

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 THE WISER OIL COMPANY FOR)
CERTIFICATION OF A POSITIVE PRODUCTION)
RESPONSE IN THE CAPROCK MALJAMAR UNIT)
AREA, LEA COUNTY, NEW MEXICO)

CASE NOS. 12,147

APPLICATION OF THE WISER OIL COMPANY TO)
QUALIFY THE SKELLY UNIT AREA WATERFLOOD)
EXPANSION PROJECT FOR THE RECOVERED OIL)
TAX RATE, EDDY COUNTY, NEW MEXICO)

12,148

APPLICATION OF THE WISER OIL COMPANY TO)
QUALIFY THE STATE "D" LEASE WATERFLOOD)
EXPANSION PROJECT FOR THE RECOVERED OIL)
TAX RATE, EDDY COUNTY, NEW MEXICO)

99 APR - 1 11:48:55
OIL CONSERVATION DIV

APPLICATION OF THE WISER OIL COMPANY TO)
QUALIFY THE STATE "AZ" LEASE WATERFLOOD)
EXPANSION PROJECT FOR THE RECOVERED OIL)
TAX RATE, EDDY COUNTY, NEW MEXICO)

and 12,150

(Consolidated)

REPORTER'S TRANSCRIPT OF PROCEEDINGS
EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

March 18th, 1999
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, March 18th, 1999, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

March 18th, 1999
Examiner Hearing
CASE NOS. 12,147, 12,148, 12,149 and 12,150 (Consolidated)

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A P P E A R A N C E S

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* * *

1 WHEREUPON, the following proceedings were had at
2 1:08 p.m.:

3 EXAMINER CATANACH: Okay, at this time we'll call
4 Case 12,147.

5 MR. CARROLL: Application of the Wiser Oil
6 Company for certification of a positive production response
7 in the Caprock Maljamar Unit Area of Lea County, New
8 Mexico.

9 EXAMINER CATANACH: Call for appearances in this
10 case.

11 MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe,
12 representing the Applicant. I have one witness to be
13 sworn.

14 Also at this time, I would like this case to be
15 consolidated for hearing with the next three cases, 12,148,
16 12,149 and 12,150. Although they involve different areas,
17 they do involve immediately adjacent areas, and the area
18 being waterflooded is the same geologic interval. And so
19 we have some common exhibits, and the testimony may be
20 similar for each project. So I would ask that they all be
21 consolidated for hearing.

22 EXAMINER CATANACH: Okay, at this time we'll call
23 Cases 12,148, 12,149 and 12,150.

24 MR. CARROLL: Application of the Wiser Oil
25 Company to qualify the Skelly Unit Area Waterflood

1 Expansion Project, the State "D" Lease Waterflood Expansion
2 Project and the State "AZ" Lease Waterflood Expansion
3 Project for the recovered oil tax rate, all in Eddy County,
4 New Mexico.

5 EXAMINER CATANACH: Call for any additional
6 appearances?

7 Okay, will the witness please stand to be sworn
8 in?

9 (Thereupon, the witness was sworn.)

10 MATT EAGLESTON,
11 the witness herein, after having been first duly sworn upon
12 his oath, was examined and testified as follows:

13 DIRECT EXAMINATION

14 BY MR. BRUCE:

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

16 A. Matt Eagleston.

17 Q. And where do you reside?

18 A. I reside in Dallas, Texas.

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

20 A. I'm a project manager for the Wiser Oil Company.

21 Q. By profession are you an engineer?

22 A. I'm an engineer.

23 Q. And have you previously testified before the
24 Division?

25 A. I have not.

1 Q. Would you please outline for the Examiner your
2 educational and employment background?

3 A. I received a bachelor of science degree in
4 petroleum engineering from Texas Tech University in 1982.
5 I've worked for several companies during the ensuing 16
6 years, I've been with Wiser for the last three, most of my
7 career working in the Permian Basin on waterflood problems.

8 Q. And does your area of responsibility at Wiser
9 include the Permian Basin of southeast New Mexico and
10 southwest Texas?

11 A. Yes, it does.

12 Q. And are you familiar with engineering matters
13 related to these four Applications?

14 A. Yes.

15 MR. BRUCE: Mr. Examiner, I'd tender Mr.
16 Eagleston as an expert petroleum engineer.

17 EXAMINER CATANACH: He is so qualified.

18 Q. (By Mr. Bruce) Now, Mr. Eagleston, we're talking
19 about basically two projects here; isn't that correct? The
20 Caprock Maljamar Unit and then the adjacent Skelly area?

21 A. That is correct.

22 Q. Okay. First, we're going to go into the Caprock
23 Maljamar Unit, or the CMU. Now, this area, if I'm correct,
24 previously received the EOR qualification when the unit was
25 expanded; is that correct?

1 A. When the unit was formed.

2 Q. When the unit was formed, excuse me.

3 A. That's right.

4 Q. And so today you are here on this particular unit
5 seeking certification of a positive production response?

6 A. That is correct.

7 Q. Let's start with Exhibit 1. Would you identify
8 that for the Examiner and tell him what it shows about this
9 unit?

10 A. Okay, this is just a map of the unit, which
11 identifies the phases that were developed when the unit was
12 formed. When the unit was originally formed in May of
13 1994, the development proceeded on a three-phase formula
14 and the certification for the EOR tax credit was granted in
15 a phase format.

16 And it was -- The original Phase 1, which is in
17 yellow, was certified at the time the unit was formed, May
18 1st of 1994. Phase 2 was certified November 8th of 1994.
19 And Phase 3 was certified October 1st, 1997. This was as
20 development proceeded and injection operations began in
21 each area.

22 The larger purple circles represent wells, infill
23 wells, that Wiser has drilled as part of a development
24 program. The red dashes indicate the waterflood patterns
25 that have been developed also in addition to that.

1 Q. Also on this map, were there any new or
2 replacement injectors drilled by Wiser as part of this
3 program?

4 A. Yes, there were several. The wells that are --
5 In order to make them more easily recognizable, we had our
6 numbering scheme, starting them with the 260. So any wells
7 that are 260, 261, 262 and so forth, were actually
8 replacement injectors. These were replacements for older
9 wells that had been plugged and abandoned or whose casing
10 integrity was such that they couldn't be used as injectors.

11 Q. Let's move on to Exhibit 2. Could you identify
12 that and give a little bit of history of this particular
13 area, which is now in this unit?

