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3 MR. STAMETS: We'll call next
4 then Case 8397.

5 MR. TAYLOR: The application of
6 Gulf Oil Corporation for statutory unitization, Lea County,
7 New Mexico.

8 MR. STAMETS: Call for appear-
9 ances in this case.

10 MR. KELLAHIN: Mr. Chairman,
11 I'm Tom Kellahin of Kellahin and Kellahin, Santa Fe, New
12 Mexico, appearing on behalf of Gulf Oil Corporation.

13 In association with me is Mr.
14 Ken M. Brown, a member of the Texas Bar and he's a staff
15 attorney for Gulf Oil Corporation.

16 MR. STAMETS: Are there other
17 appearances?

18 MR. PADILLA: Mr. Examiner, Er-
19 nest L. Padilla, Santa Fe, New Mexico, on behalf of the
20 working interest owners of Tract 55.

21 MR. SPERLING: If the Commis-
22 sion please, I'm James A. Sperling with the Modrall Law
23 Firm, Albuquerque, appearing for Exxon Company USA, a work-
24 ing interest owner in the proposed unit.

25 MR. STAMETS: Other appear-
ances?

MR. KELLAHIN: Mr. Chairman, at
this time we would request that you also call Commission

Case 8398 and Commission Case 8399, and that all three cases be consolidated for purposes of testimony and subsequent to hearing that an order be entered in each separate case.

MR. STAMETS: Is there any objection to the calling of these other cases and consolidation?

Okay, let's call those other two cases.

MR. TAYLOR: Case 8398 is the application of Gulf Oil Corporation for a waterflood project, Lea County, New Mexico.

Case 8399 is the application of Gulf Oil Corporation for pool extension and contraction, Lea County, New Mexico.

MR. STAMETS: Any opening statements?

MR. KELLAHIN: Yes, Mr. Chairman.

Mr. Chairman, on behalf of Gulf, we will present four witnesses to you today. The subject matter -- I'm sorry, there are five witnesses.

The subject matter of the principal application is the use of the New Mexico statutory unitization statute to facilitate the forming of a waterflood unit for the secondary recovery project in an area of Lea County, New Mexico, which Gulf as operator has identified as the Eunice Monument South Unit.

1
2 The project is one that has
3 been under consideration for a great many years. The evi-
4 dence will demonstrate to you that Gulf and the significant
5 portion of the other working interest owners in some five
6 and a half years have devoted hundreds, if not thousands, of
7 hours to the formation of this unit.

8 This proposed unit consists of
9 something over 14,000 acres, involves over 100 individual
10 tracts, involves some 41 working interest owners.

11 The proposed application is one
12 that includes the amendment to certain pool rules estab-
13 lished by the Oil Conservation Commission. The objective of
14 the pool amendment is to create within one pool an oil in-
15 terval that generally is defined as including the Lower Pen-
16 rose section and the Grayburg section in this area. The
17 purpose will be isolate the oil producing interval for the
18 secondary waterflood project and to remove from the pool
19 rules the gas zone in the Upper Penrose.

20 The effort of Gulf and the
21 other operators now results in some 93 percent of the work-
22 ing interest owners having consented to the formation of the
23 unit. It also includes some 99.5 percent of the royalty
24 owners.

25 The first witness we will call
is Mr. Ray Vaden, who is a petroleum landman for Gulf. His
testimony will be and the proof is that Gulf has spent a
considerable amount of -- amount of effort and time to form

1
2 the unit, and he will discuss the exact percentages of those
3 parties that now have agreed and consented to participation.

4 The evidence will also demon-
5 strate to you that the Bureau of Land Management and the
6 Commissioner of Public Lands for the State of New Mexico
7 have consented to this unit agreement.

8 The second witness will be Mr.
9 Ray Hoffman, who is a petroleum geologist for Gulf. His
10 testimony will be that the geology underlying this area for
11 this particular formation is one that is geologically suit-
12 able for unit operations.

13 His testimony will be that the
14 unit boundary line is one that's geologically reasonable to
15 the underlying formations.

16 Mr. Hoffman's cross sections
17 will demonstrate to you reasonable geologic continuity and
18 for geologic reasons he sees no reason that the waterflood
19 project would not be successful.

20 The third witness will be Mr.
21 Tom Wheeler, who is a petroleum engineer and was Gulf's re-
22 presentative on the Technical Committee. That Technical
23 Committee operated for a number of years and compiled the
24 technical data and developed the parameter table upon which
25 there was unanimous agreement among all working interest
owners as to the basis from which then to calculate the per-
centage of working interest participation in that unit.

MR. Wheeler will discuss to you

1
2 the justifications and reasons for changing the vertical
3 limits.

4 The fourth witness will be Mr.
5 Dave Berlin, who is also a petroleum engineer, and was
6 Gulf's representative to the Working Interest Committee.

7 Mr. Berlin's testimony will fo-
8 cus in on the efforts that the working interest owners made
9 to form a participation formula that is fair, reasonable,
10 and just.

11 We will discuss the concerns
12 and issues that Exxon has raised in their opposition to the
13 participation and the issues that they raised to that com-
14 mittee and why Mr. Berlin believes that their objections are
15 without merit.

16 We will focus in on those con-
17 cerns.

18 Finally, the last witness will
19 be Mr. Al Bohling. His testimony will be developed concern-
20 ing the compliance of the unit operations to the Commis-
21 sion's requirements under C-108, to the operation of an ef-
22 fective and efficient waterflood project involving in excess
23 of 350 wells, I believe.

24 That, Mr. Chairman, is our
25 proof, as we believe it will be and at the conclusion of the
proof and after all the evidence is in, we believe that
there will be substantial evidence to justify not only the
entrance of an order approving the waterflood project, ap-

1
2 proving the amendment of the vertical limits of the pool,
3 but also to show that the exercise of the statutory unitiza-
4 tion procedures in this case are fair and reasonable.

5 MR. STAMETS: Any other opening
6 statements?

7 I'd like to have all those who
8 will be witnesses in this case either for the applicant or
9 for any other party stand and be sworn at this time, please.

10 (Witnesses sworn.)

11
12 MR. KELLAHIN: Mr. Chairman, at
13 this time we'd call our first witness, Mr. Ray Vaden.

14 RAY M. VADEN,
15 being called as a witness and being duly sworn upon his
16 oath, testified as follows, to-wit:

17
18 DIRECT EXAMINATION

19 BY MR. KELLAHIN:

20 Q Mr. Vaden, for the record would you
21 please state your name and occupation?

22 A My name is Ray Vaden. I'm a Senior Land
23 Agent with Gulf Oil Corporation.

24 Q And where do you reside, Mr. Vaden?

25 A In Midland, Texas.

Q Have you previously testified before the

1
2 Oil Conservation Commission and had your qualifications as a
3 petroleum landman made a matter of record?

4 A No, sir, I have not.

5 Q Would you give us a background summary of
6 your education and work experience as a petroleum landman?

7 A Yes, sir. I was graduated from Texas
8 Tech in 1965 with a Bachelor of Science degree; from Salway
9 (sic) State University in 1968 with a Master's of science
10 degree.

11 I began a career as a public servant,
12 working in municipal, county, and state governments in en-
13 vironmental planning and management.

14 I joined the Marriott Corporation in
15 Washington, D. C. and spent five years as Director of Admin-
16 istration before returning to the southwest in 1979 and ac-
17 cepting employment with an independent oil company.

18 I joined Gulf in 1981 as a landman and
19 the majority of my work with Gulf has been contracts invol-
20 ving farmouts, sub-leases, communitization and unitizations.

21 I have worked several large Federal ex-
22 ploratory units both in the State of New Mexico and Colorado
23 and Utah.

24 I was assigned to the Eunice Monument
25 project March 12th of this year and have devoted my full
time to it since then.

Q What responsibilities were you assigned
by Gulf Oil Corporation with regards to the Eunice Monument

South Unit?

A My first responsibility was to determine the accurate working interest owners and royalty owners and overriding royalty owners in the unit, and also to prepare unit agreements and unit operating agreements and exhibits of ownership which would be accurate and acceptable to the working interest owners and the royalty owners.

Q Mr. Vaden, are you familiar with Gulf Oil Corporation's application in the statutory unit case and the vertical limits case?

A Yes.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Vaden as an expert petroleum landman.

MR. STAMETS: The witness is considered qualified.

Q Mr. Vaden, if you will identify for us Exhibit Number One, sir, and show the Commission what is indicated by the red outline on Exhibit Number One, if you'll simply go to the exhibit and show us?

A Yes. Exhibit Number One is an outline of the Eunice Monument Field, which includes this area. The red portion is the area that we're proposing as the Eunice Monument South Unit.

The field was discovered March 21st, 1929, with the completion of the well down in this area. Within five years development had spread and it was proved to be an anticlinal structure. Within ten years it had made

1
2 its first one billion barrels of oil, one million barrels of
3 oil, pardon me, and in 1979 Gulf and many others began
4 studying the area for a possible waterflood. The result of
5 that study was that a task force was formed and in April of
6 1983 this task force completed a report on the unit, which
7 estimated that 64-million barrels of additional oil could be
8 recovered from within this area.

9 Gulf, since we had the larger percentage,
10 agreed to donate our staff time and our resources to the
11 other working interest owners and in cooperation with the
12 other working interest owners attempt to form the unit.

13 Q You've identified the proposed Gulf
14 Eunice Monument South Unit on Exhibit Number One. Would you
15 identify for us the other units north of that?

16 A Yes. The existing Texaco Eunice Monument
17 Unit and then a proposed study area now by Amerada Hess,
18 which would encompass the remainder of the field.

19 I believe, I may not have said, the field
20 is approximately 14 miles long and at the widest point is 6-
21 1/2 miles.

22 Q Mr. Vaden, I have passed out what has
23 been marked as Gulf Exhibit Number Two. Would you turn to
24 that exhibit, sir, and identify it for us?

25 A Yes. Exhibit Number Two is a map of the
proposed unit area which encompasses 14,189.84 acres. The
map has the agreed upon unit boundaries and has been ap-
proved by the Bureau of Land Management and the State Lands.

1
2 It is organized so that it delineates
3 State and Federal and fee lands. Any tracts that have lots
4 are marked and the acreage of the lots are marked. Any non-
5 standard sections, such as some of these that contain over
6 900 acres, also have the acreage marked on them.

7 You may note that the State lands com-
8 prise the largest percent with 58.32 percent of the land,
9 which is 8,274.8 acres.

10 The fee lands comprise 22.41 percent of
11 the unit, and 3,180.28 acres, while the Federal lands com-
prise 19.27 percent of the unit and 2,734.76 acres.

12 Q Within the unit outline on Exhibit Number
13 Two, are numbers contained within circles. What are those?

14 A The circles denote the tract -- tract
15 number. There are 101 tracts in the unit. Four of these
16 tracts are fee tracts, are divided into A and B tracts, be-
17 cause as we got into identifying the royalty owners, the
18 mineral owners, some of them had -- most of them had inter-
19 est in the entire tract or base lease; some of them traded
20 interest and had only a partial. So in order to make it
21 more clear to them as we were communicating with the royalty
22 owners, we divided it into A and B for that one or two
23 royalty owners that not own under the entire base lease or
24 tract.

25 These tracts also list the operator of
the tract at the present time, the status of the lease,
which is held by production. For Federal and State leases

1
2 we have the lease numbers on it and I believe that's the
3 basis of it.

4 Q All right, sir, Mr. Padilla has entered
5 an appearance for the owners in Tract 55, Mr. Vaden. Would
6 you identify for us where Tract 55 is on Exhibit Number Two?

7 A Yes. Tract Number 55 is a State lease,
8 I'm having trouble finding it now.

9 It's listed on your map under Michael
10 Kline because the original lease was taken as a sub-lease
11 from Shell Oil Company to Michael Kline for the Eunice Monu-
ment oil zone.

12 Q All right, sir. Mr. Sperling has entered
13 an appearance for Exxon, Mr. Vaden. Would you identify for
14 us those tracts in which Exxon Corporation has an interest?

15 A Yes, sir, it's Tract Number 12.

16 Q And that's in the far northwest corner?

17 A Yes.

18 Q All right, sir.

19 A Tract Number 31, or Tract Number 37, I'm
20 sorry, and Tracts Number 88, a one-half interest in Tract
21 Number 89, and Tract Number 90, all in Section 10, those
last three.

22 Q You said Exxon's interest in Tract Number
23 89 is a fifty percent interest?

24 A Yes, sir.

25 Q Who has the other fifty percent?

A Gulf Oil will have the other fifty per-

cent which we will share with the working interest owners based upon the spacing.

Q Mr. Vaden, would you describe for us what your understanding is of the proposed unitized formation in the unit area?

A Yes, sir. The unitized formation is defined in the unit agreement as that interval underlying the unit area, the vertical limits of which extend from an upper limit described as 100 feet below mean sea level, or the top of the Grayburg formation, whichever is higher, to a lower limit at the base of the San Andres formation.

This unitized interval was determined by the Technical Committee of the various companies and it will be explained later.

Q Is that the definition of the unitized formation that has been used in the contract documents for the unit?

A Yes, it is.

Q All right, sir, let's turn to Exhibit Number Three and I believe that's the unit agreement?

A Yes, sir.

We can look at Exhibit Number Four, too, at the same time, if you want.

Q Mr. Vaden, I have distributed what has been marked for identification as Gulf Exhibit Number Three.

Would you identify that for us?

A Yes, sir. Exhibit Number Three is the

unit agreement for the unit area.

Q All right, sir, and we also distributed Gulf Exhibit Number Four. Would you identify that for us?

A Exhibit Number Four is the unit operating agreement for the unit area.

Q Directing your attention to the unit agreement, Mr. Vaden, have you circulated the unit agreement to all known owners of royalty interests, overriding royalty interests, and working interest owners?

A Yes, we have.

Q Would you describe for us, Mr. Vaden, the attachments on Exhibit Number Three?

A Yes. The first attachment is a small unit map, the same as exhibit -- this is labeled Exhibit A to the unit agreement.

The second is labeled Exhibit B, which is a complete listing of all working interest owners, lessees of record, percentage of participation of the tracts, and all royalty interest owners.

Q Is the proposed unit agreement, Mr. Vaden, a form that has been approved by the Commissioner of Public Lands and the Bureau of Land Management for use in statutory unitizations?

A Yes, sir, it is.

Q And this unit agreement has been submitted both to the Bureau of Land Management and the Commissioner of Public Lands?

1
2 A It has been.

3 Q Mr. Vaden, how were you able to determine
4 who were the working interest owners and the royalty owners
5 that are included in the tabulation of ownership for Exhibit
6 Number Three?

7 A We began by spending time here in Santa
8 Fe checking the records of the Bureau of Land Management,
9 the records of the OCD, and the records of the State Lands.

10 From this information I was able to
11 determine the working interest owners.

12 We then contacted each working interest
13 owner to supplement what well general information we had
14 gained, and asked that each working interest owner send us
15 current Division or title opinions or current royalty owners
16 names, addresses, and pay data.

17 We also checked records of Lea County for
18 the key -- for certain key tracts where we were not sure we
19 had all the information on it.

20 Q Would you describe for us Exhibit Number
21 Four, now, and tell us what the source is of this document
22 and whether or not the unit operating agreement complies
23 with the statutory requirements of the Commissioner of Pub-
24 lic Lands and those requirements of the Bureau of Land Man-
25 agement?

A Yes, sir. Exhibit Number Four, the unit
operating agreement, is modeled after the American Petroleum
Institute's model form agreement.

1
2 In January of '84 the first copy of a
3 unit and unit operating agreement was sent to the working
4 interest owners. We received back over thirty pages of com-
5 ments.

6 So in April we began revising these in-
7 struments, trying to get what the working interest owners
8 wanted in them, and at that time we checked with Mr. Ray
9 Graham and with the State Lands Office and also with the
10 Bureau of Land Management. They assisted us and assured us
11 that these instruments are proper.

12 Q Mr. Vaden, I'd like to direct your atten-
13 tion now to Exhibit Number Five.

14 Mr. Vaden, the Statutory Unitization Act,
15 under 70-7-6, sub-paragraph B, requires that the operator
16 have made a good faith effort to secure voluntary unitiza-
17 tion within the pool or the portion thereof directly af-
18 fected.

19 I want to ask you, sir, your understand-
20 ing and knowledge of Gulf's effort to make a good faith ef-
21 fort to get the maximum number of voluntary participation
22 interests committed to the unit.

23 In that regard would you identify Exhibit
24 Number Five and tell us, first of all, what efforts you have
25 made to secure the consent of the royalty owners.

A Yes, sir. Exhibit Number Five is a bro-
chure entitled Eunice Monument South Secondary Recovery
Unit. It is based upon the information contained within the

1
2 technical report from the working interest owners and I
3 tried to prepare it in such a manner that it's in laymen's
4 terms but yet it still gives a concise brief of what the
5 Technical Committee has come up with, and it was an attempt
6 to explain this project to the royalty owners and overriding
7 royalty owners.

8 Q When was the brochure prepared, Mr. Vaden, approximately?

9 A In April of this year.

10 Q And what have you done with the brochure?

11 A The brochure, the unit agreement, and
12 ratification and joinders were mailed to approximately 350
13 royalty and overriding royalty owners. They were mailed to
14 people in Norway, Switzerland, England, Canada, and 26 of
15 the Continental United States.

16 Q Were copies of this brochure also provided to the working interest owners?

17 A Yes, they were.

18 Q And how many different working interest
19 owners do we have in the proposed unit?

20 A Forty-two.

21 Q All right, sir, would you now describe
22 for us Exhibit Number Six? What is Exhibit Number Six?

23 A Okay.

24 Q Just tell me what it is.

25 A Exhibit Number Six is a computer printout
on a tract by tract basis listing all the royalty and over-

riding royalty owners.

Q Was this a document that was prepared under your direction and supervision?

A Yes, sir, it was.

Q And have you reviewed it to determine whether it's accurate and correct?

A Yes, sir, I have.

Q Let's turn to the caption of Exhibit Number Six, Mr. Vaden, and have you walk us through the information that's tabulated on the exhibit and then I'll ask you what you've done with the information.

A All right. The exhibit is entitled Royalty and Overriding Royalty Owners. It is complete as of 11-5-84, the date of this printing.

On the upper lefthand corner, the first column is Owner Ratification and Joinder Number and Type of Interest. Each ratification and joinder to the royalty and overriding royalty owners was numbered before it was mailed out. This number, the first one is EM001, Adobe Royalty Company, it's a royalty interest, as you see in column number one.

The second column denotes an "X" if the ratification and joinder has been signed and returned. If you'll notice at the bottom of this first page there's a series of four pluses. As we began with the divisional information, we found certain interests had been sold or inherited by others as we tried -- attempted to sign up the

royalty owners.

So that was noted with the four pluses that that interest no longer applied or if it went somewhere else.

The third column is entitled Interest Owners and Current Addresses. We continually updated this. As we would get joinders back, sometimes the addresses had been changed on the joinder, so we included those addresses on here.

The middle column is Tracts in which the interest is owned and as you will see, some of these owners owned under tracts operated by various working interest owners.

The next column is the date of initial letter, brochure, unit agreement, and joinder was sent.

The column entitled Card "X", there's an "X" in this column if we got the certified card returned.

The next column is the date the ratification and joinder was executed and acknowledged.

And then the following columns are self-explanatory but they basically are notes which will be passed on to the other working interest owners telling them that certain of their royalty owners may have changes in address or other things that we've come up with.

Q Mr. Vaden, there are currently how many royalty and overriding royalty owners within the unit area?

A 350, approximately.

1
2 Q Would you describe for us the magnitude
3 of effort you and your staff have made towards getting
4 voluntary participation by the royalty owners?

5 A Yes, sir. I have made over 1000 tele-
6 phone calls with over 600 of them documented.

7 We have made many mailings.

8 Q Over what period of time have you devoted
9 your efforts to get the voluntary participation percentage
of the royalty interest owners committed?

10 A Starting when we got the first letters,
11 which would be, oh, June 12th, we have --

12 Q Of what year?

13 A Of this year.

14 Q As of today, Mr. Vaden, what percentage
15 of the royalty and overriding royalty owners are committed
16 to the unit?

17 A 99.53 percent of the royalty owners are
18 committed.

19 Q When we look at the Exxon tracts that are
20 proposed to be included in the unit, what is the status of
commitment of the royalty interest under those tracts?

21 A All the royalty is committed with the ex-
22 ception of one tract where Exxon has a 5.something royalty,
so I believe it has 56 percent committed.

23 Q All right, sir. Now let me direct your
24 attention to the efforts to get the working interest owners
25 committed to the unit.

1
2 You've indicated to us that there were 42
3 working interest owners in the unit. Are those listed on
4 Exhibit Number Six or are they on a different exhibit?

5 A They are listed on Exhibit Number Six.

6 Q Do you also have an Exhibit Number Seven
7 that separately documents the working interest owners sum-
8 mary?

9 A Yes, sir, I do.

10 Q All right, sir, would you identify for us
11 then Exhibit Number Seven?

12 A Yes, sir. Exhibit Number Seven is entit-
13 led Working Interest Owners Summary. It alphabetically
14 lists the working interest owners and their addresses for
15 those within the unit.

16 The second column of this exhibit indi-
17 cates whether or not we have received the joinder of the
18 working interest owner.

19 The third column indicates, the third --
20 the fourth column indicates the tract number under which
21 this owner owns. The column just before that is whether or
22 not he is operator of that tract.

23 And then we have given individual tract
24 and cumulative interest on here.

25 If you'll turn to the second page of this
exhibit you'll notice that some of these tracts have aster-
isks in the column of whether joinder was received or not
received.

1
2 There are thirteen working interest
3 owners who had minor or small interests in the unit. Two
4 said that they would like to sell their interest to Gulf and
5 Gulf would then share this interest with the other owners.

6 So these thirteen owners are identified
7 in the exhibit. There was a change as of Friday of last
8 week with the Bruce Wilbanks tract. We are showing that as
9 agreeable to sell and there's a letter in here stating that,
10 but there may be some changes in that at this point; we're
11 not sure.

12 But taking what we have actually committed,
13 and what is identified as being purchases, as well as
14 what is -- the two small interests that are in the mail, one
15 from a bank, we have 93.67 percent of the working interest
16 committed, effectively committed.

17 Q 93.67?

18 A Effectively committed.

19 Q All right, sir.

20 A That does include the Wilbanks tract,
21 which is 22/100ths of one percent.

22 Q Would you identify for us the larger interests
23 of the working interest owners that have not committed
24 their tracts to participation, for example, Exxon, where
25 we find their tabulation of interest on Exhibit Number
26 Seven?

27 A Yes. Page three, Exxon has 4.86 percent
28 of the unit participation, and they're number seventeen on

1
2 this list.

3 Q All right, sir, would you identify for us
4 any others that have less than a minimal interest in the
5 working interest that are not committed?

6 A Yes. We have Cities Service with less
7 than one percent. Some of these we -- we could not get com-
8 mitments. If we didn't know, we said, no, they're not
9 joining.

10 The Fred Turner Estate we believe is not
11 going to join. That's on page five.

12 In essence we have commitments from 36 of
13 the 42 working interest owners. Again that is counting the
14 five owners under the Robex (sic) tract.

15 Q All right, sir. Mr. Vaden, what does
16 Gulf propose to use as the effective date for the unit?

17 A We are hoping for December 1 of this
18 year.

19 Q What is the importance to Gulf of having
20 an effective date of December 1st, 1984?

21 A Many of these agreements to purchase,
22 which are attached to this exhibit, had a clause in them
23 that the other working interest owners wanted. These pur-
24 chase agreements are null and void if it is not completed by
25 December 31st of this year.

Q Other than obtaining the approval of the
New Mexico Oil Conservation Commission pursuant to the sta-
tutory unitization statute, are you aware of any other re-

quirement that is needed before you can use the December 1st, 1984 date as an effective date?

A No, sir, I am not.

Q Would you describe for us, Mr. Vaden, what has been Gulf's efforts through you and your staff to get the voluntary joinder of the working interest owners?

A Yes, sir, we have made numerous phone calls. We have had various meetings with the other working interest owners, and we have, starting early in the project, had across the table negotiations on disagreements and the instruments.

Q When were the drafts of the unit and unit operating agreements first circulated to the working interest owners?

A February 6th of this year.

Q And did you subsequently receive comments and suggestions for modifications to those agreements from the various working interest owners?

A Yes, sir, we have.

Q And has Gulf, through you, addressed those concerns and comments and included the appropriate comments in the documents?

A Yes, sir, where approved by our management.

Q When was the revised unit and unit operating agreements, ratifications, and joinders sent to the working interest owners after the drafts of February, '84?

1
2 A On July 25th of this year the unit agree-
3 ment and unit operating agreement and ratification and join-
4 ders were sent with a cover letter asking that they review
5 and get any comments back to us and try to execute them
6 promptly.

7 Q All right, sir, would you summarize for
8 us after June 25th, then, what follow-up efforts you've made
9 to get the working interest committed?

10 A On July 16th I sent a letter informing
11 the working interest owners that the Bureau of Land Manage-
12 ment and the New Mexico State Lands have given preliminary
13 approval to the unit and enclosed a copy of that -- those
14 approvals to the working interest owners.

15 Q All right, sir.

16 A And at that time we again asked that they
17 attempt to get their joinders in promptly.

18 Q And as of today, then, Mr. Vaden, what
19 percentage of the working interest owners are committed to
20 the unit?

21 A 92 percent by ratification and joinder;
22 93.67 percent effectively.

23 Q Mr. Vaden, I've handed out what is marked
24 as Gulf Exhibit Number Eight, sir. Would you identify that
25 for us?

26 A Yes, sir. Exhibit Number Eight is entit-
27 led Summary and Analysis of Committed Working Interest. It
28 is a computer printout virtually identical to Exhibit B of

1 the unit agreement, which is our Exhibit Number Three.

2 Q Is this a document that was prepared un-
3 der your direction and control?

4 A Yes, sir, it was.

5 Q And have you reviewed that document and
6 satisfied yourself that it's true and correct?

7 A Yes, sir.

8 Q All right, sir, would you give us an
9 example of how the document provides information to you on
10 the status of the working interest owner?

11 A Yes, sir. The left half of this exhibit
12 pertains to the working interest owners while the right half
13 pertains to the royalty owners.

14 Starting with Tract Number 1 on the first
15 page, the second column has the tract participation of this
16 tract. The third column is the working interest owner, or
17 owners. The fourth column is what percentage of working in-
18 terest they have in each tract. The fourth column is what
19 percentage we have committed by ratification and joinder.

20 So as you see, Tract Number 1, we have
21 100 percent of the working interest owners. Going to the
22 middle of it, it defines who the lessees are, the lessors
23 are. In this case it's United States, Bureau of Land Man-
24 agement lands. The royalty is 12-1/2 percent. The next
25 column is whether the royalty is committed or not, and our
royalty commitments do include State and Federal lands.

If you can turn to page fifteen of this

1
2 exhibit there's a good example of a fee tract. If you'll
3 look at Tract 91, you'll see where we have four working in-
4 terest owners. All four of these owners have committed and
5 we've broken out the percentage of their working interest.

6 Then to the righthand portion of this ex-
7 hibit you'll notice that there's a number four and then a
8 name and percentages. This is our royalty owners. This
9 number four is identical to the number four presented in Ex-
10 hibit Number Six of royalty owners. So in other words, roy-
11 alty owner number four, the name, the interest or percentage
12 of royalty he has in the tract, and "X" in the next column
13 means we have the ratification and joinder. Then the fol-
14 lowing column is the percentage of royalty committed for
15 this particular tract and in the last column is the percent-
16 age of royalty for the entire tract, which of 101 tracts we
17 have 100 percent of royalty committed on all but four.

18 Q The unit agreement and the unit operating
19 agreement as submitted to the working interest owners, do
20 you believe that if given additional time it might be
21 reasonably probable that you would get any portion of the
22 remaining noncommitted working interest owners committed to
23 the unit?

24 A No, sir, I do not. The main working in-
25 terest and royalty we do not have committed is Exxon.

Q All right, sir.

A Tom, can we go to the last page of this,
page 25?

1
2 If you would like to look at page twenty-
3 five of this exhibit, it does give a summary, and again it
4 states working interest effectively committed 93.67; 36 of
5 42 working interest owners; royalty interest committed 93.53
6 percent.

7 These are substantially in excess of what
8 would be required for statutory unitization.

9 Thank you.

10 MR. KELLAMIN: Mr. Chairman, I
11 propose to discuss next with Mr. Vaden Exhibits Nine and
12 Ten, which are the documents and correspondence concerning
13 the approval of the BLM and Commissioner of Public Lands.

14 I only have one copy of the ap-
15 proval letters from each of those agencies, which I now show
16 opposing counsel for their inspection and possible objec-
17 tion.

18 Q Mr. Vaden, I'd like to direct your atten-
19 tion now to Exhibits Nine and Ten, which is the correspon-
20 dence from the Bureau of Land Management and the Commis-
21 sioner of Public Lands, and simply have you summarize for us
22 what has been the results of your efforts to get approval of
23 the unit from both of those agencies.

24 A Yes. Exhibit Number Nine is a copy of a
25 letter dated June 22nd, 1984, from Roy Stovall, Acting Dis-
trict Manager, United States Department of Interior, Bureau
of Land Management, Roswell District, and it does advise us
that the unit area and geology is acceptable to the Bureau

of Land Management and it is logical for secondary recovery unit. It is in essence preliminary approval.

The second letter, Exhibit Number Ten, is a letter from Ray Graham, Director of Oil and Gas Division in the Office of the Commissioner of Public Lands, also granting preliminary approval and it is also dated June 22nd, 1984.

Q Have you subsequently obtained final approval from the Bureau of Land Management and the Commissioner of Public Lands for your unit?

A Effective as of yesterday both agencies have granted final approval to this unit pending statutory unitization by this Commission.

MR. KELLAHIN: Mr. Chairman, that concludes my examination of Mr. Vaden.

We would move the introduction of Gulf Exhibits One through Ten.

A Tom, we've got ratification and joinders.

Q What's that?

A We've got the ratification and joinders exhibits.

MR. KELLAHIN: I'm sorry, I forgot some exhibits, Mr. Chairman.

Mr. Chairman, I neglected to introduce the ratifications and joinders, and with the consent of the Commission we'd like to reopen Mr. Vaden's testimony and have him discuss for us Exhibits Number Eleven

1
2 and Twelve.

3 MR. STAMETS: You may proceed.

4 Q Mr. Vaden, would you identify for us what
5 is contained in Exhibit Number Eleven?

6 A Yes, sir. Exhibit Number Eleven is the
7 ratification and joinders from the working interest owners
8 and the lessees of record for the tracts within the unit,
9 while Exhibit Number Twelve is a packet of the ratification
10 and joinders of the royalty interest owners, which of ap-
11 proximately 270 royalty interest owners, all but 12 have
been signed up.

12 Q Excuse me, Exhibit Twelve is the ratifi-
13 cation by the working interest owners and Exhibit Eleven is
14 the royalty owner ratifications?

15 A Yes. Yes, sir, I'm sorry.

16 Q And do those two exhibits conform to the
17 information you've testified to that is contained in the
computer printouts of those interests?

18 A Yes, sir, they do, to the best of my
19 knowledge.

20 MR. KELLANIN: Mr. Chairman,
21 that concludes my examination of Mr. Vaden.

22 We move the introduction of
23 Gulf Exhibits One through Twelve.

24 MR. STAMETS: I would point out
25 that both Exhibit Nine and Exhibit Ten are two part exhi-
bits.

1
2 If there is no objection, these
3 exhibits will be admitted.

4 Are there questions of the wit-
5 ness?

6 CROSS EXAMINATION

7 BY MR. PADILLA:

8 Q Mr. Vaden, I have a few questions. Do
9 you spell your name B-A-D-E-N?

10 A Yes, sir.

11 Q I just wanted to make sure so I wouldn't
12 mispronounce it.

13 MR. STAMETS: Mr. Padilla, I
14 don't believe either one of you heard the other one or an-
15 swered the other one, because I've had the same troubles.
16 With a "V" as in Veronica?

17 A Yes.

18 MR. PADILLA: I had it with a
19 "B" in correspondence.

20 MR. STAMETS: No matter how you
21 say it I hear him saying "B" as in boy.

22 Q With respect to Exhibit Number Two, you
23 have labeled tracts HBP and I think that that is "held by
24 production."

25 A Yes, sir.

Q Does that mean that it's held by produc-
tion through drilling of that particular tract or other por-

1
2 tions of an oil and gas lease?

3 A That means it's held by production on the
4 BLM and State records.

5 Q In other words, it doesn't show whether
6 or not a well is drilled on that particular tract.

7 A That's correct.

8 Q Do you know whether a well is drilled on
9 the Gulf Oil Tract No. 15?

10 A I would prefer that you bring those ques-
11 tions up to the engineers. They're more familiar with the
12 well locations and the well data.

13 Q In other words, you don't know whether or
14 not each individual tract listed on Exhibit Number Two con-
15 tains a well or not or whether it's been drilled?

16 A If I know, I still believe it would be
17 better answered by the engineers.

18 Q Now turning to Exhibit Number Three,
19 which is the unit agreement, I would like for you to turn to
20 page number seven and have you explain to me the Section 13
21 on tract participation.

22 A Is that on the formula, sir?

23 Q Yes, sir.

24 A If we could wait, that gets -- we're get-
25 ting into more details discussed under Mr. Berlin's testi-
mony on that, and the reason I'm saying that, the Technical
Committee came up with the formula. I believe they could
explain it better.

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Q Now turning to page number eight on that unit agreement, can you tell us what would be the definition of "qualified tract"?

A What article are you referring to?

Q Part of Section 14 of the unit agreement.

A And what page number again?

Q Page eight.

A Now, your question is what qualifies a tract?

Q What is a qualified tract as defined or as stated in Section 14?

A A qualified tract would be one that meets the criteria of Article XIV, which is rather lengthy.

Q Do you know what those criteria are?

A Again, they were established by the Technical Committee.

Q Well, do you have a witness who can --

A Yes, sir, we will.

Q -- discuss that? With respect to Exhibit Number Seven, on an eyeball basis would you say in general that with the exception of the non-joinder of Exxon Corporation most of the other non-people, or parties who have not joined in the unit agreement are smaller operators?

A No, sir, I would not.

Q Who would you say would be one of the larger operators (not audible)?

A Cities Service.

1
2 Q Cities Service, okay, are there any
3 others?

4 A Without reviewing it I wouldn't know.

5 Q You prepared this, didn't you?

6 A Yes, sir.

7 Q The Article VII or Exhibit Seven?

8 A Yes, sir, but without double checking I'd
9 prefer not to answer your question definitely yes or no.

10 To my knowledge that's the only other
11 large company.

12 Q Now, with respect to Tract Number 55, you
13 stated that, and it shows that the working interest owners
14 there have agreed to sell. Is that your testimony for Gulf?

15 A That was my testimony as qualified with a
16 later statement.

17 Q And what was that qualification?

18 A That as of late last week, the notes from
19 this telephone conversation with Mr. Wilbank and Mr. Hen-
20 drix, that may change, and we don't know at this point.
21 I asked pointblank if that meant they were not going to
22 sell. They said, no, we don't know at this point.

23 Q You also -- have they -- who made the of-
24 fer to purchase? Did you make the offer to purchase or did
25 --

26 A If you will notice under Number Four, Ex-
27 hibit Six, is that --

28 Q Number Seven is what I have on that.

1
2 A Okay, if you'll look at Exhibit Number
3 Seven? Turn to the attachment number three at the back of
4 this exhibit. It's entitled Michael Kline, Susan Kline,
5 Bruce Wilbanks, John Hendrix, Ethel Dennis, T. W. Ellison.
6 The first page following that is a letter from Mr. Wilbanks.
7 Following this is exhibits of our original offer to pur-
8 chase, our letter agreement, our assignment, and other data
9 that was sent to Mr. Wilbanks for execution.

10 To answer your question, January 24th,
11 1984, there was a letter from Mr. Turner to Mr. Wilbanks
12 offering to purchase these lands, this interest.

13 Q That offer has not been accepted.

14 A That offer was accepted by Mr. Wilbanks
15 by letter of July 9th, 1984, in this packet.

16 Q The offer to purchase?

17 A Yes, sir.

18 Q I'm not looking at that. And your tele-
19 phone conversation last week apparently changed that.

20 A No, sir, I could read the results of that
21 telephone conversation. I tried -- Mr. Wilbanks told me
22 that Hendrix had told him that Mr. Hendrix may want to pur-
23 chase that interest rather than him selling to Gulf and
24 then to other members of the unit.

25 He suggested I call Mr. Hendrix. When I
26 telephoned Mr. Hendrix he said they were neither saying that
27 they are for or against the unit. What they would like to
28 consider was trading property with Gulf for this interest

1
2 rather than selling to Gulf, but he wasn't sure how it was
3 going to be and they said they would get back to me.

4 They didn't get back to me.

5 Q What result has -- have you considered a
6 tradeout?

7 A I left the door open. I said we would
8 prefer to purchase but if you have a proposal we will listen
9 to it.

10 Q Did you -- did you give them notice that
11 you were coming to hearing today?

12 A Yes, sir, I did.

13 Q Was that written notice?

14 A The Commission send out written notice.
15 I gave verbal on the telephone.

16 Q Did you give the interest owners of Tract
17 55 notice that you had applied for preliminary approval of
18 the State Land Office?

19 A Yes, sir, and also sent them a letter as
20 a result of that preliminary approval. That was many months
21 ago.

22 Q And you did the same with the Bureau of
23 Land Management?

24 A Yes, that letter was also in the package.

25 Q Now is it your understanding that with
respect to the approval of the Land Commissioner that that
approval only applies to the Land Commissioner's royalty in-
terest only? Is that your understanding or do you think it

1 binds the working interest owner on a State lease?

2 A This -- that approval pertains to the
3 State's royalty interest, but this is a State and Federal
4 statutory unit. It needs the concurrence of all three, the
5 State, the Federal, and the OCD.
6

7 Q My question is, would that approval bind
8 the working interest owner a State lease?

9 A I'll defer that to one of our attorneys.
10 I'm not sure.

11 Q You have no answer, then, is that cor-
12 rect?

13 A That's correct.

14 MR. PADILLA: I believe that's
15 all the questions I have.

16 MR. STAMETS: Mr. Sperling?

17 MR. SPERLING: Yes, sir.

18 CROSS EXAMINATION

19 BY MR. SPERLING:

20 Q Mr. Vaden, I refer you to Exhibit Seven
21 again and to a letter which is appended to the exhibit from
22 Gulf, dated November 1, 1984, addressed to Brady Production
23 and signed by Mr. Turner.

24 This appears to set forth --

25 A What number is on that one, please, sir?

Q Sir?

A What number is on that, the preface sheet

1
2 to that? Is it -- okay, it's Number One, I'm sorry.

3 Q Mine doesn't have a number.

4 A This page in front of the page you're
5 looking at has a number one on it.

6 Q This letter appears to set forth the bas-
7 is for an exchange between Gulf and Brady with respect to
8 acreage within Tract 89 for acreage in Gaines County, Texas,
9 is that correct?

10 A It appears to, yes, sir.

11 Q The exhibit to the unit agreement, ac-
12 cording to your earlier testimony with reference to Tract 89
13 is --

14 A No, sir, let me back up a minute. That
15 is not the case. That is acreage that we -- we are offering
16 to him. It says that it pertains to Tract 89.

17 Q Well, it's the basis for an exchange,
18 isn't it?

19 A Yes, sir.

20 Q The exhibit to the unit agreement, Exhi-
21 bit Three, indicates that with respect to Tract 89 that
22 there is 50 percent joint interest ownership by Brady and
23 Exxon, right?

24 A If you'll notice, there's also a little
25 asterisk next to that on Exhibit Number Three. That as-
terisk, as the asterisks do in here, and that's why we use
the words "essentially committed", is these people have in-
dicated that they are willing to sell. We have said we will

1
2 purchase if the unit is approved.

3 Q So you consider effectively committed to
4 be on the basis of the acquisition by Gulf.

5 A I'm saying it will be effectively commit-
6 ted because Gulf has joined; the other interest owners that
7 we will share these leases with have joined.

8 Q How many other acquisitions has Gulf made
9 in the last year?

10 A On this unit?

11 Q Yes.

12 A Fourteen, to the best of my knowledge.

13 Q And those include cash purchases as well
14 as exchanges?

15 A Yes, sir. You may notice that we have
16 purchased -- an agreement to purchase Texaco's interest.

17 We have completed a trade for Doyle Hart-
18 man's interest.

19 Q Are all of these acquisitions contingent
20 upon the approval of the unit?

21 A All of the ones pending now, yes, sir.

22 Q And how many are pending now?

23 A Well, thirteen, more or less. I don't
24 know.

25 As of last week it was thirteen.

Q Out of a total of fourteen acquisitions.

A No, the one -- number fourteen has al-
ready been completed. The instrument, the assignment is

executed and is in here.

Q Is that the Texaco acquisition?

A No, sir, that's the Doyle Hartman. There's also another one from I believe Kenneth Headley that is in here that is completed and needs to be filed of record.

So two are completed; others are under letter agreements and assignments. Oh, there's another one that is completed from Mr. Earl Bruno that's in here.

Q Okay.

A But again it will be contingent upon the formation of the unit.

Q Now I believe you stated that the participation formula which is contained in the unit agreement was the result of draftsmanship of the Technical Committee?

A Yes, sir.

Q As a matter of fact, didn't Amoco submit that proposal?

A Would you mind deferring that question till they come up, please, sir?

MR. SPERLING: That's all.

MR. STAMETS: Are there other questions of this witness?

Mr. Kellahin, I presume later witnesses will cover all those things which we've defined as relative to the operating agreement, unit agreement, and so on.

1
2 MR. KELLAHIN: Yes, Mr. Chair-
3 man.

4 MR. STAMETS: The witness may
5 be excused.

6 MR. KELLAHIN: Mr. Chairman, at
7 this time we'll call our geologist, Mr. Ray Hoffman.

8 RAY HOFFMAN,
9 being called as a witness and being duly sworn upon his
10 oath, testified as follows, to-wit:

11
12 DIRECT EXAMINATION

13 BY MR. KELLAHIN:

14 Q Mr. Hoffman, were you sworn as a witness
15 this morning?

16 A Yes, I was.

17 Q Please state your name and address.

18 A Ray Hoffman and I live in Hobbs, New
19 Mexico.

20 Q You'll have to shout at us, Ray, so the
21 reporter can hear.

22 A Okay.

23 Q Mr. Hoffman, where are you employed and
24 in what capacity?

25 A I'm employed by Gulf Oil as a production
geologist.

Q Have you previously testified before the

1
2 Division as a petroleum geologist?

3 A No, I haven't.

4 Q Would you describe for the Commission
5 where you obtained your degree in geology?

6 A Yes, I have a Bachelor of Science degree
7 from Waynesburg College, which I received in 1973.

8 Q Subsequent to graduation as geologist,
9 Mr. Hoffman, have you practiced your profession?

10 A Not right after I graduated from college.

11 Q All right, sir, would you describe for us
12 what has been your employment as a petroleum geologist?

13 A I've been with Gulf Oil for seven and a
14 half years.

15 Q Would you summarize for us the kinds of
16 things that you have done as a petroleum geologist during
17 that period of time?

18 A Development of prospects, field studies
19 for waterfloods and enhanced recovery projects.

20 Q Would you describe for us your participa-
21 tion as a petroleum geologist on behalf of Gulf Oil Corpora-
22 tion with regards to the geology on the Eunice Monument
23 South Unit Area of Lea County, New Mexico?

24 A Yes. I prepared two maps, structure top
25 on the Grayburg and a structure top on the Penrose, as well
as cross sections in the unit area.

Q Did you prepare those structure maps and
cross sections as support for the geologic information that

1
2 was used by the Technical Committee in forming the unit?

3 A Yes, I did.

4 MR. KELLAHIN: We tender Mr.
5 Hoffman as an expert petroleum geologist.

6 MR. STAMETS: He is considered
7 qualified.

8 Q Mr. Hoffman, let me direct you to your
9 first exhibit, which will be Gulf Exhibit Number Thirteen.

10 A All right. Exhibit Thirteen is a type
11 log.

12 Q That's the type log?

13 A Yes, it is.

14 Q All right, sir, would you identify for us
15 what Exhibit Number Thirteen is?

16 A Yes. Exhibit Thirteen is a type log for
17 the Eunice Monument area and it shows the top of the Queen,
18 top of the Penrose, the top of the Grayburg, top of the San
19 Andres, and the base of the San Andres.

20 Q Where did you obtain the tops of those
21 formations, Mr. Hoffman?

22 A I got these tops from the OCD geologist
23 in Hobbs, New Mexico.

24 Q Are these the tops that were used to make
25 the correlation of the logs in the Eunice Monument South
Unit Area?

A Yes, they were.

Q All right, sir, let's go to your next ex-

1
2 hibit. That will be Exhibit Number Fourteen, and what is
3 that, sir?

4 A Exhibit Fourteen is the structure top of
5 the Grayburg map.

6 Q All right. Mr. Hoffman, does this struc-
7 ture map represent your geologic interpretation of the
8 structure --

9 A Yes.

10 Q -- on top of the Grayburg?

11 A Yes, it does.

12 Q This is your work product?

13 A Yes, it is.

14 Q All right, sir. Would you describe for
15 us what conclusions you made from examining the data and the
16 information from the structure map?

