

1 NEW MEXICO OIL CONSERVATION DIVISION  
2 STATE LAND OFFICE BUILDING  
3 STATE OF NEW MEXICO  
4 CASE NOS. 10761 and 10762 (Consolidated)  
5

6 IN THE MATTER OF:

7  
8 (10761) The Application of Mewbourne Oil  
9 Company for Statutory Unitization,  
Lea County, New Mexico.

10 Application of Mewbourne Oil  
11 (10762) Company for a Waterflood Project  
12 and Qualification for the Recovered  
13 Oil Tax Rate, Lea County, New Mexico.  
14

15 BEFORE:

16 MICHAEL E. STOGNER

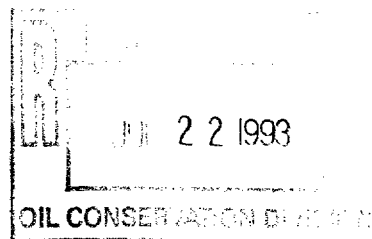
17 Hearing Examiner

18 State Land Office Building

19 Thursday, July 1, 1993  
20

21 REPORTED BY:

22 CARLA DIANE RODRIGUEZ  
23 Certified Court Reporter  
24 for the State of New Mexico  
25



**ORIGINAL**

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FOR THE NEW MEXICO OIL CONSERVATION DIVISION:

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BY: **JAMES BRUCE, ESQ.**

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1 EXAMINER STOGNER: Call next case, No.  
2 10761.

3 MR. STOVALL: The application of  
4 Mewbourne Oil Company for statutory unitization,  
5 Lea County, New Mexico.

6 EXAMINER STOGNER: Call for  
7 appearances.

8 MR. BRUCE: Mr. Examiner, Jim Bruce,  
9 from the Hinkle Law Firm in Santa Fe,  
10 representing the Applicant. I have three  
11 witnesses to be sworn, and I would request that  
12 this hearing be consolidated with Case 10762.

13 EXAMINER STOGNER: Okay. At this time  
14 I'll call Case 10762.

15 MR. STOVALL: Application of Mewbourne  
16 Oil Company for a waterflood project and  
17 qualification for the recovered oil tax rate, Lea  
18 County, New Mexico.

19 EXAMINER STOGNER: Other than the  
20 Applicant, are there any appearances in this  
21 matter?

22 At this time, will the witnesses please  
23 stand to be sworn.

24 [And the witnesses were duly sworn.]

25 EXAMINER STOGNER: Mr. Bruce.

1 MR. BRUCE: Call Mr. Cobb to the stand.  
2 first.

3 **STEVE COBB**

4 Having been first duly sworn upon his oath, was  
5 examined and testified as follows:

6 EXAMINATION

7 BY MR. BRUCE:

8 Q. Would you please state your full name  
9 and city of residence?

10 A. My name is Steve Cobb, and I live in  
11 Midland, Texas.

12 Q. Who are you employed by and in what  
13 capacity?

14 A. I'm employed by Mewbourne Oil Company  
15 as district landman.

16 Q. Have you previously testified before  
17 the Division?

18 A. No, I have not.

19 Q. Would you please briefly state your  
20 educational and work background?

21 A. I graduated from Oklahoma State  
22 University in 1977 with a marketing degree, and  
23 completed the Oklahoma University PLM program in  
24 1980.

25 For the last two years I have been

1 employed with Mewbourne Oil Company, and the 10  
2 years prior to that I was with Santa Fe Minerals  
3 in Tulsa, Oklahoma. Three years prior to that I  
4 was with South Ranch Oil Company in Oklahoma  
5 City.

6 Q. As a landman, in those two previous  
7 capacities?

8 A. That's correct.

9 Q. Are you familiar with the land matters  
10 involved in these cases?

11 A. I am.

12 Q. You're currently based in Mewbourne's  
13 Midland office?

14 A. That is correct.

15 Q. And you are familiar with land matters,  
16 or part of your job responsibility is land  
17 matters in Southeast New Mexico?

18 A. That's correct.

19 MR. BRUCE: Mr. Examiner, I would  
20 tender Mr. Cobb as an expert petroleum landman.

21 MR. STOVALL: Are you a member of any  
22 professional associations?

23 THE WITNESS: AAPL and the PBLA,  
24 Permian Basin Landman Association.

25 MR. STOVALL: And the AAPL is the

1 American Association of Petroleum Landmen?

2 THE WITNESS: That's correct.

3 MR. STOVALL: Do you have any  
4 certifications by them yet?

5 THE WITNESS: No, I do not.

6 MR. STOVALL: Nothing further.

7 EXAMINER STOGNER: Mr. Cobb, you said  
8 you were in Tulsa with Santa Fe?

9 THE WITNESS: Santa Fe Minerals.

10 EXAMINER STOGNER: Which entity of  
11 Santa Fe Minerals?

12 THE WITNESS: Kuwait. It's not the  
13 railroad.

14 EXAMINER STOGNER: Not that that would  
15 matter, which Santa Fe it was, but it's hard  
16 enough. Okay, Mr. Cobb is so qualified.

17 MR. BRUCE: Mr. Examiner, before we  
18 begin in Case 10761, Mewbourne seeks to  
19 statutorily unitize the Querecho Plains-Upper  
20 Bone Spring Pool in a portion of Township 18  
21 South, Range 22 East. The unit area does cover  
22 2400 acres of land, and it is all federal  
23 minerals.

24 In the second case, Mewbourne seeks  
25 approval of a secondary recovery waterflood



1 project for the unit, and certification of the  
2 recovered oil tax rate for the project.

3 Q. (BY MR. BRUCE) Mr. Cobb, referring to  
4 Exhibit 1, could you briefly identify that for  
5 the Examiner?

6 A. Exhibit No. 1 is a land plat which  
7 outlines our proposed unit area and identifies  
8 the separate tracts contained within that area.  
9 These tracts are divided on common mineral  
10 ownership, and there are currently 24 tracts in  
11 this unit area, and Mewbourne Oil Company or  
12 Curtis Mewbourne, operates 19 of the 24 tracts.

13 Q. Would you identify Exhibit 2, please?

14 A. Exhibit 2 is a bound volume of our unit  
15 agreement which was drafted on compiling unit  
16 agreements supplied to me through the BLM and  
17 other agreements that have been approved by the  
18 OCD.

19 The unit agreement describes the unit  
20 area, sets forth Mewbourne as operator, defines  
21 the unitized formation, and also provides for  
22 expansion of the unit area and basically sets out  
23 our relationship between all the parties involved  
24 in our unit.

25 Q. Okay. Now, Part I is the unit

1 operating agreement. What is the second part of  
2 that Exhibit 2?

3 A. Part I is the unit agreement and Part  
4 II is the unit operating agreement.

5 Q. So they're both contained in that  
6 volume?

7 A. That's correct.

8 Q. And this sets forth the duties and the  
9 authorities of the unit operator, and the  
10 relationships among the working interest owners?

11 A. That's correct.

12 Q. Now, as to tract ownership, would you  
13 describe how you identified or determined names  
14 of the working royalty interest owners in these  
15 tracts?

16 A. Several of the tracts we, Mewbourne,  
17 currently operate, and we have current Division  
18 Orders in-house or title opinions; so, for the  
19 tracts we operate, we went to our in-house  
20 records. For those tracts we do not operate, I  
21 had title opinions prepared on those.

22 Q. How many interest owners are there in  
23 the unit?

24 A. Originally there were approximately 74,  
25 75 overriding royalty interest owners, one

1 royalty interest owner, that being the United  
2 States or the BLM, and 50 working interest  
3 owners.

4 Q. How many are there currently?

5 A. Currently we have, I believe, 18  
6 working interest owners, one royalty owner, and,  
7 again, a little over 75 overriding royalty  
8 interest owners.

9 Q. Is the decrease, from 50 to 18 working  
10 interest owners, due to purchases by Mewbourne?

11 A. That's correct.

12 Q. Referring to Exhibit 3, would you  
13 discuss what that is and identify the working  
14 interest owners?

15 A. Exhibit No. 3 is a booklet which lists  
16 all the working interest owners in the unit.

17 Q. That's on the second page of that  
18 booklet?

19 A. That's correct. The persons that have  
20 a "1" by their names have approved our unit.  
21 Those that do not have a "1" by their names have  
22 not approved our unit, and those are the ones we  
23 are seeking to unitize today.

24 Q. Okay. And behind the listing are just  
25 the signature pages from the various working

1 interest owners?

2 A. That's correct, to our unit agreement.

3 Q. And, moving on to the overrides and to  
4 Exhibit 4, would you discuss ownership of the  
5 overrides?

6 A. Again, this booklet sets forth the  
7 royalty and overriding interest owners. Page 1  
8 lists those parties that have ratified our unit  
9 agreement and operating agreement. Those that do  
10 not have a "1" are, again, the parties we're  
11 seeking to unitize today. The third page to this  
12 book is the approval from the BLM.

13 Q. The preliminary approval?

14 A. The preliminary approval from the BLM.

15 Q. The other pages are the signature pages  
16 of the overriding and royalty interest owners?

17 A. That's correct.

18 Q. We've marked as Exhibit 4-A another  
19 signature page. Could you explain what that is?

20 A. I just received it this morning, by fax  
21 at this office, from Stephen Burleson, his  
22 signature page as an overriding royalty interest  
23 owner.

24 Q. And it was too late to fit it into the  
25 booklet?

1           A.       That's correct.

2           Q.       What percentage of working interests  
3 and overriding--or, I should say, royalty  
4 interest owners, have committed their interests  
5 to the unit?

6           A.       One hundred percent of the cost-bearing  
7 working interest owners have committed their  
8 interest, and 99.01 percent of the overriding  
9 royalty interest owners have committed their  
10 interest.