14 A. Exhibit 2 -- Page 1 of Exhibit 2 is just a brief
15 history of the Caprock Maljamar Unit area. The Maljamar
16 field was discovered in 1926. The first well was drilled
17 in what became eventually the Caprock Maljamar Unit in
18 1942. Over the next 20 years or so, development proceeded
19 on 40-acre spacing. Production peaked in 1959 on primary
20 operations.

21 Waterflooding, using 80-acre fivespot patterns,
22 was started in the area in the early 1960s. This was prior
23 to there being a unit. It was -- What is now the Caprock
24 Maljamar Unit was actually under flood by five separate
25 operators.

1 Waterflooding was successful and continued for
2 many years, but it had effectively ceased by the late
3 1970s. Wiser stepped in in 1992 and 1993 and in several
4 transactions acquired 100 percent of what is now the unit
5 area and subsequently unitized that entire area in 1994,
6 into the Caprock Maljamar Unit.

7 Production at the time that Wiser acquired the
8 properties was only 290 barrels a day, from 39 active
9 producers. There were 16 injection wells, but they were
10 simply recycling produced water; it was a disposal project
11 and not really an active waterflood at that time.

12 The facilities were in poor condition, and
13 production was nearing the economic limit. There wasn't a
14 lot of life left in the properties at that time.

15 Wiser bought the properties in anticipation of a
16 major development program, which they started in 1993 and
17 accelerated in late 1995, which included downspacing most
18 of the unit to 20-acre spacing and restarting the
19 waterflood, using 40-acre five-spot patterns. We had to
20 basically rebuild all the facilities at that time as well,
21 because they had deteriorated to the point of really not
22 being usable.

23 Production peaked at a little over 1300 barrels a
24 day following this program, and in November of 1998, the
25 date that I prepared this exhibit, the last information we

1 had, production averaged 868 barrels a day, from 68 active
2 producers, and we were injecting approximately 12,500
3 barrels of water per day into 81 active injection wells.
4 We used freshwater makeup from Conoco's system.

5 Q. Mr. Eagleston, before you move on to the second
6 page of this a couple of things.

7 When Wisner took this project over, was it at or
8 near its economic limit?

9 A. Right, yeah, it was pretty close to being done,
10 basically.

11 Q. And so if an expansion had not taken place, a lot
12 of these wells could conceivably have been plugged or
13 plugged and abandoned?

14 A. Absolutely.

15 Q. The other thing you mentioned, you said you
16 decreased spacing to 20 acres. Well spacing is still 40
17 acres out there; you were infill drilling?

18 A. That is correct.

19 Q. Okay. Why don't you move on to page 2 of this
20 exhibit and tell the Examiner a little bit about it?

21 A. Right, this is just a page that gives some data
22 broken down by phases, the number of producing wells,
23 injection wells, the amount of injection, volume, that's
24 going into each phase, and also when each phase began, as
25 far as injection is concerned.

1 I'd like to point out at this time that we did
2 spend a substantial amount of capital on the injection part
3 of the system, particularly here in the Caprock Maljamar
4 Unit, because of the fact that the facilities had
5 deteriorated to such a degree. In fact, the way we looked
6 at the program was on a pattern-by-pattern basis. We had
7 cost per pattern, recoveries per pattern, and so forth.

8 The cost per pattern, if you take the \$35-plus-
9 million, the cost per pattern at CMU was \$586,000. Of
10 that, it cost about \$325,000 on average to drill the infill
11 producing well, which means we spent approximately \$261,000
12 per pattern to refurbish and initiate injection operations
13 for that pattern. That would include the conversion or re-
14 entry of old producing wells and converting them to
15 injection.

16 In some cases we entered P-and-A'd wells. We re-
17 entered eight wells that had previously been plugged,
18 converted them to injection service, converted 50 existing
19 producers to injection service, and of course had to
20 completely rebuild the injection facilities. So, just to
21 point out that it was a substantial amount of capital
22 employed in the injection part of this project.

23 At the bottom of the page an item of note here,
24 estimated net value. This is the incremental cash flow
25 expected from the project. I used the year-end 1998

1 reserves in pricing that we just completed, and as you
2 know, we have to use year-end prices, flat, in that SEC
3 calculation, and therefore we were using \$9.35 a barrel for
4 that. That's the price we were receiving at the end of the
5 year, and at that rate it's obviously not an economic
6 project.

7 So what I did to make a fair representation of
8 the project, I used a more normal -- what I would call a
9 more normal price of \$17 oil for the rest of the project,
10 and that results in a \$7 million incremental profit.

11 Q. Was the project economically feasible when it was
12 first instituted?

13 A. Yes.

14 Q. And even right now, just on a month-to-month
15 basis, is there a positive cash flow?

16 A. Oh, certainly, uh-huh.

17 Q. Otherwise, you couldn't keep --

18 A. We wouldn't continue, right.

19 Q. Mr. Eagleston, let's move on to Exhibit 3 next.
20 What does that represent?

21 A. Exhibit 3 is simply a decline curve of the total
22 unit area. If course, prior to 1994, this would be the
23 combined production from several leases that eventually
24 made up the unit. And it just shows that we were on a
25 decline, a fairly modest decline, prior to the development

1 project.

2 The red line shows the decline, how it would have
3 continued. It probably would have cut off well before
4 actually where it's shown to be going, 2001. The project
5 probably would have been uneconomic before that time.

6 The green line shows production increasing
7 substantially above where it would have been had we not
8 done anything. The yellow line is our current forecast of
9 production.

10 Q. Do you have a rough estimate -- I know it's not
11 tabulated on this map -- of the amount of incremental
12 reserves that this project will recover over what would
13 have been recovered --

14 A. Right.

15 Q. -- if the project had not been expanded?

16 A. Right. We had estimated about 6 million barrels
17 incremental recovery from this project.

18 Q. Okay.

19 A. It works out to approximately -- Once again, we
20 talked in terms of patterns. It worked out to
21 approximately 100,000 barrels per pattern, is what we
22 anticipated being able to recover.

23 Q. Okay. And I notice that you -- really, at the
24 time you commenced the project, you substantially increased
25 the injection of water at that same time as you --

1 A. That is correct. Yeah, the injection work was
2 contemporaneous with the drilling of the producing wells.

3 Q. Okay.

4 A. And so injection ramped up at the same time
5 production did.

6 Q. What does the next batch of exhibits show, the
7 exhibits marked as Number 4?

8 A. These exhibits -- there's three of them -- they
9 are decline curves by phase. I didn't have the data broken
10 down in a format to go back to 1980, so we started in 1993
11 with these curves, and they simply show the same
12 information, broken down by phase.

