think that is a true statement.

Q. And, again, based on Applicant's expert's testimony, the Division found and I quote, "That the Applicant did not require any additional data such as pilot well or core sampling for this drilling effort to be successful."

A. That's correct.

Q. Do you concur?

A. Yes.

Q. So you have -- with the information you have and without taking further steps, you testify that you expect this well to be successful?

A. We do. We certainly hope that it is.

Q. All right.

A. I think "expect" is --

Q. And if you would with me, swing over to Exhibit

23. This is Matador Exhibit 23.

A. I'm not the one who is exactly qualified to speak to this one. Why don't we defer to Mr. Robinson who prepared these exhibits on this?

Q. Well, let me -- I think there is one of these that I would expect you to be able to speak to. Maybe the other two not. "Matador's criteria for success," three bullet points. The first one, "Geologic: Suitable rock quality at peak oil window."

A. That's correct.

Q. And that is present here. So you expect success on that criteria?

A. Well, again, that's where -- that's where the risk comes in. That's where the thermal maturity comes in. If we think we're close, we don't know that that's -- that's what we'll define, whether it's successful or not by these criteria. That's why we give it a 25 percent risk.

Q. Tell me some examples of Matador wells in which you've done a screening criteria in which you've concluded there was a 100 percent chance of success?

A. I'm not sure that there is such a thing as a 100 percent chance of success in the geologic risk world.

Q. So is there always 50 percent? Is that --

A. It really depends. It's prospect to prospect. It's many different factors that give that. So I don't think that there is ever a 100 percent chance of success. And like we said in the testimony, I feel like we've acquired a fair amount of data to get to a point where we're comfortable with the risk that we have.

Q. Well, enough -- enough data that working interest owners other than Matador, who is interested in what we might call experiment, should participate to their percentage interest in this $6.5 million well, or should they not?

A. Many people have elected to. That ultimately is a decision that each person has to make.

Q. How much information that you've given to us here this afternoon can you tell us was provided to those many people who have decided they would participate?

A. I can't speak to the packets that have gone out to any of the interest owners.

Q. Do you have -- can you tell us if those interest owners were told, from a geologic standpoint, you've determined that there is only 25 percent chance of geologic success?

MR. BRUCE: I'd object to this. He's talking about -- number one, the witness has already said he doesn't know what went out in the data.

My second objection is more. Everyone makes their own decisions. What those other people decide is irrelevant as to what they do consider risk, what they don't consider risk.

MR. GALLEGOS: That's so faulty. You make decisions based on information, and if you don't have information that's important, then you can't make an informed decision. And that's all I'm asking, if he knows this kind of information you're telling us --

CHAIRMAN CATANACH: I'll allow that question.

Do you know if that was given to the other interest owners?

THE WITNESS: As I said, I do not, but we are always happy to share with any interest -- any interested party what our appraisal is. So it's not -- I would argue that if stuff has not being shared, there is quite a bit of proprietary data to Matador that's represented here. We're always happy to talk to people frankly about how we feel about any of these prospects.

Q. (BY MR. GALLEGOS) I wanted to ask you and I think maybe the best place to talk about it, if I have the right exhibit, is -- it's the exhibit that shows the mileage distance from this well to other Wolfcamp wells.

I want to say 14, but I think I'm wrong.
A. I think it's 13. I'm sorry. It's 12.
Q. Is it 12?
A. Yeah.
Q. Okay. That's what I was looking for. Thank you.
A. Yeah.
Q. So proximity, Dr. Frost, is a significant matter to consider?
A. Well, it depends on how you're -- how you're trying to do this. If you're trying to say it's a type curve from southern Eddy County to the Wolfcamp here, that's -- that's a jump we're not willing to make.
You know, production -- you see -- you see quite a bit of distance there, but in some ways what you do is you look at what you understand about where these wells are, what setting they sit in, and then you compare them to what you have. It's a big step out. There are no two ways about it. And I think we've definitely shown that. But, you know, again, we feel that there is an upside to testing the Wolfcamp A here.
Q. Would you say that remoteness creates uncertainty?
A. I think uncertainty creates uncertainty. A lack of data creates uncertainty.

Q. So the distance -- you mentioned that the nearest similar well is 29 miles away. Isn't, really, that significant?

A. I think it is significant, but if you have data that helps you, you know, alleviate some of the risk parameters, there are ways that you can solve this problem, and Matador is trying to. You know, again, I think the purpose of this figure is to show the context of how big a step out this well is.

Q. Okay. But would you agree, then, that close proximity would lend to a higher degree of certainty?

A. No, not always. There are -- there are many cases -- and we brought it up today -- where -- where wells that were short distances still vary. So we try and treat each prospect with sort of the same level of detail where -- where we're doing here. When we're closer to our own data, it's a little bit easier to be comfortable with it, but, I mean, there are plenty of examples where wells perform differently based on our priority of assumptions.

Q. So is it your opinion, then, that the matter of 29 miles or 45 miles is far less important in terms of uncertainty than the kind of criteria information that you did not have available?

A. No. I don't think that's a fair appraisal. I think it is important to recognize that this is a big step out as well.

Q. So if -- let's say --

A. I think we're kind mixing -- I think we're mixing factors here a little bit. But, you know, Matador's knowledge of -- of -- of all these parameters of data we have on a well that has produced is 45 miles away. You know, when we talk about de-risking wells, you're trying to do two things. You're trying to look at your screening criteria, and you're trying to compare those to wells that produced. So we have our screening criteria. What we don't have is a nearby producer. So it's very hard to draw that inference, and that's why we do feel that this instance is an important factor here.

Q. Let me ask you to assume the following: Section 31, the Airstrip -- the proposed Airstrip well in the west half of the west half meets the criteria for success, the 400,000 barrels and so forth. Now, the next well is going to be in the east half of the west half, literally adjoining.

A. Yup.

Q. What's the uncertainty or lack of uncertainty?

A. Well, the uncertainty goes down with the first well you drill. But, I mean, we have seen variations across the section, so we can't say we eliminate all uncertainty. But we would hope that we've learned some from the first well and that the next test would be improved based on what we learned.

Q. Well, you probably encounter that with Matador quite frequently, don't you, where it's -- here's the second, third, fourth well in this section, horizontal Wolfcamp, horizontal Bone Spring?

A. We do.

Q. Yeah. And when it's the second well and the first well has proved successful, then what do you say to management as far as the prospects are for this next well?

A. Well, we look at each well critically. So if we have information, you know, sometimes we choose to drill wells in a location or a given geologic risk factor. Then we can see the things change across a section. It's our assertion that we don't see things change across the section here, but ultimately, you know, as we've said, you have to drill the well to know how it's going to perform.

Q. But you've -- but you've said in your -- the other witnesses said that as far as Section 31 is concerned, it's basically uniform.

A. That is. And I think -- I think the point that's being missed here is with the data in hand, that is our assertion. We can't know with certainty until we drill the well any different.

Q. Okay. And I understand there's always some uncertainty, but the hypothetical of the second well in the east half of the west half of Section 31, you say there is 90, 95 percent chance it's going to be in analogs as the first well?

A. I think we're more concerned with getting the first one drilled right now. We'll take the second one as it comes. We hope. We hope so, but --

Q. Well, what's been your experience with the situation I'm describing?

A. It varies. It can vary around the Basin.

Q. I just wanted to -- I think it will help everybody. You talked about you've got a thick Wolfcamp Formation --

A. Uh-huh.

Q. -- but you're going to have to place this lateral much more exactly than 1,000 or 1,200 feet, right?

A. That's correct.

Q. Okay. So on the cross sections or whatever might be appropriate, tell us where that 25-foot window is?

A. I think it's -- it's pretty clearly depicted on

Exhibit 10.

Q. All right. And is that -- do we see the top of the Wolfcamp with a line drawn there, kind of, I guess, a violet-colored or whatever that color is?

A. Yup. Yup.

Q. So where you show the -- where you show the well sidetracked, that's your 25-foot target interval?

A. I can't say that that 25 is exactly to scale, but that is an approximation of where it would be. And I think in this scale, probably the red line is a pretty good approximation of somewhere between 15 to 25 feet.

Q. And what is it about what you're seeing on the logs that tells you that that's the best target? I think that was your testimony.

A. So in our -- in our opinion, that is where we see the most porosity development, and we are in the -- sort of the middle of the broader porosity package that we identify in Wolfcamp A.

Q. And Mr. Juett's testimony that when these wells have been completed -- these Wolfcamp wells have been completed, they flow. As soon they're completed, without pump jack, they start flowing.

A. I believe that was Mr. Byrd's testimony that you're referring to.

Q. Oh, Mr. Byrd.

A. And that's true in the overpressure parts of the Basin, and that's why we've put pressure as a risk here. We don't know that this is overpressured and that this well will flow on its own.

Q. Okay. Well, Mr. Byrd testified -- Mr. Byrd testified and I quote from the transcript -- he was asked by Examiner Jones, "So is this going to flow, this well, do you think, or put a pumping unit on it pretty quick?" The witness is Mr. Byrd.

"One is I would fully expect for it to flow. Every Wolfcamp well we have drilled to date has flowed out the casing, and we don't expect anything otherwise here."

MR. BRUCE: Mr. Chairman, he's talking about Mr. Byrd's testimony. Mr. Byrd is here today. I think he should answer that question.

Q. (BY MR. GALLEGOS) I'm asking this witness. Do you disagree with that?

MR. BRUCE: He's a geologist. It's operational.

THE WITNESS: We hope that all wells will. I think likely on flowback, this well will flow. But what sustains natural flow in a well is overpressure, and that is something that we aren't certain about. And circling back to Exhibit 12, showing the distance, we pretty clearly stated that all Matador's penetrations of the Wolfcamp come from 50 miles away. So I think that's where the distance matters. We hope this well will flow, but there are no guaranties that this well will flow without being putting on artificial lift early in its history.

Q. (BY MR. GALLEGOS) Thank you, Dr. Frost.

A. Thank you.

MR. BROOKS: Mr. Catanach and Honorable Commissioners, I would like permission to ask this witness one question.

CHAIRMAN CATANACH: You may do so, Mr. Brooks.

MR. BROOKS: Thank you.

CROSS-EXAMINATION

BY MR. BROOKS:

Q. You testified, I believe, that drilling the proposed horizontal well would be more efficient and economic than developing this 160 acres with four or more vertical wells. Okay. What about drilling four really short horizontal wells, each less than a quarter of a mile? Would that make sense as a way to develop this --

A. In our opinion, no. The longer the lateral, the better the well performs. And not to keep building for Mr. Byrd here, but he has a couple figures that shows how the shorter wells have performed, and they underperformed.

Q. Thank you.

CHAIRMAN CATANACH: Why don't we take a break here.

(Recess 3:17 p.m. to 3:34 p.m.)

CHAIRMAN CATANACH: Call the hearing back to order.

