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:

COPY

APPLICATION OF LEGACY RESERVES OPERATING, L.P. TO INSTITUTE A TERTIARY RECOVERY PROJECT FOR THE DRICKEY QUEEN SAND UNIT, AND TO QUALIFY THE PROJECT FOR THE RECOVERED OIL TAX RATE, CHAVES COUNTY, NEW MEXICO.

CASE NO. 15255

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

January 8, 2015

Santa Fe, New Mexico

BEFORE: MICHAEL McMILLAN, CHIEF EXAMINER
WILLIAM V. JONES, TECHNICAL EXAMINER
GABRIEL WADE, LEGAL EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, Michael McMillan Chief Examiner, William V. Jones, Technical Examiner, and Gabriel Wade, Legal Examiner, on Thursday, January 8, 2015, 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

(8:26 a.m.)

EXAMINER McMILLAN: I would like to call Case 15255, application of Legacy Reserves Operating, L.P. to institute a tertiary recovery project for the Drickey Queen Sand Unit, and to qualify the project for the recovered oil tax rate, Chaves County, New Mexico.

Call for appearances.

MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe representing the Applicant. I have one witness.

EXAMINER McMILLAN: Any other appearances?

MR. BRUCE: Let's get you sworn in.

And we do have about 60 pounds of exhibits, Mr. Examiner.

(Mr. Metza sworn.)

EXAMINER McMILLAN: Okay. His qualifications? That's where we're at right now.

MICHAEL W. METZA,

after having been first duly 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. My name is Michael Wayne Metza.

Q. And where do you reside?
A. I live in Midland, Texas.
Q. Who do you work for?
A. I work for Legacy Reserves Operating, L.P.
Q. And what is your job with Legacy?
A. I'm a production engineer for Legacy.
Q. Have you previously testified before the Division?
A. I have.
Q. And were your credentials as an expert petroleum engineer accepted as a matter of record?
A. They were.
Q. And are you familiar with the matters involved in this application?
A. I am.
MR. BRUCE: Mr. Examiner, I tender Mr. Metza as an expert petroleum engineer.
EXAMINER McMILLAN: So qualified.
Q. (BY MR. BRUCE) Mr. Metza, would you identify Exhibit 1 and give a brief outline of what Legacy seeks in this case?
A. Exhibit 1 is Legacy's application for an EOR project involving the use of CO2 municipal displacement. The application covers the entire Drickey Queen Sand Unit, which is roughly 7,000 acres.

There have been numerous operators and changes to the unit area over the years. And if you will look at Exhibit 1A, which is a plat of the Drickey Unit outlined in red, it shows various symbols and colors representing the wells and a blue line of cross section that we'll talk about later.

The last operator expanded the unit to its current size in 2011 adding all of Section 9, most of Section 4 and the southeast of Section 34. The unit has 28 producing wells, three of which are temporarily abandoned and three which are shut in. Legacy has plans to drill eight producing wells and re-enter two plugged and abandoned wells and turn them into producers.

The unit has 31 injection wells, two of which are temporarily abandoned, four of which are shut in. One of the temporarily abandoned wells will be plugged and abandoned the first quarter of this year. That would be the Unit 816 well.

Legacy has plans to drill 11 injection wells and re-enter one plugged and abandoned well, in addition to converting eight existing water injection wells to CO2 and water injectors.

Q. And how long has the water injection been conducted within the Drickey Queen Unit?

A. The waterflood was started in 1959.

Our tentative drilling plans will be to set surface pipe in the anhydrite, which occurs around 1,450 feet. We'll then set production through the main Queen pay sand. The producers will tentatively have nine-and-five-eighths surface pipe and 7-inch production pipe. The injectors will have an eight-and-five-eighths surface pipe, with five-and-a-half production pipe. Both the injectors and the producers will have two-and-three-eighths internally plastic-tubing coating set on a packer roughly 40 feet above perforations in the well.