11          Q.       That's 99.01 percent of the override  
12 and royalty?

13          A.       Which includes the BLM, that's correct.

14          Q.       Now, as to those persons who have not  
15 yet committed their interests, I would refer you  
16 to Exhibits 5-A and 5-B. Could you very briefly  
17 discuss what Mewbourne did to obtain the  
18 commitment of those interests?

19          A.       5-A is a list of my contacts with the  
20 working interest owners that have not committed.  
21 The first one you'll notice is Lewis Burleson,  
22 and he has signed. The second one is Ann  
23 McReynolds, and she has signed. Both these  
24 parties signed yesterday.

25                   The last one I have on there is

1 Clarence Stumhoffer, and, if you'll note, he has  
2 a 0.00 percent interest in the working interest.

3 Q. He owns a working interest in a tract,  
4 is that correct?

5 A. Right.

6 Q. But it is a nonparticipating tract?

7 A. That's correct.

8 Q. So he's not a cost-bearing working  
9 interest?

10 A. That's correct.

11 Q. And Exhibit 5-B, what does that relate  
12 to?

13 A. This relates to our efforts to secure  
14 the signatures of the overriding royalty interest  
15 owners by those people that have not signed yet.

16 Q. Could you just briefly touch on each  
17 person?

18 A. The first one we come to is Gary and  
19 Candace Jo Bennett. We have, either myself or  
20 people working with me, have talked to him, and  
21 he has indicated that he would sign. As of  
22 today, we have not gotten his signature in.

23 There is a typo on this page. On my  
24 last entry there it says, "Telephoned to  
25 ascertain if joinder to unit and lien executed."

1 "And lien" should not be in there.

2 Q. Now, the contacts with them were just  
3 over the past month. Could you explain why this  
4 is?

5 A. The reason for this is, the BLM had  
6 requested that we put an additional tract into  
7 our unit.

8 Q. And that was quite recent, wasn't it?

9 A. Right. It was Tract No. 1, that we had  
10 not originally intended for it to be in our  
11 unit. After meeting with them, they requested we  
12 add it into there. We did that, had a title  
13 opinion prepared to ascertain ownership, and  
14 these are the overriding royalty interest  
15 owners. Again, these people in this tract have  
16 an overriding royalty interest, but a zero  
17 participation.

18 Q. Could you move on to the other pages?

19 A. John Borg, II, we have been trying to  
20 locate him since 1985. We currently have money  
21 in suspense for him. We've advised him of that.  
22 Mr. Calvert of our office has talked to him, and  
23 he has advised Mr. Calvert that he'll  
24 participate, but as of this date we have not  
25 received any response from him. And he's not

1 followed up on any of our attempts to release the  
2 money we're holding in suspense for him.

3 Q. The suspense money has to do--

4 A. --with other wells he's in, that's  
5 correct. Richard Borggaard, again, this is the  
6 Tract No. 1 that we were dealing with, and we've  
7 not been able to find him. We've called  
8 Anadarko, who operates that tract, and have  
9 spoken with their division order analysts, and  
10 they've advised us that they've been trying to  
11 look for him for several years, and that they  
12 have money in suspense theirselves for him, and  
13 cannot find him.

14 We found one Mr. Borggaard in Bend,  
15 Oregon, which was not the same one. Had no idea  
16 who he was. We're basically at a dead end in  
17 trying to locate him.

18 Q. Again, he has a zero participation in  
19 the unit?

20 A. That's correct. Pamela Brooks, she has  
21 advised us by telephone that she was reviewing it  
22 and she wasn't sure at this time. That was on  
23 June 8th, was the last telephone conversation  
24 we've had with her, and we've not heard back from  
25 her.



1           Stephen Burleson is signed. He signed  
2 today. That's our Exhibit 4 we just talked  
3 about.

4           Q.       4-A?

5           A.       4-A. William J. Casey, again, the last  
6 address we had on him was 1973, in New York, New  
7 York. Again, we visited with Anadarko, who  
8 operates the tract. This is that same Tract No.  
9 1. And we've not been able to locate him.  
10 Again, Anadarko has this interest in suspense.  
11 We'll keep trying to find him; and, if they have  
12 any luck, they'll notify us.

13           MR. STOVALL: This isn't the former CIA  
14 director?

15           THE WITNESS: No. That's what they  
16 asked me. Well, everybody knows where he is.

17           [Discussion off the record.]

18           A.       Nancy Hayes is Lewis Burleson's  
19 daughter and Steve's sister. She is out of town  
20 right now and unable to sign. However, her  
21 father and brother have both indicated that she  
22 will sign once she gets back from vacation.

23           Rae Little, again we've been trying to  
24 notify her and contact her since 1985, because of  
25 money we have in suspense for her. We have

1 approximately \$5,000 in suspense for her.

2 Q. She is deceased?

3 A. That's correct, but her estate has not  
4 been probated, is our understanding. And Mr.  
5 Calvert has had numerous conversations with the  
6 Little family, and has advised them of this money  
7 in suspense and of our trying to get the unit  
8 approved, and they've not responded to his  
9 inquiries.

10 Q. They haven't responded to inquiries for  
11 several years?

12 A. That's correct. Ann H. Johnson  
13 McReynolds has signed. We could delete this.  
14 She signed yesterday.

15 Margaret Johnson McCurdy is out of town  
16 until July 5th. Her secretary indicated to us  
17 that she doesn't know why she would not sign,  
18 "But I cannot act on behalf of her," is what she  
19 said. She has no reason why she wouldn't, but  
20 there's nothing she can do until she gets back.

21 Q. Again, this is Tract 1, and this is a  
22 nonparticipating interest?

23 A. That's correct. Lita Sabonis, again  
24 we've had numerous contacts with her family.  
25 We're just unable to get in touch with her. Her

1 family has given us her address and it's the same  
2 address we had in our files, and we're unable to  
3 get her to call us back. We've talked to all her  
4 relatives but can't get her to contact us. As a  
5 matter of fact, her relatives have signed this  
6 agreement. She's just hard to get ahold of or  
7 will not accept our calls, or whatever.

8 Gladys Shannon has advised us that she  
9 is involved with the Trammell Estates, who are  
10 the next people on this report. They've looked  
11 at this and they've sent us a letter advising  
12 that they will not sign. They have zero  
13 participation, why should they sign. That's the  
14 bottom line. They sent us a letter to that  
15 effect, and Gladys Shannon told us, "I'm going to  
16 do whatever the Trammell Estates does," and we've  
17 received a letter that they're not going to sign,  
18 "It's too small. We're not interested."

19 Q. So Shannon and all three Trammells--

20 A. --and all three Trammells are the same.

21 Q. And they are in Tract 1, which has a  
22 zero participation?

23 A. That's correct.

24 Q. And you mentioned that there were two  
25 unlocatable interests, William Casey and Lita

1 Sabonis. Could you describe what Exhibit 6 is?

2 A. Okay. Exhibit 6 is an affidavit of  
3 publication in the Hobbs newspaper, where we're  
4 asking for--just to put notice of what we're  
5 trying to do here, and for them to please notify  
6 us if we can find them.

7 Q. It was a publication notice to cover  
8 all your bases?

9 A. That's correct.

10 Q. There's one extra person listed on  
11 there, a Gregory Panos. Did you subsequently  
12 locate him?

13 A. Yes. I acquired his signature.

14 Q. In your opinion, has Mewbourne Oil  
15 Company made a good-faith effort to secure  
16 voluntary unitization of all the tracts?

17 A. Yes, we have.

18 Q. Has written notice of the unitization  
19 hearing been given to all locatable parties who  
20 did not voluntarily join?

21 A. Yes, it has.

22 Q. Is Exhibit 7 your affidavit of notice?

23 A. Yes, it is.

24 Q. The letter on that Exhibit 7 lists a  
25 number of people. Although the certified return

1 receipts attached are just some of those people,  
2 the people whose return receipts are omitted have  
3 since signed?

4 A. That's correct.

5 Q. As to the unit operating agreement,  
6 does it contain a provision for carrying working  
7 interest owners?

8 A. Yes, it does, that would be Section  
9 10.4.

10 Q. Does the operating agreement provide  
11 for a penalty against nonconsenting interest  
12 owners?

13 A. Yes. Section 10.5 provides for cost  
14 plus 200 percent.

15 Q. In your opinion, is this a fair  
16 penalty?

17 A. Yes, it is.

18 Q. Do operating agreements in this area  
19 typically contain similar penalties?

20 A. Yes, they do.

21 Q. 100 percent of the cost-bearing working  
22 interest owners have agreed to this penalty, have  
23 they not?

24 A. Yes, that's correct.

25 Q. What overhead rates does the unit

1 operating agreement provide for?

2 A. Currently, it provides for \$6,577  
3 drilling well rate, and \$680 as a producing well  
4 rate.

5 Q. You said the drilling well rate was  
6 what?

7 A. \$6,577.

8 Q. We'll get to that in a minute. These  
9 rates will be adjusted annually, under accounting  
10 procedures?

11 A. That's correct.

12 Q. Now, since the booklet with the unit  
13 operating agreement was printed, have there been  
14 some changes to the unit agreement?

15 A. Yes, there have.

16 Q. Referring to Exhibit 8, would you  
17 describe briefly what they are? And these are to  
18 the unit operating agreement?

19 A. That's correct. All right. Exhibit  
20 No. 8 reflects the changes we've entered into  
21 with a couple of companies. On page 24, we  
22 originally, on Article 10.5, six lines down, we  
23 originally had 30 days.

24 Q. To pay costs?

25 A. To pay costs. We have agreed with

1 Santa Fe Energy to amend that to 90 days.

2 Q. What's the next change?

3 A. Page F-10, paragraph 1.2 was amended,  
4 and in paragraph 1.3 the drilling well rate was  
5 changed from \$6,577 to \$5,400.