17 A Yes. On the western and southern bound-
18 aries of the field the dark dashed line indicates the oil-
19 water contact at a -325, and on the eastern, eastern edge of
20 the field the Grayburg porosity pinches out, and on the
21 northern --northern edge of the field, bounded by the Texaco
22 Monument Unit.

23 Q All right, would you describe for us the
24 lithology that you found in this area?

25 A Yes. It's a dolomite with intercrystal-
26 line porosity interspersed with some sands.

27 Q What does the oil/water contact determine
28 for you as a geologist, Mr. Hoffman?

1
2 A It determines the lower limit of oil pro-
3 duction in the area.

4 Q And when you talk about area, you're
5 talking about the Grayburg-San Andres?

6 A Yes.

7 Q In your opinion does the oil/water con-
8 tact generally conform to the unit boundary on the western
9 and southern edges of the unit?

10 A Yes, it does.

11 Q Do you see as a geologist a reasonable
12 geologic justification for the unit boundary as proposed by
13 the working interest owners in this unit?

14 A Yes, I do.

15 Q All right, sir, and your next exhibit
16 will be Exhibit Number Fifteen?

17 A Yes.

18 Q And what is that, sir?

19 A It is a structure map of the Penrose for-
20 mation.

21 Q All right, we've looked at the structure
22 on the lower end of the oil zone in the Grayburg and now
23 we're going to look at the structure in the Penrose, which
24 is above that.

25 A Yes.

Q All right. Is Exhibit Number Fifteen a
structure map that you've also prepared?

A Yes, it is.

1
2 Q All right, sir, would you describe for us
3 the structure map?

4 A Yes. It's similar to the Grayburg struc-
5 ture map, indicating that the Penrose formation itself is
6 uniformly thick over the entire area. If you compare the
7 two maps you can see this.

8 Q All right, sir, would you describe for us
9 the composition or make-up of the Penrose formation?

10 A Yes. It's -- it's a dolomitic -- dolomi-
11 tic sands interbedded with hard dolomite stringers and is
12 approximately 170 feet thick over the entire area.

13 Q Based upon your study of the Penrose por-
14 tion of this interval, do you have an opinion as to whether
15 or not the unit boundary as proposed has a reasonable geolo-
16 gic basis in terms of the Penrose?

17 A Yes, it does.

18 Q At this point we're going to go to some
19 cross sections, I believe.

20 A Yes.

21 Q Are those cross sections prepared by you
22 or under your supervision and direction?

23 A They're prepared by myself and C. D.
24 Stenberg, the geologist in our office.

25 Q All right, sir. Let's pull out some
cross sections. You might come down here and help me out.

All right, Mr. Hoffman, when we look at
the first cross section, which is cross section Exhibit

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Fourteen, would you go to -- when you look at cross section, Exhibit Sixteen --

MR. STAMETS: No, excuse me, Exhibit Sixteen is the plat that shows the lines of cross sections.

MR. KELLAHIN: Cross sections, that's what I want.

(Thereupon a discussion was had off the record.)

Q Okay. Let's start over, Mr. Hoffman, identify Exhibit Number Sixteen now for us.

A That's the cross section index --

Q Can't hear you. You're going to have to turn your face a little.

A That's the cross section index for the unit area and the numbers running along the left side are the cross section numbers and we have twenty-five cross sections on the unit area.

The circles on the map indicate wells that have logs and the triangles indicate the wells that are proposed water injection wells.

In this area over here we included logs from Blinebry wells which were logged through the unitized interval. These were to fill in spaces where we didn't have logs or to add more logs to cross sections.

Q All of the cross sections that were pre-

pared, Mr. Hoffman, have you reviewed those cross sections and the information contained on those cross sections?

A Yes, I have.

Q All right, sir, let's turn now to the first cross section, which is going to be Exhibit Number Seventeen.

Do you have this marked somewhere?

MR. STAMETS: I think this would be a grand time to take a short break, say about fifteen minute recess.

MR. KELLAHIN: Thank you, sir.

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will please come to order.

Mr. Kellahin, you may continue.

MR. KELLAHIN: Thank you, Mr. Chairman.

Q Mr. Hoffman, before the break we were looking at Exhibit Number Sixteen, which is a plat showing the unit outline and lines of some twenty-two different cross sections constructed across the unit.

In addition I have shown you what we've marked as Exhibit Number Seventeen and Exhibit Number Eighteen. I have distributed the lines of cross section on the map and those two cross sections to opposing counsel.

1
2 Q Mr. Hoffman, before I start asking you
3 questions, identify for us the Exhibit Number Seventeen in
4 terms of which cross section line is represented by that
5 cross section when you look at Exhibit Number Sixteen.

6 A That would be cross section 14, the real
7 long one here.

8 Q All right, Exhibit Seventeen is line of
9 cross section 14.

10 Now when we look at cross section, the
11 Exhibit Number Eighteen, it's the cross section number what
12 on Exhibit Sixteen?

13 A It's the cross section 22, running along
14 this line right here.

15 Q All right, let's go back to Exhibit Num-
16 ber Seventeen now, which is the cross section line through
17 the center of the unit running east to west, and have you
18 identify and describe what you see when you examine that
19 cross section.

20 A The logs are hung on sea level, sea level
21 down, and no horizontal scale. The wells are just spaced
22 out over that whole interval.

23 This is the top of the Penrose, this line
24 here. This is the top of the Grayburg, the line here, and
25 where the lines are dashed, that indicates that the struc-
ture top has been estimated off of the Grayburg and Penrose
structure maps. And at the base of each -- each well
there's a short summary of the original completion.

At the top of this summary is another number. It says "well" and as an example "14-4". That would indicate that it's cross section 14 and the well is at location number 4, and that is from the west.

The Penrose in this area, the lower part of the Penrose, the oil column in this area thins from the Grayburg up into the lower part of the Penrose. The middle Penrose is usually tight across the whole area except for the southern western edge of the field and this provides a pretty effective barrier between the oil column and the Penrose sand.

The Penrose sand is -- is that sand in the very top of the Penrose and generally found over the whole field.

On the western and southern edges of the field the sand, which is a dolomitic sand, changes into dolomite by a facies change or is cemented tight with dolomitic cement, with a corresponding loss of porosity and permeability along the edge of the unit.

Q All right, sir, when you look at Exhibit Number Eighteen, which is the line of cross section east to west on the southern portion of the unit, would you describe what you see in that cross section?

A Basically it's the same as you see -- basically it's the same as our cross section 14 as to tops and datums and it shows the same as cross section 14 (not clearly audible).

1
2 Q When you look at the oil column in the
3 unit area, that is included generally in the Grayburg and
4 the lower portion of the Penrose, is that correct?

5 A That's correct.

6 Q The upper portion of the Penrose is that
7 sand that is gas productive.

8 A Yes, it is.

9 Q When you talked about the dense dolo-
10 mites, are the dense dolomites between the oil column and
11 the gas column?

12 A Yes, they are. The base of the sand is
13 the top of the Penrose.

14 Q Within the Penrose section, then, there's
15 a dolomite interval that separates the oil and the gas?

16 A Yes, sir, dolomite stringers, long sand
17 stringers. The dolomite in the area is tight.

18 Q In your opinion is that an effective bar-
19 rier between the oil and the gas in the area?

20 A Yes, it is, over most of the field.

21 Q All right, when we look at the top of the
22 Grayburg and the base of the Penrose do we see any forma-
23 tional barrier between the top of the Grayburg and the base
24 of the Penrose in the oil column?

25 A No, we don't.

Q Are you familiar with what Gulf proposes
to use as the definition for the formation or the unit in-
terval?

1
2 A Yes, that would be the entire oil column
3 in the Grayburg.

4 Q When we're looking at a definition to use
5 in the unitization process and you're trying to include the
6 oil column, all right?

7 A Yes, sir.

8 Q What will that oil column consist of?

9 A That will consist of the Grayburg and San
10 Andres formations and that portion of the oil column would
11 extend to the base of the Penrose.

12 Q Do you see, based upon your study of the
13 geology, a reasonable geologic justification for the pro-
14 posed unitized interval vertically to include all of the oil
15 column?

16 A Yes.

17 Q And will that definition exclude the gas
18 column?

19 A Yes, it will.

20 Q When we look at your geology in terms of
21 the horizontal boundary for the unit, do you have an opinion
22 as a geologist as to whether or not that horizontal boundary
23 has a reasonable geologic justification?

24 A Yes, it does. It runs between the oil-
25 /water contact at -320 and the porosity pinchout on the
26 eastern portion of the unit generally defines the unit
27 boundary.

28 Q All right, sir. When we look at the type

1
2 log that you introduced earlier, in your opinion is that an
3 appropriate log to use as a type log for the purposes of
4 picking the unitized interval?

5 A Yes, it is.

6 Q All right, sir. You may return to your
7 seat.

8 MR. KELLARIN: Mr. Chairman,
9 that concludes my examination of Mr. Hoffman.

10 We will move the introduction
11 of Gulf Exhibits Thirteen through Eighteen. No, just a
12 minute. Are we right? Thirteen through Eighteen.

13 MR. STANETS: Without objection
14 the exhibits will be admitted.

15 Are there questions of this
16 witness?

17 CROSS EXAMINATION

18 BY MR. PADILLA:

19 Q Mr. Hoffman, with respect to your exhi-
20 bits that are numbered Fourteen and Fifteen, can you explain
21 for me the -- on the structure maps -- the geologic feature
22 on the western boundary of the unit, proposed unit?

23 A On the western boundary?

24 Q Yes, running from north to south along
25 the western boundary of the unit.

26 A Well, this is an asymmetrical anticline,
27 as the structure map shows, and the western part of it just

shows one flank of the anticline.

Q Is the western part different from, say, the section -- well, let me generally describe the western part as the row of sections on the western part of the unit. How does that row of sections compare to the geology of the remainder of the unit?

A The, as I mentioned in my testimony, the --

THE REPORTER: I'm sorry, Mr. Hoffman, I can't hear you.

A The upper sand in the Penrose changes into a dolomite where it becomes more -- the sand becomes more dolomitic.

Q Let me ask the question this way. Is the row of sections along the western boundary more homogeneous or less homogeneous than the remainder of the unit?

A This is less homogeneous than the rest of the unit.

Q Less homogeneous?

A Yes. It's different. It's different from the rest of the unit.

Q Can you explain to me how it is less homogeneous?

MR. KELLAHIN: Why don't you go back to your seat up there and that way the court reporter can hear you.

A Oh, right.

1
2 A You see under the top of the Penrose is
3 generally found over the structure, the top of the struc-
4 ture, but it does -- it changes as you go to the west and
5 the south, from a sand to a dolomitic sand and in some cases
6 into a dolomite.

7 Q As you understand the participation for-
8 mula in the unit agreement, does the geology on that row of
9 sections affect the participation of tracts along the west-
ern side?

10 A I am not exactly familiar with the parti-
11 cipation formula. I don't know what you mean by that.

12 Q Are you familiar with the participation
13 formula in the unit agreement?

14 A Well, what -- I'm not exactly sure what
15 you mean.

16 Q Let me -- let me hand you what has been
17 labeled as Exhibit Number Three and in particular Section
18 13.

19 As I understand it, that is the partici-
20 pation formula for the unit agreement, and my question to
21 you is whether or not that geology in the western part af-
fects the method of participation?

22 A The geology in the western part, that is,
23 that's all that's affected there is the vertical limit as to
where the oil column is.

24 I don't think I could qualify to answer
25 any more than that.

1
2 Q Well, you've said that the western part
3 is less homogeneous than the remainder of the unit, and I'm
4 just wondering whether or not --

5 A Well, compared to the -- compared to the
6 remainder of the unit.

7 Q Well, compared to the remainder of the
8 unit. Is that -- you don't know whether that participation
9 formula is affected by the geology on the western part of
the unit?

10 A I'm not sure what you're getting at.

11 Q Let me move on for the moment and ask you
12 whether some of the wells along the extreme western edge of
13 the unit are down dip in your cross section.

14 A Yes, they are.

15 Q How does the -- how would that affect the
waterflood in the area?

16 A I don't think I'm qualified to answer
17 that. You'll have to ask one of the engineers.

18 Q Well, let me, if you're pushing water in
19 an injection well, where would the water have a tendency to
20 go if the geology is down dip?

21 A I'm not a petroleum engineer. I wouldn't
22 -- I don't think I could answer that question.

23 Q Well let me ask you in terms of hydrocar-
24 bons or oil. Where would the water have a tendency to grav-
itate, down dip or up dip?

25 A That's another engineering question. I

1
2 can't comment on that.

3 MR. PADILLA: Mr. Stamets, I
4 would ask that I have a right to reserve further questions
5 of Mr. Hoffman until I've listened to the testimony of the
6 engineer.

7 MR. STAMETS: Okay, Mr. Padil-
8 la.

9 Mr. Sperling.

10 MR. SPERLING: Yes, sir.

11 CROSS EXAMINATION

12 BY MR. SPERLING:

13 Q Mr. Hoffman, I'm going to try and ask the
14 same question Mr. Padilla did in a different way.

15 Did you examine all of the geological in-
16 formation available to you with respect to the unit area?

17 A Yes, I did, that which was available.

18 Q Were there limitations on the amount of
19 that information?

20 A Yes, there were.

21 Q What were those?

22 A We have -- roughly there's 48 percent of
23 logs available for wells that will be contributed to the
24 unit. We have less than half the logs available.

25 Q Well, I take it from your answer, then,
that you made no attempt to make a geologic evaluation of
the volumetric amount of oil in place.

1
2 A That's -- that's correct.

3 MR. SPERLING: That's all.

4
5 CROSS EXAMINATION

6 BY MR. STAMETS:

7 Q Mr. Hoffman, referring back to Exhibits
8 Fourteen and Fifteen again, let's take a look at Fourteen
9 first, and you've indicated that the dashed line on the
10 southwest side represented the oil and water contact, and I
11 was curious as to why none of Section 20 was included in the
12 unit, and why the south half of the south half of Sections
13 21 and 22 were not included in the unit, since it appears as
14 though geologically those should be in.

15 A It -- as best as I can recall, lower por-
16 tions of -- the wells in the lower portions of Section 21
17 and 22, as well as those in Section 20, are classified as
18 Eumont wells and they wouldn't be -- wouldn't be included in
19 the unit.

20 Q Is there no oil in the interval which is
21 to be unitized in Sections 20 and the south half south half
22 of Sections 21 and 22?

23 A The wells there are -- I think are pro-
24 ducing out of the Eumont portion and they don't get down in-
25 to the Grayburg, which is the top of the Eunice Monument
oil. They're excluded for that reason.

Q And then Exhibit Number Fifteen shows the
Penrose extending into Section 20 and I have the same ques-

tion as to why that was not included in the unit?

A I think it's basically the classification of the wells, that they weren't Eunice Monument.

Q Would that mean in essence that -- that Gulf, nor the other operator in either one of those had the rights in the formations that we're dealing with here today?

A I don't --

Q In this particular pool?

A In those sections I don't -- I don't know.

Q Well, I'll need some more information why those are left out. Could that be submitted?

MR. KELLAHIN: We have another witness, Mr. Chairman.

MR. STAMETS: Good, I'll ask my questions again.

Any other questions of this witness?

MR. KELLAHIN: Yes, sir.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hoffman, when we look at Exhibit Number Fourteen, which is the structure map on the Grayburg, and looking at the southwest corner of the structure map, particularly in Sections 19 and 20, the heavy dashed line running northwest to southeast represents what, sir?

1
2 A It represents oil/water contact.

3 Q In your opinion, do you have an opinion
4 as a geologist whether it would be reasonable geologically
5 to include Sections 19 and 20 in the unit based upon the
6 oil/water contact?

7 A This portion, no.

8 Q When we look at the Grayburg through the
9 unit area, Mr. Hoffman, what is your conclusion with regards
10 to an opinion about its homogeneity? Is it homogeneous
11 in the Grayburg through the unit area?

12 A Yes, it is, for the most part.

13 Q And when we look in the Penrose do we see
14 any barriers to the Penrose, between the Penrose and the
15 Grayburg in the oil column?

16 A No, we don't.

17 Q Do you have an opinion as a geologist as
18 to whether or not the proposed flood interval in the oil
19 column is a suitable, is geologically suitable for secondary
20 recovery by the injection of water?

21 A Yes.

22 Q And what is that opinion?

23 A That I think it would be feasible.

24 Q All right, sir.

25 MR. KELLANIN: No further ques-
tions.

MR. STAMETS: Any other ques-
tions of this witness? Mr. Padilla.

RE CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Hoffman, in answer to some of Mr. Kellahin's questions as to whether or not you think it's suitable to waterflood the area, you just told me in answer to my questions that you were not a petroleum engineer, and I'd like for you, if you do know, tell me how the water is going to flow in the western part of the unit.

A I don't feel qualified to answer that question. I don't know how it would flow.

Q Then you're not qualified to say whether or not the waterflood would be suitable for the unit.

MR. KELLAHIN: I'm going to object to the question. I think it's argumentative. Mr. Padilla wants to ask this question qualitative questions about engineering and I asked this witness whether it was geologically suitable. He says that it's continuous, it's reasonably homogeneous; he sees no geologic barrier, and therefore concludes it's geologically suitable.

I think that's very good testimony on that issue.

If Mr. Padilla wants to ask him those kinds of questions, fine. If you want to ask him questions about where you place your flood perforations and whether you'll have an impact down dip structurally, those are engineering questions and I have two or three engineers

1
2 that can answer those questions.

3 MR. STAMETS: Mr. Padilla,
4 would you like to wait for the engineers?

5 MR. PADILLA: Yes. Thank you.

6 MR. STAMETS: Any other ques-
7 tions of this witness? He may be excused.

8 TOM WHEELER,
9 being called as a witness and being duly sworn upon his
10 oath, testified as follows, to-wit:

11
12 DIRECT EXAMINATION

13 BY MR. KELLAHIN:

14 Q Mr. Wheeler, for the record would you
15 please state your name and where you reside?

16 A My name is Tom Wheeler and I live in Mid-
17 land, Texas.

18 Q Mr. Wheeler, where are you employed and
19 in what capacity?

20 A I'm employed by Gulf Oil Corporation at
21 its Southwest Area Office in Odessa, Texas, as the Area
22 Reservoir Engineer.

23 Q Would you describe for the Commission
24 your educational background as a petroleum engineer?

25 A I graduated from New Mexico State Univer-
sity in 1971 with a Bachelor of Science degree in industrial
engineering.

1
2 I spent from July of 1971 till March of
3 1979 in the United States Air Force.

4 I joined Gulf Oil Corporation in April of
5 1979 as a general production engineer in Hobbs, New Mexico.

6 February of 1981 I was transferred to the
7 Division Office Staff as a gas engineer.

8 In October of 1981 I was transferred to
9 the Secondary Recovery Section of the Division staff, as-
10 signed to work on the Eunice Monument South Unit and I con-
11 tinued with this project until February of 1984.

12 In February of this year I was transfer-
13 red to the Southwest Area Office in Odessa as the Area Re-
14 servoir Engineer.

15 Q Mr. Wheeler, will you describe for us
16 what has been your experience on behalf of Gulf with regards
17 to the projects involved in the Eunice Monument South Unit
18 Area?

19 A Yes, sir. Beginning with my assignment
20 as Project Engineer in October of 1981 I basically handled
21 the coordination of engineering efforts for Gulf as Gulf
22 acted as the unit expediter for this unitization effort and
23 I participated in all the Technical Committee meetings in
24 1982 and 1983 and also was present at the working interest
25 owners meeting in 1983.

MR. KELLAHIN: Mr. Chairman, we
tender Mr. Wheeler as an expert petroleum reservoir engin-
eer.

1
2 MR. STAMETS: He is considered
3 qualified.

4 Q Mr. Wheeler, I'd like you to begin your
5 testimony with giving us some background information about
6 the history of the Eunice Monument Pool.

7 A Basically I'd like to refer you back to
8 Exhibit Number One, which is the large map on the wall.

9 The three areas, or proposed areas out-
10 line almost the entire extent of the Eunice Monument Pool.

11 Texaco has been operating for some time
12 in the neck of the pool, we'll say, in their Texaco Eunice
13 Monument Unit.

14 Amerada Hess is engaged in a study effort
15 to unitize the Monument portion of the original pool and
16 calling that the Monument Unit Study area, and Gulf is here
17 today seeking unitization for our proposed Eunice Monument
18 South Unit.

19 In terms of the pool development, we have
20 some exhibits, beginning with this Exhibit Nineteen, which
21 you have, Mr. Kellahin.

22 Q All right, sir. This sheet is just a
23 summary of some information about the Eunice Monument Pool
24 and the proposed unit area.

25 Mr. Vaden has already testified to the
discovery date of the pool, March 21st of 1929. The pool
was discovered by completion of the No. 1 Conoco Lockhart
"B" No. 1 Well, which is located approximately two miles

1 south of our proposed unit area.

2 You see some general reservoir character-
3 istics here listed on the page.

4 Currently the pool is producing, and this
5 is a June, 1984 figure, 242,000 barrels of oil per month.
6 Current well count in the pool is 786 active oil wells.

7 In the proposed Eunice Monument South
8 Unit Area our production rate is 63,146 barrels as of June,
9 1984. The current well count there, active well count, 221
10 wells.

11 Since its discovery the pool was basical-
12 ly developed on 40-acre spacing. The major drilling activ-
13 ity occurred between 1934 and 1937. Peak production for the
14 pool occurred in May of 1937, rather from the unit area, and
15 797,000 barrels of oil from 296 wells, that is, in the pro-
16 posed Eunice Monument area.

17 So basically that is the -- are some
18 general data about the development of the pool.

19 Regarding some effects of Conservation
20 Commission orders upon the pool, there are some things which
21 we ought to note.

22 Originally all the oil production in the
23 proposed unit area was classified as Eunice oil and the old
24 Eunice Pool included the Penrose, Grayburg, and San Andres.
25 All oil wells, as I said, were classified originally as
Eunice wells until the creation of the Eumont Gas Pool in
1953 by Order R-264.

1
2 Q When the Commission created the Eunice --
3 I mean the Eumont Gas Pool in '53, what then did they do
4 with the vertical limits?

5 A They redefined the vertical limits of the
6 -- it would have been the Eunice Pool or what we refer to
7 now as the Eunice Monument Pool, and created the overlying
8 gas pool atop the existing oil pool.

9 The original definition was that the
10 Eumont Gas Pool included from the top of the Yates down to a
11 point some 200 feet into the top of the Queen formation.

12 Subsequent to that there were orders
13 which changed the Eumont Gas Pool limits so that the Eumont
14 Gas Pool included top of the Yates down to the top of the
15 Grayburg, which in effect contracted the limits of the
16 underlying oil pool to the top of the Grayburg where it had
17 been previous to that up into the Penrose.

18 In 1956 the Commission reclassified oil
19 wells as to Eumont oil or Eunice Monument oil, so that had
20 some effect on the classification of wells in the unit.

21 In classifying or reclassifying those
22 wells the Commission did not order that remedial action be
23 taken in wellbores whose completion intervals overlapped the
24 top of the Grayburg. They were allowed to stand as they
25 were but did order that any future completions be done in
such a way as not to communicate the two pools.

Q Mr. Wheeler, I'd like to ask you some
questions about the status of the wells in the proposed unit

1
2 area now in terms of whether or not there has been adequate
3 drilling and development on a spacing dense enough to have a
4 reasonable opportunity to recover the primary oil, whether
5 or not you now believe the unit is a candidate for secondary
6 oil recovery operations.

7 A Yes, sir, I believe we could see from the
8 map and the locations of the wells on the map that the field
9 is basically completely drilled on 40-acre spacing, and as
10 there has been no significant infill drilling, I think it is
11 attested by the fact that operators believe that the 40-acre
12 spacing has been adequate to recover primary production in
the field.

13 Q All right, sir.

14 Mr. Wheeler, I have distributed what is
15 marked as Exhibit Number Twenty on behalf of Gulf and ask
16 you to identify that exhibit for us.

17 A Yes, sir. Exhibit Number Twenty is a
18 gross production plot from wells within the unit area. It
19 includes oil, which has been attributed to the Eumont oil
wells and Eunice Monument oil wells.

20 As you can see, the characteristics of
21 the plot are that production is continuing the decline and
22 has done so since its peak production in -- early in 1937.

23 It currently is declining at roughly 4
24 percent per year.

25 The line which -- which runs through all
of the production data points here is an extrapolation of

1
2 the decline curve which was placed on the unit production by
3 the Technical Committee in its work.

4 You can see that in general the produc-
5 tion since 1982 has continued to follow the predicted path.
6 Currently you can see that we're at about 63,000 barrels of
7 oil per month on this decline curve.

8 Q Would you describe for us, Mr. Wheeler,
9 what has been the effort by Gulf and other operators to
10 study the area and to form a secondary waterflood project on
11 a unit basis?

12 A Yes, sir. If I may begin at the very
13 first effort, I'd have to start with the meeting which was
14 called by ARCO back in 1979.

15 In April of 1979 ARCO called a meeting of
16 operators within the current unit, proposed unit area, and
17 in that meeting they discussed the feasibility of forming a
18 unit to install secondary recovery efforts in the southern
19 portion of the field.

20 ARCO suggested that we form a unit cover-
21 ing 9760 acres in what is basically the heart of our cur-
22 rently proposed unit area. They presented the results of a
23 preliminary in-house study which they had undertaken on
24 their own, which concluded that the waterflooding was in
25 fact feasible.

Operators agreed to establish a technical
committee at that time and they developed some charges for a
technical committee. The operators at that meeting offered

1
2 Gulf the opportunity to become the expeditor of the study
3 and eventual unit operator by virtue of the fact that Gulf
4 operates the majority of the property.

5 Gulf accepted that offer and chaired in
6 the first Technical Committee meeting on July 26th of 1979.

7 Q Mr. Wheeler, have you compiled from your
8 records and information an exhibit that contains the minutes
9 from these various Technical Committee and working interest
10 owners meetings?

11 A Yes, sir, I have. It's Gulf Exhibit Num-
12 ber Twenty-one.

13 Q For purposes of the record, Mr. Wheeler,
14 would you identify for us what is contained within Exhibit
15 Number Twenty-one and the source of the information?

16 A Yes, sir. Exhibit Number Twenty-one con-
17 tains the cover letter and actual meeting minutes of all
18 working interest owner and Technical Committee meetings
19 which were held from May the 10th, 1979, through August the
20 25th, 1983.

21 These letters are the actual letters
22 which were used to transmit the information to known working
23 interest owners at the time and that contain the actual
24 minutes of the meetings. For purposes of consolidation we
25 have not attempted to include every exhibit that was con-
tained with each letter but merely the minutes of the meet-
ings.

Q Let's start, Mr. Wheeler, by having you

1
2 discuss for us the charges or the instructions that the
3 owners committee gave to the Technical Committee back in
4 1979.

5 A If you will refer to the exhibit which
6 has just been passed out and turn to page number seven,
7 you'll find listed there the charges as were stated in the
8 minutes of the first owners meeting, which was conducted on
9 May 10th, 1979.

10 The charges basically are these: To up-
11 date and correct a base map of the proposed unit area; to
12 define the area for waterflood study; to establish a para-
13 meter table to include the following parameters: Cumulative
14 oil, gas rate suggested over a twelve month period; cumula-
15 tive oil production -- sorry, I misspoke there.

16 The first one should have been current
17 oil and gas rate, suggested over a twelve month period;
18 cumulative oil production is the second; third was total ac-
19 reage involved in a proposed unit; fourth was remaining pri-
20 mary reserves; fifth was ultimate primary reserves; and
21 sixth parameter was secondary reserves, and noted, if recom-
22 mended by the Engineering Sub-committee.

23 We were also charged to prepare a water-
24 flood study and plan of operation and to define the vertical
25 interval to be unitized.

26 Q Would you describe for us what the Tech-
27 nical Committee did in order to respond to the charges or
28 requirements from the working interest committee?

1
2 A The committee proceeded in a basically
3 step-by-step manner to perform the study which was requested
4 here. We used the expeditor method, which is fairly common.

5 Q Well, would you define for the record
6 what you mean when you use the term "expeditor method"?

7 A Yes, sir. Essentially the expeditor of
8 the unit study or potential operator agrees to perform much
9 of the data gathering and analysis on behalf of the Techni-
10 cal Committee. Then at key points in that analysis and data
11 gathering sequence the entire committee is assembled to re-
12 view the work of the expeditor, to discuss any questions
13 which may have arisen, to provide assistance to the expedi-
tor in resolving any issued that he may have come across.

14 That essentially how the expeditor system
15 works and that's the method which we used in this unitiza-
16 tion effort.

17 Q Was that a method that was agreed to by
all the participants in this project?

18 A Yes, sir, to my knowledge all the parti-
19 cipants in the original owners meeting.

20 Q Under the expeditor method, then, Gulf
21 performed the function of gathering the data, analyzing it,
22 and then submitting it to the Technical Committee --

23 A Yes.

24 Q -- upon which they would make decisions?

25 A Yes, sir, that is correct.

Q All right, sir, would you describe for us

1
2 how often the Technical Committee met to review the informa-
3 tion being compiled by Gulf?

4 A The Technical Committee met on four occa-
5 sions between July of 1979 and February of 1983. Those four
6 occasions are noted in the index sheet of this particular
7 exhibit to which we're referring. You will note the dates
8 on that index sheet.

9 Q How were individuals invited to attend
10 and participate in the Technical Committee meetings?

11 A All known owners or operators at the time
12 were invited to send technical representatives, and that may
13 have been engineers, geologists, or both, to the Technical
14 Committee, and they were notified by letter prior to the
15 committee meetings so that they could have representatives
16 in place.

17 Q On an average, Mr. Wheeler, what was the
18 percentage of attendance at the Technical Committee in terms
19 of its relationship to the ownership?

20 A On the average we had more than 85 per-
21 cent of the current ownership available at each Technical
22 Committee meeting.

23 Q Was there ever any objection by any of
24 the working interest owners to the process of how the Tech-
25 nical Committee was going about its work?

A Not to my knowledge.

Q When did the Technical Committee produce
its final work product in terms of the charges made to it by

1
2 the working interest owners committee?

3 A The final Technical Committee report was
4 published in April of 1983 and distributed to all known
5 working interest owners by mail.

6 Q All right, sir. All right, Mr. Wheeler,
7 would you begin on page one and read through page 350 on be-
8 half of Gulf?

9 A I think I could best summarize it by say-
10 ing that the Technical Committee Report basically summarizes
11 the waterflood feasibility study which was done by the
12 Technical Committee and provides the unitization parameters
13 which were requested by the working interest owners commit-
14 tee for their use.

15 And in short, that's what those pages
16 contain.

17 Q The report that we have before us as Ex-
18 hibit Twenty-two, Mr. Wheeler, was made available to the
19 various working interest owners approximately when?

20 A At the publication date, approximately
21 April -- I do not remember the exact date of mailing but Ap-
22 ril or early May of 1983.

23 Q Now we talked about the Technical Commit-
24 tee having a list of charges that they were supposed to re-
25 port back to the working interest committee on, and let's go
through some of those general charges and have you tell me
whether or not the Technical Committee in response to these
charges determined whether or not the waterflood project as

1
2 outlined by the ownership committee would be feasible and
3 profitable?

4 A Yes, sir, the Technical Committee did de-
5 termine that the waterflood project would be technically
6 feasible and profitable, and we did so by examining a number
7 of parameters which relate to the waterflood, proposed
8 waterflood area.

9 Q All right, sir, let's examine the general
10 parameters, then, that go into the reasons behind your con-
11 clusion that the waterflood project is feasible and profit-
12 able.

13 Such parameters were what? What did you
14 examine?

15 A The committee made an estimate of such
16 things as original oil in place, primary recovery, expected
17 secondary recovery, and estimates of future investments and
18 expenses which could be expected as a result of installing
19 the waterflood project.

20 Q All right, sir, based upon those general
21 parameters and the other information that you've studied,
22 what did the committee conclude?

23 A The committee concluded that there would
24 be significant volumes of oil which would not be recovered
25 by continued primary means in the area which we're calling
the proposed unit area.

They also concluded that the secondary
recovery unit could recover additional oil and estimated

1
2 that that could be as much as 64.2-million barrels of addi-
3 tional recovery if we installed a waterflood, and they also
4 concluded that the installation and operation of the pro-
5 posed waterflood unit would be profitable to the owners in
6 the area.

7 Q Missed the number, the 64.2-million bar-
8 rel number is not a total number, it's an additional
9 recovery.

10 A It's incremental recovery above what
11 could be expected under continued primary operations.

12 Q With regards to the study being made by
13 the Technical Committee, what other kinds of data did the
14 Technical Committee develop?

15 A During the course of our study we deve-
16 loped and analyzed numerous kinds of data.

17 For example, we produced the geologic
18 cross sections and structure maps which have been previously
19 introduced by Mr. Hoffman, using what logs we were able to
20 locate for the unit area.

21 We generated some computer contour and
22 mesh perspective maps based on such parameters as the cumu-
23 lative oil production through 1981; the oil, gas, and water
24 production rates of 1981, and used these computer products
25 to help us to analyze the characteristics, the production
characteristics of the area, and these products are included
in the Technical Committee report.

We also generated some water production

1
2 data by tracts and over the unit area. We used this infor-
3 mation to help us to verify that the characteristics are
4 that of a solution gas drive reservoir rather than a strong
5 water drive reservoir, which is characteristic of some of
6 the area in the Amerada Hess Monument Unit study area.

7 In addition to that, we verified the ear-
8 ly field production data showed characteristic which are
9 common to a solution gas/oil -- gas drive reservoir.

10 We completed the base map, as we were re-
11 quired to do, which showed the unit, the surrounding proper-
12 ties, to help us to locate all known wells in the area and
13 also to identify any other significant features that we
14 might find there.

15 In addition to this, we performed an ex-
16 tensive investigation into historical information concerning
17 the completion and productive intervals in unit wellbores.

18 We produced a number of wellbore schema-
19 tic cross sections. In the Technical Committee report
20 you'll find those listed in the back.

21 We also used that data to help us define
22 what we thought the approximate gas-oil contacts and water-
23 oil contacts throughout the unit area might be, and they al-
24 so helped us to determine the proposed vertical interval de-
25 finition which we'll be submitting today.

26 Q All right, let me focus your attention on
27 the problem of the vertical limits and Gulf's application
28 concerning an adjustment in the vertical limits for the pro

posed unit of the two pool rules involved.

Would you, first of all, describe exactly what Gulf is seeking with the application?

A Gulf is seeking an order from the Commission that will contract the vertical limits of the Eusmont Gas Pool and that will extend the vertical limits of the Eunice Monument Oil Pool underlying the Eunice Monument South Unit Area in Lea County.

In short, we are requesting that the vertical limits of the Eunice Monument Oil Pool underlying the Eunice Monument South Unit include all formations from the lower limit defined by the base of the San Andres formation to an upper limit defined by the top of the Grayburg formation, or -100 foot subsea datum, whichever is higher.

Q Let me ask you why gulf is seeking the upward extension of the top of the vertical limits for the Eusmont -- the Eunice Monument Pool.

A We're applying here for statutory unitization, for authority to institute a waterflood project for this unit area, and we feel that the granting of this application to redefine the limits of the Eunice Monument Pool are absolutely necessary to provide a manageable unit area, to effectively waterflood the entire oil column, which we believe we can define here, to protect the correlative rights of owners, and to prevent waste in the pool.

Q Let's go to your next exhibit, Mr. Wheeler, and let me ask you some questions about that one.

1
2 Mr. Wheeler, I've distributed what is
3 marked as Exhibit Twenty-three, which is a plat with some
4 wells located on it, Exhibit Twenty-three A and Exhibit
5 Twenty-three B.

6 I'd like for you to describe for us,
7 using these exhibits as an aide, to indicate for us what has
8 been the effect of the Oil Commission's action in describing
9 and defining the Eunice Monument Oil Pool and the overlap-
10 ping Eumont Gas Pool, and the kinds of problems that have
11 occurred.

12 A Basically the succession of orders con-
13 cerning the vertical limits of the two pools have created a
14 situation where wells within the unit area have completion
15 intervals which overlap the top of the Grayburg formation
16 and are therefore open technically in both pools.

17 The Commission did not order that these
18 existing wells be recompleted or work attempted on them to
19 segregate the two pools and to my knowledge any new wells
20 which have been drilled have complied with the order to
21 avoid communicating with two pools, but Exhibit Number Twen-
22 ty-three is a map which locates the proposed unit area and
23 the wells within that proposed unit area.

24 You'll note that we have circle a number
25 of wells and beside each circle is a number which appears to
26 look like a fraction that really is not.

27 The number at the top of the -- of the
28 semi-fraction is the total number of feet open in the Penrose

formation in the original completion interval of this well. The number at the bottom is the total number of feet open in the completion interval in the Grayburg in each well.

We see here that there are 130 wells which have the circles colored. The wells which are colored blue are classified by the Commission as Eumont oil wells.

The wells which are classified green are classified by the Commission as Eunice Monument oil wells.

There are 26 Eumont oil wells on this map colored in blue which have overlapping completion intervals, and 104 wells which have overlapping completion intervals that are classified as Eunice Monument wells.

These, I might add, are historical and current numbers. Some of these wells are not -- no longer producing in the oil zone and have been recompleted or have been plugged. This is simply historical information.

But 100 of these wells of the 130 wells are still producing, either out of the Eumont oil or the Eunice Monument oil.

I would also like to call your attention to some classification problems which exist.

If you will look at Section 6, which is about in the center on the left edge of the map, you'll note the two wells in the center, Wells No. 219 and 220, and by the way, the small number which appears generally to the right and top of each dot are well numbers.

If you'll refer to Wells 219 and 20,

you'll see that those have both historically been Eunice Monument oil wells, although the predominant interval which is open and has been completed is in the Penrose, or the upper number is larger than the smaller number, in other words. They've been Eunice Monument wells but should have been, probably, Eumont oil wells.

Continuing down to Section 7, the two wells which are located in the center of the bottom row of Section 7, note there that one well has 135 feet of Penrose open and zero feet of Grayburg. Well No. 33 has 65 feet of Penrose open and zero feet of Grayburg, and yet the two wells side by side have been classified one as Eumont oil and the other as Eunice Monument oil.

There are other items of what we might say misclassification or mistakes that have been made in classification.

If you'll look at Section 15 you'll see that there are Wells 381 and 382, which are predominantly Penrose formation wells that have been classified as Eunice Monument, as opposed to Well 404, which has good mix, which has been a Eumont well there.

Down in Section 21 and 22 there are also examples of classification problems.

On Section 21 Well No. 442, which we've also identified as being a dual producer, has 113 feet of Penrose open and no feet of Grayburg, and yet it is a Eunice Monument oil producing well, at least the dual portion of

1
2 the oil zone is the Eunice Monument.

3 And you'll note that in the bottom line
4 in many of the wells the predominant formation open in the
5 completion interval is or was Penrose, and yet they are
6 classified as Eunice Monument.

7 Q What is the effect of this kind of prob-
8 lem on the efforts to form a suitable waterflood or insti-
9 tute a waterflood in this area?

10 A If we continued with the situation which
11 we're described here on the map, it would be virtually im-
12 possible for us to unitize hydrocarbons in either one of the
13 two pools, if we continue with the current vertical interval
14 definition because we could not arrive at an equitable allo-
15 cation to all the owners in each individual pool.

16 As I'm going to discuss later, the cur-
17 rent unitization effort relies on the parameters cumulative
18 production, remaining primary reserves, and current oil pro-
19 duction from each tract.

20 If we are forced to maintain the current
21 pool definition, tracts which had wells overlapping the top
22 of the Grayburg would be extremely difficult, if not impos-
23 sible to include, because cumulative production could not be
24 reallocated between the two pools on the historical basis.
25 We simply do not have a method of allocation between the
Penrose and the Grayburg in these old wells.

Current production would also not be al-
located equitably between the two pools and the remaining

1
2 primary reserve number could certainly not be extrapolated
3 if you cannot establish a historical decline, which (not
4 clear) that.

5 Also, if we continued with the current
6 vertical limit definition here, it would be impractical to
7 attempt to design a waterflood which would sweep only the
8 lower portion or any portion of the continuous oil column,
9 which we think we have identified here.

10 Q In order to form a unit of the oil
11 column, the waterflood prospects, Mr. Wheeler, how do you
12 propose to solve the problem?

13 A We propose to solve this part of the
14 problem by changing the vertical limits of the Eunice Monu-
15 ment Oil Pool by contracting the vertical limits of the
16 Eumont Gas Pool.

17 Q All right, in order to make that change,
18 how have you determined what the change ought to be?

19 A I'd like to distribute Exhibit Number
20 Twenty-four at this time, if we might, before I begin talk-
21 ing about it.

22 I would also add that Exhibits Twenty-
23 three A and Twenty-three B, which are the two tables that
24 were just distributed with Exhibit Twenty-three are in tabu-
25 lar form the same information that you see on the map, list-
ing Eunice Monument wells with overlapping completion inter-
vals and Eumont wells with overlapping completion intervals,
so they basically, refer to each other.

1
2 Q Mr. Wheeler, let's have you describe for
3 us how the Technical Committee went about addressing efforts
4 to come up with a solution to the problem about the vertical
5 limits overlapping in the oil column.

6 A We began studying this very problem early
7 in the work of the Technical Committee in an attempt to de-
8 termine what was the extent of the oil column in our pro-
9 posed unit area.

10 Let me say that we were using three basic
11 objectives as criteria to evaluate both the horizontal and
12 vertical limits of the proposed unit and those three cri-
13 teria were these:

14 First of all, we would attempt to include
15 all wells with historical or current Eunice Monument oil
16 production. We'd attempt to define a horizontal boundary
17 which was uniform and provided a minimum number of unflood-
18 able areas within the boundary.

19 We also attempt to define a vertical in-
20 terval which would include all of the oil column, if pos-
21 sible.

22 And with this in mind we began studying
23 the geologic cross sections, the structure maps which we've
24 introduced in evidence, and we combined that with the pro-
25 duction history information, and in doing so we created a
series of well completion schematic diagrams which I in-
cluded in this exhibit and we'll be able to discuss.

We might turn to that exhibit, I might

1
2 show you that the first page is just a reference page which
3 has a generalized cross section and we show a generalized
4 east and west boundary of the proposed unit area with the
5 formations which are involved in the discussion here.

6 We have the Eumont gas formation which
7 consists of the Yates, Seven Rivers, Queen, and Penrose un-
8 der current definition, and the Eunice Monument pool, which
9 consists of the Grayburg and San Andres formations under
10 current definitions, and there is no exact scale on this but
11 you can see relative to each other the thickness of those
12 formations, and you'll also see that there is some character
13 as to the structure itself. It does dip to the west, as has
14 already been testified to, and there are some high and low
15 spots in the middle of the unit. Generally, though, it's
16 without character in the middle of the unit.

17 I would also note for you that the top of
18 the old Eunice Pool went up to the top of the Queen, which
19 is also shown in this formation.

20 If I might refer you now to page number
21 two, I'd like to discuss the general characteristics of
22 these completion interval schematics, which I've provided
23 for you.

24 In an attempt to create cross sections
25 through the field, the first thing we did was try to locate
wells which had logs on which we could call tops, and unfor-
tunately, not every row of wells, as you've seen from the
cross section index map that Mr. Hoffman showed, has all

1 wells with logs.

2 So what we did was create slices. We
3 sliced through by section and I think I can refer to this
4 map and show you.

5 We took both sections here and called
6 that my completion interval section A-A; the next row of
7 sections would be the C, D, E, and F, for the sake of look-
8 ing at the formation and the completion intervals of the
9 wellbores.

10 As you can see, there's information
11 available on page two. First of all, this is a west to east
12 cross section looking from left to right on the page.

13 The top number on each of those stick
14 diagrams is the wellbore number, 2-1 would be Row number 2,
15 Well number 1, for example, and continue across the page in
16 sequence.

17 All the datums here are shown relative to
18 sea level and what we have shown in blue are reported com-
19 pletion intervals which produce some kind of oil in a well-
20 bore.

21 In red you see a reported completion in-
22 terval which produced some kind of gas.

23 So these are not simply intervals that
24 were perforated or tested or any other thing, or DST's or
25 anything else. These are intervals which reported some kind
of production.

We've also shown on this -- this type of

1
2 diagram the top of the Queen, the top of the Penrose, and
3 the top of the Grayburg formations.

4 As I mentioned, there is no scale between
5 the horizontal wellbores but we have maintained a scale on
6 this page for vertical intervals, a scale running from ap-
7 proximately -300 feet to 200 feet above sea level.

8 You will also note that on the diagrams I
9 have shown the casing seat of the wellbores, as was ori-
10 ginally reported to us.

11 Cross section A-A as we're looking at it
12 here, is typical of completion intervals in the northern
13 portion of the unit.

14 Well number 4-2 on this page, which is
15 the No. 1 Exxon Foppiano, is a former Eunice Monument oil
16 completion, and you see that the completion interval crosses
17 the top of the Grayburg and exposes both Penrose and Gray-
18 burg pay. This well was later plugged back to become a
19 Eunice -- or, I'm sorry, a Eumont gas producing well and the
20 interval above it between -48 and +142 feet was opened to
21 that production.

22 Well number 2-1 on the other hand is the
23 No. 1 Getty "H" State. It is a former Eunice Monument oil
24 completion and producer. It, too, had both the Penrose and
25 the Grayburg pay open and later was plugged back to Eumont
gas.

Q Using this page two of Exhibit Number
Twenty-four as an example, Mr. Wheeler, what were the first

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observations that the Technical Committee made after it reviewed the various cross sections through the unit?