At this time I turn it over to Commissioner Padilla.

CROSS-EXAMINATION

BY COMMISSIONER PADILLA:

Q. Dr. Frost, thank you. I just have a couple of questions for you. You reference quite a lot in your cross -- or your answers for cross testimony.

Was the economic factor associated with a pilot hole the only reason you chose not to do it, primary reason?

A. No. We've -- the geologist always wants a pilot hole, and there is always a give-and-take from the engineering side, the drilling side. And I'll offer an example. What we call our Rustler Breaks prospect in Eddy County, we came in there and had a bit of a challenge. The first well we drilled produced some. It was a good well, but it wasn't fully what we expected, and we had some open questions about that.

So what we did is we had gone through and kind of came in with a hypothesis, figured out what our unknowns were, much like this, and kind of worked through it. So without ever drilling a pilot hole in Rustler Breaks, we've now drilled successfully, I think, somewhere in the ballpark of 15 Wolfcamp wells out there, and those are some of our best wells.

So a lot of times what we try and do at Matador is we try and find and low-cost ways to get at the problems at hand, and if we can't fully do that, I mean, the pilot hole would be the option. We are currently drilling a pilot hole in Rustler Breaks. But it would seem counterintuitive to do it after your 15th well. But there are more subtle questions that we can't answer from the data we have at hand, so now we actually have to drill the pilot hole. So we do drill them. A lot of times we feel we can de-risk and make pretty good wells without it. So, again, it's a give-and-take. I mean, I go into the president's office, and he knows I want a pilot hole at all times. So --

Q. Can you speak a little bit about the -- do you run case open-hole logs --

A. Yeah. We'll run a pretty robust suite of open-hole logs that we'll do the full triple combo or platform -- with standard porosity, resistivity. We'll run a litho scanner, which will give you, you know, basic mineral assemblages and help you get the total again at carbon. There will be some other more sophisticated tools to give you a sense of free fluid for your nuclear magnetic resonance tool, or GMR, or Schlumberger. Everybody has trade names for these. Free fluid, free water can help you identify more impossible oil phases as well. So we'll definitely take a robust, state-of-the-art log suite on this.

And reason we're doing this is we're trying to -- trying to look at some of the targets that look enticing but aren't quite as obvious as the ones we drilled the first time or perhaps not quite as obvious at the Wolfcamp target here. So we do -- we do drill them, but it's not always right off the bat.

Q. So would you take a considerable break between drilling and completion to analyze that data to maximize your completion --

A. Well -- and actually that's a good question because this is actually on a saltwater disposal well, so it's a really good opportunity to take the data without interfering with production. So here we can effectively take the data. We can learn a lot from it.

And the data comes in in different intervals, but you can learn a lot very quickly from the pilot hole. Some of the stuff is more detailed.

But, you know, for this well, you know, we're basically piggybacking on a saltwater disposal well, so we're not -- we're not affecting completion schedules or production schedules or anything like that. It's a good opportunity to get the rock we want. A lot of times we'll drill the deeper target and then log down into the curve on wells. So that was why I was saying earlier the Wolfcamp is a good place to test because the deeper you drill, the more you get a sense of what's happening uphole. So you're kind of getting a free look as you go by.

Q. So what would be the completion schedule for the Airstrip 2A?

A. I would have to defer that to either Mr. Byrd or Mr. Robinson on that.

Q. You testified earlier that for the full section, you see, basically, the same development potential in very rough parameters as what you see on this well. I don't know if this a question to you, but that is part of the reason the JOA was overlaid over that entire section?

A. Well, I can answer the first part. I think the second half, I'd have to defer to, you know, Mr. Singleton.

But, you know, it's our assertion right now that things are roughly equal in the Airstrip well. There are examples, through careful mapping, when you can identify, you know, changes in the section. For example, the x-y sands that we drill, these are basin-floor fans, and certainly you can get out of the core sands, you know, in half a section. So we do careful work to try and work prospects up at the section or quarter section scale.

Q. And I think you testified earlier that AFE questions are best reserved for Mr. Byrd?

A. Yeah.

Q. With that I'll --

A. Apologies to him. We're front-loading him here.

CHAIRMAN CATANACH: I'll do mine. I have a follow-up to Mr. Padilla's question.

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. The four 40-acre tracts that are involved in the Airstrip well, what data did you actually use to determine whether those four tracts will be productive or, say, equally productive?

A. Yeah. So -- so we have two logs on the section. We have several logs off the section. So we use basically standard mapping algorithms. To do that, we pick the zone, you know. We'll do different ways to map porosity, you know, standard practice in the industry.

We do have a proprietary 3D seismic volume over there, too. So one of the things we look at is are there faults, or is there an obvious change in acoustic impedance that would maybe tell you something about increasing or decreasing porosity, and we don't see that.

And the data we have at hand, there is nothing to tell you that there is an obvious impediment or something that would change the productivity across that section.

Q. So you anticipate the thickness would be about the same across that area?

A. Yeah, we do. We do.

Q. Okay. That's all I have.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Good afternoon, Dr. Frost.

A. Good afternoon.

Q. What is a typical EUR for Wolfcamp wells? I know -- I know your best analogs are 50 miles away.

A. Yeah. They range. I mean, I think -- you know, I think it's a little bit tricky in some cases. Some will have higher GORs, but, you know, we would certainly like to see -- you know, I think the industry would like to see the UR [sic] if you were to divide it out the length of a -- of a lateral of about 100 BO, or barrels of oil, per foot of completed lateral. And I think in many places, we -- we achieve that number. We have some wells, you know, certainly that don't perform as well as we'd like, but I'm certain that all the Wolfcamp wells we've drilled are above -- above 250 in BO and EURs, or I'll say fairly certainly.

Q. I know Matador is not a -- not a small company; it's not a major international either.

A. It feels small.

Q. But I've talked to people down in Roswell, and they say, for most projects, they're looking at a 3 to 1 return on investment, and that's how they go about risk. Maybe they had some more sophisticated tools. But they want the well to pay off three times in the first four or five years.

A. Yeah.

Q. Right?

A. Yeah. And I think I would honestly leave that to Brad Robinson when he comes up, as the person who does that more than I do.

Q. So for a $6-and-a-half million well, you're right there at $50 a barrel with 4,000 EUR?

A. Yes. Yes. The economics, sir, at that are a little skinny.

Q. I'm not that great with the forced pooling rules, but they would start getting money, right?

A. Yeah. I'd have to defer on that.

Q. First few years?

A. Yeah.

Q. What's your best Wolfcamp horizontal?

A. Well, we have -- we have a couple that are over a million. I think the one that we like to talk about the most is our Dorothy White 1H that is still, I think after two years, free flowing and not on lift. So that's what an overpressured Wolfcamp well would look like. It's producing at high rates on natural flow for a long time, and we certainly hope that's the case here.

Q. Is that in your x-y sand?

A. It is. It is.

Q. So not exactly the same thing?

A. No.

Q. Well, I've kind of gotten the impression that if this Wolfcamp wells fails, you would probably look

uphole?
A. Well, I think we would, and I think we would take the data that we collect from this well to understand if it fails, why and how can we -- how can we learn from it. And we don't view, if this well fails, as a condemnation of the Wolfcamp in the northern part of the Basin at all. So we hope that it succeeds.
Q. So that if you can't, you'd go uphole and kick off the 3rd Bone Spring or something like that?
A. We -- we have never done that before. Typically when we -- when we drill a lateral, we stick with that target, to my knowledge. And I'd defer, again, to Mr. Byrd or Mr. Robinson on that, but I'm not certain that we'd come uphole and drill another lateral off the existing wellbore.
Q. What is the typical EUR in that area for the Bone Spring?
A. It ranges. There are some to the north that are roughly in the 150, about 200 range, and then there are some down to the south that improve pretty dramatically up into the 500 range. So it varies pretty dramatically across that area, and that's one reason we feel like there's -- there's risk associated with that part of the Basin, is that you're -- you know, if you think of a slope coming down from the shelf edge, you're

kind of at that highest rate of change. So that's where reservoir units can change pretty quickly and things thin pretty quickly.

So, you know, in the Bone Spring, I know stepping up a couple miles can make a pretty big difference. There is a well called, I believe, the Acobra [phonetic] that Concho drilled that's quite a nice well. And if you look at their well three miles to the north, it's been quite a poor performer, and it tracks that general thickness of that sand body.

Q. It's not immediately overlying the 3rd Bone Spring -- 180, I think you said?

A. Yeah. I'm not sure on the exact numbers. I think, you know, some of these wells have struggled to produce a lot even in a couple years.

Q. It's pretty close to break even, right?

A. Oh, I think -- well, I wouldn't want to comment on that.

Q. You basin model?

A. Pardon? Yes.

Q. Do you do that in-house, or is that farmed out?

A. We do. We do it in-house, but we also worked with recognized industry experts on that. We've participated in a number of consortia projects, so our --

Q. Schlumberger? Petromod?

A. No. These are -- we actually use a derivative of Petromod in-house, but we've chosen to work with two geochemists out of Denver, a guy called Doug Waples and a guy called Doug Neese. Both of these guys -- Doug Waples has been in the modeling business for a long time. And basically what we've done is we've used the study that they put out to really kind of put the guardrails on or, you know, the lane striping on to figure out the basic parameters. And then we take those and apply them to offset wells from there. They're oil wells, if that makes sense.

Q. Primarily 1D or --

A. Yeah. These are 1D. Yeah. I would love to --

Q. And the cross section is 2D? You've got a 3D survey.

A. Yeah. No. We haven't -- with basin models, we haven't, but we've certainly analyzed the 3D survey front and back.

You know, I think Matador has a lot of aspirations for technical work we'd like to do. Ultimately, it kind of comes down to the fact that we have a staff of, you know, less than ten geoscientists.

Q. I'm looking again at a petroleum model --

A. Yes.

Q. -- and I'm trying to look at a wildcat formation, I'm going to be trying to determine how well it predicts other things up and down the hole?
A. Yes.
Q. So you have a lot of data and a lot of control in the 3rd Bone Spring. You're hitting your porosity, for example, that we know in the Wolfcamp.
A. Yeah.
Q. How close are you getting to porosity?
A. You know, we don't really model porosity as much. You know, we'll track -- we'll track the --
Q. Sure. That's one of the things that you can measure against a modern log --
A. It is.
Q. -- how well did you predict that.
A. Yeah. You know, in some cases, we -- we'll track organic porosity development. That does match pretty well in many cases. We certainly will match to GORs. We'll certainly match to thermal maturity where we have the data, and we often do a good job in that space.
Q. So how well does the model predict the 3rd Bone Spring, for example, that's right above that?
A. Yeah. We haven't -- we haven't gotten that level of detail with the modeling. I'm personally

having a lot of exposure to some of the diagenesis guys. I'm a little bit uncomfortable from drawing big inferences on porosity development from 1D basin models.