6 Q. So the drilling well rate will now be  
7 \$5,400 instead of what's printed in the original  
8 booklet?

9 A. That's correct. The producing well  
10 rate will remain the same. That was at a request  
11 from Anadarko.

12 Q. And finally, on page F-12, was there a  
13 change?

14 A. F-12, Item 4 was amended.

15 Q. And those were just changes in  
16 language, I believe?

17 A. Right.

18 Q. Will all working interest owners  
19 benefit from these changes?

20 A. Yes, they will. However, I wanted to  
21 add one other change we agreed to with Anadarko.  
22 We agreed that Mewbourne Oil Company agrees to  
23 allow the operating committee to approve the  
24 hiring of outside consultants. That was at the  
25 request of Anadarko, and we have agreed to that.

1 Q. These changes are to the benefit of the  
2 nonoperating interest owners, are they not?

3 A. That's correct.

4 Q. Now, as far as the unit agreement  
5 itself, and referring to Exhibit B, which is the  
6 tract schedule, are there any minor changes that  
7 will be made on here?

8 A. Yes, there are. At the request of the  
9 BLM, we have agreed to make the following  
10 changes. Tract 3 and 13 are reversed; in other  
11 words, Tract 3 will be 13, and 13 will be 3.  
12 They have also requested where we have basic  
13 royalty and percentage, that column, where we  
14 have 12 and a half percent, the BLM has requested  
15 us to put Schedule B in lieu of the 12 and a half  
16 percent. Just the words "Schedule B."

17 Q. That doesn't affect all those tracts,  
18 does it?

19 A. No, just those tracts that have a  
20 sliding scale will. And, I believe that is all  
21 that they've requested.

22 Q. The BLM changes don't change any of the  
23 participation factors?

24 A. No, they do not.

25 Q. In your opinion, will the granting of



1 these applications be in the interest of  
2 conservation, the prevention of waste, and the  
3 protection of correlative rights?

4 A. They will.

5 Q. And were Exhibits 1 through 8 prepared  
6 by you or under your direction or compiled from  
7 company records?

8 A. They were.

9 MR. BRUCE: Mr. Examiner, I move the  
10 admission of Mewbourne Exhibits 1 through 8.

11 EXAMINER STOGNER: Exhibits 1 through 8  
12 will be admitted into evidence at this time.

13 EXAMINATION

14 BY MR. STOVALL:

15 Q. Mr. Cobb, it appeared to me, from  
16 looking at the exhibits, that none of the parties  
17 that would be forced into the unit by the effect  
18 of the order, their participation or share will  
19 be the same whether it's voluntary or compulsory;  
20 is that correct?

21 A. That's correct.

22 Q. Any party who would be affected by cost  
23 issues, such as overhead rates, penalty rates for  
24 participation, et cetera, has signed the  
25 agreement and agreed to those?

1           A.       That's correct.  I do have a hundred  
2 percent.

3           MR. STOVALL:  I don't have any other  
4 questions with respect to the land issues in the  
5 case.

6                               EXAMINATION

7 BY EXAMINER STOGNER:

8           Q.       So, only noncost-bearing parties,  
9 pursuant to your question, Mr. Stovall, are being  
10 affected with this particular action?

11          A.       That's correct.

12          Q.       I assume when the application was made,  
13 that, however, was not the case?

14          A.       That's correct.

15          Q.       Now, if I go to my Exhibit No. 1 and  
16 find Tract 3, I need to change that to 13?

17          A.       That's correct.  And then, of course,  
18 13 to 3.

19                 MR. STOVALL:  Do you know why the BLM  
20 wanted to change those numbers?

21                 THE WITNESS:  They wanted these tracts  
22 in order of date, the earliest lease being Tract  
23 No. 1.  So, 13 was dated before 3.

24                 MR. STOVALL:  This isn't some sort of  
25 bureaucratic thing, is it?

1 THE WITNESS: No. No.

2 EXAMINER STOGNER: I have no questions  
3 of this witness. He may be excused at this  
4 time. Thank you.

5 **KEVIN MAYES**

6 Having been first duly sworn upon his oath, was  
7 examined and testified as follows:

8 EXAMINATION

9 BY MR. BRUCE:

10 Q. Would you please state your name and  
11 city of residence?

12 A. My name is Kevin Mayes, and I reside in  
13 Tyler, Texas.

14 Q. What is your occupation and who is your  
15 employer?

16 A. I'm a petroleum engineer with Mewbourne  
17 Oil Company.

18 Q. Have you previously testified before  
19 the Division as a petroleum engineer?

20 A. Yes, I have. As a matter of fact, I  
21 presented testimony in Case No. 10497 in July of  
22 1992. This resulted in Division Order No.  
23 R-9737, giving Mewbourne permission to test the  
24 injectivity of the First Bone Springs sand at  
25 Querecho Plains.

1 Q. So, you are familiar with the  
2 engineering matters related to the proposed unit  
3 and the waterflood for the unit?

4 A. Yes, I am.

5 EXAMINER STOGNER: What was that R  
6 number again?

7 THE WITNESS: R-9737.

8 EXAMINER STOGNER: Okay.

9 MR. BRUCE: Mr. Examiner, I tender Mr.  
10 Mayes as an expert petroleum geologist.

11 EXAMINER STOGNER: Was the order  
12 granted?

13 THE WITNESS: Yes, it was.

14 EXAMINER STOGNER: Okay.

15 MR. STOVALL: Then he's qualified.

16 EXAMINER STOGNER: I'm sorry, Mr.  
17 Bruce.

18 MR. BRUCE: I was just asking if the  
19 witness was considered qualified as an expert  
20 petroleum engineer.

21 EXAMINER STOGNER: Yes, he is.

22 Q. (BY MR. BRUCE) Mr. Mayes, referring to  
23 Exhibit 9, what is the unitized formation?

24 A. Exhibit No. 9 is a type log for the  
25 field. It's a density neutron porosity log run

1 in November 1987. It was run in Mewbourne Oil  
2 Company's Federal "L" #4 well. That well is  
3 located in Section 23, Proration Unit B.

4 For the Examiner's convenience, we've  
5 submitted a full section of that log to him, and  
6 I believe he'll find the unitized formation  
7 depths probably two-thirds of the way through  
8 that complete log, starting at approximately 8300  
9 feet.

10 EXAMINER STOGNER: 8328?

11 THE WITNESS: The actual depth will be  
12 8328 through 8620 feet in this well. And then,  
13 of course, the unitized formation will be all the  
14 strata that is geologically correlative to this  
15 interval underlying the unitized area.

16 Q. And this formation is designated by the  
17 Division as the Querecho Plains Upper Bone  
18 Springs Pool?

19 A. Yes, it is.

20 Q. Would you refer to Exhibit 10 and  
21 discuss the continuity of the formation?

22 A. Yes. Exhibit 10 is the stratigraphic  
23 cross-section across the unit area. To refresh  
24 everyone's memory, the two major sands located in  
25 the unitized formation Mewbourne has identified

1 as the green sand and the blue sand, and again  
2 this cross-section is presented today to  
3 demonstrate that the sands are continuous across  
4 the unitized area.

5 Q. This was presented in the prior  
6 hearing, also?

7 A. Yes, it was.

8 Q. Would you refer to Exhibits 11 and 12  
9 and discuss the outline of the unit area?

10 A. Exhibit No. 11 will be a net high  
11 isopach above the water/oil contact for the green  
12 sand, and Exhibit 12 will be the same isopach for  
13 the blue sand.

14 The reservoir is defined by porosity  
15 pinchouts on the north, east and west sides, and  
16 the water/oil contact on the south side.

17 Q. Does the proposed unit cover the entire  
18 Querecho Plains Upper Bone Springs Pool?

19 A. No, there are certain fringe areas of  
20 the reservoir that were omitted for economic  
21 considerations. However, we do have 100 percent  
22 of the cost-bearing participants agreeing to this  
23 unit boundary, as well as 99 percent of the  
24 royalty interests agreeing to the unit boundary.  
25 That includes the Bureau of Land Management's

1 designation of this unit area.

2 Q. And I believe Mewbourne had a couple of  
3 meetings with the BLM to discuss the outline of  
4 this unit?

5 A. That's correct.

6 Q. Referring to Exhibits 13 and 14, would  
7 you describe the history of the proposed unit  
8 area?

9 A. Exhibit 13 is a plat showing the  
10 development of the field. The discovery and  
11 initial commercial production came from Shell Oil  
12 Company's Querecho Plains #2 well, which is  
13 located in Section 27, Proration Unit M. It was  
14 brought onto production in April of 1959.

15 Quite a time lag occurred, then, before  
16 more attempts were made to complete the Upper  
17 Bone Springs Pool. Next attempts were made in  
18 1980, with two attempts made down in Section 34.  
19 And then Mewbourne completed their Federal "G" #1  
20 well, which is located in Section 27, Proration  
21 Unit K, in 1984, and then the field developed to  
22 the north/northeast in a fairly rapid fashion.

23 There were 35 completion attempts made  
24 within the unit area. There are currently 32  
25 producing wells from the proposed unitized

1 formation within the unit area. The spacing on  
2 the wells is 40 acres.

3 MR. STOVALL: How much? Say it again.

4 THE WITNESS: 40 acres.

5 Q. And Exhibit 14, please?

6 A. Exhibit 14 is a graphical  
7 representation of production from the unitized  
8 area and associated prediction of the primary  
9 depletion for the field. Peak production was  
10 29,950 barrels per month. That occurred in May  
11 of 1986. Production was fairly flat, then,  
12 during the development phase, until late 1989,  
13 and the field went on an approximate 40 percent  
14 nominal decline rate.

15 Cumulative oil production through  
16 October of 1992 is 1,556,000 barrels. Cumulative  
17 gas is approximately 5 Bcf. The drive mechanism  
18 is solution-gas, with the current GOR being 6,700  
19 standard cubic feet per stock tank barrel.

20 The reservoir pressure, the original  
21 pressure in the reservoir was 3,341 psi. It has  
22 now declined to 705 psi. Our remaining predicted  
23 primary production as of November 1, 1992, is  
24 473,376 stock tank barrels.