A Well, the first observation is that there is some distinction between gas productive intervals in general and oil productive intervals in the northern portion of the unit here. So --

Q We generally see a separation in the oil production interval and the gas production interval.

A That's correct, we do.

Q And is there any other observation you've made?

A Looking at the diagram you can see that generally the gas productive interval has been the top of the Penrose, which Mr. Hoffman has previously identified as being a sand, basically a sand body which is gas productive, and it extends above that point into the Queen and sometimes into the Yates and Seven Rivers.

Q All right, sir.

MR. KELLAMIN: Mr. Chairman, I anticipate my testimony or questions of Mr. Wheeler and his testimony will probably take another hour or so.

MR. STANETS: Let's recess the hearing till about 1:20.

(Thereupon the noon recess was taken. Thereafter, at the hour of 1:20 p.m. on the same date, the hearing was again convened and the testimony was continued as follows, to-

1
2 wit:)

3
4 MR. STANETS: The hearing will
5 come to order.

6 Mr. Kellahin, you may continue
7 with your examination of Mr. Wheeler.

8 MR. KELLANIN: Thank you, sir.

9 Q Mr. Wheeler, before the lunch break, you
10 were discussing for us the conclusions you have reached from
11 studying the cross section of completions in cross section
12 A-A' across the northern portion of the unit, running from
west to east.

13 I ask you now, sir, to turn to page 6 of
14 Exhibit 24 and look at the cross section E-E' and from that
15 exhibit tell us what the Technical Committee concluded about
16 the southern portion of the unit in terms of this
17 definitional problem that we're having with the oil forma-
tion crossing over into two separate pools.

18 A All right. As we mentioned before lunch,
19 cross section A-A is representative of completion intervals
20 in the northern portion of the unit and now cross section E-
21 E' on page 6 is representative of the completion intervals
22 which we find in the southern portion of the proposed unit
23 area.

24 You'll note that most of the completion
25 intervals shown on cross section E-E' do in fact cross the
top of the Grayburg formation. I would like to point out

1
2 that most of the wells here are classified as Eunice Monu-
3 ment oil wells, either historically or currently, except for
4 Well No. 21-1, which is the far left well on your paper. It
5 is a producing Eumont oil well and you can see that the pro-
6 ductive interval is actually into the Penrose and up into
7 the Queen.

8 Well 21-7, which is seven lines in from
9 the western edge, is Shell's No. 1 Coleman A, which is a
10 producing Eumont oil well, and you'll note that it was not
11 drilled quite as deep as some of the other wells and the in-
12 terval opened is basically right at the top of the Grayburg.

13 Well 21-10 is the No. 3 Cities Service
14 State "C". That is a TA'd Eumont oil well which has been
15 plugged back and is now a Eumont gas well.

16 What we discovered when we used the geo-
17 logical information and the completion interval information
18 was that we had to come up with some possibilities for de-
19 fining the vertical limits.

20 Looking first toward the lower limit that
21 we might propose, we could see that the most appropriate
22 limit would be the base of the San Andres because it is well
23 below known production limits. It is the statutory base of
24 the Eunice Monument Oil Pool, easily identifiable on elec-
25 trical logs. It is the logical location for the lower
limit.

For the upper limit, however, we began to
consider a number of possibilities. Specifically, we de-

1
2 cided that we would investigate four.

3 The first possibility, of course, is that
4 we define the upper limit of the proposed unitized interval
5 as the top of the Grayburg, and we illustrate that by con-
6 tinuing here on page six looking at cross section E-E'.

7 An advantage to using this possibility is
8 that, of course, it is the upper statutory limit of the
9 Eunice Monument Pool; however, as we pointed out, there are
10 a number of disadvantages. The Grayburg top is crossed by
11 completion intervals, as we've seen this morning. With 130
12 wells in the pool, or in the proposed unit, there would be
13 a costly remedial program needed to isolate the two pools if
14 that remained the upper limit. If we attempted to flood
15 only, that portion of the oil column which is technically in
16 the Eunice Monument Pool, it would not be a feasible opera-
17 tion and we would need a whole new basis for calculating our
18 unitization. We could not allocate historical or current
19 production. We could not predict future production by pool,
20 and certain parameters could not be used.

21 The second possibility which we looked
22 toward is defining the upper limit of the vertical interval
23 as the top of the Penrose formation, which would roughly
24 correlate with the original Eunice Pool definition.

25 I'd like to refer you back to Exhibit --
or to the exhibit we're in currently but back to illustra-
tion A-A', which is on page two.

Considering the possibility of using the

1
2 top of the Penrose as the top of the vertical interval, we
3 find that there are some advantages, that it is relatively
4 easily found on electrical logs, and that it will include
5 all the oil production interval except for wells on the ex-
6 tremeness western edge of the unit; however, there are some sig-
nificant disadvantages to this.

7 First of all, the Upper Penrose, as has
8 been testified to this morning, is a gas productive interval
9 over most of the unit. Inclusion of a portion of the Eumont
10 gas interval, which we recognize as being gas productive,
11 would not be beneficial to the waterflood unit because the
12 gas zones do not contribute to the oil production and fur-
13 thermore it would create a problem where owners in the gas
14 zone who are not owners in the oil pool would have a problem
15 with equities. The equity problems would become a major
16 factor and the resolution for communitization would not be
17 probable in this event, where we have gas owners who are not
owners in the prospective oil waterflood.

18 So we looked at a third possibility. We
19 began examining the Penrose itself and tried to isolate some
20 marker in the mid-Penrose which might be identifiable across
21 the unit and I would refer you to Mr. Hoffman's testimony
22 this morning that there is, in fact, a tight zone in about
the mid-Penrose level which covers most of the unit area.

23 We began looking in that vicinity for a
24 top of the vertical limit.

25 The advantage, of course, would be that

1
2 such a tight zone would exclude most of the gas productive
3 interval and it would allow us to include most of the oil
4 productive interval, but there are some disadvantages here
5 also.

6 This mid-Penrose marker would not include
7 all of the oil productive zone, as you can see by wells on
8 the western edge of the field, and furthermore, we were not
9 able to find a definitive marker that was available over the
10 entire unit.

11 So after we considered these three alter-
12 natives and could not really settle on any of these, we be-
13 gan an attempt to define in somewhat better measure the gas-
14 oil contact in the unit area and the surrounding areas.

15 Once again, as we looked at our comple-
16 tion interval schematics which you have in front of you,
17 some general correlations become clear, and as you run
18 through these, you might also pick these out.

19 In general there is reasonable separation
20 between the oil interval and the gas interval, regardless of
21 which cross section we look at in this package.

22 Also the zone from roughly sea level to -
23 100 feet below sea level is not particularly a productive
24 zone in any of the cross sections that we see.

25 At this point we also extended some of
Mr. Hoffman's cross sections further to the west to try to
identify the formations and the gas and oil productive in-
tervals to the west of our unit, and the result that we

1
2 found was that similar conditions exist for at least a mile
3 and in some cases more than a mile to the west. We observed
4 of regardless of what you call the formation, that if a well
5 is completed below -100 subsea datum it would be an oil
6 well. If it's completed above the -100 foot subsea datum,
7 generally you'll find a gas well regardless of what forma-
8 tion you complete that in.

9 The conclusion which we had to draw from
10 this geological and completion interval information was that
11 there is a common gas/oil contact in and near the proposed
12 unit area and it crosses all formation boundaries and it's
13 at a depth of somewhere between sea level and -100 feet, and
14 we could not determine a more exact depth to use.

15 So using this information we considered
16 that there was probably a poor possible definition for the
17 top of our vertical interval, and that definition is that we
18 could possibly use the -100 foot subsea datum, which is also
19 indicated in all your completion interval cross sections,
20 and you can see that by looking through cross sections A-A
21 through, actually through Z-Z in this package.

22 The advantage is that it's easily identi-
23 fied so that someone who wanted to know what the top of the
24 vertical limit was in a particular wellbore could simply
25 measure the datum, and that -100 foot datum generally segre-
26 gates most oil and gas productive intervals.

27 There is a disadvantage, however, in that
28 the -100 foot subsea datum does not allow us to include the

entire Grayburg formation.

If you look at cross sections A-A and B-B, for example, you'll see that the Grayburg rises above the -100 foot subsea datum; therefore it would be possible to have a Eunice Monument well within the physical limits of the unit boundary but not in the unitized interval, and we considered this to be a disadvantage.

So considering the four proposed definitions that we have investigated, we determined that the best definition was probably a combination of two. So we proposed the following definition for our vertical interval, which I read to you previously: The vertical interval shall be -- to be unitized shall include the formations from a lower limit defined by the base of the San Andres formation to an upper limit defined by the top of the Grayburg formation, or -100 foot subsea datum, whichever is higher, and I've further illustrated that on the diagram which is in the back of the current exhibit we're looking at on page 11.

Let's take a look at that diagram and you'll see that what we are showing here is a possible vertical interval that extends from the base of the San Andres and, as I mentioned, up to the top of the Grayburg or a -100 foot subsea datum, whichever is higher, which would allow us to do several things.

First it will allow us to include the entire Eunice Monument Pool as it is currently defined.

It would allow us to include the entire

oil column under the unit area, which we currently recognize.

And this definition would also allow us to preclude the requirement to perform this extensive remedial work which I mentioned that we'd be caused to do to try to isolate the pools in these wellbores, and it would allow us to operate our waterflood in the entire oil column and not be confined to a portion of it.

I would also like to note that prior to adoption of this possible definition by unit owners, the alternatives which I've discussed with you today, were also presented to representatives of the Commission and the Bureau of Land Management, who reviewed these definitions and agreed that the definition was appropriate for the problem which we are discussing here today.

Q Mr. Wheeler, in terms of the proposed definition for the vertical interval, do you have an opinion as to whether or not that definition will protect correlative rights?

A Yes, sir, I believe it will.

Q If I understand correctly, the -- after all the study in terms of resolving the problem about the pool definitions, that the proposed definition for the vertical limits was submitted by the Technical Committee to the working interest owners?

A Yes, sir, that is correct.

Q What was the action of the working inter-

1
2 est owners with regard to that definition?

3 A The working interest owners considered
4 this definition and alternative definitions and adopted this
5 definition.

6 Q To the best of your knowledge, Mr.
7 Wheeler, has there been any objection to the use of this as
8 a definition for the vertical interval for the unit?

9 A There has been no significant objection
10 to it.

11 Q We've discussed now the vertical limits,
12 Mr. Wheeler. I'd like to direct your attention to the ef-
13 forts that the Technical Committee made to come up with the
14 horizontal boundary of the unit.

15 In that regard, perhaps Exhibit Number
16 Fourteen, one of the structure maps, might be useful, sir,
17 to have you describe for us what the Technical Committee
18 considered in arriving at the horizontal boundaries for the
19 proposed unit.

20 A Let me find it. I might mention that the
21 original proposal by ARCO, as I stated this morning, in-
22 cluded basically 9700 acres right in the heart of this pro-
23 posed unit. Very early in the Technical Committee's discus-
24 sion that boundary was expanded to virtually what you see on
25 the map today.

At the north it adjoins the Texaco Monu-
ment Unit, which is the current operating waterflood. It
also adjoins the proposed Amerada Hess Monument Study Area

1
2 at the north.

3 The western boundary generally defines
4 the limits of the Eunice Monument productive interval and
5 the wells inside the boundary are Eunice Monument wells.

6 It generally defines that same boundary
7 on the southern portion of the field.

8 On the eastern portion of the field the
9 limits of the unit basically define the limits of known pro-
duction from the Eunice Monument.

10 What we have done here in arriving at
11 these boundaries is basically satisfied the three criteria
12 or the goals which I previously stated. When taken in con-
13 junction with the vertical interval definition, the horizon-
14 tal boundary and vertical interval together allow us to in-
15 clude virtually all wells which have current or historical
16 production from the Eunice Monument Oil Pool, and help us to
17 define a uniform boundary which we feel is floodable and
18 will have a minimum of non-swept areas or unfloodable areas,
19 and also in the process we've helped to define a vertical
interval which would include all the oil column.

20 And that, this is again the basic sugges-
21 tion of the Technical Committee to the working interest
22 owners which we see on this final outline.

23 Q Mr. Wheeler, let me ask you, sir, some of
24 your recollections of the action of the ownership for the
unit in arriving at an agreed upon boundary.

25 For example, let's look at Sections 19

1
2 and 20 to the south. Describe generally for me what your
3 recollection of the ownership, or the operating rights in
4 Sections 19 and 20, who are the operators involved?

5 A Well, from this exhibit I'd have a tough
6 time. I think I can go to this map over here and perhaps
7 see that.

8 Included in Sections 19 and 20 I can see
9 offhand Getty, Gulf, ARCO, Conoco, Shell, Chevron, and basi-
cally Gulf again to the south (inaudible).

10 Q Are each of those operators also opera-
11 tors within the unit?

12 A Not operators, but --

13 Q Working -- I'm sorry, working interest
14 owners in the unit?

15 A Yes, they are.

16 Q Would it be a correct statement, Mr.
17 Wheeler, to say that the working interest owners in 19 and
18 20 are also represented within the working interest for the
unit?

19 A To the best of my knowledge they are.

20 Q And that the unit operations, then, using
21 this as a boundary would not exclude some working interest
22 owner that does not participate in the unit.

23 A That's correct.

24 Q And was there discussion in terms of
25 reaching a consensus on drawing the western boundary for the
proposed unit?

1
2 A Yes, sir, there was a discussion. Again,
3 following our early basic assumptions, we were trying to
4 delineate the point where Eunice Monument production ceases
5 and Eumont production begins.

6 There was some discussion. ARCO tendered
7 a suggestion to enter some property to the western edge which
8 is in fact classified Eumont oil production, but that was
9 rejected by the Technical Committee and ARCO has remained an
owner in the unit and participating in the unit.

10 Q From the point of view of the Technical
11 Committee, Mr. Wheeler, can you express an opinion as to
12 whether or not the horizontal boundaries of the proposed
13 unit are reasonable and justified?

14 A Yes, sir. I believe they are and I be-
15 lieve action on the Technical Committee reflects that also.

16 Q Let me go on to another subject with re-
17 gards to action of the Technical Committee, Mr. Wheeler.
18 Did the Technical Committee make any determination of orig-
inal oil in place within the unit area?

19 A Yes, sir. The Committee estimated that
20 the original oil in place within the unit area was approxi-
21 mately 671.5-million barrels.

22 Q And what was the Committee's conclusion
23 concerning the remaining primary reserves?

24 A The Technical Committee undertook an ef-
25 fort to produce production decline curves on each operating
tract in the unit.

1
2 We discovered that the unit as proposed
3 had produced approximately 120-million barrels. We used a
4 decline curve technique to extrapolate that primary ultimate
5 reserve number at 134-million barrels, which means that
6 there is roughly 14-million barrels of primary reserve re-
7 maining in the field, which tells us that the field has
8 produced approximately 90 percent of its primary ultimate.

9 Q All right, the committee has estimated
10 the original oil in place, the remaining primary reserves,
11 and that the field has produced approximately 90 percent of
12 the primary reserves.

13 Did the committee go on and also estimate
14 for the unit the recoverable secondary reserves?

15 A Yes, sir, it did.

16 Q All right, sir, and how did you go about
17 that?

18 A The first efforts of the committee were
19 to gather all available logs and cores and fluid analysis
20 information with the anticipation that we'd be able to ap-
21 ply this information to some computer model or some rigorous
22 analysis to predict secondary recovery.

23 As we began to assemble the data, we be-
24 came aware that a computer model was not going to be pos-
25 sible, for as Mr. Hoffman has already testified, we have --
we found logs on less than one-half of the total wells in
the field. Most of these logs are vintage 1955 or earlier,
which are unsuitable for analytical purposes.

1
2 We found that cores were virtually non-
3 existent and furthermore there was very little core analysis
4 information available and no fluid analysis information was
5 available to us.

6 So we were left at this point knowing
7 that we could not perform a rigorous computer modeling.

8 After some research I was able to find a
9 published technique which allows you to predict secondary
10 reserves based on an analog method, if you will, using other
11 or similar waterfloods as examples to develop some -- some
12 parameters by which you may estimate from your own property.

13 We did that and the Technical Committee
14 reviewed both the method and the results and approved it as
15 being included in the Technical Committee report.

16 Our final prediction indicated that there
17 was approximately 64.2-million barrels of secondary reserves
18 left to be recovered and that the secondary recovery to pri-
19 mary recovery ratio would be roughly 48 percent.

20 Q All right, sir. I missed those numbers.
21 Could you give me those numbers again, please?

22 A Expected secondary recovery is 64.2-mil-
23 lion barrels of incremental oil and that is a secondary re-
24 covery to primary recovery ratio of 48 percent.

25 We found that other Technical Committee
members could validate our experience in that typical re-
coveries from such Grayburg and San Andres reservoirs may
range from 25 to 100 percent of primary recovery, and the

1
2 basic opinion of the committee was that the estimate was at
3 least realistic for future unit performance.

4 Q Let me ask you, sir, if in making the
5 predictions on recoverable secondary reserves, Mr. Wheeler,
6 whether or not there was objection made to that method or
7 methodology used by any members of the Technical Committee?

8 A No, sir, there were not.

9 Q Are you aware of any objection by any of
10 the working interest owners to using that method by which to
11 predict secondary reserves?

12 A No, sir, I'm not.

13 Q All right. All right, we've discussed
14 some of the basic elements that are going into the work of
15 the Technical Committee. Let me also ask you whether or not
16 the Technical Committee adopted any recommendations with re-
17 spect to an injection pattern?

18 A Yes, sir, it did. The unit area, as I've
19 previously mentioned, is developed on 40-acre spacing.
20 Therefore the Committee recommended that the initial injec-
21 tion pattern be 80-acre 5-spots and this essentially means
22 that you convert every other well to an injection well. A
23 diagram of that proposed pattern as to how it would look if
24 they were fully implemented is available in the Technical
25 Committee report as Figure Number 97.

Q In addition then to making recommenda-
tions about the injection pattern -- well, before we get to
that, was the injection pattern one that was agreed to by

1
2 the Technical Committee?

3 A Yes, sir, it was.

4 Q And is that an injection pattern that's
5 been accepted by the working interest owners?

6 A Yes, sir, it has.

7 Q Let me ask you this with regards to the
8 entire package of information in the Technical Committee re-
9 port, which is Exhibit Number 22, Mr. Wheeler, does this not
10 constitute the plan of operation for the unit?

11 A Yes, sir, it does.

12 Q Did the Technical Committee go on to sum-
13 marize the capital requirements needed for unit operation?

14 A Yes, sir, we did provide a cost estimate.

15 Q And have you put that together in the
16 form of an exhibit?

17 A Yes, sir, Exhibit Number Twenty-five.

18 Q All right, sir, Mr. Wheeler, would you
19 identify Exhibit Twenty-five for me?

20 A This exhibit is an update to the tabula-
21 tion which is found in the Technical Committee report as
22 Table No. 4.

23 The estimates on this exhibit were up-
24 dated to reflect current costs of equipment and labor.

25 As you can see from the front page of
this exhibit, there are seven major categories into which
costs have been grouped. The production and injection faci-
lities include all storage and transfer and treatment and

sales facilities, and things of that nature.

The Technical Committee has estimated that we would drill and equip nine water supply wells to handle the water injection requirements for the unit. You see the cost associated with those wells.

We'd estimated that we would drill and equip nineteen producers, sixteen injectors as replacements for P&A'd locations; possibly some vacant locations.

These are -- these cost estimates are shown in page one, also.

We believe that there will be a considerable remedial effort to be undertaken in the unit area on existing wellbores and that cost is roughly \$10,000,000 worth of tangible equipment and \$9,000,000 worth of intangible costs associated with that.

We anticipate coring a number of wells and we've included in the cost of coring and analyzing core on twenty wells to help us to gather reservoir data, and we anticipate as the flood begins to respond that we'll need to replace much of the existing equipment in the field and the item pumping and replacements is for that new equipment to upgrade the size of units.

You can see that the grand total here, which is a gross cost, is \$60.6-million we expect to invest to get the unit installation.

Page two is a detail of those costs by year and we expect to spend the money which we've talked

1
2 about on page one.

3 You can see that we have a considerable
4 investment to be made and that's over a relatively short
5 period of time from 1984 through 1989, essentially.

6 Q Using the estimated cost figures for the
7 unit operations of the project, Mr. Wheeler, did the Techni-
8 cal Committee go on and then calculate what the benefit
9 would be if the project was operated on a unit basis?

10 A Yes, sir, we did.

11 Q For instance, what would happen if it was
12 operated without a unit?

13 A Yes, sir, we did, and that's our Exhibit
14 Number Twenty-six.

15 Q All right, sir, would you describe for us
16 Exhibit Twenty-six?

17 A Yes, sir. Exhibit Twenty-six is a sum-
18 mary of some financial and operating measures which can be
19 used to compare the profitability of the proposed waterflood
20 model versus continuing present operation.

21 Q Would you describe for us what is meant
22 when we look at the first column that says, Base Case with-
23 out Waterflood?

24 A Yes, sir, that is -- that is the case of
25 continued primary operations if you consider the unit pro-
properties as single property as opposed to column two, which
is the incremental case, or the parameters which will help
us to evaluate the increased recovery when we have an incre-

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mental or increased cost over the current operations.

Q Would you describe for us what basic criteria that was used by the Technical Committee in making this analysis?

A Yes. First of all, let me say that there were some simplifying assumptions made for this economic analysis. It was impossible for us to consider each and every owner's economic situation, so what we did in this case was consider that all properties in the proposed unit area are essentially one property for the treatment of this economic model, as though there were a single operator being considered as a single economic enterprise.

 The data that you see here was extracted from Gulf's proprietary appraised economic program. We input the updated cost estimate which we have just discussed as Exhibit Number Twenty-five. We input the secondary recovery estimate which is available in the Technical Committee report and we also had to update the date of that instrument in the Technical Committee report, by the way. That -- that curve is from 1984, which is obviously outdated at this point, but combining the cost estimate and secondary recovery estimate, and we placed those into our economic model.

 We had to assume that Gulf's oil split between tiers in the Eunice Monument area is representative of the other owners and for that purpose and for the purpose of calculating windfall profits tax, we assumed that there

was a 60 percent tier one split to 40 percent tier two.

We also assumed that Gulf's average oil and gas prices are representative of the area, and that production expense number that was placed into the model was based on an average of ten other floods in the area.

When we ran our model we obtained the results which you see here on Exhibit Number Twenty-six. We have a number of financial measures which we could use to evaluate an economic enterprise. One of the important ones we see here is the net present value of continued operations of \$42-million as opposed to net present value of the incremental waterflood case of \$183 or almost \$184-million.

Looking at the operating measure, you see that oil production for continued primary operations, is roughly 14,000,000 barrels as opposed to an incremental recovery of 64.2-million barrels for the waterflood case.

You see the investments. We assumed that there'd be no continued or large investments under current operations, as opposed to the \$60.6-million worth of investments that need to be made for the waterflood.

Some other operating expenses which I've noted here, Federal excise taxes for the base case of \$171-million as opposed to \$669-million for the waterflood case; State production and property taxes of roughly \$105-million for continued operation as opposed to \$370-million for the waterflood, if installed; U. S. income taxes to the owners of \$208-million for the base case and almost \$1.1-billion

1
2 for the operators.

3 The bottom line, of course, is that it is
4 a profitable venture in terms of cash profit after taxes.
5 Continued operations we see here at about \$226 or \$227-mil-
6 lion as opposed to \$1.1-billion for operators if the water-
7 flood is installed.

8 Gulf provided, I would note, the results
9 of our study to all Technical Committee members and working
10 interest owners. They also had benefit of the financial
11 measures which we inputted into our own model and we encour-
12 aged them to do their own economic analysis so they could
13 evaluate their own position using whatever model they chose
14 to use.

15 In summary, the Technical Committee
16 agreed that the formation of the unit was found to be a pro-
17 fitable venture based on these models.

18 Q Approximately when was this information
19 disposed to and shared with the working interest owners?
20 Do you recall?

21 A It would have been roughly the end of
22 1982 before the publication of the Technical Committee re-
23 port and the numbers that you see today are basically an up-
24 date.

25 Q Section 70-7-6, Subparagraph 3 of the
statute on statutory unitization requires as a condition
precedent to the issuance of a Commission order that the es-
timated additional costs, if any, of conducting such opera-

tions will not exceed the estimated value of additional oil and gas so recovered, plus a reasonable profit.

Do you have an opinion as to whether or not with unit operations this will constitute a reasonable profit for the working interest owners?

A Yes, sir, I believe it will.

Q One of the other conditions precedent to the issuance of an order is an opinion that the unitized management operation and development of this unit is feasible. Do you have an opinion?

A Yes, sir, I believe it is feasible.

Q Do you have an opinion as to whether the unitized management of the Eunice Monument South Unit is necessary?

A Yes, sir, I do.

Q Explain why.

A I believe it is necessary because, as we stated earlier in testimony, that the proposed unit area contains more than 100 individual leases. These leases range from 40-acre tracts to the largest being approximately 700 acres.

Economically and physically it would be almost impossible for many of these tracts to be placed under separate secondary recovery operations.

Waterflood operations are designed to move oil from well to well and lease to lease and without agreement it would not be technically feasible to do this.

Unit arrangements benefit both working interest owners and royalty owners by protecting their correlative rights when this movement takes place.

In addition, the value of the unitized operation allows us to see that we can eliminate some lease line barriers giving us flexibility in the use of existing wells. It allows us to convert where necessary. It allows us to develop uniform patterns over a very broad area. It allows us the flexibility of modifying fluid in and fluid out rates as we learn more about the response of the reservoir.

These things can only be done on a broad scale and not on the level of a 40 or 80-acre tract.

I believe that the results of unitization would be that there would be operational flexibility here in the field which would allow us to have a maximum efficiency recovery and allow us to eliminate or minimize waste.

Q Mr. Wheeler, let me direct your attention to Tract 55, which Mr. Padilla is interested in. I'll give you a copy of that Exhibit Number Two.

A Okay.

Q Do you have an opinion, Mr. Wheeler, as to whether or not it is reasonable and feasible to include Tract 55 in the unit operation?

A Yes, sir, I believe it is.

Q Why do you say that?

A Tract 55 has been given credit in the

parameter table for having cumulative oil production on which some ownership could be based.

Also, Tract 55 needs to be included on the western boundary to maintain a reasonable development pattern for the waterflood. If we were not allowed to include Tract 55 the proposed waterflood pattern would have to be backed away in all areas around Tract 55 and therefore unit production would suffer, not only from Tract 55 being taken away but also in the matter that we would not be able to effectively sweep the properties that are immediately contiguous to Tract 55.

Q I don't want to get into a discussion with you on the participation formula that was really the work of the working interest committee, Mr. Wheeler, but in terms of the feasibility of project you've expressed an opinion about Tract 55, I would also ask you the same question with regards to the Exxon tracts that are indicated on Exhibit Number Two in terms of whether you believe it would be reasonably feasible from the Technical Committee approach to exclude the Exxon tracts from the unit?

A If we look at the Exxon properties individually, Exxon's Tract No. 12 would have the same kind of impact on the unit that Tract 55 would have. It's an edge tract of the same size.

The other tracts, 88, 89, and 90, in which Exxon holds an interest, relatively speaking could provide a window in the unit which would mean that they

1
2 would impact, technically speaking, the waterflood opera-
3 tions in that we would have to move patterns away from the
4 boundaries of those properties.

5 It would also impact the physical instal-
6 lation of -- of the waterflood equipment in that we would
7 not be laying lines across those properties as they would
8 not be unitized properties. They would in essence be a fac-
9 tor to inhibit production in and around the properties.

10 Q In addition to determining the feasibil-
11 ity of the project, Mr. Wheeler, did the Technical Committee
12 have any other charges that they fulfilled from directions
13 of the working interest committee?

14 A Yes, sir, as I stated early in the testi-
15 mony, the Committee was charged with developing certain par-
16 ameters or characteristics we could apply to each tract in
17 order for the working interest owners at a later date to de-
18 velop and equity formula, or formula for sharing expenses
19 and revenues from each of those tracts.

20 Q All right, sir, let's go on and have you
21 then describe for us what were the parameters submitted by
22 the Technical Committee to the working interest committee
23 and how were those values for these parameters developed?

24 A All right. As I mentioned earlier, the
25 first parameter was an acreage factor. They wanted -- the
working interest owners wanted to know the approximate
acreage of each individual tract within a unit.

For our Technical Committee purposes we

1 assumed that each location or each well had 40 acres
2 assigned to it, as would be consistent with the proration
3 schedule.
4

5 I say we assumed that because for most of
6 the Technical Committee work we did not have exact legal de-
7 scriptions.

8 Cumulative recovery was another parameter
9 which we were asked to investigate and the way we arrived at
10 that parameter for each tract was we researched the Oil and
11 Gas Engineering Committee annual reports on each and every
12 well and determined what the cumulative production from each
13 well was up to any cutoff date and we also asked each owner
14 to verify the numbers assigned to their own tracts.

15 Remaining primary recovery, for this
16 parameter we developed production decline curves, which are
17 shown in the Technical Committee report on each active tract
18 within the unit. The Committee reviewed each one of those
19 curves, and there are some 80 of them in there, assigned the
20 projected decline rate from which the primary ultimate re-
21 covery could be calculated by decline curve techniques.

22 For the parameter, remaining primary re-
23 serves, this is simply the difference between the projected
24 primary ultimate of each tract and its cumulative recovery
25 at any given date.

For the current oil production rate we
again went to the Oil and Gas Engineering Committee records.
In the final form we went to the records for January 1st

1 through September 30th of 1982 and compiled a number for
2 each tract for that period of time.
3

4 For the matter of secondary reserves
5 which we were asked to evaluate, the Technical Committee re-
6 commended that that parameter not be used and it is not in
7 the final parameter table.

8 The data, I might mention, developed
9 first of all by tract on a tract by tract basis for each one
10 of these parameters. Then apportioned to each owner as had
11 been identified under each tract.

12 The final parameter table was presented
13 in the Technical Committee report as Table 8, which you'll
14 find on page 41, and the last revision of the parameters is
15 shown as Table AB and it should be in the copy of each of
16 the reports that was distributed today.

17 Q All right, sir. Let's turn in the report
18 which is in the big white binder?

19 A The Technical Committee Report, yes, sir.

20 Q And if I turn to page 41 of that report
21 there is included -- page 41 is in fact Table AB?

22 A That's correct.

23 Q And that's the parameter table that the
24 Technical Committee developed.

25 A That's correct.

Q All right. With regards to the current
oil production rate used by the Committee, what is the last
date that was used for that purpose?

1
2 A The last date used is September the 30th,
3 1982.

4 Q Was the information prior to that updated
5 at the request of any of the working interest owners?

6 A During the process of the Technical Com-
7 mittee activity the information that went into the parameter
8 table was updated twice. The first time at the volition of
9 the Technical Committee as a whole, I believe, and the se-
cond time at the specific request of Exxon.

10 Q Have there been any requests to the Tech-
11 nical Committee since updating this information to September
12 30th, 1982, to further update any of the data?

13 A Not to my knowledge.

14 Q To the best of your knowledge, Mr.
15 Wheeler, was there any objection by any of the working in-
16 terest owners to the parameter table?

17 A No, sir. In fact the parameter table was
18 accepted by unanimous vote in a working interest owners
meeting as the basis for calculating equity.

19 Q The parameter table as we see it on page
20 one then was unanimously agreed by all of the working inter-
21 est owners.

22 A At the first working interest owners
23 meeting all that were present unanimously agreed.

24 Q And it is that table, then, from which
25 the working interest owners work out the formula for the
participation within the unit?

1
2 A That's correct.

3 Q Based upon your experience and knowledge
4 of this particular unit, the feasibility of this project,
5 the applications on behalf of Gulf today, Mr. Wheeler, do
6 you have an opinion as to whether or not the granting of
7 these applications by the Oil Conservation Commission will
8 result in the prevention of waste and the protection of cor-
relative rights?

9 A Yes, sir. It is my opinion.

10 Q Were Exhibits Nineteen through Twenty-
11 seven prepared by you or compiled under your direction and
12 supervision?

13 A Yes, they were. Twenty-six.

14 THE REPORTER: Twenty-six.

15 Q Is the information -- Twenty-six.

16 Was the information tabulated on Exhibit
17 Number Twenty-one concerning the meetings of the working in-
18 terest owners and the Technical Committee true and accurate
reproductions of those documents?

19 A Yes, sir, they are.

20 MR. KELLABIN: Mr. Chairman,
21 that concludes my examination of Mr. Wheeler.

22 We move the introduction of
23 Gulf Exhibits Nineteen through Twenty-six.

24 MR. STAMETS: Without objection
these exhibits will be admitted.

25 Are there questions of this

witness? Mr. Padilla.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Wheeler, on Exhibit Number Twenty-three, I'm not sure if I understand how you have colored the wells green and the wells blue. Would you explain for me what the green stands for and what the blue stands for?

A As I mentioned earlier, the green indicates that the wellbore which has been colored is or has been classified as a Eunice Monument oil well.

The blue indicates that the well is or has been classified as a Eumont oil well.

Q Are any of those colored wells commingled with other zones such as the Penrose or the Queen formation?

A If your question has to do with whether or not the productive interval that has been opened in these wells crosses the top of the Grayburg formation, in every case that's the case.

Now, as far as being commingled I'm not sure that I --

Q Well --

A -- am within your definition of commingled.

Q Are any of these wells that are colored either blue or green, are they productive from the -- a zone other than the proposed unitized zone?

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2 A Let me say that it is possible that a
3 well here has been recompleted and is now productive from
4 the Eumont gas zone, which is high, but to my knowledge
5 there was no wellbore to which I could specifically point to
6 to say that the completion interval commingled, to use your
7 phrase, the oil zone and gas zone for any significant inter-
8 val.

9 I'm not sure that I follow your line of
10 questioning.

11 Q Well, maybe I should ask the question,
12 let me ask the question are any of these wells that you know
13 of productive in both the Queen and the Grayburg formation
14 in the same wellbore?

15 A All right, if I may, let me refer to --
16 let me refer you to cross section A-A, which I believe you
17 may have in your hand right there.

18 And we can start down through these cross
19 sections, if you'd like. Perhaps the best example, I think,
20 of what you may be asking is found on cross section D-D for
21 wellbore No. 17-1 has shown a completion interval that crosses
22 from the Penrose up through the Queen and even above the
23 Queen at some time in its life.

24 So that is a wellbore which effectively
25 has crossed the interval.

26 Q Let me ask, do you know whether the upper
27 productive limits of that well are currently producing to
28 where you could have migration from the unitized formation

1
2 to the upper productive limits of that well?

3 A My only available information here is
4 that well is currently producing and is classified as a Eu-
5 mont oil well.

6 Now I'm not sure that I can say whether
7 or not there is migration up into the overlying gas zone
8 based on the information which I have available in front of
9 me here.

10 Q In other words you don't know whether any
11 of these -- any of the wells you've testified about are pro-
12 ductive from other zones other than the unitized, or pro-
posed unitized formation.

13 A Oh, yes, sir, I do. In fact many of the
14 wells which you -- are shown here in the cross sections,
15 which indicate a red bar across on them, I can say that my
16 information is that they are productive from the Eumont gas
17 zone, but they are not commingled. They've been plugged
18 back for the most case to the Eumont gas from the oil zones,
19 whichever it might have been, either Eumont oil or Eunice
Monument oil.

20 Q But you don't know whether the production
21 is actually commingled or not. You think that the upper
22 zone has been plugged back or the well has been reworked in
23 some way that they're not productive from two separate
zones.

24 A To my knowledge there are no wellbores
25 which are commingle Eumont gas and Eunice Monument or Eu-

1
2 mont oil. That's not allowed according to rules, but to my
3 knowledge that commingling does not take place.

4 There are wells which are dualled out
5 there which have the Eumont gas producing and the Eumont or
6 Eunice Monument oil producing in the same wellbore, but they
7 are not commingled.

8 Q You would agree with me that an operator
9 is allowed to seek commingling authority for a well given
10 certain standards.

11 A To my knowledge an operator is allowed to
12 ask for such authority.

13 Q Is there a lease line agreement on the
14 western boundary of the proposed unit?

15 A No, sir, there are no lease line agree-
16 ments in place for the proposed unit at this time.

17 Q As I understand, you have an overlap of
18 two different pools on the western edge of the pool -- unit,
19 is that correct?

20 A Under current definition, that's true.

21 Q Assuming you waterflood the western part
22 of the proposed unit, how would correlative rights be pro-
23 tected for interest owners beyond the western boundary of
24 the pool and/or in other formations to the west?

25 A Let me answer that by saying this: We
are not considering injection on the western edge of this
unit up to the boundary at this time. There will have to be
cooperative agreement made between the unit and operators

1
2 outside that western boundary before we can initiate injection
3 at the last row of wells along this line. That is the
4 way, to my understanding, that you would protect those cor-
5 relative rights between owners inside the unit and owners
6 outside the unit who may have wellbores in the same general
7 formation that we intend to waterflood inside the unit.

8 Q Well, on your Exhibit Number Ten you've
9 shown, or Sixteen, I should say, injection and wells with a
10 log. It appears to me that you more or less intend to al-
11 ternate injection wells along the western boundary of the
12 unit.

13 Is it your testimony that you're going to
14 start injection or unit operations closer to the center or
15 that you will even develop towards the west until a later
16 time?

17 A I cannot tell you exactly what reference
18 Mr. Hoffman used to arrive at his base map which he used to
19 show the cross sections.

20 I can tell you that it is not our inten-
21 tion to install injection wells along the western, and par-
22 ticularly western and southern boundaries immediately until
23 cooperative agreements are in place.

24 That would represent a fully developed
25 80-acre 5-spot for the entire unit area. Fully developed
means that you'd have to have the necessary agreements be-
fore you could initiate injection at the boundary line.

Q Would that mean then that -- that a tract

1
2 on the western boundary of the unit, such as Tract 55, would
3 not begin to participate until such an injection well would
4 be completed?

5 A No, sir, it does not, because those wells
6 on Tract 55 will either be -- have replacements drilled for
7 them in the case of a salt water disposal well or will come
8 into the unit as producers along the western boundary.

9 Our intent is to do the remedial work on
10 those wells on the western boundary especially which have
11 been TA'd or not available to make them producers until such
12 time as we can arrive at the agreement to then put injection
to the lease line.

13 Q How much time are we talking about as far
14 as developing the western portion of the unit?

15 A I'm afraid I can't -- I can't pin that
16 down to an exact date. I'd estimate it's going to take some
two to three years to get there with injection.

17 Q How -- how would you bill on your capital
18 expenditures, how would you bill the various parties? Let's
19 take the working interest owners in Tract 55, how would
20 they be billed for their portion of capital expenditures?

21 A Their participation in the unit for
22 sharing both revenues and expenses will be determined by the
23 participation formula which has already been established.

24 The billing would be handled on that basis.
25 As expenditures are incurred each owner will be billed
his portion of that expenditure based on his participation

1
2 in the unit.

3 Q How much -- do you have an immediate
4 billing formula or some kind of a bill that would immediately
5 be sent out upon approval of this application?

6 A To be quite honest with you, I don't know
7 the economics arrangements that are being planned and they
8 are being planned right now. So I do not have a billing
9 date or anything of that nature for you.

10 Q Now, correct me if I'm wrong, but you've
11 used Gulf's economics in calculating of the revenue
12 estimates and expenditures in this project, isn't that --

13 A Yes, sir, as I stated, we used Gulf's
14 proprietary economic appraised model, we call it.

15 Q And you considered no other -- no one
16 else's economics.

17 A No one else offered any economics that
18 I'm aware of.

19 Q Let me go back to your Exhibit Twenty-
20 four and I can understand your frustration in reaching the
21 top limit of the proposed interval, but isn't that still
22 fairly arbitrary from the standpoint of gas production and
23 oil production?

24 A No, sir, I wouldn't say it's arbitrary at
25 all. We have, as we pointed out here, reasonable definition
between the oil productive zones and the gas productive
zones. I don't see how you can conclude that that's an
arbitrary decision we've made.

1
2 Q There's no reasonable basis upon which to
3 separate the gas from the oil zone, is there, based upon a
4 datum of 100 feet below sea level?

5 A Yes, sir, there is a reasonable basis and
6 that basis is that according to our investigation of geolo-
7 gical parameters as well as the completion information which
8 we had available to us, that the gas/oil contact does in
9 fact exist somewhere between sea level and plus or minus 100
10 feet, and we can't pin it down to the exact foot, but we
11 feel that it is in that range.

12 That's based on our investigation of the
13 data.

14 Q Don't you have then a probably potential
15 waterflooding of the gas zone?

16 A Mr. Hoffman testified earlier this morn-
17 ing that over the majority of the field the gas zone and the
18 oil productive zone are basically separated by a very dense
19 dolomite, sand interspersed zone, and we feel that that is
20 protection from wholesale, if you will, communication of the
21 oil zone with the gas zone.

22 Q Well, page eleven of that exhibit doesn't
23 necessarily show that -- that you wouldn't encounter a situa-
24 tion like -- or that would eliminate that possibility. In
25 other words, you have your 100 foot line extending poten-
tially into the Penrose zone.

A Yes, sir, and as Mr. Hoffman also testi-
fied this morning, that as the Penrose dips slightly, and it

1
2 is a slight dip to the west, that it loses its distinct
3 character having a sand zone, a dense dolomite zone, and
4 then a dolomite similar to the Grayburg because on the west-
5 ern edge it becomes essentially a dolomitic material which
6 is much like the Grayburg, and we feel that the -- that the
7 oil column extends to the west a mile or even more at the
8 same basic datum, regardless of what you call the formation,
even though the formation may dip to the west.

9 Again that's based on our investigation
10 of completion intervals, of the geologic information we have
11 available, and I might also mention that during our studies
12 we were able to find one other, I would say basically a
13 qualitative if not partically quantitative study which had
14 been made of the field, and it's a study which was made in
15 1939 while the field itself was relatively new and the data,
as opposed to today, would be relatively good.

16 This study was performed by the United
17 States Department of Interior. It was entitled The Reser-
18 voir Characteristics of the Eunice Oil Field in Lea County,
19 and one of the major findings of that study -- let me -- let
20 me get to the summary here.

21 One of the major findings of that study,
22 it reads as this: From an analysis of logs that were made
23 from examinations of cuttings from wells and data concerning
24 well completions, initial oil potentials, gas/oil ratios,
25 water encroachment in the Eunice Field, three major porous
or common zones have been outlined as shown in Figure 6.

1
2 These zones must not be confused with lithologic or geologic
3 units as they may not be directly related to geologic struc-
4 ture.

5 That study which was done, and why we
6 considered it to be the best data available on the field,
7 certainly, the best data at the time, tells us the same
8 thing that we concluded here, that the gas/oil contact is a
9 generalized gas/oil contact, not confined to the Grayburg
10 nor confined to the Penrose, but extending basically over
the field in that general area.

11 The oil productive zone is relatively
12 consistent inside the unit and outside the unit, particular-
13 ly to the west. So I think we've done everything we can at
14 this point given the reservoir information which is avail-
15 able to us to define a reasonable vertical interval defini-
tion.

16 Q The limits of the pool to the east, or
17 the unitized area, they don't end at -- along the boundary
18 line, the western boundary line, do they?

19 A I'm sorry, you confused me there. You
20 said the limits of the pool to the east?

21 Q The limits of the pool to the east side.
22 Let me be more specific.

23 The Eunice Monument where -- where are
24 the limits of the Eunice Monument?

25 A Well, I don't believe I can give you the
statutory definition of the limits of the Eunice Monument

1
2 Pool.

3 Q Generally can you tell me?

4 A On the eastern edge, or boundary, or the
5 western edge?

6 Q Both.

7 A On the western edge the limits are
8 generally at the western boundary of the unit. On the
9 eastern edge, I have -- I can't tell you. I don't know.

10 Q Well, you have that overlap on both sides
11 of the western boundary.

12 A No, sir, not -- not really. On the
13 eastern boundary you have a loss of production over there.
14 There simply are not any more wells.

15 Q (Not audible.)

16 A Yes, sir. And on the western boundary we
17 have the overlap which you've alluded to.

18 MR. PADILLA: I believe that's
19 all I have.

20 MR. STAMETS: Are there other
21 questions of this witness?

22 MR. SPERLING: Yes, sir.

23 MR. STAMETS: Mr. Sperling.

24 CROSS EXAMINATION

25 BY MR. SPERLING:

Q Mr. Wheeler, would you please refer to
your Exhibit Twenty-one? And on page twenty in that exhibit

1
2 it appears to correspond with page three of the February 2,
3 1982, Technical Committee meeting. Do you have that before
4 you?

5 A Yes, sir, I do.

6 Q Okay. Now, you have testified that cal-
7 culations were made presumably subsequent to this meeting
8 which resulted in the figure for the remaining primary re-
9 serves of 14.5-million barrels as of October 1, 1982.

10 A Yes, sir, I believe that's correct.

11 Q And that calculation was based upon the
12 remaining primary reserves on each individual tract?

13 A Yes, sir.

14 Q Let me call your attention to Item No. 5,
15 which is entitled Ultimate Primary Reserves. It gives a fi-
16 gure there of 134-million barrels and the report states that
17 the calculation which resulted in the 134-million barrels
18 was based upon decline curves completed for each tract. Was
19 that in fact done?

20 A Yes, sir, decline curves were calculated
21 on each tract.

22 Q You also testified that with respect to
23 secondary reserves, this seems to be a universally accepted
24 figure, secondary reserves of 64.2-million barrels.