Q. So the thermal maturity is your biggest wild card here?

A. Yes.

Q. I mean, you've got the basin models. You should be able to track that with some level of confidence.

A. And that's right. That's why we say we're pretty close. From what we know, we're pretty close to where we want to be. But I think one of the things that's really come out in the industry in the unconventional sense is when you drill an x-y target, you're drilling a little carrier bed adjacent to two source rocks. So you're drilling a mineral matrix. It's kind of normal sandstone porosity. Granted, it's what we would consider normal sandstone porosity. It's not --

Q. It looks like Avalon Sand or something like that?

A. Yeah. Exactly. So it's a low permeability, low contrast sand. But when you step into the source rock, you now actually have to be very concerned with the amount of bitumen, which we would kind of define as insol- -- or soluble but relatively immobile oil. And it's been our experience, when you're in the earlier part of the oil window that you're clogging your pore network with bitumen. So we do care a lot about thermal maturity, and that's probably the one that I could be in on the most.

Q. So when you're doing this modeling, you're looking at this Wolfcamp interval as being the source rock for the area?

A. We are. I think that's still a little bit open. We do quite a bit of oil fingerprinting, so we will fingerprint, produce the oil, and then we will also extract oil from various source rocks. Unfortunately, for the Wolfcamp A, we don't have good source rocks here.

The other thing, as it sounds like you know, from basin modeling, is that if you have sulfur in your kerogen, potentially that 1.0 window is a little less significant because those source rocks will mature sooner.

Q. Right.

A. So there's -- there's a lot of stuff we have to figure out. And we're trying to knock out the big-picture risk factors the best we can, and, unfortunately, these are the tools we have to use.

Q. But you have that all the way back to deposition and then track depth and burial and temperature?

A. Yup. Yup. We look at all the tectonic phases that have passed over this Basin for I guess whenever the Ellenburger was deposited some 400 million years ago onwards.

Q. Commissioner Padilla touched on your logging program. What about the quality of the core when you drill these wells? Do you just acquire sidewall or --

A. No. We take whole core. We have a -- we have a lower Wolfcamp prospect north of here in the Tatum Basin. We recently acquired about 370 feet of core and a full log suite on. We have other wells, a well called Ranger 12, which, again, would be a Wolfcamp D well. We took about, I think, 150 feet of core there.

Again, it kind of depends on what we're trying to answer. If it's something where we feel like the reservoir units are finely laminated and very heterogeneous, they're going to be alias [phonetic] by logging, and that's the place where you want core.

Q. So I'm a geophysicist. I completely understand the desire to gain information.

A. Yeah.

Q. But I also understand they're interested in not spending $250,000 on a science experiment necessarily --

A. Right.

Q. -- that may or may not benefit them.

So if Matador were asked to join this JOA from somebody else --

A. Yes.

Q. -- to do the same thing, what would your advice be to them?

A. Well, we have in other cases. I mean, we would -- I think we would look at what information is provided. If we weren't comfortable with the level of information provided, we would -- we would look to see -- have discussions with the geoscientists or the engineers on that.

I honestly view participation with other operators as a positive. I feel the more people that we work with in pooling scenarios, the more we learn about what our competitors do. And in some ways, you know, a scenario like this, it's a pretty -- I mean, for a company like Matador, it's a relatively inexpensive way to get a look at something. So by participating, you learn through your competitors as well.

Q. So what is your measure of success for that 25 percent confidence?

A. I believe we defined it as a well that would produce an EUR of 400 BO --

Q. Three to four ROI --

A. Yeah.

Q. Okay. So what's the -- give me a different confidence in here. If it's 75 percent, do you make some oil?

A. Yeah. I mean, we've yet to drill a well that hasn't produced oil. You know, it's not like the conventional sense, where you come to something and you're just getting water. You know, really, I think the -- I think the biggest issue that we see are we going to produce oil at a commercial rate? And sometimes -- sometimes our first tests don't, but we do learn a lot by each test that we drill.

And that's again -- the Rustler Breaks example we used, as I mentioned, our first well, you know, by all accounts, it was a success. It wasn't quite what we expected, and we took a hard look at that. You know, we analyzed cuttings, did a lot of work with the geochemists to figure out where we thought the best zones were, and lo and behold, you know, we came in and drilled a, we feel, number of successful wells out there.

So I think -- one of the things for me has been relatively eye-opening, coming from a company like

ConocoPhillips where they spend a lot money on science projects -- that was kind of my job in many ways -- and coming to a company like Matador, there is a limit of capital expenditure that you want to put on science. We would love to do more, but what that forces you to do is focus on your most important questions and see if you can be crafty about it and do fit-to-purpose work. A lot of times, as suggested earlier, we'll send people out to various core shifts. We'll analyze them. You know, it's kind of devising the right project to understand a risk and really kind of systematically check off the most bang for the buck. And we've found a lot of times that the most bang for the buck is not necessarily the most expensive thing.

So, you know, it's -- for me to say yeah, I'm okay with not always drilling a pilot hole --

Q. So 25 percent chance it's an economic success, should be mutual funds, and eventually, a few years, start to get a little bit of money?

A. Yes.

Q. And a 75 percent chance you'll maybe break even, and nobody gets money, period?

A. Yeah. I think in the most black-and-white sense, that's a fair appraisal. But we would hope that, you know, we see something in this first well that says, Okay, well, we -- we learned something, and we can hopefully do better on the next ones. And, you know, we -- as our CEO always likes to say, we try to get a little better every day.

Q. So you drill a well and it's only 25 percent, maybe even a 50 percent case, makes a little bit of money. Very high likelihood you're going to drill the next well?

A. Unless we saw something that really showed us yeah, this was a mistake, which we don't think we will, you know, there is a high likelihood we would drill another well.

Q. That's all I have.

CHAIRMAN CATANACH: Anything further?

MR. BRUCE: I didn't -- I'd like to ask some redirect I didn't ask after Mr. Gallegos.

CHAIRMAN CATANACH: Sorry. Go ahead.

MR. BRUCE: Just a couple of clarification points.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. You mentioned Dorothy White.

A. That's in Loving County, by the town of Mentone.

Q. In Texas?

A. Yeah.

Q. And you mentioned the Rustler Breaks. That's in Eddy County?

A. That is.

Q. And in your testimony, you said you make some assumptions, and you use analog data. Is it common for Matador and other operators to do that?

A. Absolutely.

Q. All the time?

A. A lot of times that's all you have. You have to rely on analog data. I wouldn't necessarily say assumptions, but I would call them hypotheses.

Q. Yeah.

A. We're trying to test the questions that we have open in front of us.

Q. And, of course, to get more data, you've got to spend more money. That's what you're getting at?

A. Yeah, we do. We'd like to think that we're, again, somewhat crafty about that. We don't always try and spend all the money right at once if there are other ways.

Q. There is always a balancing in drilling a well?

A. There is. There is.

Q. And I think you said -- in response to Mr. Gallegos, you said what you expect. And you said something, that "expect" was too strong. Your expectations in drilling are not always realized, are they?

A. Unfortunately, no.

Q. Now, regardless of the outcome of this well, not only Matador but other operators and working interest owners, we'll learn valuable data?

A. That's right.

MR. GALLEGOS: Mr. Chairman, this is leading the witness to basically -- I think Mr. Bruce is doing most of the testifying, and I don't think it's proper redirect, anyway, because it was already covered in direct.

MR. BRUCE: I'm asking questions related to issues that you asked him that I did not have a chance to redirect.

CHAIRMAN CATANACH: Go ahead, Mr. Bruce.

Q. (BY MR. BRUCE) Really, I just have a couple more.

The term "impediment" or "geologic impediment" has been used. How do you define that?

A. I think that's a tough one to define. I think at this scale of prospecting, we would say, Is there something where the reservoir, you know, pinches out or degrades? Is there a fault that's going to preclude us from drilling? And I think it really kind of gets back to how do we expect each quarter-quarter to be fully productive. And to that end, we do think that each quarter-quarter will be productive.

Q. Do you consider this an exploratory well?

A. I do.

Q. And Mr. Singleton testified that Matador has quite a bit of acreage in the Basin?

A. That's correct.

Q. And this is the first well in the northern -- upper Wolfcamp well in the northern part of the Basin?

A. It is, yeah.

Q. And that's a large area to leave unexplored or undeveloped?

A. That's certainly how we feel.

Q. One final thing, when you drill a pilot hole, what you're seeing is a very short distance away from the wellbore, correct?

A. That's correct. You know, various well logs have a depth of investigation of, you know, 2 to 4, and some of the deeper ones will go out to a foot-and-a-half, 2 to 4 inches to 18 inches. So even a pilot hole, there are no guaranties that that is predictive.

Q. When you drill a pilot hole, does it take time to evaluate that data?

A. It does. Some -- some things you can get back quickly. Usually others take time. A lot of these things we have to put out for specialized analyses, some of the mechanic stuff. There is a whole kind of order of how analyses are performed.

Q. And I think Mr. Singleton talked about expiring term assignments, et cetera, or drilling obligations, and sometimes that might not fit into evaluating totally a pilot hole?

A. That's correct. That's correct. You know, there is some time sensitivity in this prospect where we felt drilling a pilot hole would hinder that.

MR. BRUCE: I believe that's all I have, Mr. Examiner -- or Mr. Chairman.

RECROSS EXAMINATION

BY MR. GALLEGOS:

Q. We haven't heard anything like that before. What was the time sensitivity that argued against doing a pilot hole?

A. Well, that's not the main reason we argued against the pilot hole, but we do have -- we do have wells to drill to try and hold leases. So there is a always a balance with a company like Matador that only runs a small number of rigs where every well we drill has a purpose, and sometimes data collection, unfortunately, doesn't fit into the grander schedule.

Q. But my question is was there a time sensitivity associated with this particular prospect?

A. I would have to defer to Mr. Singleton on that. But honestly, you know, some of these -- some of these analyses can take six to eight months to come back. It was our assertion that we could get a pretty good handle on what the upper Wolfcamp was capable of doing without waiting those six to eight months.

Q. Do you know of any reason the lease was in jeopardy if you took six to eight months?

A. I don't. But that would be a question for Mr. Singleton.

Q. Thank you.

CHAIRMAN CATANACH: This witness may be excused.

AARON BYRD,

after having previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you state your name and city of residence?

A. Aaron Byrd, Dallas, Texas.

Q. And who do you work for, and what do you do for them?

A. Matador Resources. I'm a senior staff drilling engineer and a completions coordinator.

Q. What are your responsibilities at Matador?

A. I manage the completions team. I also advise the drilling team on day-to-day issues, as well any major issues that arise in the drilling department.