Q. Would you identify Exhibit 2 and discuss the development plan that Legacy has in mind for the unit?

A. Exhibit 2 is a plat showing different colored 80-acre injection patterns across the unit. Again, the unit's outlined in red. The blue line through the middle of the unit is another cross section. The various colors represent patterns to be developed over a period of four to five years. Our wells in this application cover the first two stages of the development for the Drickey Queen Sand Unit.

Q. And what does Exhibit 3 reveal?

A. Exhibits 3 and 3A are the required production history of the unit in graphical and in tabular form.

Q. And what is Exhibit 4?

A. Exhibits 4 and 4A are the required production and injection forecast in graphical and tabular form.

Q. And what is discussed in Exhibit 5?

A. Exhibit 5 is a general discussion of the unit's development history and its proposed project. The unit was developed in the mid- to late-'50s on 40-acre spacing. Approximately 145 wells have been drilled in the unit. The reservoir had very limited pressure support from a water leg on the east side of the reservoir or from a gas cap which occurs on the west side of the reservoir. Primary production from the reservoir was by solution gas drive and is estimated at 10 percent of oil in place.

Waterflood operations were started in 1959 on conventional 80-acre five-spot patterns. Injection peaked in 1965, 2008 and again in 2013. Oil production peaked in 1962. Water production peaked in 1968, again in 2008 and in 2013.

After peak production, waterflood continued -- waterflood decline continued until many wells became marginal and were either shut in and plugged and abandoned. By the year 2000, only one producing well remained.

Celero Energy purchased the property in 2007. They restored many wells to either production or injection resulting in the production and injection peaks in the years 2008 and 2013.

Total recovery from the waterflood operation is estimated at 28 percent of the original oil in place. Estimated recovery from CO_2 injection is estimated at 10 percent of oil in place.

Our anticipated first injection is August of 2015. Peak oil production is estimated at 2,200 barrels of oil per day or so.

Q. What is Exhibit 6, Mr. Metza?

A. Exhibit 6 is a type log of the geologic section and main Queen oil sand, which occurs at a depth of 3,042 feet to 3,060 feet on the log of Unit Well 144. The sand generally has a gross thickness of 15 to 20 feet, with a net pay thickness of 9 to 12 feet. The Queen Sand is of Permian-Guadalupian age. It overlies a silt anhydrite sequence, and the reservoir is capped by regional halite and anhydrite deposits. The regional dip is roughly 25 feet per mile to the southeast.

The reservoir is a quartz-rich, feldspathic shallow marine to subtidal deposit consisting of fine-grain to medium-grain well-sorted sands, which is occasionally semi-consolidated.

Porosities as high as 28 percent and permeabilities as high as 1,500 millidarcies have been measured in cores. The continuity across the unit of the sand -- or excuse me -- the continuity of the sand across the unit is excellent.

Q. And does the continuity reflect in your cross section marked Exhibit 7?

A. Yes. Exhibit 7 is a west-to-east cross section of six wells which covers the roughly three-mile width of the unit. The top and base of the main Queen oil sand is noted on each log, along with the current or past completion interval. The sand is well developed in each of the wells, and it's continuous across the unit.

Q. And then before we get to the C-108, what does Exhibit 8 reflect?

A. Exhibit 8, although not required, is a table of permitted water injection wells which shows the wells' API numbers, their locations, their order number and date of the order. There is one we are missing. We were unable to locate the order for the Drickey 828. It's probably moot since the well has since been plugged.

Q. Before we start on the C-108, regarding CO2, you do have the carbon dioxide available to flood this unit?

A. Correct.

Q. And I believe that Celero and now Legend [sic] is conducting carbon dioxide injection into the Rock Queen Unit and, I believe, the North Queen Unit at this point?

A. Celero Energy, L.P. started injection in the Rock Queen Unit in 2009. That unit, along with the Drickey Queen Sand Unit and the West Cap Queen Sand Unit, was sold to Legacy Reserves Operating, L.P. in May of this year. Legacy Reserves operates the CO2 flooding in the Rock Queen Unit, and it operates the Drickey Queen Unit in the West Cap Queen Sand Unit.