13 Q. Have you seen, in your opinion, a positive
14 production response from the unit?

15 A. Yeah, we're clearly well ahead of where we would
16 have been, had the project not occurred in each phase.

17 Q. Looking at these maps, can you give an
18 approximate date when...

19 A. Yeah, I think in Phase 1, and it's not marked on
20 here, but I believe that -- and actually, you could choose
21 an earlier date, but I believe that by October 1st of 1994
22 production had ramped up to a point where it was clearly
23 and demonstrably above the trend line that was established
24 previously.

25 Q. And that was for Phase 1?

1 A. That was for Phase 1.

2 Q. What about --

3 A. In Phase 2, I would choose a June 1st, 1995,
4 date. Once again, you could choose an earlier date, but
5 that's a date that I think is pretty clearly above the
6 line.

7 And in Phase 3 we chose -- in this case, January
8 1st of 1998.

9 Q. You could again conceivably choose an earlier
10 date; isn't that correct?

11 A. That is correct.

12 Q. But the EOR certification was not obtained for
13 Phase 3 until what? In 1997?

14 A. October of 1997.

15 Q. Anything else on this exhibit, Mr. Eagleston?

16 A. Nothing.

17 Q. Okay. What does the two plots on Exhibit 5 show?

18 A. I just picked a couple of wells that are
19 representative. Caprock Maljamar Unit 167 is on the east
20 side of the unit. It's in Phase 1. Number 186 is on the
21 west side of the unit. It happens to be in Phase 3. I
22 just pulled these out as being somewhat emblematic of the
23 typical well. Of course, there's a big spread of results.
24 Some wells are better, some wells are worse. But these
25 sort of fit in the middle, so I chose them as examples of

1 performance of individual wells.

2 Q. The first page, Number 161, does that show the
3 effect of waterflooding on this well?

4 A. Yeah, 167, I think, pretty clearly shows some
5 support from water injection. There's a production
6 increase from the level, mid- to late 1996, up into 1997,
7 that I think is clearly from water injection.

8 Q. Finally, with respect to the CMU, what is Exhibit
9 6?

10 A. Exhibit 6 is a spreadsheet, a table, showing all
11 the wells that Wisser drilled in the unit, the first page.
12 It has spud dates, first production dates, some other
13 information, perforations and the initial potentials of the
14 wells. The next three pages have that same information by
15 phase.

16 Q. Now when you're drilling these wells and
17 increasing the injection, would you have -- could it have
18 been justified to just drill the infill producers alone
19 without increasing injection at the same time?

20 A. No, we don't believe so. I don't think it would
21 possible to economically drill just the infill wells. If
22 you look at the original primary recoveries for the Caprock
23 Maljamar Unit area, the average well recovered 42,000
24 barrels of oil.

25 Although we would probably have a better

1 completion procedure at this point in time than they did
2 back then, it's unlikely that we could recover 42,000
3 barrels on an infill well. There would be some drainage
4 involved, and I think it would be more likely you would
5 recover 20,000 to 30,000 barrels on an infill well in this
6 unit.

7 Q. If there had been no new injection?

8 A. If there had been no new injection, if -- simply
9 an infill project, which would not have been economical.
10 And so we looked at the infill and the waterflood, really,
11 as a combined project, difficult, probably impossible to
12 separate the two.

13 You couldn't rearrange the waterflood patterns to
14 do any good, because the previous waterflooding had
15 basically run its course, and the sweep efficiencies were
16 about as good as they were going to get using the existing
17 wellbores. So you had to add some wellbores in an d
18 rearrange the patterns to access the oil that was left
19 behind, in between the patterns.

20 So, you know, the conclusion is that out of the
21 90,000 to 100,000 barrels per pattern on average that we
22 expect to recover here, only 20 or 30 is probably from an
23 infill program. The remainder would be the effect of
24 rearranging the injection patterns --

25 Q. And increasing the --

1 A. -- and increasing injection, increasing density
2 and injection, correct.

3 Q. Okay. So in short, although it's hard to
4 separate out the effects, you really needed to drill and
5 increase injection simultaneously?

6 A. Correct.

7 Q. And that would maximize the production from the
8 unit?

9 A. That is correct.

10 Q. Okay. Now again, you've said it's not easy to
11 separate the old and new effect, but is there a correlative
12 project which helps show the effect of increased flooding
13 and production?

14 A. There is. There's one example that I've found in
15 the area, that Artesia Vacuum trend, Grayburg-San Andres
16 trend, where there's a lot of projects that are similar to
17 this, and that is over on the Devon-operated Turner B
18 lease.

19 And I have -- Exhibit 7 is a cross-section, it's
20 a rather large -- but if I might point out just a couple of
21 things for you here on this cross-section.

22 Q. I think the line of the cross-section is given in
23 the upper left of this?

24 A. I'm sorry?

25 Q. The line of the cross-section is in the upper

1 left of this?

2 A. Right. If you look at the map, the A-A' on the
3 west side is actually the Turner B Number 135, which is
4 actually adjacent to Wiser's Skelly Unit, on the west of
5 Wiser's Skelly Unit.

6 Q. And the Skelly Unit, we will discuss that?

7 A. We'll discuss it in just a few minutes. And
8 there's two Skelly Unit wells on the west side of the unit,
9 and Well 255 is kind of on the east side of the unit. And
10 then we move across further to the east and pick up CMU
11 187, which is a well on the west side of the Caprock
12 Maljamar Unit. 181 is then on the eastern side of the
13 Caprock Maljamar Unit.

14 And I built this cross-section, really, just to
15 demonstrate that across this area, this Artesia Vacuum
16 trend, we're looking at the same geologic units across many
17 miles.

18 If you look, I guess, at the second-from-the-
19 bottom top, that is marked as the San Andres, that's a
20 pretty clear marker throughout the area where you go from
21 these sandy dolomites in the Grayburg section to a clean
22 dolomite in the San Andres, and you can see that that's
23 pretty clear all the way across. The Lovington is that
24 blue marker at the bottom. That's a marker that's also
25 pretty clear. And then at the top, I believe that's a

1 Queen sand, the green, that's pretty clear all the way
2 across.

3 The sands within the Grayburg section themselves,
4 I picked one and marked it in pink. I didn't name it.
5 There's different local names for the sands within the
6 Grayburg. Some people have names for them, some people
7 have numbers for them. So I didn't note this, but you can
8 see how the sand character continues across.