25 A Yes, sir, that's approximately the calcu-
lation.

Q Why is it if you have made the calcula-
tions based upon individual tract numbers for the purposes

1
2 of these other numbers that you can't make a calculation for
3 individual tracts as to secondary reserves?

4 A It becomes a matter of accuracy of data,
5 sir. If I were an owner I want to have the most accurate
6 data possible if I were going to use secondary reserves as a
7 parameter in a parameter table.

8 As I testified, there is a distinct lack
9 of modern logs which can be qualitatively analyzed or quan-
10 titatively analyzed. There is no core information available
11 and if there -- if there were a few scattered cores from the
12 field, we're dealing with a very large area, 14,000 acres,
13 and assigning secondary reserves to individual tracts would
14 become a very not exact, if you will, calculation.

15 Q Well, the calculation of secondary re-
16 serves is anything but exact.

17 A Yes, sir. I would grant you that.

18 Q So why couldn't the same parameters apply
19 to secondary reserve tract participation as applies so far
20 as the rest of the parameters are concerned?

21 A It was the consensus of a number of the
22 Technical Committee members that we would not be able to
23 simulate secondary recovery. We would not be able to arrive
24 at a definitive and quantitative calculation of secondary
25 reserves for each and every tract on the unit.

26 You can do it for some tracts on the
27 unit. You need to be able to do it for all tracts on the
28 unit so that there is equity in the treatment of owners, and

1
2 for that reason we could not arrive at a secondary reserve
3 number for each individual tract on this.

4 If you -- if you will please, we also re-
5 member that some tracts were not even in oil production at
6 the time. Some tracts do not have current oil production.
7 There were no -- there is no way, really, to evaluate those
8 tracts as to their -- their secondary reserves.

9 Q Did you make a calculation as to which of
10 -- or did you identify which of the tracts you could not
11 make the calculation for? Did the Committee do that?

12 A I think I -- no, sir, the Committee did
13 not do that.

14 Q Did you?

15 A No, sir, I did not do that.

16 Q Have you made any attempt to assign
17 secondary reserves to individual tracts?

18 A The Committee did not do that.

19 Q In your opinion would that have been ad-
20 viseable to test the accuracy of the formula which was even-
21 tually adopted?

22 A No, sir, it would not have been advise-
23 able.

24 Q Why?

25 A Because there would have had to be too
many assumptions made on the quality of each individual
tract. There was not modern core nor log nor fluid analysis
data available to us to make those assumptions. So it would

not have been adviseable, in my opinion.

Q Well, what assumption, what additional assumption would have had to been made other than the ones that you used for the purpose of establishing remaining primary reserves, ultimate primary reserves, and secondary reserves?

A Ultimate primary reserves can be calculated using a decline curve technique based on historical production on any given well or any given lease or for that matter, any given property. It's a -- it's a mathematical technique which can be applied to a plot of production. That's ultimate primary.

Remaining primary reserves becomes the difference between ultimate primary and the cumulative production which you have credited to a well or a lease or a property at any given date. It's a mathematical calculation.

Secondary reserves becomes a very rigorous calculation which cannot be done using what we would normally term wellhead parameters; those parameters being production, production rate, things of that nature.

Q Well, do you see any relationship at all between ultimate primary reserves and secondary reserves per tract?

A Yes, sir, I believe there probably is a relationship on a per tract basis.

Q And what would that be?

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A In the matter of correlating our estimate of remaining primary reserves with our estimate of cumulative -- or of, I'm sorry, of primary ultimate as opposed to our estimate of secondary reserves, the relationship is simply that we estimated that there was approximately one-half barrel of secondary reserves remaining for each barrel of cumulative or remaining primary. It's simply a mathematical analogy there.

Q Which is precisely where your 48 percent came from.

A Yes, sir, precisely.

Q With respect to the 48 percent, would you figure that to be a conservative figure or not, based upon your knowledge of other floods?

A Well, as I stated, the normal range is generally -- that we normally use as a rule of thumb is something between 25 to 100 percent, and I've seen both. In my estimation, this is probably a realistic number and I really couldn't quantify it any more than that.

Q So it's somewhat less than half way in between the 25 and 100.

A Well, I would also point out that there's some floods closer to zero, but I didn't analyze those floods.

So I would say somewhere in between, yes, sir, you'd be correct.

Q Well, you wouldn't even consider zero in

1
2 view of your testimony that this flood is feasible.

3 A That's right, I would not. I believe it
4 is feasible.

5 Q You testified that you reached the con-
6 clusion that the adoption of the waterflood program as pro-
7 posed would be profitable. Did you make a calculation as to
8 different tracts as to whether it would be profitable for
all the tracts?

9 A No, sir, we did not make a calculation on
10 individual tracts as such, using our appraised model.

11 Q Such a calculation is possible.

12 A Yes, sir, it is possible and also I have
13 mentioned in my testimony that we encouraged each owner to
14 use his own economic model, whatever it was, and his own
15 economic parameters and constraints to evaluate his own pos-
16 ition.

17 Q Was that viewed in the light of the well-
18 bore penalty factor versus the contribution of wellbores
which is in the unit operating agreement?

19 A Yes, sir, I would have to say it is and
20 the numbers which I presented today do have that factored in
21 and that the cost estimate reflects those wellbore assess-
22 ments.

23 Q Would it surprise you to learn that with
24 respect to a number of smaller participation tracts that it
is uneconomic for those tracts?

25 A I think it would surprise me to learn

1
2 that.

3 Q Sir?

4 A I believe it would surprise me to learn
5 that, sir.

6 Q Was consideration given by the Committee
7 to the use of a usable wellbore as one of the parameters
8 which applied to the participation factor?

9 A Yes, sir, there was consideration given
10 by the Technical Committee for that.

11 Q What disposition was made of that consid-
12 eration?

13 A We could not arrive at a usable wellbore
14 parameter as a technical committee.

15 Q You mean a definition of one or the value
16 of one?

17 A We could not arrive at a calculation
18 which we could tabulate, then call a parameter for the para-
19 meter table.

20 Q Well, how was the \$100,000 figure arrived
21 at? By agreement?

22 A No, sir. If I recall, that was a discus-
23 sion item in the working interest owners meeting and we -- I
24 believe Gulf proposed that \$100,000 figure and I think Mr.
25 Berlin, who is going to follow me, may have other words to
say about that.

Q Okay. Do you recall how many participa-
tion formulas were suggested to the Technical

Committee by the working interest owners?

A I believe nine, sir.

Q Nine?

A I believe so.

Q And as distinguished from the committee, is that correct?

A In the working interest owners meeting which considered participation formulas, the parameters, the formulas were suggested by various owners who were present on that day.

Q They were not generated by the committee.

A No, sir, they were not. The committee was not asked to generate formulas.

Q As a matter of information, do you know who suggested the parameter that was finally voted upon?

A Yes, sir. My handwritten notes from that date indicate that Amoco was the company which suggested that particular formula, which we -- which we adopted.

Actually it was a double suggestion. Amoco suggested the first time; then Conoco suggested the voting on that formula.

Q Well, there was no change in the language, though.

A No, sir, there was not.

MR. SPERLING: I think that's all.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Wheeler, would you take a look at Exhibit Twenty-four and that D-D' cross section?

A Sir, is it the "D" or the "E"?

Q "D" as in dog.

A Oh, yes, sir.

Q Looking at Well 17-1 and 16-7, in both cases we have an oil column which extends more than 100 feet or is more than -100 feet below sea level.

How will wells under those conditions be waterflooded?

A Sir, each one of these wells, and there are more than just these two, in fact if you look at the 17-19 on the same page, each one of these wells will have to be evaluated on its own to determine where the completion interval is.

Those wells should have remedial action which will put them effectively into the pool in which they're producing. I would suggest from what little I know about remedial procedures that we'd want to squeeze any interval that is open if in fact that well remains open at that interval which I've shown. This basically is an indication of the original completion interval, whatever it may have been.

16-7 is a well which has been perforated

1
2 above the casing shoe, would need to be squeezed.

3 17-19, we have a problem there where we'd
4 have -- we'd need to run a production liner of some kind to
5 confine the injection and production into the unitized in-
6 terval, which we have proposed.

7 There are some of these wells, however,
8 they're not numerically a very large number of wells, to our
9 knowledge.

10 Q Based on what you have seen in all of
11 your committee work, in situations like this are we dealing
12 with a continuous oil column or an oil column which is dis-
13 continuous which will allow you to do these squeeze jobs and
14 carry on waterflood operations without affecting the oil
higher in the hole?

15 A We believe this is a continuous oil
16 column, sir, and one of the reasons I say this is that if
17 you go through all the records you'll find such information
18 as the API gravity of a well which is completed high or low.

19 The similarities of the oil indicate that
20 these -- this is the same oil, whether it is called for our
purposes Eumont oil or Eunice Monument oil.

21 We believe that we're dealing with one
22 continuous oil column which happens to transgress the top of
23 the Grayburg as it has been defined the top of the pool,
24 which we don't believe it is.

25 Q Based on the committee work would there
be objections to altering the pool limits on individual

1
2 well so that the entire oil column could be produced on cer-
3 tain wells?

4 A No, sir, based on our committee work
5 there would not be objection.

6 Q Is that the sort of thing that Gulf, in
7 your opinion, should consider?

8 A Changing the vertical limit -- I'm sorry,
9 I missed a part of the question.

10 Q Well, being able to change the vertical
11 limits on a well by well basis?

12 A No, sir.

13 Q In order to take full advantage of the
14 oil column and recover the maximum amount of oil?

15 A I'm not sure that I follow you on a well
16 by well basis. I think we have to --

17 Q Take Well No. 17-1, for example.

18 A Yes, sir.

19 Q You indicated that you'd get in there and
20 squeeze off the column of oil about the -100 foot contour.

21 A I would hasten to point out here again
22 that this is a completion interval and at this point I have
23 no indication that that footage above -100 feet is produc-
24 tive of either oil or gas. It would have to be considered
25 on an individual basis here.

Q Let's consider this on an individual bas-
is and assume this is a continuous oil column. Under those
circumstances why -- what would be the benefit in squeezing

off that upper 80 feet or so from the rest of the wellbore?

A There would be no benefit if it is in fact oil productive. If it is not oil productive, the benefit would be to get it within a statutory description of the pool in which we intend to waterflood.

Q Okay, would it be Gulf's intention, then, when you find individual situations with an oil column above the -100 foot contour interval or above the Grayburg formation, whichever is higher, to seek an exception to the pool limits to allow that well to be produced?

A One of the things which we intend to do in installing this waterflood unit is to conduct what's been missing here all along, and that is a reservoir analysis based on newly drilled wells and cores and logs and fluid analysis, and I would assume that as a prudent operator, if in the course of that reservoir analysis we discovered that the definition needed adjustment and if it proved there was more oil column than we originally thought in place, that we would in fact come back as a prudent operator and try to amend those limits to include known oil which could be swept under waterflood operations.

Q Okay. Based on the work you've done, do you have an opinion as to why the oil has migrated up the formation column in parts of the reservoir?

A No, sir, I'm -- I cannot.

Q Has the Committee looked at the possibility of drilling infill wells?

1
2 A At this point in time, no, sir, we have
3 not, and the reason being that in order to evaluate infill
4 drilling, for example, on a 20-acre spacing, we need to have
5 some projection of recovery in order to base your economics
6 and there have been no wells which we could classify as in-
7 fill wells drilled for that evaluation.

8 So we have not considered at this point
9 infill drilling.

10 Again I would refer you to what I hope to
11 be a very good reservoir study which would take place at
12 unitization and continue through the life of the unit.

13 Q Do you believe that considering infill
14 drilling would be an appropriate part of this study?

15 A Yes, sir, I believe in my opinion it
16 would be an appropriate part of the study, if we in fact
17 gain that data.

18 Q And for what period of time would such a
19 study be made?

20 A Well, as I mentioned, it ought to start
21 with the very first well we can enter and drill and in my
22 opinion it's a continuing thing, a continuing study through
23 the life of the waterflood, which would at future dates en-
24 tail perhaps a study of infill drilling or other enhanced
25 recovery techniques or just evaluating the waterflood which
we would be operating to maximum its recovery.

26 Q Under normal operating conditions when --
27 when do you think the operator should have some idea as to

1
2 the likelihood of infill drilling being a valuable recovery
3 tool?

4 A I would think when we arrive at some --
5 some point towards the fill-up of the -- of the unit and
6 we're able to establish that we have patterns of sweep in
7 the reservoir and then at that time are able to evaluate an
8 infill prospect, for example.

9 Q How long would that fill-up take?

10 A I estimate between five and seven years.

11 MR. STAMETS: Are there other
12 questions of this witness?

13 MR. KELLAHIN: Yes, Mr. Chair-
14 man.

15 REDIRECT EXAMINATION

16 BY MR. KELLAHIN:

17 Q Mr. Wheeler, I'd like to follow up on a
18 question that Mr. Padilla asked you to make sure I have it
19 clear.

20 Mr. Padilla was asking you, I believe,
21 with regard to Tract 55 when that tract would participate in
22 revenues from the unit.

23 My question is would Tract 55 share in
24 its proportionate percentage of the unit production from the
25 first date of unit operations or will it not participate un-
til there is a producing oil well on Tract 55?

A It will participate from the first day of

1
2 effective unitization.

3 Q So the presence or absence of a producing
4 well on Tract 55 makes no difference in whether that tract
5 receives its proportionate share of unit production.

6 A No, sir, not at this point.

7 Q Let me follow up on some questions that
8 Mr. Sperling asked you.

9 When we talk about the Technical Commit-
10 tee's parameter table are we talking about something differ-
11 ent than the participation formula that was discussed and
12 agreed upon by a majority of the working interest owners?

13 A The parameter table is a reflection of
14 each tract's characteristics under those parameters and
15 those parameters are the one which we used to build a parti-
16 cipation formula.

17 Q In looking at the parameter table what
18 are the three basic parameters that were developed by the
19 Technical Committee?

20 A There is a cumulative oil production num-
21 ber.

22 A Correct.

23 Q Then on page 41 of the Technical Commit-
24 tee that is the third column from the right.

25 A Correct.

Q The second column from the right is the
remaining primary reserves.

A Correct.

1
2 Q And the last one is the current produc-
3 tion between two dates.

4 A That's correct.

5 Q All right. When the working interest
6 committee talks about the participation formula, and Mr.
7 Sperling asked you, said there were some nine differnt for-
8 mulas, are we not talking about the working interest owners
9 taking various percentage from each of those columns and
figuring out what's equitable?

10 A Yes, sir, that's correct.

11 Q All right. When we look a the parameter
12 table itself and disregarding the participation formula and
13 how those percentages are weighted one against the other,
14 when we look at that table itself, was there any objection
15 by Exxon to the parameters in the parameter table?

16 A Not to my knowledge, sir.

17 Q Was there any objection by Exxon to the
18 secondary reserves calcualted for the unit?

19 A Not to my knowledge.

20 Q Did Exxon ever object to the fact that
21 the secondary reserve parameters were not conducted on an
individual tract by tract basis?

22 A Not to my knowledge.

23 Q When we put aside the parameter table
24 which was unanimously agreed upon by all working interest
25 owners and look at the participation formulas, there appar-
ently were ballots on some nine different formulas?

1
2 A Yes, sir, to the best of my recollection
3 there were nine.

4 Q And the discussion in the working inter-
5 est owner committee about how to weight each one of those
6 factors is the subject of Mr. Berlin's testimony that fol-
7 lows here.

8 A That's correct.

9 MR. KELLAHIN: Nothing further,
10 Mr. Chairman.

11 MR. STAMETS: Any other ques-
12 tions?

13 MR. SPERLING: I have just one.

14 RECROSS EXAMINATION

15 BY MR. SPERLING:

16 Q Mr. Wheeler, in response to Mr. Kella-
17 hin's question, by the majority of the working interest
18 owners you aren't speaking of the numerical majority, you
19 were speaking of the majority participating at that particu-
20 lar time.

21 A Could you help me with the specific ques-
22 tion that he asked, sir, I --

23 Q I think he asked you if the parameters
24 were not -- were voted upon, ones selected were voted upon
25 by a majority of the working interest owners and I'm asking
you in what sense did he use the word "majority" and in what
sense did you respond.

1
2 A At the working interest owners meeting
3 the parameter table was presented as the basis for negotia-
4 tion of ownership and all working interest owners present at
5 that meeting unanimously agreed that the parameter table
6 should be used as the basis for calculating a participation
7 factor.

8 All present and I do not know exactly
9 what working interest ownership present at that date was,
10 but it was certainly over 90 percent.

11 Q Okay, thank you.

12 MR. STAMETS: Are there any
13 other questions? The witness may be excused.

14 MR. KELLANIN: Mr. Chairman,
15 before we take a recess, if that's appropriate at this time,
16 I believe there's a representative from Shell that is not
17 going to be able to stay much longer and I believe he wanted
18 to make a statement for the record, and I would appreciate
19 the courtesy of the Commission extended to that individual
20 so he could make his statement and make his airplane because
21 we won't be here tomorrow and it is apparent to me that this
22 case is going to go to tomorrow.

23 MR. STAMETS: I think you're
24 right. We'll be happy to let him speak.

25 Will the representative of
Shell make his statement at this time, please?

 MR. PFAU: My name is Donald
J. Pfau, Shell Western E&P out of Houston.

1
2 I have a statement I was going
3 to read. Quite a bit of it would be repetitious, so what I'd
4 like to do is just give it to the court reporter, if I
5 could, and simply say that we would support Gulf in the pro-
6 posals that they have made as being fair and equitable and
7 reasonable as compromises of many interests involved.

8 And as a matter of interest, we
9 made a proposed formula at the working interest owners meet-
10 ing which was voted down and we voted for the one that was
11 successful on the second round of voting.

12 We felt that it was a reason-
13 able compromise on what we were looking for, a reasonable
14 compromise, and on that basis we support it.

15 MR. STAMETS: Thank you, we ap-
16 preciate that.

17 And we'll take about a fifteen
18 minute recess.

19 (Thereupon a recess was taken.)
20
21

22 MR. STAMETS: The hearing will
23 please come to order.

24 You may call your next witness.

25 MR. KELLARIN: Thank you, Mr.
Chairman.

At this time we'll call Dave Berlin.

DAVE BERLIN,
being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Berlin, this morning when witnesses were sworn by the Commission were you also sworn?

A Yes, I was.

Q For the record would you please state your name and where you reside?

A My name is Dave Berlin and I live in Odessa, Texas.

Q Mr. Berlin, by whom are you employed and in what capacity?

A I'm employed by Gulf Oil Corporation as the Manager of Enhanced Recovery Operations for the Western Division.

Q Would you describe generally for the Commission what it means when you say you're the Manager of Enhanced Recovery Operations for the Western Division?

A Basically I'm responsible for a group of reservoir engineers who do secondary and enhanced recovery studies and also that includes general managerial respons-

ibilities for the technical aspects of ongoing enhanced recovery and secondary recovery projects.

Q When we talk about the Western Division of Gulf, what area are we talking about?

A We're talking about the western United States beginning from the midpoint of Texas around Ft. Worth, all the way to the west coast, including the State of California.

Q On behalf of Gulf have you been involved in other secondary recovery projects?

A I have participated in a number of them over my employment with Gulf, that's correct.

Q Would you describe for the Commission when and where you obtained your professional degree in petroleum engineering?

A I graduated from the Colorado School of Mines with a degree, a professional degree in petroleum engineering in 1968 and since that time I've spent the past sixteen years in various engineering positions in west Texas and New Mexico, including two and a half years in our Hobbs Office as Area Engineer where we were directly responsible for the operation of these particular properties.

Q When we talk about the Eunice Monument South Unit Area, that the working interest owners with Gulf as the operator propose to use for secondary recovery, would you describe for us how long you've been involved in that project?

1
2 A I've been involved in these study efforts
3 from the very beginning which began five and a half years
4 ago in April of 1979.

5 Q With regards to the various committees
6 that were formed by the working interest owners to study,
7 evaluate, and formulate this unit, what, if any, function
8 did you serve on behalf of Gulf?

9 A Actually, I was the Chairman of the Tech-
10 nical Committee but also represented Gulf on the working in-
11 terest owners committee, serving as Chairman at times during
12 that process.

13 MR. KELLAHIN: Mr. Chairman, we
14 tender Mr. Berlin as an expert petroleum engineer.

15 MR. STAMETS: He is considered
16 qualified.

17 Q Mr. Berlin, I'd like to direct your at-
18 tention first of all to what has been introduced as Exhibit
19 Number Twenty-one, which is a compilation of the minutes
20 from the technical and working interest owners meetings.

21 Do you have a copy of that, sir?

22 A Yes, I do.

23 Q And while we're talking about exhibits,
24 Mr. Berlin, I'll show you what I have marked as Gulf Exhibit
25 Number Twenty-one-A.

Would you -- you certainly don't have to
describe but simply identify for us what is included in the
pages stapled together and marked as Gulf Exhibit Number

1
2 Twenty-one-A.

3 A Twenty-one-A is a summary of the partici-
4 pation formulas and the votes on those formulas that were
5 taken during the working interest owners meeting of, I be-
6 lieve, August 25th, 1983.

7 Q All right, sir, we'll come back to the
8 participation formulas in a minute.

9 Mr. Wheeler spent some time talking about
10 the work of the unit interests from the point of view of the
11 Technical Committee. I will ask you, sir, to describe for
12 us from the working interest owners committee approach to
13 the unit process.

14 When did the working interest owners
15 first get together in a meeting in order to begin to study
16 this property as a possible candidate for secondary water-
17 flooding?

18 A Actually the first working interest
19 owners meeting was called by ARCO on May the 10th of 1979,
20 at which time there was agreement that a waterflood project
21 was feasible and in fact they began the formation of a Tech-
22 nical Committee and set out the charges to that committee at
23 that meeting.

24 Q From that first meeting approximately how
25 many companies were you dealing with in terms of working in-
26 terest ownership?

27 A There are 42 working interest owners cur-
28 rently identified in the unit area and not all of them were

1
2 known at the time. I think there were probably approximate-
3 ly 36, or so, that were known owners at the time we were
4 going through the Technical Committee work.

5 Q And during this period of the Technical
6 Committee work, what percentage of the ownership was invol-
7 ved with and participated in this unit work?

8 A Well, as Mr. Wheeler testified, over 85
9 percent was present at all of the Technical Committee meet-
10 ings and in fact we had a much greater percentage involved
11 in the Working Interest Owners Committee meetings.

12 Q Let me ask you initially how the working
13 interest owners handled their business in terms of voting
14 and voting percentages on any given motion.

15 A It was agreed in the meeting of June the
16 1st of 1983, which was the first meeting after the Technical
17 Committee finished its report and submitted it to the work-
18 ing interest owners, it was agreed at that time that a vote,
19 an approval vote of 75 percent of the ownership would be re-
20 quired to pass a motion.

21 Q One of the first things that Mr. Wheeler
22 discussed that the Technical Committee did was to make an
23 examination of the unit boundary and make recommendations
24 back to the Working Interest Owner Committee on a unit boun-
25 dary.

My questions for you, sir, is what ac-
tion, if any, did the committee take, the Working Interest
Owner Committee take with regards to the unit boundary?

1
2 A At the meeting of June 1st, 1983, there
3 was actually a motion to modify that boundary by the inclu-
4 sion of some additional acreage and that acreage was re-
5 jected by the working interest owners primarily because it
6 was already in the Amerada Hess study area and we didn't
7 feel it appropriate to change the boundary to add additional
8 acreage at this time.

9 We also considered two requests, actual-
10 ly, to delete acreage from the unit, these being submitted
11 by Mr. Doyle Hartman and Mr. James Rasmussen.

12 These requests were also unanimously re-
13 jected by the working interest owners of the good secondary
14 recovery potential that existed on those tracts and because
15 of the adverse impact that deleting them would have on the
16 secondary recovery on the tracts surrounding those deleted
17 tracts.

18 So in fact we ended up accepting the
19 Technical Committee recommendation on the unit boundary.

20 Q Did any of the owners involved in Mr. Pa-
21 dilla's Tract 55 request the working interest owners to de-
22lete that tract from the unit?

23 A They did not.

24 Q Did Exxon ever make any requests that any
25 of their tracts be deleted from the unit?

 A They did not.

 Q Directing your attention to the working
interest owners actions concerning the vertical limit defi-

1
2 nition, would you describe for us what the working interest
3 owners did in approving or disapproving the definition as
4 proposed by the Technical Committee?

5 A Yes. We considered all of the possibili-
6 ties that the Technical Committee representatives consi-
7 dered, and in fact did not find any better definition that
8 hadn't been arrived at by the Technical Committee, so the
9 working interest owners agreed with that definition and in
fact accepted it and incorporated it into the agreements.

10 Q There was a working interest owners meet-
11 ing on August 25th, 1983, I believe.

12 A That's correct.

13 Q All right, sir, would you summarize for
14 us the major topics of -- under consideration at that meet-
15 ing?

16 A At the August 25th meeting we considered
17 the definition of usable wellbore and the monetary value
18 that a wellbore would have in unit operations and these were
19 in fact agreed upon and we also discussed the parameter
20 table that had been submitted by the Technical Committee and
21 as previously stated, it was unanimously accepted by the
22 working interest owners as the base for developing a parti-
23 cipation formula, and we proceeded to negotiate that formula
at the August 25th, 1983, meeting.

24 93 percent of the owners were present at
25 that meeting and it was -- the parameter table was accepted
unanimously by all of those owners as the basis for partici-

1
2 pation.

3 Q What is the purpose of the participation
4 formula, Mr. Berlin?

5 A Very simply the participation formula is
6 used to allocate the oil and gas production to the indivi-
7 dual tracts and individual owners within the unit and as the
8 basis for sharing the investments and the operating costs of
the unit.

9 Q How was the participation formula for
10 this unit determined?

11 A At the August 25th, 1983 meeting there
12 were several different formulas proposed and those formulas
13 have been submitted as Exhibit Twenty-one-A.

14 These formulas were proposed by different
15 owners who were present and they were considered and voted
16 upon and in an attempt to try to get a consensus of owner-
ship on what is an equitable formula.

17 We didn't have anywhere near a consensus
18 and you can go through these formulas to determine that, on
19 what equity should be in the unit, what an equitable formula
20 would be.

21 We didn't have what we considered the re-
22 quired 75 percent on any of the formulas until Conoco agreed
23 to compromise their position and actually change their vote
24 on Formula No. 2. They asked that it be resubmitted and
25 they changed their vote which gave us the greatest consensus
that we were able to obtain in any of these particular for-

1
2 mulas.

3 Q All right, let's look at Participation
4 Formula No. 2, which is the second page of Exhibit Twenty-
5 one-A.

6 Is this the participation formula that
7 was finally agreed upon by some 93 or 92 percent of the
8 working interest owners?

9 A This is the formula. This is the parti-
10 cular weighting. Actually it was -- this is the vote on the
11 original submission of the formula. Later on you'll see it
12 resubmitted again on the same weighting and the same parame-
13 ters as Formula Two-A -- yeah, it's on the following page,
14 and that is the particular formula that was ultimately adop-
15 ted for the unit agreements and received the current percent
16 of 92 percent of the ownership and 99-1/2 percent of the
17 royalty owners.

18 Q We talked about the balloting on that
19 formula. Would you go through for us and tell us how the
20 three parameters have been weighted in this formula?

21 A As you can see there, the weighting on
22 the particular parameters is 50 percent on cumulative
23 production, 40 percent on remaining primary reserves, and 10
24 percent on the current production parameter.

25 So you can take those weightings and you
can determine the participation on any particular tract by
dividing the tract's cumulative production by the unit's
cumulative production and multiplying by 50 percent, taking

1
2 the remaining primary reserves of any tract, dividing by the
3 total unit remaining primary reserves and multiplying by 40
4 percent, and finally taking the current production from any
5 individual tract, dividing by the total unit current produc-
6 tion and multiplying by a weighting factor of 10 percent.

7 The sum of those three products will then
8 be that tract's participation in the unit.

9 Q All right, once you use this formula for
10 the participation, how do you calculate a given tract's
11 interest then under the formula?

12 A Well, it's just as I described. Once
13 again, you would take the parameters on any individual
14 tract and divide by the total unit parameter and multiply by
15 the appropriate weighting factor and that will give you that
16 tract's participation.

17 Q Is the participation formula a method for
18 allocating the participation among the tracts set forth in
19 the unit agreement?

20 A Yes, it is. That can be found on -- in
21 Section 15-A on page nine of the unit agreement. The unit
22 agreement was previously submitted as Exhibit Number Three,
23 I believe.

24 Q My copy of the unit agreement shows it on
25 page seven, Mr. Berlin. Let's make sure we're looking at the
same participation formula.

A That's -- that's correct.

Page seven is correct.

1
2 Q With regards to the participation formula
3 that has been agreed to by this 93 percent of the working
4 interest owners, do you have an opinion as to whether or not
5 that participation formula allocates the production of the
6 unitized hydrocarbons to the separately owned tracts in the
7 unit area so as to be fair, reasonable, and equitable?

8 A It is my opinion that it is equitable.
9 There were only two working interest owners out of a total
10 of 42 owners that have ever voiced any concern about the
11 participation formula and indeed said they would not ratify
12 the agreements on that basis.

13 Those two companies were Cities Service
14 and Exxon.

15 Cities Service, and you can check the
16 vote on 2, Formula Number 2 and Number 2-A, actually voted
17 in favor of the formula during the meeting, but they have
18 subsequently changed their mind for some unknown reason.

19 Exxon believes that the formula is
20 weighted too heavily on the remaining primary parameter and
21 not enough on the cumulative production parameter and there-
22 fore they will not receive an equitable share of the secon-
23 dary reserves.

24 At the meeting of August 25th when we
25 were negotiating these formulas, or this particular formula,
we looked at different weightings of both of those para-
meters and in fact the weighting on cumulative production
ranged from 40 percent to as high as 70 percent.

1
2 The weighting on cumulative production of
3 70 percent is shown as Formula Number 3 and this was a for-
4 mula that was favored by Exxon, as you can see by their
5 vote. They voted in favor of that formula.

6 Gulf, in fact, also voted in favor of
7 that formula, but you can see by the tabulation at the bot-
8 tom, even with Gulf's 30 percent that particular formula was
9 not believed to be equitable by the majority of the owner-
ship.

10 Q How did Gulf vote in terms of all the
11 various formulas proposed?

12 A I think you will see by thumbing through
13 these particular votes that we voted in favor of every for-
14 mula. We did this in the spirit of compromise, knowing how
15 important this unit was to us and to all the participants
16 and in fact our participation does not really change that
17 much, so we were in a rather unique position, I think, of
being able to vote favorably on all of them.

18 Q Let me ask you this. If the cumulative
19 oil production is weighted at 70 percent as opposed to
20 weighting at 40 percent, is that to Gulf's economic advan-
21 tage one way or another on this parameter table?

22 A Actually it makes very little difference
23 to Gulf. I think you can look at the weighting of 70 per-
24 cent and our participation with that weighting would have
25 been 30.115 percent and on the formula that we have, I'll
have to find the 40 percent weighting, it's shown as Formula

1
2 No. 5, our participation would have been 30.82 percent, so
3 there's very little difference in the effect that the
4 weighting would have had on Gulf's participation.

5 Q Mr. Berlin, I'd like you to give us some
6 background and some reasons why it's in your opinion neces-
7 sary to weight the different parameters on different percent-
8 ages.

9 What's the basis behind doing that?

10 A The basis is obviously to arrive at a
11 consensus of opinion as to what's equitable, what's equit-
12 able in terms of recoveries from the unit and sharing of ex-
13 penses.

14 We think that the weighting, and of
15 course we're supported by the majority of the other owners
16 that think that the weighting on the current formula, the 50
17 percent for current production and 40 percent for remaining
18 primary, is in fact equitable. It takes into consideration
19 the near term benefits that will accrue to operators as well
20 as the long term benefits.

21 In order to consider the near term bene-
22 fits you have to look at the relative value of primary re-
23 serves versus secondary reserves. Primary reserves are the
24 reserves that are produced first under unit operations and
25 have the greatest present value. They have that because
they're produced first and they have -- they're much less
expensive to produce than the secondary reserves.

You have another factor that needs to

1
2 come into play. There is considerably less risk associated
3 with the primary reserves; there's practically no risk, as a
4 matter of fact.

5 The secondary reserves on the other hand
6 have a considerable amount of risk, and that risk needs to
7 be taken into consideration on the weighting also in deter-
8 mining equity.

9 Q Is there any information you can draw
10 from the Technical Committee reports to you that shows a
11 reason or basis that classifies the weighting percentages
12 that were used in Formula Number 3, in terms of the ratio of
13 secondary reserves for each barrel of production?

14 A Yes. You have to consider the cumulative
15 production parameter in detail. It is not per se secondary
16 reserves. In fact, the cumulative parameter only represents
17 half a barrel of secondary reserves.

18 The remaining primary, on the other hand,
19 represents one full barrel of reserves and in fact repre-
20 sents another half a barrel of reserves for secondary, so
21 that means that the remaining primary, you're going to get
22 1.1-1/2 barrels of unit reserves for only half a barrel of
23 reserves based on cumulative production parameter.

24 Q If I asked you that --

25 A There's a difference of three times.

Q I asked you that in terms of Formula Num-
ber 3 and I think I was really asking you in terms of For-
mula 2-A, the one adopted by the working interest owners.

1
2 A That's correct. That's what I recited,
3 yes.

4 Q Let's turn to the Technical Committee re-
5 port, Mr. Berlin, and to page 41 that has the parameter
6 table on it. Do you have one of those available there?

7 A I have the parameter table, yes.

8 Q All right, sir.

9 I'd like to direct your comments to page
41.

10 A I'll have to have the parameter table.
11 I've got it.

12 Q Okay. Looking at the parameter table and
13 if we find Exxon's interest on the parameter table. Under
14 the unit participation for the Exxon tracts, what is their
percentage participation?

15 A Well, you can't determine --

16 Q No, sir, not from the parameter table.

17 A -- from the table.

18 Q -- but your other knowledge of Exxon's
19 interest, what is that percentage?

20 A Exxon's interest in the unit will be 4.86
21 percent based on this formula.

22 Q Can you draw any comparison, Mr. Berlin,
23 between Exxon's participation in the unit in terms of what
24 the Technical Committee has estimated for their remaining
primary production from Exxon?

25 A Yes. You can look at the parameter table

1
2 and see that the percentage of remaining primary that Exxon
3 was estimated to recover under continued operations repre-
4 sented only two percent of the total, whereas under the par-
5 ticipation formula they're going to receive 4.86 percent of
6 the remaining primary reserves, over two and a half times
7 what the Committee estimated they would receive under con-
tinued operations.

8 Q In your opinion is that a fair and equit-
9 able way in which to have Exxon's interest participate in
10 the unit?

11 A I think it's fair and equitable when you
12 consider the fact that these remaining primary barrels have
13 a greater present worth and in fact have absolutely or es-
sentially no risk associated with their recovery.

14 Q Are there any other working interest
15 owners that we can point to on Exhibit Number -- page 41 of
16 Exhibit Number Twenty-two which are working interests in a
17 similar relationship as Exxon is?

18 A Yes, I believe there are several. Amer-
19 ada Hess is the first one the list that comes to mind. If
20 you look at their cumulative recovery percent versus their
21 remaining primary percent, they have a much greater --
22 they're in a very similar position to Exxon. Their cumula-
tive parameter is higher than their remaining primary.

23 Amerada has ratified the agreement.

24 Q All right.

25 A You can look further.

Q How about Getty?

A Yes, Getty is in that same position. They have 9.5 percent of the remaining -- excuse me, of the cumulative recovery parameter and less than half of that as remaining primary reserves and they also have ratified the agreement.

Q All, right, sir, a couple of others. Do you see any others on the list?

A I see Koch and Landrith are two of the smaller owners that are in a similar position, and both of them have also ratified the agreements.

Q What will happen to Exxon's current production with and without unitization? What happens to that current production?

A Actually, because of the 4.86 participation that they will be given in the unit their production on the effective date of the unit will actually increase, as will their current income.

Q When we look at the unit operating expenses and capital investments, Mr. Berlin, how are those to be allocated to the various separately owned tracts in the unit?

A Article XII on page sixteen, I believe, of the unit operating agreement, which was introduced as Exhibit Number Four, sets forth the method of allocating the costs of unit operation and to summarize it very briefly, each working interest owner's share of the capital invest-

1
2 ments and operating expense again will be the same as their
3 -- will be based on their participation in the unit.

4 Q All right, sir, and do you consider that
5 method of allocating the unit expenses to fair, reasonable,
6 and equitable?

7 A Yes, I do.

8 Q And also under the contractual arrange-
9 ments what is to be the method for credits or charges made
10 for such items as tanks, pumps, and machinery, and equipment
11 contributed to the unit operations?

12 A Again, in the unit agreement Article X
13 states that all items contributed to the unit operations by
14 the working interest owners are to be inventoried by a com-
15 mittee of the owners and a value assigned immediately after
16 the effective date.

17 Once this inventory has been approved by
18 the ownership, the unit will, in effect, purchase that
19 equipment from those owners.

20 Now that's done through an inventory ad-
21 justment procedure where that an owner who contributes more
22 than his share of equipment will actually receive a credit
23 or a payment for his -- for the difference.

24 On the other hand, if an owner has not
25 contributed his share of the total inventory, he will re-
ceive a bill for the difference.

Q Is there any disagreement among the work-
ing interest owners about the operating expenses, the capi-

1
2 tal investment and the method for allocating the unit expen-
3 ses, such as tanks, pumps, machinery, et cetera?

4 A There has been none to my knowledge.

5 Q Let me ask you a question, Mr. Berlin,
6 with regards to the participation formula. We've talked
7 about the one agreed to by 93 percent of the working inter-
8 est owners, 40 percent weighted on the cumulative oil.

9 Let's assume that the Commission changes
10 that participation and requires it, the participation for-
11 mula is changed to weight the cumulative oil to the 70 per-
12 cent number, which was the only one apparently Exxon agreed
13 to, what will happen to the unit process?

14 A It will be considerable disruption, to
15 say the least, in the unitization process.

16 First of all, it's my belief that the
17 owners will ask that the parameters be updated. That means
18 we'll have to go back to the Technical Committee to update
19 the parameters, which means we're going to suffer a delay of
20 probably a year or two years to where we could get to this
21 same point again.

22 When we get to this same point, it's my
23 opinion, based on the negotiations that I've seen take place
24 in the meetings and with conversations with the individual
25 owners, when we got back to this point again we would have
less of a consensus than we now have, considerably less.

26 Q In your opinion at that point, a year or
27 more from now, do you believe that you would have the mini-

1
2 num 75 percent consent of working interest owners in order
3 to continue, then, with the statutory unitization pro-cess?

4 A I believe it would be questionable
5 whether we could even get the 75 percent based on a formula
6 weighted 70 percent. In fact I know we could not, because
7 Gulf probably would not support that formula at this time.

8 Q Let's talk about how the working interest
9 owners addressed the problem or the concern of dealing with
10 wellbore values. You mentioned earlier that the committee
11 unanimously agreed to the value --

12 A Right.

13 Q -- placed on a wellbore. We're going to
14 talk about wellbores for some time this afternoon. Let's
15 talk about the valuation of that wellbore, first of all, and
16 have you describe what was discussed and what was at issue.

17 A In determining the value of a usable
18 wellbore we had to consider old wellbores of 1930 vintage
19 versus new wellbores that might be drilled, and of course we
20 estimated the cost to drill a new wellbore at about
21 \$250,000. We recognized that you couldn't -- that the util-
22 itarian value of an old wellbore would not approach
23 \$250,000. So therefore the owners determined that \$100,000
24 of value was more representative of the value of an old
25 wellbore without logs, open hole completions, things of that
nature, probably requiring a lot of remedial work, certainly
did not have the utilitarian value that a new wellbore would
have.

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2 So we valued it considerably less than
3 the value of a new wellbore. We valued it at \$100,000.

4 There was no disagreement whatsoever in
5 the \$100,000 value.

6 Q Was that an item that was discussed when
7 Exxon's representatives were present at a working interest
8 meeting?

9 A Exxon was present at that meeting, yes,
10 and they did not object to that valuation.

11 Q So when we talk about the valuation of
12 the old wellbores, the \$100,000 number is not one that's in
13 dispute, is that correct?

14 A That's correct.

15 Q All right. Where is the handling and
16 valuation of the wellbore situation covered in the operating
17 agreement, Mr. Berlin?

18 A It's covered in Article XI beginning on
19 page 14 of the unit operating agreement.

20 The reason, if I may go on, the reason
21 that the owners felt like we needed a particular article
22 dealing with wellbore equity was the fact that there were
23 already 23 wells plugged and abandoned. There were 48 wells
24 that were temporarily abandoned, and there were 52, or some
25 odd others that were plugged out of the Eunice Monument oil
producing interval back to the Eumont Gas Pool.

The owners felt that it was necessary to
create some kind of an incentive to have operators contri-
bute as many wellbores as possible toward the unit so that

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2 we might conduct operations and in order to balance the in-
3 equity that would come about when unit owners did not con-
4 tribute a full complement of wells on every tract.

5 Q When we talk about the definition of a
6 usable wellbore, was there any disagreement among the work-
7 ing interest owners about the definition?

8 A There was no substantial; it was discus-
9 sed at length and I think there was general agreement
10 on the definition of a usable wellbore.

11 Q We've agreed upon a value; we've agreed
12 upon a definition. In determining how to account to the
13 unit for the wellbore situation, what were the various pos-
14 sibilities considered by the Working Interest Committee?

15 A We considered three possibilities dealing
16 with this inequitable situation. The first --

17 Q I can ask you in detail about each one
18 but tell me what the three are so we can keep track of them.

19 A The first one was to develop a usable
20 wellbore plan for consideration in the participation for-
21 mula.

22 The second --

23 Q It's a parameter for a wellbore contribu-
24 tion that goes into the calculation on the participation
25 formula.

A It could have become a part of the for-
mula, yes.

26 Q That's one possibility.

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A That's a possibility.

Q What's the second possibility?

A The second one was to handle wellbores on an inventory basis, where an owner would be given credit for the wellbores contributed.

And the third possibility is to deal with it on a wellbore assessment, where you actually assess a portion of the cost of the replacement well for the owner who does not contribute wellbores.

And that third approach, as we'll discuss, is the one that's been incorporated into the agreements and supported by the majority of the owners.

Q All right, let me go back and ask you to tell me now why it's necessary to have an incentive for the unit, an incentive for the working interest owners in a unit to contribute wellbores to the unit. What's -- what's the problem you're dealing with?

A Well, the problem is that these wellbores have value in producing other intervals, and particularly the Eumont Gas Pool. If there is not an incentive the owners of the wells could actually withhold those wells from the unit in order to utilize them as a completion in the Eumont Gas Pool, which would in effect necessitate nearly the complete redrilling of the total unit.

Q Would that be reasonable in terms of the unit operations for the secondary recovery?

A The economics of the waterflood project

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2 would not support that kind of redrilling. No, it's not
3 reasonable.

4 Q In your opinion, then, it's absolutely
5 necessary for the success of the unit to have a wellbore
6 contribution incentive.

7 A Yes.

8 Q All right, let's look at the three ap-
9 proaches. What's the first one?

10 A Once again, it was discussed fairly
11 briefly but we considered the possibility of utilizing a
12 usable wellbore parameter. The Technical Committee, as Mr.
13 Wheeler discussed, was not able to develop this particular
14 parameter for use by the working interest owners. The
15 reason that they could not determine that parameter was the
16 fact that the owners could not tell us how many wells they
17 would contribute to the unit until they knew the value of
18 that wellbore and what weighting it would receive in the
19 participation formula, and that could not be known prior to
20 actually determining a participation formula.

21 So it was just not possible to develop a
22 parameter on that basis.

23 Another thing that we considered was the
24 fact that a parameter based on an item of cost, as a well-
25 bore would be, was not fair to the royalty owners to impact
the participation in the formula, so on that basis alone we
rejected the use of that usable wellbore parameter.

Q The inclusion of a wellbore factor in the

parameter has the effect of charging against a working interest -- I mean a royalty owner interest certain costs that are normally borne by working interest owners.

A That would be the effect if it had been included in the participation formula, yes.

Q You said the second approach that was examined by the working interest owners was this inventory valuation?

A That's correct.

Q And I believe this is the one that Exxon has favored?

A Exxon does favor this approach. It is an approach that was actually put forth by Gulf at the working interest owners meeting and, if I might describe how this --

Q All right, sir.

A -- would work.

Q Tell us how it works.

A Every wellbore that would be contributed to the unit under this approach would receive \$100,000 of value and let me, I guess, cite an example would be the best way to explain it.

If you look at Article XI, which is the article dealing with the requirement for wellbores, there will be 344 wells required to be contributed to the unit.

Now let's just assume that only 300 wells are contributed to the unit. The inventory value for those 300 wells then would be 300 times \$100,000, or \$30,000,000.

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That would be the total inventory value of those wellbores.

Now, let's look at an actual example.

Let's take the case of Shell. They have 15 wellbores that they've produced from the unitized interval. If they were to contribute every one of those wells to the unit, they would receive a credit toward that inventory of 15 wells times \$100,000, or \$1,500,000.

Now under the inventory approach, even though Shell contributed all the wellbores that they possibly could and were required to, they would still have to pay an additional Half a Million Dollars to the inventory.

Q How come?

A Their participation, which is a little over 6 percent, I believe, times the total unit inventory comes out to be \$2,000,000, where they only receive credit for a Million and a Half Dollars.

Q All right.