Q. And have you previously testified before the Division and been qualified as an expert in drilling?

A. Yes, I have.

Q. You have not testified before the Commission before?

A. I'm sorry. Not before the Commission.

Q. Yeah. But I asked the Division, but you have not testified in front of these gentlemen before?

A. No.

Q. For the record, can you describe your educational and employment history?

A. I graduated from the University of Texas in 2005 with a petroleum engineering degree and a minor in business.

I went to Encana after graduating, and I spent three years training in their new-hire training program. I spent about a year in production, completions, reservoir and drilling. I then spent about three years drilling horizontal wells for them in the Haynesville Shale.

After that, I left and I went to a company in Fort Worth called Legend Natural Gas, where I worked as their sole drilling representative for their Barnett Shale assets, where we started a two-rig program, and I handled all drilling operations cradle to grave for them.

In late 2012, I moved over to Matador Resources as a senior drilling engineer, where I focused my work on the South Texas Eagle Ford project and the New Mexico and West Texas Delaware Basin project. Since then, over about the last nine months to a year, I've also taken on, basically, a completions management role and advisor to the drilling team as well.

Q. Do you hold any certifications or belong to any professional associations?

A. Yes, the Society of Petroleum Engineers, as well as the AADE, the American Association of Drilling Engineers.

Q. Are you familiar with the application that has been filed here by Matador?

A. Yes.

Q. And are you familiar with drilling and operational matters regarding this application?

A. Yes.

MR. BRUCE: Mr. Chairman, I'd tender Mr. Byrd as an expert in drilling operations and drilling operational matters.

MR. GALLEGOS: No objection.

CHAIRMAN CATANACH: Mr. Byrd is so qualified.

Q. (BY MR. BRUCE) Would you please identify Exhibit 16A for the Commissioners?

A. This is an AFE dated May 9th, 2016, and it was provided to our pool parties in accordance with the Division order hearing.

Q. And what is an AFE?

A. An Authority For Expenditure.

Q. It's an estimate?

A. Yes, sir.

Q. What -- sorry. I'm missing something here.

When you're preparing this AFE, do you have available data -- data points to estimate the cost of the oil?

A. Yeah. We have our wells in the area, offset wells in the area, which we use as data points in order to get time estimates, as well as completion estimates.

Q. Okay. Are there any horizontal wells in this

section of the formation within 30 miles?
A. Not in the Wolfcamp horizon --
(The court reporter requested the witness speak louder.)
A. Not in the Wolfcamp -- sorry -- the upper Wolfcamp horizon that we're planning to drill into.
Q. Now, there's been some comment about the original AFE sent out by Matador. What was the approximate amount of the AFE sent by Matador to the working interest owners about a year and a half ago?
A. 9.3, 9.4, I believe. Or it was 9.1, I believe.
Q. $9.1 million?
A. Uh-huh.
Q. What has happened since March --
Let me ask you first: What is the estimated completed well costs under your current AFE?
A. Just under 6.5 million.
Q. What has the -- why has the -- that's about a 30 percent decrease; is that correct?
A. Uh-huh.
Q. What has happened to reduce the well costs in that well?
A. Well, there are a lot of things that have happened. You know, we have made tremendous learning -- we've come up the learning curve quite a bit in the

entire Delaware Basin. We've renegotiated our drilling and completion contracts and just costs in general have come down.

Q. And this -- I think this AFE was in May of this year?

A. Yes.

Q. And are these costs in line with the cost of other horizontal wells drilled to this depth in this area of New Mexico?

A. I would say that they're in line for horizontal wells, from the information we have, but I would reiterate we do not have horizontal wells drilled into this horizon that we know of.

Q. Based on -- based on what you know, this is fair and reasonable, but it is an estimate?

A. Absolutely.

Q. Do the costs of this AFE, 16A, include the costs to drill, complete and equip the well for production?

A. Yes. They include drilling, completions and production costs, as well equipping the well and building a facility for the well.

Q. Does the AFE provide for a contingency clause?

A. Yes, it does.

Q. And what are the contingency costs designed to provide for?

A. Most of Matador's contingency costs are used to basically -- they're used for minor problems such as BHA failures downhole while you're drilling, maybe small losses, maybe nonproductive time from vendors, maybe, on the completion side, toe prep that's necessary, slight variations to your frac design, but nothing major, catastrophic to the well.

Q. And is there a cost fluctuation with the various service providers?

A. I don't understand the question.

Q. Okay. Let me ask it this way. Let's just turn to Exhibit 16. Can you walk us through the elements of the AFE for equipping the well?

A. Sure. As you can see here from a production standpoint, we would include the purchase and installation of the production flowline, the production tree, your production tubing, your separator, your artificial lift that actually goes downhole and any safety systems upstream of your separator.

Now, from a facilities standpoint, that would include your tangible and intangible costs from the three-phase separation, which is typically your heater treaters, your -- the oil and water storage, your metering, your gas capture and processing systems, your gas purchaser, gathering lines and any safety systems that are downstream of your separator, as well as any necessary piping for that facility.

Q. Does equipping -- okay. This is an unconventional reservoir, correct?

A. Yes.

Q. Do you need to install the surface equipment up front in order to produce the well?

A. In order to produce the well? Yes. You do need to put it up front because otherwise you'll shut the well in for two or three months. You'll pay an exorbitant amount of flowback if you don't have that facility in place beforehand, or you'll produce your oil and gas and you'll produce into a temporary tank and flare your gas, which is not something we like to do.

Q. Flaring the gas would be an unnecessary waste of that gas?

A. Correct.

Q. And this has to be done before you know whether the well -- what the EUR of the well is going to be?

A. Uh-huh.

Q. Before whether you know the well will be economic?

A. Correct.

Q. Do you consider this a necessary charge and reasonable cost, to include equipping the well as part of the cost that should be subject to a risk penalty?

A. Yes.

Q. And surface equipment can get quite expensive?

A. Sure.

Q. For a single well, do you have a range or any idea of what it costs to --

A. With the surface facility?

Q. Yes.

A. The AFE -- I think it's around 500,000. I don't know the exact number, but -- just for the -- just for the facility, it's 570,000.

Q. That's a lot of money to put up front when you don't know whether the well is going to be economic?

A. Sure.

Q. Are you familiar with the production and facility construction process?

A. Yes, I am.

Q. And could you walk us through the procedures and the timing for equipping a well for production?

A. We'll typically build a tank battery in the pipelines to produce the well soon after stimulation and in the flowback period, whenever we see, hopefully, our hydrocarbons come and the sand production has fallen off enough that you can flow into production. So typically that could begin simultaneously with the drilling operation, sometimes 30 or 60 days, even longer, the first sales.

After stimulation, we'll build and install our flowline from the facility to your wellhead, and after that, we'll set our production tree and install any artificial lift on the well as well.

Q. And what would happen if you waited to equip a well until you knew if and what quantities it would produce?

A. Like I said before, I think we would have to shut in the well for as long as that took to build, which is anywhere between 30 to 90 days sometimes, or we'd have to pay for flowback costs, which are roughly, say, $7,000 a day, for an extended period of time.

Q. To rent equipment?

A. Correct.

Q. Is it typical that these costs are included in the well AFE?

A. Yes, sir.

Q. Let's take a step back to the drilling and completion design. Turn to Exhibit 17 and please explain briefly what is depicted on that plat?

A. This is just a simple drilling completion design with the first and last penetration points, as well as the bottom-hole location noted. And we plan to drill, complete and produce the well from a standard location on the edge of the project area.

Q. The first and last perforation will be at standard locations?

A. Absolutely.

Q. What is Exhibit 18?

A. It's our more detailed drilling wellbore diagram. And what you have here is -- on the left-hand side, we have our planned -- our estimated lithology depths. Starting in the next column, we have our expected mud weights, and we'll discuss what our drilling plan will be. We have our casing diagram and casing criteria, as well as our cement information in here as well.

Q. Is this a typical drilling and completion plan for a Wolfcamp well?

A. Yes.

Q. And they differ from Bone Spring wells, for the most part; do they not?

A. Correct.

Q. How many completion stages, volumes of fluid and proppant are there in this well?

A. 21 stages; proppant would be 2,000 pounds a foot at 40 barrels a foot.

Q. And how many horizontal wells has Matador drilled from the Delaware Basin?

A. We're in the range of 75.

Q. And is there some in New Mexico?

A. Yeah. There's about 40 in Texas and 35 in New Mexico.

Q. Okay. And how many -- how many different intervals within the Wolfcamp are potentially productive?

A. Potentially productive? I don't know. I might have to defer to Ned on that one. I know that we've drilled, I think, eight or ten in the Wolfcamp, across the Wolfcamp B -- Wolfcamp B, Wolfcamp A and the upper Wolfcamp, what we term "the fat." So I think it's between eight or ten that we've drilled.

Q. From a drilling, fracing and equipping the well standpoint, do you have different sets of issues between different intervals in the Wolfcamp?

A. Yes.

Q. And within the same interval, what about different sets of issues based on which area you're in, over in Rustler Breaks or in northern Lea County?

A. Well -- so in Rustler Breaks, you typically -- I'll start in Ranger where this Airstrip well --

Q. Is Ranger in Lea County?

A. Yes. Sorry. That's what we call our prospect, the Ranger area.

So in the Ranger area, it's deeper. Let's just go with the 2nd Bone Spring well. Usually it ends up being about 1,000 to 2,000 feet deeper in that area. The rock strengths are considerably harder than over in Eddy County. We plan anywhere between week or ten days more to drill a Bone Spring well over there just because of the amount of BHA and everything else that it takes to get to a TGA planned well.

In fact, in the Rustler Breaks area, there are shallower formations. It's softer rock. And we have a whole lot better data set in Eddy and, you know, the Rustler Breaks area to plan our wells by.

Q. Even with more wells in Eddy County, are there operational issues?

A. Yes.

Q. Such as?

A. We've had -- I mean, I think we have 15 or 20 wells there. I think, as Ned said, we have 15 Wolfcamp wells, somewhere in that range. We've had sidetracks on wells that are within a half a mile of each other, in the same horizon. We've had faulting and folding in our laterals that have caused extended days on wells. We've had problems placing fluid and proppants before. We've had lots of problems even on wells in the same pad.

Q. There's always a learning process?

A. Sure.

Q. So what you're saying is that -- are the wells -- the Wolfcamp wells in Rustler Breaks, can they be compared apples to apples with the development planned in Lea County?

A. No.

Q. Even when there are nearby wells that have penetrated the Wolfcamp, could you encounter new and different risks?

A. Yes. Just like I was talking about earlier, we have a well in Rustler Breaks that we're drilling right now. It's a well that Ned was referring to in the shallow holes. We have hit major losses on that well that we didn't encounter, and we have other wells in the same section. We have wells on the same pad that are 30 foot apart that we have losses at a certain depth that you don't have on any other well. We have wells -- I can't speak to it enough -- that, you know, you can drill one well for 2 million bucks or 3 million bucks, or whatever it is, the other one -- or 18 days. The next one may be 25.