Q. Okay. Briefly, what is Exhibit 9?

A. Exhibit 9 is the required OCD Form C-108, and we will be covering wells in expansion one and two.

Q. Now, this is just the first couple of pages of the C-108. Did you break up the C-108 into separate exhibits to make it a little more easy to address?

A. I did. There is a lot of paper involved with this application.

Q. Well, let's start with the first. What does Exhibit 10 reflect? And the remaining exhibits, except for the notice exhibits, are pretty much the base -- or compile the complete C-108?

A. Correct.

Q. And what does Exhibit 10 show?

A. Exhibit 10 are the required well sketches and data sheets for the 20 wells in our application.

Q. And I believe you already discussed how those wells will be completed?

A. Yes.

Q. And what is Exhibit 11?

A. Exhibit 11 is the required land plat which shows the unit boundary for the Drickey Queen Sand Unit in blue. Shown in red is the unit boundary for the Legacy-operated Rock Queen Unit to the north, and the unit boundary in green is the Legacy West Cap Queen Sand Unit to the south.

Q. And what is Exhibit 12?

A. Exhibit 12 is the required area of review map for wells in our application. The wells are shaded in blue, with their combined areas of review outlined in red.

Q. And did Legacy's land department conduct an examination of the various county and other records to determine who was entitled to notice for this area of review?

A. Yes.

Q. And we will submit that data later; is that correct?

A. Yes.

We may want to set Exhibit 12 aside, since

I'll refer to it in testimony later.

Q. And what is Exhibit 13?

A. Exhibit 13 is the required table of wells in the area of review which shows the wells of a construction and completion.

Q. And it's color-coded to show what type of wells they are?

A. The pink wells are planned WAG injection wells. The green wells are planned producer redrill or re-entries.

Q. And next, what is Exhibit 14?

A. Exhibit 14 are the required P&A reports of those plugged-and-abandoned wells in the area of review. Records indicate that, for the most part, all of the wells appear to be adequately plugged and abandoned, except the Trigg Federal Number 14.

Q. And that's the first well on top of this package?

A. It is the well that has the yellow marker right on top, API Number 3000500983, located 2,310 from the south line, 1,650 from the east line, Unit J, Section 4, Township 14 South, Range 31 East.

The well was plugged in a substandard manner by LaRue & Muncy in January 1986. The well was plugged by pumping cement down the production casing and the surface casing to fill the hole to a depth of 1,025 feet, where the production pipe was apparently parted.

Now, if you'll refer to Exhibit 12, this well falls in the area of review of Legacy's planned Unit Number 316 well, which is in the northwest quarter of the southwest quarter, Section 3, Township 14 South, 31 East.

Q. That's on the southwest side of the -- toward the southwest side of the unit?

A. Correct.

Q. And how far away -- looking at the 316 well, how far away is the Trigg Federal Number 14?

A. The Trigg Federal Number 14 is roughly 2,300 feet almost due west of Legacy's planned Unit Number 316 well. However, the Drickey Queen Sand Unit Number 806 is an active pumping well producing from the Queen Sand between the Trigg Federal 14 and the planned unit well Number 316. Unit wells Number 19, 22 and 23 will also be producing wells offsetting the planned unit well, Number 316.

Lastly, there is not currently any injection directly west, south or north of the Trigg Federal Number 14.

Q. And just for information purposes, in Exhibit 14, the current wellbore sketches, those were prepared by you from data from the Division's records, correct?

A. That's correct.

Q. What is Exhibit 15?

A. Exhibit 15 is an attachment to OCD Form C-108 feeling [sic] with items Number 7, Number 8, Number 9 and Number 11 of OCD Form C-108. Legacy is proposing maximum injection rates of 1,500 barrels of water per day and 3 million cubic feet per day of CO2 per well. We're also proposing average rates of 600 barrels of water per day and 1,250 Mcf per day per well.

Alternating and varying-size slugs of produced water, along with fresh water and CO2, along with produced hydrocarbon gas, will be injected into the reservoir. The system will be closed. Produced CO2 and hydrocarbon gases will be recompressed and reinjected. Produced water, along with occasional freshwater makeup, will be reinjected.

