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

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

APPLICATION OF PETROLIA ENERGY CORPORATION FOR APPROVAL OF REACTIVATION OF AUTHORITY TO INJECT IN CHAVES COUNTY, NEW MEXICO. CASE NO. 16250

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

June 28, 2018

Santa Fe, New Mexico

BEFORE: PHILLIP GOETZE, CHIEF EXAMINER
DAVID K. BROOKS, LEGAL EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, Chief Examiner, Phillip Goetze, and David K. Brooks, Legal Examiner, on Thursday, June 28, 2018, 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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APPEARANCES

FOR APPLICANT PETROLIA ENERGY CORPORATION:

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EXHIBITS OFFERED AND ADMITTED

(1:42 p.m.)

EXAMINER GOETZE: We'll go back on the record.

At this time we will call Case Number 16250, application of Petrolia Energy Corporation for approval of reactivation of authority to inject in Chaves County.

Call for appearances.

MR. DOMENICI: Good afternoon. Pete Domenici and Reed Easterwood for Petrolia.

Hello, Mr. Brooks.

EXAMINER BROOKS: Hello.

EXAMINER GOETZE: And no other appearances?

Witnesses?

MR. DOMENICI: We have two witnesses.

EXAMINER GOETZE: Go ahead, at this time, stand, identify yourself for the court reporter and be sworn in.

MR. MAXEY: John Maxey, Roswell, New Mexico.

MR. BAGBY: Jason Bagby, Rockdale, Texas.

(Mr. Maxey and Mr. Bagby sworn.)

MR. DOMENICI: May we proceed?

EXAMINER GOETZE: Please, by all means.

MR. DOMENICI: So there is a preliminary

matter. We have the exhibit book in front of you. Exhibit 1 is the proof of notice, and we do have -- we have both an Affidavit of Publication and green cards to all of the parties mentioned in the application, which are the surface owners and the other operators, and the supplemental Exhibit 1, which is the final green card, but it's all part of Exhibit 1.

Just by way of background, this application is to reinstate injection authority within the Twin Lakes Unit that has historically been prior -- previously approved, and we're seeking to reinstate injection authority for five wells where, over the history of the Twin Lakes Unit, there have been at times more than 50 injection wells. So it's somewhat of a limited first step to get -- to reinstate this reinjection and water flow purposes. So that's why the notice goes to who it goes to. Everything is within the unit, and it's very much centrally within the unit, not affecting any parties outside of the unit.

We also made and have in your book, Mr. Hearing Examiner -- we went ahead and made the application Exhibit 8. It's our record, but we thought it might come up, so we thought we would go ahead and make it an exhibit. So it's part of the book also.

EXAMINER GOETZE: Thank you.

MR. DOMENICI: With that, we would proceed with Mr. Maxey, with our testimony, if that pleases --

EXAMINER GOETZE: Go ahead. That's fine.

JOHN MAXEY,

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

DIRECT EXAMINATION

BY MR. DOMENICI:

Q. Mr. Maxey, have you testified before the OCD before?

A. Yes, I have.

Q. And have you been accepted as an expert witness in petroleum engineering?

A. Yes, I have.

Q. And did you do the work that is reflected in Exhibits 3, 4, 5, 6 and 7 of the exhibit book?

A. Yes.

MR. DOMENICI: So I would move Mr. Maxey as an expert petroleum engineer.

EXAMINER GOETZE: Well, based upon your previous appearances, yes, we'll go ahead and make him a qualified witness.

Q. (BY MR. DOMENICI) So, Mr. Maxey, can you describe the analysis you performed for purposes of supporting this application to reactivate injections?