A So there is an extra Half a Million Dollars that they would have to pay.

On top of that Shell would have to pay for the redrilling of 44 wells that were not contributed by other owners and that would amount to another Three-quarters of a Million Dollars.

We can look at a similar example on a smaller scale, a small working interest owner, to see what the impact might be.

Look at Tract 81. This is a one-well tract that's operated by Apollo.

Q Let me find Tract 81. That's the tract just to the north of Exxon's acreage in Section 10?

A It is a forty acre tract. I believe that's the correct position.

Q All right. Describe for us what happens if we use an inventory valuation for the wellbore as applies to someone like Apollo in Tract 81.

A Okay. We'll take the same example as before, using 300 wells contributed by the owners to the unit.

Under this situation, with Apollo's interest, the three working interest owners in that well would have to pay into the -- toward the inventory, \$30,000 even though they contribute that one and only well that they can possibly contribute on that tract.

In addition, as I cited with Shell, they will have to bear their proportionate cost of redrilling the 44 wells that were withheld by other operators.

The ownership did not feel that the inventory approach was equitable for those reasons.

Q When you talk about the ownership did not feel it was equitable, can you describe for us what percentage of the working interest owners did not feel that the inventory approach was an equitable way to treat the wellbore problem?

A I suppose the only thing I can cite is

1
2 the fact that 92 percent of the owners do favor the agree-
3 ments that incorporate. There was never a vote taken on in-
4 cluding the inventory as the method, but on the opposite
5 side of that, 92 percent of the owners favor another ap-
6 proach, so by -- you might surmise that they did not sup-
port the inventory approach.

7 Q All right, sir, the third approach is the
8 wellbore assessment approach?

9 A That's correct.

10 Q And that's the one that's included in the
11 agreement?

12 A Yes, as Article XI, that's right.

13 Q All right, sir, describe for us what that
14 approach is.

15 A This method, which we call the wellbore
16 assessment method, and which was approved by the majority
17 ownership, is simply to have the owner who fails to contri-
18 bute wells pay a greater portion of the replacement well
cost.

19 For example, if the cost of replacing a
20 non-contributed well is \$250,000, the owner that does not
21 contribute that well pays the first \$100,000 of value and
the unit owners pay the remaining \$150,000 cost.

22 Q So even under the agreed upon wellbore
23 assessment approach, the unit, working interest owners as a
24 unit, are going to pick up the other \$150,000 cost of the
25 well.

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2 A They will pay the greatest portion of the
3 replacement well cost, that is correct.

4 Q Does the operating agreement provide for
5 a situation where a working interest owner does not pay his
6 share of unit expenses?

7 A Yes, that's included as Article XII.IV
8 and it basically says that if an owner fails to pay is share
9 of the expenses, that the -- those expenses will be deducted
10 out of the sale of unitized substances accruing to that
owner with interest at the rate of prime plus two percent.

11 Q Mr. Berlin, in order to make a good faith
12 effort to secure voluntary agreement to the unit, has Gulf
13 as the proposed unit operator made various offers to the
14 working interest owners, including Exxon, to acquire or pur-
15 chase their interest in this unit if they did not want to
participate on a voluntary basis?

16 A Yes, we were in fact approached by some
17 of the smaller owners who did not feel basically that they
18 could live with the long negative cash flow period that's
19 about seven years. They asked us to in fact make them an
20 offer for their property, which we did, and we also felt
21 that if we're going to make some of the small owners an of-
22 fer, we should go ahead and extend the same offer to at
least all of the owners.

23 We in fact did that and as Mr. Vaden tes-
24 tified this morning, we have successfully, I think, con-
25 cluded the acquisition of approximately 14 owners who do not

1
2 wish to participate in the unit, including Texaco, one of
3 the major owners.

4 Exxon also asked us to make them an offer
5 for their properties. We offered Exxon, I believe the num-
6 ber was \$3.7-million for their properties in the unit. Ex-
7 xon did not accept that particular offer.

8 Q When we talk about equity, Mr. Berlin,
9 concerning Exxon's interest in the unit, is there any corre-
10 lation or justification to tie in the wellbore contribution
11 to Exxon's percentage participation in the unit?

12 A Is there any correlation that you can see
13 there?

14 I can't arrive at any correlation. The
15 participation that's determined for any individual owner is
16 based on parameters such as cumulative production, remaining
17 primary reserves, and current oil rates. None of these,
18 these are reservoir parameters that really don't relate to
19 wellbores. You need wellbores no matter what the quality of
20 those wellbores. Obviously some tracts are better than
21 other tracts and have receive the proper credit in the par-
22 ticipation formula for the quality of the tracts. The fact
23 that wellbores may be of different quality also does not re-
24 late to the participation in my mind.

25 We need to have a wellbore on every 40-
acre location regardless of the quality of that wellbore.

Q Let's talk about the mechanics of the
wellbore contribution as it applies to Gulf and then as it

1
2 applies to Exxon, Mr. Berlin.

3 When we look at Exxon, how many wells do
4 they have and what is the possibility of not being able to
5 contribute wellbores to the unit?

6 A Well, when we ran -- we tried to assess
7 all of the individual owners, the effect of this particular
8 provision on all the individual owners. We weren't able to
9 do that for the same reason that the Technical Committee was
10 not able to develop a usable wellbore parameter. We don't
11 know how many wells an individual operator is willing or
12 able to contribute to the unit.

13 In Exxon's case, for example, Exxon oper-
14 ates 29 wells. They have 13 wells temporarily abandoned, 5
15 wells plugged back to the Eumont Gas Zone, and 2 wells that
16 have been permanently plugged and abandoned.

17 We surmise from their correspondence that
18 they wish to withhold 7 wellbores from the unit, the 2 that
19 are plugged and abandoned and the 5 that are plugged back to
20 the Eumont Gas Zone. The 5 that are plugged back represents
21 17 percent of their total wells and the 2 that are plugged
22 and abandoned represents about 7 percent of their total
23 wellbores.

24 In Gulf's situation, we operate 102
25 wells. We have 13 wells plugged back to the Eumont gas; 4
wells temporarily abandoned; and 12 wells plugged and aban-
doned.

Our plugged and abandoned wells represent

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2 approximately 12 percent of our total wellbores, which is
3 about twice as many plugged wells as Exxon has.

4 Our wells plugged back to the Eumont gas
5 is approximately 12 percent of our total wellbore, which is
6 about twice as many plugged wells as Exxon has.

7 Our wells plugged back to the Eumont gas
8 is about 13 percent of our total, which is approximately the
9 same magnitude percentawise as Exxon has.

10 So we're, frankly, in a worse position
11 than probably any other owner as far as wellbores and being
12 able to contribute them to the unit.

13 Q With the inclusion of the wellbore as-
14 sessment as agreed to by the majority of the working inter-
15 est owners, and as you understand Exxon's position to be,
16 will Exxon's participation in the unit process still be pro-
17 fitable?

18 A In my opinion, very definitely. It will
19 be extremely profitable for Exxon as well as the other work-
20 ing interest owners.

21 Q Based upon your study and knowledge of
22 this particular situation, Mr. Berlin, do you think it's
23 reasonably possible to exclude Exxon and its acreage from
24 the unit?

25 A In my opinion it is not possible to ex-
clude Exxon and continue with the unitized operation. The
biggest problem that will arise is that we won't be able to
arrive at equity across the lease lines with our current

1
2 There would be a duplication of facilities that would be re-
3 quired and in order to arrive at equity you would have to do
4 one of -- well, in order to arrive at equity across the
5 lease line tracts between the rest of the unit and Exxon
6 tracts, you would have to drill additional injectionw wells
7 to protect those lease lines. That results, of course, in a
8 duplication and probably inefficiency since those wells
9 would not conform to the pattern that we've developed for
the rest of the unit.

10 Q Does the unit agreement and the operating
11 agreement, Mr. Berlin, provide for the designation and re-
12 moval of the unit operator?

13 A Yes, it does. Section 6 of the unit
14 agreement and Article VI of the unit operating agreement de-
15 signate Gulf as the unit operator.

16 Article VI and Sections 7 and 8 of the
17 unit agreement provide a procedure for the removal of the
unit operator and the selection of a successor operator.

18 Q And does the unit operating agreement
19 provide for a method for voting on unit matters?

20 A Yes, it does. Article IV of the unit
21 operating agreement sets forth voting procedures for voting
22 on matters to be decided by the working interest owners.

23 Q I asked Mr. Vaden this morning about the
24 effective date for the unit. I will also ask you the same
question, Mr. Berlin.

25 What does the unit operating agreement

1
2 provide for putting the unit into effect and terminating it?

3 A Yes. Section 24 of the unit agreement
4 provides for putting the unit into effect.

5 Q All right, and what is the effective date
6 that you're attempting to use for the unit?

7 A December the 1st of 1984 is the effective
8 date that we have asked for.

9 Q In your opinion, Mr. Berlin, is the
10 granting of this application or these applications by Gulf
11 in the best interest of conservation, the prevention of
12 waste, and the protection of correlative rights?

13 A Absolutely.

14 Q In the event the statutory unitization is
15 not approved, can you forecast for us what the likelihood is
16 of having a unit operation for this interval in this area?

17 A Well, we hope, of course, that we're not
18 going to be faced with that situation. We've devoted five
19 and a half years of effort toward the formation of this unit
20 and very frankly, it's becoming difficult to justify the
21 amount of man-hours that we as unit expeditor have devoted
22 to the effort, which we don't feel like we're adequately
23 compensated for, not even considering all of the manpower
24 hours that have been devoted by the ownership of the total.

25 Another important factor to consider is
the ages of these wellbores. The age and condition of these
wellbores can only get worse as time goes on and we're
going, if the applications are not approved as submitted,

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2 we're going to be faced with a considerably longer period to
3 get to this point again.

4 I've been involved in the negotiations
5 from the very beginning and I've seen the give and take.
6 I've heard the pros and cons, the opposing points of view,
7 and I don't believe we can ever get to this point again with
8 the consensus of opinion supporting our effort that we now
9 have.

10 MR. KELLAHIN: At this time,
11 Mr. Chairman, we'd move the introduction of Gulf Exhibit
12 Number Twenty-one A.

13 MR. STAMETS: Exhibit Twenty-
14 one A will be admitted.

15 MR. KELLAHIN: That concludes
16 our examination of this witness.

17 MR. STAMETS: Are there ques-
18 tions of this witness? Mr. Padilla.

19 CROSS EXAMINATION

20 BY MR. PADILLA:

21 Q Mr. Berlin, in answer to a question that
22 Mr. Kellahin asked you, I believe the question was whether
23 or not any of the working interest owners had asked to be
24 eliminated from the proposed unit area, and I believe your
25 answer was no.

A That is not correct. We had two owners
that asked to be deleted. That was Mr. Hartman and Mr. Ras-

1
2 mussen. We did not agree with their request but have subse-
3 quently in fact resolved that situation through an acquisi-
4 tion as we described.

5 Q It's sort of elementary at this point to
6 ask to be eliminated from the unit area.

7 A We would certainly prefer to have all the
8 parties participate in the unit with us, yes.

9 Q You wouldn't let any one of the units, or
10 any one of the tracts out at this point, though?

11 A We see no reason to do that, no.

12 Q Let me direct your attention to page 41
13 and the page of -- and the parameter table that Mr.
14 Kellahin's been asking questions about.

15 A All right.

16 Q And at the same time I would direct your
17 attention to the participation formula and ask you with re-
18 gards to the Wilbanks tract, which is the second from the
19 bottom of the page, the last two columns on that parameter
20 table show zero for that interest.

21 A That's correct.

22 Q How did -- can you tell me how you ar-
23 rived at zero for that particular tract for both those para-
24 meters?

25 A There is no current production from the
26 Wilbanks tract and so therefore, no remaining primary re-
27 serves.

28 Q And that's the basis for determining

1
2 whether there are any remaining primary reserves, current
3 production?

4 A There was no production. I don't know
5 when the production from that tract ceased right offhand,
6 but it ceased prior to the time that we were extrapolating
7 the decline curves, and if there is no production, you can-
8 not extrapolate a decline curve.

9 Q Conceptually the participation that Wil-
10 banks would have under Tract S5 would be 50 percent of A
11 over B, is that correct?

12 A That would be the cumulative production
13 over total unit cumulative production, that is correct.

14 Q So the 40 percent of C over D plus 10
15 percent of E over F would not be applicable in that tract.

16 A The multiplication is zero, yes.

17 Q Now if we look at the Apollo tract which
18 is 40 acres and that's the third from the bottom, they do
19 have apparently current production, and that would entitle
20 that particular tract to greater participation than the Wil-
21 banks tract.

22 A They have remaining primary reserves and
23 current production, that is correct. Not necessarily, it
24 again depends on the weighting.

25 Q I understand.

A They would get credit for those two fac-
tors because they do have remaining reserves and they do
have current production, that is correct.

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2 Q That does not take into consideration
3 that there may be a wellbore problem or whether a well can
4 be recompleted to obtain current production.

5 A I would assume that their reserves could
6 be recovered. An operator would do that. That can be my
7 only assumption, yes.

8 Q Yet under the Wilbanks tract those
9 working interest owners would be contributing two wellbores.

10 A That's correct.

11 Q In addition they would be assessed their
12 proportionate share of the costs of the project.

13 A They would be assessed their
14 proportionate share of the cost of the project as determined
15 by their participation, yes.

16 MR. PADILLA: I believe that's
17 all I have, Mr. Chairman.

18 MR. STAMETS: Mr. Sperling.

19 MR. SPERLING: Yes, sir.

20 CROSS EXAMINATION

21 BY MR. SPERLING:

22 Q Mr. Berlin, would you agree with me that
23 there could be two types of incentive, one being the carrot
24 approach, which is the reward approach; the other being the
25 stick approach, which is the punishment approach?

A I agree there can be more than one type
of incentive, yes.

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2 Q I think you mentioned there were two
3 reasons why -- I think you mentioned that there might be two
4 possibilities why wellbores would not be contributed under
5 the arrangement suggested by the unit operating agreement.

6 One of those was, as I recall, some of
7 these wells may be plugged back to the Eumont Gas section
8 and therefore the wellbores are in use to produce gas re-
serves.

9 A That's correct.

10 Q Would you quarrel with that decision by
11 an operator?

12 A No, I don't quarrel with that decision.
13 As a matter of fact, we've plugged back several of them our-
14 selves.

15 Q So that sort of eliminates the option of
16 contributing that wellbore, doesn't it?

17 A No, sir, it does not. In fact, in Gulf's
18 case we plan to contribute every one of our gas wells to the
unit.

19 Q And how much is the conversion going to
20 cost per well?

21 A I don't follow your question, conversion?

22 Q Well, what are you going to do with the
23 remaining gas reserves?

24 A We're going to -- we're going to squeeze
25 the Queen interval in that particular wellbore and contri-
bute it to the unit.

Our plans are to redrill our Queen wells in order to actually improve the drainage of the Queen gas zone by locating wells away from the original completions. So that is the approach that we're talking with our wellbores.

Q And you have determined that that is economic considering the Eumont gas reserves in the area?

A Yes, sir, we have. It is our intention.

Q Another reason suggested by you as a possible reason for withholding contribution of a wellbore was that it had previously been plugged and abandoned.

Now that may or may not have been as a result of some regulatory action or management decision, is that correct?

A I have no knowledge of the reason for plugging or abandoning the wells, yes.

Q Could be one or the other?

A Yes.

Q So at this point in time if either of those conditions exist, with the exception that you mentioned about redrilling the gas wells, the owner of such wells at this point in time really has no option, does he, by way of contribution?

A Yes, certainly they have options. They can contribute the wells and redrill them, as we plan to do.

We also --

Q I said with the exception of that.

1
2 A We have options with regard to plugged
3 and abandoned wells also.

4 We plan to re-enter our plugged and aban-
5 doned wells and make them usable for the unit.

6 Q I see, and have you a cost estimate on
7 that?

8 A We have made cost estimates, yes.

9 Q Could you give me an approximate figure?

10 A That was done by our Area Office in Hobbs
and I do not have those numbers.

11 Q I believe you pointed out that the for-
12 mula participation under the Two-A parameter or the adoption
13 of the Formula 3 percentage with the inappropriate weighting
14 as indicated on the exhibit that you produced, would make
15 very little difference insofar as Gulf is concerned.

16 A That's correct.

17 Q Either of those formulas.

18 A That's correct.

19 Q Yet you say that Gulf would not now sup-
20 port the parameter suggested by Number 3 as opposed to Num-
ber 2. Why?

21 A The reason we wouldn't support it is be-
22 cause of the effect it would have on our current status of
23 unitization. We don't want to have to go back and spend two
24 years to get to this same point again and come to hearing
25 with a lesser percentage than we would have under the cur-
rent formula.

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2 It's not that it affects our participa-
3 tion that greatly.

4 Q You stated that the inventory credit ap-
5 proach was considered and rejected.

6 Would you review for me again why that
7 was?

8 A Yes, sir.

9 Q Why it was treated any differently than
10 the other approaches?

11 A I would have to go through the examples
12 that I cited. Those were the kinds of things that were dis-
13 cussed among the working interest owners, the fact that some
14 owners might contribute every one of the wellbores which
15 they could possibly contribute and still suffer a payment in
16 the inventory. That was the basic reason for rejection of
17 that approach by the majority of the owners.

18 Q Well, didn't Texaco point out to you or
19 your company a letter objecting to the use of that approach,
20 illustrating how they would be hurt drastically by the ap-
21 plication of what you had suggested?

22 A I do recall the letter by Texaco in which
23 they objected to this approach. I don't right offhand re-
24 call the specifics of that letter.

25 Q Would you quarrel with the figures which
suggest that Texaco would be paying \$581,324 as an invest-
ment in the unit or 52 percent more investment than the unit
participation would justify?

1
2 A I'd have to know the basis for those num-
3 bers, whether I could accept them.

4 Q Well, let me show you the letter and see
5 if that refreshes your memory.

6 A Well, I'd like to read one statement out
7 of this letter, if I might.

8 MR. KELLAMIN: Mr. Chairman,
9 I'm going to object to this line of questioning. The Texaco
10 letter is hearsay. I think it's been testified earlier by
11 Mr. Vaden that Texaco's interest has now been acquired by
12 Gulf.

13 Texaco's relationship to this unit no
14 longer is relevant and material to this discussion and Mr.
15 Sperling's attempt to get in some argument that Texaco may
16 have written in correspondence to Gulf over some issue is no
17 way relevant to this case today.

18 So it's hearsay. If Texaco is inter-
19 ested, they may come and testify. If Mr. Sperling is inter-
20 ested in this kind of testimony from Texaco, he could have
21 subpoenaed them and had they come.

22 But we believe this approach is improper.

23 MR. SPERLING: This is a com-
24 munication acknowledged to have been received by Gulf. It
25 provides a fair inference as to what incentive Texaco might
have had for disposing of its interest and certainly bears
upon the fair and equitable consideration which is before
the Commission.

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2 MR. STAMETS: Mr. Kellahin,
3 we're going to overrule your objection and allow the witness
4 to answer the question and the Commission will give it the
5 weight which it is worth.

6 A I'd like to make one point from this let-
7 ter that I see. It says, "Texaco" -- Texaco is referring to
8 two plugged and abandoned wells that they plugged -- Texaco
9 had these wells, and I quote, for possible secondary
10 recovery until 1977 at which time they were P&A'd.

11 Texaco recognized that there was going to
12 be at some point in time secondary recovery operations and
13 they could have with that knowledge have plugged these wells
14 in such a way that they could re-enter.

15 Texaco had some discretion in this mat-
16 ter and they did not exercise it.

17 Q Doesn't Texaco point out in the fore part
18 of the letter that this particular area had been ripe for
19 secondary recovery for ten to fifteen years?

20 A They certainly do. They should have re-
21 cognized that as should any other owner who plugged and
22 abandoned wells in the unit area.

23 Q Well then why didn't the unit effort move
24 forward sooner?

25 A I have no knowledge of that.

Q Do you have an estimate as to the period
of time in the future it would take to recover the remaining
primary?

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2 A Yes, I'd refer you to the Technical Com-
3 mittee report in which they show a projection of that con-
4 tinued production and I --

5 Q Give us your best recollection of what
6 that would be.

7 A Fifteen years. Fifteen years remaining
8 primary. The projection that it goes on for another fifteen
9 years.

10 We simply have to look in the Technical
11 Committee report to see when that comes to an end.

12 Q I'll hand you what's been identified as
13 Exhibit Twenty-two, the Technical Committee Report. I think
14 you're much ore familiar with that than I am.

15 A Yes, sir. On page 96 of that report is
16 the projection of primary production and it goes on until
17 the year 2014, according to this projection.

18 Q 2014.

19 A That's correct.

20 Q Okay, and what about the recovery period
21 for projected secondary recovery, secondary reserves?

22 A It goes beyond that date.

23 Q So they will co-exist for some period of
24 time?

25 A Yes, sir. They will co-exist except in
the first -- according to the projections there will be no
secondary reserves produced for the first four or five years
of unit operations.

1
2 So they don't co-exist completely over
3 the same time period, but there is a period that they do co-
4 exist.

5 Q Do you recall a specific recommendation
6 by Gulf at one point in time to the effect that owners
7 should receive a credit in inventory for operational well-
bores?

8 A Yes, sir, we put that forth for consider-
9 ation by the unit owners, I believe at -- I believe it was
10 June 1st, 1983 working interest owners meeting. We did put
11 that proposal for consideration to the owners, yes, sir.

12 Q But you subsequently changed your mind as
13 to --

14 A As a result --

15 Q -- to that.

16 A As a result of the discussions which took
place, we in fact did change our mind, yes, sir.

17 MR. SPERLING: That's all.

18
19 CROSS EXAMINATION

20 BY MR. STAMETS:

21 Q Mr. Berlin, did you indicate that your
22 recompletion into the Queen formation, the drilling of new
23 wellbores, might enhance your reserves out of the gas reser-
voir?

24 A That's correct.

25 Q On what basis would that be?

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2 A Well, again, I didn't make this assess-
3 ment in particular. This was an assessment made by our
4 operating staff in Hobbs, but I believe the basis for that
5 assessment is the fact that the Queen is a lenticular type
6 reservoir and that the current spacing is not necessarily
7 draining the full acreage.

8 MR. STAMETS: Any other ques-
9 tions of the witness? Mr. Kellahin.

10 REDIRECT EXAMINATION

11 BY MR. KELLAHIN:

12 Q Mr. Berlin, I have a follow-up question
13 to Mr. Sperling's last question to you, Mr. Berlin.

14 You referred to a June 10th, 1983 working
15 interest owners meeting minutes. The question was did not
16 Gulf submit for consideration by the working interest owners
17 the inventory approach to the wellbore situation, and your
18 answer was yes, that Gulf later changed its mind. Yes, you
19 changed your mind.

20 My question is upon what reasons and
21 basis did you change your mind on the inventory approach to
22 the wellbore assessment?

23 A Well, it's for the reasons that I cited
24 before. The other owners pointed out that in fact an opera-
25 tor could contribute all of their wells and still suffer a
payment to the inventory under this approach, and we didn't
recognize that at the time and as that was pointed out, we

1
2 recognized that that was indeed a problem and we would need
3 to consider some other alternative, which we did and came
4 back at the next meeting and proposed the wellbore assess-
ment approach.

5
6 Q Do you have an opinion as to whether or
7 not using the inventory approach and submitting that to vote
8 would have resulted in the necessary minimum 75 percent
working owners participation in this unit?

9 A I'm sorry, would you restate that,
10 please?

11 Q Yes, sir.

12 A The inventory approach?

13 Q Using the inventory approach do you be-
14 lieve that you could have obtained the necessary percentage
15 of the working interest owners participation in the unit,
using that approach?

16 A As a result of the discussions that took
17 place at that meeting, my answer would be definitely not.

18 Q And the wellbore assessment approach is
19 the one that some 93 percent then agreed to.

20 A Yes, sir.

21 MR. STAMETS: Are there any
22 other questions of this witness? He may be excused.

23 Mr. Kellahin, how long do you
24 think your next witness will take?

25 MR. KELLAHIN: Mr. Chairman, we
do anticipate that Mr. Bohling's testimony on the C-108 re

1
2 quirements for the waterflood, hopefully, are not controver-
3 sial. They are well organized and I would expect that he
4 and I could make that presentation probably within thirty
5 minutes.

6 MR. STAMETS: How long do you
7 anticipate your direct testimony to take, Mr. Sperling?

8 MR. SPERLING: I would expect
9 at least one and a half to two hours.

10 MR. STAMETS: We will recess
11 the hearing this afternoon and will reconvene the hearing at
12 8:30 tomorrow morning at this same location.

13 (Thereupon the evening recess was taken.)
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REPORTER'S CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY this is a true, full and correct record of the hearing reported by me on the 7th day of November, 1984; that the hearing is scheduled to continue at 9:30 a. m. on the morning of the 8th day of November, 1984.

Sally W. Boyd

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO

8 November 1984

COMMISSION HEARING

VOLUME II OF II VOLUMES

IN THE MATTER OF:

Application of Gulf Oil Corporation CASE
for statutory unitization, Lea 8397
County, New Mexico.

Application of Gulf Oil Corporation CASE
for a waterflood project, Lea 8398
County, New Mexico.

Application of Gulf Oil Corporation CASE
for pool extension and contraction, 8399
Lea County, New Mexico.

BEFORE: Richard L. Stamets, Chairman
Commissioner Ed Kelley

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation	Jeff Taylor
Commission:	Attorney at Law
	Legal Counsel to the Division
	State Land Office Bldg.
	Santa Fe, New Mexico 87501

(Thereupon, at the hour of 8:30 a. m. on the 8th day of November, 1984, the hearing was reconvened in Morgan Hall, State Land Office Bldg., Santa Fe, New Mexico, with Mr. Richard L. Stamets, Chairman, presiding, and Commissioner Ed Kelley also in attendance, at which time the following proceedings were had, to-wit:)

MR. STAMETS: The hearing will please come to order.

Mr. Kellahin, you may proceed with your next witness.

ALAN BOHLING,
being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Bohling, would you please state your name and where you reside?

A My name is Alan Bohling and I reside in Odessa, Texas.

Q Mr. Bohling, would you describe for the Commission what your educational background has been?

A I graduated in 1974 from Michigan Technological University with a geological engineering degree.

1
2 After that I was commissioned in the
3 United State Army Corps of Engineers where I spent four and
4 a half years.

5 In 1979 I signed on with Gulf Oil Corpor-
6 ation in their Goldsmith Area Office. I worked as an engi-
7 neer there for two and a half years and I was assigned to
8 the Division Proration Section.

9 And then in February of 19 -- of this
10 year I was assigned to the Division Secondary Recovery Sec-
11 tion.

12 Q With regards to Commission Case 8398,
13 which is Gulf's application for a waterflood project, would
14 you describe for the Commission what has been your responsi-
15 bilities on behalf of Gulf?

16 A My responsibilities have been pretty well
17 to take over where Tom Wheeler left off on the Eunice Monu-
18 ment South Unit project, primarily responsible for coordi-
19 nating and consolidating efforts towards bringing the Eunice
20 Monument South Unit Statutory Unit for the statutory uniti-
21 zation hearing, waterflood hearing, and verticle limits
22 hearing.

23 Q Mr. Bohling, are you familiar with the
24 Commission requirements as outlined in Commission Form C-108
25 for approval of a waterflood project?

A Yes, sir, I am.

MR. KELLANIN: Mr. Chairman, we
tender Mr. Bohling as an expert petroleum engineer.

1
2 MR. STAMETS: The witness is
3 considered qualified.

4 Q Mr. Bohling, would you identify for us
5 what has been marked as Gulf Exhibit Number Twenty-seven?

6 A Our Exhibit Twenty-seven is the OCD Form
7 C-108, which is the application for the waterflood project
8 in Eunice Monument South Unit.

9 Q Was this form executed by you and
10 submitted with the application in this case when it was
11 filed with the Commission?

12 A Yes, sir, it was.

13 Q All right, sir, let's turn to Exhibit
14 Twenty-eight.

15 Would you identify and describe Exhibit
16 Twenty-eight for us, Mr. Bohling?

17 A Exhibit Number Twenty-eight is a plat of
18 the Eunice Monument South Unit Area. The unit is outlined
19 the hachured marks. It covers approximately 14,190 acres
20 and encompasses 357 40-acre proration units, which are
21 further subdivided into approximately 101 tracts for
22 statutory unitization purposes and these tracts represent 42
23 working interest owners.

24 The current status of all wells within
25 the unit area, as well as within the two mile distance of
the unit area, is indicated on this plat.

The proposed new well numbering system for
the unit area is also indicated on the plat.

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Q Do you have a plat, Mr. Bohling, that shows the proposed plan of operation, showing the injection wells?

A Yes, sir. Our Exhibit Number Twenty-nine is such a plat. It is of the Eunice Monument South Unit only. It also depicts the current status of all the unit, proposed unit wells within the unit area.

It indicates the proposed numbering system for those unit wells.

The solid triangles on this map indicate the proposed injection wells which are planned -- or wells which are planned to be initially converted to injection wells. There is 133 of these.

The remaining 46 dashed triangles represent those wells which are proposed for water injection conversions but are contingent upon lease line agreements and these dashed triangles also represent new drill injection well locations.

The unit area when fully developed will have a total of 179 injection wells and 178 producers and will be on an 80-acre 5-spot pattern.

I might add that to avoid confusion on these two plats, rather than drawing a one-half mile radius of review circle around each injection well, the area of review will include the entire unit area, as well as a one-half mile wide strip outside and encompassing the unit area for the purpose of this application.

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2 Q For purposes of describing an area of re-
3 view, then, you have used an area of review larger than re-
4 quired by the Commission.

5 A We should fulfill the Commission's re-
6 quirements for the area of review, yes.

7 Q All right. We spent a great deal yester-
8 day talking about the interval that is going to be subject
9 to the waterflood project. Would you go ahead and again de-
10 scribe for us how that unitized interval is going to be
11 flooded in the project?

12 A Okay. We plan on injecting water through
13 selectively perforated intervals within and covering the
14 unitized interval, as defined by the unit agreement for the
15 Eunice Monument South Unit.

16 The unitized interval shall include the
17 formations from a lower limit defined by the base of the San
18 Andres formation to an upper limit defined by the top of the
19 Grayburg formation or -100 foot subsea datum, whichever is
20 higher.

21 Q Mr. Bohling, will you refer to what we've
22 marked as Exhibit Number Thirty and identify that for us?

23 A Exhibit Number Thirty is a computer
24 printout which lists all of the unit, all of the wells with-
25 in the area of review which are inside the unit area and
those within the half mile strip outside the unit area.

I've attempted to show by this computer
printout, which is in the proposed new well numbering system

1
2 order, the current New Mexico Oil Conservation Division
3 classification and status of the wells within the area of
4 review.

5 Also indicated in this computer printout
6 are those wells which we plan on having as water injection
7 conversions and they're indicated by an asterisk next to the
8 new well number in Column 2.

9 Q This tabulation of wellbore information
10 in Exhibit Thirty is in compliance with the Commission rule
11 with regards to the submission of a tabulation for data on
12 wells within the area of review.

13 A Yes, sir, it is.

14 Q To supplement the information in the com-
15 puter printout, Mr. Bohling, do you have an exhibit that
16 shows the specific wellbore information about all the wells?

17 A Yes, sir, our Exhibit Number Thirty-one
18 is a notebook of the individual well data sheets and well-
19 bore diagrams on all wells of public record within the area
20 of review.

21 Each data sheet in this wellbore diagram
22 book lists the detailed location, the operator, lease names,
23 casing sizes, casing seats, cementing volumes and tops, past
24 and present completions, dates and details as applicable.

25 The information in this Exhibit Number
Thirty-one should be used in conjunction with Exhibit Number
Thirty, the computer printout.

The information in Exhibit Number Thirty-

one reflects what was found on individual well files at the Hobbs District OCD Office.

The book is arranged in tabs so that it's in township and range order and then within each tabbed section it goes by section number and then the unit that well is located in within the section.

Q All right, sir, your book is divided by wells described as inside the unit area and after that tab, then, by township, range, and section. Someone using the index can locate specific wellbore information on each of the wells within the unit.

A Yes, sir.

Q And then if we go later in the book there is a separate tabulation of wellbore information for wells outside the unit area within this half mile area of review.

A Yes, sir.

Q All right. Again then within the area outside the unit the wells are identified by township, range and section, and then after that information is the last tab that shows plugged and abandoned wells?

A Yes, sir. I made a little bit of a mistake in putting the book together. In the P&Ad section the wellbore diagrams under that section represent only the P&Ad wells within the unit area.

There are fourteen P&Ad wells outside the unit area, which are included in the outside unit area well section.

1
2 Q All right, so behind the tabulation --
3 tab that shows P&A wells, those are P&A wells within the
4 unit.

5 A Yes, sir.

6 Q If the Commission is concerned about P&A
7 wells outside the unit, then they go to that information be-
8 hind the outside unit area tab.

9 A Yes, sir. Also, the P&A section --

10 MR. STAMETS: Would you run
11 through once more?

12 Q When we look at the wellbore information
13 after the tab in the end of the book that's P&A wells --

14 MR. STAMETS: Okay.

15 Q -- those are P&A wells within the unit.

16 A Yes, sir.

17 Q Where do I go in the book to find P&A
18 wells that are within a half mile of the outer boundary of
19 the unit?

20 A They will be found in their respective
21 order in the outside unit area section of the book.

22 I can give you specific page numbers that
23 those wells, P&A wells are found on, if you like.

24 Q You do not have a separate section that
25 shows the P&A wells outside the unit area within the area of
review.

A No, sir, I don't. I meant to include
those in this P&A section, but I did not do that.

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Q Thank you. We can find those wells, can we, by going to the computer printout on Exhibit Thirty or is Exhibit Thirty only the well count within the unit?

A Only the -- well, you can find them off of that, yes.

Q Was this packet of information, the computer printout and the wellbore information, data, submitted with the application for the approval of the waterflood project when that application was filed with the Commission?

A Yes, sir, it was.

Q Have you subsequently, Mr. Bohling, met with the Commission staff in the District Office and reviewed the wellbore information along with representatives of the Commission staff in Santa Fe, to determine possible, what I'll call problem wells?

A Yes, sir, we have.

Q Can you summarize for us, Mr. Bohling, what has been the results of your meetings with the Commission staff concerning the status of existing wells, both plugged and abandoned and producing wells, in terms of their compliance with requirements of C-108?

A For the purposes of the C-108 the OCD Office in Hobbs personnel and in our conversations with them have indicated that they see no real problem with any of the wells meeting the C-108 requirements.

Q Let me ask you some questions with regards to the information tabulated in the book for the plug-

ged and abandoned wells. Have you showed the locations as best you can determine of the cement plugs in those plugged and abandoned wells?

A Yes, sir, as they are recorded off individual well files at the OCD District Office in Hobbs.

Q And with regards to the producing wells, have you made a diagrammatic sketch of the wellbore information for producing wells so that the Commission staff can review that information and determine whether or not there's adequate cementing across the casing strings in the proposed injection intervals?

A Yes, sir. we have.

Q Are you aware of any, what we will characterize, as problem wells which you believe will require remedial action on behalf of Gulf as the operator of the unit?

A We've pointed out basically five such wells to the OCD District in Hobbs.

Do you want me to run through each individual case?

Q Only insofar as to describe to me what the remedial action the operator proposes to take with regards to those five problem wells.

A Two of the wells are located within the unit area. One is just going to be a -- it just has a cast iron bridge plug, and we're going to monitor that situation to make sure that it might not provide a leak up the well-

bore to the surface.

Mr. Sexton said that he assumed that when they installed the cast iron bridge plug that they adequately pressured up on that bridge plug to insure that it would adequately seal off the lower part of that well.

We have another well where a cement plug was not placed in the top of the Eunice Monument and we have plans to go in and drill out and recement so it properly meets the plugged and abandoned requirements on that well.

There were three Blinbry wells who did not have adequate cement circulated up over the interval and of all known -- known producing intervals up the wellbore, and Mr. Sexton indicated that he would take care of those for us, insuring that they will meet compliance with the OCD.

Q You're talking about three producing wells outside the producing area?

A Yes, sir, I am.

Q And he's made no requirement upon Gulf as operator to take remedial action on those offsets --

A No, sir, he has not.

Q -- off unit wells?

A No, sir.

Q Describe for us what the plan of operation will be with regards to injection wells, Mr. Bohling,

1
2 in terms of satisfying the Commission that those wellbores
3 are suitable for injection purposes.

4 A Okay. Our Exhibit Number Thirty-two is a
5 series of injection well data sheets.

6 All right, sir, I've passed out Exhibit
7 Number Thirty-two, Mr. Bohling. Would you describe for us
8 what's contained in that exhibit?

9 A This exhibit contains a series of injection
10 well data sheets, showing the downhole particulars typical
11 of the majority of the proposed injection wells for the
12 Eunice Monument South Unit Area.

13 Each diagram represents proposed conditions
14 for injection of fluids after approval to inject has
15 been granted.

16 Approximately ninety percent of the proposed
17 Eunice Monument South Unit injection conversions fall
18 under the category of being a 3-string open hole well.
19 On all of our injection wells we plan to -- prior to converting
20 them to water injection wells, running casing bond
21 logs, cement bond logs, to determine where the actual cement
22 tops are in these wells and correlating these to the calculated
23 cement tops on the producing wells to insure that adequate
24 casing protection is provided in all cases, both injection
25 wells and producing wells in the unit area.

We then plan to run cement liners where
applicable, cement them in, perforate them in selected intervals
in the unitized formation for injection.

1
2 Q We spent some time yesterday, Mr. Boh-
3 ling, talking about the procedures the unit has recommended
4 for an incentive for unit working interest owners to contri-
5 bute wellbores that be converted for injection and for pro-
6 duction.

7 Do you have any estimate of a likely num-
8 ber of wellbores to be contributed to the unit?

9 A No, sir. That's really going to be
10 dependent on what each individual operator chooses to con-
11 tribute to the unit.

12 Q Once a wellbore is contributed, then,
13 Gulf as the unit operator will make a determination of how
14 best to complete that wellbore for purposes in the unit
15 waterflood project?

16 A Yes, sir, they will.

17 Q And the schematics of the injection wells
18 are a typical example of proposed methods for conversion to
19 injection?

20 A Yes, sir, they are.

21 Q Are these wellbore schematics that you
22 have reviewed with Mr. Sexton in Hobbs and with other mem-
23 bers of the Commission staff?

24 A Yes, sir, we've reviewed these with them.

25 Q All right. To the best of your know-
ledge, information and belief, Mr. Bohling, are these pro-
posed schematics in compliance with Commission orders?

A Yes, sir, they are.

1
2 Q In addition to distributing in this pack-
3 age of exhibits Exhibit Thirty-two, I've also distributed
4 the next exhibit, which is 33-A.

5 A Yes, sir.

6 Q All right, would you identify that for
7 us?

8 A It lists data on the proposed operation
9 of the injection system for the waterflood project in the
Eunice Monument South Unit.

10 Q All right, sir, would you describe for us
11 what the proposed method of operation is for the unit?

12 A Okay. As shown on Exhibit Number Thirty-
13 three-A, our average daily rates and maximum daily rates are
14 400 and 500 barrels of water per day, respectively. The
15 system is going to be a closed system. The proposed average
16 and maximum injection pressures will be 350 psi and 740 psi,
respectively.

17 This will be until we can determine a
18 fracture gradient and obtain proper approval from the OCD
19 Director for possibly injecting at higher injection pres-
20 sures.

21 To monitor and control the rates and
22 pressures at the wellhead, our plans are to install pressure
23 rate controllers on each injection well.

24 There are currently plans to drill approx-
25 imately nine water supply wells to provide make-up water
from the San Andres formation. This make-up water will be

1
2 used initially as the primary source of injection water and
3 once we have the unit fully developed, we will be switching
4 over to using produced water as our primary source of injection
5 water.

6 Q Do you have any estimates now of the per-
7 centages between make-up water and produced water that will
8 be used by the project?

9 A Not at this time. Our present plans are
10 that initially we'll be using approximately 60,000 barrels
11 of water per day for 133 injection wells.

12 Q And what is the source of produced water
13 in the unit?

14 A It will be from the unitized intervals,
15 the Grayburg formation, principally.

16 Q Do you anticipate that the maximum injection
17 pressure at any individual injection well will be based
18 upon the .2 psi per foot of depth gradient established as
19 matter of practice by the Commission until you have other
20 data available to justify a higher rate?

21 A Yes, sir, that's our plan.

22 Q All right, sir, it you'll turn to Exhibit
23 Number Thirty-three-B, I believe, is the next one, and de-
24 scribe that one for us.

25 A Thirty-three-B is a water compatibility
analysis performed on the make-up water and the produced
water and it illustrates that there is no incompatibility
evident by the mixing of these two waters.

1
2 Q All right, sir, and if you'll turn to
3 Thirty-three-C, would you describe for us the proposed stim-
4 ulation program?

5 A Thirty-three-C illustrates what a typical
6 completion and stimulation program might be for the -- for
7 an injection well.

8 Perforation intervals and volumes and
9 types of stimulation fluids used will determine -- will be
10 determined and may vary on a well-by-well basis as part of
11 an on-going study of reservoir rock and fluid properties is
performed.

12 Q All right, sir, if you'll turn to Exhibit
13 Thirty-four-A and identify that for us.

14 A Exhibit Thirty-four-A lists each of the
15 formations, injection zones. It gives their geological
16 names with their approximate depths and their approximate
gross thicknesses.

17 It also lists lithological detail on each
18 one of the injection zones.

19 Q Based upon the study by you and other
20 Gulf representatives of this project, do you find any indi-
21 cations of faulting or other hydrologic connections between
22 the proposed injection intervals and any fresh water
23 sources?

24 A No, sir, we do not find such hydrological
connections.

25 Q In your opinion is the proposed method

1
2 for the injection of water for secondary recovery in this
3 interval one that will protect fresh water sources in the
4 area?

5 A Yes, sir, it is.

6 Q Let's turn, Mr. Bohling, to Exhibit Num-
7 ber Thirty-five and have you identify that for us.

8 A Our Exhibit Number Thirty-five is a list
9 of proposed injection wells which do not have well logs
10 available. There are 86 of these wells out of 179 and the
11 remaining wells do have well log data on file with the OCD.

12 Q All right, sir, let's turn to Exhibit
13 Number Thirty-six, then, and have you describe that for us.

14 A Exhibit Number Thirty-six is a geological
15 detail and data on the fresh water aquifers which overlies
16 and/or underlie the proposed injection interval in the area
17 of the Eunice Monument South Unit.

18 Q Generally what is the deepest source of
19 fresh water in the area?

20 A The deepest source are the Triassic Chinle
21 and the Santa Rosa aquifers and on the north end of the
22 unit the Chinle is at a depth of approximately 50 feet and
23 the Santa Rosa is at a depth of approximately 675 feet, and
24 at the southern end of the unit the Chinle is at an approxi-
25 mate depth of 200 feet and the Santa Rosa is at an approxi-
mate depth of 1000 feet.

Q Have you reviewed with the Commission
staff and Mr. Sexton in Hobbs the method by which wells will

1
2 be drilled through the fresh water aquifers to satisfy the
3 Commission that the fresh water sources will be protected?

4 A Yes, sir, we have.

5 Q And have they agreed with you that the
6 method contemplated by Gulf as the unit operator is one that
7 ought to insure the successful protection of fresh water
8 sources?

8 A Yes, sir.

9 Q Would you go to Exhibit Thirty-seven for
10 us and identify that one?

11 A Exhibit Number Thirty-seven is a compilation
12 of chemical water analysis done on several fresh water
13 wells located within one mile of the proposed unit area.

14 Q Attached to Exhibit Number Thirty-seven
15 are what, sir?

16 A They are the chemical analyses of the
17 fresh water results for four fresh water locations within
18 the unit area?

19 Q Was a search made of the records of the
20 State Engineer's Office to determine the location and depth
21 of fresh water wells in the area?

22 A Yes, sir, there was. Our Exhibit Number
23 Twenty-eight shows the fresh water supply well locations as
24 best as we can determine through the review of the State Engineer's records and they are indicated by a small square.

25 There are several down in Sections 19 and
20, Township 21 South, Range 36 East, and there are also

several located down in Section 23, Township 21 South, Range 36 East.

Q Apart from the search of the State Engineer's records, have you also made a search of other available information to determine the location and information on other fresh water sources?

A Yes, sir. We have taken two samples of fresh water locations that are apparently not on file with the State Engineer's Office.

Q All right, sir, and if you'll turn to Exhibit Thirty-eight and describe that for us.

A Exhibit Thirty-Eight is our affirmative statement, which states that all available geological and engineering data has been examined and find -- Gulf finds no evidence of any hydrological connection between the injection zone and any underground fresh water source is present.

Q The Commission required in their regulations that the applicant furnish copies of your waterflood project application to the surface owners at each proposed injection well location, plus the operators within a half mile area of any of the well locations.

Have you caused that to happen, Mr. Bohling?

A Yes, sir, we have. Our Exhibit Number Thirty-nine is a copy of the letter dated September 24th, 1984.

Q Hang on, I've got to find it.

1
2 A Okay. I believe they have them already,
3 Tom, as part of the package.