25 Q. Is the unit area in an advanced state



1 of depletion with respect to primary production?

2 A. Yes, it is. The wells currently  
3 average seven barrels of oil per day.

4 Q. Has the portion of the pool which you  
5 propose to unitize been adequately defined by  
6 development?

7 A. Yes, it has.

8 Q. Is this portion of the pool suitable  
9 for unitization and waterflooding?

10 A. Yes, we believe so. There are no Bone  
11 Springs sand waterfloods in New Mexico, to the  
12 best of my knowledge. However, the results of  
13 two injectivity tests, the continuous nature of  
14 the sands and the results obtained from computer  
15 modeling, suggest that this formation is suitable  
16 for a waterflood.

17 Q. When did Mewbourne Oil Company first  
18 consider unitizing this pool?

19 A. The reservoir was first considered a  
20 potential EOR candidate with fluid and core  
21 analysis work performed in late 1987.

22 Q. And, referring to Exhibit 15, would you  
23 discuss the feasibility study which was prepared  
24 for the proposed unit?

25 A. Yes. Exhibit 15 is a third-party

1 consultant's report on the pool. In particular,  
2 it's Petresim Integrated Technologies out of  
3 Houston, Texas. The report is submitted in its  
4 entirety, as it contains some very good summaries  
5 of the fluid work and rock work that we did. It  
6 also has a complete reservoir description in it,  
7 and, of course, the production predictions for  
8 primary depletion as well as waterflood  
9 operations.

10 Q. Has Mewbourne done anything to confirm  
11 the study prepared by Petresim?

12 A. Yes. As a result of our hearing last  
13 year and as a result, actually, of a June 1992  
14 operators' meeting concerning this project, we  
15 applied for and received the Division Order from  
16 last year, the Division Order R-9737, to test the  
17 injectivity of the sand.

18 Q. And, moving on to Exhibits 16, 17 and  
19 18, would you discuss them together and the  
20 results of the injectivity tests?

21 A. Yeah. Exhibit 16 is going to be a plat  
22 showing the location of the two injectors.

23 Exhibit 17 is going to be a performance  
24 curve for the Government "K" #2 well, which was  
25 one of the two test wells.

1           Exhibit 18 is a performance curve for  
2 the Federal "E" #11 well. Petresim's simulation  
3 suggested these wells would only take 200 barrels  
4 of water per day, and, as one can see from the  
5 performance curves, we got injectivity along the  
6 lines of 700 to 800 barrels per day. This was  
7 much better than we were anticipating and is very  
8 encouraging to us.

9           Q.       Referring to Exhibit 19, what injection  
10 pattern will you use for the waterflood?

11           A.       Exhibit 19 is a plat showing our  
12 proposed initial injection pattern. This pattern  
13 is the optimum pattern as it was determined by  
14 Petresim's computer modeling work.

15           Q.       And it's a line drive model?

16           A.       Yes, it is, line drive with the  
17 injectors aligned east/west.

18           Q.       Okay. Let's move on to Exhibits 20, 21  
19 and 22, and will you discuss the predicted  
20 performance of your waterflood?

21           A.       Yes. Exhibit No. 20 is Petresim's  
22 predicted production under waterflood  
23 operations. This prediction, I'll make a note  
24 for the Examiner, is slightly different from  
25 what's presented in their report, as this

1 prediction in Exhibit 20 takes into account  
2 modifications for the injectivity tests being  
3 better than we thought they were going to be.

4 Exhibit 21, then, is a graphical  
5 representation of Petresim's prediction, and  
6 Exhibit 22 is a graphical representation of the  
7 difference in the oil production that will be  
8 obtained during waterflood operations versus  
9 primary depletion.

10 Again, you can see on Exhibit 22, the  
11 remaining primary for the pool would be 473,376  
12 barrels of oil, and the incremental oil, due to  
13 the waterflood, is predicted to be 1.4 million  
14 barrels of oil.

15 Q. Referring to Exhibit 23, would you just  
16 briefly discuss the economics of the proposed  
17 unit?

18 A. Yes. Exhibit 23 is a summary of the  
19 economics. You can see the initial capital  
20 investment required for this project is  
21 \$2,850,000. If one uses the 1.4 million barrels  
22 of incremental oil, it generates approximately  
23 \$14 million of present worth to the working  
24 interest owners as a group.

25 The return on investment will be 5.9 to

1 1, and the internal rate of return will be 52  
2 percent. Also listed in Exhibit 23 is the  
3 benefit to the BLM and the benefit to the  
4 overriding royalty interests as a group.

5 I'll note these economics do have the  
6 BLM royalty reduction Schedule B taken into  
7 consideration, as well as the state's EOR.

8 Q. Will the oil and gas recovered by unit  
9 operations exceed unit costs plus a reasonable  
10 profit?

11 A. Yes, it will.

12 Q. What is the estimated life of the  
13 waterflood?

14 A. Approximately 12 years. We believe the  
15 waterflood operations will extend production into  
16 the year 2005.

17 Q. Is the unit area so depleted that it's  
18 prudent to apply an enhanced recovery program?

19 A. Yes, it is.

20 Q. In your opinion, is the waterflood  
21 application economically and technically feasible  
22 at this time?

23 A. Yes, it is.

24 Q. Will waterflood operations in this  
25 portion of the pool prevent waste?

1 A. Yes, it will.

2 Q. And will they result, with a reasonable  
3 probability, in increased recovery of  
4 substantially more hydrocarbons than would  
5 otherwise be recovered?

6 A. Yes, it will.

7 Q. In your opinion, will unitization and  
8 secondary recovery operations benefit the working  
9 and royalty interest owners in the portion of the  
10 pool being unitized?

11 A. Yes, it will.

12 Q. Will unitization of just a portion of  
13 the pool adversely affect the nonunitized  
14 portions of the pool?

15 A. No. If anything, offset operators may  
16 receive some pressure maintenance from our  
17 project in the fringe areas.

18 Q. Let's move on to Exhibit 24. Will you  
19 identify that?

20 A. Yes. Exhibit 24 is the New Mexico  
21 State Form C-108. It was submitted with our  
22 application, and it is required in order to  
23 inject fluids.

24 Q. Would you please discuss your proposed  
25 injection wells?

1           A.       Yes.   Pages 2 through 16 of the C-108  
2 are schematics of all of our proposed injection  
3 wells.

4           Q.       And the pages of the C-108 are numbered  
5 for the ease of the Examiner?

6           A.       For the convenience of the Examiner,  
7 yes, sir.

8           Q.       Go ahead, Mr. Mayes.

9           A.       If I could refer everybody to page 2,  
10 on the first schematic, how we calculated the top  
11 of cement is documented on that first schematic,  
12 and how we calculated that top of cement is used  
13 throughout the C-108.

14                    It was calculated using the appropriate  
15 cement yield at 25 percent reduction to this  
16 yield, and no consideration was given to casing  
17 collars.

18                    It is our intention to set a packer  
19 within 100 feet of the top perforation and use  
20 noncoated tubing.

21           Q.       Would you please discuss the wells in  
22 the area of review.

23           A.       Yes.   The area of review is defined as  
24 a one-half mile radius around each injector.  
25 Pages 18 through 23 of the C-108 contain a spread

1 sheet list of all mechanical information for  
2 wells within this area of review which penetrate  
3 the unitized formation.

4 Q. Are there any plugged and abandoned  
5 wells within the area of review?

6 A. Yes, there are. Pages 24 through 27  
7 contain schematics of all plugged and abandoned  
8 wells.

9 Q. To the best of your knowledge, is the  
10 mechanical integrity of all of these wells  
11 sufficient for you to conduct your waterflood  
12 operations?

13 A. Yes, I believe so. However, I would  
14 like to discuss the Federal E #1 well, as it was  
15 the topic of our last hearing.

16 EXAMINER STOGNER: What page am I going  
17 to find that on?

18 THE WITNESS: We're going to submit a  
19 new exhibit.

20 Q. If you could, Mr. Examiner, refer to  
21 Exhibit 25, and I'll refer Mr. Mayes to that, and  
22 discuss the Federal E #1 well. And, as you said,  
23 this was brought up at the hearing last July, was  
24 it not?

25 A. That's correct. Exhibit 25 are some



1 calculations concerning the E #1 well. The  
2 concern with the E #1 well is that the calculated  
3 TOC, top of cement, does not cover the First Bone  
4 Springs sand. We did a thorough check of our  
5 records and indeed we did not run a temperature  
6 log or a cement bond log to verify this top of  
7 cement.

8           However, we do have a caliper log, and  
9 these calculations reflect using the caliper  
10 volume at 100 percent slurry volume, and taking  
11 casing collars into account. However, the  
12 calculated top of cement is 10,666 feet, and it  
13 still does not cover the First Bone Springs  
14 sand.

15           However, in defense of not reentering  
16 the E #1 for potential squeeze operations, I  
17 would like to offer up some items for defense.

18           First of all, the mud that is in the  
19 annulus between the 5-1/2" casing and the  
20 wellbore, is an 11.8 pound per gallon mud. This  
21 is a very heavy mud. We tried to find the mud  
22 records and find the additives that were actually  
23 added to this mud, and we could not find them.

24           However, an 11.8 per pound gallon mud,  
25 we suspect, has substantial amount of gel and

1 possibly barite used to weight it up that heavy.

2           One of the items in the Division Order  
3 that was issued last year, was that we would  
4 monitor the casing annulus on this E #1 well to  
5 see if any pressure would occur on the surface.  
6 We've monitored that casing spool at the surface  
7 for almost a year now and have never seen any  
8 pressure on that annulus.