A. Yes. I'll start with Exhibit 1. I've been engaged by --

Q. That might not be Exhibit 1, actually.

A. I'm sorry. Exhibit 3. Yeah. We had three -- two exhibits, my first exhibit, Exhibit 3.

Q. Okay.

A. Thank you.

I was engaged by Petrolia. They would like to restore injectivity in five wells in the Twin Lakes San Andres field -- Twin Lakes San Andres Unit. And as I took a brief look at the unit, the unit was actually -- the Twin Lakes San Andres field was discovered in the late '60s, and injection was started in about 1988. So this field is an old waterflood. There's been some work done on it over a period of time by many different operators. So my study was treated more as a scoping study to see just kind of how this system -- this unit has performed.

So Exhibit Number 3 is a map -- cumulative oil production map for the Twin Lakes San Andres field. The field has produced about 5.6 million barrels of oil and 9.8 Bcf of gas. On this particular map, the five red circles are -- the circles are the actual injection wells that Petrolia would like to get injection authority for. It's Twin Lakes San Andres Unit 50, 59, 68, 70 and 88.

Also on this map, there is a type log. I pulled one type log off. It's a little hard to get petrophysical data off of this because -- from the unit because most of the logs in the unit are -- case hole is drawn or open hole is drawn. There are very few lateral logs or induction logs run, any kind of resistivity logs. I saw references to core data, of which I have none, so working primarily off of -- I wanted to illustrate that with the type log in one of the future exhibits.

You can see that one of the things this -- as I scoped this that this illustrates is that you have -- I'll call it an inverse C, kind of a backwards C. There is a sweet spot that runs through the northwest to the east side of the unit back to the southwest. And in Exhibit 4, you'll be able to see that injectivity kind of followed the sweet spot by the amount of water that could be placed in the unit.

Q. Okay.

A. So Exhibit 4, I wanted to look at kind of the history of the water injection on the unit. And, again, you know, the cumulative oil map basically gives me an idea of sweet spot higher perm intervals, and that's what I'm seeing on the injection map. And, you know, when you combine the two maps, what I was seeing was the effect that you're having from injection on some of the offset producers. And one of the things that -- that I noticed and that I illustrate in a later example, number one, there was some pretty quick water breakthrough after the unit was placed on the waterflood, but there was -- there's definitely some areas of pretty high perm, possibly a little fracturing, accepting a lot more water than other areas. And one of the things I could tell here was balance of injection, conformity issues probably were a problem over the life of the unit. There's been a multitude of operators. The well -- the field was originally drilled on 40-acre spacing. It's been despaced, and that varies because the patterns have been changing over time. So it's a little bit of a convoluted unit the way it is now.

Petrolia actually didn't take over operations until November of '17. So all of this has really been inherited by Petrolia.

So just to give you an idea how much water has gone in the unit, the field -- it was a pretty rapid -- rapidly developing waterflood. It didn't take a lot of time to go ahead and make the decision to set up the injectors. They were primarily converted in 1988, and the initial flood was set up. And since then, there's been 40.3 million barrels of water injected in the unit.

Q. And what does Exhibit 5 show?

A. Okay. So Exhibit 5, I wanted to illustrate the unitized interval from the documents that I had seen. The San Andres porosity, the P1 and P2 porosities, with the anhydrite section between the two, basically that's the unitized interval. It's approximately 100 feet of porosity in the San Andres. The top of the San Andres, from the OCD records, ranged to about -- from about 2,000 to 2,100 feet across the field. So this porosity develops about 5- to 600 feet into the San Andres.

Q. Will you please describe Exhibit 6?

A. Exhibit 6 is a curve on total field performance. And so it's a busy plot, but there are some things I wanted to look at. As I got an idea just of the history and injection, I looked at the performance of the field, and you can see this curve starts in about 1969. You can see the well count. All these curves are labeled. The blue well count, increasing well count, until about, oh, '83, when you reach the max well count and you reach peak oil.

You can see the water injection in purple. That's labeled. That was initiated in '88, and you've got about 18 years of consistent injection in this unit.

And you didn't see a big peak in oil production on the response, but you did see a pretty good decrease in the decline. So that's a -- that's a significant response.