Legacy is proposing a maximum surface injection pressure of 800 psi for produced water. The pressure is higher than the traditional 0.2 psi per foot of depth which is normally allowed.

If you will look at Exhibit 15A, we are basing our recommended surface injection pressure on the results of 25 step-rate tests which have been performed in the Drickey Queen Sand Unit and the Rock Queen Unit.

Seventeen of those tests were performed by prior operators. Most notably, the tests done in the Rock Queen Unit to the north, which is outlined in blue on the map, were performed by Celero Energy, L.P. The test towards the south end of the Drickey Queen Sand Unit, which have boxes outlined in black, were performed by a prior operator when those horizontal wells were drilled in the 1990s.

The OCD approved a unitwide surface injection pressure of 800 psi on produced water and 1,200 psi on CO2 for the Rock Queen Unit as a result of Case 14505. The OCD has also approved higher surface injection pressures by letters [sic] on the Rock Queen Unit Number 19, the Number 308 and the Number 309, along with the Drickey Queen Sand Unit Number 54, Number 55, Number 56 and Number 57.

More recently, Legacy performed eight step-rate tests on wells in the Drickey Queen Sand Unit. The results of those tests are summarized on Exhibit 15B. The individual test results for the wells are also attached to 15B. Included with 15B is a copy of Exhibit 33 in Case Number 14505, which shows the manner in which a surface injection pressure of 800 psi on produced water is corrected to a surface injection pressure of 1,200 psi on CO2.

Q. And that's the last page on Exhibit 15B; is it not?

A. Correct.

The corrections apply due to the density differences between the produced water and CO2.

Q. And so as a result, you're requesting similar rate pressure limitations, the 800 psi for water and the 1,200 psi for CO2, as in the Rock Queen Unit?

A. That's correct.

Lastly, if you'll look at Exhibit 15C, 15C is data on the freshwater wells in Section 34 of the Drickey Queen Sand Unit and Section 35 of the unit, along with a produced water sample from the Drickey Queen Sand Unit Number 28 well. Attached to that exhibit is a compatibility test of produced water from the Rock Queen Unit and the fresh water from the well in Section 35 of the Drickey Unit. This was presented as Exhibit 34 in Case 14505. Fresh water from both freshwater wells and the produced water from both units are very similar. We do not anticipate that the waters will be incompatible.

Q. Mr. Metza, based on your examination of the geologic and engineering data, is there any evidence of open faults in this area?

A. None.

Q. Or is there any other hydrologic connection between the disposal zone or the injection zone and freshwater sources in the area?

A. No.

Q. Now, one of your exhibits -- and I forget which one -- Mr. Metza, contained data on the cost of the facilities.

A. That would be Exhibit Number 1. It outlines the costs, the economics of the project.

Q. And will this project be economic?

A. Yes.

Q. And is the -- now, the units in this area, they're all -- the injection zone in all of these -- the producing zone in all of these units is the Caprock Queen pool, correct?

A. Correct.

Q. It extends outside the Drickey Queen Unit?

A. Yes.

Q. Is the unitized portion of the Caprock Queen pool in this case suitable for the institution of a tertiary project?

A. Yes.

Q. And is the project area so depleted that it's prudent to apply enhancement recovery procedures?

A. Yes.

Q. And is the CO2 project technically and economically feasible at this time?

A. Yes.

Q. And will the value of the oil recovered by unit operations exceed the project costs plus a reasonable profit?

A. Yes.

Q. And will the tertiary operations result in the recovery of substantially more hydrocarbons from the pool than will otherwise be recovered?

A. Yes.

Q. And finally, will enhanced recovery benefit the working interests and royalty interest owners in the area?

A. Yes.

Q. Mr. Metza, you already mentioned that Legacy's land department conducted a records examination to determine the parties to be notified in the area of review. Is Exhibit 16 the spreadsheet prepared by the land department regarding notification in this case?