Q. How many strings of casing are you proposing for this well?

A. Four.
Q. Can you drill a Wolfcamp well vertically with three strings of casing?
A. Yes, you can.
Q. And why do you not want to use three strings in a horizontal Wolfcamp well?
A. In Matador's experience, when you try to use the mud weight that your upper Bone Spring and Delaware Mountain Group sands withstand, your well will collapse on you. We've tried to drill Wolfcamp wells below a about a 12.5 mud weight, and our wells started to collapse. And your Bone Spring and your Delaware Mountain Group sands will only withstand -- the mud weight before they will start to break down.
Q. And what are the implications if that happens?
A. You could have hole packing off, lost circulation. You can stick your BHA, you can stick your casing, and you could sidetrack your well or end up losing your well as a whole.
Q. And I was going to ask you about the cost of some of those. The items you just mentioned, what could be the potential cost of curing that little issue or big issue?
A. We've had sidetracks cost us a million and a half. We've been in wells where sidetracks have cost

about 25 days to redrill the well, where we were working as a partner in the well. We've had major losses where we've had a million and a half mud fills on Wolfcamp wells. There are major implications causing --

Q. I wasn't planning on asking you, but it's come up, about the pilot hole in this well. Do you have an estimation of what it would cost to drill a pilot hole in this well?

A. An exact number including or excluding geology?

Q. Let's do excluding first.

A. It's probably going to be pretty close to the drilling cost that's on the AFE now, because when you get horizontal, if things go well, you can drill very fast, typically, in your horizontal. A pilot hole may constitute different challenges that we may not have seen.

Q. What if you're including the geology?

A. In those times, the full log suite that we do and all the analysis, the time with the rig, probably in the range of a half million to 750-, if I had to put a number to it, on top of the 3-, I'm going to say, a pilot hole just by itself would cost.

Q. The pilot itself would be 300,000?

A. 3 million.

Q. 3 million.

One final thing, the extra string of casing you were talking about, that increases the cost of the AFE versus a Bone Spring well?

A. Correct.

Q. Turning to Exhibit 19, what are you showing in this exhibit?

A. This is a map showing Wolfcamp horizontals in the area.

Q. Before we go further, I want to ask you: Are these Wolfcamp horizontals testing the same zone that Matador is testing in the Airstrip well?

A. No.

Q. They are lower Wolfcamp wells?

A. Yes.

Q. Okay. Go ahead.

A. So you see here we see a couple different wells from Concho. EOG has three of them, and BOPCO has one. Three of these wells were built four strings, and they ended up having an average lateral of 4,170 feet, and three of the wells drilled with three strings had an average lateral of 1,600.

The three-string Wolfcamp designs were kicked off below the top of the Wolfcamp. And as long as you kick off below the top of the Wolfcamp, you should be able to have the pressure support to drill down into your Wolfcamp horizontally, because your Wolfcamp is able to withstand the 12,5 vertically that you're going to need horizontally to drill the well.

Q. But if you don't use the four strings of casing, you'll generally be in trouble --

A. Correct.

Q. -- in the Wolfcamp?

A. Yes.

Q. In your opinion from an operations standpoint, is the cost plus 200 percent risk charge justified in this case?

A. Yes.

Q. Could you tell me about some of the risks involved in drilling, completing and equipping horizontal wells in this area of southeast New Mexico? And I refer you to Exhibit 20.

A. So what we have here is we have all of our risk -- our operational risks laid out from a drilling, completions, production and operations standpoint. And what we have listed here are some of the different operational risks that we've experienced drilling the Delaware Basin, drilling the horizontals.

We've had wells that -- have encountered well control that took us 14 to 17 days to get under control. We've had wells that we've had massive lost circulation, like I stated before, that have cost us a million, million and a half in mud fills.

We've had Wolfcamp laterals that have had geosteering in the landing target zone, the faulting zone issues. What I mean by that is we've actually been rotating in a couple Wolfcamp laterals, and we've had 40-degree doglegs at a rotation, which means they're getting tossed around down there off of stringers or hard rocks or whatever is downhole that causes a basic 40-degree dogleg. BHA, bottom-hole assemblies, don't take kindly to 40-degree doglegs. So we've broken numerous BHAs when we get these doglegs, and we have to trip out and basically sidetrack the well, figure out what's going on. So we've had those issues.

We've had another well where we've had collapsed casing. The intermediate casing collapsed on us, and we had to redrill the well. From a completion and operations standpoint, over the last year, we've either had workover tubing or coil tubing stuck on about five or six wells as you're doing your clean-outs. It's something that happens, and we try to plan that it doesn't. But these operational risks are always there.

Q. And have you, yourself, experienced any of these risks in overseeing drilling and operations for Matador?

A. Almost all of them.

Q. Are the days spent on a well in order to reach production -- reach the point of production, is that a metric of success?

A. Absolutely. We've spent as many 110 days on a -- 102 days on a Wolfcamp well and 110 days 2nd Bone Spring well very close to where we're proposing this well. That's just the drilling.

Q. Drilling the well?

A. Correct. Just drilling the well.

Q. The chance of operational success, you list as about 75 percent. But despite this, is there a guarantee that you will not have a catastrophic event that would result in you not having an economic well?

MR. GALLEGOS: Mr. Chairman, this is such speculation. That's what most of this has been, and that really is improper questioning.

CHAIRMAN CATANACH: I'll allow that question.

THE WITNESS: Could you repeat the question, please?

Q. (BY MR. BRUCE) Your chance of success says 75 percent. That's a, you know, pretty moderate decent chance of success of drilling. Would you say that?

A. Yes.

Q. Does this guarantee you won't have a catastrophic event?

A. No. There is a 100 percent chance that there are operational risks anytime we're drilling out in the Delaware Basin, but it does not mean that we won't have an event that causes this well to be uneconomic, no.

Q. If you run these same items in a -- when you enter a new area, could the risk be higher?

A. Absolutely. We feel like we de-risk some of it with the wells in the area, but we still have the challenge of the lateral, the horizontal, the curve. We haven't done that yet.

Q. Are each of these risks cumulative, or could you run risk if you encounter and compound another risk?

MR. GALLEGOS: Again, Mr. Chairman, this is just speculation, what-ifs. If there is a well and actual -- that's relevant, but not just kind of what in the world could happen --

MR. BRUCE: Mr. Chairman --

MR. GALLEGOS: -- a catastrophe.

MR. BRUCE: They're contesting the risk charge. I think our witness is entitled to testify about the risks he perceives in completing a well.

MR. GALLEGOS: Yeah, Mr. Chairman, he is, but not to speculate with these questions that are asking, you know, what if the slide falls in.

CHAIRMAN CATANACH: Mr. Bruce, you may proceed.

Q. (BY MR. BRUCE) As I said, could you encounter geosteering problems? Could that aggravate another problem that you could incur?

A. They can always be compounded and have a snowball effect on your operation. If you have losses or if you have a geosteering problem, it might cause extra days even when you get done with that problem because you're now torque and drag in your wellbore. There are many instances where one problem leads to problems continuing on in the wellbore. Yes.

Q. Do you think this well will flow if and when it's drilled and completed?

A. Yes, I do.

Q. What does it mean to have a well flow?

A. Well flows, if it's bottom-hole pressure, can overcome the hydrostatic fluid column pressure applied against your reservoir.

Q. And what -- what is flowing in the well?

A. I sure hope it's hydrocarbons, but it very well could be water that's coming out of the reservoir. I don't know. We won't know until we drill it.

Q. And if it's water, that doesn't mean that it's -- it could maybe only for a month, but you don't know at this point?

A. No. It could be a month. It could be six months. It could be a couple of years. We do not know.

Q. And as of today, has Matador drilled and completed and equipped any horizontal Wolfcamp well in this area?

A. No.

Q. Are there specific risks, operational risks, because this is a step-out well?

A. There are always is. Matador's first couple wells in the Basin, we jumped around quite a bit. Our first well was up in Lea, and it was a vertical well. It was the Ranger 12. The second well we drilled, the first horizontal well, was the Ranger 33, and that was one of the wells that was 116 days. And it had a pilot hole, and it had complications and a sidetrack as well.

The next well we drilled was the Dorothy White down in Loving, Mentone, and that was one of the wells I referred to that had a 17 -- a 14 to 17-day well-control incident, to get the well under control. The next well we drilled was the Rustler Breaks 12 24 27 in Eddy County. That was the first well there for Matador, and that was our longest well to date in that area. And then we moved up to the northern part of Lea

County, and we had the Pickard and the Jim Rolf [phonetic]. The Pickard #2H took 102 days drilling, and the Jim Rolf [phonetic] was a redrill.

So absolutely, moving into a new area compounds the problems you can have in drilling a new well.

Q. If the well reaches the planned target, will you still have to constantly adjust the drill and operational plans to achieve what you are targeting?

A. Yeah. And as we discussed earlier, in our Rustler Breaks in Eddy County, we aimed for some of these smaller sand-package windows or even just a 20-foot window. And we've experienced where if you get out of that window up or down, sometimes it acts like a floor or a ceiling. So it often takes a couple of days of BHA to get back into our preferred window and continue with the well. So it adds an extended amount of time to the well. So sometimes staying in that zone is very difficult, and the geologists and drilling engineers are always working back and forth to try and do that, obviously.

Q. So it would take longer to drill and complete the well?

A. Absolutely.

Q. And you might have to replace equipment, like you're talking about, or use different equipment in such situations?

A. I guess I don't -- I mean, in a new area, we've experienced where we've produced contaminants that we were not expecting, so we've had that problem before. We've run different tubing or different surface equipment because of what came out of the wellbore. But we don't know what's up here because we haven't drilled a well in this formation.

Q. It's always time and money, is that correct, when you have a problem?

A. Yes.

Q. Have you ever -- do you know of instances where operational issues have caused a well to not pay out?

A. I would speculate here, but I would assume it's the 100-day wells that did not pay out. I'm sure Brad can answer that question.

Q. The next witness --

A. Yes.

Q. -- Mr. Robinson?

Matador is willing to take the risk of drilling this well?

A. Correct.

Q. That doesn't mean there is no risk?

A. No.

Q. Were Exhibits 16 through 20 prepared by you or under your direction and control?

A. Yes, they were.

Q. And in your opinion, is the granting of this application in the interest of conservation and the prevention of waste?

A. Yes.

MR. BRUCE: Mr. Chairman, I move the admission of Exhibits 16 through 20.

MR. GALLEGOS: No objection.

CHAIRMAN CATANACH: Exhibits 16 through 20 will be admitted.

(Matador Exhibit Numbers 16 through 20 are offered and admitted into evidence.)

CHAIRMAN CATANACH: Mr. Gallegos, your witness.

MR. GALLEGOS: Thank you, Mr. Chairman.

Let me put a copy of our exhibits up here. Here's one (indicating).

CROSS-EXAMINATION

BY MR. GALLEGOS:

Q. Mr. Byrd, if you'll find Exhibit 19 in that notebook, it's a copy of the transcript of the Division hearing in this case, and it includes your testimony. Did you find that?