9           The E #1 well is the direct west offset  
10 to one of our test injection wells, also, and we  
11 injected 50,000 plus barrels of water into that  
12 test injector, which is getting close to being a  
13 fill up volume for the E #1 area. Again, if we  
14 were going to see pressure at the surface of the  
15 E #1 on that annulus, we would have expected to  
16 see it during injection procedures in the offset  
17 test well; but, again, we never did see any  
18 pressure there.

19           I would like to reiterate some  
20 testimony I gave last year concerning this  
21 issue. This very heavy mud has been in that  
22 annulus for approximately 20 years now. I've had  
23 similar experience in trying to circulate cement  
24 into an annulus after a heavy mud has been  
25 located there for this length of time, and our

1 experience was that we punched some holes in the  
2 casing and tried to circulate some cement into  
3 the annulus, and what we ended up doing was just  
4 exceeding frac gradient, and we never could get  
5 that mud to move in that annulus again. It had  
6 set up to a point of having almost immobile  
7 properties.

8 Our concern with reentering the E #1  
9 would be that we would try cement and squeeze  
10 operations and essentially the same thing would  
11 happen to us. We would exceed frac gradient and  
12 we would squeeze our cement out into the frac  
13 plane and we would never get any cement  
14 circulated into that annulus.

15 Another point I'll make is that  
16 mud-laden fluids are used in plugging and  
17 abandoning wells, and that mud-laden fluid is  
18 trusted to keep cross-flow from reservoir to  
19 reservoir from occurring.

20 I also might go back, excuse me if I  
21 can and revert a little bit, down at the bottom  
22 of this Exhibit 25 are some hydrostatic  
23 calculations for that mud. That mud, 11.8 pound  
24 per gallon mud, generates a hydrostatic head at  
25 the top of the Bone Springs formation of 5,106

1 psi. And I'll remind you that the virgin  
2 pressure for the Bone Springs pool was 3,341 psi,  
3 and the maximum predicted reservoir pressure we  
4 anticipate during waterflood operations is 3,971  
5 psi.

6 Just strict hydrostatics would dictate  
7 that nothing will enter the annular area from the  
8 First Bone Springs formation, due to this heavy  
9 mud.

10 Q. As part of your tests, you did monitor  
11 the annulus of the E #1?

12 A. Right. We've monitored that annulus  
13 for about a year now, and we've still not seen  
14 any pressure on that annulus. The E #1 does  
15 contain significant Morrow gas reserves. It's  
16 currently producing out of the Morrow formation.  
17 We feel that reentering that well provides a  
18 tremendous amount of risk to losing those gas  
19 reserves, so we would again request that  
20 monitoring this wellbore be allowed, versus  
21 reentering that wellbore.

22 Q. Is it in the best interest of the  
23 working interest owners to keep all injected  
24 water in the unitized formation?

25 A. That's correct. You lose efficiency

1 with a waterflood any time you let water out of  
2 the unitized formation, and we will make every  
3 effort not to let that happen.

4 Q. Will you please discuss your plans for  
5 reworking the injection wells?

6 A. The proposed injection wells are all  
7 currently producing and will require removal of  
8 rod pump equipment. We plan to install a packer  
9 within 100 feet of the top perforation in each  
10 well, and have an inert fluid circulated into the  
11 casing tubing annulus. All injectors will  
12 receive acid treatments during their conversions,  
13 and all wellheads will have pressure gauges  
14 installed on the tubing and casing annuli.

15 Q. What additional facilities will  
16 Mewbourne Oil Company need to install for the  
17 unit and the waterflood?

18 A. We propose both a central injection  
19 facility and a central production facility. The  
20 injection facility will consist of appropriate  
21 storage capacity, filters, meters and injection  
22 pumps. The production facilities will consist of  
23 appropriate storage, separating equipment, meters  
24 and sales hookups. Produced water will be  
25 reinjected, and all flow lines will be rerouted

1 accordingly. A water service line approximately  
2 three miles in length will be built to connect to  
3 the City of Carlsbad's Double Eagle system.

4 Q. What injection pressure do you request  
5 approval of?

6 A. The projection prediction we obtained  
7 from computer modeling is based on injecting at a  
8 surface pressure at 2,000 psi, and we would  
9 request allowing that 2,000 psi as the maximum  
10 injection pressure.

11 Q. Referring to Exhibit 26, could you  
12 discuss the basis for your request?

13 A. Yes. Again, Exhibit 26 contains  
14 calculations showing the frac gradient will not  
15 be exceeded with the 2,000 psi surface pressure.

16 Again, this 2,000 psi surface pressure  
17 was a topic of our July 92 hearing. The  
18 Division's Order allowed for a tubing pressure of  
19 1,650 psi, with a procedure for administrative  
20 approval for 2,000 psi. It turns out that we use  
21 produced Delaware water as source water for  
22 testing those injectors, and it was much heavier  
23 than we anticipated, so administrative approval  
24 was never sought.

25 The gradient hydrostatic head for this

1 Delaware water was .51 psi per foot, and  
2 generated a total head of .70 when 1,650 psi was  
3 added to it.

4 The injected fluid for the full flood  
5 will be a mostly low-dissolved-solids content  
6 water from the City of Carlsbad. If one uses a  
7 .45 fluid gradient for that City of Carlsbad  
8 water, and a 2,000 psi surface pressure, one  
9 calculates a total head of .69 psi per foot, well  
10 below the frac gradient, and the frac gradient is  
11 established as the .74 for the pool.

12 Q. Is this request supported by the  
13 results of your injectivity tests?

14 A. Yes, it is. I'll refer everyone to  
15 Exhibits 27, 28 and 29, which showed that the  
16 water stayed contained in the Bone Springs during  
17 those injectivity tests.

18 Exhibit 27 is a pressure gradient  
19 survey confirming the head of the Delaware water  
20 was .51 psi per foot and, as a result, we were  
21 injecting at .70 psi per foot during our test.

22 And Exhibits 28 and 29, are injection  
23 surveys showing that the water stayed contained  
24 within the unitized formation. You can see on  
25 the second page of the--well, let's take Exhibit

1 28 which is the profile survey for the Government  
2 K #2 well, you can see on Page No. 2 of that  
3 exhibit that the survey company concluded that no  
4 fluid moved above the top perforation.

5 Page No. 2 which is very busy, and I  
6 kind of apologize for that but, it has a series  
7 of temperature logs run at various shut-in  
8 periods to verify that the water did not go past  
9 the bottom perforation.

10 Then Exhibit 29 is going to be a  
11 similar profile log for the Federal E #11, and  
12 again these two profile logs on our two test  
13 wells do show that the wells stayed contained,  
14 and we will be injecting at a lower gradient than  
15 we were during these tests, during our whole  
16 flood operations.

17 Q. Of the injection water, what percentage  
18 do you anticipate will be fresh water from the  
19 Carlsbad system?

20 A. Approximately 90 percent should be City  
21 of Carlsbad water. And 10 percent we hope to  
22 pick up as produced water from various offset  
23 operators in our own operations.

24 Q. Will this be a closed system?

25 A. Yes, it will.



1 Q. Are there any fresh water sources  
2 within a mile of the proposed injection wells?

3 A. There are no active fresh water wells,  
4 according to the New Mexico State Engineer's  
5 Office. There was an attempt to develop a water  
6 well in Section 26; however, it was dry and  
7 abandoned.

8 Q. Are there any faults or hydrologic  
9 connections between fresh water sources and the  
10 injection point?

11 A. No, there are no faults, to my  
12 knowledge, and all wellbores have casing said to  
13 a depth sufficient to cover known fresh water  
14 sources in the region.

15 Q. Is the proposed injection water  
16 compatible with the formation water?

17 A. Yes. An analysis is presented on pages  
18 30 through 36 of the C-108. This report was  
19 prepared by a commercial laboratory and indicates  
20 minimal compatibility problems exist.

21 Q. Is the unitized management, operation  
22 and development of this pool necessary to  
23 effectively carry on secondary recovery  
24 operations?

25 A. Yes, it is.

1 Q. And, in your opinion, will it  
2 substantially increase the ultimate recovery of  
3 oil from the unitized portion of the pool?

4 A. Yes, I believe so.

5 Q. In your opinion, does the unit  
6 agreement provide for a fair and equitable plan  
7 of unitization?

8 A. Yes, it does.

9 Q. Mr. Mayes, if you could refer back to  
10 Exhibit 2, could you describe how production will  
11 be allocated among the tracts under the unit  
12 agreement?

13 A. Yes, and we are referring back to the  
14 unit agreement, if everybody wants to get that  
15 back out.

16 Q. And what pages in particular do we want  
17 to refer to?

18 A. I'll refer everyone to pages 6 and 7 of  
19 the unit agreement, and that will be Articles  
20 2.23 and 2.24. What we propose is a two-phase  
21 allocation formula, the initial phase defined as  
22 the primary phase and Article 2.23 is set up to  
23 allocate the remaining primary reserves of the  
24 reservoir to the separate tracts.

25 Then, on page 7, we propose a later

1 phase, which is defined as the secondary phase in  
2 Article 2.24, and it is set up to allocate the  
3 secondary reserves, i.e., the 1.4 million barrels  
4 of oil, and the capital costs associated with  
5 these secondary reserves.

6 Referring back to page 6 real quick,  
7 the primary phase will be in place until the  
8 total unit remaining primary is produced, and  
9 again that volume is determined to be this  
10 473,376 barrels of oil as of November 1, 1992.

11 I'll refer everybody ahead to page 22  
12 real quick. The proposed primary formula is 100  
13 percent remaining primary reserves as they were  
14 determined by decline curve analysis, i.e., the  
15 tract remaining primary divided by the total unit  
16 remaining primary. The production will then be  
17 allocated to the tracts based on the secondary  
18 formula, which we propose is 100 percent ultimate  
19 primary oil, as determined by decline curve  
20 analysis.

21 Q. In your opinion, does the participation  
22 formula allocate the produced, and saves  
23 hydrocarbons to the individual unit tracts on a  
24 fair, reasonable and equitable basis?