There was evidence of pretty high GORs prior to injection -- or excuse me -- GORs that were increasing very rapidly, so you were losing energy initially. And then like I said, you saw -- after injection was started, there was some evidence of breakthrough in some of the offsets fairly quickly. So there was directional permeability in this unit, and over a period of time, changes in the pattern -- altering of some of the patterns has helped recovery.

But the thing I wanted to point out on this curve was approximately 2008, which is 08 on the axis -- on the x-axis -- that's the beginning of the year 2008 -- you notice just prior to 2008, something was happening in the unit. And I don't know who was operating at the time, but there were wells -- a few wells went off line, and then in 2008, the thing I wanted to note, in July of 2008, WTI price was $145 a barrel. That same year, in December, WTI had crashed at $30 a barrel -- $30.28 a barrel, and you see the decline in production somewhat. Whoever was operating, obvious to me that they made a decision to start shutting in wells and cutting their costs. Injection fell off.

Production -- I would imagine, producing wells were shut in, but I cannot differentiate injection wells versus production wells, which ones were shut in. But it does definitely appear like a cost-cutting effort.

And then by 2012, you see a dramatic drop in the well count.

And then finally, I've got noted where Petrolia takes over as operator in November of 2007 [sic].

One thing I can determine from performance, we're looking at about 4.7 million barrels of oil on primary recovery from the unit. And secondary recovery, based on performance, was approximately 1.3 million barrels of oil. So, basically, you have a secondary to primary ratio of less than a third of a barrel of oil. It actually calculates .28 barrels of secondary for every barrel of primary. That's -- that's pretty low, but San Andres is low because you do have directional permeability. You have some issues with water breakthrough. I don't see large -- in southeastern New Mexico -- Texas, it's different because you have more -- you have a thicker section. But in the San Andres, Northwest Shelf-type waterfloods, I don't see high secondary to primary ratios.

So really it's all about trying to optimize your pattern, possibly change -- alter some viscosity of your injected fluid, change mobility ratio, change the pattern. And now we have horizontal drilling as a possibility for altering the way this unit's operating.

But that's -- that's somewhat brainstorming right now. Petrolia is here to see if they can get permission to put five wells back on injection.

The last exhibit I have is actually the -- is a summary curve not of the field but of the five actual wells that they would like to return to injection. And you can see that these wells came on pretty steep decline, the green oil curve. All these -- if I drop down to the well count curve at the bottom of the graph, you can see these were all drilled relatively quickly. You see a very dramatic increase in GOR. I mean, we're talking, you know, from 1,000 to 4-, 5-, 6,000 cubic feet per barrel of oil very quickly, so a dramatic loss of energy.

The wells were converted in 1988 as part of the bigger project. And, again, these wells in that 18 years of consistent injection I had on the prior exhibit, you see these are -- you know, you've got some pretty good injection, pretty flat. It's up and down, but it is flat over that period of time. And then, again, in the time period I illustrated earlier, you see a pretty dramatic falloff in injection.

And lastly I note where Petrolia actually takes over is after this unit had been mothballed and there wasn't a lot of production taking place or injection.

So one of the things in the prior exhibit I didn't discuss was the pink -- the pink symbols, and that was basically a ratio of oil produced divided by thousands of barrels of water injected every -- you know, barrels of oil produced per thousand barrels of water injected. And you can see that ratio is very flat. So there was -- the average of that ratio within that unit during 18 years was 40 barrels of oil per month were produced for every thousand barrels injected. And that's the ratio -- as a scoping project, I took that to the five wells and used to calculate what kind of cash flow could be expected if you had full injection support like existed in the entire unit.

And at 40 barrels per thousand times the average of 35,000 barrels of water per month for these five wells, you're looking at these wells giving pressure support to 1,400 barrels of oil [sic] per month or 74,000 barrels of oil a month if you use the latest sour posting price.