A. Yup. Yes.

Q. All right. Please refer to page 113. Let's actually start this on page 105. I'm sorry, Mr. Byrd. Let's start on 105. And I refer you to line 6, in which the question was: "How many horizontal wells has Matador drilled in the Delaware Basin?" And your answer to that? What was your answer?

A. It says "over 35."

Q. "And how many of those are Wolfcamp wells?"

A. "25."

Q. Now, when asked about those wells -- let me take your attention over to pages 112 and 114. And if you'd look particularly at -- down on page 13 [sic], the six wells that you then proceed to name them, identify them, Rustler Breaks well 12 24 27, and so forth, the Guitar well, the Guitar well, Scott Walker Tiger, Tiger, so forth?

A. Uh-huh.

Q. Is that your testimony? You identified the Wolfcamp wells?

A. Yes.

Q. At page 115, I draw your attention to the end of line nine. The question was: "Okay. And was the Rustler -- the well that's named the Rustler Breaks was the first well drilled there?" And would you read your answer, please?

A. "For Matador, yes," sir [sic].

Q. "For Matador, yes, it was." Isn't that the answer?

A. Correct.

Q. Okay. Question: "So we would understand that that would not be a development well, correct?"

A. "Yeah. I would not call it a development well."

Q. "All right. What are the results of that well," you were asked.

A. I can re-read it.

Q. Yeah.

A. "Well, there were challenges with that well moving into the area. Taking what we've learned in Loving County and trying to apply it up there, there were challenges drilling and completing the wells to start with. But the -- the results of the well were very favorable."

Q. And the question, then, on page 116 was: "Can you tell us what the production is, cumulative production has been, and what the estimated reserves are?"

A. "I don't know that number," was my answer.

Q. Okay. And the question: "But very favorable results today?"

A. I said, "Favorable, yes."

Q. And I'll draw your attention down to page 117, beginning at line 11. The question was: "Okay. And each of the wells was drilled to target?"

A. "To the plan target?"

Q. Question: "To the plan target."

A. Answer: "Yes."

Q. Question: "And each of the wells was completed as planned?"

A. "Correct."

Q. Now, as far as the pilot-hole question you were asked about and gave an estimate, Mr. Byrd, have you been a participant in Matador actually drilling a pilot hole?

A. A pilot hole with a horizontal attached to it or a pilot hole just by itself?

Q. Pilot hole by itself.

A. They've always had another -- besides -- a pilot hole strictly for science, I don't believe we have. We've tried to produce a vertical well -- by getting the science from the pilot hole? Yes. We've drilled another pilot where we kicked off and went horizontal, yes. We're currently drilling a pilot hole that's associated because we're drilling an SWD, yes.

But have I drilled a pilot hole to basically say, This was a science well, and we're not doing anything from this point forward? I don't believe so.

Q. So you don't actually have any knowledge of what the cost of such a hole would be?

A. I've drilled to those depths before, so I think I have some knowledge.

Q. Okay. Give us that information.

A. Drilling down to the vertical in these horizontal wells is a big chunk of your cost, hence why horizontals development is the better way to go than the vertical, as was discussed earlier, or short quarter-section laterals.

Q. But I thought you were telling us you've had experience with a vertical well that would -- and I thought you were trying to make that analogous to drilling a pilot hole. And so my question was what was the cost?

A. I don't know the number off the top of my head, but I sure can get it for you tell. I can tell you what oil has cost us to get down to a certain depth before we kicked off sidewall [phonetic]. I can get those numbers for you on those four wells, but I don't have them off the top of my head.

Q. It seems like we're kind of mixing the subjects, so let's be clear. My question was: Have you drilled a pilot hole to obtain science? And you said something to the effect of well, we have drilled vertical wells, which would be similar. So far that's been basically the question and answer.

A. Correct.

Q. All right. So my question was if you can tell us the cost of drilling a hole of that nature. If you can't and you can get the information, we'll leave it at that.

A. I can tell you it would be very different now than it was before -- or different. I don't know the number.

Q. On the questions that were asked you about surface equipment and associated with the questions were risk, what is your definition of risk when we're referring to the cost of surface equipment?

A. The definition of risk for myself or for Matador would be not sizing it to the right scale or oversizing it, possibly not having the right equipment on location as far as needing, you know, a separator versus a heater treater or, again, needing to upscale that and any -- again, back to the contaminants. If you're producing contaminants, you would probably need

to adjust your surface equipment for that.
Q. And if it turns out the -- let's take an example. The pump jack motor is undersized. What do you do?
A. Change the pump jack motor.
Q. And that, in your definition, is risk?
A. Not building it upfront and not being prepared or having a plan in place and being prepared for a production as soon as the well is stimulated, we don't think is a good avenue for Matador. So when it comes to wanting to build it out in advance and build it 60 days prior to first production, we have to have a plan of what we think it will produce, and that's what we go by.
Q. And you go by a good bit of that based on experience of other wells; do you not?
A. We don't have another well in that formation in this area.
Q. I know, but you have other Wolfcamp wells.
As far as surface equipment, is this well going to be significantly different than any other well -- upper Wolfcamp well that you've completed?
A. We don't know the answer to that.
Q. Well, what's your plan for it?
A. The plan is to put in our tanks and our surface equipment, your separators, your heater treater, your

free-water knockouts that we expect to be needed for this Wolfcamp well, and storage and water tanks.

Q. And you have in mind what you will need and will expect to be needed for the well; do you not?

A. Correct.

Q. And you also have experience with tanks heater treaters, all the kind of equipment you expect to put on this well?

A. Yes, Matador does.

Q. And if you're -- if you're careful and competent, you're going to get equipment that's going to be used once the well is completed and starts to flow; isn't that a fact?

A. That's our plan.

Q. I'm going to refer you to -- for a moment, to your Exhibit 20 in the Matador exhibit book.

I'm sorry, Mr. Byrd. How long have you been with Matador?

A. Four years in October.

Q. Can you tell us the year that Matador began drilling the horizontal wells in the Permian Basin, either Bone Spring or Wolfcamp?

A. Yeah. I just need to think about it for a second because I drilled it. It would have been the first -- the first well was the Ranger 12. It was in

April of '13. That's the first well since I was here. I can't attest if they had another well that I wasn't aware of. But when we first moved the rig here, that was the well, April 30th.

Q. Has the average drilling time for these horizontal wells improved since 2013?

A. Yes.

Q. Can you give the Commission some idea the number of days of average improvement?

A. Number of days of average improvement, I can give you some examples. From the first wells in the area in Mentone, we had -- what used to be in the 40- to 50-day range were as the low 20s and high teens, and very similar results in our Rustler Breaks in Eddy County, where our very first couple wells were in the high 30, low 40 range, and are now in the high teens, low 20 range, as well for our Wolfcamp wells.

Q. Has it been a practice of Matador to use rigs that are particularly suited, I guess the word might be, or designed for drilling and completing Matador's wells in this area?

A. Yes.

Q. And were those rigs -- well, what is the particular -- I read something in the investor preparations, but if you could shortcut it for the

Commission. What's unique about those rigs that particularly contributes to the efficiency?

A. Well, there are a couple of things, and I'll just kind of go down a couple of them. One of them is they have a hydraulic flowline. If you've ever been out to a rig before and they've just rigged up the surface casing and rigged up their VHP, sometimes rigging up your flowline can take 18 to 24 hours. Unless it's joystick controlled, you can put it in place in 30 minutes to an hour, so essentially you're taking 18 to 24 hours off your critical path off your wells.

Another example I would give is the 7,500 psi pumps that some of our rigs come with, that all of our Wolfcamp wells have utilized because you can run -- you run harder on your bottom-hole assemblies. You can pump higher rate. And typically we'll have 6,000 psi on standby [sic] pressure. And previously, most 1,500 rigs had 5,000 psi iron pumps and everything else, so you obviously couldn't do that. So you can minimize or try to minimize the days on the well.

Q. And how many rigs are there typically of these special rigs?

A. What do you mean? For Matador or for the industry?

Q. For Matador.

A. There are three.

Q. And is it true that those rigs do drilling and completion of wells in Loving County, Texas just as they do in Lea or Eddy County, New Mexico?

A. Yes.

Q. If you would, in the Jalapeno notebook, the white notebook, flip to Exhibit 16. I'm sorry. It's 18. Do you recognize that, on the cover sheet, as being the Investor Presentation of Matador Resources Company, July 2016?

A. Yeah. Sure do, yes.

Q. Let me ask you to turn to page 14. Does that page show graphs with improved drilling times for Wolfcamp A, Loving County, Texas, beginning at 43 days down to 17.3 days?

A. Yes, sir. Matches the numbers I just gave.

Q. Okay. And if you turn to page 16, does that provide similar information for Wolfcamp A wells, Eddy County, New Mexico.

A. Yes.

Q. And there the drilling time has been reduced from 24.5 to 13.8 days?

A. Yes.

Q. Page 17, Wolfcamp B wells, Eddy County, New Mexico, drilling time from 41.3 days to 17.5 days.

A. Yeah. That's our record well. That's what our -- as our record well, yes.
Q. That's the Rustler Breaks, Wolfcamp.
Your record well -- what do you mean record well?
A. Best well Matador has in the area.
Q. Pardon me?
A. Best well that Matador has in the area for drilling times is what we're pointing out.
Q. I see. Okay.
And when we look at these bar graphs from left to right -- we don't have anything on the horizontal scale so that we know time, but if we start with the left-hand bar with the most days, what year could we understand that would be the case?
A. I don't understand the question.
Q. Okay. What I'm trying to do is we've got -- we've got five bars across in each of these and the left-hand -- and there is no horizontal scale here that says years or months. So I'm trying to ask you to help the Commission by saying if you look at that first bar on the left-hand side of the page, on each page --
A. Sure.
Q. -- where it has the highest drilling dates, could you tell us approximately what year that would be?

A. Well, the legend shows it. So the left bar would have been '14.

Q. It does?

Oh, I see it. I'm sorry. I missed that up at the -- in that box in the upper, right-hand corner is the information I was looking for. Okay.

Now, page 18. And this is, in particular, your area, isn't it, Mr. Byrd, "drilling, drilling cost improvements"?

A. Yes.

Q. And from H2 2014, what would that be?

A. Second half of 2014.

Q. Okay. The well cost was, I guess, average, 7.4 million?

A. That was just a drilling cost.

Q. The drilling cost.

A. Correct.

Q. Yeah. And that's down to -- 2015, to 3.6 dollars [sic]?

A. Correct.

Q. And let's flip over to page 20 for completion costs, Wolf area. Okay. And that has gone from, in 2014, 4.6 million to 2.4 million in 2015, correct, shown by this?