25 A. Yes, we do.

1 Q. What is the initial project area for  
2 the waterflood?

3 A. The initial project area pursuant to  
4 Division Rule 701(G)(3) will encompass 1,280  
5 acres, all located inside the unit boundary.

6 Q. What project allowable does Mewbourne  
7 request?

8 A. Mewbourne would request that each  
9 producing well be granted an allowable equal to  
10 its capacity to produce.

11 Q. And do you request that the order  
12 entered in this matter contain an administrative  
13 procedure for approving unorthodox well locations  
14 or for changing producing wells to injection  
15 wells?

16 A. Yes. In order to optimize the  
17 waterflood in the future, it may be necessary to  
18 convert producing wells to injectors, or to drill  
19 additional wells at unorthodox locations and we  
20 would request that an administrative procedure be  
21 established in the order to accomplish this.

22 Q. Is your proposal submitted as Exhibit  
23 30?

24 A. Yes, it is.

25 Q. Was notice of the waterflood sent out

1 as required by Form C-108?

2 A. Yes, it was. We notified all operators  
3 and lessees within one-half mile of the proposed  
4 injectors, together with surface owners and all  
5 lessees of surface rights.

6 Q. Is Exhibit 31 your affidavit regarding  
7 notice?

8 A. Yes, it is. It contains the return and  
9 certified receipts.

10 Q. In your opinion, will the granting of  
11 this application be in the interests of  
12 conservation and the prevention of waste?

13 A. Yes, it will.

14 Q. Were Exhibits 9 through 31 prepared by  
15 you or under your direction, or compiled from  
16 company records?

17 A. Yes, they were.

18 MR. BRUCE: Mr. Examiner, I move the  
19 admission of Exhibits 9 through 31.

20 EXAMINER STOGNER: Exhibits 9 through  
21 31 will be admitted at this time.

22 EXAMINATION

23 BY EXAMINER STOGNER:

24 Q. Mr. Mayes, on Exhibit No. 30, this is  
25 your proposed rules, there's a lot of information

1 that's been simulated, so forgive me if I'm  
2 repeating a few things I might have missed.

3 Are you going to propose an  
4 administrative procedure for injection increase  
5 or--I know the 2,000 psi is over the .2 psi per  
6 foot to the uppermost perf that we require. Is  
7 your 2,000 going to be the maximum throughout the  
8 lifetime, or do you anticipate a higher injection  
9 pressure?

10 A. No, sir. 2,000 psi will be our maximum  
11 pressure throughout the life.

12 Q. In reviewing your schematic for your  
13 injection wells, you'll be using 2-7/8" or 2-3/8"  
14 tubing for your proposed injection wells?

15 A. Right.

16 Q. First of all, how many injection wells  
17 total?

18 A. 15 will be converted. Of course, two  
19 are already converted and 15 total.

20 Q. I notice that there is no proposal or  
21 plan for plastic-lined or lined tubing, that  
22 you're going with bare steel. What is the  
23 configuration on the two existing injection wells  
24 at this time?

25 A. They both have bare steel in them. We

1 ran some corrosion coupons in our injection lines  
2 during our test and, after running analysis on  
3 those coupons, it was established the corrosion  
4 weight was approximately 1.6 mil per year. I  
5 have experienced in floods where corrosion rates  
6 of four and five mils per year was obtained, or  
7 effective. And throughout an eight-year life  
8 that I worked with that waterflood, we never had  
9 any tubing problems associated with that high of  
10 a corrosion rate.

11 Q. And, if I heard correctly, your water  
12 source will be at least 90 percent City of  
13 Carlsbad. Is this fresh water, or is this from  
14 the sewer system?

15 A. It's their Double Eagle System which, I  
16 believe, it's Caprock water. We have an analysis  
17 of it which is located in that C-108 water  
18 analysis package, the latter pages of the C-108,  
19 and I believe--well, let me just give you the  
20 correct TDS content of that water.

21 Okay, total dissolves solids--

22 Q. Which page are you on?

23 A. I don't have a numbered one.

24 MR. STOVALL: Page 31. Is it the  
25 letter from Caprock Laboratory?

1 THE WITNESS: Yeah. Just following  
2 that are some analysis sheets.

3 A. Page 33 is the Double Eagle analysis,  
4 and they've got a number down the left side of  
5 that page, No. 16 is the total dissolved solids  
6 content of the water, 8,213 parts per million.

7 Q. Do you know what formation this water  
8 is from?

9 A. I really don't know, exactly.

10 Q. Do you know where their well is  
11 located, or is this from a system?

12 A. Yeah, their wells are north and east of  
13 us, a good 15, 20 miles, and then their system  
14 runs several miles to the City of Carlsbad.

15 Q. But this is one of the systems or one  
16 of the wells, whatever the case may be, that  
17 feeds fresh water into the City of Carlsbad?

18 A. Yes, and it's quite an extensive system  
19 ride. It is permitted and tapped for industrial  
20 use all along its way, also.

21 Q. And you would just be picking up a  
22 portion of it?

23 A. Correct.

24 Q. You said 10 percent, would that be  
25 reinjected source water from your proposed



1 injection, or would there be other produced  
2 waters from outside this unit?

3 A. It will be both. We'll recycle all the  
4 unit-produced water, as well as we have offset  
5 operators to us producing fairly substantial  
6 amount of Delaware water that we're negotiating  
7 to take off their hands for them.

8 Q. Is there a technical reason or  
9 formation or geologic reason why 100 percent  
10 produced water or reinjection water could not be  
11 utilized in this project?

12 A. Well, during the life of the flood,  
13 currently the flood, all the wells in the unit,  
14 produce approximately 100 barrels of water a day,  
15 and we require 10,000 barrels of water a day for  
16 the flood. As the flood matures and the  
17 producing wells break through, of course, the  
18 produced water will increase.

19 Is that your question? I don't know if  
20 I understand you correctly.

21 Q. Yes, and in fact you're going into it  
22 to the detail that I think is applicable.  
23 Throughout the life, what are you going to be  
24 seeing and what kind of changes?

25 A. We estimate that probably three years

1 into the life of the flood we'll be cycling 80  
2 percent of our water and only receiving 20  
3 percent of our water from the City of Carlsbad.

4 Of course the TDS content of that  
5 produced water is going to be breakthrough water  
6 that will have City of Carlsbad quality or Bone  
7 Springs quality and we feel like the total  
8 dissolved solids of the water is not going to  
9 increase substantially over the life of the  
10 waterflood, over the life of cycling that water.

11 Q. Say in about another 10 to 15 years,  
12 when you're utilizing, say, 80 percent  
13 reinjection as opposed to 20 percent City water,  
14 essentially makeup water at that point--

15 A. Right.

16 Q. --what kind of water analysis would you  
17 expect, as far as total dissolved solids?

18 A. Well, I haven't done that calculation  
19 so it's hard to give you a hard and fast number;  
20 but, if one looks at that, this analysis in the  
21 back of the C-108, there's a Bone Spring  
22 analysis.

23 Q. I believe that's page 34.

24 A. That's correct. And you can see that  
25 the dissolved solids of this water is 149,000

1 parts per million, but the water that's actually  
2 going to be Bone Spring-produced water is going  
3 to be so diluted by the City of Carlsbad water  
4 that I would anticipate that that total dissolved  
5 solids would not appreciably increase over 8,000  
6 parts per million.

7 Again, you know, I haven't done those  
8 calculations and it's hard to give you a hard and  
9 fast number.

10 Q. Your water analysis shows no hydrogen  
11 sulfite?

12 A. Right.

13 Q. So this is a sweet oil pool?

14 A. The temperature of the reservoir is  
15 130, 140 degrees, and I would anticipate that any  
16 bacteria that might form H<sub>2</sub>S during the life of  
17 the project will be killed at those  
18 temperatures. We're not anticipating a heavy H<sub>2</sub>S  
19 problem.

20 Q. My concern at this point is bare steel,  
21 allowing it at this point, and what happens in  
22 the future.

23 A. Well, I would submit that, again, we  
24 are going to have an inert fluid in between the  
25 tubing and casing annulus on all of our injection

1 wells, and we'll be monitoring the pressure of  
2 that annulus at the surface. If we would have a  
3 tubing leak occur, we're going to be able to see  
4 it very quickly. And if it appears to us that  
5 bare steel is going to become a problem, then in  
6 the future we might consider coating our tubing  
7 at that time. But we would propose initially,  
8 going into the flood, that we use bare steel and  
9 monitor the situation.

10 Q. Is the grade of tubing that you're  
11 utilizing just standard, oil field grade, regular  
12 production-type tubing, or anything special?

13 A. It's standard N80 J55 tubing.

14 Q. In referring to your C-108, Exhibit No.  
15 24, starting with page 18, this is your review of  
16 wells within the area of review, the half-mile  
17 area?

18 A. Uh-huh.

19 Q. When you show tops of cement, were  
20 these all calculated or were any of them from  
21 temperature surveys, or were they from various  
22 means?

23 A. For the most part they're calculated.  
24 However, there are some that the column--I'll  
25 refer you to the first page, the third well down

1 has some letter symbols in parentheses next to  
2 the top of cement?

3 Q. You're talking about the Mewbourne  
4 Federal M #1 and the letter V, as in Victor,  
5 shows up?

6 A. Right. The "V" stands for visual. In  
7 other words, I actually saw the cement come back  
8 to surface on those wells. There are some other  
9 letter designations. There's a CBL, little "B"  
10 in parenthesis occasionally, which stands for  
11 Cement Bond Log, and this is all labeled on the  
12 last page of that spreadsheet--well, was. I take  
13 that back. It's not. I apologize.

14 A V is for Visual, and a CBL is for  
15 Cement Bond Log, and I believe those are the only  
16 two notations that--yeah, those are the only two  
17 notations that I put in there. All the rest will  
18 be calculated tops of cement.