So will Petrolia be able to return these wells to injection and see this kind of rate? No. Right now they have virtually no production. They are working diligently to get the field back in shape, get some wells back on according to their agreed compliance order. What they need is to get these five wells on that are in the gut of the unit to start -- to help them start to redevelop pressure support so they can produce oil to generate some income.

And so what -- what I'm trying to illustrate here is what these wells generated for the unit under total -- 100 percent pressure support. So once they get these wells back on injection, they hope to start generating a fraction of this, and it's really not known because this is -- exactly what they're going to generate until they see results. This is not -- in other words, you don't have the pressure support from the other offsetting wells outside these five that they wanted to put on. So that's what they're trying to accomplish with this right now.

Q. So let me ask you a couple of follow-up questions. In your opinion, is it reasonably necessary to carry on secondary recovery operations to recover oil in this area as shown on your maps and shown as part of the application?

A. Yes. This field is beyond primary production.

Secondary production has been successful to a point -- secondary operation has been successful to a point. There was a collapse of the operation. It does appear to coincide with the collapse in the oil price, to which it never recovered. So it appears, based on the secondary to primary ratio, there is oil still in the ground. It's just a matter of trying to figure out how to get it out. The first step would be to reestablish pressure support for this field that's pretty much depleted on a primary basis.

Q. Will the use of these injection wells increase the ultimate recovery of oil and gas from a portion of this unit?

A. Yes.

Q. And is the proposed method of operation technically and economically feasible?

A. Yes.

Q. And are the estimated additional costs to reinstate this injection likely to not exceed the value that would be created?

A. That's correct. The -- Petrolia is -- is having to work on the field already. They've got issues to work with. The electrical grid, some of their producing vessels, that type of thing, they have to work on anyway. These particular wells are already -- in discussing this with Petrolia, these wells are already set up for injection. Four of the five have had MIT tests that were successful. They're ready to go back on line. It's a very simple, inexpensive process to get them back on line. One well that did not pass MIT appears to be, in discussions with Petrolia, a tuning [sic; phonetic] leak, which would be a pretty simple fix.

Q. And would the proposed injection operations in conjunction with the production -- secondary production, would it benefit working interest owners and royalty owners of the Twin Lakes Unit?

A. Yes, through recovery of additional oil reserves.

Q. And would the granting of this application have any adverse effect on the Twin Lakes Unit?

A. No.

Q. In your opinion, would the granting of this application be in the interest of conservation?

A. Yes.

Q. And would it prevent waste?

A. Yes.

Q. And would it protect correlative rights?

A. Yes.

Q. And would there be any fresh water impacted?

A. No.

MR. DOMENICI: That's all I have of this witness. I have an operational witness.

EXAMINER GOETZE: Mr. Brooks?

EXAMINER BROOKS: Well, I think this is kind of too technical for me, so I'll pass it off to you.

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. Well, I would like to revisit one thing. So we've got a history of production such that this waterflood is still active; is this correct? We've gotten everyone -- who is the designated operator of this?

MR. DOMENICI: Okay. So the designated operator for all of these injection wells and most of the producing wells is the Applicant, Petrolia.

EXAMINER GOETZE: Okay. And then the status of the unit agreement which forms this, has this been revisited with -- I believe these leases are state leases?

MR. DOMENICI: There are some state leases. This is highly private -- mostly a private unit. The application shows the unit and the ownership. That's the exhibit --

EXAMINER GOETZE: The C-108?

MR. DOMENICI: Yes. And about halfway through, so on page -- it's one of the attachments. Exhibit B shows the unit and would show the state portion.

EXAMINER GOETZE: The reason I'm asking this is because the basis -- the ability to approve injections is we still have a waterflood that's active and satisfy any terms of the unit agreement. So we would make sure that we have clarity in who is the unit operator before we move forward with approving injection authority, since they have to be pretty much the same unless they've been designated -- Petrolia been designated as the operator.