4 MR. KELLAHIN: Mr. Chairman, my
5 copy of the exhibit does not contain Thirty-nine, sir. Does
6 yours?

7 MR. STAMETS: We have it.

8 MR. KELLAHIN: All right, sir.

9 Q Mr. Bohling, would you refer, then, to
10 Exhibit Number Thirty-nine and identify that for the Commis-
11 sion?

12 A Okay. As I've stated, it is a letter
13 dated September 24th, 1984, and it is a copy of our letter
14 sent to the OCD for applications for statutory unitization,
15 waterflood, and vertical limits hearings, and this letter
16 was sent out to all the working interest owners, surface
17 land owner, and offsetting operators, as well as the Dis-
18 trict Office of the OCD in Hobbs, the Commissioner of Public
19 Lands for the State of New Mexico, and the Department of
20 Energy and Minerals, or excuse me, the United States Depart-
21 ment of Interior, Bureau of Land Management in Roswell.

22 Q Disregarding for a moment, Mr. Bohling,
23 the question of Exxon's participation in the unit as a work-
24 ing interest owner, and those questions concerning that
25 last 6 or 7 percent, have you received any objections from
any of the surface owners or any of the operators within the
half mile radius of review as to the method of operation for
the project?

1 A No, sir, I have not.

2 Q Mr. Bohling, I've handed you what is
3 marked as Gulf Exhibit Number Forty and ask you identify
4 what's contained in this package.

5 A This package contains certified return
6 receipt requests for the mailing of the letter dated Septem-
7 ber 24th, 1984, and it -- it indicates those individuals in
8 the mailing list attached to the letter of September, 1984,
9 who have received this letter, September 24th, 1984.

10 Q As I understand, you're still receiving,
11 continuing to receive an occasional certified receipt card
12 from this mailing?

13 A Yes, sir.

14 Q But as of at least a few days ago, this
15 represented the proof of receipt by these various indivi-
16 duals of the application as required.

17 A Yes, sir.

18 Q In your opinion, Mr. Bohling, will appro-
19 val of the waterflood project be in the best interests of
20 conservation, the prevention of waste, and the protection of
21 correlative rights?

22 A Yes, sir, it will.

23 MR. KELLAHIN: Mr. Chairman,
24 that concludes my examination of Mr. Bohling.

25 We move the introduction of Ex-
hibits Twenty-seven through Forty.

MR. STAMETS: These exhibits

1
2 will be admitted.

3 Are there questions of Mr. Boh-
4 ling? Mr. Padilla.

5
6 CROSS EXAMINATION

7 BY MR. PADILLA:

8 Q Mr. Bohling, I just have one question.
9 On the well names on Exhibit Number
10 Thirty some are -- have in parentheses NCT-A; I see some
11 with a B, and some of the wells that are operated by Gulf on
12 the last page of the exhibit, the Ramsey-Leonard Wells are
13 labeled or have that NCT-C and I'm curious to know about
14 that.

15 A NCT-C? Non-contiguous tracts, and that
16 is the "C" tract of the several -- series of noncontiguous
17 tracts is my understanding of that notation.

18 Q And the same would apply for the
19 designation as "A" or "B"?

20 A Yes, they would be -- the lease name
21 applies to the A tract, to the B tract, to the C tract. It
22 is just that A is not contiguous with B, which is not
23 contiguous with C.

24 Those -- those leases may be located
25 elsewhere.

MR. PADILLA: That's all.

MR. STAMETS: Are there other
questions of this witness?

Mr. Sperling?

MR. SPERLING: I have no questions but we would like to state on behalf of Exxon that we commend Gulf on the excellent technical work.

MR. STAMETS: Very good. I'm sure they're happy to hear that.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Bohling, I would like a list of the well names, numbers, and locations on the five wells that have been identified as problem wells. You can submit that at a later time; I don't need that right now.

A Okay, sir.

Q I believe you indicated, or it shows somewhere in these exhibits that cement will be circulated to the surface on all of the injection wells, regardless of if they're new wells being drilled or old wells being converted, is that correct?

A Yes, sir, our plans are to run liners in the open hole completed wells and attempt to circulate cement to the surface when we cement the liner in place.

Q Okay. I presume that each one of those wells would have a pressure test on the casing.

A Yes, sir.

Q Okay. Now, you were going to go along with the OCD .2 of a pound per foot of depth pressure limit-

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2 ation. We can plug a lot of that into the computer to check
3 you to see that -- on your reports -- to see that you're
4 really following that. That's a lot of calculations for all
5 of us to try and figure out what individual pressure limits
6 are.

7 I'm wondering if it would be possible to
8 establish groupings of pressures in this reservoir, say per-
9 haps all the wells on the two sections on the west side
10 would have the same pressure limit, and the three down in
11 the middle, the same pressure limit, and so on, let's say,
12 for the east side, so that we wouldn't have, what, 149 dif-
13 ferent pressures; we might have, say, five or six different
14 pressure limits within the limits of the pool we would have
15 to process.

16 A With the installation of those pressure
17 rate controllers we'd be able to control pressures and rates
18 on an individual injection well basis.

19 Where we may want a well to take -- take
20 more water, inject more water into a well, it might require
21 different pressures, other situations.

22 Q It's just a suggestion. We can look into
23 it and if it works out, we'll try and do it.

24 A Okay, sir.

25 Q Now I understand that you will be in-
26 jecting only into the Grayburg and the Penrose and not the
27 San Andres, is that correct?

28 A That is correct.

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Q And all of the mailings were by certified mail.

A Yes, sir, they were.

MR. STAMETS: Are there any other questions of this witness?

MR. KELLAHIN: One comment, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Bohling, Mr. Stamets asked you about cementing the liners in and circulating that cement to the surface.

Some of these wellbores that may be contributed were drilled in the twenties and thirties. Some of those may have been plugged and abandoned in such a way that that process becomes very difficult.

What kind of commitment is Gulf making with regards to the adequacies of the cement in relation to the liners in these wellbores?

A Our attempt is going to be to insure that there is adequate cement covering each casing over the injection interval and above the injection interval.

Q In those situations where it looks like even a prudent operator acting in good faith and using diligence cannot meet that requirement, are you willing to meet with the District staff of the Commission in order to work

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2 out some kind of a solution concerning those wells?

3 A Yes, sir, we are.

4 Q All right.

5 MR. STANETS: Any other ques-
6 tions of this witness? He may be excused.

7 MR. KELLAHIN: I wonder if I
8 might have a moment to see if I've forgotten anything?

9 Mr. Chairman, for the record, I
10 believe we've introduced Exhibits One through Forty. In re-
11 viewing the list of exhibits that have been admitted there
12 was no Exhibit Thirty-four. Exhibit Thirty-four was separ-
13 ated out to be Exhibit Thirty-four A and B, so if you look
14 through the exhibits and do not find Exhibit Thirty-four,
15 that's because there is not.

16 We have nothing further to pre-
17 sent on our direct case, Mr. Chairman. We rest our case.

18 MR. STANETS: Mr. Sperling, I
19 believe you have a witness.

20 MR. SPERLING: Yes, sir.
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25

W. E. NOLAN,
being called as a witness and being duly sworn upon his
oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. SPERLING:

Q Mr. Nolan, you recall that you were sworn
yesterday as a witness in this matter and that you're still
under oath?

A Yes, sir.

Q For the record would you please state
your name, your place of residence, and spell your last name
for the reporter.

A My name is William E. Nolan and I cur-
rently reside at Midland, Texas.

I'm employed by Exxon Corporation.

Q And in what capacity are you employed?

A I'm currently employed as a Technical Ad-
visor, located in the Midland, Texas office.

Q Would you give us a brief resume of your
educational background and led to your qualifications?

A Yes, sir. I graduated in 1943 from the
University of Kentucky with a degree in engineering.

Q Would you relate for us your work exper-
ience in your profession?

A Yes, sir. After graduation I went to
work for Sohio Petroleum Company. I worked for ten years.

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2 I started out as a trainee engineer and when I finally left
3 Sohio I was District Engineer of a large secondary recovery
4 unit located in Edmond, Oklahoma, the West Edmond Hunton
5 Lime Unit, one of the first statutory units in the State of
6 Oklahoma.

7 From 1954 to 1961 I was employed by Mon-
8 terey Oil Company as Chief Engineer of the Pullerton Clear
9 Fork Unit. This is also a large secondary recovery volun-
10 tary unit located in Andrews County, Texas.

11 From 1961 to 1984 I've been employed by
12 Exxon and its predecessor corporation in an engineering --
13 various engineering capacities, presently Technical Advisor,
14 located in Midland, Texas.

15 I've participated in numerous technical
16 studies relative to unitization and enhanced recovery.

17 I've appeared as a technical witness re-
18 lated to unitization and secondary recovery before regula-
19 tory agencies in Texas, Wyoming, and New Mexico.

20 Q What work experience have you had with
21 respect to southeast New Mexico and in particular the area
22 which is under consideration here?

23 A Well, in 1977 I participated in the tech-
24 nical study for the Double L Queen unit located in Chaves
25 County, New Mexico, and again I think that that unit was the
first statutory unit. We thought it was at the time.

I represented Exxon in the negotiations
and I assisted in the preparation of exhibits that were pre-

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2 sented by Burke Royalty Company, the unit operator.

3 In 1978 I participated in the East Vacuum
4 Unit technical study; represented Exxon during the unitiza-
5 tion and in the unitization negotiations.

6 In 1980 I participated in the North Hobbs
7 Grayburg-San Andres Unit technical study. That unit is lo-
8 cated in Lea County, New Mexico; participated in the techni-
9 cal study; advised Exxon regarding the negotiations, and I
10 appeared before this Commission in opposition to one feature
11 of the unit operating agreement in that unit.

12 And that's about my -- that's the last
13 time I have had involvement before the Commission, is in
14 1980.

15 Q Are you familiar with the Eunice Monument
16 South Unit Area?

17 A Yes, sir. As a Technical Advisor in the
18 Unitization Section, we have a number of engineers that work
19 in that and some younger ones and some older ones, and I
20 have consulted with these fellows as they have attended var-
21 ious technical meetings and became familiar with it.

22 I reviewed the technical study and could
23 find nothing wrong with it.

24 Q Are you referring now to the exhibit in-
25 troduced by Gulf and identified as the technical report?

A Yes, sir. Was that, I believe, Exhibit
Number Seven?

That is the technical report I'm refer-

ring to, in any event.

Q Actually it was Exhibit Twenty-two.

A I didn't miss it too far.

MR. SPERLING: Mr. Chairman, we tender Mr. Nolan as an expert witness qualified to testify.

MR. STAMETS: He is considered qualified.

Q First of all, Mr. Nolan, does Exxon oppose the unitization of the Eunice Monument South Unit for waterflood purposes?

A No, sir, Exxon does not oppose. Exxon supports the unitization of this project.

Q Perhaps it would be helpful to the Commission and others if you would give a statement of the position of Exxon with respect to certain particulars that may have been alluded to previously as attributed to Exxon.

A Exxon opposes approval of the structure of the tract participation formula contained in Section 13 of the unit agreement.

We will present evidence that shows this tract participation formula does not allocate unitized hydrocarbons on a fair, reasonable, and equitable basis. We will introduce evidence that four particular tracts having slightly over 3 percent of the surface acreage will under this unitization formula be allocated in excess of 20 percent of the future unit reserves.

We will show that because of this dis-

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2 parity the individual correlative rights of the various par-
3 ties owning the remainder of the tracts are not protected.

4 We will show that voting control for un-
5 itization lies with a few owners of these four particular
6 offending tracts.

7 We will show that with a change in the
8 voting position of these owners this inequity can be cor-
9 rected and that the needed unitization for secondary re-
covery can be promptly accomplished.

10 That is our opposition to the unit agree-
11 ment.

12 Exxon also opposes a provision of the
13 unit operating agreement. Exxon opposes approval of the de-
14 mand well provision contained in Article XI of the unit
operating agreement.

15 We will present evidence that this provi-
16 sion results in confiscation of the property of certain par-
17 ties to the benefit of a few parties.

18 We will show that the same few parties
19 having voting control and benefitting under the tract parti-
20 cipation formula enjoy further benefits under this demand
21 well provision.

22 We will present evidence that because of
23 the demand well provision the unit operating agreement fails
24 to provide a fair and reasonable basis for the determination
25 of the charges to be made among the various owners in the
unit area for their investment in wells and equipment.

We will present evidence showing that because of the objectionable provisions of Section 11 of the unit operating agreement the cost of conducting unit operations exceeds the value of the additional oil and gas recovered in several tracts in the unit.

We will show that with a change in Article X and the removal of a portion of Article XI the inequity of the unit operating agreement will be eliminated and that this change can be promptly accomplished.

Q Mr. Nolan, I take it from your statements that your testimony can be divided into two segments, one relating to Exxon's objection to the unit agreement as such, the tract participation formula, and the other relating to the demand well provision of the unit operating agreement. Is that a fair statement?

A Yes, sir, that is correct and I think it would be convenient for us to just go through it in that manner. We'll first present our evidence related to the unit agreement and then our evidence to the unit operating agreement.

Q Mr. Nolan, I direct your attention to what has been marked for identification as Exxon's Exhibit Number One and ask you to explain that exhibit, it's purpose, and the source of the information contained in that exhibit.

A All right, sir. This information relates to the proposed Eunice Monument South Unit. In general it

1
2 shows the unit area production and reserve estimates and it
3 also shows the allocation formula proposed by the unit oper-
4 ating -- unit agreement.

5 There are three corky dots on there.

6 Q Does that equate to asterisks?

7 A It's a round asterisk.

8 The first at the top of this page, the
9 first -- the first section relates to the ultimate primary
10 recovery of this unit.

11 I believe these numbers to be the same as
12 previously testified to but I would like to review them
13 again.

14 The ultimate primary recovery as shown
15 here is 134-million barrels of oil. This 134-million bar-
16 rels of oil is really an important number since it estab-
17 lishes the remaining primary oil production. It establishes
18 the secondary oil production. It establishes the original
19 oil in place in this unit as it was used in the technical
20 study presented by Gulf.

21 The 134-million barrels was determined to
22 be 20 percent of the original oil in place and as previously
23 testified to, this was a number determined by analogy to
24 numerous similar types of waterflood and similar types of
25 reservoirs in that the ultimate primary recovery was 20 per-
cent of the oil in place in many of these projects.

26 So the number presented in the Technical
Report of 670-million barrels of original oil in place was

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2 obtained by taking the 134-million barrels of ultimate prim-
3 ary and dividing it by .2, so that you could then multiply
4 the oil in place by 20 percent and come up with 134-million
5 barrels of ultimate primary oil.

6 Now then, the remaining primary oil is
7 simply the ultimate primary with the cumulative production
8 subtracted from it and, of course, that's a running target
9 depending on when you want to determine the remaining, you'd
10 have to determine the cum up to that point.

11 So you've seen some numbers, different
12 numbers in the Technical Report, like 14-1/2-million bar-
13 rels, 12-million barrels is what we show here, this is the
14 number we estimate will be the remaining primary at the time
15 of unitization. There will be 12-million barrels of primary
16 left.

17 Now, the secondary recovery that's been
18 testified to as being 48 percent of the ultimate primary re-
19 covery, if you take 20 percent of 48 percent you find that
20 the secondary recovery is 9.6 percent of the oil in place.
21 This is a very reasonable number, that the secondary recov-
22 ery from a unit -- from a reservoir of this type and nature
23 is the low value of 9.6 percent of oil in place. Many re-
24 servoirs in southeast New Mexico the secondary is expected
25 to be 30 percent of the original oil in place, ultimate.

So this is a conservative estimate of the
secondary recovery.

Now, additionally, this field probably

has tertiary recovery potential and infill drilling potential for additional recovery.

To further increase the recovery above the 29 percent -- 29.6 percent, we get that from averaging the 9.6 percent secondary and the 20 percent primary, ultimate then through secondary is 29.6 percent of oil in place. I feel this is a conservative number, could be further increased by a considerable amount with infill drilling at a much later date and by tertiary recovery at a time after that.

So we're talking in terms, now, that the future recovery of the unit, as shown in the second round asterisk, actual years recoverable reserves on January the 1st, 1985, is 12-million barrels of remaining primary and 64.2-million barrels of secondary for a total of 76.2-million barrels.

Now that is the amount of oil which will be allocated forever, for however long this unit lasts, to the various parties and the various tracts under the unit by the allocation formula. The allocation formula is shown in the third -- in the third part of that exhibit. It is Formula 2-A, which has been referred to as the formula in the unit agreement, which is 10 percent oil production for the first nine months of 1982. It's 40 percent of the remaining primary oil reserve on October 1st of '82, for a total of 50 percent primary related parameters, and it's 50 percent cumulative oil production from the unitized interval as of Sep-

tember the 30th, 1982. That is a secondary recovery related, closely related, to the ultimate primary recovery.

Now then, the 76-million barrels will then be allocated in accordance with that formula, which means that 38, as shown in that third part of the exhibit, 38.1-million barrels of oil will be allocated under primary factors and 38.1-million barrels will be allocated under secondary factors.

Now this is the crux of Exxon's objection to the unit agreement; that it allocated this oil on that -- on the basis of 50 percent related to primary, 50 percent related to secondary.

You'll notice, if we'll go through just one more little mathematical derivation here, that if we have a tract which is produced or has a remaining primary recovery, a remaining primary recovery of 1.2-million barrels, let's just say arbitrarily that we have a tract which by the decline curve method used has a remaining primary of 1.2-million barrels, okay, now that's 10 percent of the total 12-million barrels of remaining primary, and if you relate those two, then the formula allocation for that one, the 1.2-million barrels of remaining primary that was determined by -- as I've previously tried to describe, and I don't believe I did completely describe, the fact that those numbers come from decline curves. It was presented in earlier evidence. In any event, the remaining primary of 1.2-million earns 3.8 barrels by virtue of the allocation formu-

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2 is used in the unit agreement. The 10 percent remaining
3 primary of 1.2-million would then earn 3.8-million barrels
4 by virtue of the formula.

5 I need to additionally qualify my little
6 trying to simplify an example. In addition to the tract
7 having a remaining primary of 10 percent, it would also have
8 to have a current production rate, or a production rate of
9 10 percent. This wouldn't be unusual because if the tracts
10 had an average decline equivalent to the field average, that
11 would be a very close number, that the current production
12 would be the same percentage as the remaining primary.

13 So if we then assume that this particular
14 tract recovered 1.2-million barrels on primary, that then
15 blows up to 3.8-million barrels by virtue of the skewing of
16 this formula.

17 A factor of 3.2 to 1, so that each bar-
18 rel, then, of primary recovery earns 3.2 barrels under this
19 formula, 2.2 barrels more than it may deserve.

20 I look upon this formula as two separate
21 pieces; half of it's allocated on primary and half of it's
22 allocated on secondary. The parameters are also indepen-
23 dent, so when you apply them you can apply the parameters to
24 half of it, half the remaining reserve, and the proper allo-
25 cation, rather than the 50/50, would be related to the se-
cond part of this where only 15.8 percent is remaining re-
covery and 84 -- is remaining primary and 84.2 percent is
remaining secondary. By dividing one of those numbers into

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2 the other, you come up with this same, exact same 3.2 bar-
3 rels per barrel, so that the skewing of the formula over
4 what is actually contributed by a given tract is in a factor
5 of 3.2 to 1.

6 Also, I'd like to point out now that this
7 is a secondary recovery unit. The principal reason is to --
8 for communitization is secondary, so this again, in my mind
9 gives weight to the secondary parameters.

10 It happens that certain tracts in this
11 unit are at a very low stage of depletion compared to the
12 other tracts. As a matter of fact, the four particular
13 tracts that I'm going to discuss produce nine times the per
14 well rate of the remainder of the field, so to those tracts
15 are skewed a lot of additional oil because of this multipli-
16 cation factor.

17 I will show that because of this Exxon is
18 skewed out of 908,000 barrels of oil.

19 Q Does that conclude your reference to Ex-
20 hibit One, Mr. Nolan?

21 A Yes, sir.

22 Q Now will you please refer to what is
23 marked as Exhibit Two, Exxon, and identify that exhibit,
24 it's purpose, and what you're trying to show?

25 A All right, sir. Shown on here is the
same unit outline that you can see on Exhibit A of the unit
agreement -- of the -- yes, of the unit agreement.

Also in dashed lines you'll see that the

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2 various tracts shown on Exhibit A are the same -- are shown
3 on here exactly as they are on Exhibit A. To my best know-
4 ledge they are exact.

5 So that this gives us a visual picture of
6 the layout of the various tracts in the unit. Now we see a
7 number on each of these tracts. Now this number is deter-
8 mined simply by taking the 76.2-million barrels of oil which
9 we feel is a minimum that this unit will produce, and multi-
10 plying that 76.2-million barrels by the participation frac-
11 tion shown in the unit agreement, which is, of course, de-
rived from that skewed participation formula.

12 This is the thing that I normally do in
13 -- in looking at, you know, how is a given tract treated in
14 a unit. You need some sort of a visual aid to show you, you
15 know, what does it look like? How does it compare to its
16 neighbors? What do the offsets look like? Is there reasons
for big differences? Are there reasons for big differences?

17 So if we look at this, then, we'll see a
18 number of tracts, four tracts, specifically, that are high-
19 lighted. They have little speckles on them and I think on
20 the other exhibits they have a yellow color, or something.
21 There are four particular tracts. The tract numbers are
22 shown. They are Tract 53 to the north end of the unit.
23 They are Tract 27 and 17, sort of in the middle, and then
just south offsetting that, Tract 8.

24 I'd like to point to those four tracts as
25 being tracts that enjoy particular benefits under this allo-

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2 cation formula.

3 Q Did you identify Tract 27? I didn't hear
4 you.

5 A I may have missed Tract 27, yes, sir, the
6 four tracts are Tract 53, Tract 17, Tract 27, and Tract 8.

7 Now, to just thrown another statistic at
8 you, the average per well recovery in this unit for the
9 76.2-million barrels that it's estimated will be its future
10 production, we take that, divide it by 344, we find that the
11 average is 221.5 thousand barrels per well.

12 Now this 221.5 thousand barrels per well
13 needs to be allocated to each tract in some manner. The
14 average production for the 344 qualifying tracts will be
15 221.5 thousand barrels per well.

16 If we look at that Tract 53 on the north,
17 the unitization formula allocates 3,896,000 barrels to that
18 tract. That's the amount of oil that will be allocated un-
19 der the formula during the life of the project.

20 That's an average allocation per well, or
21 per 40-acre tract, of 974,000 barrels, a very substantial
22 amount above the average for the unit.

23 Now if we look at the offset tracts, to
24 the east is an Exxon tract. Now that tract is allocated
25 1,495,000 barrels. It has twelve 40-acre proration units on
it, being 480 acres in area. We divide the twelve into the
1,495,000, we see that that offsetting tract is allocated
124,000 barrels of oil and that's compared to 974,000 bar-

rels allocated to each well on the offset tract.

We can take this happy exercise all the way around that tract.

The north offset shows 90,000 barrels per well. The west offset shows 300,000 barrels. The south offset, that 80-acre tract, shows 336,000, one-third, a little more than a -- a little less than a third -- of what is allocated to Tract 53.

I'd like to look now further to the south. That's the least offensive tract.

Tract Number 27, an 80-acre tract, is allocated 2,043,000 barrels of oil, an average of 1,021,000 barrels per well.

Tract 17 is allocated 2,840,000, 1,420,000 barrels per well.

Tract 8 to the south is the star performer. It's allocated 6,903,000 barrels. That's an average of 1,725,000 barrels per well.

Those four tracts are allocated a total of 15.6-million barrels, an average of 1.3-million barrels per well.

We subtract what those tracts will be credited with during the life of the project, we have a remaining reserve to allocate to all the rest of the field of 60.6-million barrels, allocated to 332 wells, for an average of 182,000 per well.

And that's Exxon's problem with this uni-

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2 tization formula.

3 Q Would you now refer to Exhibit Two-A?

4 A The Exhibit Two-A shows the same outline,
5 the same tract boundaries, and we have taken the liberty of
6 allocating the unit reserve of 76-million barrels than the
7 unitization formula.

8 You will recall, in order for the Techni-
9 cal Committee to determine the 134-million barrels of ulti-
10 mate primary recovery they went through each tract and
11 determined its ultimate primary and added those together to
12 determine the 134-million barrels, and you'll recall that
13 that 134-million barrels was used to determine the secondary
14 recovery and that 134-million barrels also includes the re-
15 maining primary.

16 So we took the liberty, then, of going
17 back through and reallocating to each and every tract its
18 remaining primary as determined by the Technical Committee
19 for that tract, plus a secondary oil calculated on the basis
20 of the oil in place determined by the 134-million barrels
21 ultimate primary.

22 In other words, we took the 634 -- 671-
23 million barrels. We took the 9.8 percent that will be the
24 average recovery, and we allocated that on the basis of the
25 percentage of ultimate primary recovery, which was the basis
 upon which the 671-million barrels was determined and the
 basis upon which, of course, the remaining primary was
 determined.

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2 So we feel this is a reasonable way to
3 look at what might be, if we believe everything in the Tech-
4 nical Report, what be a reasonable way to allocate oil on a
5 fair and reasonable basis rather than a basis determined by
6 parties negotiating on their participation rather than tract
7 participation.

8 So we look at this then, we see that,
9 boy, these tracts that we have shaded, the same tracts, are
10 pretty darned good tracts. We even, with this type of
11 allocation, Tract Number 53 recovers 2,749,000 barrels;
12 that's 687,000 per well. It was cut from 974 by this method
13 to 687. You'll see that each tract is reduced. Tract 27
14 drops from 2,043,000 down to 1,494,000. Tract 17 goes from
15 2,840,000 to 2,000,003, and the star performer there went
16 from 6,903,000, Tract 8, to 4,713,000.

17 That carves off some of that, and of
18 course that is then reallocated to all other tracts and we
19 can look at those tracts. You see particularly that some of
20 these poor, little, old tracts around the edge of the unit
21 off on the east side, for instance, we see a tract there
22 which has 37,000 barrels credited to it under this method.
23 I don't know what tract number that is, but in any event,
24 that on the previous draft you see that was 24,000, so that
25 little, old tract picked up from 24,000 to 37,000.

 So you know, it favors the edge stuff and
carves some off of these tracts that had the high
allocations.

Now the total of these, under this method the total allocation for those tracts would be 10,957,000, still a very healthy allocation for those twelve wells, 913,000 barrels per well rather than the 1,300,000 barrels.

Now the next graph simply pounds down on the same point and --

Q You're referring now to Exhibit Two-B?

A Sorry, sir.

Q That's all right, Two-B is next?

A Yes, sir, Two-B, right, part of the same exhibit.

This is Exhibit Two-B, showing the outline of the unit and the tracts and then just showing the subtraction of these two maps.

It shows that Tract 53 was allocated 1,146,000 barrels more than what we would judge to be one equitable way to distribute the production, or the remaining production.

Tract 27, it loses 549,000.

Tract 17, 836,000, and that big Tract 8 has a difference of 2.2-million barrels, 2,190,000 barrels. Actually that tract has the biggest difference. The difference on that tract is 548,000 barrels per well. That's twice the average allocated to each well.

Q So Exhibit Two-B is simply a comparison of (not clearly understood.)

A Yes, sir, and it shows that a total of

1
2 4.7-million barrels is swapped from one -- from four tracts
3 to all the other tracts.

4 Q What is the information contained on the
5 lower lefthand side of the exhibit? Does that require ex-
6 planation?

7 A Yes, sir. Yes, sir. This is just an-
8 other statistic which is of interest.

9 There are seventeen tracts on this -- on
10 this map which show to gain production, a total production
11 of 6.4-million barrels under the allocation formula and that
12 is redistributed under the, what I call the tract contribu-
13 tion map, Exhibit Two-A, 82 tracts gain that 6,640,000 bar-
14 rels. So we're going to take by the one method over the
15 other, you would take 6,640,000 off the higher allocation
16 tracts and distribute it to 82 of the lower allocation
17 tracts.

18 I believe that's all unless you have --
19 all right.

20 Now the next thing simply goes through
21 the -- or presents --

22 Q This is Two-C that you're referring to
23 now.

24 A Yes, sir, Exhibit Two-C shows an example
25 calculation as to how each of those maps was obtained and I
believe I did explain it, probably not too well, but Tract
8, for instance, the one that I keep classifying as one of
the major offenders here, the formula allocation there is

tract has 9.05 percent unit participation. You multiply that factor by the 76,000,000 barrels of reserves and you come up with 6,900,000 stock tank barrels.

On the second map, Two-A, for Tract 8 we add the 2,115,000 barrels of actual recoverable reserves attributable, future primary recovery reserves attributable to that tract to its cumulative or ultimate -- ultimate primary recovery percentage of 4. -- of .04047, or 4.04 percent. That particular tract has 4.0 -- contributed 4.047 percent of the ultimate primary recovery, multiplying that by 64,000,000 barrels we come up with a total, then, of -- I'm sorry, I didn't explain that very well and I'd like to go back to it again.

The actual recoverable reserves are the sum of the remaining primary reserves plus the ultimate primary fraction times the unit secondary reserves. I should have read it better.

So here is what we did with the mathematics. That tract is allocated 2,115,000 barrels of remaining primary reserves and it has a 4.047 percent ultimate primary fraction of the total unit for a total of 4.7-million and when we add those two together we get a total of 4. -- in any event, the total allocated by taking the primary and the contributed secondary from the unitization formula is 4.713-million barrels, and I want to check and make sure that Tract 8 has 4.713, and that is correct. It's allocated 4.7-million barrels and the difference is, then, of the 6.9

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2 allocated under the unit formula to the 4.7 allocated on the
3 basis I just tried to describe is 2.2-million barrels.

4 Q Anything further on that exhibit?

5 A No, sir.

6 Q Would you now please refer to what has
7 been marked as Exhibit Three for Exxon and explain the in-
8 formation contained on that exhibit?

9 A This shows the reserve gain for the four
10 tracts benefiting from the current participation formula.

11 On the left side again are the tract num-
12 bers. This shows the ownership of those particular tracts
13 in the next column; shows that in Tract 8 Amoco has 25 per-
14 cent; ARCO owns 25; Conoco owns 25; and Chevron owns 25.

15 Tract 17, Gulf owns 100 percent.

16 Tract 27, ARCO owns 100 percent.

17 Tract 63, Shell owns 100 percent.

18 The third column shows the acreage.
19 There's a total of 480 acres in these four tracts. There's
20 a total unit area of 14,189.9 acres, so that that represents
21 3.38 percent of the acreage in the unit.

22 The total percentage of future production
23 allocated under the unitization agreement is 20.579 percent
24 for the four tracts; a total of 9 percent for Tract 8; 3.7
25 percent for Tract 17; 2.6 percent for 27; and 5.1 percent
for 53, for a total of 20.6 percent.

This is a total allocation in reserves of
15.6-million barrels for the four tracts and the way we have

1 contributed -- we have calculated the remaining -- the re-
2 serves that these tracts will contribute, which is the sum
3 of the remaining primary plus the allocable secondary based
4 on oil in place, is 6.2 percent participation Tract 8, and
5 so on down for a total of 14.4 percent for the four tracts,
6 an allocation of 10.9 or 11-million barrels of remaining re-
7 serve of the 76.2-million in the field, and a total differ-
8 ence between the two methods of allocating reserves to
9 tracts of 4.7-million barrels.

10 Now then, down in the lower lefthand cor-
11 ner, this is just summarized by owners.

12 Amoco gains 549,000 barrels of that; ARCO
13 gains 1,096,000; Conoco and Chevron each 400 -- 548,000;
14 Shell, 1,146,000, and I can see why their fellow was here to
15 support it; Gulf gains 836,000, for a total again of 4.7-
16 million for these four tracts alone.

17 Q Does that conclude your testimony for the
18 moment on Exhibit Number Three?

19 A Yes, sir.

20 Q Will you now refer to Exhibit Four and
21 identify that for us, please?

22 A Exhibit Number Four now jumps over from
23 tract allocation to owner allocation. It is the working in-
24 terest owner tabulation showing a comparison of the reserves
25 contributed by the tracts and the reserves allocated to each
tract, and they're arranged in order of the gain in reserves

that these parties have under the allocation formula.

Shell is at the top of the list. Their reserve contribution of all of their tracts is 4.2-million barrels and their reserve allocation by the formula is 5.1-million barrels for a difference of 908,000 barrels.

Chevron is next in line. They have 4.7-million barrels contributed and 5.2-million barrels allocated, for a difference of 500,000 barrels.

ARCO has 450,000 increase by the formula.

Gulf has 382,000 barrels by the formula.

Amoco has 321,000 barrels.

I got off the line. Conoco has 321,000 barrels.

Amoco has 262,000.

Apollo, who was mentioned yesterday as an example, by the way, of the well thing, and this shows why that example was picked, they gained 19,000 -- they gain, I'm sorry, 10,000 barrels under the formula.

S&S, whoever they are, gains 10,000 and Brady gains 6, down to now talk about the losers under this allocation system.

Exxon loses 908,000 barrels, a difference between the reserves contributed and the reserves allocated, and you saw one good example of that, our offsetting tract having some 130,000 barrels per well allocated against the offsetting tract having 970,000 barrels per well allocated.

So this all sums up, then, to where Exxon

has a difference of 908,000.

Getty is the next loser with 683.

Cities, with 245,000 barrels.

Amerada, 193,000.

Sun, 171,000.

And then we see all of the other owners, without exception, everyone of them a loser by the difference in the allocation formula.

Now this explains some of the reason these trades are being made.

I believe that --

Q All right, let's move on to Exhibit Five, if you will, and explain some of the things that are contained on that exhibit.

A Now, we don't propose that every allocation formula has to be exactly reserves. This particular exhibit shows how Formula Number 3, which was discussed in earlier testimony, how Formula Number 3 would allocate the reserves to the various tracts.

That formula was 70 percent cumulative, 15 percent remaining primary for the same period shown on the earlier exhibit, and 15 percent current production, the same exact parameters.

Now, as I come here I'd like to mention something. There's been a lot of testimony about the difference between parameters and formulas.

Exxon in no way has taken exception to

1
2 the parameters developed by this Technical Committee. We
3 have not opposed them. We've supported them. We believe
4 the parameters are about as good as you could get.

5 So we don't take any exception to the
6 parameters. We take exception to the arrangement of the
7 parameters.

8 So this formula, then, was made up of 70
9 percent cum, 15 percent remaining primary, and 15 percent
10 current production.

11 So then we can say that the allocation of
12 unit reserves by this participation formula would be 15 per-
13 cent primary based on the oil production from January
14 through September of 1982, 15 percent remaining primary re-
15 serves after October 1st of '82, for a total of 30 percent
16 total primary allocation. This would allocate on primary,
17 then, 22.86-million barrels. This is still in excess, as
18 you will recall, of the 12-million actual remaining primary
19 that there is in the reservoir. It's not quite two to one.

20 Secondary then allocated on 70 percent
21 cumulative oil is -- amounts to 53-million barrels again for
22 the same total of 76.2-million barrels.

23 Q Exxon has related exhibits which are
24 identified respectively as Five-A, B, C, and D. Will you
25 consider those as a group and explain what the information
is as set forth on that exhibit, the manner in which it is
presented, and the reason for that presentation?

A Yes, sir. Well, this series of exhibits

1
2 was prepared to show the effect on the distribution of oil
3 of this alternate -- alternate participation formula we call
4 it, but it is Formula Number 3 as presented in the, I be-
5 lieve, August 25th Working Interest -- of 1983 -- Working
6 Interest Owner meeting. That's where that formula comes
7 from.

8 We then wanted to show the tract distri-
9 bution that is made by that formula so then we can compare
10 it to the tract distribution made by the other formula, or
11 the map showing the distribution on an exact reserve, or
12 what we say is an exact reserve basis. So we can compare it
13 any way we want, then.

14 Now we might want to -- we have a
15 difference map so no use jumping back and forth.

16 Under the alternate reserve, the
17 alternate Formula Number 3, Tract Number 53, and again this
18 is the same map showing the same tract outlines, the same
19 tract numbers, of course, and the same four tracts are
20 highlighted. This formula would allocate 2,854,000 barrels
21 to Tract Number 53. This compares to 3,896,000 allocated
22 under the other formula.

23 Tract 27 gets a million and a half
24 barrels.

25 Tract 17, 2.1-million and Tract 8, 4.2-
million.

In each case those are less than that
which was allocated under Formula 2-A, and it was determined

1
2 in exactly the same manner, by taking the tract participa-
3 tion under Formula 3 and multiplying it by the 76-million
4 barrel remaining reserve.

5 So this formula then reduces those four
6 tract's reserve without exception and it adds to many other
7 tracts in the unit. We didn't count which gained and which
8 lost. We do show that -- shall I go ahead with Exhibit
9 Five-B?

10 Q Yes.

11 A I believe that's all I need -- I have to
12 say about Exhibit Five-A. We'll go to Five-B.

13 Now this shows the difference between the
14 reserves allocated under the alternative Formula 3 and the
15 current Formula 2-A. This is the shifting in reserves that
16 takes place if we compute it on the basis of one formula and
17 the other formula.

18 We see then, of course, that the big
19 losers by this redistribution are Tract 53, with a million
20 barrels difference. One fell swoop that tract lost a mil-
21 lion barrels had Formula 3 been adopted.

22 Tract 27 loses 545,000 barrels.

23 Tract 17 loses 781,000 barrels.

24 And Tract 8 loses 2,682,000 barrels.

25 There are 72 -- I'm sorry, there are 82
tracts on here that gain reserves and 17 that lose if we
counted them exactly correctly.

And the total of the four tracts is

1
2 5,000,000, which is distributed differently than Formula 2-
3 A, if we copied all the numbers correctly and added them all
4 correctly.

5 Q I believe the Exhibit Five-C requires
6 some explanation.

7 A Now, Exhibit Five-C is similar to the
8 earlier working interest owner tabulation that I reviewed
9 only this time we're going to show the working interest own-
10 er tabulation comparing the reserves allocated under the two
11 different formulas to show the shifting by owners of the two
12 formulas.

13 The first column, of course, the owners
14 are shown on the left in exactly the same order as they were
15 shown on the previous exhibit.

16 The reserves allocated by the alternative
17 Formula 3 are shown first. Of course, they total 76.2-mil-
18 lion barrels. For Shell, for instance, it's -- the alloca-
19 tion under that formula is 4,342,000 barrels. The greatest
20 amount, of course, is allocated to Gulf with 22,947,000 bar-
21 rels.

22 The reserve allocation formula in the
23 agreement, Formula 2-A, is shown on column three. As we can
24 see, Shell is allocated 5,102,000 barrels.

25 Chevron is allocated 5-million 2.

Shell -- ARCO, 15-million.

Get down to Gulf with 22.9-million, we'll
see here that Gulf really doesn't lose very much. In fact,

1
2 actually, as I look at it, Gulf gains some more, you see.
3 Under this allocation formula Gulf actually is allocated
4 more reserve under Formula Number 3 than they are under For-
5 mula Number 2-A, and of course, the reasons for this are
6 that -- the reason for this is Gulf in general has pretty
7 even distribution of the various parameters. The problem is
8 brought about here by the disparity between parameters.

9 When you have units trying to put them
10 together with a big disparity between, say, remaining pri-
11 mary and secondary and current production, that's when these
12 problems arise. That's when these big differences occur.
13 And Shell happens to be in the nice position of being level
14 on all parameters so it doesn't matter too much to them what
15 formula, as far as the reserve allocation it doesn't matter
16 to them, what formula is selected.

17 What they're interested in is putting to-
18 gether the unit so they're willing to take reserves from
19 some tracts not owned by them and allocate it to some tracts
20 of other people not owned by them in order to put this unit
21 together, and I guess I can't criticize them. I might try
22 to do the same thing if I was charged with putting this unit
23 together.

24 Okay. The fourth column shows the gain
25 and loss that the various parties, and by adopting Formula
Number Two-A, the upper -- in general the parties listed at
the top of this exhibit gain 3,066,000 barrels at the ex-
pense of the parties listed in the lower part of the exhi-

1
2 bit, or if we could put the shoe on the other foot, under
3 the Formula 3-A the lower parties would gain and the upper
4 parties would lose. It depends on who you subtract from
5 what.

6 Q Mr. Nolan, I think you mean to refer to
7 Formula 2-A, not 3-A.

8 A I'm sorry, yes, I do mean the second col-
9 umn is Formula 2-A, yes, sir.

10 And then just for reference the partici-
11 pation percentages are shown in the fifth and sixth columns.
12 Of course, the percentage was used to multiply by the 6 --
13 76.2-million barrels to get the numbers in columns number
14 two and three. That's just shown for reference. It shows
15 the swap in percentage; it shows the swap in reserves, and
16 the actual reserve allocated under the formula by the two --
17 allocated by the two formulas.

18 Q What does Exhibit Five-D show? I don't
19 believe you've mentioned that.

20 A No, sir. Five-D again shows a working
21 interest owner tabulation comparison of reserves contributed
22 by each owner and the reserves allocated by the Formula 3.
23 We showed this same comparison between Formula 2-A so now
24 we'd like to show it for Formula 3. Showing for each owner
25 in their same sequence with Shell at the top and Shell will
be at the bottom, what they are -- what the reserves contri-
buted out of their various tracts are against the reserves
allocated under Formula 3.

And now we see some shifting back and forth instead of them all one way and we see that the numbers are much smaller, such that Shell's gain is only 148,000.

Chevron is going to lose 137,000.

ARCO loses 291,000 when comparing to the reserve computation.

Gulf gains 427,000. They're still better off with -- of course, because their change was very small between Formula 3 and Formula 2-A.

So we can see then and we can compare what the gains and losses by the various formulas are compared to some sort of base which we think is reasonable of what the tracts contributed and then a comparison between the two formulas, and under this thing the gain and loss here is 910,000 and I believe the gain and loss on the previous exhibit was 2.8-million.

So this reserve or this formula much more closely approaches a reasonable allocation in our view.

Q Does that conclude your reference to Five-B?

A Yes, sir.

Q All right. Refer to Exhibit Six and Six-A which appears to be related.

A Yes, sir.

Q And explain --

A Well, this --

Q -- Exxon's position with respect to those exhibits and what they show.

A Right. Well this Exhibit Six shows what would have to happen to Article XIII of the unit agreement in order to adopt Formula Number 3.

We'd have to change three numbers in the participation formula.

The first number being 70 percent, which is the cumulative oil production. In the original formula that was 50 percent. That changes -- we would recommend the change to 70.

The second part of that tract participation formula which shows 15 percent C/D, that weighting on the other formula was 40 percent and that's the remaining primary.

And the third part of that formula would -- is 15 percent E/F, which is the amount of oil produced during the first nine months of 1982, that weighting would be changed from 10 percent to 15 percent, as shown here.

Now that's all that would have to happen to the unit agreement in our view to make the change.

And this last half of Exhibit Six shows those parties who have the controlling votes to affect the change from Formula 2-A to Formula 3. And you'll see they're in practically the same order as the top of that list in earlier exhibits.

There are five parties involved: Amoco,

1
2 ARCO, Conoco, Chevron, and Shell.

3 Under the current participation formula
4 their ownership totals 50.664 percent and that formula was
5 approved at the first meeting by additional parties totaling
6 31.682 to give that formula 82.346 participation and from
7 then on it was adopted and additional approvals have been
8 obtained and I didn't recall just what the total is but it's
9 well over 90 percent at the present time.

10 The alternate participation formula --
11 under the alternate participation formula, column three,
12 those five parties have a total participation of 46.7 per-
13 cent and there were 46.7 percent, as a coincidence, of other
14 parties voting for that formula at the meeting that the For-
15 mula 2-A was adopted.

16 So if we add those together, we have a
17 total of 93.4 percent, so that if by some miracle these five
18 parties would change their vote, this formula could be adop-
19 ted by a majority of 93.4 percent. And these parties would
20 lose a total of 4 percent participation.

21 Q Mr. Nolan, does Exxon have a recommenda-
22 tion with respect to the financial exchange that would be
23 appropriate assuming the adoption of Formula Number 37 Is
24 that detailed in Exhibit Six-A?

25 A Yes, sir. The change would be only that
Section 13 tract participation as shown here on this --

Q And you're referring to the unit agree-
ment?

1
2 A Yes, sir. Is -- is --

3 Q Section 13.

4 A Section 13 of the unit agreement, right.
5 The language here is taken directly from the unit agreement
6 and I believe we copied it, unless there is some typo er-
7 rors. The only three changes that would be required is the
8 substitution of the percentage differences that we discussed
9 previously.

10 And that is shown in the portion called
11 Tract Participation Equals where we show 70 percent A/B, 15
12 percent C/D, and 15 percent E/F. Those underlined numbers
13 would have to be changed to 50 percent, 40 -- I'm sorry, let
14 me back up.

15 Those -- the change would be to the
16 underlined numbers from 50 percent A/B, 40 percent C/D, and
17 10 percent E/F.

18 The numbers we recommend are 70 percent
19 A/B, 15 percent C/D, and 15 percent E/F to change this for-
20 mula to shift the reserves in the manner we've discussed.

21 Q Do you have any other comments to --

22 A This would greatly correct the skewing of
23 reserves.

24 MR. SPERLING: Mr. Chairman, I
25 think this would be an appropriate place to interrupt the
testimony.

MR. STAMETS: A fifteen minute
recess?

MR. SPERLING: Yes.

MR. STAMETS: So be it.

(Thereupon a recess was taken.)

MR. STAMETS: Mr. Sperling, you may continue.

MR. SPERLING: Thank you.

Q Mr. Nolan, you indicated to me at the recess that you wished to make a correction. You made erroneous reference to a party?

A Yes, sir. I -- I was trying to make the point that Gulf is in a rather unique position in this unit in that their parameters are all about -- fairly close to the same, much closer to the same than say Exxon or some of the other parties.

Q Do you mean parameters or participation?