19 Q. Pursuant to the same calculation that  
20 you utilized on page 2 of the C-108?

21 A. That's correct.

22 Q. There again, figuring in no collars?

23 A. That's correct.

24 Q. And a 25 percent access?

25 A. That's correct.

1           Q.       Now I'm going to refer to Exhibit No.  
2 22 and do somewhat of some kind of comparison  
3 work here to Exhibit 15.

4                   Now, when I show your incremental oil,  
5 referring to **Exhibit No. 22, this** is the oil  
6 **which we expect to recover with the waterflood,**  
7 **the 1.4 million barrels,** is that correct?

8           A.       That's correct.

9           Q.       Now, I could not find an Exhibit No.  
10 15, but is it different when I find that  
11 information in here, or is it even presented in  
12 your Exhibit 15?

13           A.       No. Exhibit 15 are just going to be  
14 the results of the production coming out of the  
15 computer modeling work. I guess I should ask a  
16 follow-up to your question. It has all of the  
17 production coming out of the unit area during the  
18 flood operations. In other words, it has both  
19 the primary plus the secondary, is their  
20 prediction. Is that the answer you're looking  
21 for?

22           Q.       I believe it is. There was a reference  
23 in your summary. Reservoir depletion was  
24 estimated to be 1.86 million standard stock tank  
25 barrels.

1           A.       Stock tank barrels, yes.

2           Q.       Is this figure utilized throughout, or  
3 am I going to see different reservoir figures?

4           A.       No.    The 1.4 and the 473,000 barrels of  
5 oil, adding up to this 1.8 you're referring to,  
6 is taking Petresim's computer simulation numbers  
7 and applying Mewbourne Oil Company economic  
8 evaluation to those predictions.

9                    So Exhibit 22, the incremental oil is  
10 based on economic parameters, not just computer  
11 modeling that Petresim did in Exhibit 15.

12          Q.       I hate to belabor this, but when I look  
13 at your Exhibit 19, I show 15 injection wells.

14          A.       That's correct.

15          Q.       Is that 13 new ones, or 13 conversions  
16 plus your two, or are you going to have a total  
17 of 17?

18          A.       No, you have it correct.  It's two  
19 existing and 13 will be converted, for a total of  
20 15.

21          Q.       And those are all conversion Bone  
22 Spring completions?

23          A.       That's correct.

24          Q.       You testified that the average well  
25 produces seven barrels of oil at this point, is

1 that correct?

2 A. That's correct.

3 Q. What's the high side? What's one of  
4 your best producers out there?

5 A. Probably 15 barrels per day. In other  
6 words there were some wells that didn't quite  
7 meet the BLM's Schedule B royalty reductions, and  
8 their cap is 15 barrels per day, so I'll offer up  
9 15 barrels a day as a high side.

10 Q. How about your low side?

11 A. There are some wells that are shut in,  
12 currently.

13 Q. What's economic producers out there?

14 A. Three barrels per day.

15 Q. Do you have some of those?

16 A. Well, you know, I say three barrels per  
17 day. Please understand, that's depending on the  
18 gas rates out of the well, et cetera, et cetera.

19 Q. To come up with seven barrels of oil a  
20 day, did you include those ones that are shut in?

21 A. Yes, I did. Basically, all the wells  
22 in the unit area currently make 230 barrels per  
23 day total, and I divided that by the 32 wells  
24 that are being unitized.

25 Q. Now, if I remember right, there were 35



1 completion attempts?

2 A. Yes, sir.

3 Q. And 32 producing wells?

4 A. Currently producing. Yes, sir.

5 Q. Now, are those actually producing or  
6 are some of them shut in?

7 A. Well, true. Some of them are shut in.  
8 Those are wells that currently have perforations  
9 open to the First Bone Spring sand.

10 Q. Do you know how many actually are  
11 pumping and actually making oil?

12 A. Well, 32, minus the two test injectors  
13 is 30, minus the Sprinkle No. 2.

14 Q. Just a rough estimate, how many shut-in  
15 wells have you got?

16 A. Let's say 29.

17 MR. STOVALL: 29 shut in, or 29  
18 active?

19 THE WITNESS: 29 active.

20 Q. If I look at that average production on  
21 those 25 active wells, would that fall under 10  
22 barrels of oil per day. Okay. The 29 active  
23 wells--

24 A. --divided into the 230 days, would be  
25 less than 10 barrels a day, yes.

1 Q. So we're definitely talking stripper  
2 wells?

3 A. Yes.

4 EXAMINER STOGNER: We will take  
5 administrative notice of Order No. R-9737 and the  
6 previous case that resulted in that order, and  
7 with that, I have no other questions of this  
8 witness at this time.

9 MR. STOVALL: Well, I do.

10 EXAMINATION

11 BY MR. STOVALL:

12 Q. I think your application states you are  
13 asking for the EOR tax credit?

14 A. That's correct.

15 Q. Other than your injectivity test this  
16 is a new project, is that correct?

17 A. That's correct.

18 Q. I note, in looking at your various  
19 maps, there are some undeveloped proration units  
20 within the pool. Have those been determined to  
21 be just not productive or no oil in place within  
22 the unit area?

23 A. Can you be a little more specific?

24 Q. I'm looking at Exhibit 19. I'm looking  
25 at Exhibit 19, specifically, because it has the

1 injectors, but Section 27, Section 28--

2 A. Right.

3 Q. --they look pretty well developed  
4 within the interior pool. Are most of the  
5 undeveloped tracts on the exterior of the pool?

6 A. A couple of things are happening with  
7 that area of the pool. One is, there's not a lot  
8 of mapping points over there, and we don't know  
9 how much deposition occurred over there. We  
10 don't know how much net height to give that  
11 area.

12 Obviously, the owners of those tracts  
13 were not interested in those tracts for the  
14 primary reserves alone, and did not drill a well  
15 for the primary reserves.

16 However, we, and of course all the  
17 participants in the unit, and the BLM, believe  
18 that there might be justification to drill a well  
19 for the primary plus the secondary reserves of  
20 those tracts. We plan on developing those tracts  
21 as soon as the waterflood has proven itself to be  
22 successful.

23 Q. Is the potential primary in there  
24 calculating 400-and-some-thousand primary?

25 A. No, sir.

1 Q. It's not included? It's only in the  
2 developed?

3 A. That's correct.

4 Q. How familiar are you with the EOR tax  
5 credit provision or rate reduction?

6 A. Oh, vaguely familiar. I'm familiar  
7 with the rates, not familiar with the paperwork  
8 to apply for it.

9 Q. This is it. You're in it.

10 A. Okay.

11 Q. I will explain it briefly to you, that  
12 what has to happen is that this is a new  
13 project. The approval of a project after the  
14 date can qualify the project, it meets the basic  
15 criteria for qualification. That does not mean  
16 you get the tax rate, that means we can certify  
17 it as a qualified EOR project.

18 You would not be eligible for the tax  
19 rate until such time as there is a  
20 production--what's the word?

21 MR. BRUCE: Production response.

22 Q. Positive production response. Thank  
23 you, Mr. Bruce. When do you plan to actually  
24 start waterflood operations?

25 A. We'll put the unit into effect the

1 first of the month, after we receive the Division  
2 order.

3 Q. I mean actual water. I don't care  
4 about the unit.

5 A. We're going to start water into those  
6 two test injectors as soon as we receive the  
7 division order.

8 Q. Now, you've already put some water in  
9 those, is that correct?

10 A. That's correct.

11 Q. And have you had any response from  
12 that?

13 A. No, we haven't. Not yet. Those will  
14 just to test the injectivity.

15 Q. Which wells are those? Well, where are  
16 those wells located? I'm looking at Exhibit 19,  
17 because it kind of gives me an aerial.

18 A. It's Section 23, Proration Unit K, and  
19 Section 27, Proration Unit A.

20 Q. How long is it going to take to  
21 construct and convert the rest of the unit?

22 A. To get full flood up and running, it  
23 would take approximately three months, I would  
24 estimate.

25 Q. From the dates the project is

1 certified, because this is a secondary project,  
2 you would have five years to get a positive  
3 production response. I'm kind of gathering, from  
4 what you're saying, that three months isn't going  
5 to be a big deal or make it or break it?

6 A. No. No, sir.

7 Q. So, we could certify the project at the  
8 time as of the date that the order is entered  
9 approving the project?

10 A. Yeah.

11 Q. Now, actually, that five years is not  
12 to get the response, but is to apply for a  
13 certification of positive production. You may  
14 get it in a year, but if you don't apply to us  
15 within the five years, you lose the credit  
16 regardless of when you got the response.

17 You're not talking about phase  
18 development of this project, is that correct?  
19 You're going to start converting and keep on  
20 moving?

21 A. Uh-huh.

22 Q. What we will do at the time we approve  
23 it would be to certify the area, and it would  
24 seem to me appropriate to certify the unit area  
25 at that time.

1           How long do you anticipate it will take  
2 to get your Phase I out onto the unit agreement?

3           A.     Our estimates are three and a half  
4 years right now, about 470,000 barrels.

5           Q.     But you do anticipate there will be an  
6 increased production rate during that period?

7           A.     Yes.

8           Q.     And that's simply for accounting  
9 purpose, not for a recovery purpose?

10          A.     Right.

11          Q.     At the time we certify the area, as I  
12 say, I think we can certify the entire unit  
13 area. The question I'll have, at the time you  
14 come in with a positive production response, it  
15 is very likely that the Division will look  
16 closely at where you are actually injecting and  
17 appear to be receiving a benefit.

18                 Now, what you're going to have to do is  
19 come in and demonstrate, and I think in this  
20 case, be prepared to show which wells have  
21 benefited from the response, by use of production  
22 curves. I assume you have curves on most of the  
23 wells, is that correct?

24          A.     Yes, sir, we do on all of them, yes.

25          Q.     So, you could come in and say which

1 wells are receiving it. What I'm particularly  
2 concerned with in this case is in those tracts  
3 that are undeveloped, in which you may drill.