MR. DOMENICI: So just to be clear on this, Petrolia is the operator. Petrolia is under a compliance order where they brought as many wells as they could afford to bond into a compliance order. So there are some unbonded wells. Therefore, there is -- no one's able to operate those.

EXAMINER GOETZE: Okay. I just want to make sure we have continuity, because once production ceases, the unit flood ceases, and, therefore, you can't make application.

MR. DOMENICI: There has been continuity on the production.

Q. (BY EXAMINER GOETZE) Then we'll move over to: The five wells selected, Mr. Maxey, based upon their location in the unit, there will be no impact to the lateral adjacent leaseholders?

A. No. These are interior to the unit and have producers between the injectors and the unit boundary.

Q. So we have -- any type of pattern selected at this point, or is this just --

A. You know, the pattern has been a mishmash. It started off as a 40-acre five spot. If you look at Section 6 -- if you actually look at the well count, it's 30-acre spacing. Some of it's 20. Some of it's 40. If you look up in 31, it's basically 40-acre spacing, and it's a combination of five spot. And so I'm sure -- in my opinion, when they saw a breakthrough, they converted some of the wells where they had breakthrough. So you've got a combination of a line drive/five-spot.

Q. So the injection pattern was an injection pattern of opportunity, basically what they saw?

A. Exactly.

Q. Venture to guess what is going to be the ultimate recovery versus oil in place if we continue with this?

A. Well, as Petrolia -- I discussed this with the CEO just asking about future plans, and really their emphasis is on getting these five wells and trying to establish some revenue. However, one of the things that came up -- I know there is a CO2 pipeline under the unit. That is not, at the moment, really even on their radar. They know the CO2 is there. It's a possibility. Horizontal drilling is a possibility. It's not something really being considered concrete, but we've discussed, you know, the ability -- I've been involved in horizontal drilling in old units that have been flooded. I've seen the results of those. So there is a lot of opportunity in that area. It's going to take more study of the area, but that is something in a brainstorming sense that is being considered.

Q. Okay.

A. But that gets back to altering the pattern, and you have a lot better opportunity to alter patterns with horizontal wells than you do with --

Q. Okay.

EXAMINER GOETZE: Well, that's all the questions I have for Mr. Maxey today.

MR. DOMENICI: I would call our second witness, Jason Bagby.

JASON BAGBY,

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

DIRECT EXAMINATION

BY MR. DOMENICI:

Q. Mr. Bagby, what is your position with Petrolia?

A. I am Petrolia's field operations manager.

Q. How long have you been involved in operating oil fields?

A. Eleven years total, three years in construction offshore facilities, eight years in --

Q. In field?

A. Yeah, in field operations, which, after the third year, is when I got my T2 facilities operations, API certification through James Ulmer [sic; phonetic] & Associates in Lafayette, Louisiana.

Q. And you've been to the Twin Lakes field many times?

A. Yes.

Q. What I'd like you to describe is -- assuming this permit is issued, what's going to happen as far as activity that would actually produce water that would then be injected potentially to secondary recovery?

A. Right. First of all, it'll give us, obviously, some -- generate more income, oil, and also give us a place to go with our water, which we don't have now. We've been alternating wells, and obviously we can't bring them on full time because of the lack of ways to get rid of our water. It'll also enable the testing -- of where we move forward, to do communication testing, the pressures, waterflood implementation, to be able to start from being shut in to actually monitoring the -- from start to where our timers would be set as far as intermittent production versus water injection volumes.

Q. What kind of infrastructure do you have ready or available to --

A. We -- we've been working on wells off of the agreed compliance order. We soon realized we had a lot of electrical issues in the power grid. Once we started working on those, we realized the field is set up in satellites. We've recognized facility problems at the satellites. So basically what we did is we backed up and regrouped and said, "Okay, we're going to go per satellite and just group our wells off of the compliance list on a most [sic] per satellite and start from there." And that's where we started, and then we just started intermittently. Once we bring a well on, we'll run it for a couple of days, turn it off, go to the next, turn it on, turn off. I mean, we don't -- we've got one well, I think, listed under disposal or something to get rid of the water, but it's not enough to, you know, accommodate the 20 to 30 --

Q. And maybe it's obvious, but so the record's clear, how will you get water from the wells to get it in a condition where you can inject it?