A. Correct. Yes.

Q. So then we can put together, on page 22, for the Commission, the combination of the drilling and completion cost improvements. Is that what page 22 shows?
A. That's year-end 2016, estimated for the Wolf area. Again, it's Mentone, Texas.
Q. It's what?
A. Mentone, Texas.
Q. Well, the same crews or the same rigs are doing the drilling; are they not?
A. Very different rock, but yes.
Q. So what is the explanation when you say it's different rock?
A. So the explanation is -- and Ned would probably be able to speak to the geology of it better. I can speak to what we look at from the drilling engineering standpoint -- from the drilling standpoint, is rock-strength analysis. So we look at logs -- sonic log and triple combos and do an analysis of logs in the area and figure out what the rock strength is.
If you have a lower rock strength, you should be able to drill the well a lot faster. That's what I discussed earlier. Your rock strength gets harder as you move south to north in the Basin. So the same lithology rock, 2nd Bone Spring, in Loving, Texas,

in Mentone, Texas, are way softer than they are near Hobbs, New Mexico or the Ranger area that we're discussing today. So you're not going to have the same days of drilling when you're talking about drilling a 4,000-foot day. When all the drilling engineers are trying to do is push the time down, you're not going to find that in Lea County, New Mexico like you're going find in Loving County, in Mentone.

Q. Does this presentation have any explanation, just as you've given, that the 4.5 million, the 4.8 million can't be relied on overall?

A. For the entire Delaware Basin? Is that what you're asking?

Q. That's what I'm asking, if this shows -- this is an investor presentation, so it's misleading to investors to think that drilling --

MR. BRUCE: I object to this. I object to him calling it misleading.

Q. (BY MR. GALLEGOS) The total drilling and completion cost has been reduced from 12 million to 4.8 million?

A. In our Wolf area, the total drilling and completion costs, yes.

Q. Okay. And the Wolf area includes Eddy and Lea Counties, New Mexico?

A. The Wolf area is strictly the Mentone area that we have. All of our analysts and banks know of our Wolf area. That it is our Mentone area. That's what we call our Wolf, a very tight --

Q. So somebody would have to read this as Wolf area and know it was only the Mentone, Texas area?

A. Please don't confuse Wolf with Wolfcamp. It's not. It's Wolf because of the name of the person that purchased -- that we made -- it has nothing to do with Wolfcamp.

Q. So what can you tell us about drilling and completion cost improvement? Has there been any in the Basin of the Wolfcamp drilling?

A. What I can tell you is when you move into an area, it's very common to see $12 million to build and complete a well. It's very common when you move from 43 days down to 17. It's very common to go from 41 days down to 17, 24 days down to 13.8. So this being the first well in the area -- and I can tell you that most people are drilling Bone Spring wells in that area in the range of 22 to 24 days. We're going to run an extra string of casing and drill down another 1,500 to 2,000 feet deeper, and we've got an AFE at 28.

Q. Right. All I'm trying do is -- so we have some understanding.

A. Sure.
Q. The drilling times improvement information is or is not applicable to southeast New Mexico, Bone Spring, Wolfcamp?
A. I would say for Eddy, yes. Loving and Eddy, yes. We have not drilled that many Wolfcamp wells up there. We will have another learning curve. Hopefully it's a faster learning curve because we can take what we've learned in the other two areas and apply it to this well.
Q. In drilling time and production, that's seen here, would correlate, you would agree, to overall cost to drilling and completion?
A. Sure.
Q. But we can't -- we can't go by the -- by the 4.8 million figure that's on page 22?
A. No.
Q. Do you have -- do you have the number for average drilling and completion for southeast New Mexico?
A. For operators or as a whole? I mean, we've just now moved the rig back into Lea County, so it's mainly all of our Eddy County information.
Q. Well, let's -- understand, this isn't exact. I'm just trying to get some idea. You've got drilling

time improvement. We're just trying to get some idea of cost reduction --

A. Okay so --

Q. -- if you can give us that.

A. I guess I'm not understanding the question. Please ask it again.

Q. I'm thinking in terms of what we see on Exhibit 22, going from a drilling cost of 12 million down to 4.8 million. You've told us that is not applicable to the area southeast New Mexico.

A. On page 22?

Q. So far so good?

A. On page 22?

Q. Page 22.

A. Okay.

Q. All I'm asking is if you have the information, can you tell the Commission what has been the savings that have resulted from, you know, the experience, the drilling time reduction and basic experience that Matador's had by drilling additional horizontal wells.

A. Well, when we get into multiple wells in an area, I think you can see that from late '14 to now, it's in the 40 to 60 percent range over getting into development phase.

Q. 60 percent cost of the -- 60 percent reduction in cost, drilling and completion?

A. That also falls the same time oil obviously took a -- so --

Q. And it also corresponds to, does it not, reduced charges, reduced costs for the service companies?

A. Absolutely. Yeah. That's what I was referring to. When the oil went down, all the service costs went down. At the same time, we had to tighten our belts and get better at what we do.

Q. Okay. That completes my questions. Thank you.

MR. BRUCE: May I just ask a couple?

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Just very briefly, a pilot hole -- there are a couple of different ways. You could just simply drill a vertical well to log it and look at everything?

A. Correct.

Q. But one associated with, say, a horizontal Wolfcamp well, you could drill a little lower into the Wolfcamp and come back up and drill the lateral?

A. Correct. We've done that.

Q. But there would be an incremental cost to that well by drilling down and doing the geology?

A. Yes.

Q. Now, these special rigs that you were talking about, they do cost more than just a regular drilling rig, do they not, with the extra equipment on it?
A. Yes, but the benefits far exceed the cost.
Q. And then let's -- Jalapeno Exhibit 18, although you have the cost of drilling wells in the Wolf area of Mentone -- and, first of all -- actually, turn to page 11.
A. Okay.
Q. That identifies various areas that Matador is drilling at?
A. Correct.
Q. Wolf is in Loving County, in the Mentone area?
A. Correct.
Q. Up in Lea County, it's Ranger?
A. That is correct.
Q. And Rustler Breaks, over in Eddy County?
A. It's the southern part of Eddy County.
Q. So anybody reviewing this could figure out where these wells are?
A. Yes.
Q. And even though you don't have the average well costs, you do have the improved drilling times for Wolfcamp A and Wolfcamp B wells in Eddy County?
A. Yes.

Q. And even looking at those, yup, they're going down, but obviously grosses [sic] do happen. 2016 year-to-date average is about the 2016 plan.

A. Where are you?

Q. Pages 16 and 17?

A. Correct. We're pointing out our -- pointing out our best wells but our year-to-date average, correct. 2016, that actually encompass one well that drilled fine and another well that was very close to a previous well, and it had a sidetrack associated to it.

Q. Stuff happens when you're drilling?

A. Correct.

Q. And then when Mr. Gallegos was directing you to some of your prior testimony, I think even in the prior testimony you testified how drilling in the Loving area doesn't translate to drilling in the Rustler Breaks, Eddy County area?

A. No.

Q. And that could happen, trying to translate your drilling activity up to northern -- Northern Delaware Basin?

A. Yeah. The surfaces are set in different depths, and every casing is set in different depths. We've talked about the rock strength and different challenges drilling incurred. We don't even know what the lateral will bring. So --

Q. But when you do minimize the drilling time and improve your efficiency, that doesn't benefit just Matador?

A. No.

Q. It benefits everyone on those wells?

A. Correct.

MR. BRUCE: Thank you.

MR. BROOKS: Mr. Chairman, again, I would like to ask one question of this witness.

CHAIRMAN CATANACH: Go ahead, Mr. Brooks.

MR. BROOKS: Thank you.

CROSS-EXAMINATION

BY MR. BROOKS:

Q. Mr. Byrd, you testified that a large portion of the cost of drilling a horizontal well is the vertical drilling down to where you kick off?

A. Yes.

Q. That would seem to me to indicate that if you drilled four short horizontal wells within a one-mile area, that that would cost you a whole lot more than drilling one well. Would that tend to lead to the conclusion that the four short wells would not be an economic and efficient way to develop the 160-acre that's proposed in this case?

A. That is Matador's opinion.
Q. Thank you.

CROSS-EXAMINATION

BY COMMISSIONER PADILLA:
Q. I just have a few questions. I'll try to keep it brief, since we're pushing time.
I notice the contingency on your AFE is 10 percent. Is that standard for Matador?
A. We use 10 percent on most of our new wells in a new area. As we get more into the development phase, we will take that down.
Q. You don't generally do a contingency on tangibles?
A. No. We don't see that often anymore.
Q. You mentioned flared gas and the potential for that if you didn't have facilities in place. Is it Matador's standard operating procedure to have a pipeline in place prior to testing the well?
A. We typically -- we almost always have our gas facilities and pipeline take-away ready to go when the completion is done.
Q. To reduce flaring or to --
A. Correct. We have flowback on, and we get our -- we get to sales as soon as sand allows.
Q. What's your flowback estimate for this well?

A. I could take a quick look.
Q. Take your time.
A. I don't see it in here. I would tell you Matador typically plans for between 10 and 12 days. Sometimes it's as little as a week. Sometimes it's as much as three, three-and-a-half weeks. Again, going back to us putting sand through our facility, we just want to do that. We always wait for the demand content to go down and stabilize -- we go into production as soon as we can. Typically, we would be in the range of a hundred grand for that 10 to 12 days.
Q. All in the 7,000-a-day range?
A. All -- yes, sir.
Q. What kind of lift system do you normally use on these wells?
A. On the wells in question today?
Q. Right, assuming it didn't flow back -- I mean assuming it didn't just flow.
A. Currently, today, the AFE is written up with 4-and-a-half inch casing, so we would plan to run gas leak valves.
Q. With that -- that stronger rock property you see in this area, what's your estimated frac treatment pressure for this?
A. I'll let Brad tell me if I'm wrong when I

answer this when he gets up probably tomorrow, but I think it's going to be in the .7 range. It could be up -- I'm sorry. Wolfcamp. It's probably going to go probably in the .8 range.

Q. Okay. You mentioned you've seen doglegs up to 40 degrees?

A. Yes, sir.

Q. What is your max tolerance you like to see?

A. So that's not in the curve. That was drilling a lateral and rotation, kicking along about 2,000 foot into the lateral, and all of a sudden, we basically went up from a 92 down to an 84. And that's 8 degrees. But we pulled it out and the motor was broken. Ran back in. Motor broke immediately.

So we have the engineer going, Okay, this is not okay. I went in there with a straight-hole assembly and an MWD, a roller cone, drilled it out another 200 feet, came back and took check shots and just worked our way into this and determined that the 8-degree dogleg happened over a 20-foot interval. No BHA that we use today handles that. It will break every time.

So we ended up going back to a point in the well and basically doing a -- doing basically what we did today -- wow -- a sidetrack underneath. I really,

really can't think of the name of it right now. So we ended up sidetracking the well and just drilling around it. What we did is we drilled up to that faulting spot again. We went ahead and just slowed down and tried to slide at the angle in which it was kind of -- it kicked us to prior to, and we got through probably a 10-degree dogleg and drilled on the TD. That's happened a couple of times in that area, actually.