A The parameters for Gulf, the sum of the parameters of their ownership for the parameters are much closer and therefore most any arrangement of those parameters gives you the same answer, and when I made that statement, I didn't realize it, I said Shell, and I certainly didn't mean to say Shell. I meant to say that it's Gulf who is in a fairly unique position in having their, each of their parameters be about the same value compared to the other -- they're not exact but compared to other parties.

1
2 So they can accept a much wider range of formulas and still
3 get their equity than other parties can.

4 And that was -- I in error said Gulf -- I
5 said Shell when I meant to say Gulf.

6 Q All right. Now considering the opening
7 statement of position that you made with respect to Exxon's
8 participation in this hearing, I believe that it would be
9 appropriate to now continue with reference to the exhibits
10 which appear to be relevant to Exxon's objection to operat-
ing agreement provisions, is that correct?

11 A Yes, sir.

12 Q Okay.

13 A The exception, the single exception that
14 Exxon takes to the unit operating agreement, and you recall
15 in the opening statement, we took exception to the demand
16 well provision as it's contained in Article XI of the unit
17 operating agreement, and I would like to read into the re-
cord that provision. This is Article XI.1. Demand Wells.

18 Upon the effective date of unitization or
19 thereafter as demanded by the unit operator pursuant to the
20 unit plan of operations, working interest owners will pro-
21 vide a usable wellbore as defined in Article XI.3 on each 40
22 acres which would constitute a proration unit within the
23 unit area. If any such 40 acres is not provided with a
24 usable wellbore upon demand the owner or owners contributing
25 the 40-acre location shall have the option for ninety days
to provide a usable wellbore.

1
2 If a usable wellbore is not provided
3 within the ninety day period the owner or owners contri-
4 buting the 40-acre location shall within ten days of the end
5 of such ninety day period remit the sum of \$100,000, and in
6 brackets [\$100,000] to the unit operator to be applied to-
7 ward the cost of drilling, completing and equipping a well
8 on the deficient 40-acre location.

8 Q With that preface would you please refer
9 to what's been marked as Exhibit Seven and explain what that
10 is designed to show?

11 A All right. Exhibit Seven again shows the
12 outline of the unit area from Exhibit A of the unit agree-
13 ment and the tracts, locates the tract location with a
14 dashed line within that area.

15 The sum -- there are certain numbers
16 shown on each of these tracts. Those numbers represent the
17 number of wells which may be demanded by the unit operator
18 under Article XI.1 for each tract.

18 You'll notice that Tract 53, for in-
19 stance, again we have highlighted the same tracts here as
20 were highlighted on the prior exhibits.

21 Tract 53, which is 160-acre tract has
22 four demand wells on it. It's required to furnish four
23 wells.

24 Tract 17 is required to furnish two
25 wells.

Tract 27, two wells.

1
2 And Tract 8, four wells.

3 You might recall that these tracts were
4 allocated in excess of a million barrels under the communi-
5 tization formula, and of course you look around the perime-
6 ter of the unit and you'll see tracts which had way less re-
7 serves allocated to them with similar numbers. Of course
8 it's on a per acre basis, so that the poor tracts are re-
9 quired to furnish as many wells as the good tracts under
this demand well provision.

10 There are actually 101 tracts within this
11 unit and there are 400 -- 344 total wells which fall in this
12 demand well category. From earlier testimony we heard that
13 they are actually producing now some 221 wells. So, ob-
14 viously, there are 123 wells, then, which for some reason
15 weren't producing. Now these are the wells that are really
16 subject to this XI.1 because, obviously, you can make
17 \$100,000 by contributing -- you can save \$100,000 by contri-
18 buting your well but you are then charged for a possible 123
19 wells, because for some reason those wells are not pro-
20 ducing. They're either temporarily abandoned, abandoned, or
21 converted to gas injection and there are 123 of those fel-
lows.

22 There's a lot of money involved here.

23 There's actually 357 total tracts but 13
24 of these tracts never contributed any production, so they're
25 not shown. You'll see some of these tracts around the edge
of the unit where only the number one is shown where it's

1
2 obvious that it's an 80-acre tract, that means that one of
3 those wells never contributed any production. That's why
4 there's a little discrepancy between the actual acreage and
5 those numbers.

6 Q Now, Exhibit Number Seven, to which
7 you've already referred, through Seven-B and Seven-C all ap-
8 pear to be related. Rather than identifying each one, con-
9 sider each one, would you please direct your attention to
10 those exhibits and as you refer to a particular exhibit
11 would you identify that exhibit by its number designation?

12 A All right, sir. Now, Exhibit Seven-A,
13 which is a companion exhibit to Seven, shows the same unit
14 outline, it shows the same tract boundaries. Instead of
15 showing the tracts demanded, on this map we show the total
16 number of wells credited -- credited to each tract by the
17 unitization formula.

18 Now I'd like to just step aside here
19 just a minute. The normal procedure in a unit is that an
20 inventory evaluation adjustment is made to provide for the
21 transfer of personal property from one party to the other
22 when a -- when a unit is formed. The reason for this is
23 that some parties drop in percentage of participation and
24 contribute more equipment, others gain participation and
25 contribute less equipment, so in every agreement that I've
been involved with there is always an investment adjustment
provision which provides for this exchange in value of per-
sonal property.

1
2 So this exhibit would show you how many
3 wells would be credited if we took the total number of 344
4 wells which are needed for this unit and allocated them to
5 the various tracts on the basis of the unit participation
6 percentage of that tract.

7 Again we see the four tracts, Tract 53,
8 which contributed four wells, is credited under the unit --
9 under the percentage participation with 17.6 wells of the
10 344 total.

11 Tract 27 contributed two. It will own
12 9.2 wells after unitization. They become the property of
13 that -- of the owners of that tract. They've contributed
14 two. Under the unit formula they will own their percentage
15 of 344, so they've gained 7.2 wells with a value of \$100,000
16 each for a total of \$700,000.

17 Now again the star performer, Tract Num-
18 ber 8. It contributed four wells and under the unit formula
19 by virtue of its 9 percent participation will be credited
20 with 27 -- with 31.2 wells, a difference of 27.2 wells, or
21 \$2,700,000 worth of wells.

22 So not only did that tract gain a bunch
23 of reserves, it gains \$2.7-million worth of wells by virtue
24 of the allocation formula when parties are forced to provide
25 additional wells to the benefit of that tract.

 There's a -- I think we can conclude from
this that there's a considerable shifting in the value of
personal property and it looks to me like it's confiscation

of personal property.

The next exhibit is one that we've submitted similar to in the past. This shows the difference between the two maps and if we refer to Tract 8 again, it picks up 27.2 wells, and difference between the four contributed and the 31.2 allocated. There's a total shifting on here of -- on the speckled are the high reserve tracts, those four tracts. They pick up a total of 58.8 net wells.

Now this has been taken from tracts which we have highlighted with the little cross hatched dashed lines. These tracts show -- that cross hatching shows tracts which lost greater than three wellbores due to this shifting in ownership caused by the participation formula.

So we see the tracts that lose and the tracts that gain. On the four tracts, their net gain was 58.8 wells for a total of \$5.88-million and the tracts which lost three or more wells, a total of 36.8 wells, \$3.68-million.

We cross hatched this because two of Exxon's tracts fall within this category, the one directly offsetting Tract 53, which loses 5.3 wells, and the vertical -- I don't know what section that is, but it shows a 3.8 net well loss. It's the only one showing sort of in the middle of the map. That's an Exxon tract as well. So those two tracts are going to lose 7.7 wells for Exxon at a cost of \$770,000.

And that's all I have to say about that.

1
2 Q I don't believe you have referred to
3 Seven-C yet.

4 A No, sir. Now again Exhibit Seven-C shows
5 an example calculation, or how these maps exactly were
6 determined. The number of wells demanded, say, for example
7 on Tract 8 is obvious. There are four wells because it's a
8 160-acre tract. The total number of wells allocated, the
9 wells allocated are equal to the tract participation times
10 the total demand wells in the unit.

11 For instance, for Tract 8 the wells allo-
12 cated is .09059, which is the unit participation percentage
13 of that tract in the unit agreement times the total number
14 of wells, the 344, which shows 31.2 wells, and the differ-
15 ence between the wells allocated and the wells demanded,
16 then, is just a subtraction of those two numbers, 31.2 minus
17 4, gives us the total difference of 27.2 wells, and the
18 sources of this information are the Technical Report to get
19 the number of qualifying wells and the proposed unit agree-
20 ment, Exhibit C.

21 I believe that's all we have to say about
22 that.

23 Q Please refer to what is marked as Exhibit
24 Eight and explain it.

25 A Again we're showing the four horsemen
here, Tract 8, Tract 17, Tract 27, and Tract 53.

The second column on that table which is
titled Wellbore Value Gained for Four Tracts Benefitting

Most from Current Formula 2-A, we show in the second column ownership. Again Amoco, ARCO, Conoco, and Chevron each own 25 percent of Tract 8. Gulf owns Tract 17. ARCO owns Tract 27, and Shell owns Tract 53. And again we can see why those particular owners prefer a penalty method rather than an inventory adjustment method.

The reserve gain is shown here simply for reference. You'll recall I said a lot of words about the gain in reserves of these various tracts. This is simply taking the numbers from a previous exhibit and showing that these four tracts gain 4.7-million barrels when we look at this thing on an individual tract basis.

The wellbores credited by the formula, we show the percentage of each tract, totalling again 20.579 percent, multiplying each individual tract by the total of 344, we say that after unitization these individual tracts are going to be credited with ownership of this number of wells, a total of 70.8 wells, and you will recall that these, of these four tracts the percent of wellbores contributed is shown in the fifth column such that under Tract 8, which contributed four wells, that's 1.162 percent of the 344 wells, so that tract has a participation of 9 percent and a wellbore contribution of 1.1 percent.

And that amounts to a gain of 7.8 percent of the total number of wells or 27.2 wells with a total value of \$2.7-million.

We move down the line to Gulf. On their

1
2 Tract 17 they have contributed in the fifth column, they
3 contributed two wells and in the fourth column they are
4 credited under the formula with 12.8 wells, a gain of 10.8,
5 for a gain of \$1,000,000 investment inventory value.

6 Tract 27 in column five contributed two
7 wells, is credited, as shown in column four, with 9.2 wells,
8 a difference of 7.2.

9 And just to go through the last one,
10 Shell. Shell contributes on Tract 53 four wells, is
11 credited with 17.6, a difference of 13.6 wells for a value
12 difference of \$1,300,000, for a total value of all wells for
13 these four tracts of \$5.88-million.

14 Now just to show down in the lower left-
15 hand, it's summarized by owner. It shows who gets what.
16 The big gainer here is ARCO with \$1,400,000. They probably
17 like this arrangement.

18 The second is Shell with \$1,360,000.

19 Third Gulf. Gulf gains \$1,080,000 on
20 this basis.

21 ARCO -- Amoco, Conoco, and Shell each
22 gain (not clearly understood.) And I want to point out
23 that's just for these four tracts. That's just for these
24 four tracts.

25 Now, each of these parties had interests
other places and they may have a tract that loses, but on
these four tracts this is the exchange of value.

I saw you shaking your head. And that's

1
2 I have to say about this exhibit.

3 Q Is it appropriate now to refer to Exhibit
4 Nine and explain it? Actually, this is a series of exhi-
5 bits, too, Nine through Nine-B.

6 A Yes, sir.

7 Q Would you discuss them together or separ-
8 ately or whatever you choose?

9 A Yes, sir. Well, I think I'd just like to
10 talk about Exhibit Nine, then Nine-A, and then Nine-B.
11 They're all related, and then we'll stop and then we'll go
12 to Ten.

13 Now we talked about the tract shifting of
14 wellbores. Now I'd like to direct your attention to the
15 ownership shifting because some parties on some parties lose
16 and on other tracts gain, and some of it washes out and some
17 of it doesn't, so we want to show you the net difference in
18 the wellbore demanded under the unit agreement and the well-
19 bores allocated by the unitization formula, and the gain and
20 loss for the various parties.

21 I'd like to point out before I get asked
22 the question on cross examination that that 344 is a fixed
23 number. We don't -- it makes no difference how many contri-
24 buted or non-contributed wells there are. This is a differ-
25 ence in value because each party is required to furnish a
well or pay \$100,000, so this is a difference regardless of
how many wells you actually turn over.

Now Shell, for instance, in column two,

1
2 the wellbores demanded under the unit agreement are 15. The
3 sum of all Shell's ownership on that previous map is 15
4 wells.

5 The wellbores allocated under the uniti-
6 zation formula is 23. So we see again in this table, and
7 this table is laid out in the same order, the same sequence
8 as all of our previous tables to show that those parties who
9 gain reserves also gain inventory value because of this de-
10 mand well provision, Section XI.1 of the unit operating
11 agreement.

12 Shell, for instance, contributes 15
13 wells. They're allocated 23.03 wells and they gain 8.03
14 wells.

15 Chevron contributes 15.5 and they're al-
16 located under the formula 23.72, because they're a high
17 owner, high percentage owner, they gain 8.22 wells with a
18 value of \$822,000.

19 ARCO gains the most. Under the unit
20 agreement they have a total of 54.8 tracts, which under the
21 unit agreement, the unit operator can demand a wellbore.
22 Looks to me like in that paragraph it's his option, but in
23 any event he can demand a well. He can demand 54.8 wells
24 from ARCO.

25 The wellbores allocated under the uniti-
zation formula by virtue of their participation is 67.8 for
a gain of 13 wells worth \$1.3-million to the future value of
the unit.

1 Gulf, because of the fact they've got
2 their feet in a couple different tracts, lots of different
3 tracts, they contribute their on demand clause, they have
4 98.84 demand wells. They're going to contribute -- I'm sor-
5 ry, the wellbores allocated to them under the unitization
6 formula are 103.38. 98.84 are the demand wells and the dif-
7 ference is 4.54. They still gain but only \$454,000, and re-
8 member that on the previous table, I think on these particu-
9 lar four tracts, and I think I saw some shaking heads on
10 that, where Gulf gained -- I'm sorry -- yes, Gulf gained
11 \$1,080,000. This means that somewhere they've given back
12 part of those -- those wells, so their net is \$458,000.

13 And right on down the line, then, and we
14 see we stop right at Exxon again. They gain .23 wells and
15 all of these parties, without exception, are gainers under
16 the unit formula.

17 Exxon is the biggest loser by far. Exxon
18 has 29.5 demand well tracts. Exxon's allocated share under
19 the 4.8 percent ownership in the unit is 16.72 wells after
20 unitization for a net loss of 12.78 wells with a value of
21 \$1,278,000 and of course this right here is why we're here
22 complaining. We don't think this is fair and equitable.

23 And the net difference regardless of the
24 wells contributed or not contributed is \$1,278,000.

25 And we go right on down the line.
There's a total of all owners, and some of this is severe on
these very small owners because they have very little unit

1 participation and they're required to furnish a well. They
2 can't afford to do it. In fact we are later going to point
3 out several tracts which actually lose money because they're
4 required to furnish these wells.

5 But every small owner loses wells and
6 coupled with the fact that those owners weren't credited
7 with a really appropriate share or reasonable and equitable
8 share of reserves, is the reason many of them have gotten
9 out of this thing and have sold their interest or traded it
10 or done whatever, and some thirteen of these tracts have
11 changed -- some thirteen of these owners have tendered their
12 tracts to the unit owner -- to the unit operator.

13 So now we come to the bottom line there
14 of some 41.93 wells that are transferred from some parties
15 to other parties and the total value of that is \$4.13-mil-
16 lion.

17 Exhibit Nine-A, now, the agreement ac-
18 tually is -- invokes a penalty for a well not contributed.
19 So here we've broken out what we estimate to be the wells
20 that will not be contributed to the unit to show the effect
21 on the parties who for one reason or another either have
22 abandoned a well, have a well producing from a gas zone, or
23 temporarily abandoned, or in bad shape in some manner. We
24 believe these are the wells that will not be contributed to
25 the unit.

Now we based this table on some informa-
tion furnished by Gulf to the Technical Committee where they

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made an estimate and it was difficult to get and as they have pointed out in testimony, this is hard to determine in advance. The parties that are contributing the wells don't know if they're in acceptable condition to classify as qualifying under the restrictions for them to come into the unit. So until they know whether those wells are acceptable and clear to the bottom or haven't got collapsed casing or something, we won't know exactly how many of these wells there'll be.

But this is our best estimate on how many there'll be. We think there'll be 86. We know Exxon, the number is 7, and this follows pretty closely with information gathered by the Technical Committee.

There's a total of 86 of these demand wells that won't be contributed. They have a value of \$8.6-million distributed among the owners in the manner shown there.

The column number 4 shows the allocated share of the non-contributed demand wells. Now we're concentrating on these 86 wells.

The ownership of those wells once they are demanded and put into the unit, or the party pays the \$100,000, the ownership of that money or that well goes -- is distributed under these allocation percentages.

For instance, Shell has in the column 4, Shell has 6.69 percent of the unit ownership. This means that this value of \$8,600,000, which is paid by the parties,

6.69 percent of \$8.6-million is \$576,000 goes to Shell, for a net gain of Shell, they contributed -- they had to pay \$100,000 into this thing and their net gain is \$476,000.

Chevron, we think they have 4-1/2 wells that they've going to have to contribute or that they're going to have to pay for or redrill, or do whatever. They have a value of \$450,000. Their unit ownership applied to the \$8.6-million is \$593,000, so they gain \$143,000 on this transaction.

ARCO, they contribute 12.36 wells and they have an ownership of 19.7 percent, which will credit them with \$1,695,000 in value for these 86 wells, total gain of \$459,000.

Now Gulf on this transaction, on this particular transaction, Gulf incurs a loss. Their non-contributed wells, from the information we've gotten, about 28.71 and they'll probably correct me on that, but \$2.871-million. Their contributed share or their ownership after they go into the unit is 30.54 percent for a total value of \$2,584,000, a loss to them, then, of \$287,000.

So if we go down to the bottom of the page we see that there are certain gains and losses.

As to Exxon, I'd like to -- to -- I'd like to read you Exxon's numbers. Exxon, and we're pretty sure of these numbers, Exxon will have to pay for 7 wells we do not believe are in any condition to be put into the unit, so we'll have to pay under that demand well provision

1
2 \$700,000 up front.

3 Our allocated share at 4.86 percent of
4 the total \$8.6-million is \$418,000 and our loss then is
5 \$282,000 on this particular segment of the gain and loss.

6 Now you've seen and you've been told some
7 numbers in previous testimony, and you probably recognize
8 there's some difference between these numbers and what
9 you've been shown before.

10 And the main reason is that earlier tes-
11 timony didn't provide any way to calculate what credit, what
12 was owned by a party after unitization. It just showed the
13 penalty portion, this portion.

14 So now we come down to the bottom line.
15 There's a value exchange here, a net of \$1,798,000, and it
16 will be taken out of total contribution of \$8,600,000.

17 Do you have any questions on that one?

18 Now, then, we'd like to show you the net
19 effect without this of Exxon's proposal, which is the reward
20 method rather than the penalty method. We would like to --
21 we believe that Shell has a valid point when they -- or
22 Shell, we believe that Gulf, correct that, please, we be-
23 lieve that Gulf has a valid point in their previous testi-
24 mony where they say you must have a provision to encourage
25 the operators to put their wells in the unit because other-
wise if we didn't have some provision like that they'd just
keep them for whatever they're worth, up hole, down hole, or
whatever.

1
2 Now this was the subject of great discus-
3 sion in the Working Interest Owners meeting on the value of
4 \$100,000 placed on these wells and almost with the flip of a
5 coin it was decided that instead of applying that \$100,000
6 as an investment value, or inventory value, we'd apply it as
7 a penalty, so that if you didn't contribute you had to pay
8 the \$100,000, rather than if you did contribute, you got
\$100,000 for your well.

9 And what we're proposing is that we now
10 go to the more conventional method. I've seen a lot of unit
11 agreements but I've never seen that XI.1 in any of them,
12 that Shell is proposing -- that Gulf is proposing.

13 I've seen where wells have been given
14 value, and this is what we propose, that the wells be given
15 a value of a million -- of \$100,000 apiece and then this
will show you the effect on the parties.

16 Shell, their contributed wells will be
17 14. Now that number is precise unless we've made a mistake
18 adding, but you can add on the tract map that Shell's con-
19 tributed wells will be 14.

20 I want to correct that statement. That's
21 not correct.

22 Again, we did have to estimate. This is
23 not a precise number. We did have to estimate this by sub-
24 tracting from the known 344 wells requirement. The previous
25 table shows 86 wells and from the same parties then we sub-
tracted their known contributed well number. Of the 344

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2 wells we know how many each of those will contribute, so you
3 must subtract, then, the table, prior table, which shows
4 that -- not taken from the prior table. It's the addition
5 of these two tables.

6 In other words, Shell's actual share of
7 the 344 wells is 15. We believe that Shell will have a non-
8 contributed demand well of just one well, so that leaves
9 them 14 wells which will be contributed by Shell. Only one
10 of their wells, by our estimate, is in not -- will not come
into the unit with some value, with the \$100,000 value.

11 And then so on down the line. If you add
12 up the 258 and the 86 we should come to 344 known number of
13 demand well tracts. Those two columns are additive. 285
14 wells in our judgment will be contributed and 86 will not be
15 contributed.

16 For each owner, then, you could add the
17 two numbers and find out how many total of the 344 wells
18 those owners will contribute, and that is a known number,
the 344 and the distribution by owners is a known number.

19 But we don't know exactly which wells
20 will be contributed.

21 And now we're going through the mathema-
22 tics, we take the contributed wells in column 2 with a value
23 at \$100,000 is calculated then in column 3, just taking
24 \$100,000 times the number of wells, and then the -- the
25 fourth and fifth columns show the unit allocation of contri-
buted well value. Now this where we take the unit partici-

pations and multiply it by the total value of these wells which you see down at the bottom of column 3 is \$25.8-million worth of wells which we judge will be contributed. 86 will not. Sum of the 86 and the 258 is 344. But \$25.8-million worth of wells, it is our judgment that the number of wells which will be contributed.

In column 4, the unit participation, that unit participation was, a fraction of participation, was multiplied by the \$25,800,000 total value of the wells. This shows how much -- what is the value to each one of these owners after unitization, or that's what that unit owner will have to pay to someone because of the wells he's picked up, the number of wells he's picked up.

In other words, for -- in the case of Shell, they have a working interest ownership of 6.69 percent. We're saying that \$25.8-million worth of wells contributed. Shell's going to have to pay into that \$25.8-million a total of \$1,728,000.

So then if we take columns 3 and 5 and subtract it, we see the net effect on Shell. They have contributed \$1,400,000 worth of wells and the unit value that they will have to pay as an investment adjustment is \$1,728,000. So that their net loss on an inventory adjustment is \$328,000.

Again referring, I always like to refer to the biggest gainer. ARCO will be in this case the biggest gainer. We judge they'll contribute 44. -- in the

1
2 third line down, we judge they will contribute 44 -- 42.44
3 wells for a contributed value to the investment adjustment
4 number of \$4.244-million. This is what they will receive on
5 one side of the ledger on the investment adjustment, inven-
6 tory adjustment.

7 On the other side of the ledger they have
8 a 19.707 percent interest in the unit. They will have to
9 pay a total on the other side of the ledger of \$5,083,000.

10 So the difference between what they've
11 contributed and what they will own after the unit is a dif-
12 ference between 5083 and 4244, a difference of \$839,000
13 which they'll have to pay because they have gained wells in
14 this unit and the use of the wells and the reserves that are
15 produced through those wells.

16 So we don't need to labor through all of
17 these numbers, but you can see that again the significant
18 thing on here is, if you go right on down through Brady in
19 the same order that all the other tables are presented.

20 There are ten gainers and the rest are
21 losers without exception.

22 So the high reserve parties, the gainers,
23 will have to pay, will have to pay into the investment ad-
24 justment, and this is a reasonable and fair thing because
25 they're gaining the reserve. They're getting credit for the
reserves and they're making the profit, highest profit in
this unit.

Q Will you move on to what's been marked as

1
2 Exhibit Ten?

3 A Okay, Exhibit Ten now, now this just sum-
4 marizes the numbers that we've shown on several of the pre-
5 vious tables, and it's our -- it's our final exhibit we're
6 going to have to throw numbers at you on.

7 Exhibit Ten. It shows the value of the
8 well and the reserves taken over under the unit agreement.

9 It shows the effect of both the wellbore
10 penalty and the inventory credit methods, the entire swing
11 between the two, which is the swing we recommend.

12 We recommend that we delete Paragraph
13 XI.1 and that we add some language to provide for inventory
14 value for the well.

15 Q And Exhibit Ten is simply a compilation
16 or combination of the two previous exhibits, is that not
17 correct?

18 A Yes, sir, that's correct. This is a com-
19 pilation, actually, of three previous exhibits because we
20 also would like to show on this same exhibit the gain and
21 loss in reserves which we talked about in the prior half of
22 this presentation.

23 So now we see that Shell, with a unit
24 participation in the second column, 6.69 percent, previous
25 testimony has shown by our judgment, by the way we have
skewed these reserves, that Shell's gaining 908,000 barrels
of reserve, and the value of those reserves is shown in col-
umn 5. The way we computed that value, simply to show a

1
2 comparison number to the value of the wells, was to take
3 from the Technical Committee report the net profit shown of
4 the \$273,000,000 and divide that by the 76.2-million barrels
5 of reserves to get a per barrel profit to apply to the bar-
6 rels gained by the various -- or lost by the various par-
ties.

7 We selected arbitrarily a 12 percent pre-
8 sent value because at the time that was the prime rate. To-
9 day it's down to 11-3/4ths, I think, but in event, we used
10 12 percent. We had to take the present value profile from
11 the unit -- from the Technical Report and compute what the
12 \$273 -- what the 12 percent. We knew the 10 and we knew the
13 15, computed the 12 percent to present it here. That number
14 is \$273,000,000. We divided that by 76.2-million barrels
15 for a value discounted 12 percent after taxes of \$3.6 --
16 \$3.60 a barrel. That's a net profit on a per barrel basis
for the 76.2-million barrels production.

17 So then we take the gains and losses and
18 multiply them by the \$3.60. We see that Shell picked up
19 \$3.3-million by virtue of the unitization formula.

20 Gulf, I can point them out, Gulf picked
21 up \$1,375,000, not a great amount when you consider their
ownership.

22 Going down and shifting over to the loss
23 column, you see Exxon heading the list again, a loss of
24 908,000 barrels with a value of \$3.3-million.

25 Of course that's -- that's what our prob-

1
2 lem was earlier in the first half of this testimony.

3 Now in the last two columns we show a sum
4 of the two previous exhibits regarding well value. This is
5 a swing between the two methods of adjusting, or methods of
6 providing incentive to bring wells in, the loss method and
7 the gain method, or the reward method and the penalty
8 method.

9 Again, exactly these top ten or eleven
10 parties, two, four, six, eight, ten parties, the top ten
11 parties have a gain ranging from \$1,300,000 for ARCO down to
12 the little fellows of \$12,000 gain for Apollo and S & S.

13 Now Exxon, we add the two -- we add the
14 numbers from the two previous exhibits, has a net swing be-
15 tween the two methods of \$1,278,000.

16 And then we can go on down and show other
17 parties. Some of the other big losers are Cities Service at
18 \$358,000 net loss by this feature of the unit agreement,
19 unit operating agreement.

20 And I might point out that columns, the
21 loss in column -- column 5 and 6, or by virtue of the uniti-
22 zation formula and relate to the unit agreement, and are
23 separate and apart from the losses incurred under the unit
24 operating agreement having to do with well adjustments, but
25 we want to show that coincidentally the same parties, exact
26 same parties gain reserves under the unit agreement, would
27 be charged for wells under this -- under the method we pro-
28 pose and would receive credit for the wells under the penal

1
2 ty method proposed in the unit operating agreement now.

3 There was a total shift in value of
4 \$4,193,000 from one party to the other. That's a net change
5 between the penalty method and the inventory credit method,
6 which is proposed as -- by Exxon as a curative measure to
7 make this unit operating agreement fair and equitable.

8 Q All right.

9 A That's all we have on Exhibit Ten.

10 Q Now would you identify Exhibit Eleven,
11 please.

12 A Exhibit Eleven shows the effect of the
13 penalty method at the top of the page, the top half of the
14 page. It shows the effect of the penalty method on three
15 arbitrarily selected tracts having low participation. This
16 shows the wellbore penalty method effect on those tracts.

17 Now, there are tracts in the lefthand
18 column. There are Tracts 58, 65, and 74, and of course
19 those are perimeter tracts having very low participation
20 which will under the demand well provision be required to
21 furnish at least one well.

22 So if we take the percent participation,
23 for instance, of -- and this is shown at the bottom, arbi-
24 trarily selected to calculate on the basis of Tract 74, the
25 bottom of those three -- those three tracts. Let's look at
26 Tract 74. It has a percent participation of .09017. Now
27 that's a fractional participation of .00029.

28 So if we take the .00029 and the

\$373,000,000, this is right at the bottom of the page, this is to calculate the net profit attributable to that tract under the unit agreement -- under the -- yes, under the unit formula and based on the Technical Report, Tract 74 would get a 12 percent present value profit of \$79,170 cumulative throughout the life of the unit.

Tract 58 computed the same way would have an \$87,000 present value profit.

65 would have a \$25,000 present value profit.

74 would have a \$79,000 present value profit.

Now, these three wells, these three tracts are going to be charged a penalty for their failure to bring in a well of \$100,000, so the net loss through unitization for these tracts, for Tract 58 is \$13,000; for Tract 65, \$75,000; and for Tract 74 it's \$21,000.

Now we'd like to show at the bottom of the page here the effect of the inventory method on the low participation tracts with a well inventory method rather than the penalty.

The first three columns are exactly the same. Shows the tracts, shows the percent participation, shows the unit revenue. Regardless of which method you use those first three columns are fixed under the unit agreement so they ain't going to change.

So we have again an \$87,000 profit for

58; \$25,000 profit for 65, Tract Number 65, and \$79,000 profit for Tract Number 74.

Now under the method we propose those tracts would have to pay an inventory cost equivalent to the total value of all wells in the unit. They're not contributing any so they're going to have to pay some money to get their reserves. They're going to have to pay something. So the amount that they have to pay is shown under 2 down there.

You take the value of the 344 wells at \$100,000. That's the inventory cost. That's \$34.4-million. And for Tract Number 74, which is our example, it has a pay \$9976, or lined out in the table above, 74 shows at inventory cost, \$10,000.

For Tract 58 that inventory cost is \$11,000, and for Tract 65 that inventory cost, for the use of those wells, for the ownership they'll have in those wells when they come into the unit, 344 wells, with their small percentage. That's the amount you have to pay into the inventory adjustment up front.

What they stand to gain on a 12 percent discounted basis, the revenue, shown in column 3 of \$87,000 for Tract 58, \$25,000 for Tract 65, and \$79,000 for Tract 74. This gives them net gain instead of losses, a net gain of \$76,000 for 54, \$22,000 for 65, \$69,000 for Tract 74, so I think this shows pretty clearly that small tracts having small reserves around the edge of the unit that now are

1
2 abandoned generally because this is an old field and they've
3 depleted their reserves, under the method proposed by Gulf
4 they're going to be penalized, to bring their reserves for
5 someone else to use in the unit. Under the method proposed
6 by Exxon they can afford to pay for the value of the 344
7 wells and make some profit so that the tracts are better
8 protected.

9 We think that the tract -- on a tract by
10 tract basis this method protects the tracts and results in
11 equitable treatment of the tracts, where the other method is
12 inequitable.

13 I believe we're asking the Commission
14 that -- that this -- this be changed; the operator to be
15 sent back to the toolhouse and renegotiating.

16 Q Well, in that connection I take it that
17 Exxon has a recommendation to make with respect to making
18 this change appropriate to reflect Exxon's recommendations.

19 For that purpose would you refer to Exhibit
20 Twelve, please?

21 A Yes, sir. Exhibit Twelve shows the revisions
22 of the unit operating agreement only to effect the
23 wellbore inventory evaluation. As I previously stated, this
24 affects only the unit operating agreement and the unit operating
25 parties, not the royalty owners or the State or the
26 Feds or whoever. It just affects the working interest owners
27 in a matter between the working interest owners.

28 It will be necessary to revise Paragraph

10.1. Personal Property Taken Over, of the unit operating agreement to read, Usable wells as defined in Article XI.3 completed in the unitized formation from which working interest owners elect to contribute -- which owners -- working interest owners elect to contribute, together with the casing, tubing, and downhole equipment, up to and including the Christmas tree. This then defines unit well -- usable wells. This would make a proper definition of usable wells in Paragraph 10.1.1.

Now the main paragraph that the -- that's a -- that's going to have to be changed just to coincide with the -- or be in agreement with the main change that's required of Paragraph 10.2, Inventory and Evaluation of Personal Property.

It will be necessary in Paragraph 10.2 to delete the last sentence of the paragraph, which reads as follows: It is specifically provided that with respect to each well taken over for unit operation no value shall be assigned to intangible drilling costs of such well or to the downhole casing therein, and we would need to substitute this following language in Paragraph 10.2: It is -- and this is the main paragraph involved here.

It is specifically provided that each usable well as defined in Paragraph 11.3 hereof taken over for unit operations shall be assigned a value of \$100,000 to be included in the inventory and valuation of personal property taken over.

1
2 This merely swaps it to a value taken --
3 for inventory of personal property taken over rather than
4 the penalty method.

5 And then just to -- there'll be some
6 minor changes needed in Article XI, Wellbores. We'll have
7 to delete where it says demand wells, we'll have to delete
8 the whole Paragraph XI.1 which defines demand wells. We'll
9 have to delete Paragraph XI.2 which is in regard to excep-
10 tion to demand well requirements, and in the first sentence
11 of Paragraph XI.3.1 delete the word "demanded" and substi-
tute the word "needed".

12 Those particular changes would implement
13 changing the unit agreement to provide for a well inventory
14 evaluation rather than a well penalty, and this is what Ex-
xon recommends, that it be done. Period.

15 Q Do you have anything further with respect
16 to the exhibits?

17 A Unless you have any suggestions.

18 Q I want to offer them.

19 MR. SPERLING: I'd like to of-
20 fer at this time Exhibits -- well, I'd better preface that.

21 Q Were these exhibits prepared by you or
22 under your supervision?

23 A Yes, sir, with the good help of Glenn
Wood sitting next to you there.

24 Q All right.

25 MR. SPERLING: I would like to

offer Exxon Exhibits One through Twelve.

MR. STANETS: Without objection these exhibits will be admitted.

Does that conclude your direct case?

MR. SPERLING: Yes, it does. I want to ask Mr. Nolan one more question.

Q Mr. Nolan, in your opinion and based upon your professional experience, would the acceptance by the Commission of the recommendations of Exxon protect correlative rights --

A Yes, sir, I --

Q -- with regard to this agreement?

A Yes, sir. I believe it would and I believe the difference here in what we're proposing and what the unit agreement and the unit operating agreement, the unit agreement particularly proposes, is a tract protection.

The parties negotiated a unitization formula based on parameter values for their companies. They presented no evidence. I couldn't find any evidence in the presentation that individual tracts had been looked at. Now maybe they did this at home but they didn't present it as direct evidence.

So I believe that the formula we're proposing would make the unit agreement come much closer to protection of correlative rights than the tract offered -- presently offered in the formula.

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2 And then with respect to the unit operat-
3 ing agreement, I believe that agreement could be challenged
4 on the basis that certain of the tracts become uneconomical
5 when you have to pay the wellbore penalty and you're going
6 to have your oil confiscated, and there's 120-some wells in
7 this unit which receive no credit for the first fifty per-
8 cent of the unit formula. Those particular wells are all
9 subject to the penalty.

10 So the combination of these two things
11 really, what Exxon's complaining about and would like to
12 complain about separately and individually as to our damage
13 under the unit formula and our damage under the unit operat-
14 ing agreement.

15 Q Thank you.

16 MR. SPERLING: That concludes
17 our presentation, Mr. Chairman.

18 MR. STAMETS: Mr. Kellahin, I
19 presume you have extensive cross examination which will take
20 equally as long.

21 MR. KELLAHIN: Mr. Chairman, I
22 don't know how extensive it will be. I hope it will be con-
23 cise and penetrating and brilliant. It may take me more
24 than ten minutes to do that.

25 MR. STAMETS: What I am -- what
we are going to do is recess this case until after the lunch
hour which we will set shortly. I'm going to call the Caul-
kins case because I understand there is no testimony in that

1
2 case and then we will confer with the parties in Case 8087
3 and see what they desire to do and then we'll recess for
4 lunch.

5 MR. KELLAHIN: Mr. Chairman,
6 what are our time constraints this afternoon with the Com-
7 mission's schedule?

8 MR. STAMETS: We are
9 tentatively scheduled to appear before the LPC at 3:30 and
10 we expect that to slip a little bit.

11 Okay, we will temporarily re-
12 cess this case.

13 (Thereupon the hearing was in recess.)

14 (Thereafter at the hour of 1:30 o'clock
15 on the same afternoon the hearing was
16 again called to order at which time the
17 following proceedings were had, to-wit:)

18
19 MR. STAMETS: All right, we'll
20 now resume the hearing of the three Gulf cases, 8397 through
21 8399.

22 And we're ready for your cross
23 examination, Mr. Kellahin.

24 MR. KELLAHIN: Thank you, sir.
25

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Nolan, I'd like to have you, sir, review with me Exxon's participation in the various studies and efforts that have gone on over the years in an attempt to form the Eunice Monument South Unit Area in Lea County.

The testimony yesterday was that there was on this latest effort a Working Interest Owners meeting approximately May 10th of 1979.

Were you, sir, or representatives of Exxon to your knowledge present at that first Working Interest Owners meeting?

A I don't know whether Exxon was represented at that first meeting.

Q The first Technical Committee meeting that was described yesterday was a meeting that occurred approximately July 26, 1979.

Was Exxon present with representatives at the Technical Committee meeting?

A I believe that you entered into evidence the minutes of the various meetings. I would like to have a copy of that and then I can read through there and tell you which ones Exxon attended. I cannot recall offhand who attended what meetings.

Q All right, sir, based upon your recollection now, Mr. Nolan, would you describe for us when you first began participating or under your direction members of

1
2 your staff began participating in the process to form a unit
3 for this area?

4 A I personally have not been involved in
5 the actual technical work formulating the Technical Report.

6 I have been in association with several
7 engineers, beginning with Bill Purdy who did attend certain
8 of these meetings and Exxon, I believe, attended most of the
9 meetings. I don't recall how many, and through the years
10 and over the months we've had several engineers attending
11 these meetings and participating in a technical study, and
12 this is an effort coordinated as described earlier with Gulf
13 as the coordinator, these various engineers attending then
14 review the work done and make comments and suggestions and
15 such.

16 We did attend these meetings. I'd like
17 to point out that we have taken no exception to this report.
18 We have reviewed the work in that report. We've reviewed
19 nearly every number in that report. I looked at every de-
20 cline curve.

21 The report is quite complete. I feel
22 that there was an excellent job done under the -- on the
23 basis of the material available in this old field.

24 So I believe that Exxon has supported
25 this study and has agreed. We have not taken exception to
the Technical Report itself.

We have not taken exception to the para-
meters developed by the -- out of the Technical Report. We

1
2 have supported these parameters. We agreed to those para-
3 meters as 100 -- as the rest of the parties did.

4 We began to take exception to this propo-
5 sal with the formulation of the participation formula.

6 Q I appreciate your comments, Mr. Nolan.
7 My question was, however, to what extent you have been per-
8 sonally involved in the unit process, and let me ask you
9 again, sir, when did you personally -- did you personally
attend any of the Working Interest Owner meetings?

10 A I attended only one technical meeting.

11 Q All right, sir, and --

12 A And one Working -- I did attend one Work-
13 ing Interest, because everybody else was out of town.

14 Q All right, sir. And can you relate to us
15 now which of those meetings that you attended yourself?

16 A I can't recall. I'd have to get the
17 minutes of those meetings and see which ones my name was on.

18 Q You made reference to the Working Inter-
19 est Owners meetings in August, I believe, 25th of 1983, in
which there were some nine different formulas balloted on.

20 A Correct.

21 Q Did you attend that meeting, sir?

22 A No, I did not. The gentleman -- one of
23 the gentlemen who did is here about it, yes. I did not at-
tend that meeting.

24 Q Before discussing some of your exhibits
25 and conclusions, Mr. Nolan, to make sure I understand how

1
2 Exxon feels about the unit, when we look at the participa-
3 tion formula that the unit has proposed to the Commission,
4 the one that's got a 50 percent weight on cumulative oil
5 production, is that a participation formula that will allow
6 Exxon to contribute its tracts and participate in the unit
at a profit?

7 A Yes, sir.

8 Q When we look at the wellbore assessment
9 portion of the unit operating agreement and should the Com-
10 mission approve the use of the wellbore assessment formula as
11 proposed by the unit operator, is that a formula that will
12 allow Exxon to participate with its tracts at a profit?

13 A Yes.

14 Q Let's turn to the first package of your
15 exhibits, Mr. Nolan, with regards to the comparison that you
16 have made concerning what I will call the unit formula,
17 which is the one that Gulf has proposed in the case here,
the one that represents 50 percent on the cumulative oil.

18 A This is Exhibit One?

19 Q Well, it will be several of those exhi-
20 bits One through Six. We'll talk about them.

21 A All right.

22 Q When I talk about the unit formula, so
23 that you and I have our definitions correct, I will be re-
24 ferring to the one that was approved by 93 percent of the
working interest owners.

25 A Yes, sir.

1
2 Q Using that 50 percent weighted average on
3 the cumulative oil.

4 When I refer to the Exxon proposal,
5 that's the one that's got the 70 percent weight on the cumu-
6 lative oil.

7 A All right.

8 Q If we look at Exhibit Number Two, let me
9 see if I understand the methodology that you went about in
10 analyzing the comparison between what you believe to be the
11 merits of the unit formula versus the Exxon formula.

12 On Exhibit Number Two -- well, let me
13 back up so I don't lose anybody.

14 On Exhibit Number One we're going to be
15 dealing with 76,000,000 barrels of oil that represents the
16 secondary recovery and includes the oil production between
17 the dates in '82 and the remaining primary oil. You add
18 those up and we get the 76,000,000 oil -- million barrels.

19 A Well, that's -- yes, it's actually that
20 12,000,000 is actually adjusted to forward unitization, not
21 the date of September the 30th, 1982. There has been rough-
22 ly 3/4 of a million barrels of oil produced per year. It's
23 been two years since 14-1/2-million barrels was determined
24 on the -- by the Technical Committee and subtracting out the
25 production, estimating when the date would occur, there
would be 12,000,000 barrels remaining at the time we esti-
mate the unit will be formed.

That number was published by Gulf in the

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material sent to the State and Federal government and to the royalty owners.

Q In that 76,000,000 barrel number --

A Yes, sir.

Q -- we have some 38,000,000 barrels of it that have simply been allocated to the secondary reserve.

A Yes, sir.

Q All right.

A Correct.

Q On Exhibit Number Two, then, it's an effort by Exxon to take the 76,000,000 barrels --

A Correct.

Q -- and to allocate those reserves on a tract by tract basis so that you could make some comparisons.

A Well, not exactly. That Exhibit Number Two is probably the most factual exhibit that we could present. It is simply taking the unit formula given in the unit agreement where each tract's participation is shown.

We took that tract participation and multiplied that number by 76,000,000 barrels, which is, if the unit produces the estimated 76,000,000 barrels, that's exactly what those tracts, each and every one, will be allocated under the unitization formula. That's the easiest exhibit we had to prepare in this basic -- now we then want to compare other things to that, and these other things are much more nebulous. That's an exact, if there is an exact

1 piece of evidence that we have, that's the best we can do.

2 Q All right, sir, I appreciate it. The
3 four preferred tracts.

4 A Yes, sir.

5 Q Have you made any attempt to analyze the
6 relative merits of those four tracts in relation to other
7 tracts in the unit in terms of their value insofar as they
8 produce certain quantities of oil, cumulative production
9 numbers?

10 A Yes, sir, I have looked at cumulative
11 production of those tracts. The total cumulative production
12 of those tracts is 6.9 percent, I believe is the number, of
13 the total unit.

14 The cumulative production for the four
15 tracts is 8,362,000 barrels. The cumulative production for
16 the entire unit was 119,786,000 barrels. That's a percent-
17 age of 6.981 -- a percentage of 6.981, showing that those
18 tracts which have a unit formula allocation of 20.579 per-
19 cent had a contributing cumulative production of 6.981. Now
20 that is, that cumulative production is the only factual,
21 real, in the tanks data that those tracts that contributed
22 where we can measure the quality.

23 Now the rest of these tracts, the rest of
24 these numbers, are estimated by putting a decline curve and
25 calculating the amount of oil under it, and you know, we all
know the problems involved there. You can change the decline
rate slightly and have a large effect on the decline --or on

primary remaining under the decline curve.

Q All right, sir, when we look at those four tracts in terms of the cumulative production, am I correct in understanding that those four tracts generally are some of the best tracts in terms of cumulative production?

A They are, they're very good tracts. The 12 wells contributing just about 7,000,000 barrels, that's -- that's a pretty good amount of oil, and you just calculate that out, eight, four --

MR. STAMETS: I thought that was 8.3-million barrels.

A I'm sorry, it is 8.3-million. I'm going to use 8.4 and divide it by 12. The cumulative production of those wells is 700,000 barrels per well, and those are very good tracts.