A. Right. So there's a -- there's a pretty elaborate injection system set up, header system. So it's -- basically, produced water is sent back to each satellite, and then from there, it's pumped into the injection wells from the header system. And they also have the ability to bypass and isolate for wells we won't be using, you know, for obvious safety and cleanliness.

Q. How quickly do you expect to be able to take advantage of injection authority if it's acquired?

A. Pretty quickly, within two to three months. That's stretching it. Yeah, pretty quickly. I mean, the wells are in pretty good shape now. As John said, there's -- we did some pre-MIT testing. I say "we." It was just before I came, but our field guy has the records of the pre-MITs they did for the integrity of the wells. Everything -- everything is there, the flowlines, everything. The injection lines are hooked up, basically ready to go. From there, we'll start one well to make sure everything is tight.

Q. That's all I have.

EXAMINER GOETZE: Mr. Brooks?

EXAMINER BROOKS: No questions.

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. Okay. We've looked at five coming on line. Your scope of testing, what do you foresee within 2018? You're hoping to obtain information, and what's the plan after that?

A. Right. So obviously we'll get good news from the implementation of the waterflood, and from there, the plan is, I believe, my understanding is to spread out from there and purchase the existing wells from -- I believe it's Blue Sky to complete the whole field. And then there's obviously going to be some plugging in there somewhere. They did talk about drilling. That's been moved. Our plan is to basically make a complete sweep of the field, get it up and running and then decide from there what production looks like, what testing and -- waterflood, whether it's worth going in and doing some infill drilling after plugging.

Q. Hmm. Well, there is still the pending activity around the compliance order, and that will have to be considered in your application, since we still have another entity, Blue Sky, involved, and it's still in

there as an operator also, technically.
A. Right.
Q. With that in mind, are you aware that this field has an IPI associated with the increased pressure -- injection pressure increase order associated with it?
A. I believe -- I believe the allowables are around 500. Are you talking about injection?
Q. Yeah. They're up to 800.
A. Okay.
Q. And the problem we have with that is since the injection authority went away, so does the IPI.
A. Right. I don't think -- from what I've seen so far, I don't think there is going to be an issue with the high pressures. The one well we have now, it's -- I mean, it's just like a light switch, basically. We're not even really pumping into. We're gravity feeding into it. And the two wells near it, you can tell when you're flowing into it. So I don't see any pressure problems as of now anyway. I mean, it could -- it could come up.
Q. I'm just clarifying that since we've lost injection authority --
A. Right.
Q. -- that the IPI will go away with it, that

you'll be back with a 22 gradient. And with that, you'll have to work such that if you do go, you'll have to run a step-rate test.

A. Right.

Q. And since you brought up the discussion about the saltwater disposal well, that was designed contingent on the fact this well would be operated with the field coming back on line. I've looked at the history of it, and at this point, we have an issue with it because it had over 12 consecutive months with no injection, which means it loses its injection authority ipso facto. So that's something we also will have to address. It is evident at least -- I don't know who's running the shop in the field, but looking at the report, May 2016 down to January 2018, we had -- we have pressure recorded, which is amazing, but nothing injected.

A. Huh.

Q. So with that, that's something else we're going to have to consider in this order. Is it feasible for you, that without the SWD, which technically should be more of an injection well for a waterflood --

A. Right.

Q. -- that you would be able to live without it?

A. No. We would pretty much have to shut down.

We have a pretty -- pretty large facility for water, but it doesn't take long to --

Q. To accumulate?

A. Yeah. We do keep them pretty full.

Q. With the five injectors approved, would the SWD be required?

A. No.

Q. Okay. Let's see. And your electrical grid is up and running?

A. Portions of it are. That's mainly what we're working on, that and the satellites.

Q. Hopefully it will be approved by the folks in licensing and regulation, don't have the issue we had down in Eddy County. It was not properly permitted.