A. Yes, it is.

Q. And is Exhibit 17 the notice letter sent out by Legacy to the locatable offset parties?

A. Yes.

Q. Are there still several outstanding green cards

that have not been returned?
    A.   As of yesterday morning, I believe we received 19. We are missing five.
    Q.   Have any of the notice letters been returned to you?
    A.   As of yesterday, none have been returned.
                MR. BRUCE: Because of that, Mr. Examiner, I would like the hearing continued for two weeks so that we can complete the notice materials.
                EXAMINER McMILLAN: This is an engineering [sic] so I would like the engineer -- since his questions will be more relevant than mine.
                MR. BRUCE: And, Mr. Examiner, I am also awaiting -- there were a few unlocatable parties, and I am awaiting the Affidavit of Publication from the Roswell newspaper, another reason to continue for two weeks.
    Q.   (BY MR. BRUCE) Mr. Metza, were Exhibits 1 through 17 either prepared by you or at your direction or compiled from company business records?
    A.   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, it is.

MR. BRUCE: Mr. Examiner, I'd move the admission of Exhibits 1 through 17.

EXAMINER McMILLAN: Exhibits 1 through 17 will be accepted as part of the record.

(Legacy Reserves Operating, L.P. Exhibit Numbers 1 through 17 were offered and admitted into evidence.)

MR. BRUCE: And I have no further questions of the witness.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. Mr. Metza, how do you spell your name?

A. M-E-T-Z-A.

Q. Gotcha.

So a typical well, you're expecting 3 million CO2s -- or 600 barrels of water and 1,250 Mcf. Is that the injection -- injection well, that's what --

A. Those are the average rates we're asking for.

Q. Okay. Those are the rates you're asking for.

A. The maximum rates we're requesting are 1,500 barrels of water per day per well and 3 million cubic feet per day per well of CO2.

Q. What about producing well? What are you expecting are those for a typical producing well?

A. I would expect the rates, in some cases, very close to what we inject. We've seen that on the Rock Queen Unit. We have wells producing nearly as much CO_2 in the offsetting injectors as they are injecting. Ultimately, the idea is to balance your injection with your offset production so you don't have wild swings in the reservoir pressure.

Q. So you have a SCADA System out there that would -- you can use it to help balance your patterns?

A. Actually our patterns are balanced by an engineer, but rates are recorded daily on the injection wells. And there are a minimum of two well tests each month on the producing well. Obviously, if we see something going on that is of interest, we'll test more often, but the facility will be in place, yet at least two tests per month on a producing well.

Q. Okay. So little pumping units on these wells?

A. No. These will all be set up to flow.

Q. Okay.

A. There will be a packer set. There will be two gas -- in the case of the production wells with 7-inch casing, there will be two capillary strings concentric to the well that are strapped alongside the tubing that inject CO_2 directly above the packer to aid in lift.

Q. Oh. So it's a gas lift -- closed gas lift?

A. Technically, it's -- it's a gas lift system. We call it gas lift assist.

Q. Okay. So you want to do -- you need to do corrective action on the Trigg Federal Number 14, and you're okay with us putting that as a condition of injection within a half mile of that well?

A. We're not recommending any corrective action on the Trigg Federal Number 14 at this time. We think, rather, we can balance our withdrawals from the wells surrounding the 316 with whatever is injecting into 316. Like I said, there isn't any other injection in that part of the reservoir at this time, and we do have a pumping well between the planned 316 and this Trigg Federal Number 14.

Q. So you have a pressure sump between your nearest injection and this problem well?

A. Correct.

Q. And you'll keep it going all the time?

A. The 806, which is the pumping well, will be on pump, or in the event it goes to flowing, we'll naturally drop a packer in it.

Q. What would it take to go into that well and fix it, the 314?

A. Ideally, you'd have to drill out cement all the way down to the casing part, and then there would be no guarantee you got past the casing part. The other option, obviously, is to drill a relief well 100 to 200 feet away from it and put it on production.

I think, in the future, if the project gets expanded to that part of the field, I would recommend that Legacy try drilling that well out, because it's -- the location of the well is an injection well. You would like to have it as an injection well.