9 The thicknesses of the units don't change a whole
10 lot across, and many of the sands appear to carry all the
11 way across.

12 I would, though, mention that obviously this is
13 not to scale horizontally. There's a lot of distance
14 between wells. And in fact, some of these sands come and
15 go. As you know, there's a lot of heterogeneities out
16 here, and even some sands that do appear to be correlative
17 may not be continuous between wellbores.

18 But I think basically the point we're trying to
19 make is that this is the same animal and that the
20 conclusions that I can draw from the Turner B can be used
21 to describe what's happening in the Caprock Maljamar
22 Unit --

23 Q. So the same --

24 A. -- as far as infill drilling and waterflooding is
25 concerned.

1 Q. -- the same sands that are being flooded in the
2 Turner B and the Skelly Unit and the Caprock Maljamar Unit
3 are the same?

4 A. That is correct.

5 Q. Okay. Well, let's go on to your next two
6 exhibits, then, 8 and 9, Mr. Eagleston, and --

7 A. Right.

8 Q. -- tell the Examiner how you determine that there
9 is an effect from the increased injection in this area.

10 A. Okay, you might kind of pull those out and look
11 at those side by side. The reason that this area is
12 important an interesting to study is that in the early
13 1990s Devon's predecessor drilled 22 wells in the Turner B
14 lease, 20-acre infill producers. They did not convert the
15 offset injectors. And so it would be the case of just
16 drilling the wells without doing the injection side of the
17 plan.

18 A bit later, after Devon acquired the properties,
19 if you look at Exhibit 8, in 1996 Devon drilled some
20 additional wells on the Turner B. I believe there's 15.
21 This is a type curve of the 22 and a type curve of the 15.
22 And you can see that they started and actually looked quite
23 similar in terms of initial rates and decline profiles and
24 so forth. But then they start to look a little bit
25 differently when you start to see the effect of the water

1 injection.

2 And that's where Exhibit 9, where I backed them
3 up so that they're normalized timewise. And you can see
4 that they're very similar early on, but as water injection
5 begins to take effect, the later wells, which were
6 receiving injection support earlier in their lives, are
7 beginning to increase above the trend line established by
8 the older wells.

9 And if you glance back at Exhibit 8, you can see
10 that, in fact, the older 22 wells are beginning to see some
11 effect, apparently, from the increased injection support as
12 well.

13 This is the only case that I know of where you
14 have a substantial number of wells in the same area where
15 some were drilled and had no injection support for some
16 period of time, and then another later group was drilled
17 with injection support, and you have this kind of
18 comparison available to you.

19 Everywhere else that I'm aware of, it was done
20 like we did, which was simultaneously.

21 Q. Does this support the conclusion that there has
22 been a positive production response in the CMU?

23 A. Yes, I believe it does.

24 Q. Well, let's move on to the next -- actually, the
25 next three cases, having to do with the Skelly area, Mr.

1 Eagleston. Would you identify Exhibit 10 for the Examiner?

2 A. Exhibit 10 is a map of the Skelly unit area. The
3 legend, the symbols and so forth are the same as what we
4 used in the Caprock Maljamar Unit map earlier, so the
5 purple dots represent wells that Wiser has drilled, and the
6 red dashes represent the waterflood patterns that have been
7 established.

8 Once again, we did have to drill -- redrill some
9 wells for injection purposes, we had to re-enter, in fact,
10 nine P-and-A'd wells, we converted 47, did work on many
11 others, in order to establish these patterns.

12 The yellow area is actually the Skelly unit
13 proper. The green is the Lea "D" lease, which is adjacent
14 to and is served by the same injection system and is really
15 incorporated into the Skelly Unit development plan. And
16 the blue, up on the northwest side of Skelly, is the State
17 "AZ" lease, and has also been incorporated into the
18 injection plan.

19 Q. And Mr. Eagleston, immediately to the west of the
20 Skelly Unit is the Turner B lease; is that right?

21 A. That is correct, that is correct. And the State
22 "AZ" well, in purple, is the State "AZ" Number 3 and was
23 actually drilled as a lease line cooperative well with
24 Devon, and was drilled in the corner of their lease and the
25 State "AZ" lease and the Skelly unit, to situate it into

1 most advantageous position for recovery out of that
2 pattern, and we support that pattern with injection from
3 the Skelly Unit and also from the Turner B lease.

4 Q. And Wiser and Devon have several other wells
5 along their lease line that have been drilled as
6 cooperative wells?

7 A. That's correct, we drilled a total of seven.
8 Devon operates three, the 134, 135 and 136 that you see
9 just west of the lease line. And then if you look a bit
10 further south, the 400, 401 and 402 were drilled and
11 operated by Wiser.

12 Q. Okay. A couple of final questions. On this map,
13 what does -- what numerical sequence identifies new
14 injectors that you drilled?

15 A. The 300-series wells. There's a couple -- the
16 Number 3- -- Let me find it here. The Number 300 is on the
17 east side of the unit. It was drilled as a replacement for
18 Number 71. There's a -- Number 301 is on the west side.
19 It was drilled as a replacement for Number 92. We also
20 drilled Number 302 as a replacement for Number 91. We are
21 currently producing that well, but it will be converted to
22 an injector. It was drilled as an injector.

23 Q. So it wasn't just that new producers were drilled
24 in this area either?

25 A. No, no, absolutely not. We drilled -- To kind of

1 go over the same kind of statistics that we did on Caprock
2 Maljamar Unit, the Skelly unit is a little shallower, so it
3 was less expensive to develop.

4 Also, the injection system that our predecessor,
5 Texaco, had left behind was in much better condition. So
6 it didn't cost as much money for us to do the development
7 at Skelly. We spent approximately \$358,000 per pattern, as
8 opposed to the 586 over at CMU. Of the \$350,000, about
9 \$230,000 goes to drill an infill well on average. That
10 means we spent about \$128,000 on injection, or about 35
11 percent of the capital was spent on the injection side of
12 the --

13 Q. Why don't you move on to Exhibit 11 and do what
14 you did with the CMU and just discuss a little bit of the
15 history of this area and the costs involved in this
16 project.

17 A. Uh-huh. The Skelly Unit, or the first well
18 drilled in what became the Skelly Unit was drilled in 1926.
19 It's now Skelly Unit 41. And that area, as was the case
20 throughout this trend, was developed on 40-acre spacing
21 over the next 30 to 40 years.