A. Right.

Q. Very good. I have no further questions for this witness. Thank you.

MR. DOMENICI: If I may follow up on the SWD.

REDIRECT EXAMINATION

BY MR. DOMENICI:

Q. How long have you been familiar with the actual production taking place in the field?

A. A little over a year and a half.

Q. Has SWD been down any part of that or in a

period of the disuse?

A. Not to my knowledge, but there was quite a while we went with -- you know, the power was down, and we're back to working on that. So we really didn't have any production to really have the need of getting rid of the water.

MR. DOMENICI: I'm just wondering if there might be a reporting issue.

EXAMINER GOETZE: Well, we're always sympathetic to not handing in homework.

My question would be: Would you be able to provide some sort of information to demonstrate that during that period you did not have 12 consecutive months without injection? So we will give you that opportunity and ask you to provide us either something along the lines --

THE WITNESS: Right.

EXAMINER GOETZE: -- of well information, your folks in the field, whatever. And if it is such that we do have a gap or misinformation, something not provided, we would request you update the C-115s and reflect current. And if we're going to do that, you should also do the same for any other injection, and then we will revisit that. At this point the application is for these five wells, and that's what we'll focus on.

MR. DOMENICI: Right. And we weren't planning -- to our knowledge, there is no other injection other than the SWD, but we will supplement an exhibit for this proceeding. Is that a more appropriate way?

EXAMINER GOETZE: Okay. And at this point, I've gotten most of the way through the C-108. If I need additional information, I shall give you a phone call.

MR. DOMENICI: Okay.

EXAMINER GOETZE: And you can talk to your consultant. He can supplement it through you, and we'll go that way. All right?

MR. DOMENICI: Okay. I would tender our exhibits, 1 through 8. And at the end of the exhibits is 1A, which is just the way --

EXAMINER GOETZE: Well, unfortunately, you're following in the pattern of Mr. Bruce (laughter).

We will accept into the record Exhibits 1 through 7 --

MR. DOMENICI: 1 through 8.

EXAMINER GOETZE: -- 8 and then 1A.

MR. DOMENICI: Yes.

EXAMINER GOETZE: So entered into the

record.

(Petrolia Energy Corp. Exhibit Numbers 1 through 8 and 1A are offered and admitted into evidence.)

EXAMINER BROOKS: We have a prejudice up here. We like the exhibits to be consecutively numbered (laughter), but we don't -- we have not insisted upon it consistently in the past, so if we insisted upon it now, somebody would claim that they were being mistreated. I just mention that --

MR. DOMENICI: Thank you.

EXAMINER BROOKS: -- for future reference.

MR. DOMENICI: We can just move 1A behind.

EXAMINER GOETZE: Well, you already opened your mouth in front of the court reporter, so you've got to follow through.

(Laughter.)

MR. DOMENICI: Okay.

EXAMINER GOETZE: I would also -- in the history of this field, there is a copy of the unit agreement. It does involve the State of New Mexico. I might suggest you touch base with those folks over there at the State Land Office, just get their feelings -- they're very supportive of waterfloods -- and make sure everything is satisfactory with them.

MR. DOMENICI: We have been in touch with them. They were notified -- they received notice, and they've been in contact with us.

EXAMINER GOETZE: I didn't go through your notice, so I'm guilty of that.

All right. If that's the end of this one, then we will take Case Number 16250 under advisement.

And that's the end of the docket.

(Case Number 16250 concludes, 2:25 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.

I FURTHER CERTIFY that the Reporter's Record of the proceedings truly and accurately reflects the exhibits, if any, offered by the respective parties.

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.

DATED THIS 25th day of July 2018.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2018
Paul Baca Professional Court Reporters