Q. Okay. I forgot to ask initially: This unit is a federal-state voluntary unit, correct?

A. Yes.

Q. And it was last expanded in --

A. 2011.

Q. So there is no expansion since that time. Do you plan on any expansion?

A. Not at -- not at this time.

Q. Okay. That was the sixth amendment [sic] to the unit?

A. It was the sixth or seventh.

Q. So your prediction of 10 percent CO2 -- additional recovery due to CO2, is that based on analogy, or is that a model or --

A. It's based on the performance of analogous fields throughout the Permian Basin. It's an empirical correlation of injection recovery over time.

Q. You guys -- this is the first Queen CO2 injection that I know of in the Permian. So basically, your Rock Springs is your -- your Rock Queen Unit is your analogy?

A. Is our analogy. Prior to that, we looked at the Postell [phonetic] Field as an analogy, which is a little deeper. It's sandstone, Morrow sandstone, toward the Panhandle, and we use that as an analogy.

Q. Oh, really? Okay.

That was shallow Morrow in the Panhandle?

A. If I remember correctly, it run from 6,000 or so to 6,800 feet.

Q. Okay. So you're above miscible pressure here with your CO2?

A. We anticipate keeping it above the minimum miscibility pressure, which is slightly more than 1,000 pounds. We've been operating the Rock Queen Unit in the range of the 1,300 to 1,600 pounds of reservoir pressure.

Q. Okay. But you said here you're going to do some freshwater -- in other words, you're going to do some -- you need some makeup water?

A. Occasionally we have makeup water. The majority of our fresh water used out there is in our producing wells. We have another concentric string alongside the tubing, which allows us to pump chemical and fresh water down below the packer to aid in removing any salt that might be deposited from the formation water and to help in controlling the deposition of paraffin in the tubing string.

Q. So your current reservoir pressure out there -- this is an active water flow, is that correct, right now?

A. Yes.

Q. So what do you think your average reservoir pressure is as compared to what it was initially before any drilling?

A. Original core pressure was -- in my estimation, was slightly more than 1,000 pounds.

Q. Okay.

A. The pressure in the Drickey had dropped to around 700 psi in certain parts of the field. We are now just moving produced water from the Rock Queen Unit over to the Drickey to help to pressure the Drickey Queen Unit up so that we'll get it above minimal miscibility before we start injecting.

Q. Okay. So you may -- you may ramp up your water injection for a while before you get your pressure up -- before you start your CO2?

A. Correct. It's our plan to have the core pressure above minimum miscibility before we start injecting CO2.

Q. So these patterns are pretty big out here. 40-acre well density, 80-acre five-spots --

A. Correct.

Q. -- is that optimal for your pooling, or why don't you infill drill this stuff? It's pretty shallow.

A. When I worked for Celero, we did some 20-acre infill drilling, and I cannot in good conscience propose it as a matter of being economic. Certainly another operator may have the opinion it would be a wise thing to do solely for the benefit of accelerating the project, but our numbers -- our economics said otherwise.

Q. Any H2S out here?

A. Yes.

Q. So you're going reinject your gas stream after you strip out the propane; is that correct?

A. We do not strip.

Q. Okay. You just totally reinject?

A. At this point all produced hydrocarbon gas, along with whatever H2S there is, is recompressed and reinjected with -- in the short term, for a couple of years, with clean CO2, until we quit buying CO2. But there is a contingency plan on file with the Commission.

Q. Okay. What kind of H2S?
A. The concentrations are very low. It starts out at -- I've seen them as low as 20 parts per million. We may be operating at 40 to 80 parts per million at injection stream now. My -- the work I've done in the past indicated that we would probably have 500 parts per million H2S in the reinjection stream after 20 years of operating the field.
Q. How is the topography out there? Pretty flat?
A. For the most part. There are a few low spots, and then the west edge, naturally you fall off the cap.
Q. So your winds are okay out there? It keeps you out of trouble?
A. The wind study we've done said that the wind blows 58 percent of the time.
Q. Your 28 percent original in place, how much of that was due to water injection? What's your primary --
A. Primary recovery we estimated at 10 percent of original oil in place. Waterflood was an additional 28 percent of original oil in place. If you look at the production plots, this thing was a textbook example for waterflood. It performed very well.
Q. What kind of injection withdrawal ratio have you had on that waterflood?
A. Early on, it was managed fairly well. Later in

its life, it became more of a get-rid-of-the-water kind of project rather than being managed. And like I said, it had seven or eight different operators in its life.