22 In 1965 a pilot waterflood was installed. It
23 worked very well, so it was expanded to the rest of the
24 unit in 1968. Active waterflooding continued until the
25 late 1980s, when they ceased injecting makeup water and it

1 became simply a disposal operation, similar to what we saw
2 over at the Caprock Maljamar Unit.

3 Wiser acquired the property from Texaco in 1995.
4 Production was down to 250 barrels of oil per day from 66
5 active wells. There were 18 injection wells recycling the
6 produced water. And once again, this is close to the
7 economic limit. There was not much in the way of reserves
8 left at that time under existing operating conditions.

9 So we started shortly after we acquired the
10 properties in late 1995 with the development program that
11 included drilling a total of 77 producers and converting
12 the numerous wells and re-entering plugged wells and so
13 forth to create these 40-acre fivespot patterns.

14 Our production peaked at a bit over 2300 barrels
15 a day in early 1997. We came in and did a bit more work in
16 late 1997, and by November of 1998 production was averaging
17 1036 barrels a day, about 7300 barrels of water a day, from
18 108 active producing wells.

19 And I need to make a note here that on the Skelly
20 Unit the shallower Seven Rivers interval is also productive
21 and, in fact, until recently was a separate reservoir
22 called the Fren-Seven Rivers reservoir. Devon -- The
23 reservoir basically was on the Skelly Unit and the Turner
24 B. Devon had petitioned previously to abolish the Fren-
25 Seven Rivers and combine it into the Grayburg-Jackson

1 reservoir. And so it was.

2 But we still have a number of shallower Seven-
3 Rivers-only wells on the lease, and that's why we have 108
4 active producing wells. There's only actually 77 active
5 Grayburg wells. The remainder are those shallow Seven
6 Rivers wells, which we are not actively waterflooding at
7 this time. We're actively waterflooding the Grayburg and
8 the San Andres.

9 We also are injecting about -- in November
10 injected almost 15,000 barrels a day into 81 active
11 injectors. Once again, we're getting makeup fresh water
12 through Conoco's system in the area.

13 Moving on to the Lea "D", the Lea "D" is adjacent
14 to the Skelly Unit, as we noted on the map. It was part of
15 the original Skelly Unit waterflood. The plant and
16 injection system were tied together. At the time we
17 acquired the property, actually from Apache in 1997, they
18 had acquired it from Texaco previously. Production was
19 from only well, five barrels a day. Injection had ceased
20 long ago. And we instituted an infill development program
21 and drilled six wells, converted seven wells to injection,
22 and are now making 84 barrels a day and 374 barrels of
23 water a day, and injecting almost 1200 barrels a day there.

24 And the State "AZ" lease on the northwest part of
25 the Unit is a 40-acre tract. Once again, we acquired that

1 from Apache in 1997. We drilled a single well down in the
2 corner of that 40-acre tract to develop reserves along the
3 lease line and provide a take point for a pattern along the
4 lease line that we share with Devon. The well in November
5 of 1998 -- actually, that well plus the wells that were
6 already on the lease, were averaging 47 barrels a day,
7 about 20 barrels of water per day.

8 And we support -- although there's no injection
9 directly on the State "AZ" lease, we support that pattern
10 with between 200 and 300 barrels a day of injection from
11 the offsets in that pattern. So it is an integral part of
12 our waterflood plan.

13 The third page in this exhibit is a data page,
14 once again. It gives well counts by lease, injectors and
15 producers, injection volumes. Those volumes, as I note
16 here with the asterisk, excludes offset injection. Those
17 leaseline wells, including the State "AZ", are supported by
18 injection from the Devon side, and that's not included in
19 our --

20 Q. This project is ultimately a little more
21 profitable than the CM Unit?

22 A. Yeah, it's going to be substantially better from
23 a financial perspective. We didn't have to spend as much
24 money, and it's performed better as well, so it is going to
25 turn out to be a better project.

1 Q. Why don't you go to Exhibit 12 and discuss the
2 extra production you hope to get out of the project.

3 A. All right, this next group, Exhibit 12, is a
4 group of decline curves by -- Well, the first one is the
5 combined Skelly-Lea "D"-State "AZ" curve, and then behind
6 that you have a curve for each of the leases, which shows
7 the same information that we presented for the Caprock
8 Maljamar Unit.

9 It shows production prior to our development
10 program, with the red line being an extrapolation of what
11 production would have done had we not redeveloped the area.
12 Once again, production actually would have ceased probably
13 prior to that, the end of that red line, due to just
14 becoming uneconomic.

15 Q. What -- Do you have another figure on reserves
16 you hope to recover with this project?

17 A. Right, in the Skelly area incremental reserves
18 are estimated to be about 7.5 million barrels. And once
19 again, kind of using some of the same analysis that we
20 looked at on the Caprock Maljamar Unit, the average primary
21 per well in the Skelly area was 52,000 barrels, a little
22 bit better than Caprock Maljamar.

23 Once again, though, I think it would be unlikely
24 to recover a similar amount from an infill well, due to
25 partial drainage. So I would estimate 25,000 to 35,000 per

1 infill well would be reasonable to expect with no
2 additional injection support.

3 Once again, our estimates on a per-pattern basis
4 approach 100,000 barrels, so the remainder, 65,000 to
5 75,000 barrels, would be attributable to the reactivation
6 of the waterflood and rearranging the waterflood patterns.

7 Q. In your opinion, is this project economically and
8 technically feasible at this time?

9 A. Yes.

10 Q. And in your opinion, was it prudent to expand the
11 waterflood projects to maximize the recovery of crude oil?

12 A. Yes.

13 Q. And will these projects lead to the recovery of
14 an increased amount of crude oil which will ultimately be
15 recovered from these formations?

16 A. That is correct.

17 Q. Do you consider these projects to be significant
18 expansions of the projects Wiser purchased in the 1990s?

19 A. Yes.

20 Q. By increasing the infill drilling, you are in
21 effect increasing the geographic and geologic area you are
22 recovering reserves from; is that correct?

23 A. Well, we're contacting and recovering oil that
24 was not recoverable with previous spacing and operational
25 practices.

1 Q. Because of the heterogeneity of the reservoir?

2 A. That is correct. And I would point out too, in
3 the case of the Caprock Maljamar Unit -- this is kind of
4 going back to that -- that in addition to the better
5 connectivity created by the tighter spacing, we also -- or
6 the previous waterflooding in many areas of the unit was on
7 the Grayburg only, and we deepened a number of the other
8 injectors to include the upper member of the San Andres,
9 the Vacuum, locally known as the Vacuum, and we are
10 waterflooding the Vacuum and the Grayburg. So we added the
11 Vacuum in many areas of the unit as well. It was not
12 waterflooded previously.