4 It may be that initially, when you get  
5 the positive production, those areas will be  
6 excluded, because there is some primary recovery  
7 that's going to occur first, before you get a  
8 secondary response.

9 A. Okay.

10 Q. Is that making sense? I'm not telling  
11 you what will happen but I'm telling you things I  
12 think we'll need to look at.

13 A. And be prepared to address those  
14 issues?

15 Q. Be prepared to address those, because  
16 if you've got areas within the project which have  
17 not had any primary production at all, and then  
18 you go and develop them subsequent to the  
19 certification of your project, I think we may, as  
20 I say, constrict the actual area which is  
21 qualified for the rate, at the time you get the  
22 positive production response, to those areas that  
23 have shown a true positive responses over an  
24 established primary decline rate.

25 A. Okay.



1           Q.       And those areas, again, Section 28,  
2       27. Those look like the biggest ones; maybe 13,  
3       where you don't have an established primary there  
4       and, as I say, they may not be included in the  
5       project area, because the rate applies to all  
6       production, not just to incremental production.

7           A.       Okay. But you have to show a response?

8           Q.       But you have to show a response. The  
9       objective is to give you the credit, really, for  
10      the incremental oil you're going to be  
11      recovering, but do it by way of giving you half a  
12      tax rate on all of the oil rather than having to  
13      calculate some incremental number.

14                    That is an issue that we will want to  
15      look at when you come in for your positive  
16      production response hearing. I guess what that  
17      means, if you want to qualify those areas early,  
18      you may want to think about early development of  
19      those areas so you can get an established decline  
20      rate and then show a response.

21                    That's obviously a management  
22      question. Either that, or you go ahead and  
23      develop them later and come back in for an  
24      expansion into those areas, when you expand the  
25      flood into those areas. If that's the case, that

1 you go and drill and get primary, then you can  
2 come back when you're ready to expand, and get a  
3 secondary and expand the response area. And  
4 we'll get you the credit at that time.

5 A. Okay.

6 Q. That's pretty much the process. Five  
7 years from the date that the order is going to be  
8 entered will be your magic date. If you don't  
9 get us an application in by that date, you will  
10 not receive the credit regardless of how good a  
11 job you did.

12 A. I'm sure we'll apply for that as soon  
13 as possible.

14 Q. Also, the effective date of the credit  
15 is to the date of the positive production  
16 response. So, what we've encouraged operators to  
17 do is to make sure it is truly a positive  
18 production response and not just a burp in the  
19 production, because you're taking better care of  
20 the wells and putting new equipment on them.

21 A. Seeing gas flaps gallons and some  
22 other--

23 A. Right.

24 Q. It doesn't hurt you to wait six months  
25 to make sure it's a valid response and then come

1 back in, because the credit will go back to the  
2 date we determine is a response date. You will  
3 not lose that value for that period.

4 A. Okay.

5 Q. I think that's all I have, unless you  
6 have any further questions about the process?

7 A. No. I think we can accommodate that.

8 MR. CALVERT: May I ask a question?

9 EXAMINER STOGNER: For the record, why  
10 don't you identify yourself, and then ask.

11 MR. CALVERT: All right. My name is  
12 Ken Calvert. I'm employed by Mewbourne Oil  
13 Company as manager of secondary recovery, and I  
14 have a question, not of anything that we've  
15 talked about here, but do you have, Mr. Stovall,  
16 an explicit one, two, three, four application for  
17 the tax abatement, other than what you have  
18 verbally told us?

19 MR. STOVALL: We do not. You have done  
20 the first process here of getting the project  
21 approved. You have completed Step 1. Step 2 is  
22 to implement the project and get a positive  
23 production response. And the burden is on you to  
24 come back and say, "We've received a positive  
25 production response. Please certify that

1 response to Taxation and Revenue," at which time  
2 we would say, "Which wells and what lands?"

3 But the burden is on you to come back  
4 in and demonstrate it and show us how that's  
5 happening. And, no, we do not have a one, two,  
6 three, four cookbook process. We haven't had a  
7 positive production response yet. We've had  
8 several cases for the certification of a project,  
9 but no positive production responses yet since  
10 it's only been in effect since March.

11 MR. MAYES: Can I ask a follow-up to  
12 that? So, do you apply, when you apply for the  
13 application after receiving the response, do you  
14 do that on a tract-by-tract basis?

15 MR. STOVALL: No. Again, in this case,  
16 the entire unit area will be certified as the  
17 project area. You'll apply for a positive  
18 production response, and, at that time,  
19 demonstrate which wells within that project area  
20 are actually benefiting from the waterflood and  
21 showing a response.

22 Again, for example, using Section 27,  
23 you have an injector out in the, looks like, Unit  
24 G of 27, and if those offsetting producing wells  
25 didn't show a response, that might be excluded

1 from a project area even though you've got  
2 injection going on.

3 With enhanced recovery, if you're not  
4 actually getting a response from the producers in  
5 the pattern, it could conceivably be excluded  
6 from the response area and might not get the  
7 credit until you get the response in. Does that  
8 answer your question?

9 MR. MAYES: I guess what I have trouble  
10 understanding, the revenues are distributed to  
11 the wells on a tract-by-tract basis. How would  
12 you tax abate one well without another well in  
13 the same tract?

14 MR. STOVALL: That's something you  
15 might want to address when you come back in for a  
16 the response. Each time we do it, a new question  
17 comes up. Good question. That's a  
18 consideration, too.

19 MR. MAYES: I'll follow that one up a  
20 little bit.

21 MR. STOVALL: It may be, is your tax  
22 rate going to be part of your participation  
23 formula? Even though one well qualified for the  
24 tax rate and the other didn't, that tract would  
25 still share in the revenue, on the basis of the

1 tract participation, without regard to  
2 the--because the credit is a reduction of  
3 expense, it's not a positive production share.  
4 It's not a production share, it's a reduction of  
5 expense over the unit.

6 MR. MAYES: Sounds like a question to  
7 ask the accountants.

8 MR. CALVERT: Mr. Stovall, may I make a  
9 statement concerning that? Typically, a lot of  
10 units are put together where the royalty owner,  
11 all tracts are so-called unitized, and the  
12 participation, royalty, and everything, everybody  
13 has one number for the entire unit, okay?

14 MR. STOVALL: Okay.

15 MR. CALVERT: We have found, in dealing  
16 with some other large units, that it is very  
17 cumbersome to deal with, and what you have just  
18 said, it would be almost impossible to have one  
19 number for everybody, because that one number  
20 might have different taxes.

21 In other words, for instance, if, say,  
22 Tract 5--or any of them--but a person had  
23 interest in Tract 5 and had an interest in Tract  
24 2, those wouldn't be taxed at a different rate.  
25 And, in other words, if 5 got abatement and 2

1 didn't, but you had to credit a royalty owner or  
2 a working interest owner with that amount, that  
3 would be very difficult to track.

4 So, from what you're saying, our  
5 tracking by tract and maintaining tracts separate  
6 throughout the unit, will probably be the easiest  
7 way to handle that.

8 MR. STOVALL: Well, my suggestion to  
9 you is, and again you'll have to talk to your  
10 accountants about that because that's an  
11 accounting problem, not a recovery problem--

12 MR. CALVERT: True.

13 MR. STOVALL: --is that regardless of  
14 which portions of the unit qualify for the  
15 credit, if you're applying the rate, the rate's  
16 going to be on total production from the unit,  
17 except for those portions of the unit which do  
18 not qualify.

19 It may be that you just simply don't  
20 discriminate--those tracts may get the benefit of  
21 the credit even though those wells have not  
22 specifically shown a positive production  
23 response, and the production from those specific  
24 wells, if you're not getting a positive  
25 production response, the tax rate on three to

1 seven barrels a day is not going to make or break  
2 any tract.

3 That's really the key issue there. I  
4 wouldn't spend a whole lot of accounting money.  
5 I don't think it changes your accounting, it  
6 simply just changes the number in the cost  
7 column. I don't see why you would have to  
8 separate the way you account to the owners in a  
9 tract which did not receive the EOR tax rate.

10 My guess would be that just simplicity  
11 would dictate that you treat them the same,  
12 regardless, because they've shared in the cost  
13 and they've contributed to the rent. It is  
14 simply a--the only people it will effect are the  
15 overall costs to you and the revenue to the  
16 state.

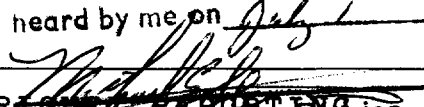
17 At the time that it actually comes up,  
18 we may have to relook at it. I think it's a  
19 valid question.

20 EXAMINER STOGNER: Anything further in  
21 either of these cases at this time?

22 If not, then, Case Nos. 10761 and 10762  
23 will be taken under advisement.

24 Let's take a 10-minute recess.

25 (And the proceedings concluded)  
I do hereby certify that the foregoing is  
a complete record of the proceedings in  
the Examiner hearing of Case Nos. 10761 and 10762  
heard by me on July 1, 1993.

  
Rodolfo C. Repuset, Examiner  
Oil Conservation Division  
(505) 988-1772




## CERTIFICATE OF REPORTER

1  
2  
3 STATE OF NEW MEXICO )  
4 COUNTY OF SANTA FE ) ss.  
5

6 I, Carla Diane Rodriguez, Certified  
7 Court Reporter and Notary Public, HEREBY CERTIFY  
8 that the foregoing transcript of proceedings  
9 before the Oil Conservation Division was reported  
10 by me; that I caused my notes to be transcribed  
11 under my personal supervision; and that the  
12 foregoing is a true and accurate record of the  
13 proceedings.

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

19 WITNESS MY HAND AND SEAL July 21, 1993.  
20

21  
22   
23 CARLA DIANE RODRIGUEZ, RPR  
24 CCR No. 4  
25