Q. Your high-risk -- high-risk potential categories, I guess, your lost circulation, geosteering and pipe stuck during drill-out, can talk about the potential for that in this proposed well?

A. Yeah. So let's flip to that if we can here. So we've had a couple times where drilling a Wolfcamp well -- depending on the area, like I said before, you need about a 12,5 to handle mud weight. We've seen sometimes where you might hit a fracture zone and you might hit something that you just have losses. Even though the well's not flowing before that, you hit a zone that will take your money, and it'll just take 10,000 barrels, 5,000 barrels a month. You multiply that out on your oil base, mud charge, and it ends up being a million, million and a half mud fills that we were discussing. And it can also lead to whole collapse, packing off later on. Those are the types of issues that can compound, like Jim and I had discussed earlier.

What we had talked about also was geosteering in the laterals. Because typically when we aim for these small windows, there have been numerous times that we've gotten below or above one of the windows. And trying to get back into it, what it will do is it will bounce it off -- it will bounce it off, and you have to attack it with a higher-degree angle with your BHA and your bit downhole than your bed dip in order to break through it and get back in your zone. We've had to use as many as four BHA changes to get back into zone, meaning that's a full trip from, let's say, 14,000 feet, you know, in probably 18 to 24 hours to do that to get back in. So that can add costly time to your well.

Q. So do you see casing problems trying to run casing through those kind of hold?

A. I will tell you that Matador is very good at getting casing to bottom, and we have not seen that problem, no.

Q. You talked about unexpected contaminants that could cause problems. Can you give us some kind of example of what you seen and where you've seen it?

A. So we drilled a well in what we term our northeast Loving County. It's real close to the Texas-New Mexico border and by the Central Basin Platform. So it's right in the area, and we drilled a new horizon. And nothing had told us that we were going to run into H2S or CO2. I don't know the exact numbers, but we had to modify our tubing design and other things because of what was coming out of the well. But we were one of the first people in the area to test that.

Q. And you talked briefly about pilot holes and not coming back uphole. I'm assuming you're not going down, pumping back up and then kicking off out of them. You're using just whatever data you get out of the vertical extent of the well?

A. So we've had a couple vertical wells. We've had, I believe, two vertical wells -- we now have an SWD -- where we've kind of incorporated pilot holes and science into them. We have also done a couple where we've drilled down, cemented them back and went out horizontally.

Q. Are you using whipstocks or anything for those?

A. I don't think my management will ever let me run a whipstock again because two of those -- the times we ran whipstocks, we cemented them in place due to hiccups, and those were two of the 100-day wells we had.

Q. Relating to the battery for this proposed well, what are you planning that battery based on? There was some talk from Mr. Gallegos about how you estimate that. I'm wondering, for this well in particular, what are you going to put out there?

A. I don't know the number of tanks, but I will tell you that, you know, we'll have our -- we'll have our separator, two-stage -- our two-phase and our three-phase being the heater treater. We typically run a free-water knockout, like I discussed. I do not know the number of tanks. I would assume it would probably be in the eight to ten number range to handle our total fluids, oil and water.

Q. Oil and water?

A. Yes, sir.

Q. Okay. And last question: You mentioned getting a coil tubing stuck, if I remember correctly?

A. Again, nightmares, but yes.

Q. Is that generally what you're using for drill-out?

A. Yes.

Q. Coil tubing?

A. Yes.

Q. Why?

A. I would say, on the Delaware Basin side, often on the Wolfcamp well, you're dealing with pressure. And if you're going to deal with pressure with a stick-pipe unit or a cooler unit, you're going to be doing a snubbing unit operation most of the time. But a coil has, you know, their BOPs and their hydraulic injector head, which accommodate for 2- to 4,000-pound wellhead pressure sometimes with, you know, different Wolfcamp wells across the our Basin.

Q. So that's pretty standard?

A. 95 percent of what we do is coil tube.

Q. Great. Thank you.

A. Yes, sir.

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. Mr. Byrd, at what point do you start to purchase and install surface equipment? Is that prior to the spud of the well?

A. We'll purchase it as much as a quarter to 90 days in advance. And typically when drilling rate starts drilling, that surface construction -- the construction of the production pad is going at the same time, simultaneously.

Q. Same time.

Did you participate in putting together the new AFE for this well?

A. I reviewed it. I did not personally do it myself, no.

Q. I did not see in the AFE the number of days that you project to be drilling on this well.

A. I looked at it. It's not on the AFE. It's 28.

Q. 28?

A. Yes, sir.

Q. And did you -- did you participate in that part of it, to determine how long it would take to drill the well?

A. I reviewed it with the guys, yes, but they put the AFE together.

Q. I'm curious how 28 days was determined?

A. So our fastest Bone Spring well in the area, I believe spud release is in the 22- to 24-day range. We have about three or four, and that's a Bone Spring well. That goes back to what I was saying before. We have to run another string of casing, and it's usually about 10-, 11,000 feet of 7-inch, all in. And you're laying down your 5-inch, picking up your 4-inch, and changing your mud solution from waterbase to oil-based mud. Usually that takes about three, three-and-a-half days. And we figure the lateral, plus running the -- 22 to 24 brand-new interval we haven't drilled before, adding on top of our best Bone Spring in the area with the harder rock, let's give it 28. 28 I feel is pretty aggressive

for the first well, to be quite honest with you.
Q. So how many wells have you actually drilled? How many horizontal Wolfcamp wells?
A. Myself?
Q. Well, I mean with the company.
A. Matador's about 50-plus, 53, I believe.
Q. So out of those 53, how many -- how many have encountered problems that have resulted in the substantially more cost than anticipated; do you know?
A. I don't know the number off the top of my head, but I can tell you -- I mean, I can go through a bunch of them.
Q. Well, just give me maybe an estimate. We don't want to --
A. Yeah. Probably 10 to 15, if I had to guess. I'd love to get you a more accurate number. It wouldn't take me very long. But I think that's probably pretty accurate. And when I say substantial, I mean some of them possibly adding a couple million bucks, not a couple hundred thousand. I was thinking a couple million dollars for the substantial stuff, the big sidetracks, the freezing of a wellhead, freezing of a casing to get a wellhead off, you know those things, a couple weeks or a month to figure out.
Q. Okay. So part of the risk that you -- I

believe I heard you testify that part of the risk on the surface equipment was that if you mis-size something, you have to shut the well in, which caused, I guess, delays in production. Does that -- do you believe that that harms the well?

A. Probably not, but it just adds to the expense of getting back out there and redoing all the labor and getting everything rigged up.

Q. So you don't think that would reduce the ultimate recovery from the well?

A. I'd love for Brad to speak to that, but my answer initially would be I don't believe so.

CHAIRMAN CATANACH: That's all I have.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. The installation of the equipment -- if the well didn't make any oil or made reduced amounts and you -- increment out, you would move to some other well?

A. Correct.

Q. You don't throw it away. So it's not completely sunk costs, right?

A. Correct.

Q. In fact, this well will probably be -- the equipment will be that you're not using somewhere else?

A. I don't know if we have any of that right now, to be honest with you. As Ned had pointed out, we don't have a well that's not producing hydrocarbons.

Q. So you said this particular well is about a 75 percent chance of operational --

A. Operational success.

Q. I'm sorry. Success.

What is that defined as? When is it not an operational success?

A. I think if we don't drill it down in 28 days and we have events that can make it not economic because of operational risks or losing the wellbore completely.

Q. Losing the wellbore?

A. Uh-huh.

Q. Having to redrill?

A. Yeah.

Q. And how does that compare with all of your other Wolfcamp experience? Say you get down into your Wolf area. What's your operational success rate there?

A. Back to what he was asking, we've had our 8- and $12 million wells before. We've had two wells over $15 million in the Delaware Basin. We've had, you know, numerous wells that have been up there, and almost all of them correlated back to one -- the first or -- you know, the first well in that area or one of the first handful wells in the area for Matador, so this being one of those wells. I think the risks are pretty high.

Q. So drilling is time and money?

A. Absolutely.

Q. What's your, kind of approximately, daily rig costs?

A. A rig cost is probably in the range of 20 to 22. But spud rate, depending on what you're doing, especially in the production hole, it's still upwards in the range of 50 to 65, depending on what's going on. You've got oil-based mud. You've got directional on location. Those things add up. And I'm doing an average, right, because --

Q. So 100 days, 102 days, you said? 110 days?

A. They remind me of that all the time. My nickname is "Trip."

(Laughter.)

Q. You're talking about some pretty expensive wells that probably never pay out?

A. That's exactly right. Again, my opinion. I'm sure he can speak to that.

Q. Is there a point, with that information in your back pocket, where you would pull the plug, saying it's not worth going forward, or are you always going to try to finish the well if you can?

A. I think, depending on the area, we might pull the plug and say, Hey, there's too much operational risk. I don't think there is ever, right now, an area that we don't think we can get a well down in if we had to start over and redo it. Does that make sense? I think, you know, if we ran into enough compounded issues, we might go ahead and just pull the plug and start over. But there is nowhere in the Delaware Basin that Matador doesn't think that we can get a well down, especially if we have two shots at it.

But, again, I think we would learn a lot from the well. Depending how close we were to the end, management would want to see that well to TD and get the information from it.

Q. That's all I have. Thank you.

A. Yes.

CHAIRMAN CATANACH: Anything else from this witness?

MR. BRUCE: Nothing further from this witness, Mr. Chairman.

CHAIRMAN CATANACH: Okay. This witness may be excused.

So the situation is we can go until about 2:30 tomorrow afternoon because Commissioner Balch has another engagement. I'm hoping to finish by then. I don't know, but I suggest that we start at 8:00 tomorrow morning and try and get finished up. If we can't -- I'm supposed to be in Farmington on Thursday. I may be able to get out of that. We may have to go on Thursday, possibly Friday. I'm not sure.

MR. BRUCE: I mean, we will be done -- one more witness, and we'll be done tomorrow morning, I hope.

CHAIRMAN CATANACH: Mr. Gallegos, your side of the case will take several hours?

MR. GALLEGOS: Depends how long the first witness is, but I think we've got a shot at getting finished by 2:30 or before.

COMMISSIONER BALCH: We need time for deliberation.

MR. GALLEGOS: No. Don't allow time for that.

CHAIRMAN CATANACH: We can always deliberate at a different time as long as we can schedule that amongst ourselves.

COMMISSIONER PADILLA: Bring a sandwich.

CHAIRMAN CATANACH: All right. So I guess we'll see what happens tomorrow. We'll start at 8:00 tomorrow morning.

Thank you.

(Recess 5:28 p.m.)

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, Certified Court Reporter, New Mexico Certified Court Reporter No. 20, and Registered Professional Reporter, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

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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.

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