13 Q. What is contained in Exhibit 13, Mr. Eagleston?

14 A. Exhibit 13 is, once again, just some examples,
15 individual well decline curves for this area.

16 Skelly 189 is sort of in the northern part of the
17 unit. It's been very well supported, I think, by
18 injection, essentially flat.

19 266 is down in the southern -- southeastern part
20 of the unit, and I think once again you can see some
21 injection support there.

22 And 273 is on the western side of the unit and
23 has been also a very good well that has seen some injection
24 support.

25 The State "AZ" Number 3 is a relatively new well.

1 It looks like it's going to be a very fine producer, but
2 it's a little early to see what kind of injection support
3 might be apparent on the curve.

4 And I guess I ought to stop and point out, when I
5 say that injection support is apparent, that's from a
6 classic waterflood standpoint where production actually
7 goes up. In many cases here, you're not going to see that
8 on an individual well basis, because you're immediately in
9 a drag-flood situation. And so what you get is perhaps a
10 shallower decline than would have been seen before, but not
11 necessarily a classic secondary response. Just like to
12 point that one out.

13 And then in the final well, individual decline
14 curve that we have, is one of the Lea "D" wells, the Lea
15 "D" Number 20.

16 Q. What is Exhibit 14?

17 A. Exhibit 14 is a spreadsheet of all the wells that
18 Wisner drilled in this area, Skelly, Lee "D" and State "AZ",
19 with spud dates, first-production dates, perforations,
20 potentials and so forth, just a listing of all the wells.

21 Q. And finally, what is Exhibit 15?

22 A. And Exhibit 15 is just the tabular data that was
23 presented in graphical form earlier, the production and
24 injection data for the three leases in the Skelly area, as
25 well as the Caprock Maljamar Unit.

1 Q. Just backup for what you previously --

2 A. Just backup, that's correct, backup for the
3 graphical data,

4 Q. Okay. In your opinion, are the three Skelly area
5 leases or units qualified for an EOR, enhanced oil
6 recovery, credit?

7 A. Yes.

8 Q. Were Exhibits 1 through 15 prepared by you or
9 under your direction?

10 A. They were.

11 Q. And in your opinion, is the granting of these
12 four Applications in the interests of conservation and the
13 prevention of waste?

14 A. Yes, it is.

15 MR. BRUCE: Mr. Examiner, I'd move the admission
16 of Exhibits 1 through 15 into the record.

17 EXAMINER CATANACH: Exhibits 1 through 15 will be
18 admitted as evidence.

19 EXAMINATION

20 BY EXAMINER CATANACH:

21 Q. Mr. Eagleston, most of the work in the CMU
22 involved infill drilling producers on 20-acre spacing; is
23 that correct?

24 A. Right. And converting all the existing or older
25 offset producers or injectors to active injection service.

1 Q. Do you know how many wells were converted to
2 injection?

3 A. We -- and these numbers actually may be off a
4 well or two here -- we re-entered eight P-and-A'd or TA'd
5 wells and converted them to injection. We converted 50
6 existing producers or shut-in producers to injection. We
7 drilled ten new wells as injectors, and we also worked on
8 12 wells that were existing injectors, either deepening
9 them or adding perforations, stimulating, so forth.

10 So we now have a total in -- Well, in November of
11 1988 we had 82 active injection wells. And when we took
12 over the project, there were 16 wells that were actively
13 injecting water, recycling produced water. So we added 66
14 wells beyond that 16. In addition, we worked on 12 out of
15 those 16 in some fashion. So we essentially worked on
16 every well in the unit, with a few exceptions.

17 Q. So you actually did an extensive amount of work
18 to the injection wells?

19 A. Absolutely. Yeah, we spent, out of the
20 capital -- I think I gave you a 35-percent number on
21 Skelly. The comparable number at CMU is 45 percent; 45
22 percent of the total capital expended was for injection
23 purposes. That included working on the wells, and a brand-
24 new -- two totally new injection plants and a totally new
25 injection -- fiberglass high-pressure injection system was

1 installed here.

2 Q. Now, all of that work was done in all three of
3 the phases?

4 A. That's correct. Yeah, we have two separate
5 injection plants. Because of the funny shape of the unit,
6 there's one plant that just serves that little southern
7 appendage down there. It's a smaller plant. And then
8 there's another bigger plant up kind of in the center of
9 the main body of the unit. And as I mentioned, both those
10 plants were -- we had to basically start from the ground
11 up, from the concrete slab up. The old facilities were
12 simply not usable.

13 I guess I could point out too, as we did on the
14 Skelly unit, we have some leaseline wells. We have a
15 leaseline agreement on the northeastern part of the CMU
16 with Shahara. They operate a three-hundred -- the western
17 half of Section 16 there. And they drilled and operate
18 Well Numbers 100 and 101. We drilled 400 and 401 and -- to
19 help -- or to develop the reserves along the lease line.
20 That was part of their development program for their 320
21 acres that was unitized in the last few months, I believe.

22 Q. Okay. So within Phase 1 you guys started
23 injecting in about May of 1994?

24 A. That's correct. Yeah, I can tell you the
25 injection start dates. The -- Yeah, injection start date,

1 May of 1994 for Phase 1. For Phase 2, November of 1994,
2 which was contemporaneous with the certification date.
3 Phase 3, first injection actually was in October of 1996.
4 Certification came in October of 1997.

5 Q. Okay. So in Phase 1, you actually started to get
6 an increase in production before you started injecting,
7 right?

8 A. There were some infill wells drilled --

9 Q. Right.

10 A. -- that is correct.

11 Q. Okay, and your position is that you can't
12 separate the effect of increased production on infill
13 drilling and on waterflood response?

14 A. I can make an estimate, and my estimate would be,
15 as I mentioned, kind of going back to the original primary
16 production and looking at that, saying, well, we have
17 42,000 barrels a well there, you're not going to infill
18 drill and do any better than that, most likely, unless you
19 had a major leap forward in completion technology.

20 And although we -- I think we probably could do a
21 better job, I still would think it would be more reasonable
22 to think that you would get maybe 20,000 or 30,000 barrels
23 per well, with no injection support, mind you. So that's
24 about the best analysis I can do, probably, in trying to
25 separate that.