Q. What economic limit would you look at for a producer out there? I mean, get the water cut up to a certain amount, and then you give up on it?

A. I haven't looked at the economics of an individual producing well in the Drickey Unit under waterflood, but I can tell you this: When Celero Energy operated it, we were producing 60 to 80 barrels of oil a day and doing our best to manage the produced water and we could make a cash profit on it. The waterflood itself -- restoring the waterflood at a 1 percent to one-and-a-half percent oil cut will not justify the capital expenditure involved.

Q. Did you get all your files from Celero? Did they give you everything they had; do you think?

A. I worked for Celero --

Q. Okay.

A. -- so I got everything they had.

MR. BRUCE: Can we have that off the record, please? No (laughter).

THE WITNESS: No. They were quite -- they were good-natured about it. They made sure that Legacy received all their well files.

Q. (BY EXAMINER JONES) So you are requesting the 800 psi to water and 1,200 psi for gas? Any kind of gas, whether it's CO_2 or recycled gas?

A. The recycled gas right now is running 95 percent CO_2.

Q. Okay.

A. And with the hydrocarbon in it, it will -- the addition of hydrocarbon gas will only serve to lower the density of the injected gas, so the mixture of hydrocarbon and CO_2 is actually less dense than pure CO_2.

Q. So 1,200 is a good number? Okay for you?

A. I believe so.

Q. Okay. That's all the questions I've got.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. Okay. These questions may have been asked, but I want to make sure. You're going to have the installation of an automatic shut-off equipment at the wellhead to permit the outflow of gas? You're going to have something like that?

A. We have a shutdown -- there will be a shut-in on flow lines.

RECROSS EXAMINATION

BY EXAMINER JONES:

Q. So if your flow line got knocked off, something would shut --

A. The shut-in has a -- is pressure actuated. We set the controls. If it goes up too high, it shuts in. If, say, it were to drop too low, it would shut in, but it will shut in the flow line at the well.

Q. At the wellhead?

A. At the well, yes.

Q. And it's a fenced operation; everything's fenced off there? You have any grazing going on?

A. Yes. We have grazing leases in parts of the unit.

RECROSS EXAMINATION

BY EXAMINER McMILLAN:

Q. You'll have the SCADA System?

A. Yes.

Q. Okay. And the annual testing using a blanket plug MIT for each well?

A. We do not run a blanket plug in the tubing when we do the MITs. When we do MITs, we just pressure-test the casing 500 pounds and chart it, -- injectors.

RECROSS EXAMINATION

BY EXAMINER JONES:

Q. So they do a series of external MITs?

A. Correct.

Q. And if you did -- just for argument sake here, if you did do a profile nipple or a seating nipple on your well, how long would it take for that to be eroded out by injection?

A. We actually run profile nipples in the wells. In the producing wells, there are multiple profiles. In the injection wells, there is one -- we install an on-and-off tool above the packer, and there is a profile at that packer.

Q. Okay.

A. The notion of it corroding out I don't think is relevant because it's 3/16th stainless steel. It shows to have very good wear throughout the life of these projects. I don't think we'll have the well rates capable of eroding the nipple out.

Q. Okay.

EXAMINER McMILLAN: I have no further questions.

Do you have any?

EXAMINER WADE: I have none.

MR. BRUCE: I have nothing further in this matter, Mr. Examiner. I'd request that it be continued for two weeks for notice purposes.

EXAMINER McMILLAN: That sounds acceptable.

Let's take about a five-minute break. Actually, let's come back at 9:25.

(Case Number 15255 concludes, 9:18 a.m.)

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. ______, heard by me on ________________ ______.

__________________________, Examiner
Oil Conservation Division

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, 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.

Mary C. Hankins

MARY C. HANKINS, CCR, RPR
Paul Baca Court Reporters, Inc.
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Date of CCR Expiration: 12/31/2015