They are among the best tracts in the unit. We're not trying to say they're not.

Q When we look at current producing rates of oil --

A Yes, sir.

Q -- are those same four tracts also some of the best tracts in there in terms of current oil production?

A Yes, sir, that's correct. They -- those four tracts produce a total of 20, almost 24 percent, 23.856 percent of the total unit producing rate; 12 wells produce 24 percent and, of course, that's why they were allocated

1
2 very high remaining reserve parameters -- a very high re-
3 maining reserve parameter.

4 The remaining reserves is 36 percent of
5 the unit total remaining reserves. That's in excess of
6 their current contribution. This means that in the future
7 they'll have to contribute more than 23 percent to come out
8 even on the remaining primary.

9 Those four tracts, I'll read across this
10 sheet. Those four tracts have produced 6.98 percent of the
11 unit's cumulative. They are allocated 36.7 percent of the
12 total unit remaining primary recovery and they are currently
13 producing at a rate of 23.856 percent of the unit's produc-
14 tion. So they are excellent tracts and they have been pro-
15 perly rewarded under all these formulas.

16 Q Mr. Nolan, what percentage of the working
17 interest ownership in the unit does Exxon represent here to-
18 day?

19 A Well, under this formula, I think 4.86
20 percent.

21 Q And that is Gulf's participation -- I'm
22 sorry, Exxon's participation for --

23 A You did it, too.

24 Q Yes, sir, probably do it again. Those
25 are Exxon's participation on the four tracts in which it has
some interest.

A Yes, sir.

Q Do you also speak for or represent any of

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the other percent of working interest owners in the unit?

A I do not.

Q Exxon's proposal for its participation formula is one that was balloted on by the working interest owners back in August of 1983, is that not correct?

A Yes, that's true, yes.

Q And in the package of Gulf's Exhibits Twenty-one-A it represents Formula Number 3, is that not true?

A That is correct.

Q Okay.

A Somewhere I have a copy of it. Do I need that exhibit?

Q I'd be happy to share it with you --

A Well, no, I guess I have it right here. Which one are we looking at?

Q Zero three.

A Three, okay, got her.

Q When this Exxon formula was proposed to the working interest owners in '83, the total number of working interest percentages that agreed to vote on this formula in an affirmative fashion was about 48 percent.

A It was, yes, that's correct, and half of that, 30 percent of that was Gulf.

Q Subsequent to that date --

A Actually that formula was proposed by Sun.

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Q I understand that.

A Okay.

Q We characterized it for shorthand --

A Yes.

Q -- as the Exxon formula.

A Fine.

Q Subsequent to that effort, am I correct in understanding that Exxon has made efforts to have this particular participation formula agreed upon by other working interest owners?

A We have done our best to advise owners that we thought that the 2-A was not as advantageous to them as 3 or that they were -- they were being allocated less oil than the tracts were contributing under Formula 2-A. We feel this Formula 3 better allocates the oil contributed by a given tract.

Q As of today, Mr. Nolan, has Exxon been able to persuade any of the other working interest owners to agree to the Exxon formula so that the percentage vote, as indicated on this exhibit, showing the tabulation under Formula 03 would exceed an affirmative vote of 48 percent?

A Well, we have made efforts. Gulf cut our legs right out from under us. They took 13 of the parties and purchased their interest.

Only one that I know of prefers the 3 and has not signed the agreement, and I believe would agree to Formula 3 rather than 2-A.

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2 Q That would be Exxon and what other opera-
3 tor, or working interest owner?

4 A Cities Service.

5 Q All right. All right, sir, if we turn to
6 Page 4 in your package -- or Exhibit Number Four in your
7 package of exhibits, Mr. Nolan --

8 A Yes, sir.

9 Q -- in the far right column under the Loss
10 column --

11 A Right.

12 Q -- I believe that all of the entries from
13 Exxon below represent working interest owners under your
14 calculation that if the unit formula is adopted would suffer
15 a loss when you compare the reserves allocated under that
16 formula to the way you have allocated the reserves on Exhi-
17 bit Number Two on a tract by tract basis.

18 A That's right.

19 Q All right, that's how we made the compar-
20 ison.

21 A That's right.

22 Q When we look at the loss column, Mr.
23 Nolan, other than Exxon and Cities Service, can you identify
24 any other working interest owners in that Loss column that
25 notwithstanding the loss -- well, realizing the loss, have
26 agreed to the Exxon's formula?

27 A Well, of course, Texaco agreed to sell
28 their interest to Gulf and I understand twelve or thirteen

1
2 others did.

3 None of the other parties have taken the
4 position as we have in actually opposing this thing. I
5 think they felt that with the vast majority approval you
6 had, it was sort of a wasted thing.

7 So, no, to answer your question, other
8 than Cities none of these other parties have joined with us.

9 Q Mr. Nolan, when we turn to a considera-
10 tion of the wellbore problem, I understand there are two ap-
11 proached to that solution, provide an incentive for the con-
12 tribution of wellbores to the unit, one is what I will call
13 the unit approach, which was the one we described yesterday
14 as requiring a working interest owner to contribute a
15 usable wellbore, versus the Exxon approach, which would be
16 to give you value in an inventory arrangement for that well-
17 bore.

18 A Yes, sir.

19 Q In making your comparison between the two
20 formulas, the tabulations, I think, are based upon a projec-
21 tion of the likely number of wells that will not be contri-
22 buted to the unit.

23 A One of the tabulations -- two of the
24 tabulations actually, in order to prepare those tabulations,
25 the one shown on Exhibit Nine-A and the one shown on Exhibit
26 Nine-B, in order to prepare those exhibits it was necessary
27 to estimate or ascertain which wells would be contributed
28 and which wells would not be contributed, to make those two

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2 tabulations.

3 Q We know that the unit is going to require
4 344 wellbores.

5 A Yes, sir.

6 Q And there is some range of numbers where
7 there is a likelihood that wellbores will not be contri-
8 buted.

9 A We could not make that determination
10 exactly, although the Technical Committee make an effort to
11 do that. We used that information and what other informa-
12 tion that we could gather, and you'll notice, of course,
13 that those two exhibits, Nine-A and Nine-B, the total number
14 of wells shown is 258 on one page and 86 on the other, and
15 that totals up to be the 344 wells.

16 So that if -- if a well doesn't happen to
17 be a demand well it will appear on the other page. In other
18 words --

19 Q Yes, sir.

20 A -- the only option here is that you swap
21 those wells back and forth but they have to be swopped with-
22 in the ownership.

23 We know exactly how many wells each party
24 contributes of the 344. That's fixed by the agreement.

25 Q But we do not know exactly how many well-
bores each party is likely not to contribute.

A That's correct. But if we -- if they
don't contribute it, then it appears in the other column.

1
2 Q All right. What is the range of wells
3 likely not to be contributed to the unit that you told me
4 the Technical Committee furnished in its report? What is
5 that range?

6 A Well, let's see, that -- that -- see if I
7 can find that.

8 Okay, that -- it's titled Proposed Eunice
9 Monument South Unit Wellbore Count by Owner and on this all
10 the owners appear in the lefthand column. It starts off
11 with Amerada having four active oil producers, three tempo-
12 rarily abandoned wells, and one plugged back to gas, for a
13 total of eight wells. Goes right on down and says that Ex-
14 xon has eleven and a half, which is now corrected to ten and
15 a half. We had thirteen TA'd wells, now corrected to
16 twelve; two PA'd wells is correct, five; plugged back to gas
17 is correct, for a total of twenty-nine and a half, and I
18 could read you on here.

19 Actually, Gulf's -- Gulf's total is
20 70.143. They show three duals, three --

21 Q I'm sorry, Mr. Nolan, I don't want to in-
22 terrupt you, but --

23 A Oh, I thought you wanted to know --

24 Q -- I don't think I made myself clear in
25 the question.

A I'm sorry.

Q My question is --

A I didn't understand it. You probably

made it correct.

Q My question is, using the Technical Committee Report and the various discussions in minutes that can be examined, the likely range for non-contributed wellbores shown in the unit can vary anywhere from 34 to I guess you used 86 today.

A I used 86, yes.

Q There is some range, then, in wellbores that may not be contributed.

A Yes. In some other exhibits that Gulf presented they took the example of 40. I say that's on the low side.

So I'd say some place between 40 and 90 might be the number that we're talking about here.

Q Somewhere between 40 and 90 and the problem is that we really don't know how many it's going to be.

A Well, I see that -- that Gulf hasn't really come to the bottom line yet, you probably will.

Q I'm working on it.

A But it makes no difference in this arrangement how many are contributed or not contributed.

The difference we show on the last exhibit is exact regardless of how many wells are contributed or not contributed, but the parties profit and lose exactly as we show regardless of how many wells they contribute or do not contribute.

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2 Maybe you need to get your engineers to
3 check that.

4 Q Well, why don't we use something that
5 your engineers did.

6 A All right, sir.

7 Q Mr. Nolan, I'm seeking to get us copies
8 of Exxon's letter of April 23rd, 1984, from Exxon to Gulf,
9 in which there is attached to that, Attachment Number One,
10 in which there has been an analysis of the issue we're dis-
cussing now.

11 A Yes, sir.

12 Q All right, sir. Here, Mr. Nolan, is a --

13 A Copy, okay.

14 Q -- copy of the letter and attachment.

15 A Uh-huh.

16 Q I'll give Mr. Sperling a copy of that
17 same letter and attachment. I think I found enough copies
to go around.

18 MR. KELLANIN: Mr. Chairman,
19 I'm referring to the attachment on an Exxon letter of April
20 23rd, 1984.

21 A Yes, sir, I've seen this letter.

22 Q All right, sir.

23 A WGL down there in the lower lefthand cor-
24 ner is Glenn Lee (sic), that young fellow sitting right to
your left.

25 Q When we look at the tabulation, look at

1
2 the far left where it identifies the entries for the col-
3 umns, and we come down two-thirds, it says, likely non-con-
4 tributed, and has the number 81.

5 A Yes, sir.

6 Q All right.

7 A Since that time we have restudied and in-
8 creased that by 8 wells.

9 Q All right, sir, were you --

10 A You see this was made in March of 1984.

11 Q And the number you've used for it today
12 was 86.

13 A 86 number, yes, sir.

14 Q Below that is an entry that says invent-
15 ory payment in thousands of dollars. Below that it says Ex-
16 xon proposal.

17 A Yes, sir.

18 Q The other one it says penalty payment. I
19 assume that equates to the wellbore assessment that Gulf has
20 been talking about yesterday.

21 A Yes, sir, that's correct.

22 Q All right. When we go over and look at
23 the Exxon entry --

24 A Right.

25 Q -- and you go down the Exxon entry till
you get to the inventory payment under the Exxon proposal --

A Yes, sir.

Q -- it will show under the inventory pay-

1
2 ment --

3 A Yes.

4 Q -- that Exxon will have to contribute
5 \$13,000.

6 A That's correct.

7 Q And that assumes likely non-contributed
8 wells being one.

9 A That's right.

10 Q All right. My question is, if instead of
11 likely non-contributed wells being 81 that number is on the
12 lower end and is 40 --

13 A Yes, sir.

14 Q Without giving me the precise mathemati-
15 cal calculation, will that not result in the Exxon, under
16 the inventory payment --

17 A Uh-huh.

18 Q -- having the unit have to pay Exxon
19 money under that formula?

20 A Yes. Yes. Now I would like to point out
21 just to be fair, if you'll notice under Exxon, there are
22 two, the last two columns, it says inventory payment, 13; it
23 says penalty payment, 1291.

24 Now if you subtract those two numbers you
25 get the net difference because one's a payment and one's a
penalty, you subtract the 13 from the 1291, the difference
is 1278, and I would refer you to Exhibit Number Ten, and if
we look across at Exxon's payment, we look across at Exxon's

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2 payment, we see a number 1278. That's exactly the same num-
3 ber as is in this letter expressed in different terms, and
4 that's the difference between the method proposed by Gulf
5 and the method proposed by Exxon. There's no inconsistency
6 in those numbers, and regardless of how many wells Exxon
7 contributes or doesn't contribute, that 1278 remains con-
8 stant. We simply do not get as much on an inventory adjust-
9 ment when we don't contribute the wells, but we don't get
penalized as much as we do under your arrangement.

10 So the swing is exactly -- and each and
11 every party should be exact if Glenn calculated those num-
12 bers right.

13 Q All right, let's examine the relationship
14 of the impact of those two proposals on various working in-
15 terest owners, Mr. Nolan.

16 A Yes, sir.

17 Q Let me go back and ask you, you said that
18 you've had considerable experience in unit matters. Is the
19 approach of using the wellbore assessment as the unit has
20 proposed to the Commission one that has never been used be-
fore?

21 A I was on the stand once before and asked
22 a question like that and I said to my knowledge that parti-
23 cular thing had never been done before, and you know what
24 that fellow told me? He said, Exxon did that down in
Louisiana.

25 Well, now on this thing I'll have to an-

1
2 swer you the same way. I didn't -- to my knowledge I've
3 never seen a wellbore penalty in a unit agreement.

4 Q And I'm going to tell you.

5 A There you go.

6 Q Tell you, Mr. Nolan, that Texaco did it.

7 A Uh-huh.

8 Q In Commission Order 5496.

9 A And was this in what unit?

10 Q I don't have the unit name down here,
11 sir. We can dig the order out but --

12 A I'm sure if you look -- if you look far
13 enough, it has been, but it's much more common, you'll have
14 to admit, to go inventory adjustment, or the more common
15 thing is, no penalty and no reward. It's simply give no
16 value to wells. That's -- that's what's in the API agree-
17 ment. That's the 1970 API agreement. It was removed in
18 1974.

19 Q All right, let's look at Page -- Exhibit
20 Eleven of your package of exhibits, and see who's hurt by
21 the unit formula that gives a wellbore assessment.

22 A Exhibit Eleven.

23 Q Yes, sir, we've got Tract 58.

24 A Yes, sir.

25 Q Will you believe me when I tell you
that's --

A That's an Amoco tract.

Q -- an Amoco tract.

1
2 A Absolutely. These were examples, and
3 Amoco profits on some other tracts.

4 Now this points out the -- I want to say
5 the danger, but the difficulty of protecting tracts and pro-
6 tecting owners.

7 Normally, when we unitize fields, you and
8 whoever, all of us who work on those, we're looking at
9 ownership of working interest owners. We're looking at
10 parameter tables developed for working interest owners. We
11 don't look back at the individual, normally.

12 Now, we should. We should do more of
13 that and a lot of times you're protected pretty well because
14 there's not a great swing in parameters that there are here,
15 but this -- actually, you're right, that's an Amoco tract.
16 I think that -- then who's the next one?

17 Q All right, 65, would you believe me when
18 I tell you that's a Getty tract?

19 A Getty tract, okay.

20 Q And Getty's in the unit, right?

21 A Oh, yes, because --

22 Q All right.

23 A -- of course, they come out all right,
24 but the -- but the -- the royalty owners have nothing to do
25 with this, but that's right. Getty comes out because of
their ownership in other tracts.

26 Q That's an interesting point, Mr. Nolan.
27 This whole conversation about the participation formula, the

wellbore arrangements, has no effect on the royalty owners.

A That's right, it does not.

Q In fact we've got some 99-plus --

A Right.

Q -- of the royalty saying this is all right.

A That's correct.

Q All right. 74 is Ed Hudson and his family, that's his tract, if you'll believe me.

A Yes, sir, I believe you.

Q All right, sir, and that's one that's been purchased and his problem is dismissed.

A That's right. We particularly used these just as an example to demonstrate the difference between -- with some simple arrangement, because it is -- it is a little complex to explain all the way from one to the other. We've had difficulty communicating with each other on this in meetings.

Q Well, what you have done is identified for us, tracts that show a net loss through the unitization process as Gulf proposes, yet for each of those three examples, the problem has disappeared.

A But as to those tracts the problem is exactly like is shown there.

Q All right, sir. One of the last things you said this morning, Mr. Nolan, was that you thought there was enough in equity by examining the information as you've

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2 done to ask the Commission to agree with you on the formulas
3 or at least compel the parties to go back and try to renegot-
4 tiate this thing.

5 My question for you, sir, based upon your
6 knowledge of this unit, what is the likelihood that you will
7 get 75 percent of the working interest owners to agree to
8 the Exxon formula?

9 A Well, I would say if that formula were
10 proposed not by Exxon but by this Commission, and it is, of
11 course, within their power, to revise that formula, that
12 there's a good chance those parties would approve it because
13 they'd refer and they'd have to answer the questions you
14 asked me of do they profit in these -- under this format.
15 They all profit; they just don't profit as much.

16 So I'd say there's a good chance. Now
17 there is precedent for this, as you're probably well aware.
18 I know Mr. Stamets is aware.

19 The first unit in this form under the
20 statute was the Double-L Queen Unit, and there were changes
21 made. Of course I understand from Mr. Stamets there were
22 some errors made in the computations. There were also some
23 changes made due to the economic limit.

24 Q Let's try to put it in context, Mr.
25 Nolan, and examine the likelihood, as you understand it --

A Yes, sir.

Q -- of getting a necessary 75 percent min-
imum working interest commitment based upon your formula.

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A Uh-huh.

Q Now we've already put it to ballot in August of '83 and we could only get 48 percent.

Let's go look at Exhibit Number Six that you submitted.

A Exhibit -- oh, I thought we were through with these things.

Q No, sir, we're going -- we're going to fool with it some more.

A Exhibit Six.

Q All right. We look at Exhibit Six and look at the center column and look at the bottom line, there's 93 percent there.

A Oh, I must have the wrong exhibit. There is a Six and a Six-A.

Q I'm sorry.

A Six-A, okay, Exhibit Six-A.

Q All right, sir. Okay.

A Were some of them numbered wrong?

Q It's identified on the back. I'm looking at the vote change required for --

A I have that.

Q -- approval.

A Yes, sir, that -- my copy shows Exhibit Six-A.

Q All right, whatever the number, it's the vote change required.

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A Yes, sir.

Q If I include the Gulf interest, which is already included in that 46.721 number --

A Yes, sir.

Q -- at the bottom of the middle column --

A Yes, sir.

Q -- if I understand the exhibit right, we're going to have to go back in and get ARCO and some of these other five working interest owners to agree to Formula Number 3 in order to have a minimum 75 percent.

A You're saying that if Gulf is not included in those that voted for the formula?

Q I misspoke. If it is included, then you'll have 46 percent.

A Yes, well, I misunderstood. Okay. The 46.7 percent does include Gulf's vote, since they did vote for the formula at that time.

Q Let's assume Gulf stays with you on the vote.

A All right, sir.

Q Have you contacted Amoco, ARCO, Conoco, Chevron, Shell, or any of them to determine whether or not it's likely that they would change their vote to agree to a formula as proposed by Exxon?

A No, sir, I have not.

Q And we already know how all four -- how all five of those companies voted on the --

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2 A Yes, we're well aware of why they voted
3 that way.

4 Q All right, sir. Let's talk about some
5 what ifs, Mr. Nolan.

6 What if the Commission sends the working
7 interest owners back to further negotiate?

8 A The only basis that would be practical
9 for that to happen would be that the Commission would decide
10 in its own mind, its own wisdom, that another formula did
11 indeed protect the rights of the individual tracts better
12 than the formula proposed in that unit agreement, and if the
13 Commission so decided, under the statute they could send it
14 back and it would require re-ratification and that would
15 take some time.

16 Then the unit parties would be faced with
17 either accepting something for secondary or perhaps a ten
18 year delay, or whatever, or never putting this unit
19 together, but still their profit would lie in the direction
20 of agreeing to what the Commission decided was a fair for-
21 mula, and that's why we're up here. We've appealed all we
22 can to operators and you, or sorry, to Gulf and to -- to the
23 other operators about it and complaining.

24 Q Let me try to understand your answer.
25 You said if the Commission sends this back to the parties to
negotiate some more.

 A No, sir, I didn't. I misspoke if I did.
I said if the Commission, as they can under the statute,

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2 says this is the formula. Say it's half of this one and
3 half of that one. They think, well, Gulf's got some points;
4 Exxon's got some points. They say, okay, add them up
5 together and divide it by two, now that's going to smooth
6 out these differences, big differences and can better pro-
tect the tracts. We're surmising now.

7 Q All right, sir.

8 A Surmise that the Commission does that.
9 They then issue an order that says we'll approve this agree-
10 ment with this particular formula.

11 Then we have a choice.

12 Now that would be the only practical way
13 that this could possibly occur. There's no way that the
14 unit owners can sit down and arrive at a formula and hope to
15 agree on it, in my opinion, but I believe that if the Com-
16 mission, who we're putting between a rock and a hard place,
17 sort of, but hell, that's their job, decides that this for-
18 mula or that formula or another formula better protects
19 equity between tracts, they come out with it, then we've got
20 the choice of either putting the unit together that way or
21 sitting back on our heels, and I believe it would be ap-
proved.

22 Q Let me suggest that the formulas we're
23 discussing in this range in here are all based upon this
parameter table --

24 A Absolutely.

25 Q -- agreed to back in October of 1982.

A Yes, sir, and which we agreed to and we
ree and have never disagreed with that table.

Q And in order to return this project to session again it will likely require that the Technical Committee update and examine the parameter table that is two years old.

A Not if the Commission decides that since
cent of the people accepted that parameter table,
se their order on the basis of that parameter table,
re's no way they can go back and negotiate. They've
ive or take -- they've got to take it or leave it
it's based on that parameter table.

Who's going to ask that it be updated?

Q Apart from Exxon can you commit working that this parameter table won't be changed?

A Are there any of those present and could
men?

Q I believe it was Mr.Berlin's testimony that unless the proposal is approved by the Com-
row, he says it's virtually impossible.

A That's Mr. Berlin's opinion. I've ex-
a different opinion. I do not know whether Berlin
erlin was familiar with the statute. I believe he
he was talking about renegotiating this formula
owners and that's not what I'm talking about.

Those are different parameters. We're

1
2 appealing to this Commission to help us. We're appealing to
3 this Commission to protect the individual tracts.

4 Q When we talked about the impact of ad-
5 justing the participation formula and were looking at this
6 76,000,000 barrels of reserves --

7 A Yes, sir.

8 Q -- I believe you told us this morning, to
9 make sure I understand, that what we're dealing with is a
10 shift of some 5,000,000 barrels from those four tracts that
11 have been treated in a preferential way and redistributing
12 that 5,000,000 barrels among other tracts of which Exxon
13 would receive approximately 30 percent.

14 A I didn't calculate it exactly to see of
15 that particular number of barrels how many Exxon -- I calcu-
16 lated it for Exxon's overall ownership and Exxon would --
17 would profit by, or the difference for Exxon would reduce
18 the 980,000 barrels of loss to something way less than that.

19 Q All right.

20 A But it is substantially correct, yes,
21 sir.

22 Q Can you tell me in dollars, Mr. Nolan,
23 what the shift in redistributing the 5,000,000 barrels of
24 oil will be if we take it from these four tracts and redis-
25 tribute it? Is there a dollar value we can put on that?

26 A Well, based on the Technical Report and
27 there's a lot of room to make different kinds of economic
28 analyses based on that Technical Report, but the average

1
2 value of a barrel of oil at 12 percent is \$3.60, and that
3 doesn't sound like a whole lot but this is a long term unit
4 and that's -- the discounting enters into it so I would say
5 that if we were looking at the value of -- what a value of a
6 barrel of oil, it would be something very close to that
7 range, \$3.60 a barrel, so if there's 5,000,000 barrels we
8 could take 5 times 3 -- can't do anything in my head --
9 well, you aren't going to believe it but this computer just
10 ran out of juice.

11 5 times -- it would be \$17-1/2 million,
12 something in that range.

13 Q And do you agree with Mr. Wheeler's cal-
14 culations yesterday about the ultimate benefit for unit
15 operations being in the magnitude of \$1.2-billion?

16 A Well, looking at it on an actual value
17 basis, that -- actual value is probably not representative
18 relating it to present value, and his -- the numbers pre-
19 sented on a present value basis would be quite close to the
20 273-million included in the Technical Report. I don't be-
21 lieve that change is too great.

22 You didn't run a 12 percent number but
23 you ran a 15 and a 10. Judging between those two it would
24 probably be 280, 285-million compared to the 273 that we
25 have used out of the Technical Report.

Like maybe a 10 percent difference.

26 Q Can you give us an estimate of the econo-
27 mic loss to the unit if the unit operation is delayed for,

say, one year?

A Well, again you're -- you're talking about economics, which include escalation and acceleration, various things, when we -- in order to run that you have to know about what the price -- prices are going to do in oil; if the price goes up quite drastically in the future and down in the first year, why, very little loss would occur by a year's delay, because this unit is already at such a low pressure that further pressure depletion is going to have very little effect on the ultimate recovery, so that the differences then come about in discounted money value. Those differences hinge on what we view -- how we view the future price of oil. If the price of oil goes down in early years, then up sharply when decontrol might occur in 1990, under those circumstances you might profit by a year delay.

On the other hand, if the price goes up now and then falls off later, there'd be considerable loss to the unit.

The one year delay in many cases where we have solution gas drive and rapidly dropping pressures, there are ultimate recovery losses by waiting.

In this particular case, the field's been operated since, I don't know, 1930, another year's delay can have very little pressure difference and from the standpoint of ultimate recovery loss, I think that there'd be a tiny amount but to have any particular big effect on the -- on the ultimate recovery.

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Q Let me ask you your opinion in terms of Exxon's position of the range between weighting the cumulative oil factor between the 50 and the 70 percent. We know Exxon doesn't like the 50 percent number. We know you like the 70 percent. Is there a point within that range in which Exxon's objection and dispute over that participation formula is resolved?

A Yes, sir, I think that Exxon would, as it always has, deal fairly with all the parties and, you know, assign the percentage that each party thinks he should have, why you'll always come up with 120 percent, and now you've got to share that 20 percent on a cut some way, and we feel like the other parties are doing a reasonable job or are being reasonable in taking what they view as a loss. We always do the same, so I think, yes.

Q Do you have a number that you can express to me today in terms of what percentage?

A We -- we have brought along a young manager to make deals on this if that should happen to occur and if somebody would make us an offer we'd tell you -- we'd tell you what we -- what we'd take, but I'd say the 3, the Formula 3, we like that formula and we feel it was fair even though it's much less, it's less than the oil contribution. We recognize our current production is low.

On a single phase formula we're going to have to take a loss of reserves.

So, yes, we'd be willing to negotiate.

1
2 Q But you can't express to us today a
3 figure.

4 A I haven't been given such a figure. My
5 feeling is that yes, certainly Exxon would be willing to
6 trade.

7 Q And in fact that's the whole process that
8 the working interest owners go through in this kind of
9 problem and the exact kinds of things that were discussed
10 back in August of 1983.

11 A It just happens that in this particular
12 case you have 80 percent of the parties on the same side of
13 the fence because of their unique ownership around the
14 field, particularly their ownership of those four particular
15 high reserve tracts, so they had the voting power and there
16 was very little negotiation.

17 You've been talking about how long it
18 took to put this unit together. There were thousands of
19 manhours spent in putting this together and we recognize
20 that. We appreciate that. We appreciate that Shell has
21 expended many thousands of manhours on this thing.

22 Please correct that to Gulf has spent
23 many, many thousands of hours and they've done a very good
24 job.

25 But that unitization formula was
negotiated in two hours by group of managers not many of
whom had a great deal of familiarity with that Technical
Report. What they went to school with was a number in their

1
2 pocket of what their company thought equity was that
3 generally was handed to them by the engineer that
4 participated, however it's done; that's how it's done in our
5 company. When they got this number they said yes. They did
6 not look at the individual tracts. We did not look at the
7 individual tracts until we really were faced with this
8 problem and wondered why in the devil this thing happened,
9 and we can see that the individual tracts are not fairly
10 treated, and we are not fairly treated because of that.

11 But you had the voting power within those
12 80 percent that were the six top parties on all of those
13 lists.

14 Q Based upon your experience and knowledge
15 of this area, you've allowed Exxon to sit back for more than
16 a year, some fourteen months, before you attempted to try to
17 persuade the other working interest owners, some of these
18 people like Getty that are in a similar position, and you
19 allowed them to go ahead and sign this agreement when you
20 might have persuaded them otherwise?

21 A With 20/20 hindsight, we should have
22 started earlier.

23 Q You come to the Commission after five and
24 a half years at the eleventh hour and tell us that for 4.86
25 percent of Exxon's interest, that this is not fair.

26 A Yes, sir, that's what we're saying.

27 MR. KELLAHIN: No further
28 questions.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Nolan, would you take a look at your Exhibits Four and Five-D?

A Okay, Four, yes, sir.

Q The first column to the right of the owner names --

A Yes, sir.

Q -- if I understood you correctly, you derived this by taking the cum production for the leases that those operators control, added in the remaining primary, and then added in a figure which was equivalent to what, 40 percent of the total of the -- of the ultimate primary.

A Ultimate primary, which is the 62,000,000 barrels of secondary.

Q Based on the testimony of Gulf, they -- according to the Technical Committee Report, they felt that that is as close as anybody could reasonably come to what the secondary recovery would be.

A The 48 percent of the ultimate primary is the number in the Technical Report and I believe supported by Gulf, yes, sir.

Q All right. Exhibit Four, then, is --

A Exhibit Four --

Q -- this done on the Gulf formula and Exhibit Five is the same calculations, then, done on the Exxon formula to allocate the production to the individual owners?

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A That's correct, sir.

Q And I also remember from listening early on, it seems as though if we waited till primary production is over, that would be another fifteen years before secondary recovery can get started.

A No, sir. That would be --

Q I'm referring back to Gulf's previous testimony.

A Yes, someone did testify about fifteen years remaining primary. Now I'd like to correct that, and I'm sure that Tom there will back me up on this.

Actually you'd have to wait 150 years because those large, those tracts with high reserves have depletion times up to 150 years. They will be producing primary over a period of 150 years. The decline rates vary between two and a half and four percent for those four tracts.

You can compute the time if you know the initial rate, final rate, and the amount of the reserve. We computed the time for those four tracts and it ranged from 80 years to 150 years on the longest tract.

So it is not correct when they imply that compressing this thing and you're going to get your money back quicker on primary. That's just absolutely not correct.

Now, the Technical Committee didn't look at that. They just put a decline slope on there. They knew the initial rate, they knew the final rate, they plugged it

1
2 into a formula and calculated the remaining recovery.

3 We want one step further and calculated
4 the time it would take to get that under the same decline
5 curve.

6 So actually the waterflood will compress
7 the time and you're going to profit more by the secondary
8 because of the acceleration.

9 Now all tracts are not that way. The
10 poorer tracts are depleted in a much shorter time and the
11 overall average is about 30 years if you say, okay, I want
12 to put it all in one pot, but that's not the way you can
13 look at it because the individual tracts will still be
14 producing in 150 years, one of them. That's the longest. I
15 picked the one that the most impressive operating life.

16 Q If we waited 150 years to put this --

17 A Yeah.

18 Q -- into effect, then those people who own
19 the reserves that are still on production would have been
20 making money all this time, right?

21 A That's correct, yes, sir.

22 Q And those people that don't have pro-
23 ducing properties would have been long gone.

24 A Those properties would probably be owned
25 by someone else. You fail to own, you lose your leases.

Q The expenses of instituting this project
later in the life would be higher than it would be today.

A Yes, sir. Exxon certainly does not want

1
2 to impose a great delay in this. The only salvaging we can
3 see is if the Commission would take a strong action here.
4 We've given our best shot to it. We don't know how it --
5 how it stacks up in your mind or the mind of the other parties
6 involved, and -- and we recognize there is going to be
7 a delay but viewing it in one way the delay is not
8 intolerable. It could be less than -- it could be six
9 months.

10 Q Viewed in this light is it improper for
11 those people with substantial remaining primary reserves to
12 have a bigger piece of the pie in the secondary recovery
13 project right away?

14 A Well, I view the contribution of a tract
15 to be what it should get in the way of reserves.

16 Now to satisfy the two things of time
17 rated money and reserves, you've got to go to a split phase
18 formula. This was not proposed.

19 If we were actually -- had the opportunity
20 to put our own formula in, we probably would go with
21 a split phase formula because it better protects both kinds
22 of equity. One is reserve equity and the other is money
23 equity, and time rate so that the early on production would
24 be given at the higher percentage to those tracts now contributing
25 and, of course, later on they would suffer by that. That would protect the reserve barrels and still provide some protection for those parties that are contributing a high rate of production at the present time.

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2 Q I presume Exxon had the opportunity to do
3 that.

4 A Again, had we to do it over, we probably
5 would try to -- to develop a two phase formula that would
6 have had more appeal to Gulf and the other parties, not
7 Gulf, but the other parties, the five parties involved, and
8 we did not do that.

9 Q I've heard a lot of talk here about con-
10 tributing fractions of wells. I'm not certain exactly how
11 that would be done. Now I realize that if you prorate wells
12 by the same percentages that you prorate the production you
13 can have portions of wells. Is that what we're talking
14 about?

15 A Well, on the contributing side of the --
16 in the demand well thing there are fractions of wells be-
17 cause some of the parties own fractions of a lease. They
18 own 75 percent of the wells right now, and the other side,
19 when we apply the participation formula to the total number
20 of wells, yes, we wind up with fractions of wells and that's
21 what they -- this is exactly what happens with tank bat-
22 teries or pumping units.

23 Q But let me go ahead, then. You do have
24 to have a situation where you have one whole wellbore con-
25 tributed before anybody can claim a half of it, is that cor-
rect?

A Yes, that is true.

Q On primary production, in order for you

1
2 to share in the production of the field, don't you have to
3 drill and complete a well?

4 A Well, you and other parties, of course,
5 could contribute, could drill the well and you'd own a frac-
6 tion.

7 Q Someone has to --

8 A Yeah, someone has to drill a well. Yes.

9 Q All right. Why should that be any dif-
10 ferent for secondary recovery?

11 A Well, I guess I miss the point as to why.
12 We're talking about 344 whole total wells. We're talking
13 about then sharing that 344 wells in various fractions.
14 This can occur by fractional ownership of a lease.

15 Q But the point I'm trying to get at is why
16 if somebody has 160-acre tract in this unit, why should they
17 not be required to contribute four wellbores?

18 A We say they should.

19 Q Okay.

20 A And under the formula that we proposed
21 unless they did that they would lose the value of \$100,000.

22 We say they should contribute every
23 tract.

24 Now some of them are going to get plus
25 and some of them are going to get minus.

26 Q Let's say that you've got this same 160
27 out there.

28 A Uh-huh.

1
2 Q If you contribute two wellbores and you
3 pay in \$200,000, is that correct?

4 A That's right. Anybody with four, 160 you
5 have four, okay. Uh-huh, be paying \$400,000.

6 Q You've given two wellbores.

7 A Oh, all right.

8 Q And you pay in \$200,000.

9 A Well, let me go back and ask you, sir,
10 you're talking about 160-acre tract.

11 Q Yes.

12 A And normally this well would have -- this
13 tract would have four wells on it.

14 Q Right.

15 A Now you're going to contribute two and
16 two you're going to hold back.

17 Q Right.

18 A Okay. Now I have the scenario. What was
19 the question?

20 Q Under that circumstance you will contri-
21 bute two wellbores and pay \$200,000.

22 A Well, you would contribute two hundred --
23 two wells and you would under Exxon's scenario, under Ex-
24 xon's formula --

25 Q Well, I'm talking about under the --

A Under Gulf's, okay. Yes, you would con-
tribute two wells and you would pay \$200,000, that's cor-
rect.

1
2 Q And then Gulf as unit operator would
3 drill two other wells.

4 A Yes.

5 Q And those wells would be expected to cost
6 \$250,000.

7 A That's correct.

8 Q Okay, and those persons owning the lion's
9 share of the unit would be paying the lion's share of the
10 cost of drilling those wells.

11 A Yes, and receiving the lion's share of
12 the oil.

13 Q I have difficulty seeing what the oil has
14 to do with the wellbores. It's --

15 A Participation.

16 Q I'm trying to understand why you should
17 participate at all if you don't have any wells in there. If
18 you have not developed your tract why should you partici-
19 pate?

20 A Well, if you had your wells plugged out,
21 say, you plugged your wells out, why should you -- why
22 should you participate, why should you get some participa-
23 tion in the unit? Is that the question? I mean that's
24 along the same --

25 Q The question basically is if there are no
wellbores on that tract why should you participate?

A Well, someone is going to go back in
there and recover secondary oil and if it wasn't economic to

1
2 drill the wells and do it, they wouldn't go back in and
3 drill the wells, would they?

4 Now who should get that money? Should
5 the lease owner share in any of it or should it all go to
6 the fellows that drill the well?

7 Q I'm obviously not asking that question
8 properly.

9 A I guess I'm answering it in a politi-
10 cian's way. I'm trying not to.

11 MR. STAMETS: Are there any
12 other questions of this witness?

13 He may be excused.

14 Any closing statements? You
15 have none, Mr. Sperling?

16 I have a gentleman back in the
17 back.

18 MR. LOWDER: I'm here repre-
19 senting ARCO Oil and Gas Company.

20 We're in support of Gulf Oil
21 Corporation's application and I'd like to submit this letter
22 to that effect.

23 I'd also like to say that ARCO
24 Oil and Gas is planning -- we currently own an interest in
25 16 wells that are in the proposed unit area that are pro-
ducing from the Eumont, or upper gas zone, and we plan or we
are encouraging all our co-owners in these wells to go ahead
and contribute these wells to the unit in order to help out

1
2 the unit operations.

3 That's about it.

4 MR. HUSSER: My name is Tom
5 Husser. I'm with Cities Service Oil and Gas Company in Mid-
6 land, Texas, and I haven't written any prepared statement.
7 Most everything has been hashed over several times, but I'd
8 just like to say that Cities Service supports Exxon's posi-
9 tion concerning the participation formula and also the pro-
posal for assessing wellbore penalty.

10 The exhibits presented by Exxon
11 have showed that Cities Service will be adversely affected
12 by the participation formula and also adversely affected by
13 the penalties for wellbores.

14 I see no point in rehashing the
15 numbers, but I would hope that the participation formula and
16 the penalties were equitable.

17 MR. KELLANIN: I have a state-
18 ment, Mr. Chairman.

19 For some five and a half years
20 the working interest owners in this project have been trying
21 to put together a secondary waterflood project in this area.

22 I think Mr. Berlin told us very
23 eloquently yesterday afternoon that if the agreement as we
24 see it now is not adopted and approved it would be a con-
siderable period of time before it would get back to the
Commission.

25 The problem as outlined by Mr.

1
2 Nolan is not as simple to resolve as he would lead you to
3 believe. We're dealing with 101 tracts, some 41 different
4 working interest owners, and have met for a considerable
5 period of time to resolve this problem.

6 They have gone through every
7 means available to them to accommodate and to arrange the
8 minimum number of percentage working interest owners that
9 are in a position to object to the unit. You'll note from
10 the discussion in testimony that the last Working Interest
Owners meeting was August of '83.

11 I asked Mr. Nolan about his ar-
12 guments, his ideas, his suggestions. He says, yeah, they
13 were at the Working Interest Owners meeting in '83. He says
14 if he had to do it again they might have sent smarter fel-
15 lows, done a harder job trying to persuade others, whatever
16 it was.

17 But the point of the fact is
18 that these agreements did not go out for signature until the
19 spring of this year. That was some six months in which Ex-
20 xon made no effort to persuade others to consolidate a posi-
21 tion around Exxon, with the exception of Cities Service,
which participated in all those meetings and votes.

22 Mr. Nolan throws out to us the
23 fact that, well, maybe a phase in participation works and if
24 they'd have thought about it, they'd have done it. They did
25 it. They tried it. It's in here, August '83 there's two
different ballots on phase participation formulas, neither

1
2 one of which got the necessary required vote to make this
3 thing work.

4 Mr. Nolan gratuitously gives us examples
5 of tracts that are somehow unfairly dealt with in the unit
6 process. There's not one of those tracts that is still sub-
7 ject to the statutory unitization process. Amoco's agreed,
8 the Hudson Family has been purchased out, and the Getty in-
9 terest, which is important and I hope you followed the Getty
10 interest throughout the case, the Getty position is very
11 similar to the Exxon position and yet nobody twisted Getty's
12 arm to sign these things, but in each instance they've
13 agreed to participate using the formulas agreed upon by some
93 percent of the working interest owners.

14 I give Mr. Nolan a great deal of credit.
15 I think that discussion this morning was very interesting
16 concerning the comparison on the participation formulas.
17 What he did was extremely interesting. On Exhibit Number
18 Two he's taken some reserve numbers, a 76,000,000 barrels
19 reserve number. A portion of that represents secondary re-
20 serves, and he's attempted to allocate that on a tract by
21 tract basis, and then he makes a comparison between the re-
22 lative merits of each formula having put those reserves on a
tract by tract basis.

23 What he wants you not to remember is that
24 the premise upon which he draws the comparison is absolutely
25 without foundation.

The Technical Report in which he has un-

1
2 animous agreement and no one complained says secondary re-
3 serves, the estimate of secondary reserves cannot be accu-
4 rately made because of a lack of pore volume reservoir data.
5 He's doing what the Technical Committee cannot do in making
6 the comparison.

7 When we look at the parameters
8 used there has been no disagreement to those parameters.
9 They have been in place since October 1st, 1982, and for two
10 years they've been working on those parameters to get a
11 formula and everybody will agree to it. The Commissioner of
12 Public Lands has agreed to this prospect. Why? Why not?
13 12-1/2 percent royalty on \$1.2-billion revenues is a hunk of
14 change for the State of New Mexico. You're looking at
15 \$140,000,000 of royalty revenues to the State of New Mexico
16 that in order to accommodate Exxon and their 4.86 percent,
17 that we're going to postpone?

18 Mr. Berlin says you'll postpone
19 it forever because with their good faith ability and effort
20 they do not think they would ever get back in this position
21 again.

22 I think it's also important to
23 notice that in the tabulation of information that Exxon's
24 provided that they put in a disadvantaged situation in some
25 of their computations about 18 percent of the working
 interest owners. How many of those people have they
 persuaded in the last 14 months to agree to their position?
 I'm not aware of any other than Cities Service. It might

1
2 make some meaningful effort for the Commission to require
3 the unit operator and the working interest owners to go back
4 and further negotiate this if there was any reasonable like-
5 lihood or probability that it would result in some kind of
6 agreement that was equitable.

7 We say, and Mr. Berlin has said
8 that it will not happen. I've asked Mr. Nolan to tell me
9 which ones of these operators in his list of five that would
10 have a sufficient working interest percentage to vote to
11 change the outcome to have a minimum 75 percent required for
12 statutory unitization and he can't tell me that any of them
13 will.

14 I think it's a useless exercise
15 to send us back to try to negotiate this. I think there is
16 substantial evidence on the record to support the 50 percent
17 numbers we have used. Mr. Berlin and Mr. Wheeler have given
18 you examples of why those are equitable and they balanced
19 them against certain situations in which the Exxon formula
20 is not equitable. You've got to decide if it's basically
21 fair.

22 The guy that could complain
23 about this is the one that's not here, the Getty fellow with
24 one of those tracts that doesn't really work for him. He's
25 agreed. He's in the unit.

26 We will not get to this posi-
27 tion again in the foreseeable future. The question is
28 whether or not the allocation that Mr. Nolan has made is

1
2 better than ours. I can't see any appreciable differences
3 in judging that 4.8 percent or 5.8 percent of the working
4 interest owners have provided you with a formula that is
5 better and more equitable than the one that we have.

6 It's there, it's in place,
7 we're ready to go. The chance is now. We ought to take it
8 and approve it.

9 MR. STAMETS: Did you change
10 your mind?

11 MR. SPERLING: Yes. I think
12 the fallacy of Mr. Kellahin's argument is that he equates an
13 80 percent vote with fair and equitable. That does not ne-
14 cessarily follow.

15 I believe that as Mr. Nolan
16 stated, it would be difficult to renegotiate this thing, but
17 the statute gives the Commission a mandate to examine these
18 things in a manner which is fair and equitable to all the
19 parties, not the 80 percent.

20 That's the basis for (not
21 clearly understood.)

22 MR. STAMETS: Mr. Padilla?

23 MR. PADILLA: I'm obviously re-
24 presenting small interest owners in this case and I'm swept
25 between two giants in this case. Nonetheless, looking at
the definitions of relative value in the statutory -- Statu-
tory Unitization Act, Section 6 of 86 of 70-7-6 and Section
C on allocation under official orders, 70-7-7, also on the

1
2 language of the definition for the landmark case of Con-
3 tinental Oil Company versus the Oil Conservation Commission,
4 I believe that the Exxon approach comes closest to giving
5 the definition of what relative values are and allocation on
6 a tract basis.

7 You well know the mandate given by the
8 New Mexico Supreme Court in that case, that in protecting
9 correlative rights the Commission must ascertain as
10 practicably as can be done the reserves underlying
11 individual tracts and view the case against this.

12 MR. STAMETS: I believe we have
13 a statement in support by Continental Oil Company which they
14 ask be made part of the record, and then Shell's, also.

15 Is there anything further in
16 the cases we have before us?

17 They will be taken under
18 advisement and the hearing is adjourned.

19 (Hearing concluded.)

20 REPORTER'S NOTE: Statements from ARCO Oil and Gas Company,
21 Conoco, and Shell Western E & P, Inc. are attached to the
22 original of this transcript furnished to the Commission.
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24
25

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Commission was reported by me; that the said transcript is a full, true, and correct record of the hearing, contained in two volumes numbered Volume I of II Volumes and Volume II of II Volumes, prepared by me to the best of my ability.

Sally W. Boyd CSR