1 Q. Okay, go over those figures again. You estimate
2 42,000 --

3 A. The average primary recovery per well in the unit
4 area was 42,000 barrels. And I think given the state of
5 depletion, my experience with these kind of reservoirs, I
6 think getting between 50 and 75 percent of primary on a
7 pure infill-only case is a reasonable thing. So that would
8 make it between 20 and 30 or so. I'm rounding the numbers
9 a bit.

10 Q. Okay, and you're estimating -- with waterflood
11 operations, you're estimating 100 barrels?

12 A. We actually started out at 110, and as things
13 have gone along a bit, we've backed that down closer to
14 about 95, actually, per pattern.

15 Q. Now, when you say "per pattern", that's one
16 producing well?

17 A. That's correct.

18 Q. Okay.

19 A. So I would -- you know, I would place the
20 reserves attributable to the waterflooding part of the
21 project at the difference between 95 and, you know, 20,000
22 to 30,000 barrels.

23 But once again, in our view the two really can't
24 be separated because you wouldn't drill for 20,000 or
25 30,000 barrels. You couldn't drill a \$325,000 well for

1 20,000 or 30,000 barrels, because it would also be a fairly
2 low-rate well.

3 And by the same token, you couldn't rearrange the
4 waterflood using existing producers and really add much
5 either. They had done about all they could in the 1960s
6 and 1970s utilizing those wellbores. So what you had to do
7 was add some wellbores so you could rearrange your patterns
8 to recover incremental oil. So they really just go hand in
9 hand.

10 Q. Okay, you're estimating a response date for Phase
11 1 of October 1st, is that -- How did you get that?

12 A. A response --

13 Q. Yeah.

14 A. -- of -- Yeah, October of 1994.

15 Q. October of 1994.

16 A. Yeah, that was purely, if you look at the Phase 1
17 decline curve -- and of course it doesn't go back
18 previously, but the first thing that we did was that jump
19 up in production in mid-1993, okay. There was actually two
20 wells drilled -- No, I'm sorry, there were four wells
21 drilled in the unit prior to unitization, and that's what
22 that jump up in production is in mid-1993.

23 So production prior to our arrival in Phase 1 was
24 at the -- you know, a little over 100-barrels-a-day level.
25 Okay. So you could -- And it was declining at the rate of

1 about five, six, seven percent, somewhere in that
2 neighborhood.

3 So if you draw a line along there, what I looked
4 at, I said, Well, okay, this 1993 stuff, that was before
5 the unit was formed. We really didn't start injecting
6 until May, then you see a large jump in production in late
7 1994. And I picked that point which is in October, which
8 is where we were at about 300 barrels a day, as being at a
9 point that was clearly and demonstrably above the
10 previously established decline, which would have been still
11 at around 100 barrels a day. So you were a couple hundred
12 barrels --

13 Q. Are we looking at the same exhibit? I'm sorry,
14 are you looking at the Phase 1?

15 A. Uh-huh, yes.

16 Q. Okay.

17 A. Right. I'm sorry, I should have annotated that a
18 bit more.

19 Q. Well, I'm not sure about your scale on the --
20 you're using a --

21 A. These are barrels per month on the scale.

22 Q. Okay.

23 A. Yeah, so we're at -- The bottom is at 1000, so
24 production was at about -- a little over 3000 barrels a
25 months. So just a tad over 100 barrels a day. I switched

1 back and forth, sorry. It was about 3000 barrels a month
2 before we arrived on the scene.

3 Q. Okay.

4 A. And the typical decline out there was around five
5 to seven percent at that time, so it's declining at five to
6 seven from that point forward.

7 And I picked November -- or, I'm sorry, October
8 of 1994 as a proposed date of response because that's a
9 point where production has clearly departed in a
10 substantial way from the previous decline trend that -- if
11 you drew a line on there, I mean, it's going to look
12 something like this, Mr. Examiner. You know, this decline
13 is going to be something like this. And so I just picked a
14 point where there would be no question that we were well
15 above that line, which is this point right here. And I'm
16 sorry, I should have annotated that on this graph.

17 Q. Let me make sure I understand you. Your bottom
18 scale --

19 A. Uh-huh.

20 Q. -- where it says 1994, is that -- Exactly what is
21 that?

22 A. Well, that's just a time scale. That's 1994.

23 Q. Where it says 1994, is that a particular month?

24 A. Yeah, January is on the -- is the divider. So
25 the grid where you have this line that goes all the way up

1 the graph, that's January. So February, March, April, May,
2 June -- Where the number 1994 appears would be July. So
3 August, September, October is that point right there on the
4 graph. And I'm sorry, I'm not making myself clear, but --

5 Q. Oh, I got it.

6 A. You got it?

7 Q. Uh-huh.

8 A. Okay, yeah.

9 Q. I just needed a month for that --

10 A. Right.

11 Q. -- to see where that was.

12 A. Right, yeah. Yeah, on this particular graph --
13 and I know it's different graphs, but January is on the
14 gridline. And I used the same, you know, kind of thinking
15 to pick the positive production response dates for the
16 other two phases as well. I looked at what the established
17 trend line was and picked a month where production had
18 clearly departed and was substantially above that trend
19 line

20 Q. Okay, for Phase 3, you don't have anything until
21 January 1st of 1998?

22 A. Right, and the reason there is, the certification
23 did not occur until October of 1997. And although we
24 started injecting in that phase in October of 1996, the
25 certification date was October of 1997. So that's why I

1 picked the January of 1998 date, having to pick a date
2 subsequent to the certification date.

3 Q. Okay, and we'll talk about the Skelly a little
4 bit.

5 A. Okay.

6 Q. This is the first attempt you've made to qualify
7 these areas for the EOR tax credit?

8 A. Well, we made a -- I guess Mr. Bruce could
9 probably speak to that. We had sent some materials in
10 previously, requesting administrative approval of this.
11 But I think it was determined that a hearing would be
12 required.

13 Q. Okay, most of this work was performed --

14 A. 1996 and 1997. We started at the tail end of
15 1995.

16 Q. And this was in an area that had already been
17 waterflooded previously as well, right?

18 A. That is correct.

19 Q. Texaco had flooded this area?

20 A. Right, it was actually a Skelly, ergo the Skelly
21 unit name. Skelly actually had the property from way, way
22 back, and it made its way eventually into Texaco's hands.
23 But it followed a development pattern identical, really, to
24 the Caprock Maljamar Unit. All these units along this
25 trend line were developed and waterflooded during the same

1 time frames.

2 Q. Okay. So basically what you did in this whole
3 area is the same thing, you infill drilled on 20-acre
4 spacing?

5 A. That is correct.

6 Q. There was a lot less work that you did on the
7 injection wells --

8 A. Right.

9 Q. -- in this unit, though?

10 A. Right, we -- a couple of -- or, well, the main
11 reason there on the injection system was that Texaco -- the
12 Texaco injection system itself was in much better
13 condition, and we were able to use it with less work, less
14 modification required.

15 But as I mentioned previously, still 35 percent
16 of the total capital expended -- which we spent, I think,
17 about \$27 million -- 35 percent of that still went to the
18 injection system. We re-entered -- kind of giving the same
19 stats that we talked about with Caprock. We re-entered
20 nine P-and-A'd or TA'd wells, to convert to injection. We
21 converted 47 existing or shut-in producers to injection.
22 We worked over 11 of the existing injection wells, and we
23 drilled three wells. And there's a total now of 88 active
24 injection wells.

25 Q. Do you guys have those numbers somewhere in your

1 exhibits, or is that just something --

2 A. That's just some notes I made. I can provide
3 that for you, though.

4 Q. Yeah, would you, please?

5 A. Okay. I would like to go back and double-check a
6 couple of them. I think I mentioned I might be a well or
7 two off, but I'll get the exact numbers and provide them to
8 you.

9 Q. Did you guys significantly increase the injected
10 volumes in this area?

11 A. Oh, yes, yes. Whenever we -- As I mentioned, in
12 the late 1980s they had stopped injecting makeup water, and
13 it was simply a recycling project. So in 1995 when we
14 acquired the property, they were producing 250 barrels of
15 oil per day and 650 barrels of water. That was it, 650
16 barrels of water a day was all that was being injected. In
17 November of 1998 we injected almost 15,000 barrels of water
18 a day.

19 Q. Now, as I understand it, the Seven Rivers is now
20 within the same pool in this --

21 A. It's in the Grayburg, it's been combined into the
22 Grayburg-Jackson Pool.

23 Q. Okay, but the Seven Rivers is not being flooded?

24 A. Not currently. It has been flooded previously,
25 and we actually do have some plans to go in and reactivate

1 a portion of that. We haven't done so yet. A little
2 matter of low oil pricing at the moment has deterred us.

3 Q. Are you suggesting that -- If we choose to
4 certify this as an EOR project, in your opinion have we
5 already seen the same positive production response as we
6 have --

7 A. Yeah --

8 Q. -- similarly in --

9 A. -- using the same thinking and analysis, yes.

10 Q. And do you have suggested dates for those
11 responses?

12 A. I do, and you could refer to the decline curves
13 by lease. I can give it to you by lease here.

14 MR. BRUCE: Exhibit 12.

15 THE WITNESS: Yeah, this is Exhibit 12. On the
16 second page of Exhibit 12, the Skelly Unit decline curve,
17 we would suggest that June of 1996 -- and actually it might
18 be easier to see, Mr. Examiner, on the tabulated data,
19 which is Exhibit 15, because these decline curves are kind
20 of squeezed together. But we would suggest June of 1996
21 for the Skelly unit. We would suggest November of 1997 for
22 the Lea "D" and May of 1998 for the State "AZ".

23 Q. (By Examiner Catanach) I think I've got those
24 numbers on the primary for that area.

25 A. Yeah, it was 52,000 per well on primary in the

1 Skelly unit.

2 Q. And 25,000 to 35,000 infill?

3 A. Yeah, that's once again using that kind of a 50-
4 to 75-percent recovery on 20-acre infills versus the 40-
5 acre primaries.

6 Q. Okay, and again, you're looking at 100,000 per
7 pattern?

8 A. We're looking at -- It's actually about 95,000.

9 Q. And do your decline curves for those areas, do
10 they support those numbers?

11 A. Yeah, they -- Once again, Exhibit 12, the yellow
12 projection, that projection will get you the 95,000 per
13 well.

14 As I mentioned, in Caprock we actually had to
15 reduce our reserve estimate in Caprock slightly. At Skelly
16 we have not.

17 Q. Okay. Mr. Eagleston, do we have a list of all
18 the producing wells in both of these areas that would
19 qualify for the EOR tax?

20 A. I believe in the case of the Caprock Maljamar
21 unit, which was certified in phases, that you do have that
22 information, but I could certainly provide that again if
23 necessary. And in the case of the Skelly unit, let me just
24 check. I'm not sure in the materials we submitted
25 previously whether we had that information or not. Well --

1 Q. I'll tell you what, why don't --

2 A. I'll provide it in any case, if that's --

3 Q. What I'm going to need is, within the Caprock
4 Maljamar Unit, just a list of the producing wells that I
5 can send to Taxation and Revenue saying that these wells
6 qualify for the EOR tax credit.

7 A. Okay.

8 Q. I need all of the wells, including API numbers
9 for the wells.

10 A. Okay.

11 Q. And you might as well do that for all the Skelly-
12 area wells as well --

13 A. All right.

14 Q. -- in case we decide to do that.

15 A. Yeah, as I mentioned, the two projects are really
16 carbon copies of each other and are quite -- they're a
17 carbon copy of the Devon project that adjoins Skelly on the
18 west. They did exactly what we did --

19 Q. Okay.

20 A. -- which I think you guys have dealt with
21 previously, if I remember correctly.

22 EXAMINER CATANACH: Jim, if you don't mind doing
23 some rough orders, not -- You don't have to do anything
24 elaborate, but just make sure I have the dates and the
25 important things covered in the orders, make sure that we

1 have them right.

2 MR. BRUCE: Will do.

3 EXAMINER CATANACH: Okay, I don't have anything
4 else.

5 Is there anything else?

6 MR. BRUCE: I have nothing further in this
7 matter, Mr. Examiner.

8 EXAMINER CATANACH: Okay, there being nothing
9 further, Cases 12,147, 12,148, 12,149 and 12,150 will be
10 taken under advisement.

11 (Thereupon, these proceedings were concluded at
12 2:15 p.m.)

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I do hereby certify that the foregoing is
a complete record of the proceedings in
the Examiner hearing of Case No. D107-50
heard by me on 1/16/99 1999.
David R. Catanach, Examiner
OR Conservation Division

CERTIFICATE OF REPORTER

STATE OF NEW MEXICO)
) ss.
 COUNTY OF SANTA FE)

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL March 22nd, 1999.



STEVEN T. BRENNER
 CCR No. 7

My commission expires: October 14, 2002